REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR THE STATE OF ARIZONA

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Air Quality Division
Arizona Department of Environmental Quality

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APPENDIX A-1. BACKGROUND

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Appendix A-1a. Definitions

Applicable definitions from 40 CFR 51.301:

BART-eligible source means an existing stationary facility as defined in this section.

Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant, which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Deciview means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index = 10 $1n_e$ (b_{ext}/10 Mm^{-1}).
Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

Existing stationary facility means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,
Coal cleaning plants (thermal dryers),
Kraft pulp mills,
Portland cement plants,
Primary zinc smelters,
Iron and steel mill plants,
Primary aluminum ore reduction plants,
Primary copper smelters,
Municipal incinerators capable of charging more than 250 tons of refuse per day,
Hydrofluoric, sulfuric, and nitric acid plants,
Petroleum refineries,
Lime plants,
Phosphate rock processing plants,
Coke oven batteries,

Sulfur recovery plants,
Carbon black plants (furnace process),
Primary lead smelters,
Fuel conversion plants,
Sintering plants,
Secondary metal production facilities,
Chemical process plants,
Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
Taconite ore processing facilities,
Glass fiber processing plants, and
Charcoal production facilities.

Federal Class I area means any Federal land that is classified or reclassified Class I.

Federal Land Manager means the Secretary of the department with authority over the Federal Class I area (or the Secretary's designee) or, with respect to Roosevelt-Campobello International Park, the Chairman of the Roosevelt-Campobello International Park Commission.

Federally enforceable means all limitations and conditions which are enforceable by the Administrator under the Clean Air Act including those requirements developed pursuant to parts 60 and 61 of this title, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to Sec. 52.21 of this chapter or under regulations approved pursuant to part 51, 52, or 60 of this title.

Implementation plan means, for the purposes of this part, any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.

Indian tribe or tribe means any Indian tribe, band, nation, or other organized group or community, including any Alaska Native village, which is federally recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians.

In existence means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

Major stationary source and major modification mean major stationary source and major modification, respectively, as defined in Sec. 51.166.

Mandatory Class I Federal Area means any area identified in part 81, subpart D of this title.

Most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment.

Natural conditions includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

Reasonably attributable means attributable by visual observation or any other technique the State deems appropriate.

Reasonably attributable visibility impairment means visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources.

Regional haze means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

State means ``State" as defined in section 302(d) of the CAA.

Stationary Source means any building, structure, facility, or installation, which emits or may emit any air pollutant.

Visibility impairment means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.

Applicable Definitions from 40 CFR 51.309:

16 Class I areas means the following mandatory Class I Federal areas on the Colorado Plateau: Grand Canyon National Park, Sycamore Canyon Wilderness, Petrified Forest National Park, Mount Baldy Wilderness, San Pedro Parks Wilderness, Mesa Verde National Park, Weminuche Wilderness, Black Canyon of the Gunnison Wilderness, West Elk Wilderness, Maroon Bells Wilderness, Flat Tops Wilderness, Arches National Park, Canyonlands National Park, Capital Reef National Park, Bryce Canyon National Park, and Zion National Park.

Transport Region State means one of the States that is included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming).

Commission Report means the report of the Grand Canyon Visibility Transport Commission entitled *Recommendations for Improving Western Vistas*, dated June 10, 1996.

Fire means wildfire, wildland fire (including prescribed natural fire), prescribed fire, and agricultural burning conducted and occurring on Federal, State, and private wildlands and farmlands.

Milestone means the maximum level of annual regional sulfur dioxide emissions for a given year, assessed annually consistent with paragraph (h)(2) of this section beginning in the year 2003.

Mobile Source Emission Budget means the lowest level of VOC, NOx, SO_2, elemental and organic carbon, and fine particles which are projected to occur in any area within the transport region from which mobile source emissions are determined to contribute significantly to visibility impairment in any of the 16 Class I areas.

Geographic enhancement means a method, procedure, or process to allow a broad regional strategy, such as a milestone or backstop market trading program designed to achieve greater reasonable progress than BART for regional haze, to accommodate BART for reasonably attributable impairment.

BHP San Manuel means: (i) The copper smelter located in San Manuel, Arizona which operated during 1990, but whose operations were suspended during the year 2000, (ii) The same smelter in the event of a change of name or ownership.

Phelps Dodge Hidalgo means: (i) The copper smelter located in Hidalgo, New Mexico which operated during 1990, but whose operations were suspended during the year 2000, (ii) The same smelter in the event of a change of name or ownership.

Definitions for the Fire Programs

Land Manager means any federal, state, local, or private entity that owns, administers, directs, oversees or controls the use of public or private land, including the application of fire to the land.

Prescribed fire or ***prescribed burn*** means any fire ignited by management actions to meet specific objectives, such as achieving resource benefits.

Wildland Fire Used for Resource Benefits means naturally ignited wildland fire that is managed to accomplish specific prestated resource management objectives in predefined geographic areas.

Definitions for the Western Emission Backstop Trading Program Applicable to Sections 7 and 8 of Implementation Plan

EPA Administrator means the Administrator of the United States Environmental Protection Agency or the Administrator's duly authorized representative.

Floor allocation means the amount of allowances set by the Director in accordance with this Plan that represents the minimum necessary for a source to operate under stringent control assumptions.

Reducible allocation means the amount of allowances set by the Director in accordance with this Plan that represents, for each source, emissions in excess of the floor allocation that shall be reduced over time as the regional milestone is decreased.

Tribal Set-Aside means a 20,000-ton SO_2 WEB allowance allocated to tribes on an annual basis. The tribes will decide how to distribute the allowances in the set-aside among tribes in the region. The set-side is intended to ensure equitable treatment for tribal economies and to prevent barriers to economic development.

Trigger refers to the activation of the WEB Trading Program for SO_2 in accordance with this Plan.

WEB Trading Program refers to the Western Backstop (WEB) Trading Program Rule that shall be triggered as a backstop in accordance the provisions of this Plan to ensure that regional SO_2 emissions are reduced.

Western Regional Air Partnership (WRAP) means the collaborative effort of tribal governments, state governments, and federal agencies to promote and monitor implementation of recommendations from the Grand Canyon Visibility Transport Commission authorized under Section 169B(f) of the Clean Air Act, and to address other common Western regional air quality issues.

Appendix A-1b. Arizona Department of Environmental Quality – Air Quality Division Organization Charts

Arizona Department of Environmental Quality
Air Quality Division

AQD Director's Office
21100

0005 B-1
Nancy Wrona 230[illegible]
AQD Director Gr [illegible]4
A/AP

1223 B-2
Ira Domsky 2365
AQD Deputy Director Gr [illegible]3
F/A/AP

0458
Laura McFarland 2379
Admin Sec III Gr 14
A/AP

Vehicle Emissions Section
23110

0576
John Walls (SD) 7017
Env Prog Mgr Gr 23
V

Air Assessment Section
24100

0463 B-7
Vacant
Ev Env Prog Mgr Gr 23
A/F

Planning Section
25100

0886 B-7
Theresa Pella 2375
Ev Env Prog Mgr Gr 2[illegible]
A/AP

Permits Section
26100

0313 B-7
Eric Massey 2288
Ev Env Prog Mgr Gr 23
AP

Compliance Section
27100

0937 E
Cathy O'Connell 2328
Ev Env Prog Mgr Gr 23
AP

Arizona Department of Environmental Quality
Air Quality Division

Compliance Section
27100

0937 B-7
Cathy O'Connell **2328**
Ev Env Prog Mgr Gr 23
AP

Section Support

0885
Mary Canez **4332**
Admin Asst I Gr 13
AP

0622
Rosita Slider **2301**
Admin Sec II Gr 13
AP

0914
Vacant
Env Prog Spec Gr 20
AP/F

0910
Sandra Olding **4330**
Admin Sec I Gr 12
AP

Inspections & Field Services Unit
27210

0610 B-7
Lynn Ogata **2286**
Ev Env Prog Spvr Gr 22
F/AP

CRO Inspection Team
27220

0660
Lucinda Chavez **4553**
Env Prog Spec Gr 20
F

0615
Steve Rose **2280**
Env Eng Spec Gr 21
AP

0919
Fred Ellis **4851**
Env Eng Spec Gr 21
AP

1071
Emily Bonanni **2324**
Env Eng Spec Gr 21
AP

0933
Vacant
Env Eng Assoc Gr 18
AP

1166
Tracy Neal **2333**
Env Prog Spec Gr 20
F

0389
Frank Keene **4493**
Env Eng Spec Gr 21
AP

0915
Martin Landis **4537**
Env Eng Spec Gr 21
AP

0913
Galileo Gutierrez **4495**
Env Eng Spec Gr 21
AP

Performance/Test CEM Team
27250

0392
Wayne Hunt **2327**
Env Eng Spec Gr 21
AP

0924
Raza Abbas **4485**
EHS II Gr 19
AP

0922
Lynn Ott **4494**
EHS II Gr 19
AP

Technical Services Unit
27310

0932 B-7
Vacant
Ev Env Prog Spvr Gr 22
F/AP

Technical Review Team
27320

0613
Joanie Wadas **4489**
Env Eng Spec Gr 21
AP

0912
Karla Copeland **2282**
Env Eng Spec Gr 21
AP

1072
Leonard Ishihara **2343**
Env Eng Spec Gr 21
AP

1073
Weiwen Daly **2281**
Env Eng Spec Gr 21
AP

1074
Tarun Sinha **4488**
Env Eng Spec Gr 21
AP

1141
Richard Baker **2325**
Env Eng Spec Gr 21
AP

Information Management Team
27330

0379
Latha Toopal **2273**
Env Eng Spec Gr 21
AP

0923
Carol Tuttle **2344**
Info Tech Spec III Gr C3
AP

1070
Darlene Celaya **7662**
EHS II Gr 19
AP

JULY 2003

Arizona Department of Environmental Quality
Air Quality Division

Permits Section
26100

0313 B-7
Eric Massey **2288**
Ev Env Prog Mgr Gr 25
AP

Section Support

0935
Barbara Dennie **2320**
Admin Asst I Gr 13
AP

0936
Shirley Gaertner **2287**
R & SA II Gr 17
AP

New Source Unit
26510

0611 B-7
Barbara Sprungl **2283**
Ev Env Prog Spvr Gr 22
AP

0620
Sylvia Nelson **2338**
Admin Sec I Gr 12
AP

New Source Review Team
26520

0619
Paul Babonis **2334**
Env Eng Spec Gr 21
AP

0616
Trevor Baggiore **2321**
Env Eng Spec Gr 21
AP

0927
Francis Udoh **2336**
Env Eng Spec Gr 21
AP

1063
Shudeish Mahadev **2323**
Env Eng Spec Gr 21
AP

0743
Naveen Savarirayan **2285**
Env Eng Spec Gr 21
AP

0897
Smita Nagubandi **4338**
Env Eng Spec Gr 21
AP

0896
Mark Hajduk **2317**
Env Eng Spec Gr 21
AP

Existing Source & General Permit Unit
26610

0928 B-7
Balaji Vaidyanathan **4527**
Ev Env Prog Spvr Gr 22
AP

0621
Priscilla Begay **2337**
Admin Sec I Gr 12
AP

Existing Source & General Permit Team
26620

0898
Sunil Varma **2322**
Env Eng Spec Gr 21
AP

0617
Pavinder Tandon **2358**
Env Eng Spec Gr 21
AP

0281
Vacant
Env Eng Spec Gr 21
AP

0894
Heath Wanamaker **2284**
Env Eng Spec Gr 21
AP

1064
Vacant
Env Eng Spec Gr 21
AP

0899
Imran Bajwa **4492**
Env Eng Spec Gr 21
AP

0618
Zigang Fang **4490**
Env Eng Spec Gr 21
AP

0614
David Sitterud II **4310**
Env Eng Spec Gr 21
AP

1065
Rana Kazemnia **2332**
Env Eng Spec Gr 21
AP

JULY 2003

Arizona Department of Environmental Quality
Air Quality Division

Planning Section
25100

0886 B-7
Theresa Pella **2375**
Ev Env Prog Mgr Gr 23
A/AP

0672
Mollie Lemoine **2373**
Admin Sec II Gr 13
A/AP/F

1363
Mohan Toopal **2335**
Exec Consultant II Gr 22
A

0684
David Lillie **4461**
Economist III Gr 22
A

SIP & Program Development Unit
25210

0890 B-7
Mark Lewandowski **2230**
Ev Env Prog Spvr Gr 22
F

SIP Team
25220

0705
Deborrah Martinkovic **2372**
Env Prog Spec Gr 20
A

0676
Catherine Jordan **2371**
Planner II Gr 19
A

0674
Andra Juniel **4417**
Planner II Gr 19
F

0891
Vacant
EHS II Gr 19
F

Rules Team
25230

0889
Dena Konopka **2378**
Env Prog Spec Gr 20
F/AP

0892
Vacant
EHS II Gr 19
AP/A

1302 B-5
Bruce Friedl **2259**
Ev Env Prog Spec Gr 20
F

1179 B-7
Kevin Force **4480**
Ev Env Rules Spec Gr 21
A

Fund & Project Management Unit
25300

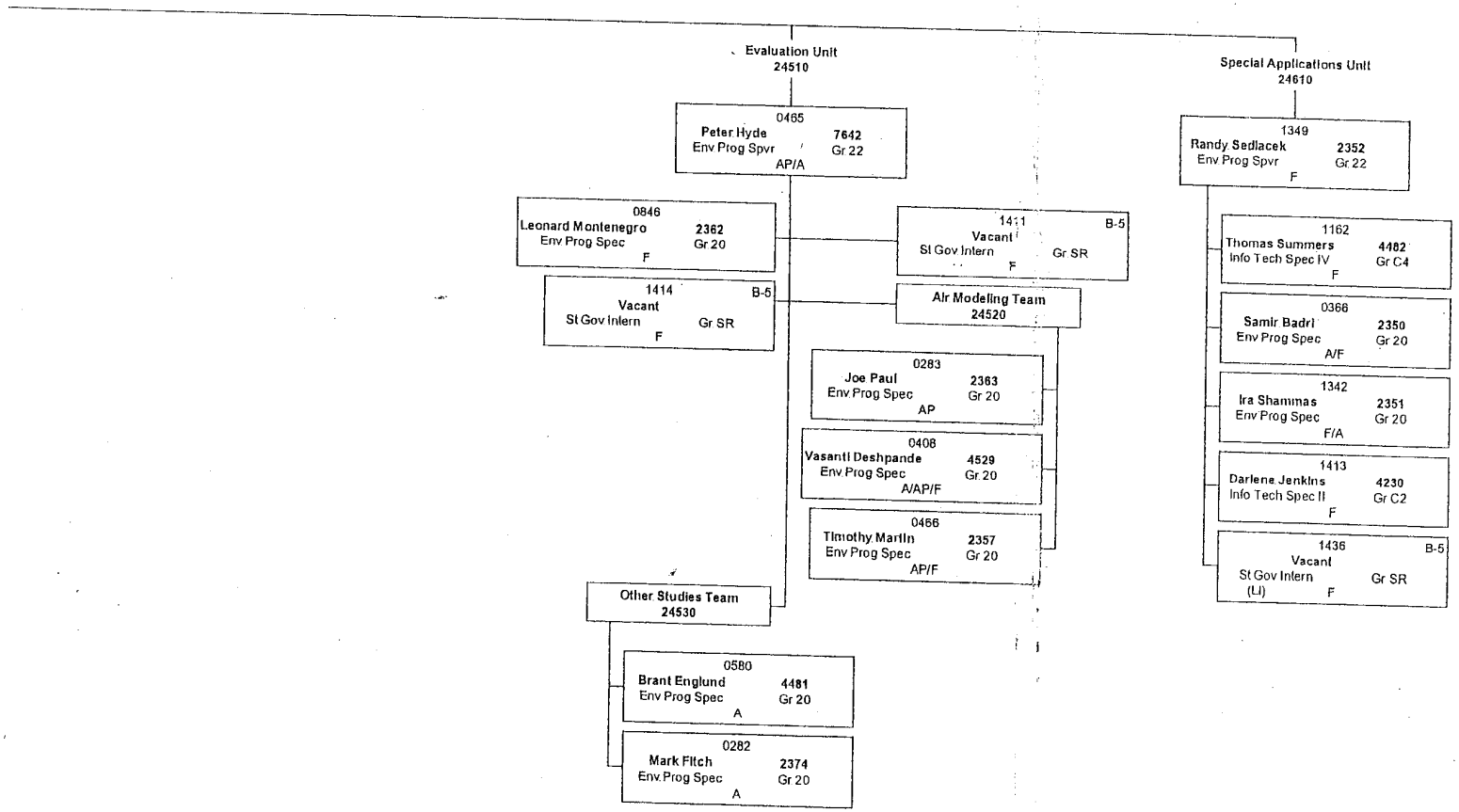
0853
David Biddle **2376**
Env Prog Spec Gr 20
A

1169
Sondra Francis **2370**
P & PS II Gr 19
F/A

0887 B-2
Sherri Zendri **4775**
Ev P & PS II Gr 19
(PT) A

JULY 2003

Arizona Department of Environmental Quality
Air Quality Division
Air Assessment Section (continued)



Arizona Department of Environmental Quality
Air Quality Division

Air Assessment Section
24100

- 0463 B-7 — Vacant, Ev Env Prog Mgr, Gr 23, F/A/AP
- 0471 — Roberta Besenczky, Admin Sec II, 2347, Gr 13, A

Section Support
- 1069 — Tina Summers, Admin Asst II, 2275, Gr 15, A/F

Monitoring Unit 24230
- 0464 B-7 — Darcy Anderson, Ev Env Prog Spvr, 7665, Gr 22, F/A/AP
- 1048 — Vacant, Admin Sec I, Gr 12, F

Instrumentation Team 24210
- 0884 — Randy Redman, Env Eng Spec, 2278, Gr 21, A/AP
- 0601 — Harold Monteith, EHS II, 2298, Gr 19, AP
- 0602 — Ralph Lucero, EHS II, 2390, Gr 19, AP/F
- 0604 — Vacant, EHS II, Gr 19, F/A/AP
- 0605 — Vacant, EHS I, Gr 17, F/A/AP
- 1219 — Warren Mason, EHS I, 2394, Gr 17, F

Air Monitoring Lab Team 24220
- 1291 — Phil DeNee, Env Prog Spec, 2355, Gr 20, F
  - 0470 — Delfina Olivarez, EHS II, 2222, Gr 19, A/AP
  - 1431 B-5 — Lamont Harvey (PT), St Gov Intern, 2354, Gr SR, F
  - 1415 B-5 — Kanika Simmons (PT), St Gov Intern, 2354, Gr SR, F

QA/QC Team 24240
- 0849 — Fred Strasser, Env Eng Spec, 2395, Gr 21, A/F
- 0744 — Dan Catlin, Env Eng Spec, 2289, Gr 21, F/A

Special Projects Unit 24410
- 0901 — Theresa Rigney, Env Prog Spvr, 2349, Gr 22, A
- 1343 — Christopher Reith, Env Prog Spec, 2360, Gr 20, F/AP
- **HAP Research** 24420
  - 0856 — Marnie Greenble, Env Prog Spec, 2201, Gr 20, A/AP
- **Visibility Research** 24430
  - 0407 — Vacant, Env Prog Spec, Gr 20, F
  - 0845 — Michael Sundblom, Env Prog Spec, 2364, Gr 20, A
  - 0868 — Terry Taflinger, EHS II, 2392, Gr 19, A
- **Data Management Team** 24440
  - 1290 — Sandra Wardwell, Env Prog Spec Team Ldr, 4383, Gr 20, F
  - 0603 — Vacant, EHS II, Gr 19, A/F/AP
  - 1067 — Judith Needham, R & SA II, 7676, Gr 17, A
  - 1292 — Andy Clifton, EHS II, 4382, Gr 19, F
  - 1409 B-5 — Vacant, St Gov Intern (PT), Gr SR, F
  - 1273 B-5 — Vacant, St Gov Intern (PT), Gr SR, F
- **Level II QA** 24480
  - 0467 — Vacant, Info Tech Spec III, Gr C3, F/AP/A

Arizona Department of Environmental Quality
Air Quality Division

Vehicle Emission Section
23110

0576 John Walls (SD) 7017 Gr 23 Env Prog Mgr V

VEI Business Team 23120

0573 Cecilia Hartley 7001 Gr 15 Admin Asst II V

0598 Nicole Dockery 7028 Gr 10 Rev Ctl Info Tech V

VEI Admin Team 23130

0593 Dennis Betz 7004 Gr 13 Admin Sec II V

0594 Marcus Brown 7010 Gr 11 Clk Typist III V

Phoenix Operations Unit 23260

0577 Thomas Cisco 7013 Gr 22 Env Prog Spvr V

23210

0571 Tony Godoy 7005 Gr 19 EHS II V

0590 Michael Reuter 7000 Gr 16 EIT II V

0575 Mike Mutters 7000 Gr 16 EIT II V

0964 Vacant Gr 16 EIT II V

0606 Michael Ybarra 7000 Gr 16 EIT II V

0963 Louis Grisham 7000 Gr 16 EIT II V

23220

0169 Rex Martin 7023 Gr 19 EHS II V

0957 Vacant Gr 16 EIT II V

23240

0959 Jim Gass 7005 Gr 19 EHS II V

0962 Hamid Eltezam 7000 Gr 16 EIT II V

0961 Donald Crane 7000 Gr 16 EIT II V

Tucson Operations Unit (SRO) 23310

0578 Florentino Angulano (520) 628-6036 Gr 22 Env Prog Spvr V (SRO)

0164 Sandra Malings (520) 628-5651 Gr 13 Admin Asst I V (SRO)

0599 Connie Huebner (520) 628-5651 Gr 11 Clk Typist III V (SRO)

23320

0607 Tom Swigart (520) 628-5651 Gr 19 EHS II V (SRO)

0586 Mark Pilgrim (520) 628-5651 Gr 16 EIT II V (SRO)

0986 Vacant Gr 16 EIT II V (SRO)

0588 Russell Ledbetter (520) 628-5651 Gr 16 EIT II V (SRO)

0591 Vacant Gr 16 EIT II V (SRO)

Inspections & Compliance Unit 23410

0579 (A) John Gibbons 7015 Gr 22 Env Prog Spvr V

0579 (B) Don Bauer (PT) 7012 Gr 20 Env Prog Spec V

0595 Lisca Sanchez 7007 Gr 11 Clk Typist III V

1095 Vacant Gr 11 Clk Typist III V

1097 Alex Studham 7008 Gr 18 P & PS I V

0980 Richard Day 7018 Gr 18 P & PS I V

23420

0589 Adrion Osborne 7011 Gr 19 EHS II V

0587 Dave Skowronek 7038 Gr 16 EIT II V

0592 Angelina Tautimer 7040 Gr 16 EIT II V

0584 Tonna Smith 7041 Gr 16 EIT II V

0185 Tom McDaniel 7009 Gr 16 EIT II V

Emissions Research Lab. Unit 23500

0461 Frank Cox 7024 Gr 22 Env Prog Spvr V

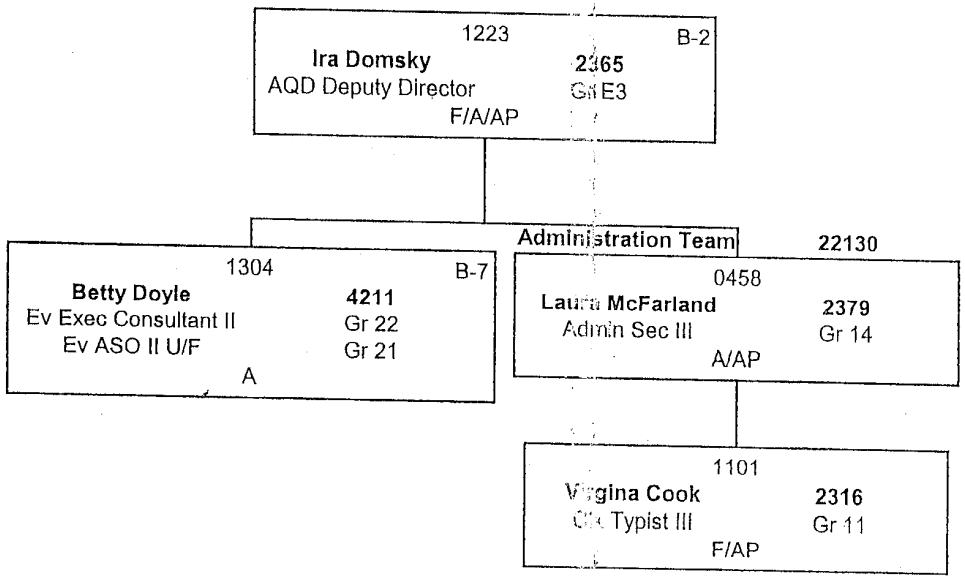
Remote Sensing Unit 23600

0173 Vacant Gr 22 Env Prog Spvr V

1006 Alicia Miner 7039 Gr 9 Clk Typist II V

1005 Hsiu-Feng Ling 7033 Gr 17 R & SA II V

AQD Deputy Director
22110



APPENDIX A-2. DESCRIPTIONS OF ARIZONA

This appendix contains work products and references relied upon by Arizona in the development of Chapter 2 of the Regional Haze SIP.

Appendix A-2a. Bibliography for Chapter 2

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Web sites:

http://www.nps.gov/grca

http://www.fs.fed.us/r3/kai/recreation/wild_syc

http://www.wilderness.net/nwps/wilderness.cfm/Sycamore%20Canyon

http://www.americansouthwest.net/arizona/sycamore_canyon

http://www.cr.nps.gov/worldheritage/grcan

Appendix A-2a. Bibliography for Chapter 2 (Continued)

http://www.petrifiedforest.areaparks.com/parkinformation

http://www.wmonline.com/attract/pforest/pforest

http://www.geo.arizona.edu/geos256/azgeology/pwood/parkintro

http://cpluhna.nau.edu/Places/white_mountains

http://www.flyfishingworld.com/features/mwwhiteriver

http://geography.asu.edu/azclimate/narrative

APPENDIX A-5. ATTRIBUTABLE IMPAIRMENT

This appendix contains work products and references relied upon by Arizona in the development of Chapter 5 of the Regional Haze SIP.

Appendix A-5a. Arizona's RAVI rule

NOTICES OF FINAL RULEMAKING

The Administrative Procedure Act requires the publication of the final rules of the state's agencies. Final rules are those which have appeared in the *Register* first as proposed rules and have been through the formal rulemaking process including approval by the Governor's Regulatory Review Council or the Attorney General. The Secretary of State shall publish the notice along with the Preamble and the full text in the next available issue of the *Register* after the final rules have been submitted for filing and publication.

NOTICE OF FINAL RULEMAKING

TITLE 18. ENVIRONMENTAL QUALITY

CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR POLLUTION CONTROL

PREAMBLE

1. Sections Affected — **Rulemaking Action**

R18-2-101	Amend
Article 16	New Article
R18-2-1601	New Section
R18-2-1602	New Section
R18-2-1603	New Section
R18-2-1604	New Section
R18-2-1605	New Section
R18-2-1606	New Section

2. The statutory authority for the rulemaking, including both the authorizing statute (general) and the statutes the rules are implementing (specific):

Authorizing statutes: A.R.S. §§ 49-104(A)(11) and 49-425

Implementing statutes: A.R.S. §§ 49-414 and 49-414.01

3. The effective date of the rules:

December 2, 2003

4. A list of all previous notices appearing in the Register addressing the final rules:

Notice of Rulemaking Docket Opening: 9 A.A.R. 390, February 7, 2003

Notice of Proposed Rulemaking: 9 A.A.R. 763, March 7, 2003

5. The name and address of agency personnel with whom persons may communicate regarding the rulemaking:

Name: Deborrah "Corky" Martinkovic

Address: ADEQ, Air Quality Planning Section
1110 W. Washington
Phoenix, AZ 85007

Telephone: (602) 771-2372 (Any extension may be reached in-state by dialing 1-800-234-5677, and asking for a specific number.)

Fax: (602) 771-2366

E-mail: martinkovic.deborrah@ev.state.az.us

6. An explanation of the rules, including the agency's reasons for initiating the rules:

Summary. This rule sets forth the process Arizona Department of Environmental Quality (ADEQ) will use to determine whether Best Available Retrofit Technology (BART) will be required for sources determined to be contributing to visibility impairment in a mandatory Federal Class I area. Federal regulations allow Federal Land Managers (FLMs) to certify sources defined in 40 CFR 51.301 as potential contributors to visibility impairment in any of the Arizona mandatory Federal Class I areas under Section 169A of the Clean Air Act (CAA).

Background. In 1977 Congress added a new section to the Clean Air Act - Section 169A, Visibility Protection for Federal Class I Areas - which established a national goal for, "the prevention of any future, and the remedying of any existing impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution." In addition, the section required states to submit state implementation plans (SIPs) requiring best available retrofit technology (BART) for certain existing stationary sources found to cause or contribute to visibility impair-

ment. On November 30, 1979, EPA promulgated a list of mandatory Federal Class I Areas (Class I areas) where visibility is an important value (44 FR 69122). There are 12 Class I areas identified in Arizona: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness (40 CFR 81.403).

On December 2, 1980 (45 FR 80084), EPA defined the role of the FLMs in certifying visibility impairment in the mandatory Federal Class I areas. On November 24, 1987 (52 FR 45132), FLMs identified Petrified Forest National Park, Saguaro Wilderness, and Grand Canyon National Park, as having visibility impairment possibly attributable to stationary sources. Under the 1980 rule, if found to cause or contribute to the impairment, certain existing stationary sources operating in or near the identified Class I areas could be subject to BART (A list of sources eligible for the possible application of BART can be found at 40 CFR 51.301). On October 3, 1991, the Navajo Generating Station (NGS) was found by EPA to be causing or contributing to visibility impairment for the Grand Canyon National Park and eligible for BART (56 FR 50172). BART control analyses were subsequently performed by EPA, and other parties through related court actions. Under the 1980 rule, the federal expectation is that actions for determination of possible source attribution will be performed by the states. Therefore, Arizona needs to be prepared to proceed with an attribution analysis and assessment for the application of controls upon any determination of a BART eligible source being the possible cause or contributor to visibility impairment in a Class I area. This rule addresses that need.

Current Conditions. ADEQ has determined that this rule applies to any source in existing stationary source categories identified in 40 CFR 51.301 that are operating in or near the mandatory federal Class I areas in Arizona. The source is an existing stationary facility that includes any reconstructed source that was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year of any regulated pollutant. ADEQ estimates that there are potentially 10 such sources within Arizona. “In existence” is interpreted by EPA to be consistent with the term, “commence construction” found in Prevention of Serious Deterioration (PSD) regulations (40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21(b)(9)). If construction commenced after August 7, 1977, the source would be subject to the PSD/NSR (new source review) program (the state regulations are found at 18 A.C.C. 2, Article 4). However, EPA also notes “that sources, are not BART eligible if the only change at the plant was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not themselves trigger a BART review.”[1]

[[1]EPA proposed rule, 66 Federal Register 38119, July 20, 2001.]

Under this rule, ADEQ, when analyzing an attributable source for BART controls, must consider several factors including, for example, costs, remaining useful life of the source, and degree of improvement anticipated to result from the application of the controls (the factors are detailed in R18-2-1605). Sources required by ADEQ to install and operate BART controls have a final opportunity to request exemption from the requirement prior to the application of controls. This opportunity for a federal exemption from BART, is contained in R18-2-1606, and 40 CFR 51.303.

Summary. This rule outlines the process through which sources eligible for the application of BART will proceed if certified by the state of Arizona or an FLM as possibly causing or contributing to visibility impairment due to attribution. If found to be attributable for the impairment, a BART analysis will be performed to determine the level of controls necessary to remedy the impairment. This rule enables Arizona to fulfill the requirements of the Clean Air Act and the goal of section 169A of the Act to return the Nation’s federal parks and wilderness areas to natural conditions.

Section-by-Section Explanation for the Rules

R18-2-1601	This Section lists the definitions that apply to this rule.
R18-2-1602	This Section lists the Class I areas addressed by this rule for the applicable existing stationary facilities, as defined in R18-2-1601(2).
R18-2-1603	This Section establishes the procedure for certification of impairment by either a Federal Land Manager with authority over a mandatory Federal Class I area, or the Director, should either believe there exists reasonably attributable visibility impairment in a Federal Class I area as listed in R18-2-1602.
R18-2-1604	This Section establishes the procedure for an attribution analysis after certification of a source or group of sources as outlined in R18-2-1603. Upon completion of the attribution analysis, the procedure for the Director to issue draft and final attribution findings is outlined in R18-2-1604(C).
R18-2-1605	This Section establishes the best available retrofit technology (BART) analysis procedure after a source is identified under R18-2-1604. Upon completion of the BART analysis, the procedure for the Director to issue draft and final BART findings, including alternatives to emission standards, is outlined in R18-2-1605(B) and (C), respectively. The specific conditions where BART would be satisfied due to past or planned actions by the facility are outlined in R18-2-1605(D). EPA determinations regarding new technology that might require a BART analysis

for an applicable source, regardless of a source or small group of sources previously being certified and found attributable, are covered in R18-2-1605(E).

R18-2-1606 This Section establishes the procedures for obtaining a federal exemption from a BART requirement.

7. A reference to any study relevant to the rules that the agency reviewed and either relied on in its evaluation of or justification for the rules or did not rely on in its evaluation of or justification for the rules, where the public may obtain or review each study, all data underlying each study, and any analysis of each study and other supporting material:

None

8. A showing of good cause why the rules are necessary to promote a statewide interest if the rules will diminish a previous grant of authority of a political subdivision of this state:

Not applicable

9. The summary of the economic, small business, and consumer impact:

A. Rule Identification

These rules amend R18-2-101 ("visibility impairment" definition) and add new Sections R18-2-1601 through R18-2-1606. For sources under ADEQ jurisdiction, the rules take the place of federal regulations that currently govern this area.

B. Entities Directly Impacted

1. Federal Land Managers. R18-2-1603 allows Federal Land Managers (FLMs) to certify visibility impairment in mandatory Class I areas. This was already allowed by federal rule. Under R18-2-1601 of the rule, the FLMs able to certify impairment in Arizona are with the United States Forest Service and the National Park Service. There are no FLMs in Arizona from the United States Fish and Wildlife Service, because this agency does not have jurisdiction over any of Arizona's mandatory federal Class I areas.

2. ADEQ. R18-2-1604 requires ADEQ to identify stationary sources that could cause or contribute to the certified visibility impairment. Prior to this rule, this function was carried out by EPA. R18-2-1605 would require ADEQ to analyze for BART (best available retrofit technology) controls those sources identified as causing or contributing to visibility impairment. Prior to this rule, this function was carried out by EPA. The impact of this rule on ADEQ will primarily be on the Air Quality Division, Permits and Assessment sections, with a corresponding reduction of impact on EPA.

3. Stationary sources. R18-2-1605 also requires stationary sources identified in #2 to install or operate the BART as determined by the Director. Prior to this rule, only EPA determined and required BART. To determine impacted stationary sources, ADEQ staff reviewed Title V permits from ADEQ's Air Permit files. Of the 26 industry categories listed in 40 CFR 51.301, only five categories were found to exist under ADEQ's jurisdiction: steam electric plants, cement plants, primary copper smelters, lime plants, and industries using non-utility boilers. As a result, potentially 10 sources, representing 16 BART eligible units (boilers and kilns), could be affected by this rule. The combined potential to emit from these sources totaled 94,287 tons per year for NO_x, 141,036 tons per year for SO_2, and 12,146 tons per year for PM. The combined potential to emit for all pollutants for these 10 sources total approximately 250,000 tons per year.

C. Probable Costs and Benefits Associated with the BART/Visibility Impairment Process

1. Direct Costs - FLMs: FLM activities to certify visibility impairment in mandatory Class I areas may involve preparation and analysis of monitoring data, emission inventories, meteorological records, etc. ADEQ estimates that this cost per certification could be as much as $50,000 if extensive analysis is conducted. These costs exist whether or not these rules became final.

2. Direct Costs - ADEQ: ADEQ costs related to identifying whether a BART eligible stationary source causes or contributes to visibility impairment in Class I areas are based on the activities identified in R18-2-1604(A). ADEQ estimates that these costs could range from $100,000 – 200,000 per attribution analysis, and be primarily borne by the ADEQ's Air Quality Assessment Section. Costs related to analyzing identified sources for BART are based on the activities identified in R18-2-1605(A) and will be moderate, but less expensive than the attribution analysis. These costs will be primarily borne by ADEQ's Permits Section. These costs will accrue to the state. Finally, incorporating BART into an existing state air quality permit may require additional resources from the Permits Section. However, these costs, unlike costs for the attribution and BART analysis, would be covered by permit revision fees paid by the source, and would have existed whether or not these rules became final.

3. Direct Costs - Stationary sources: If a source or small group of sources is found to cause or contribute to visibility impairment, and the BART determination requires installation of retrofit controls, the costs to sources required to install BART will be substantial. The total cost to install a technology similar to BART at the Navajo Generating Station was estimated by SRP to be in the hundreds of millions of dollars (51 Federal Register 50172, October 3, 1991). However, the example of the Navajo Generating Station shows costs to install technology similar to BART can result even where there is no state rule. According to EPA, "Where a State defaults on its obligations under the visibility

regulations, EPA may act in place of the State pursuant to a FIP under section 110(c) of the Act, 42 U.S.C. 7410(c)[2], and promulgate such limitation and measures as are required to achieve reasonable progress." (Ibid. at 50173, footnote not included). Although ADEQ is listing these costs for information purposes, ADEQ is not attributing any costs to install and operate BART to this rule because such requirements can be imposed by the federal government without any state rule.

Benefits. Two kinds of benefits are associated with this rule. The first benefit is derived from reduced emissions. Although, BART could be required to be installed on sources even without this state rule, it is helpful to list the emission benefits. When BART is installed, visibility is improved. Over four million recreation visits were made to Grand Canyon National Park in FY 2001. These visits generate substantial revenue in and for the state of Arizona. Other scenic resources could also be improved with the installation of BART, and, though less significant than the Grand Canyon, would enhance the tourism resources of Arizona, as well as the quality of life for Arizona citizens. In addition, reduction of visibility-impairing emissions also has health benefits.

The second benefit is through the replacement of federal regulation with state regulation. The lack of state regulations implementing BART results in Arizona sources being subject to federal regulation implemented by EPA from Washington and San Francisco, headquarters for EPA's Region IX. These rules place the identification and analysis of BART sources with ADEQ rather than with EPA. Arizona is currently under a visibility Federal Implementation Plan (FIP), and one or two Arizona sources have considered or implemented technology similar to BART under federal rules. Because ADEQ already permits many of these sources, ADEQ will be more familiar with the various factors that go into the BART analysis. This would be a benefit to sources being regulated. ADEQ would be implementing the same BART rules that EPA does, with a resulting increase in costs for ADEQ and a decrease in costs for EPA.

This final rule further allows ADEQ to proceed with the implementation of the entire federal rule for visibility improvement. The rule addresses the requirements of 40 C.F.R. §§ 51.302 – 51.307. These sections must be satisfied before ADEQ can implement the requirements of 40 C.F.R. §§ 51.308 and 51.309. The plan to implement Section 309 must be submitted to EPA by December 31, 2003.

D. Small Business Analysis

A.R.S. § 41-1055(B)(5) requires agencies to state the probable impact of a rulemaking on small businesses. A.R.S. § 41-1035 requires agencies to reduce the impact of a rule on small businesses by using certain methods when they are legal and feasible in meeting the statutory objectives for the rulemaking. These methods include: (1) exempting them from any or all rule requirements, (2) establishing performance standards which would replace any design or operational standards, or (3) instituting reduced compliance or reporting requirements. An agency may accomplish the third method by establishing less stringent requirements, consolidating or simplifying requirements, or setting less stringent schedules or deadlines.

"Small business" is defined in A.R.S. § 41-1001 as "a concern, including its affiliates, which is independently owned and operated, which is not dominant in its field and which employs fewer than one hundred full-time employees or which had gross annual receipts of less than four million dollars in its last fiscal year." Interpreting this definition means that if a concern has annual gross receipts of more than four million dollars, but fewer than 100 employees, it would not be classified as a small business.

ADEQ expects that none of the potential BART eligible sources will be classified as a small business. ADEQ's conclusion is that this rule will not impact small business sources. However, if a BART eligible source would qualify as a small business, under federal rule, ADEQ could not establish different requirements for these small business sources. If there are any small businesses that sell, install, or maintain BART-related technology, they will benefit from this rule.

In the preliminary EIS, ADEQ requested comment and additional information relating to any of the conclusions reached above and did not receive any.

10. A description of the changes between the proposed rules, including supplemental notices, and final rules (if applicable):

Changes were made with the cooperation of G.R.R.C. Staff to improve the clarity, conciseness and understandability of the rule. The changes are shown below:

A new definition was placed at R18-2-101(71), to clarify a term used in the proposed definition of "visibility impairment" at R18-2-101(123):

71. "Natural conditions" includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

In addition, the word "and" was removed from the definition of "visibility impairment," as shown:

~~123.~~124. "Visibility impairment" means any humanly perceptible change in visibility (light extinction, visual range, contrast, ~~and~~ coloration) from that which would have existed under natural conditions.

Both definitions are copied exactly from federal regulations at 40 CFR 51.308.

In addition, new Article 16 was amended as follows:

ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1601. Definitions

In addition to the definitions contained in Articles 1 and 4 of this Chapter and A.R.S. § 49-401.01, the following definitions apply to this Article:

1. "Best available retrofit technology (BART)" means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant ~~that is~~ emitted by an existing stationary facility. The emission limitation is established on a case-by-case basis ~~in accordance with~~ under R18-2-1605.
2. "Existing stationary facility" means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation ~~prior to~~ before August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. ~~In determining~~ A person who determines potential to emit~~,~~ shall count fugitive emissions~~,~~ to the extent quantifiable~~, must be counted~~.
   a. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input~~,~~;
   b. Coal cleaning plants (thermal dryers)~~,~~;
   c. Kraft pulp mills~~,~~;
   d. Portland cement plants~~,~~;
   e. Primary zinc smelters~~,~~;
   f. Iron and steel mill plants~~,~~;
   g. Primary aluminum ore reduction plants~~,~~;
   h. Primary copper smelters~~,~~;
   i. Municipal incinerators capable of charging more than 250 tons of refuse per day~~,~~;
   j. Hydrofluoric, sulfuric, and nitric acid plants~~,~~;
   k. Petroleum refineries~~,~~;
   l. Lime plants~~,~~;
   m. Phosphate rock processing plants~~,~~;
   n. Coke oven batteries~~,~~;
   o. Sulfur recovery plants~~,~~;
   p. Carbon black plants (furnace process)~~,~~;
   q. Primary lead smelters~~,~~;
   r. Fuel conversion plants~~,~~;
   s. Sintering plants~~,~~;
   t. Secondary metal production facilities~~,~~;
   u. Chemical process plants~~,~~;
   v. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input~~,~~;
   w. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels~~,~~;
   x. Taconite ore processing facilities~~,~~;
   y. Glass fiber processing plants~~,~~; and
   z. Charcoal production facilities.
3. "Federal Land Manager" means the Secretary of the department, or the Secretary's designee, with authority over the Federal Class I area.
4. "Mandatory Federal Class I Area" means any area identified in 40 CFR §§ 81.400-81.436.
5. "Reasonably attributable" means ascribable by visual observation or other techniques ~~the Director deems appropriate~~ described in R18-2-1604.
6. "Reasonably attributable visibility impairment" means visibility impairment that is caused by the emission of air pollutants from one source, or a small group of sources.

R18-2-1602. Applicability

This Article applies to any existing stationary source located in the state that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Federal Class I area identified in 40 CFR §§ 81.401-81.436. Mandatory Federal Class I areas within Arizona are: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness.

R18-2-1603. Certification of Impairment

A. A Federal Land Manager with authority over a mandatory Federal Class I area may certify to the Director, at any time, that ~~there exists~~ a reasonably attributable visibility impairment exists in ~~the~~ a mandatory Federal Class I area. The Director may also certify that ~~there exists~~ reasonably attributable visibility impairment exists in any mandatory Federal Class I area ~~as necessary~~ to assure reasonable progress under section 169A(b)(2) of the Clean Air Act.

B. Documentation ~~from the affected Federal Land Manager or Director~~ that supports the Federal Land Manager or Director's certification shall include:
1. The mandatory Federal Class I area for which visibility impairment is being certified,
2. Any information documenting the basis for the certification of impairment.

R18-2-1604. Attribution Analysis; Finding

A. ~~Upon certification of reasonably attributable visibility impairment in any mandatory Federal Class I area~~ If a mandatory Federal Class I area is certified as having reasonably attributable visibility impairment, the Director shall conduct an attribution analysis to identify each existing stationary source that may be reasonably anticipated to cause or contribute to visibility impairment. The Director shall notify the Federal Land Manager, affected source or small group of sources, and local air pollution control officer of the intent to conduct an attribution analysis. The attribution analysis shall be based on the following:
1. Monitoring information obtained through the Arizona Class I Visibility Monitoring Network or special studies approved by ADEQ to ascertain:
   a. The times visibility impairment occurred, and
   b. The pollutants contributing to the visibility impairment~~.~~;
2. Transport analysis or air quality modeling based upon meteorological records to ascertain whether the pollutants were transported to the mandatory Federal Class I area~~.~~;
3. Other available studies, modeling analyses, and emissions inventories of point, area, and mobile source emissions to ascertain:
   a. The pollutant ~~or pollutants~~ causing the impairment, and
   b. The source, or a small group of sources, emitting the ~~impairing~~ pollutant; ~~or pollutants.~~
4. Other relevant supporting documentation provided by the Federal Land Manager or Director used to make the draft attribution analysis finding~~.~~; and
5. Consideration of any documentation provided by the source, ~~or~~ a small group of sources~~.~~, or other interested parties.

B. In conducting the attribution analysis, the Director shall use monitoring information, meteorological records, and emissions inventories that represent times and locations reasonably concurrent with the visibility impairment.

C. The Director shall issue a draft attribution finding that impairment has or has not occurred, and provide public notice of the draft attribution finding. The Director shall publish notice of the draft attribution finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, if any, and shall clearly set forth reasons why the Director should review the draft attribution finding ~~should be reviewed~~. The Director shall issue ~~A~~ a final attribution finding ~~shall be issued~~ after the public comment period. If the Director finds existing stationary sources ~~found to~~ cause or contribute to visibility impairment in a mandatory Federal Class I area, the source shall be subject to a BART Control Analysis under R18-2-1605.

R18-2-1605. BART Control Analysis; Finding

A. The Director shall analyze for BART controls each existing stationary source for which a final attribution finding is made under R18-2-1604(C). The Director shall consider the following factors:
1. Available control technology;
2. New source performance standards (NSPS) ~~as adopted~~ in Article 9;
3. Alternative control systems if retrofitting to comply with applicable NSPS standards ~~adopted~~ in Article 9 is ~~found~~ infeasible~~.~~;
4. Cost of compliance;
5. Energy and non-air quality environmental impacts of compliance;
6. Existing pollution control technology in use at the source or small group of sources;
7. Remaining useful life of the source or small group of sources;
8. Net environmental impact associated with the proposed emission control system;
9. Economic impacts associated with installing and operating the proposed emission control system; and
10. Degree of improvement in visibility anticipated to result from application of the proposed emission control system.

B. The Director shall issue a draft BART finding, and provide public notice of the draft BART finding. The Director shall publish notice of the draft BART finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, and shall clearly set forth reasons why the Director should review the draft BART ~~finding should be reviewed~~. The Director shall issue a final BART finding after the public comment period.
1. The Director shall submit each final BART finding ~~that an existing stationary source is required to meet BART~~ to the Administrator as a revision to the ~~state implementation plan (~~SIP~~)~~.

2. The Director shall require that each existing stationary source meet BART as expeditiously as practicable but in no case later than five years after EPA approval of the ~~revision to Arizona's State Implementation Plan~~ SIP revision.

C. If the Director determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary source would make the imposition of an emission standard infeasible, the Director may, as part of the finding under subsection (B), ~~instead~~ prescribe a design, equipment, work practice, ~~or other~~ operational standard, or combination ~~thereof~~ of design, equipment, work practice, or operational standard. ~~Such~~ The standard, to the degree possible, ~~is to~~ shall set forth the emission reduction to be achieved by implementation of ~~such~~ the design, equipment, work practice, or operation, and ~~must~~ shall provide for compliance by means ~~which~~ that achieve equivalent results.

D. The Director shall make a finding that the attributable source ~~has satisfied~~ satisfies the BART requirement if the attributable source ~~has~~:

1. Voluntarily ~~applied~~ applies best available retrofit technology;
2. Previously applied emission control standards equivalent to BART; or
3. ~~Agreed~~ Agrees to shutdown or curtail operations at the attributable source within ~~5~~ five years of the finding. An attributable source that does not shutdown or curtail operations shall ~~proceed to~~ meet BART as expeditiously as practicable, but in no case later than five years after EPA's approval of the revision to ~~Arizona's State Implementation Plan~~ the SIP.

E. If the Director determines that the imposition of BART or a standard ~~pursuant to~~ under subsection (C) ~~of this section~~ is ~~not feasible~~ infeasible at the time of the finding, the Director shall require the attributable source ~~shall be required~~ to install and operate BART ~~upon a determination by the Director~~ at a later date when the Director determines that BART or equivalent controls are ~~now~~ feasible.

F. The Director shall provide for a BART control analysis of any existing stationary source that might cause or contribute to impairment of visibility in any mandatory Federal Class I area identified under this Article at such time~~s,~~ as ~~determined by~~ the Administrator~~,~~ determines new control technology for ~~control of~~ the pollutant becomes reasonably available if:

1. The pollutant is emitted by that existing stationary source,
2. Controls representing BART for the pollutant have not previously been required under this Article, and
3. The impairment of visibility in any mandatory Federal Class I area is reasonably attributable to the emissions of that pollutant.

R18-2-1606. Exemption from BART

Any existing stationary source required to install, operate, and maintain BART ~~pursuant to~~ under this Article, may apply to the Administrator for an exemption from that requirement according to 40 CFR 51.303. ~~by obtaining prior written concurrence from the Director according to 40 CFR 51.303.~~ The existing stationary source shall obtain the Director's written concurrence before sending the application for exemption to the Administrator.

11. A summary of the comments made regarding the rules and the agency response to them:

ADEQ received one written comment. It expressed general support for the rules and for protecting visibility in Arizona's Class I parks and wilderness areas.

Comment: ADEQ received an oral comment that the word "facility" should be replaced by "source" in the definitions of "best available retrofit technology" and "existing stationary facility" to be consistent with the rest of the rule.

Response: ADEQ has kept these definitions the same as the federal definitions to ensure consistency. The definitions use the term "source" to define the terms, and "source" is used thereafter in the rules. ADEQ is not aware of any inconsistency.

12. Any other matters prescribed by statute that are applicable to the specific agency or to any specific rule or class of rules:

Not applicable

13. Incorporations by reference and their location in the rules:

Not applicable

14. Were these rules previously adopted as emergency rules?

No

15. The full text of the rules follows:

TITLE 18. ENVIRONMENTAL QUALITY

CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR POLLUTION CONTROL

ARTICLE 1. GENERAL

Section
R18-2-101. Definitions

ARTICLE 16. VISIBILITY; REGIONAL HAZE

Section
R18-2-1601. Definitions
R18-2-1602. Applicability
R18-2-1603. Certification of Impairment
R18-2-1604. Attribution Analysis; Finding
R18-2-1605. BART Control Analysis; Finding
R18-2-1606. Exemption from BART

ARTICLE 1. GENERAL

R18-2-101. Definitions

In addition to the definitions prescribed in A.R.S. §§ 49-101, 49-401.01, 49-421, 49-471, and 49-541, in this Chapter, unless otherwise specified:

1. No change
2. No change
   a. No change
   b. No change
   c. No change
   d. No change
   e. No change
3. No change
4. No change
5. No change
6. No change
7. No change
8. No change
9. No change
10. No change
    a. No change
    b. No change
    c. No change
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ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1601. Definitions

In addition to the definitions contained in Articles 1 and 4 of this Chapter and A.R.S. § 49-401.01, the following definitions apply to this Article:

1. "Best available retrofit technology (BART)" means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant emitted by an existing stationary facility. The emission limitation is established on a case-by-case basis under R18-2-1605.
2. "Existing stationary facility" means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation before August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. A person who determines potential to emit shall count fugitive emissions to the extent quantifiable.
   a. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input;
   b. Coal cleaning plants (thermal dryers);
   c. Kraft pulp mills;
   d. Portland cement plants;
   e. Primary zinc smelters;
   f. Iron and steel mill plants;
   g. Primary aluminum ore reduction plants;
   h. Primary copper smelters;
   i. Municipal incinerators capable of charging more than 250 tons of refuse per day;
   j. Hydrofluoric, sulfuric, and nitric acid plants;
   k. Petroleum refineries;
   l. Lime plants;
   m. Phosphate rock processing plants;
   n. Coke oven batteries;

o. Sulfur recovery plants;
p. Carbon black plants (furnace process);
q. Primary lead smelters;
r. Fuel conversion plants;
s. Sintering plants;
t. Secondary metal production facilities;
u. Chemical process plants;
v. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input;
w. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels;
x. Taconite ore processing facilities;
y. Glass fiber processing plants; and
z. Charcoal production facilities.

3. "Federal Land Manager" means the secretary of the department, or the secretary's designee, with authority over the Federal Class I area.
4. "Mandatory Federal Class I Area" means any area identified in 40 CFR 81.400 through 81.436.
5. "Reasonably attributable" means ascribable by visual observation or other techniques described in R18-2-1604.
6. "Reasonably attributable visibility impairment" means visibility impairment that is caused by the emission of air pollutants from one source, or a small group of sources.

R18-2-1602. Applicability

This Article applies to any existing stationary source located in the state that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Federal Class I area identified in 40 CFR 81.401 through 81.436. Mandatory Federal Class I areas within Arizona are: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness.

R18-2-1603. Certification of Impairment

A. A Federal Land Manager with authority over a mandatory Federal Class I area may certify to the Director, at any time, that a reasonably attributable visibility impairment exists in a mandatory Federal Class I area. The Director may also certify that reasonably attributable visibility impairment exists in any mandatory Federal Class I area to assure reasonable progress under section 169A(b)(2) of the Clean Air Act.

B. Documentation that supports the Federal Land Manager or Director's certification shall include:
1. The mandatory Federal Class I area for which visibility impairment is being certified,
2. Any information documenting the basis for the certification of impairment.

R18-2-1604. Attribution Analysis; Finding

A. If a mandatory Federal Class I area is certified as having reasonably attributable visibility impairment, the Director shall conduct an attribution analysis to identify each existing stationary source that may be reasonably anticipated to cause or contribute to visibility impairment. The Director shall notify the Federal Land Manager, affected source or small group of sources, and local air pollution control officer of the intent to conduct an attribution analysis. The attribution analysis shall be based on the following:
1. Monitoring information obtained through the Arizona Class I Visibility Monitoring Network or special studies approved by ADEQ to ascertain:
   a. The times visibility impairment occurred, and
   b. The pollutants contributing to the visibility impairment;
2. Transport analysis or air quality modeling based upon meteorological records to ascertain whether the pollutants were transported to the mandatory Federal Class I area;
3. Other available studies, modeling analyses, and emissions inventories of point, area, and mobile source emissions to ascertain:
   a. The pollutant causing the impairment, and
   b. The source, or a small group of sources, emitting the pollutant;
4. Other relevant supporting documentation provided by the Federal Land Manager or Director used to make the draft attribution analysis finding; and
5. Consideration of any documentation provided by the source, a small group of sources, or other interested parties.

B. In conducting the attribution analysis, the Director shall use monitoring information, meteorological records, and emissions inventories that represent times and locations reasonably concurrent with the visibility impairment.

C. The Director shall issue a draft attribution finding that impairment has or has not occurred, and provide public notice of the draft attribution finding. The Director shall publish notice of the draft attribution finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name

of the person and the person's agent or attorney, if any, and shall clearly set forth reasons why the Director should review the draft attribution finding. The Director shall issue a final attribution finding after the public comment period. If the Director finds existing stationary sources cause or contribute to visibility impairment in a mandatory Federal Class I area, the source shall be subject to a BART Control Analysis under R18-2-1605.

R18-2-1605. BART Control Analysis; Finding

A. The Director shall analyze for BART controls each existing stationary source for which a final attribution finding is made under R18-2-1604(C). The Director shall consider the following factors:

1. Available control technology;
2. New source performance standards (NSPS) in Article 9;
3. Alternative control systems if retrofitting to comply with applicable NSPS standards in Article 9 is infeasible;
4. Cost of compliance;
5. Energy and non-air quality environmental impacts of compliance;
6. Existing pollution control technology in use at the source or small group of sources;
7. Remaining useful life of the source or small group of sources;
8. Net environmental impact associated with the proposed emission control system;
9. Economic impacts associated with installing and operating the proposed emission control system; and
10. Degree of improvement in visibility anticipated to result from application of the proposed emission control system.

B. The Director shall issue a draft BART finding, and provide public notice of the draft BART finding. The Director shall publish notice of the draft BART finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, and shall clearly set forth reasons why the Director should review the draft BART finding. The Director shall issue a final BART finding after the public comment period.

1. The Director shall submit each final BART finding to the Administrator as a revision to the SIP.
2. The Director shall require that each existing stationary source meet BART as expeditiously as practicable but in no case later than five years after EPA approval of the SIP revision.

C. If the Director determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary source would make the imposition of an emission standard infeasible, the Director may, as part of the finding under subsection (B), prescribe a design, equipment, work practice, operational standard, or combination of design, equipment, work practice, or operational standard. The standard, to the degree possible, shall set forth the emission reduction to be achieved by implementation of the design, equipment, work practice, or operation, and shall provide for compliance by means that achieve equivalent results.

D. The Director shall make a finding that the attributable source satisfies the BART requirement if the attributable source:

1. Voluntarily applies best available retrofit technology;
2. Previously applied emission control standards equivalent to BART; or
3. Agrees to shutdown or curtail operations at the attributable source within five years of the finding. An attributable source that does not shutdown or curtail operations shall meet BART as expeditiously as practicable, but in no case later than five years after EPA's approval of the revision to the SIP.

E. If the Director determines that the imposition of BART or a standard under subsection (C) is infeasible at the time of the finding, the Director shall require the attributable source to install and operate BART at a later date when the Director determines that BART or equivalent controls are feasible.

F. The Director shall provide for a BART control analysis of any existing stationary source that might cause or contribute to impairment of visibility in any mandatory Federal Class I area identified under this Article at such time as the Administrator determines new control technology for the pollutant becomes reasonably available:

1. The pollutant is emitted by that existing stationary source,
2. Controls representing BART for the pollutant have not previously been required under this Article, and
3. The impairment of visibility in any mandatory Federal Class I area is reasonably attributable to the emissions of that pollutant.

R18-2-1606. Exemption from BART

Any existing stationary source required to install, operate, and maintain BART under this Article, may apply to the Administrator for an exemption from that requirement according to 40 CFR 51.303. The existing stationary source shall obtain the Director's written concurrence before sending the application for exemption to the Administrator.

Appendix A-5b. Notification letters to FLMS on contact person, and Public Comment Period

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

Governor Jane Dee Hull Jacqueline E. Schafer, Director

April 13, 2000

Eleanor Townes
US Forest Services
517 Gold Avenue SW Region
Albuquerque, New Mexico 87105

Dear Ms. Townes:

I am writing to welcome your participation in the Arizona Department of Environmental Quality's (ADEQ) efforts to improve visibility in our Class I areas. One of our duties under the EPA Regional Haze Regulations (64 Fed. Reg. 35,714, July 1, 1999) is to notify you of our state contact person for regional haze issues. Mike George, Assessment Section Manager, Air Quality Division, has been assigned this responsibility. He can be reached at (602)207-2274. General inquiries may also be directed to Corky Martinkovic of the Air Quality Planning Section at (602)207-2372.

ADEQ will also send written notices to all affected federal land managers of public hearings to be held prior to submittal of a related State Implementation Plan (SIP) to EPA. Arizona is presently under a Federal Implementation Plan (FIP) for reasonably attributable visibility impairment, but is developing a SIP revision to replace the FIP. You will receive an official notice when the public hearing date is finalized, which is expected to be later this year. A draft SIP will be included with the notice of public hearing date for review and comment. Further, affected federal land managers will be notified of applicable rulemaking activities.

ADEQ looks forward to working with you to protect our clean air resource. If you have questions or comments, you may contact me at (602)207-2308, or Mike and Corky at the above phone numbers.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division

cc: Mike George, ADEQ
Theresa Pella, ADEQ
Pete Lahm, ADEQ

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Joseph Alston, Federal Land Manager
Grand Canyon National Park
P.O. Box 129
Grand Canyon, AZ 86023

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Alston:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

Consultation with the federal land managers is an integral part of the regional haze regulations, and we invite you to participate in the review of the proposed SIP during the upcoming 30-day public comment period. The proposed SIP will be posted to the ADEQ Website at www.adeq.state.az.us/environ/air/plan/haze. It is ADEQ's intent to have the Regional Haze SIP available for public comment in mid-September of this year, culminating with public hearings held throughout the state during the middle or end of October. A notice regarding the commencement of the public comment period and dates/locations of the public hearings will be sent separately. The SIP must be submitted to EPA by December 31, 2003, to meet the requirements of 40 CFR 51.309.

Until further notice, I will be the contact person for regional haze at ADEQ. General inquiries may still be directed to Corky Martinkovic of the Air Quality Planning Section at (602) 771-2372 or dam@ev.state.az.us. ADEQ looks forward to working with you to protect our national parks and wilderness areas.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Joseph Alston

cc: Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Lee Baiza, Federal Land Manager
Petrified Forest National Park
P.O. Box 2217
Petrified Forest, AZ 86028

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Baiza:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

Consultation with the federal land managers is an integral part of the regional haze regulations, and we invite you to participate in the review of the proposed SIP during the upcoming 30-day public comment period. The proposed SIP will be posted to the ADEQ Website at www.adeq.state.az.us/environ/air/plan/haze. It is ADEQ's intent to have the Regional Haze SIP available for public comment in mid-September of this year, culminating with public hearings held throughout the state during the middle or end of October. A notice regarding the commencement of the public comment period and dates/locations of the public hearings will be sent separately. The SIP must be submitted to EPA by December 31, 2003, to meet the requirements of 40 CFR 51.309.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division

cc: Joseph Alston
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Carl Bowman, Federal Land Manager
Grand Canyon National Park
P.O. Box 129
Grand Canyon, AZ 86023

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Bowman:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Carl Bowman

cc: Joseph Alston
Lee Baiza
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
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1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Ms. Sarah Craighead, Federal Land Manager
Saguaro National Monument
3693 S. Old Spanish Trail
Tucson, AZ 85730

Re: Arizona's Regional Haze State Implementation Plan

Dear Ms. Craighead:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

Consultation with the federal land managers is an integral part of the regional haze regulations, and we invite you to participate in the review of the proposed SIP during the upcoming 30-day public comment period. The proposed SIP will be posted to the ADEQ Website at www.adeq.state.az.us/environ/air/plan/haze. It is ADEQ's intent to have the Regional Haze SIP available for public comment in mid-September of this year, culminating with public hearings held throughout the state during the middle or end of October. A notice regarding the commencement of the public comment period and dates/locations of the public hearings will be sent separately. The SIP must be submitted to EPA by December 31, 2003, to meet the requirements of 40 CFR 51.309.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Sarah Craighead

cc: Joseph Alston
Lee Baiza
Carl Bowman
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
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1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Harv Forsgren, Federal Land Manager
U.S. Forest Service – Southwest Region
333 Broadway SE
Albuquerque, NM 87102

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Forsgren:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

Consultation with the federal land managers is an integral part of the regional haze regulations, and we invite you to participate in the review of the proposed SIP during the upcoming 30-day public comment period. The proposed SIP will be posted to the ADEQ Website at www.adeq.state.az.us/environ/air/plan/haze. It is ADEQ's intent to have the Regional Haze SIP available for public comment in mid-September of this year, culminating with public hearings held throughout the state during the middle or end of October. A notice regarding the commencement of the public comment period and dates/locations of the public hearings will be sent separately. The SIP must be submitted to EPA by December 31, 2003, to meet the requirements of 40 CFR 51.309.

Until further notice, I will be the contact person for regional haze at ADEQ. General inquiries may still be directed to Corky Martinkovic of the Air Quality Planning Section at (602) 771-2372 or dam@ev.state.az.us. ADEQ looks forward to working with you to protect our national parks and wilderness areas.

Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Harv Forsgren

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Michael King
Pete Lahm
Neil Mangum
John McGee
Colleen McKaughan
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Michael King, Federal Land Manager
Pine Mountain Wilderness
344 S. Cortez Street
Prescott, AZ 86303

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Siderits:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Michael King

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
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Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Pete Lahm, Federal Land Manager
U.S. Forest Service
c/o Arizona Department of Environmental Quality
1110 W. Washington Street, 3415A-3
Phoenix, AZ 85007

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Lahm:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Pete Lahm

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Neil Mangum
John McGee
Colleen McKaughan
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
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Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Neil Mangum, Federal Land Manager
Chiricuahua National Park
13063 E. Boenito Canyon
Wilcox, AZ 85643

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Mangum:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Neil Mangum

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. John McGee, Federal Land Manager
Galiuro Wilderness
300 W. Congress
Tucson, AZ 85701

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. McGee:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
John McGee

Northern Regional Office
1515 East Cedar Avenue • Suite F • Flagstaff, AZ 86004

Southern Regional Office
400 West Congress Street • Suite 433 • Tucson, AZ 85701

Printed on recycled paper

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Bruce Polkowsky, Federal Land Manager
National Park Service
P.O. Box 25287
Denver, CO 80225

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Polkowsky:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Bruce Polkowsky

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
John McGee
Colleen McKaughan
Joseph Mikitish
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Ms. Nora Rasure, Federal Land Manager
Sycamore Canyon Wilderness
2323 E. Greenlaw Lane
Flagstaff, AZ 86004

Re: Arizona's Regional Haze State Implementation Plan

Dear Ms. Rasure:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Nora Rasure

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Chris Shaver
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Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Ms. Chris Shaver, Federal Land Manager
National Park Service
P.O. Box 25287
Denver, CO 80225

Re: Arizona's Regional Haze State Implementation Plan

Dear Ms. Shaver:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Chris Shaver

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
John McGee
Colleen McKaughan
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Karl Siderits
Mike Williams
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Karl Siderits, Federal Land Manager
Sierra Ancha/Superstition/Mazatzal Wildernesses
2324 E. McDowell Road
Phoenix, AZ 85006

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Siderits:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Karl Siderits

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
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Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Mr. Mike Williams, Federal Land Manager
Sycamore Canyon Wilderness
800 S. 6th Street
Williams, AZ 86046

Re: Arizona's Regional Haze State Implementation Plan

Dear Mr. Williams:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Mike Williams

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Elaine Zieroth

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

August 22, 2003

Ms. Elaine Zieroth, Federal Land Manager
Mt. Baldy Wilderness
P.O. Box 640
Springerville, AZ 85938

Re: Arizona's Regional Haze State Implementation Plan

Dear Ms. Zieroth:

The purpose of this letter is to provide notice to you in accordance with 40 CFR 51.302(a)(2)(ii), regarding the availability of a draft Regional Haze State Implementation Plan (SIP) for Arizona. In April 2000, I sent notices to the federal land managers that Arizona was beginning to develop a state implementation plan to address visibility impairment in the Class I areas. Arizona's Regional Haze SIP will address visibility impairment for the four mandatory Federal Class I areas in Arizona that are part of the Grand Canyon Visibility Transport Commission's Colorado Plateau: Grand Canyon National Park, Petrified Forest National Park, Sycamore Canyon Wilderness, and Mount Baldy Wilderness.

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Sincerely,

Nancy C. Wrona, Director
Air Quality Division
Elaine Zieroth

cc: Joseph Alston
Lee Baiza
Carl Bowman
Sarah Craighead
Harv Forsgren
Michael King
Pete Lahm
Neil Mangum
Colleen McKaughan
John McGee
Joseph Mikitish
Bruce Polkowsky
Nora Rasure
Chris Shaver
Karl Siderits
Mike Williams

Appendix A-5c. Supporting Documents Related To The Promulgation Of Arizona's RAVI Rule

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

MEMORANDUM

DATE: January 7, 2003

TO: Visibility Rule Stakeholders

FROM: Nancy C. Wrona, Director
Air Quality Division

SUBJECT: Preliminary Draft Notice of Proposed Rulemaking for Reasonably Attributable Visibility Impairment (RAVI) Rule

---

You are invited to a stakeholder meeting on **Tuesday, January 14, 2003, 1:30 p.m., Room 145, ADEQ, 1110 W. Washington, Phoenix, Arizona**. The purpose of this meeting is to review a draft Notice of Proposed Rulemaking (NPRM) for the Reasonably Attributable Visibility Impairment (RAVI) rule. The RAVI rule, formerly known as the "visibility rule," has had numerous stakeholder reviews, but now contains the preamble portion required for submission to the Secretary of State. Once the RAVI rule is submitted to the Secretary of State for publication in the *Arizona Administrative Register*, the rule will have a 30 day public review period, culminating in a public hearing in mid March 2003.

The proposed rule deals with state requirements within the federal visibility/regional haze rule 40 CFR §§51.302 - 307. Sections 302 through 307 deal with a specific type of visibility impairment caused by certain categories of exiting stationary sources operating in and near national parks and wilderness areas (federal Class I areas).

Due to the length of the draft NPRM, we will not be faxing the document with this notice. However, you can access the RAVI rule via the ADEQ Web page at www.adeq.state.az.us/environ/air/plan/haze.html. You can also receive a copy of the draft NPRM by contacting Corky Martinkovic at the number or e-mail shown below.

I look forward to seeing you on January 14th. If you have any questions regarding the meeting, please call me at (602) 771-2308 or Corky Martinkovic at (602) 771-2372, or by e-mail at martinkovic.deborrah@ev.state.az.us. If you are in Arizona, but outside of the Phoenix area, call 1-800-234-5677, then dial extension 771-2372. Copies of the draft NPRM will also be available at the January 14th meeting.

PUBLIC NOTICE

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC HEARING
ON NOTICE OF PROPOSED RULEMAKING
REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

The Arizona Department of Environmental Quality (ADEQ) will hold a public hearing to receive comments on the Notice of Proposed Rulemaking for Reasonably Attributable Visibility Impairment (RAVI) rule. This rule impacts specific stationary sources emitting 250 tons per year or more of visibility impairing air pollutants in or near Arizona's 12 mandatory federal class I areas (national parks and wilderness areas). The rule directs the state of Arizona and the stationary sources on the actions necessary should a source or small group of sources be certified by a Federal Land Manager as possibly causing or contributing to visibility problems in any of the 12 national parks and wilderness areas.

A public hearing on the Notice of Proposed Rulemaking will be held on Wednesday, April 7, 2003, at the Coconino Library, 300 W. Aspen, Flagstaff, Arizona. All interested parties will be given an opportunity at the public hearing to submit relevant comments, data, and views, orally and in writing. Written comments must be received at ADEQ by 5:00 p.m. on Friday, April 11, 2003. ADEQ anticipates sending the proposed rule and any comments received to the Governor's Regulatory Review Council on or after April 21, 2003.

All written comments should be addressed, faxed, or e-mailed to:

Deborrah "Corky" Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 W. Washington Street
Phoenix, AZ 85012-2905
FAX: (602) 771-2366
E-Mail: martinkovic.deborrah@ev.state.az.us

Copies of the proposal are available for review beginning Thursday, March 13 (ADEQ) and March 17 (Flagstaff), 2003, at the following locations:

Arizona Department of Environmental Quality
First Floor Library
1110 W. Washington Street
Phoenix, Arizona 85012
Lorraine Akey, (602) 771-4335

Locally:
Coconino Library
300 W. Aspen
Flagstaff, Arizona
Dawn Gardner, (928) 779-7670

PUBLIC NOTICE

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC HEARING
ON NOTICE OF PROPOSED RULEMAKING
REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

The Arizona Department of Environmental Quality (ADEQ) will hold a public hearing to receive comments on the Notice of Proposed Rulemaking for Reasonably Attributable Visibility Impairment (RAVI) rule. This rule impacts specific stationary sources emitting 250 tons per year or more of visibility impairing air pollutants in or near Arizona's 12 mandatory federal class I areas (national parks and wilderness areas). The rule directs the state of Arizona and the stationary sources on the actions necessary should a source or small group of sources be certified by a Federal Land Manager as possibly causing or contributing to visibility problems in any of the 12 national parks and wilderness areas.

A public hearing on the Notice of Proposed Rulemaking will be held on Wednesday, April 8, 2003, at the Arizona Department of Environmental Quality, 1110 W. Washington Street, Room 145, Phoenix, Arizona. All interested parties will be given an opportunity at the public hearing to submit relevant comments, data, and views, orally and in writing. Written comments must be received at ADEQ by 5:00 p.m. on Friday, April 11, 2003. ADEQ anticipates sending the proposed rule and any comments received to the Governor's Regulatory Review Council on or after April 21, 2003.

All written comments should be addressed, faxed, or e-mailed to:

Deborrah "Corky" Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 W. Washington Street
Phoenix, AZ 85012-2905
FAX: (602) 771-2366
E-Mail: martinkovic.deborrah@ev.state.az.us

Copies of the proposal are available for review beginning Thursday, March 13, 2003, at the following locations:

Arizona Department of Environmental Quality
First Floor Library
1110 W. Washington Street
Phoenix, Arizona 85012
Lorraine Akey, (602) 771-4335

Other Hearing Locations:

Flagstaff - April 7, 2003
Tucson - April 9, 2003

PUBLIC NOTICE

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC HEARING
ON NOTICE OF PROPOSED RULEMAKING
REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

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A public hearing on the Notice of Proposed Rulemaking will be held on Wednesday, April 9, 2003, at the State Office Building, 400 W. Congress, Room 158, Tucson, Arizona. All interested parties will be given an opportunity at the public hearing to submit relevant comments, data, and views, orally and in writing. Written comments must be received at ADEQ by 5:00 p.m. on Friday, April 11, 2003. ADEQ anticipates sending the proposed rule and any comments received to the Governor's Regulatory Review Council on or after April 21, 2003.

All written comments should be addressed, faxed, or e-mailed to:

Deborrah "Corky" Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 W. Washington Street
Phoenix, AZ 85012-2905
FAX: (602) 771-2366
E-Mail: martinkovic.deborrah@ev.state.az.us

Copies of the proposal are available for review beginning Thursday, March 13 (ADEQ) and March 17 (Tucson), 2003, at the following locations:

Arizona Department of Environmental Quality
First Floor Library
1110 W. Washington Street
Phoenix, Arizona 85012
Lorraine Akey, (602) 771-4335

Locally:
State Office Building
400 W. Congress, Room 158
Tucson, Arizona
Julie Benner, (520) 628-6902

NOTICE OF PROPOSED RULEMAKING

TITLE 18. ENVIRONMENTAL QUALITY

CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR POLLUTION CONTROL

ARTICLE 16. VISIBILITY; REGIONAL HAZE

PREAMBLE

1. **Sections Affected** — **Rulemaking Action**

R18-2-101	Amend
R18-2-1601	New Section
R18-2-1602	New Section
R18-2-1603	New Section
R18-2-1604	New Section
R18-2-1605	New Section
R18-2-1606	New Section

2. **The statutory authority for the rulemaking, including both the authorizing statute (general) and the statutes the rules are implementing (specific):**

General Authority: A.R.S. §§ 49-104(A)(11) and 49-425

Specific Authority: A.R.S. §§ 49-414 and 414.01

3. **A list of all previous notices appearing in the Register addressing the proposed rule:**

Notice of Docket Opening: 9 A.A.R. 390, February 7, 2003

4. **The name and address of agency personnel with whom persons may communicate regarding the rulemaking.**

Name: Deborrah "Corky" Martinkovic

Address: ADEQ, Air Quality Planning Section, 1110 West Washington Street, Phoenix, AZ 85007

Telephone: (602) 771-2372 (Any extension may be reached in-state by dialing 1-800-234-5677, and asking for a specific number.)

Fax: (602) 771-2366

E-mail: martinkovic.deborrah@ev.state.az.us

5. <u>An explanation of the rule, including the agency's reasons for initiating the rule</u>:

<u>Summary.</u> This rule sets forth the process Arizona Department of Environmental Quality (ADEQ) will use to determine whether Best Available Retrofit Technology (BART) will be required for sources determined to be contributing to visibility impairment in a mandatory Federal Class I area. Federal regulations allow Federal Land Managers (FLMs) to certify sources defined in 40 CFR 51.301 as potential contributors to visibility impairment in any of the Arizona mandatory Federal Class I areas under Section 169A of the Clean Air Act (CAA).

<u>Background.</u> In 1977 Congress added a new section to the Clean Air Act - Section 169A, Visibility Protection for Federal Class I Areas - which established a national goal for, "the prevention of any future, and the remedying of any existing impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution." In addition, the section required states to submit state implementation plans (SIPs) requiring best available retrofit technology (BART) for certain existing stationary sources found to cause or contribute to visibility impairment. On November 30, 1979, EPA promulgated a list of mandatory Federal Class I Areas (Class I areas) where visibility is an important value (44 FR 69122). There are 12 Class I areas identified in Arizona: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness (40 CFR 81.403).

On December 2, 1980 (45 FR 80084), EPA defined the role of the FLMs in certifying visibility impairment in the mandatory Federal Class I areas. On November 24, 1987 (52 FR 45132), FLMs identified Petrified Forest National Park, Saguaro Wilderness, and Grand Canyon National Park, as having visibility impairment possibly attributable to stationary sources. Under the 1980 rule, if found to cause or contribute to the impairment, certain existing stationary sources operating in or near the identified Class I areas could be subject to BART (A list of sources eligible for the possible application of BART can be found at 40 CFR 51.301). On October 3, 1991, the Navajo Generating Station (NGS) was found by EPA to be causing or contributing to visibility impairment for the Grand Canyon National Park and eligible for BART (56 FR 50172). BART control analyses were subsequently performed by EPA, and other parties through related court actions. Under the 1980 rule, the federal expectation is that actions for determination of possible source attribution will be performed by the states. Therefore, Arizona needs

to be prepared to proceed with an attribution analysis and assessment for the application of controls upon any determination of a BART eligible source being the possible cause or contributor to visibility impairment in a Class I area. This rule addresses that need.

Current Conditions. ADEQ is proposing that this rule apply to any source in existing stationary source categories identified in 40 CFR 51.301 that are operating in or near the mandatory federal Class I areas in Arizona. The source is an existing stationary facility that includes any reconstructed source that was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year of any regulated pollutant. ADEQ estimates that there are potentially 10 such sources within Arizona. "In existence" is interpreted by EPA to be consistent with the term, "commence construction" found in Prevention of Serious Deterioration (PSD) regulations (40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21 (b)(9)). If construction commenced after August 7, 1977, the source would be subject to the PSD/NSR (new source review) program (the state regulations are found at 18 A.C.C. 2, Article 4). However, EPA also notes "that sources, are not BART eligible if the only change at the plant was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not themselves trigger a BART review."[1]

Under this proposed rule, ADEQ, when analyzing an attributable source for BART controls, must consider several factors including, for example, costs, remaining useful life of the source, and degree of improvement anticipated to result from the application of the controls (the factors are detailed in R18-2-1605). Sources required by ADEQ to install and operate BART controls have a final opportunity to request exemption from the requirement prior to the application of controls. This opportunity for a federal exemption from BART, is contained in R18-2-1606, and 40 CFR 51.303.

Summary. This rule outlines the process through which sources eligible for the application of BART will proceed if certified by the state of Arizona or an FLM as possibly causing or contributing to visibility impairment due to attribution. If found to be attributable for the impairment, a BART analysis will be performed to determine the level of controls necessary to remedy the impairment. This rule enables Arizona to fulfill the requirements of the Clean Air Act and the goal of section 169A of the Act to return the Nation's federal parks and wilderness areas to natural conditions.

[1] EPA proposed rule, 66 Federal Register 38119, July 20, 2001.

Section-by-section Explanation for the Proposed Rule

R18-2-1601	This section lists the definitions that apply to this rule.
R18-2-1602	This section lists the Class I areas addressed by this rule for the applicable existing stationary facilities, as defined in R18-2-1601(2).
R18-2-1603	This section establishes the procedure for certification of impairment by either a Federal Land Manager with authority over a mandatory Federal Class I area, or the Director, should either believe there exists reasonably attributable visibility impairment in a Federal Class I area as listed in R18-2-1602.
R18-2-1604	This section establishes the procedure for an attribution analysis after certification of a source or group of sources as outlined in R18-2-1603. Upon completion of the attribution analysis, the procedure for the Director to issue draft and final attribution findings is outlined in R18-2-1604(C).
R18-2-1605	This section establishes the best available retrofit technology (BART) analysis procedure after a source is identified under R18-2-1604. Upon completion of the BART analysis, the procedure for the Director to issue draft and final BART findings, including alternatives to emission standards, is outlined in R18-2-1605(B) and (C), respectively. The specific conditions where BART would be satisfied due to past or planned actions by the facility are outlined in R18-2-1605(D). EPA determinations regarding new technology that might require a BART analysis for an applicable source, regardless of a source or small group of sources previously being certified and found attributable, are covered in R18-2-1605(E).
R18-2-1606	This section establishes the procedures for obtaining a federal exemption from a BART requirement.

6. <u>A reference to any study relevant to the rule that the agency proposes to rely on in its evaluation of or justification for the proposed rule or proposes not to rely on in its evaluation of or justification for the rule, where the public may obtain or review each study, all data underlying each study, and any analysis of each study and other supporting material:</u>

Not Applicable

7. <u>A showing of good cause why the rule is necessary to promote a statewide interest if the rule will diminish a previous grant of authority of a political subdivision of this state:</u>

Not applicable

8. <u>The preliminary summary of the economic, small business, and consumer impact</u>:

A. <u>Rule Identification</u>

These rules would amend R18-2-101 ("visibility impairment" definition) and add new sections R18-2-1601 through R18-2-1606. For sources under ADEQ jurisdiction, the rules would take the place of federal regulations that currently govern this area.

B. <u>Entities Directly Impacted</u>

1. Federal Land Managers. Proposed R18-2-1603 would allow Federal Land Managers (FLMs) to certify visibility impairment in mandatory Class I areas. This is already allowed by federal rule. Under R18-2-1601 of the proposed rule, the FLMs able to certify impairment in Arizona are with the United States Forest Service and the National Park Service. There are no FLMs in Arizona from the United States Fish and Wildlife Service, because this agency does not have jurisdiction over any of Arizona's mandatory federal Class I areas.

2. ADEQ. Proposed R18-2-1604 would require ADEQ to identify stationary sources that could cause or contribute to the certified visibility impairment. This function is currently carried out by EPA. Proposed R18-2-1605 would require ADEQ to analyze for BART (best available retrofit technology) controls those sources identified as causing or contributing to visibility impairment. This function is currently carried out by EPA. The impact of this rule on ADEQ would primarily be on the Air Quality Division, Permits and Assessment sections.

3. Stationary sources. Proposed R18-2-1605 would also require stationary sources identified in #2 to install or operate the BART as determined by the Director. Currently, EPA determines and requires BART. To determine impacted stationary sources, ADEQ staff reviewed Title V permits from ADEQ's Air Permit files. Of the 26 industry categories listed in 40 CFR 51.301, only five categories were found to exist under ADEQ's jurisdiction: steam electric plants, cement plants, primary copper smelters, lime plants, and industries using non-utility boilers. As a result, potentially 10 sources, representing 16 BART eligible units (boilers and kilns), could be affected by this proposed rule. The combined potential to emit

from these sources totaled 94,287 tons per year for NO_x, 141,036 tons per year for SO_2, and 12,146 tons per year for PM. The combined potential to emit for all pollutants for these 10 sources total approximately 250,000 tons per year.

C. Probable Costs and Benefits Associated with the BART/Visibility Impairment Process

1. Direct Costs - FLMs: FLM activities to certify visibility impairment in mandatory Class I areas may involve preparation and analysis of monitoring data, emission inventories, meteorological records, etc. ADEQ estimates that this cost per certification could be as much as $50,000 if extensive analysis is conducted. These costs exist whether or not these proposed rules become final.

2. Direct Costs - ADEQ: ADEQ costs related to identifying whether a BART eligible stationary source causes or contributes to visibility impairment in Class I areas are based on the activities identified in R18-2-1604(A). ADEQ estimates that these costs could range from $100,000 – 200,000 per attribution analysis, and be primarily borne by the ADEQ's Air Quality Assessment Section. Costs related to analyzing identified sources for BART are based on the activities identified in proposed R18-2-1605(A) and will be moderate, but less expensive than the attribution analysis. These costs will be primarily born by the Permits Section. These costs would not accrue to the State unless the proposed rule becomes final. Finally, incorporating BART into an existing State air quality permit may require additional resources from the Permits Section. However, these costs, unlike costs for the attribution and BART analysis, would be covered by permit revision fees paid by the source, and would exist whether or not these proposed rules become final.

3. Direct Costs - Stationary sources: If a source or small group of sources is found to cause or contribute to visibility impairment, and the BART determination requires installation of retrofit controls, costs to sources required to install BART would be substantial. The total cost to install a technology similar to BART at the Navajo Generating Station was estimated by SRP to be in the hundreds of millions of dollars (51 Federal Register 50172, October 3, 1991). However, the example of the Navajo Generating Station shows costs to install technology similar to BART can result even where there is no state rule. According to EPA, "Where a State defaults on its obligations under the visibility regulations, EPA may act in place of the State pursuant to a FIP under section 110(c) of the Act, 42 U.S.C. 7410(c)[2], and promulgate such limitation and measures as are required to achieve reasonable progress."(Ibid. at 50173, footnote not included). Although ADEQ is listing these costs for information purposes, ADEQ is not attributing any costs to install and operate BART to this rule because such requirements can be imposed by the federal government without any State rule.

Benefits. Two kinds of benefits are associated with this proposed rule. The first is reduced emissions. Although, BART could be required to be installed on sources even without this state rule, it is helpful to list the emission benefits. When BART is installed, visibility is improved. Over 4 million recreation visits were made to Grand Canyon National Park in FY 2001. These visits generate substantial revenue in and for the state of Arizona. Other scenic resources that could also be improved with the installation of BART, and, though less significant than the Grand Canyon, would enhance the tourism resources of Arizona, as well as the quality of life for Arizona citizens. In addition, reduction of visibility-impairing emissions also has health benefits.

The second benefit is replacement of federal regulation with state regulation. The lack of state regulations implementing BART results in Arizona sources being subject to federal regulation implemented by EPA from Washington and San Francisco. These proposed rules would place the identification and analysis of BART sources at ADEQ rather than with EPA. Arizona is currently under a visibility Federal Implementation Plan (FIP), and one or two sources have considered or implemented technology similar to BART under federal rules. Because ADEQ already permits many of these sources, ADEQ is more familiar with the various factors that go into the BART analysis. This would be a benefit to sources being regulated. ADEQ would be implementing the same BART rules that EPA does.

The rule further allows ADEQ to proceed with the implementation of the entire federal rule for visibility improvement. The proposed rule addresses the requirements of 40 C.F.R. §§51.302 – 307. These sections must be satisfied before ADEQ can implement the requirements of 40 C.F.R. §§51-308 and 309. The plan to implement Section 309 must be submitted to EPA by December 31, 2003.

D. Small Business Analysis

A.R.S. §41-1055(B)(5) requires agencies to state the probable impact of a rulemaking on small businesses. A.R.S. §41-1035 requires agencies to reduce the impact of a rule on small businesses by using certain methods when they are legal and feasible in meeting the statutory objectives for the rule making. These methods include: (1) exempting them from any or all rule requirements, (2) establishing performance standards which would replace any design or operational standards, or (3) instituting reduced compliance or reporting requirements. An agency may accomplish the third method by establishing less stringent requirements, consolidating or simplifying requirements, or setting less stringent schedules or deadlines.

"Small business" is defined in A.R.S. §41-1001 as "a concern, including its affiliates, which is independently owned and operated, which is not dominant in its field and which employs fewer than one hundred full-time employees or which had gross annual receipts of less than four million dollars in its last fiscal year." Interpreting this definition means that if a concern has annual gross receipts of more than four million dollars, but fewer than 100 employees, it would not be classified as a small business.

ADEQ expects that none of the potential BART eligible sources would be classified as a small business. A preliminary conclusion is that this proposed rule will not impact other small businesses. However, if a BART eligible source would qualify as a small business, ADEQ is unable to establish different requirements for small businesses. Except for applying for an exemption, as mentioned under "Alternative Methods," ADEQ cannot establish less stringent requirements or exemptions for small businesses, or any BART eligible source.

ADEQ requests comment and additional information relating to any of the conclusions reached in this preliminary EIS.

9. The name and address of agency personnel with whom persons may communicate regarding the accuracy of the economic, small business, and consumer impact statement:

Name: David Lillie

Address: ADEQ, Air Quality Planning Section, 1110 West Washington, Phoenix, AZ 85007

Telephone: (602) 771-4461 (Any extension may be reached in-state by dialing 1-800-234-5677, and asking for a specific number.)

Fax: (602) 771-2366

E-mail: Lillie.David@ev.state.az.us

10. The time, place, and nature of the proceedings for the making, amendment, or repeal of the rule or, if no proceeding is scheduled, where, when and how persons may request an oral proceeding on the proposed rule:

Date: April 7, 2003

Time: 4:30 p.m.

Location: Coconino Library, 300 W. Aspen, Flagstaff, AZ

Date: April 8, 2003

Time: 4:30 p.m.

Location: ADEQ, 1110 W. Washington St, Rm 145, Phoenix, AZ

Date: April 9, 2003

Time: 4:30 p.m.

Location: State Office Building, 400 W. Congress, Rm 158, Tucson, AZ

Nature: Oral Proceedings with opportunity for formal comments on the record

Close of Comment: 5:00 p.m., April 11, 2003

11. Any other matters prescribed by statute that are applicable to the specific agency or to any specific rule or class of rules:

Not applicable

12. Incorporation by reference and their location in the rule:

Not applicable

13. The full text of the rule follows:

TITLE 18. ENVIRONMENTAL QUALITY
CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR POLLUTION CONTROL
ARTICLE 1. GENERAL

Section

R18-2-101 Definition of "visibility impairment" …… Amend

ARTICLE 16. VISIBILITY; REGIONAL HAZE

Section

R18-2-1601 Definitions …… New Section

R18-2-1602 Applicability …….New Section

R18-2-1603 Certification of Impairment ……..New Section

R18-2-1604 Attribution Analysis; Finding ……...New Section

R18-2-1605 BART Control Analysis; Finding …….New Section

R18-2-1606 Exemption from BART …… New Section

ARTICLE 1. GENERAL

R18-2-101. Definitions

In addition to the definitions prescribed in A.R.S. §§ 49-101, 49-401.01, 49-421, 49-471, and 49-541, in this Chapter, unless otherwise specified:

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123. "Visibility impairment" means any humanly perceptible change in visibility (light extinction, visual range, contrast, and coloration) from that which would have existed under natural conditions.

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ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1601. Definitions

In addition to the definitions contained in Articles 1 and 4 of this Chapter and A.R.S. § 49-401.01, the

following definitions apply to this Article:

1. "Best available retrofit technology (BART)" means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant that is emitted by an existing stationary facility. The emission limitation is established on a case-by-case basis in accordance with R18-2-1605.

2. "Existing stationary facility" means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

    a. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,

    b. Coal cleaning plants (thermal dryers),

    c. Kraft pulp mills,

    d. Portland cement plants,

    e. Primary zinc smelters,

    f. Iron and steel mill plants,

    g. Primary aluminum ore reduction plants,

    h. Primary copper smelters,

    i. Municipal incinerators capable of charging more than 250 tons of refuse per day,

    j. Hydrofluoric, sulfuric, and nitric acid plants,

    k. Petroleum refineries,

    l. Lime plants,

    m. Phosphate rock processing plants,

    n. Coke oven batteries,

    o. Sulfur recovery plants,

    p. Carbon black plants (furnace process),

    q. Primary lead smelters,

    r. Fuel conversion plants,

    s. Sintering plants,

    t. Secondary metal production facilities,

    u. Chemical process plants,

    v. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,

w. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,

x. Taconite ore processing facilities,

y. Glass fiber processing plants, and

z. Charcoal production facilities.

3. "Federal Land Manager" means the Secretary of the department, or the Secretary's designee, with authority over the Federal Class I area.

4. "Mandatory Federal Class I Area" means any area identified in 40 CFR §§81.400-81.436.

5. "Reasonably attributable" means ascribable by visual observation or other techniques the Director deems appropriate.

6. "Reasonably attributable visibility impairment" means visibility impairment that is caused by the emission of air pollutants from one source, or a small group of sources.

R18-2-1602. Applicability

This Article applies to any existing stationary source located in the state that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Federal Class I area identified in 40 CFR §§81.401-81.436. Mandatory Federal Class I areas within Arizona are: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness.

R18-2-1603. Certification of Impairment

A. A Federal Land Manager with authority over a mandatory Federal Class I area may certify to the Director, at any time, that there exists reasonably attributable visibility impairment in the mandatory Federal Class I area. The Director may also certify that there exists reasonably attributable visibility impairment in any mandatory Federal Class I area as necessary to assure reasonable progress under section 169A(b)(2) of the Clean Air Act.

B. Documentation from the affected Federal Land Manager or Director shall include:

1. The mandatory Federal Class I area for which visibility impairment is being certified,

2. Any information documenting the basis for the certification of impairment.

R18-2-1604. Attribution Analysis; Finding

A. Upon certification of reasonably attributable visibility impairment in any mandatory Federal

Class I area, the Director shall conduct an attribution analysis to identify each existing stationary source that may be reasonably anticipated to cause or contribute to visibility impairment. The Director shall notify the Federal Land Manager, affected source or small group of sources, and local air pollution control officer of the intent to conduct an attribution analysis. The attribution analysis shall be based on the following:

1. Monitoring information obtained through the Arizona Class I Visibility Monitoring Network or special studies approved by ADEQ to ascertain:
   a. The times visibility impairment occurred, and
   b. The pollutants contributing to the visibility impairment.
2. Transport analysis or air quality modeling based upon meteorological records to ascertain whether the pollutants were transported to the mandatory Federal Class I area.
3. Other available studies, modeling analysis, and emissions inventories of point, area and mobile source emissions to ascertain:
   a. The pollutant or pollutants causing the impairment, and
   b. The source, or small group of sources, emitting the impairing pollutant or pollutants.
4. Other relevant supporting documentation provided by the Federal Land Manager or Director used to make the draft attribution analysis finding.
5. Consideration of any documentation provided by the source or small group of sources.

B. In conducting the attribution analysis, the Director shall use monitoring information, meteorological records, and emissions inventories that represent times and locations reasonably concurrent with the visibility impairment.

C. The Director shall issue a draft attribution finding that impairment has or has not occurred, and provide public notice of the draft attribution finding. The Director shall publish notice of the draft attribution finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, if any, and shall clearly set forth reasons why the draft attribution finding should be reviewed. A final attribution finding shall be issued after the public comment period. Existing stationary sources found to cause or contribute to visibility impairment in a mandatory Federal Class I area shall be subject to a BART Control Analysis under R18-2-1605.

R18-2-1605. BART Control Analysis; Finding

A. The Director shall analyze for BART controls each existing stationary source for which a final attribution finding is made under R18-2-1604(C). The Director shall consider the following factors:

1. Available control technology;
2. New source performance standards (NSPS) as adopted in Article 9;
3. Alternative control systems if retrofitting to comply with applicable NSPS standards adopted in Article 9 is found infeasible.
4. Cost of compliance;
5. Energy and non-air quality environmental impacts of compliance;
6. Existing pollution control technology in use at the source or small group of sources;
7. Remaining useful life of the source or small group of sources;
8. Net environmental impact associated with the proposed emission control system;
9. Economic impacts associated with installing and operating the proposed emission control system; and
10. Degree of improvement in visibility anticipated to result from application of the proposed emission control system.

B. The Director shall issue a draft BART finding, and provide public notice of the draft BART finding. The Director shall publish notice of the draft BART finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, and shall clearly set forth reasons why the draft BART finding should be reviewed. The Director shall issue a final BART finding after the public comment period.

1. The Director shall submit each final BART finding that an existing stationary source is required to meet BART to the Administrator as a revision to the state implementation plan (SIP).
2. The Director shall require that each existing stationary source meet BART as expeditiously as practicable but in no case later than five years after EPA approval of the revision to Arizona's State Implementation Plan.

C. If the Director determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary source would make the imposition of an emission standard infeasible, the Director may, as part of the finding under subsection (B),

instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results.

D. The Director shall make a finding that the attributable source has satisfied the BART requirement if the attributable source has:

1. Voluntarily applied best available retrofit technology;
2. Previously applied emission control standards equivalent to BART; or
3. Agreed to shutdown or curtail operations at the attributable source within 5 years of the finding. An attributable source that does not shutdown or curtail operations shall proceed to meet BART as expeditiously as practicable, but in no case later than five years after EPA's approval of the revision to Arizona's State Implementation Plan.

E. If the Director determines that the imposition of BART or a standard pursuant to subsection C of this section is not feasible at the time of the finding, the attributable source shall be required to install and operate BART upon a determination by the Director at a later date that BART or equivalent controls are now feasible.

F. The Director shall provide for a BART control analysis of any existing stationary source that might cause or contribute to impairment of visibility in any mandatory Federal Class I area identified under this Article at such times, as determined by the Administrator, new technology for control of the pollutant becomes reasonably available, if:

1. The pollutant is emitted by that existing stationary source,
2. Controls representing BART for the pollutant have not previously been required under this Article, and
3. The impairment of visibility in any mandatory Federal Class I area is reasonably attributable to the emissions of that pollutant.

R18-2-1606. Exemption from BART

Any existing stationary source required to install, operate, and maintain BART pursuant to this Article, may apply to the Administrator for an exemption from that requirement by obtaining prior written concurrence from the Director according to 40 CFR 51.303.

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

AIR QUALITY DIVISION

PUBLIC HEARING
on
PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

PLEASE NOTE THE MEETING LOCATION AND TIME:

Coconino Public Library
300 W. Aspen, Flagstaff, AZ
Monday, April 7, 2003, 4:30 p.m.

Pursuant to ARS § 49-425 for air quality rule hearings, notice is hereby given that the above referenced meeting is open to the public. Copies of the proposal are available for review locally at the Coconino Public Library and the Arizona Department of Environmental Quality Library, 1110 W. Washington Street, Phoenix, Arizona.

AGENDA

1. Welcome and Introductions
2. Purposes of the Oral Proceeding
3. Procedure for Making Public Comment
4. Brief Overview of the Proposed Reasonably Attributable Visibility Impairment Rule
5. Question and Answer Period
6. Oral Comment Period
7. Adjournment of Oral Proceeding

For additional information regarding the hearing, please call Corky Martinkovic, ADEQ Air Quality Division, at (602) 771-2372] or 1-800-234-5677, Ext. 771-2372. Persons with a disability may request a reasonable accommodation, such as a sign language interpreter, by contacting Katie Huebner at (602) 771-4794 or 1-800-234-5677, Ext. 771-4794. Requests should be made as early as possible to allow sufficient time to make the arrangements for the accommodation. This document is available in alternative formats by contacting ADEQ TDD phone number at (602) 771-4829.

Arizona Department of Environmental Quality
Air Quality Division

Please Sign In

PUBLIC HEARING FOR

SUBJECT REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE DATE 4-7-03 (FLAGSTAFF)

	NAME	ORGANIZATION	PHONE	FAX	E-MAIL
1.	Carl Bowman	National Park Service	928-638-7817	928-638-7757	carl_bowman@nps.gov
2.					
3.					
4.					
5.					
6.					
7.					
8.					

P U B L I C H E A R I N G 04 /07 /03

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALTIY

IN THE MATTER OF ARIZONA'S
PROPOSED REASONABLY ATTRIBUTABE
VISIBILITY IMPAIRMENT RULE.

PUBLIC HEARING

At: Flagstaff, Arizona

Date: April 7, 2003

NOTE: Due to circumstances beyond ADEQ's control, the official transcript for this public hearing is not available. The hearing did follow verbatim the text of the public hearing officer script; therefore, that script has been included here along with a copy of the one comment read into the record.

Proposed Reasonably Attributable Visibility Impairment Rule

Oral Proceeding
Hearing Officer Script

April 7, 2003

I now open this oral proceeding. Good afternoon, thank you for coming. This oral proceeding is on the proposed Reasonably Attributable Visibility Impairment Rule. This is a proposed rule to direct the State of Arizona and affected permitted stationary sources on the procedures should a Federal Land Manager certify that any one of these sources or small group of sources have emissions that may cause or contribute to the reduction of visibility at specific national parks or wilderness areas in Arizona or adjacent states.

It is now Monday, April 7, 2003, 4:30 [ ] p.m. The location is Coconino Library, 300 W. Aspen, Flagstaff, Arizona.

My name is Cathy O'Connell and I have been appointed by the Director of the Arizona Department of Environmental Quality to preside at this proceeding.

The purposes of this proceeding are to provide the public an opportunity:
(1) to hear about the substance of the proposed rule,
(2) to ask questions regarding the proposed rule, and
(3) to present oral argument, data and views regarding the proposed rule in the form of comments on the record.

Representing the Department are myself and Ms. Corky Martinkovic of the Air Quality Planning Section.

The procedure for making a public comment on the record is straightforward. If you wish to comment, you need to fill out a speaker slip, which is available at the sign-in table, and give it to me. Using speaker slips allows everyone an opportunity to be heard and allows us to match the name on the official record with the comments.

You may also submit written comments to me today in person or by mail, e-mail, or fax to Corky Martinkovic by the end of the comment period. The end of the comment period is 5:00 p.m. on Friday, April 11, 2003. If mailed, e-mailed, or faxed, written comments must be "postmarked" no later than April 11, 2003. Submit your written comments to:

Corky Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 W. Washington Street
Phoenix, Arizona 85007
Fax: (602) 771-2366
E-Mail: martinkovic.deborrah@ev.state.az.us

Comments made during the formal comment period are required by law to be considered by the Department in the preparation of the final rulemaking. This is done through the preparation of a concise explanatory statement in which the Department responds in writing to written and oral comments made during the formal comment period.

The agenda for this hearing is simple. First, I will present a brief overview of the proposed rule.

Next, I will conduct a question and answer period. The purpose of the question and answer period is to provide information that may help you in making comments on the rule.

Thirdly, I will conduct the oral comment period. At that time, I will begin to call speakers in the order that I have received speaker slips.

Please be aware that any comments you make at today's hearing that you want the Department to formally consider must be given either in writing or on the record during the oral comment period of this proceeding.

* * * * *

At this time, I [(or)] will give a brief overview of the proposed rule.

The Reasonably Attributable Visibility Impairment Rule, or RAVI for short, will, upon approval, become a new section in the environmental chapter of the Arizona Administrative Code. States are required to adopt this rule under Federal regulations.

The rule addresses a specific type of air pollution that can reduce visibility in national parks and wilderness areas. This type of pollution is a type of air pollution that can be

traced to a certain type of existing stationary source. When a source has this type of air pollution traced directly to their operations, they are said to be "reasonably attributable" for that type of pollution.

For the purposes of this rule, this type of pollution originates from a specific type of existing stationary source operating in or near federal national parks and wilderness areas, known formally as federal mandatory Class I areas. Arizona has 12 of these Class I areas. These national parks and wilderness areas are managed by Federal Land Managers. Federal Land Managers are able to "certify" for the national park or wilderness area for which they have jurisdiction that there exists a reduction in visibility. They can document the reduction in visibility they observe in the park or wilderness area, and then complete a formal report certifying impairment of visibility.

Once the State of Arizona receives a certification of visibility impairment from a Federal Land Manager, under the proposed rule, the State would determine if the source is one of the type of stationary sources covered by the rule. Then the State of Arizona would analyze if that source is in fact causing or contributing to the reduction in visibility, or in the words of the rule, is "reasonably attributable."

If the source is eligible for emission controls and found to be attributable for the reduction in visibility, under the proposed rule, the State of Arizona would then proceed with an analysis for the application and operation of emission controls for that source's air emissions. The emission controls applied under this rule are known as Best Available Retrofit Technology, or BART. BART is applied to existing stationary sources that are too old to operate under what is termed, New Source Performance Standards, and yet emit 250 or more tons per year of air pollutants that impair visibility.

Along with outlining the procedures for the BART control analysis of the attributable source, the proposed rule points to options for a source to pursue equivalent or better alternatives, or apply for a federal- level exemption.

This concludes the explanation period of this proceeding on the proposed rule.

* * * * *

Are there any questions before we move to the oral comment period?

[If there are questions, introduce appropriate staff as the Department's representative to respond to any questions.]

[or, "Hearing none, ..."]

This concludes the question and answer period of this proceeding on the proposed rule.

* * * * *

I now open this proceeding for oral comments.

[Call speakers in the order in which they submitted their speaker's slips; if there are many speakers present, you may limit each speaker's time to speak.]

[or, “Seeing no speaker slips, ...]

This concludes the oral comment period of this proceeding.

* * * * *

I encourage everyone to submit written comments on the proposed rule. Your participation is an essential part of the rulemaking process. Again, you may also submit written comments by mail, e-mail, or fax to Corky Martinkovic by the end of the comment period. The end of the comment period is 5:00 p.m. on Friday, April 11, 2003. If mailed, e-mailed, or faxed, written comments must be “postmarked” no later than April 11, 2003. Submit your written comments to:

Corky Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 W. Washington Street
Phoenix, Arizona 85007
Fax: (602) 771-2366
E-Mail: martinkovic.deborrah@ev.state.az.us

Thank you for attending.

The time is now _____. I now close this oral proceeding.

Arizona Department of Environmental Quality
Air Quality Division

SPEAKER SLIP

Date: April 7, 2003 Speaker Slip No. 1

Name: Carl Bowman

Representing: National Park Service

Mailing Address: P.O. Box 129, Grand Canyon, AZ 86023

- [x] I wish to make an oral statement.
- [ ] I have submitted written comments.
- [ ] I will submit written comments at a later time.

Subject: [illegible]

Oral Remarks, April 7, 2003

I am Carl Bowman, Air Quality Specialist at Grand Canyon National Park, and am here representing the National Park Service. Our agency has participated in workshops to develop the proposed "Reasonably Attributable Visibility Impairment (or "RAVI") Rule since June of 2000. The rule as proposed today addresses a key resource issue by helping to protect and improve the magnificent vistas in Arizona's Class I parks and wilderness areas. There is no substitute for seeing clearly the rugged beauty of the Grand Canyon, the vibrant colors of the Painted Desert, or the beauty of the other Parks and Wilderness Areas that stand to benefit from this proposal. We believe the proposed rule not only meets the requirements of the Clean Air Act in protecting clear air from specific sources of air pollution, but will also assist the State of Arizona in evaluating and remedying specific pollution sources found to affect these areas.

As participants in the State's process to develop the proposed RAVI Rule, we also appreciate the diligence shown by the Department of Environmental Quality in reaching out to all potentially affected parties and in the open process used to develop the proposed Rule. Such stakeholder processes may take longer and be more cumbersome, but they do allow ample opportunities to gather comments, concerns and support from a wide spectrum of viewpoints, and thus, to craft a more complete and acceptable package.

The effort to preserve and restore visibility in Arizona's twelve Class I Parks and Wilderness Areas will require efforts on many fronts. We know that voluntary commitments have already been made in Arizona and other western states through the regional haze process, including the work of the Grand Canyon Visibility Transport Commission and the Western Regional Air Partnership. Once incorporated into a state regional haze rule, we can hope these commitments will be sufficient to make the goal of natural visibility conditions possible. At the same time, we realize that other tools, like the RAVI Rule, may be necessary on occasion, to address specific concerns. Together, we believe the various existing air programs, today's Proposal, and the regional haze work in progress will move us toward our clear air goal.

Thank you.

Arizona Department of Environmental Quality
Air Quality Division

Public Hearing Presiding Officer Certification

I, Cathy O'Connell, the designated Presiding Officer, do hereby certify that the public hearing held by the Arizona Department of Environmental Quality was conducted on April 7, 2003, in the Coconino Public Library, Flagstaff, Arizona, in accordance with public notice requirements by publication in Arizona Administrative Register and other locations beginning March 7, 2003. Furthermore, I do hereby certify that the public hearing was recorded from the opening of the public record through concluding remarks and adjournment, and the transcript provided contains a full, true, and correct record of the above-referenced public hearing.

Dated this 7th day of April 2003.

Cathy O'Connell
[NAME OF PRESIDING OFFICER]

State of Arizona)
) ss.
County of Maricopa)

Subscribed and sworn to before me by _____ this 7 day of April 2003

Laura McFarland
Notary Public

Notary Public State of Arizona
Maricopa County
Laura McFarland
Expires April 02, 2004

My commission expires:

April 02, 2004

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

AIR QUALITY DIVISION

PUBLIC HEARING
on
PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

PLEASE NOTE THE MEETING LOCATION AND TIME:

Arizona Department of Environmental Quality, Room 145
1110 W. Washington Street, Phoenix, AZ
Tuesday, April 8, 2003, 4:30 p.m.

Pursuant to ARS § 49-425 for air quality rule hearings, notice is hereby given that the above referenced meeting is open to the public. Copies of the proposal are available for review at the Arizona Department of Environmental Quality Library, 1110 W. Washington Street, Phoenix, Arizona.

AGENDA

1. Welcome and Introductions
2. Purposes of the Oral Proceeding
3. Procedure for Making Public Comment
4. Brief Overview of the Proposed Reasonably Attributable Visibility Impairment Rule
5. Question and Answer Period
6. Oral Comment Period
7. Adjournment of Oral Proceeding

For additional information regarding the hearing, please call Corky Martinkovic, ADEQ Air Quality Division, at (602) 771-2372] or 1-800-234-5677, Ext. 771-2372. Persons with a disability may request a reasonable accommodation, such as a sign language interpreter, by contacting Katie Huebner at (602) 771-4794 or 1-800-234-5677, Ext. 771-4794. Requests should be made as early as possible to allow sufficient time to make the arrangements for the accommodation. This document is available in alternative formats by contacting ADEQ TDD phone number at (602) 771-4829.

Northern Regional Office
1515 East Cedar Avenue • Suite F • Flagstaff, AZ 86004
(928) 779-0313

Southern Regional Office
400 West Congress Street • Suite 433 • Tucson, AZ 85701
(520) 628-6733

Printed on recycled paper

PUBLIC HEARING
RAVI RULE
PHX.

Arizona Department of Environmental Quality
Air Quality Division

Please Sign In

PROPOSED RULE:
SUBJECT REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT (RAVI) DATE 4-8-03

	NAME	ORGANIZATION	PHONE	FAX	E-MAIL
1.	Byron James	ADEQ-Community Liaison	(928) 337-3515	(928) 337-5515	byron.state.az.us
2.	JERRY GEERING	THORNWOOD FURN.	602 2540434	602 3061455	
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5 ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY
6 PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY
7 IMPAIRMENT RULE
8
9 ORAL PROCEEDING
10
11
12
13 REPORTER'S TRANSCRIPT OF PROCEEDINGS
14
15 Phoenix, Arizona
16 April 8, 2003
4:45 p.m. - 4:55 p.m.
17
18
19 **ARIZONA REPORTING SERVICE, INC.**
Court Reporting
20 Suite Three
2627 North Third Street
21 Phoenix, Arizona 85004-1103
22 BY: DAWNA J. BOSWELL, RPR
Certified Court Reporter
23 Certificate No. 50326
Prepared for:
24
25 ADEQ

CERTIFIED COPY
(When in red)

1 PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY
2 IMPAIRMENT RULE ORAL PROCEEDING
3 taken on April 8, 2003, commencing at 4:45 p.m., at
4 the offices of the Arizona Department of Environmental
5 Quality, 1110 West Washington Street, Room 145,
6 Phoenix, Arizona, before DAWNA J. BOSWELL, Certified
7 Court Reporter No. 50326 for the State of Arizona.
8
BEFORE: MR. SEAN P. McCABE, Hearing Officer
9
10
11 APPEARANCES:
12 For Arizona Department of Environmental Quality:
13 Ms. Deborrah "Corky" Martinkovic
Air Quality Division
14 1110 West Washington Street
Phoenix, Arizona 85007
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25

1 HRG. OFF. McCABE: I now open this Oral
2 Proceeding. Good afternoon, and thank you for coming.
3 This Oral Proceeding relates to the
4 Reasonably Attributable Visibility Impairment Rule
5 proposed by the Arizona Department of Environmental
6 Quality and published in the Arizona Administrative
7 Register on March 7, 2003, Volume 9, Issue 10,
8 page 763. This rule, if it becomes effective, would
9 direct the State of Arizona and affected permitted
10 stationary sources on the procedures to follow in the
11 event that a Federal Land Manager certifies that any
12 one of these sources or a small group of sources have
13 emissions that may cause or contribute to the
14 reduction of visibility at specific national parks or
15 wilderness areas in Arizona or adjacent states.
16 This is Tuesday, April 8th, 2003, at
17 4:45 p.m. We are located in Room 145, Arizona
18 Department of Environmental Quality, 1110 West
19 Washington Street, Phoenix, Arizona. My name is Sean
20 McCabe, and I have been appointed by the Director of
21 the Arizona Department of Environmental Quality to
22 preside at this hearing.
23 The purposes of this proceeding are to
24 provide the public an opportunity, one, to hear about
25 the substance of the proposed rule; two, to ask

1 questions regarding the proposed rule; and three, to
2 present oral argument, data and views regarding the
3 proposed rule in the form of comments on the record.
4 Representing the Department are myself, and
5 Ms. Corky Martinkovic of the Air Planning Quality
6 Section.
7 The procedure for making a public comment on
8 the record is straightforward. If you wish to
9 comment, you need to fill out a speaker slip which is
10 available at the sign-in table and give it to me.
11 Using speaker slips allows everyone an opportunity to
12 be heard and allows us to match the name on the
13 official record with the comments.
14 You may also submit written comments to me
15 today in person or by mail, e-mail, or fax to Corky
16 Martinkovic by the end of the comment period. The end
17 of the comment period is 5:00 p.m. on Friday,
18 April 11th, 2003. If mailed, e-mailed, or faxed,
19 written comments must be postmarked no later than
20 April 11, 2003.
21 Submit your written comments to Corky
22 Martinkovic, Air Quality Planning Section, Arizona
23 Department of Environmental Quality, 1110 West
24 Washington Street, Phoenix, Arizona, 85007.
25 The fax number is (602) 771-2366, and the

1 e-mail is martinkovic.deborrah@ev.state.az.us.
2 Comments made during the formal comment
3 period are required by law to be considered by the
4 Department in the preparation of the final rulemaking.
5 This is done through the preparation of a concise
6 explanatory statement in which the Department responds
7 in writing to written and oral comments made during
8 the formal comment period.
9 The agenda for this hearing is simple.
10 First, I will present a brief overview of the proposed
11 rule. Next, I will conduct a question and answer
12 period, the purpose of which is to provide information
13 that may help you in making comments on the rule.
14 Thirdly, I will conduct the oral comment period. At
15 that time, I will call any speakers in the order in
16 which I have received speaker slips.
17 Please be aware that any comments you make at
18 today's hearing that you want the Department to
19 formally consider must be given either in writing or
20 on the record during the oral comment period of this
21 proceeding.
22 At this time, I will give a brief overview of
23 the proposed rule.
24 The Reasonably Attributable Visibility
25 Impairment Rule, or RAVI rule for short, will upon

1 approval become a new section in the environmental
2 chapter of the Arizona Administrative Code. States
3 are required to adopt this rule under federal
4 regulations.
5 The rule addresses a specific type of air
6 pollution that can reduce visibility in national parks
7 and wilderness areas. This type of pollution is a
8 type of air pollution that can be traced to certain
9 types of existing stationary sources. When a source
10 has this type of air pollution traced directly to
11 their operations, they are said to be "reasonably
12 attributable" for that type of pollution.
13 For the purposes of this rule, this type of
14 pollution originates from a specific type of existing
15 stationary source operating in or near federal
16 national parks and wilderness areas known formally as
17 federal mandatory Class I areas. Arizona has 12 of
18 these Class I areas. These national parks and
19 wilderness areas are managed by Federal Land Managers.
20 Federal Land Managers are able to certify whether the
21 national park or wilderness area for which they have
22 jurisdiction that there exists a reduction in
23 visibility. They can document the reduction in
24 visibility they observe in the park or wilderness area
25 and then complete a formal report certifying

1 impairment of visibility.

2 Once the State of Arizona receives the

3 certification of visibility impairment from a Federal

4 Land Manager, under the proposed rule, the State will

5 determine if the source is one of the type of

6 stationary sources covered by the rule. Then the

7 State of Arizona will analyze if that source is in

8 fact causing or contributing to the reduction of

9 visibility, or in the words of the rule, is reasonably

10 attributable.

11 If the source is eligible for emissions

12 controls and found to be attributable for the

13 reduction in visibility, under the proposed rule, the

14 State of Arizona would then proceed with an analysis

15 for the application and operation of emission controls

16 for that source's air emissions. The emission

17 controls applied under this rule are known as Best

18 Available Retrofit Technology or BART. BART is

19 applicable to existing stationary sources that are too

20 old to operate under what is termed New Source

21 Performance Standards and yet emit 250 or more tons

22 per year of air pollutants that impair visibility.

23 Along with outlining the procedures for the

24 BART control analysis of the attributable source, the

25 proposed rule points to options for a source to pursue

1 equivalent or better alternatives or apply for a
2 federal level exemption.
3 This concludes the explanation period of this
4 rulemaking, and I would like to ask if there are any
5 questions before we move on to the oral comment
6 period.
7 MR. GEERING: I just had a question about
8 what the definition of that in or near is. Obviously
9 in, but near --
10 MS. MARTINKOVIC: Generally there's a
11 50 kilometer, I believe that translates to 30-mile
12 buffer that goes around each Class I area. That's
13 considered to be a near area impact.
14 MR. GEERING: And then the pollutants that
15 affect visibility being like PM-10?
16 MS. MARTINKOVIC: Yes, and Nox, and sulfur,
17 SO2.
18 HRG. OFF. McCABE: The comment is by Jerry
19 Geering, Thornwood Furniture, and answered by Corky
20 Martinkovic.
21 Are there any other questions?
22 I now open -- go ahead.
23 MR. GEERING: We have this nonverbal
24 communication here.
25 HRG. OFF. McCABE: Yes.

1 MR. GEERING: Record that nonverbal
2 communication.
3 In reading through this, it says that you
4 guys looked at the list of things that the EPA
5 regulates, the industries, and then of those you found
6 10 and so on, and maybe 16 sources.
7 MS. MARTINKOVIC: Yes.
8 MR. GEERING: Just flat out, where is that
9 list contained? And, you know, woodworking
10 facilities, I know there's a few Title V permits in
11 the State that weren't included in the list, so my
12 assumption would be they are not on the EPA's list.
13 MS. MARTINKOVIC: If your source is not on
14 the actual list that is in the rule, you're not one of
15 those 26 categories, then you're not a BART eligible
16 source. So if you're not --
17 MR. GEERING: I couldn't find it. There they
18 are; I see it.
19 MS. MARTINKOVIC: Yes, it would be in the,
20 almost the next to the last page. There's a series
21 here under definitions in 1601, number 2, it lists all
22 the sources there. So if you're a facility that makes
23 250 tons per year of those air pollutants or is one of
24 these categorical sources, then that would put you in
25 that group.

1 MR. GEERING: Thank you.

2 HRG. OFF. McCABE: If there are no further

3 questions, we can proceed with the oral comment period

4 of this proceeding. If there is anyone who has oral

5 comments, please make them at this time.

6 Hearing none, I will encourage people to

7 submit written comments on the proposed rule. Your

8 participation is an essential part of the rulemaking

9 process, and again, you may also submit written

10 comments by mail, e-mail, or fax to Corky Martinkovic

11 by the end of the comment period which is 5:00 p.m. on

12 Friday, April 11, 2003. Your mailed, e-mailed, or

13 faxed written comments must be postmarked no later

14 than April 11, 2003, and submitted to Corky

15 Martinkovic, Air Quality Planning Section, Arizona

16 Department of Environmental Quality, 1110 West

17 Washington Street, Phoenix, 85007, or fax, area code

18 (602) 771-2366. E-mail is

19 martinkovic.deborrah@ev.state.az.us.

20 I thank you for attending. The time is now

21 4:55, and I close this oral proceeding.

22 (The proceedings concluded at 4:55 p.m.)

23

24

25

STATE OF ARIZONA)
) ss.
COUNTY OF MARICOPA)

I, DAWNA J. BOSWELL, Certified Court Reporter No. 50326 for the State of Arizona, do hereby certify that the foregoing printed pages constitute a full, true and accurate transcript of the proceedings had in the foregoing matter, all done to the best of my skill and ability.

WITNESS my hand this 22nd day of April, 2003.

Dawna J. Boswell
DAWNA J. BOSWELL
Certified Court Reporter
Certificate No. 50326

Arizona Department of Environmental Quality
Air Quality Division

Public Hearing Presiding Officer Certification

I, Sean McCabe, the designated Presiding Officer, do hereby certify that the public hearing held by the Arizona Department of Environmental Quality was conducted on April 8, 2003, at Arizona Department of Environmental Quality, Phoenix, Arizona, in accordance with public notice requirements by publication in Arizona Administrative Register and other locations beginning March 7, 2003. Furthermore, I do hereby certify that the public hearing was recorded from the opening of the public record through concluding remarks and adjournment, and the transcript provided contains a full, true, and correct record of the above-referenced public hearing.

Dated this 8th day of April, 2003.

[NAME OF PRESIDING OFFICER]
Sean P. McCabe

State of Arizona)
) ss.
County of Maricopa)

Subscribed and sworn to before me by _____ this ___ day of April 2003

Notary Public

My commission expires:
April 02, 2004

Notary Public State of Arizona
Maricopa County
Laura McFarland
Expires April 02, 2004

3033 North Central Avenue, Phoenix, Arizona 85012, (602) 207-2300

Janet Napolitano
Governor

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.adeq.state.az.us

Stephen A. Owens
Director

AIR QUALITY DIVISION

PUBLIC HEARING
on
PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

PLEASE NOTE THE MEETING LOCATION AND TIME:

State Office Building, Room 158
400 W. Congress, Tucson, AZ
Wednesday, April 9, 2003, 4:30 p.m.

Pursuant to ARS § 49-425 for air quality rule hearings, notice is hereby given that the above referenced meeting is open to the public. Copies of the proposal are available for review locally at the State Office Building and the Arizona Department of Environmental Quality Library, 1110 W. Washington Street, Phoenix, Arizona.

AGENDA

1. Welcome and Introductions
2. Purposes of the Oral Proceeding
3. Procedure for Making Public Comment
4. Brief Overview of the Proposed Reasonably Attributable Visibility Impairment Rule
5. Question and Answer Period
6. Oral Comment Period
7. Adjournment of Oral Proceeding

For additional information regarding the hearing, please call Corky Martinkovic, ADEQ Air Quality Division, at (602) 771-2372] or 1-800-234-5677, Ext. 771-2372. Persons with a disability may request a reasonable accommodation, such as a sign language interpreter, by contacting Katie Huebner at (602) 771-4794 or 1-800-234-5677, Ext. 771-4794. Requests should be made as early as possible to allow sufficient time to make the arrangements for the accommodation. This document is available in alternative formats by contacting ADEQ TDD phone number at (602) 771-4829.

Public Hearing - Tucson

Arizona Department of Environmental Quality
Air Quality Division

Please Sign In

SUBJECT Reasonably Attributable Visibility Impairment Rule (RAVI) DATE 4-9-03

	NAME	ORGANIZATION	PHONE	FAX	E-MAIL
1.	Jeff Yockey	TEP	520-884-3692	520-884-3666	jyockey@tucsonelectric.com
2.					
3.					
4.					
5.					
6.					
7.					
8.					

ADEQ
AIR QUALITY DIVISION
03 MAY 19 PM 2:37

ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

PUBLIC MEETING and ORAL PROCEEDINGS

PROPOSED REASONABLY ATTRIBUTABLE VISIBILITY IMPAIRMENT RULE

April 9, 2003

State Office Building, 400 West Congress

Tucson, Arizona

Reported By:
Arizona Court Reporting
Tucson, AZ (520) 623-3375

ORIGINAL

MR. MASSEY: I now open this oral proceeding. Good afternoon, thank you for coming. This oral proceeding is on the proposed Reasonably Attributable Visibility Impairment Rule. This is a proposed rule to direct the State of Arizona and affected permitted stationary sources on the procedures should a Federal Land Manager certify that anyone of these sources or small group of sources have emissions that may cause or contribute to the reduction of visibility at specific national parks or wilderness areas in Arizona or adjacent states.

It is now Wednesday, April 9, 2003, 4:36 P.M. The location is Room 158, State Office Building, 400 West Congress, Tucson, Arizona.

My name is Eric Massey and I have been appointed by the Director of the Arizona Department of Environmental Quality to preside at this proceeding.

The purpose of this proceeding is to provide the public an opportunity:

1. To hear about the substance of the proposed rule.
2. To ask questions regarding the proposed rule.
3. To present oral argument, data and views regarding the proposed rule in the form of comments on the record.

Representing the Department are myself and Mr. Ira Domsky of the Air Quality Division.

The procedure for making a public comment on the record is straightforward. If you wish to comment, you need to fill out a speaker slip, which is available at the sign-in table, and give it to me. Using speakers slips allows everyone an opportunity to be heard and allows us to match the name on the official record with the comments.

You may also submit written comments to me today in person or by mail, e-mail, or fax to Corky Martinkovic by the end of the comment period. The end of the comment period is 5:00 p.m. on Friday, April 11, 2003. If mailed, e-mailed or faxed, written comments must be "postmarked" no later than April 11, 2003. Please submit your written comments to:

Corky Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 West Washington Street
Phoenix, Arizona 85007
Fax (602) 771-2366
E-mail: martinkovic.deborrah@ev.state.az.us

Comments made during the formal comment period are required by law to be considered by the Department in the preparation of the final rule making.

This is done through the preparation of a concise explanatory statement in which the Department responds in writing to written and oral comments made during the formal comment period.

The agenda for this hearing is simple. First, I will present a brief overview of the proposed rule.

Next I will conduct a question and answer period. The purpose of the question and answer period is to provide information that may help you in making comments on the rule.

Thirdly, I will conduct the oral comment period. At that time I will begin to call speakers in the order that I have received speaker slips.

Please be aware that any comments you make at today's hearing that you want the Department to formally consider must be given either in writing or on the record during the oral comment period of this proceeding.

****

At this time I will give a brief overview of the proposed rule

The Reasonably Attributable Visibility Impairment Rule, or RAVI for short, will, upon approval,

1 become a new section in the environmental chapter of the
2 Arizona Administrative Code. States are required to
3 adopt this rule under Federal regulations.
4 The rule addresses a specific type of air
5 pollution that can reduce visibility in national parks
6 and wilderness areas. This type of pollution is a type
7 of air pollution that can be traced to a certain type of
8 existing stationary source. When a source has this type
9 of air pollution traced directly to their operations,
10 they are said to be "reasonably attributable" for that
11 type of pollution.
12 For the purposes of the rule, this type of
13 pollution originates from a specific type of existing
14 stationary source operating in or near federal national
15 parks and wilderness areas, known formally as Federal
16 Mandatory Class I areas. Arizona has 12 of these Class I
17 areas. These national parks and wilderness areas are
18 managed by Federal Land Managers. Federal Land Managers
19 are able to "certify" for the national park or wilderness
20 area for which they have jurisdiction that there exists a
21 reduction in visibility. They can document the reduction
22 in visibility they observe in the park or wilderness area
23 and then complete a formal report certifying impairment
24 of visibility.
25 Once the State of Arizona receives a

1 certification of visibility impairment from a Federal
2 Land Manager, under the proposed rule, the State would
3 determine if the source is one of the type of stationary
4 sources covered by the rule. Then the State of Arizona
5 would analyze if that source is in fact causing or
6 contributing to the reduction in visibility or in the
7 words of the rule, is reasonably attributable.
8 If the source is eligible for emission
9 controls and found to be attributable for the reduction
10 in visibility, under the proposed rule, the State of
11 Arizona would then proceed with an analysis for the
12 application and operation of emission controls for the
13 source's air emissions. The emission controls applied
14 under this rule are known as Best Available Retrofit
15 Technology, or BART. BART is applied to existing
16 stationary sources that are too old to operate under what
17 is termed, New Source Performance Standards, and yet emit
18 250 or more tons per year of air pollutants that impair
19 visibility.
20 Along with outlining the procedures for the
21 BART control analysis of the attributable source, the
22 proposed rule points to options for a source to pursue
23 equivalent or better alternatives, or apply for a
24 federal-level exemption.
25 This concludes the explanation period of

1 this proceeding on the proposed rule.

2 Are there any questions before we move to

3 the oral comment period?

4 MR. YOCKEY: So this would be just questions

5 about specific language in the rule or anything like

6 that?

7 MR. MASSEY: Yes.

8 MR. YOCKEY: My name is Jeff Yockey and I am

9 with Tucson Electric Power.

10 I do have one comment. In the definition in

11 1601, it gives the definition for existing stationary

12 facility. And then under the applicability in Section

13 1602, it says this article applies to any existing

14 stationary source, and I guess what I am wondering is

15 that -- is existing stationary source in 1602 supposed to

16 fall in with the definition of existing stationary

17 facility under the definition, or is that a larger group?

18 MR. DOMSKY: It should match up with the

19 definition.

20 MR. YOCKEY: So it is intended just to

21 include those that are included under the definition?

22 MR. DOMSKY: Right and I would ask you to

23 make a comment to the affect.

24 MR. YOCKEY: Okay.

25 MR. DOMSKY: This rule has been edited

1 enough times based on informal comments that some of the
2 flip-flop back and forth between facility and source, we
3 might not have caught all of those instances.
4 MR. MASSEY: Are there any other questions?
5 If there are no other questions then, this concludes the
6 question and answer period of this proceeding on the
7 proposed rule. I now open this proceeding for oral
8 comments, and if I could get the speaker slips.
9 And this is Jeff Yockey?
10 MR. YOCKEY: Yes.
11 My name is Jeff Yockey and I am here
12 representing Tucson Power, and my comment relates to the
13 definitions and applicability. If primarily the
14 applicability section relating to 1602, and it starts:
15 "This article applies to any existing stationary source,"
16 and I believe that it is intended to refer to the
17 definition in Section 1601, and I guess I would request
18 that that wording be changed to "existing stationary
19 facility" to match accurately with your definition.
20 MR. MASSEY: Mr. Yockey's speaker's slip is
21 the only speaker slip I have. Are there any others that
22 wish to submit comments this evening?
23 Seeing no additional speaker slips, this
24 concludes the oral comment period at this proceeding.
25 I encourage everyone to submit written

comments on the proposed rule. Your participation is an essential part of the rule making process. Again, you may also submit written comments by mail, e-mail or fax to Corky Martinkovic by the end of the comment period. The end of the comment period is 5:00 on Friday April 11, 2003. If mailed, e-mailed or faxed, written comments must be postmarked no later than April 11, 2003. Again, please submit your written comments to:

Corky Martinkovic
Air Quality Planning Section
Arizona Department of Environmental Quality
1110 West Washington Street
Phoenix, Arizona 85007
Or by fax: (602) 771-2366
By e-mail, martinkovic.deborrah@ev.state.az.us

Thank you all for attending. The time is now 4:49. I now close this oral proceeding.

1

2 C E R T I F I C A T E

3

4 STATE OF ARIZONA)
) ss.
5 COUNTY OF PIMA)

6

7 BE IT KNOWN that I took the foregoing Public
8 Hearing pursuant to request; that I was then and there a
9 Notary Public in and for the County of Pima, State of
10 Arizona; and that the testimony of the witness was
11 reduced to writing under my direction, all done to the
12 best of my skill and ability.
13 I DO FURTHER CERTIFY that I am not a
14 relative or attorney of either party, or otherwise
15 interested in the events of this action.

16

17 Ronald L. Lunsford, RPR

18

19

20 Notary Public

21 My Commission Expires:
22 December 31, 2004

23

24

25

Arizona Department of Environmental Quality
Air Quality Division

Public Hearing Presiding Officer Certification

I, Eric Massey, the designated Presiding Officer, do hereby certify that the public hearing held by the Arizona Department of Environmental Quality was conducted on April 9, 2003, at the State Capitol Building, Tucson, Arizona, in accordance with public notice requirements by publication in Arizona Administrative Register and other locations beginning March 7, 2003. Furthermore, I do hereby certify that the public hearing was recorded from the opening of the public record through concluding remarks and adjournment, and the transcript provided contains a full, true, and correct record of the above-referenced public hearing.

Dated this 9th day of April.

Eric C. Massey
[NAME OF PRESIDING OFFICER]

State of Arizona)
) ss.
County of Maricopa)

Subscribed and sworn to before me by _____ this 9 day of April 2003

Laura McFarland
Notary Public

Notary Public State of Arizona
Maricopa County
Laura McFarland
Expires April 02, 2004

My commission expires:

April 02, 2004

NOTICE OF FINAL RULEMAKING

TITLE 18. ENVIRONMENTAL QUALITY

CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR POLLUTION CONTROL

ARTICLE 16. VISIBILITY; REGIONAL HAZE

PREAMBLE

1. **Sections Affected** — **Rulemaking Action**

R18-2-101	Amend
Article 16	New Article
R18-2-1601	New Section
R18-2-1602	New Section
R18-2-1603	New Section
R18-2-1604	New Section
R18-2-1605	New Section
R18-2-1606	New Section

2. **The statutory authority for the rulemaking, including both the authorizing statute (general) and the statutes the rules are implementing (specific):**

General Authority: A.R.S. §§ 49-104(A)(11) and 49-425

Specific Authority: A.R.S. §§ 49-414 and 414.01

3. **The effective date of the rules:**

60 days after filing with the Secretary of State

4. **A list of all previous notices appearing in the Register addressing the final rules:**

Notice of Docket Opening: 9 A.A.R. 390, February 7, 2003

Notice of Proposed Rulemaking: 9 A.A.R. 763, March 7, 2003

5. **The name and address of agency personnel with whom persons may communicate regarding the rulemaking.**

Name: Deborrah "Corky" Martinkovic

Address: ADEQ, Air Quality Planning Section, 1110 West Washington Street,

Phoenix, AZ 85007
Telephone: (602) 771-2372 (Any extension may be reached in-state by dialing 1-800-234-5677, and asking for a specific number.)
Fax: (602) 771-2366
E-mail: martinkovic.deborrah@ev.state.az.us

6. An explanation of the rules, including the agency's reasons for initiating the rules:

Summary. This rule sets forth the process Arizona Department of Environmental Quality (ADEQ) will use to determine whether Best Available Retrofit Technology (BART) will be required for sources determined to be contributing to visibility impairment in a mandatory Federal Class I area. Federal regulations allow Federal Land Managers (FLMs) to certify sources defined in 40 CFR 51.301 as potential contributors to visibility impairment in any of the Arizona mandatory Federal Class I areas under Section 169A of the Clean Air Act (CAA).

Background. In 1977 Congress added a new section to the Clean Air Act - Section 169A, Visibility Protection for Federal Class I Areas - which established a national goal for, "the prevention of any future, and the remedying of any existing impairment of visibility in mandatory class I Federal areas which impairment results from man-made air pollution." In addition, the section required states to submit state implementation plans (SIPs) requiring best available retrofit technology (BART) for certain existing stationary sources found to cause or contribute to visibility impairment. On November 30, 1979, EPA promulgated a list of mandatory Federal Class I Areas (Class I areas) where visibility is an important value (44 FR 69122). There are 12 Class I areas identified in Arizona: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness (40 CFR 81.403).

On December 2, 1980 (45 FR 80084), EPA defined the role of the FLMs in certifying visibility impairment in the mandatory Federal Class I areas. On November 24, 1987 (52 FR 45132), FLMs identified Petrified Forest National Park, Saguaro Wilderness, and Grand Canyon National Park, as having visibility impairment possibly attributable to stationary sources. Under the 1980 rule, if found to cause or contribute to the impairment, certain existing stationary sources operating in or near the identified Class I areas could be subject to BART (A list of sources eligible for the possible application of

BART can be found at 40 CFR 51.301). On October 3, 1991, the Navajo Generating Station (NGS) was found by EPA to be causing or contributing to visibility impairment for the Grand Canyon National Park and eligible for BART (56 FR 50172). BART control analyses were subsequently performed by EPA, and other parties through related court actions. Under the 1980 rule, the federal expectation is that actions for determination of possible source attribution will be performed by the states. Therefore, Arizona needs to be prepared to proceed with an attribution analysis and assessment for the application of controls upon any determination of a BART eligible source being the possible cause or contributor to visibility impairment in a Class I area. This rule addresses that need.

Current Conditions. ADEQ has determined that this rule applies to any source in existing stationary source categories identified in 40 CFR 51.301 that are operating in or near the mandatory federal Class I areas in Arizona. The source is an existing stationary facility that includes any reconstructed source that was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year of any regulated pollutant. ADEQ estimates that there are potentially 10 such sources within Arizona. "In existence" is interpreted by EPA to be consistent with the term, "commence construction" found in Prevention of Serious Deterioration (PSD) regulations (40 CFR 51.165(a)(1)(xvi) and 40 CFR 52.21(b)(9)). If construction commenced after August 7, 1977, the source would be subject to the PSD/NSR (new source review) program (the state regulations are found at 18 A.C.C. 2, Article 4). However, EPA also notes "that sources, are not BART eligible if the only change at the plant was the addition of pollution controls. For example, if the only change at a copper smelter during the 1962 through 1977 time period was the addition of acid plants for the reduction of SO_2 emissions, these emission controls would not themselves trigger a BART review."[1]

Under this rule, ADEQ, when analyzing an attributable source for BART controls, must consider several factors including, for example, costs, remaining useful life of the source, and degree of improvement anticipated to result from the application of the controls (the factors are detailed in R18-2-1605). Sources required by ADEQ to install and operate BART controls have a final opportunity to request exemption from the requirement prior to the application of controls. This opportunity for a federal exemption from BART, is contained in R18-2-1606, and 40 CFR 51.303.

Summary. This rule outlines the process through which sources eligible for the application of BART will

[1] EPA proposed rule, 66 Federal Register 38119, July 20, 2001.

proceed if certified by the state of Arizona or an FLM as possibly causing or contributing to visibility impairment due to attribution. If found to be attributable for the impairment, a BART analysis will be performed to determine the level of controls necessary to remedy the impairment. This rule enables Arizona to fulfill the requirements of the Clean Air Act and the goal of section 169A of the Act to return the Nation's federal parks and wilderness areas to natural conditions.

Section-by-section Explanation for the Rule

R18-2-1601	This section lists the definitions that apply to this rule.
R18-2-1602	This section lists the Class I areas addressed by this rule for the applicable existing stationary facilities, as defined in R18-2-1601(2).
R18-2-1603	This section establishes the procedure for certification of impairment by either a Federal Land Manager with authority over a mandatory Federal Class I area, or the Director, should either believe there exists reasonably attributable visibility impairment in a Federal Class I area as listed in R18-2-1602.
R18-2-1604	This section establishes the procedure for an attribution analysis after certification of a source or group of sources as outlined in R18-2-1603. Upon completion of the attribution analysis, the procedure for the Director to issue draft and final attribution findings is outlined in R18-2-1604(C).
R18-2-1605	This section establishes the best available retrofit technology (BART) analysis procedure after a source is identified under R18-2-1604. Upon completion of the BART analysis, the procedure for the Director to issue draft and final BART findings, including alternatives to emission standards, is outlined in R18-2-1605(B) and (C), respectively. The specific conditions where BART would be satisfied due to past or planned actions by the facility are outlined in R18-2-1605(D). EPA determinations regarding new technology that might require a BART analysis for an applicable source, regardless of a source or small group of sources previously being certified and found attributable, are covered in R18-2-1605(E).
R18-2-1606	This section establishes the procedures for obtaining a federal exemption from a BART requirement.

7. <u>A reference to any study relevant to the rule that the agency reviewed and either relied on in its evaluation of or justification for the rule or did not rely on in its evaluation of or</u>

justification for the rule, where the public may obtain or review each study, all data underlying each study, and any analysis of each study and other supporting material:

None

8. A showing of good cause why the rules are necessary to promote a statewide interest if the rules will diminish a previous grant of authority of a political subdivision of this state:

Not applicable

9. The summary of the economic, small business, and consumer impact:

A. Rule Identification

These rules amend R18-2-101 ("visibility impairment" definition) and add new sections R18-2-1601 through R18-2-1606. For sources under ADEQ jurisdiction, the rules take the place of federal regulations that currently govern this area.

B. Entities Directly Impacted

1. Federal Land Managers. R18-2-1603 allows Federal Land Managers (FLMs) to certify visibility impairment in mandatory Class I areas. This was already allowed by federal rule. Under R18-2-1601 of the rule, the FLMs able to certify impairment in Arizona are with the United States Forest Service and the National Park Service. There are no FLMs in Arizona from the United States Fish and Wildlife Service, because this agency does not have jurisdiction over any of Arizona's mandatory federal Class I areas.

2. ADEQ. R18-2-1604 requires ADEQ to identify stationary sources that could cause or contribute to the certified visibility impairment. Prior to this rule, this function was carried out by EPA. R18-2-1605 would require ADEQ to analyze for BART (best available retrofit technology) controls those sources identified as causing or contributing to visibility impairment. Prior to this rule, this function was carried out by EPA. The impact of this rule on ADEQ will primarily be on the Air Quality Division, Permits and Assessment sections, with a corresponding reduction of impact on EPA.

3. Stationary sources. R18-2-1605 also requires stationary sources identified in #2 to install or operate the BART as determined by the Director. Prior to this rule, only EPA determined and required BART. To determine impacted stationary sources, ADEQ staff reviewed Title V permits from ADEQ's Air Permit files. Of the 26 industry categories listed in 40 CFR 51.301, only five categories were found to

exist under ADEQ's jurisdiction: steam electric plants, cement plants, primary copper smelters, lime plants, and industries using non-utility boilers. As a result, potentially 10 sources, representing 16 BART eligible units (boilers and kilns), could be affected by this rule. The combined potential to emit from these sources totaled 94,287 tons per year for NO_x, 141,036 tons per year for SO_2, and 12,146 tons per year for PM. The combined potential to emit for all pollutants for these 10 sources total approximately 250,000 tons per year.

C. Probable Costs and Benefits Associated with the BART/Visibility Impairment Process

1. Direct Costs - FLMs: FLM activities to certify visibility impairment in mandatory Class I areas may involve preparation and analysis of monitoring data, emission inventories, meteorological records, etc. ADEQ estimates that this cost per certification could be as much as $50,000 if extensive analysis is conducted. These costs exist whether or not these rules became final.

2. Direct Costs - ADEQ: ADEQ costs related to identifying whether a BART eligible stationary source causes or contributes to visibility impairment in Class I areas are based on the activities identified in R18-2-1604(A). ADEQ estimates that these costs could range from $100,000 – 200,000 per attribution analysis, and be primarily borne by the ADEQ's Air Quality Assessment Section. Costs related to analyzing identified sources for BART are based on the activities identified in R18-2-1605(A) and will be moderate, but less expensive than the attribution analysis. These costs will be primarily borne by ADEQ's Permits Section. These costs will accrue to the State. Finally, incorporating BART into an existing State air quality permit may require additional resources from the Permits Section. However, these costs, unlike costs for the attribution and BART analysis, would be covered by permit revision fees paid by the source, and would have existed whether or not these rules became final.

3. Direct Costs - Stationary sources: If a source or small group of sources is found to cause or contribute to visibility impairment, and the BART determination requires installation of retrofit controls, the costs to sources required to install BART will be substantial. The total cost to install a technology similar to BART at the Navajo Generating Station was estimated by SRP to be in the hundreds of millions of dollars (51 Federal Register 50172, October 3, 1991). However, the example of the Navajo Generating Station shows costs to install technology similar to BART can result even where there is no state rule. According to EPA, "Where a State defaults on its obligations under the visibility regulations, EPA may act in place of the State pursuant to a FIP under section 110(c) of the Act, 42 U.S.C. 7410(c)[2], and promulgate such limitation and measures as are required to achieve reasonable progress." (Ibid. at 50173, footnote not

included). Although ADEQ is listing these costs for information purposes, ADEQ is not attributing any costs to install and operate BART to this rule because such requirements can be imposed by the federal government without any State rule.

Benefits. Two kinds of benefits are associated with this rule. The first benefit is derived from reduced emissions. Although, BART could be required to be installed on sources even without this state rule, it is helpful to list the emission benefits. When BART is installed, visibility is improved. Over 4 million recreation visits were made to Grand Canyon National Park in FY 2001. These visits generate substantial revenue in and for the state of Arizona. Other scenic resources could also be improved with the installation of BART, and, though less significant than the Grand Canyon, would enhance the tourism resources of Arizona, as well as the quality of life for Arizona citizens. In addition, reduction of visibility-impairing emissions also has health benefits.

The second benefit is through the replacement of federal regulation with state regulation. The lack of state regulations implementing BART results in Arizona sources being subject to federal regulation implemented by EPA from Washington and San Francisco, headquarters for EPA's Region IX. These rules place the identification and analysis of BART sources with ADEQ rather than with EPA. Arizona is currently under a visibility Federal Implementation Plan (FIP), and one or two Arizona sources have considered or implemented technology similar to BART under federal rules. Because ADEQ already permits many of these sources, ADEQ will be more familiar with the various factors that go into the BART analysis. This would be a benefit to sources being regulated. ADEQ would be implementing the same BART rules that EPA does, with a resulting increase in costs for ADEQ and a decrease in costs for EPA.

This final rule further allows ADEQ to proceed with the implementation of the entire federal rule for visibility improvement. The rule addresses the requirements of 40 C.F.R. §§51.302 – 51.307. These sections must be satisfied before ADEQ can implement the requirements of 40 C.F.R. §§51.308 and 51.309. The plan to implement Section 309 must be submitted to EPA by December 31, 2003.

D. Small Business Analysis

A.R.S. § 41-1055(B)(5) requires agencies to state the probable impact of a rulemaking on small businesses. A.R.S. § 41-1035 requires agencies to reduce the impact of a rule on small businesses by using certain methods when they are legal and feasible in meeting the statutory objectives for the rule

making. These methods include: (1) exempting them from any or all rule requirements, (2) establishing performance standards which would replace any design or operational standards, or (3) instituting reduced compliance or reporting requirements. An agency may accomplish the third method by establishing less stringent requirements, consolidating or simplifying requirements, or setting less stringent schedules or deadlines.

"Small business" is defined in A.R.S. §41-1001 as "a concern, including its affiliates, which is independently owned and operated, which is not dominant in its field and which employs fewer than one hundred full-time employees or which had gross annual receipts of less than four million dollars in its last fiscal year." Interpreting this definition means that if a concern has annual gross receipts of more than four million dollars, but fewer than 100 employees, it would not be classified as a small business.

ADEQ expects that none of the potential BART eligible sources will be classified as a small business. ADEQ's conclusion is that this rule will not impact small business sources. However, if a BART eligible source would qualify as a small business, under federal rule, ADEQ could not establish different requirements for these small business sources. If there are any small businesses that sell, install, or maintain BART-related technology, they will benefit from this rule.

In the preliminary EIS, ADEQ requested comment and additional information relating to any of the conclusions reached above and did not receive any.

10. <u>A description of the changes between the proposed rules, including supplemental notices, and final rules (if applicable):</u>

Changes were made with the cooperation of GRRC Staff to improve the clarity, conciseness and understandability of the rule. The changes are shown below:

A new definition was placed at R18-2-101(71), to clarify a term used in the proposed definition of "visibility impairment" at R18-2-101(123):

<u>71.</u> <u>"Natural conditions" includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.</u>

In addition, the word "and" was removed from the definition of "visibility impairment", as shown:

~~123~~124. "Visibility impairment" means any humanly perceptible change in visibility (light extinction, visual range, contrast, ~~and~~ coloration) from that which would have existed under natural conditions.

Both definitions are copied exactly from federal regulations at 40 CFR 51.308.

In addition, new Article 16 was amended as follows:

ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1601. Definitions

In addition to the definitions contained in Articles 1 and 4 of this Chapter and A.R.S. § 49-401.01, the following definitions apply to this Article:

1. "Best available retrofit technology (BART)" means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant ~~that is~~ emitted by an existing stationary facility. The emission limitation is established on a case-by-case basis ~~in accordance with~~ under R18-2-1605.
2. "Existing stationary facility" means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation ~~prior to~~ before August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. ~~In determining~~ A person who determines potential to emit~~,~~ shall count fugitive emissions~~,~~ to the extent quantifiable~~, must be counted~~.
    a. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input~~,~~;
    b. Coal cleaning plants (thermal dryers)~~,~~;
    c. Kraft pulp mills~~,~~;
    d. Portland cement plants~~,~~;
    e. Primary zinc smelters~~,~~;
    f. Iron and steel mill plants~~,~~;
    g. Primary aluminum ore reduction plants~~,~~;
    h. Primary copper smelters~~,~~;
    i. Municipal incinerators capable of charging more than 250 tons of refuse per day~~,~~;
    j. Hydrofluoric, sulfuric, and nitric acid plants~~,~~;
    k. Petroleum refineries~~,~~;
    l. Lime plants~~,~~;

m. Phosphate rock processing plants~~,~~;

n. Coke oven batteries~~,~~;

o. Sulfur recovery plants~~,~~;

p. Carbon black plants (furnace process)~~,~~;

q. Primary lead smelters~~,~~;

r. Fuel conversion plants~~,~~;

s. Sintering plants~~,~~;

t. Secondary metal production facilities~~,~~;

u. Chemical process plants~~,~~;

v. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input~~,~~;

w. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels~~,~~;

x. Taconite ore processing facilities~~,~~;

y. Glass fiber processing plants~~,~~; and

z. Charcoal production facilities.

3. "Federal Land Manager" means the Secretary of the department, or the Secretary's designee, with authority over the Federal Class I area.

4. "Mandatory Federal Class I Area" means any area identified in 40 CFR §§81.400-81.436.

5. "Reasonably attributable" means ascribable by visual observation or other techniques ~~the Director deems appropriate~~ described in R18-2-1604.

6. "Reasonably attributable visibility impairment" means visibility impairment that is caused by the emission of air pollutants from one source, or a small group of sources.

R18-2-1602. Applicability

This Article applies to any existing stationary source located in the state that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Federal Class I area identified in 40 CFR §§81.401-81.436. Mandatory Federal Class I areas within Arizona are: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness.

R18-2-1603. Certification of Impairment

A. A Federal Land Manager with authority over a mandatory Federal Class I area may certify to the

Director, at any time, that ~~there exists~~ a reasonably attributable visibility impairment exists in ~~the~~ a mandatory Federal Class I area. The Director may also certify that ~~there exists~~ reasonably attributable visibility impairment exists in any mandatory Federal Class I area ~~as necessary~~ to assure reasonable progress under section 169A(b)(2) of the Clean Air Act.

B. Documentation ~~from the affected Federal Land Manager or Director~~ that supports the Federal Land Manager or Director's certification shall include:

1. The mandatory Federal Class I area for which visibility impairment is being certified,
2. Any information documenting the basis for the certification of impairment.

R18-2-1604. Attribution Analysis; Finding

A. ~~Upon certification of reasonably attributable visibility impairment in any mandatory Federal Class I area~~ If a mandatory Federal Class I area is certified as having reasonably attributable visibility impairment, the Director shall conduct an attribution analysis to identify each existing stationary source that may be reasonably anticipated to cause or contribute to visibility impairment. The Director shall notify the Federal Land Manager, affected source or small group of sources, and local air pollution control officer of the intent to conduct an attribution analysis. The attribution analysis shall be based on the following:

1. Monitoring information obtained through the Arizona Class I Visibility Monitoring Network or special studies approved by ADEQ to ascertain:
   a. The times visibility impairment occurred, and
   b. The pollutants contributing to the visibility impairment~~.~~;
2. Transport analysis or air quality modeling based upon meteorological records to ascertain whether the pollutants were transported to the mandatory Federal Class I area~~.~~;
3. Other available studies, modeling analyses, and emissions inventories of point, area, and mobile source emissions to ascertain:
   a. The pollutant ~~or pollutants~~ causing the impairment, and
   b. The source, or a small group of sources, emitting the ~~impairing~~ pollutant; ~~or pollutants.~~
4. Other relevant supporting documentation provided by the Federal Land Manager or Director used to make the draft attribution analysis finding~~.~~; and
5. Consideration of any documentation provided by the source, ~~or~~ a small group of sources~~.~~, or other interested parties.

B. In conducting the attribution analysis, the Director shall use monitoring information,

meteorological records, and emissions inventories that represent times and locations reasonably concurrent with the visibility impairment.

C. The Director shall issue a draft attribution finding that impairment has or has not occurred, and provide public notice of the draft attribution finding. The Director shall publish notice of the draft attribution finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, if any, and shall clearly set forth reasons why the Director should review the draft attribution finding ~~should be reviewed~~. The Director shall issue ~~A~~ a final attribution finding ~~shall be issued~~ after the public comment period. If the Director finds existing stationary sources ~~found to~~ cause or contribute to visibility impairment in a mandatory Federal Class I area, the source shall be subject to a BART Control Analysis under R18-2-1605.

R18-2-1605. BART Control Analysis; Finding

A. The Director shall analyze for BART controls each existing stationary source for which a final attribution finding is made under R18-2-1604(C). The Director shall consider the following factors:

1. Available control technology;
2. New source performance standards (NSPS) ~~as adopted~~ in Article 9;
3. Alternative control systems if retrofitting to comply with applicable NSPS standards ~~adopted~~ in Article 9 is ~~found~~ infeasible~~.~~;
4. Cost of compliance;
5. Energy and non-air quality environmental impacts of compliance;
6. Existing pollution control technology in use at the source or small group of sources;
7. Remaining useful life of the source or small group of sources;
8. Net environmental impact associated with the proposed emission control system;
9. Economic impacts associated with installing and operating the proposed emission control system; and
10. Degree of improvement in visibility anticipated to result from application of the proposed emission control system.

B. The Director shall issue a draft BART finding, and provide public notice of the draft BART finding. The Director shall publish notice of the draft BART finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source.

The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, and shall clearly set forth reasons why the Director should review the draft BART ~~finding should be reviewed~~. The Director shall issue a final BART finding after the public comment period.

1. The Director shall submit each final BART finding ~~that an existing stationary source is required to meet BART~~ to the Administrator as a revision to the ~~state implementation plan (~~SIP~~)~~.
2. The Director shall require that each existing stationary source meet BART as expeditiously as practicable but in no case later than five years after EPA approval of the~~ revision to Arizona's State Implementation Plan~~ SIP revision.

C. If the Director determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary source would make the imposition of an emission standard infeasible, the Director may, as part of the finding under subsection (B), ~~instead~~ prescribe a design, equipment, work practice, ~~or other~~ operational standard, or combination ~~thereof~~ of design, equipment, work practice, or operational standard. ~~Such~~ The standard, to the degree possible, ~~is to~~ shall set forth the emission reduction to be achieved by implementation of ~~such~~ the design, equipment, work practice, or operation, and ~~must~~ shall provide for compliance by means ~~which~~ that achieve equivalent results.

D. The Director shall make a finding that the attributable source ~~has satisfied~~ satisfies the BART requirement if the attributable source ~~has~~:

1. Voluntarily ~~applied~~ applies best available retrofit technology;
2. Previously applied emission control standards equivalent to BART; or
3. ~~Agreed~~ Agrees to shutdown or curtail operations at the attributable source within ~~5~~ five years of the finding. An attributable source that does not shutdown or curtail operations shall ~~proceed to~~ meet BART as expeditiously as practicable, but in no case later than five years after EPA's approval of the revision to ~~Arizona's State Implementation Plan~~ the SIP.

E. If the Director determines that the imposition of BART or a standard ~~pursuant to~~ under subsection (C) ~~of this section~~ is ~~not feasible~~ infeasible at the time of the finding, the Director shall require the attributable source ~~shall be required~~ to install and operate BART ~~upon a determination by the Director~~ at a later date when the Director determines that BART or equivalent controls are ~~now~~

feasible.

F. The Director shall provide for a BART control analysis of any existing stationary source that might cause or contribute to impairment of visibility in any mandatory Federal Class I area identified under this Article at such time~~s,~~ as ~~determined by~~ the Administrator~~,~~ determines new control technology for ~~control of~~ the pollutant becomes reasonably available if:

1. The pollutant is emitted by that existing stationary source,
2. Controls representing BART for the pollutant have not previously been required under this Article, and
3. The impairment of visibility in any mandatory Federal Class I area is reasonably attributable to the emissions of that pollutant.

R18-2-1606. Exemption from BART

Any existing stationary source required to install, operate, and maintain BART ~~pursuant to~~ under this Article, may apply to the Administrator for an exemption from that requirement according to 40 CFR 51.303. ~~by obtaining prior written concurrence from the Director according to 40 CFR 51.303.~~ The existing stationary source shall obtain the Director's written concurrence before sending the application for exemption to the Administrator.

11. A summary of the comments made regarding the rule and the agency response to them:

ADEQ received one written comment. It expressed general support for the rule and for protecting visibility in Arizona's Class I parks and wilderness areas.

Comment: ADEQ received an oral comment that the word "facility" should be replaced by "source" in the definitions of "best available retrofit technology" and "existing stationary facility" to be consistent with the rest of the rule.

Response: ADEQ has kept these definitions the same as the federal definitions to ensure consistency. The definitions use the term "source" to define the terms, and "source" is used thereafter in the rules. ADEQ is not aware of any inconsistency.

12. Any other matters prescribed by statute that are applicable to the specific agency or to any specific rule or class of rules:

Not applicable

13. <u>Incorporation by reference and their location in the rule:</u>

Not applicable

14. <u>Were these rules previously adopted as emergency rules?</u>

No

15. <u>The full text of the rule follows:</u>

TITLE 18. ENVIRONMENTAL QUALITY

CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY

AIR POLLUTION CONTROL

ARTICLE 1. GENERAL

Section	
R18-2-101	Definitions

ARTICLE 16. VISIBILITY; REGIONAL HAZE

Section	
R18-2-1601	Definitions
R18-2-1602	Applicability
R18-2-1603	Certification of Impairment
R18-2-1604	Attribution Analysis; Finding
R18-2-1605	BART Control Analysis; Finding
R18-2-1606	Exemption from BART

ARTICLE 1. GENERAL

R18-2-101. Definitions

In addition to the definitions prescribed in A.R.S. §§ 49-101, 49-401.01, 49-421, 49-471, and 49-541, in this Chapter, unless otherwise specified:

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71. "Natural conditions" includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

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~~123.~~124. "Visibility impairment" means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.

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ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1601. Definitions

In addition to the definitions contained in Articles 1 and 4 of this Chapter and A.R.S. § 49-401.01, the following definitions apply to this Article:

1. "Best available retrofit technology (BART)" means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant emitted by an existing stationary facility. The emission limitation is established on a case-by-case basis under R18-2-1605.
2. "Existing stationary facility" means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation before August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. A person who determines potential to emit shall count fugitive emissions to the extent quantifiable.
   a. Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input;
   b. Coal cleaning plants (thermal dryers);
   c. Kraft pulp mills;
   d. Portland cement plants;

e. Primary zinc smelters;

f. Iron and steel mill plants;

g. Primary aluminum ore reduction plants;

h. Primary copper smelters;

i. Municipal incinerators capable of charging more than 250 tons of refuse per day;

j. Hydrofluoric, sulfuric, and nitric acid plants;

k. Petroleum refineries;

l. Lime plants;

m. Phosphate rock processing plants;

n. Coke oven batteries;

o. Sulfur recovery plants;

p. Carbon black plants (furnace process);

q. Primary lead smelters;

r. Fuel conversion plants;

s. Sintering plants;

t. Secondary metal production facilities;

u. Chemical process plants;

v. Fossil-fuel boilers of more than 250 million British thermal units per hour heat input;

w. Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels;

x. Taconite ore processing facilities;

y. Glass fiber processing plants; and

z. Charcoal production facilities.

3. "Federal Land Manager" means the Secretary of the department, or the Secretary's designee, with authority over the Federal Class I area.

4. "Mandatory Federal Class I Area" means any area identified in 40 CFR §§81.400-81.436.

5. "Reasonably attributable" means ascribable by visual observation or other techniques described in R18-2-1604.

6. "Reasonably attributable visibility impairment" means visibility impairment that is caused by the emission of air pollutants from one source, or a small group of sources.

R18-2-1602. Applicability

This Article applies to any existing stationary source located in the state that may reasonably be anticipated to cause or contribute to visibility impairment in any mandatory Federal Class I area identified

in 40 CFR §§81.401-81.436. Mandatory Federal Class I areas within Arizona are: Chiricahua National Monument Wilderness, Chiricahua Wilderness, Galiuro Wilderness, Grand Canyon National Park, Mazatzal Wilderness, Mount Baldy Wilderness, Petrified Forest National Park, Pine Mountain Wilderness, Saguaro Wilderness, Sierra Ancha Wilderness, Superstition Wilderness, and Sycamore Canyon Wilderness.

R18-2-1603. Certification of Impairment

A. A Federal Land Manager with authority over a mandatory Federal Class I area may certify to the Director, at any time, that a reasonably attributable visibility impairment exists in a mandatory Federal Class I area. The Director may also certify that reasonably attributable visibility impairment exists in any mandatory Federal Class I area to assure reasonable progress under section 169A(b)(2) of the Clean Air Act.

B. Documentation that supports the Federal Land Manager or Director's certification shall include:

1. The mandatory Federal Class I area for which visibility impairment is being certified,
2. Any information documenting the basis for the certification of impairment.

R18-2-1604. Attribution Analysis; Finding

A. If a mandatory Federal Class I area is certified as having reasonably attributable visibility impairment, the Director shall conduct an attribution analysis to identify each existing stationary source that may be reasonably anticipated to cause or contribute to visibility impairment. The Director shall notify the Federal Land Manager, affected source or small group of sources, and local air pollution control officer of the intent to conduct an attribution analysis. The attribution analysis shall be based on the following:

1. Monitoring information obtained through the Arizona Class I Visibility Monitoring Network or special studies approved by ADEQ to ascertain:
   a. The times visibility impairment occurred, and
   b. The pollutants contributing to the visibility impairment;
2. Transport analysis or air quality modeling based upon meteorological records to ascertain whether the pollutants were transported to the mandatory Federal Class I area;
3. Other available studies, modeling analyses, and emissions inventories of point, area, and mobile source emissions to ascertain:
   a. The pollutant causing the impairment, and
   b. The source, or a small group of sources, emitting the pollutant;

4. Other relevant supporting documentation provided by the Federal Land Manager or Director used to make the draft attribution analysis finding; and

5. Consideration of any documentation provided by the source, a small group of sources; or other interested parties.

B. In conducting the attribution analysis, the Director shall use monitoring information, meteorological records, and emissions inventories that represent times and locations reasonably concurrent with the visibility impairment.

C. The Director shall issue a draft attribution finding that impairment has or has not occurred, and provide public notice of the draft attribution finding. The Director shall publish notice of the draft attribution finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, if any, and shall clearly set forth reasons why the Director should review the draft attribution finding. The Director shall issue a final attribution finding after the public comment period. If the Director finds existing stationary sources cause or contribute to visibility impairment in a mandatory Federal Class I area, the source shall be subject to a BART Control Analysis under R18-2-1605.

R18-2-1605. BART Control Analysis; Finding

A. The Director shall analyze for BART controls each existing stationary source for which a final attribution finding is made under R18-2-1604(C). The Director shall consider the following factors:

1. Available control technology;
2. New source performance standards (NSPS) in Article 9;
3. Alternative control systems if retrofitting to comply with applicable NSPS standards in Article 9 is infeasible;
4. Cost of compliance;
5. Energy and non-air quality environmental impacts of compliance;
6. Existing pollution control technology in use at the source or small group of sources;
7. Remaining useful life of the source or small group of sources;
8. Net environmental impact associated with the proposed emission control system;
9. Economic impacts associated with installing and operating the proposed emission control system; and

10. Degree of improvement in visibility anticipated to result from application of the proposed emission control system.

B. The Director shall issue a draft BART finding, and provide public notice of the draft BART finding. The Director shall publish notice of the draft BART finding in a newspaper of general circulation in each county containing the mandatory Federal Class I area and the affected source. The Director shall provide at least 30 days from the date of the notice for public comment. Written comments to the Director shall include the name of the person and the person's agent or attorney, and shall clearly set forth reasons why the Director should review the draft BART finding. The Director shall issue a final BART finding after the public comment period.

1. The Director shall submit each final BART finding to the Administrator as a revision to the SIP.
2. The Director shall require that each existing stationary source meet BART as expeditiously as practicable but in no case later than five years after EPA approval of the SIP revision.

C. If the Director determines that technological or economic limitations on the applicability of measurement methodology to a particular existing stationary source would make the imposition of an emission standard infeasible, the Director may, as part of the finding under subsection (B), prescribe a design, equipment, work practice, operational standard, or combination of design, equipment, work practice, or operational standard. The standard, to the degree possible, shall set forth the emission reduction to be achieved by implementation of the design, equipment, work practice, or operation, and shall provide for compliance by means that achieve equivalent results.

D. The Director shall make a finding that the attributable source satisfies the BART requirement if the attributable source:

1. Voluntarily applies best available retrofit technology;
2. Previously applied emission control standards equivalent to BART; or
3. Agrees to shutdown or curtail operations at the attributable source within five years of the finding. An attributable source that does not shutdown or curtail operations shall meet BART as expeditiously as practicable, but in no case later than five years after EPA's approval of the revision to the SIP.

E. If the Director determines that the imposition of BART or a standard under subsection (C) is infeasible at the time of the finding, the Director shall require the attributable source to install and operate BART at a later date when the Director determines that BART or equivalent controls are feasible.

F. The Director shall provide for a BART control analysis of any existing stationary source that might cause or contribute to impairment of visibility in any mandatory Federal Class I area identified under this Article at such time as the Administrator determines new control technology for the pollutant becomes reasonably available:

1. The pollutant is emitted by that existing stationary source,
2. Controls representing BART for the pollutant have not previously been required under this Article, and
3. The impairment of visibility in any mandatory Federal Class I area is reasonably attributable to the emissions of that pollutant.

R18-2-1606. Exemption from BART

Any existing stationary source required to install, operate, and maintain BART under this Article, may apply to the Administrator for an exemption from that requirement according to 40 CFR 51.303. The existing stationary source shall obtain the Director's written concurrence before sending the application for exemption to the Administrator.

Appendix A-5d. New source review rule - R18-2-410

R18-2-410. Visibility Protection

A. For any new major source or major modification subject to the provisions of this Chapter, no permit or permit revision under this Article shall be issued to a person proposing to construct or modify the source unless the applicant has provided:
   1. An analysis of the anticipated impacts of the proposed source on visibility in any Class I areas which may be affected by the emissions from that source; and
   2. Results of monitoring of visibility in any area near the proposed source for such purposes and by such means as the Director determines is necessary and appropriate.

B. A determination of an adverse impact on visibility shall be made based on consideration of all of the following factors:
   1. The times of visitor use of the area;
   2. The frequency and timing of natural conditions in the area that reduce visibility;
   3. All of the following visibility impairment characteristics:
      a. Geographic extent,
      b. Intensity,
      c. Duration,
      d. Frequency,
      e. Time of day;
   4. The correlation between the characteristics listed in subsection (B)(3) and the factors described in subsections (B)(1) and (2).

C. The Director shall not issue a permit or permit revision pursuant to this Article or Article 3 of this Chapter for any new major source or major modification subject to this Chapter unless the following requirements have been met:
   1. The Director shall notify the individuals identified in subsection (C)(2) within 30 days of receipt of any advance notification of any such permit or permit revision under this Article.
   2. Within 30 days of receipt of an application for a permit or permit revision under this Article for a source whose emissions may affect a Class I area, the Director shall provide written notification of the application to the Federal Land Manager and the federal official charged with direct responsibility for management of any lands within any such area. The notice shall:
      a. Include a copy of all information relevant to the permit or permit revision under this Article,
      b. Include an analysis of the anticipated impacts of the proposed source on visibility in any area which may be affected by emissions from the source, and
      c. Provide for no less than a 30-day period within which written comments may be submitted.
   3. The Director shall consider any analysis provided by the Federal Land Manager that is received within the comment period provided in subsection (C)(2).
      a. Where the Director finds that the analysis provided by the Federal Land Manager does not demonstrate to the satisfaction of the Director that an adverse impact on visibility will result in the area, the Director shall, within the public notice required under R18-2-330, either explain the decision or specify where the explanation can be obtained.
      b. When the Director finds that the analysis provided by the Federal Land Manager demonstrates to the satisfaction of the Director that an adverse impact on visibility will result in the area, the Director shall not issue a permit or permit revision under this Article for the proposed major new source or major modification.
   4. When the proposed permit decision is made, pursuant to R18-2-304(J), and available for public review, the Director shall provide the individuals identified in subsection (C)(2) with a copy of the proposed permit decision and shall make available to them any materials used in making that determination.

Historical Note

Adopted effective May 14, 1979 (Supp. 79-1). Former Section R9-3-410 renumbered without change as Section R18-2-410 (Supp. 87-3). Section R18-2-410 renumbered to R18-2-610, new Section R18-2-410 adopted effective November 15, 1993 (Supp. 93-4).

APPENDIX A-6. CLEAN AIR CORRIDOR

This appendix contains work products and references relied upon by Arizona in the development of Chapter 6 of the Regional Haze SIP.

Appendix A-6a. WRAP Policy on Clean Air Corridors

WRAP Policy on Clean Air Corridors

Approved by WRAP Board
November 13, 2002

I. Summary of WRAP Policy

1. *Pursuant to 40 CFR 51.309(d)(3), the WRAP directs its Technical Oversight Committee (TOC) to track emissions and to describe the tracking process in such a way that can be included in state and tribal implementation plans. At a minimum, using the most recent state emission inventories available, the TOC should produce a report for each five-year implementation plan revision on the current and projected emissions in the clean air corridor and in areas outside the corridor and compare these emissions to a 1996 baseline for purposes of this section.*

2. *Pursuant to 40 CFR 51.309(d)(3)(i), the WRAP identifies one clean air corridor as shown in **Figure 1**. The counties within the corridor are listed in **Table 1**. For ease of administration, the corridor's boundary follows county lines.*

3. *Pursuant to 40 CFR 51.309(d)(3)(ii), the WRAP has examined patterns of growth in the corridor and finds that they are not causing significant emission increases that could have or are having visibility impacts at one or more of the 16 Class I areas. Nor, at this time, are such emission increases expected during the first planning period (2003-2018). Analyses performed by the Grand Canyon Visibility Transport Commission found that an increase of 25% in weighted emissions would result in a 0.7 dv reduction in visibility, whereas the weighted emission increase expected by 2018 is only 4%.*

4. *Pursuant to 40 CFR 51.309(d)(3)(iii), the WRAP has examined emissions growth in areas outside the corridor and finds that significant emissions growth is not occurring that could begin or is beginning to impair the quality of the air in the corridor and thereby lead to visibility degradation for the least impaired days in one or more of the 16 Class I areas.*

5. *Since impairment of air quality in clean air corridors has not been identified pursuant to 40 CFR 51.309(d)(3)(ii) and (iii), the WRAP finds no requirement under 40 CFR 51.309(d)(3)(iv) for further visibility impact analysis or additional emission reduction measures until at least the next SIP revision (2008). However, the WRAP encourages its appropriate technical activities – such as the Causes of Haze report – to take into account the assessment and protection of clean air corridors.*

6. *Pursuant to 40 CFR 51.309(d)(3)(v), the WRAP finds no other clean air corridors beyond the corridor identified in **Figure 1**.*

II. Clean Air Corridors, The Clean Air Act, And The Regional Haze Rule

The Clean Air Act Amendments of 1990 specifically require that visibility transport commissions, including the Grand Canyon Visibility Transport Commission ("Commission"), address "the establishment of clean air corridors, in which additional restrictions on increases in emissions may be appropriate to protect visibility in affected class I areas."[1] The Clean Air Act also requires protection of clean air corridors in a less direct way. The Act establishes as a national goal the prevention of any future impairment of visibility in mandatory Class I areas. As a measure of progress towards this goal, the U.S. Environmental Protection Agency (EPA) has established a criteria of no degradation on the 20% cleanest days. Such days on the Colorado Plateau are usually dominated by northwest winds, hence defining a corridor to the northwest that must be protected to meet the broader visibility goal of the Clean Air Act.

In its regional haze rule, the EPA provides more specificity on the requirements to protect clean air corridors, based largely on the recommendations of the Commission. The preamble of the rule defines a clean air corridor as "a region that generally brings clean air to a receptor region" The preamble also says, "the requirement to track emissions will enable states to quickly determine if changes in patterns of emissions will reduce the number of clean air days (defined as the average of the 20% clearest days) in any of the 16 Class I areas." The actual requirements of the rule are found in 40 CFR 51.309(d)(3):

> The [state implementation] plan must describe and provide for implementation of comprehensive emission tracking strategies for clean-air corridors to ensure that the visibility does not degrade on the least-impaired days at any of the 16 Class I areas. The strategy must include:
>
> (i) An identification of clean-air corridors. The EPA will evaluate the State's identification of such corridors based upon the reports of the Commission's Meteorology Subcommittee and any future updates by a successor organization.
>
> (ii) Within areas that are clean-air corridors, an identification of patterns of growth or specific sites of growth that could cause, or are causing, significant emissions increases that could have, or are having, visibility impairment at one or more of the 16 Class I areas.
>
> (iii) In areas outside of clean-air corridors, an identification of significant emissions growth that could begin, or is beginning, to impair the quality of air in the corridor and thereby lead to visibility degradation for the least-impaired days in one or more of the 16 Class I areas.
>
> (iv) If impairment of air quality in clean air corridors is identified pursuant to §§51.309(d)(3)(ii) and (iii), an analysis of the effects of increased emissions, including provisions for the identification of the need for additional emission reductions measures, and implementation of the additional measures where necessary.

[1] 42 U.S.C. 2169B(d)(2)(A).

(v) A determination of whether other clean air corridors exist for any of the 16 Class I areas. For any such clean air corridors, an identification of the necessary measures to protect against future degradation of air quality in any of the 16 Class I areas.

These requirements do not apply to states submitting state implementation plans (SIPs) under §308 of the rule. However, such states should provide the data necessary for other states to comply and should make a good faith effort to protect the integrity of clean air corridors.

III. The Commission's Findings and Recommendations

The Commission found that clean air corridors exist and that, generally, clean air comes to the Colorado Plateau from the northwest.[2] The Commission determined that one such corridor covers southern Utah, eastern Oregon, southwestern Idaho, and major portions of Nevada. This corridor was identified by the Commission's Meteorology Subcommittee, which examined the size and boundaries of the corridor under varying assumptions about the number of days defined as clean and the amount of protection to be afforded.[3]

Related work by Green et. al. [4] identifies three factors that explain why air from the northwest is clean when it arrives at the Colorado Plateau: low emissions of air pollutants, enhanced dispersion of the air pollutants due to higher average ventilation (wind speed multiplied by mixing depth), and increased removal of pollutants due to precipitation. Although the corridor is mostly arid, the cleanest days occur most frequently in the winter, when there is more precipitation than average. Green et al., nonetheless, conclude that the most important factor at the south rim of the Grand Canyon for most weather conditions is the low emissions of pollutants in the area to the northwest.

In addition to identifying a clean air corridor, the Commission projected emissions growth within the corridor through 2040 and found that growth is not expected to have a perceptible negative impact on the cleanest days on the Colorado Plateau. Specifically, a working group within the Meteorology Subcommittee used results from the IAS model (the model used to project visibility impacts in other Commission work) to estimate the emissions increase from 1990 that would be necessary to cause a perceptible decrease in visibility on the Plateau.[5] The working group found that increasing emissions by 25% within the corridor would result in an average change of 0.7 deciviews (dv), which would be imperceptible to most people under most conditions, while a 100% increase in emissions within the corridor would result in a change of 2.5 dv.[6] This

[2] Grand Canyon Visibility Transport Commission. Recommendations for Improving Western Vistas. Western Governors' Association. Denver, CO. June 1996.
[3] Meteorological Subcommittee, Grand Canyon Visibility Transport Commission. Clean Air Corridors: A Framework for Identifying Regions that Influence Clean Air on the Colorado Plateau. Denver, CO. August 1995.
[4] Green, M. C.; Pitchford, M. L.; and Ashbaugh, L.L. Identification of Candidate Clean Air Corridors for the Colorado Plateau. *J. Air & Waste Manage. Assoc. 1996. 46(5),* 446.
[5] Marc Pitchford. Oral communication. October 3, 2002. Participants on the working group included Dr. Pitchford, Dr. William Malm, and Dr. Ivar Tombach.
[6] BBC Research & Consulting, Inc., for the Operations Committee of the Grand Canyon Visibility Transport Commission. Clean Air Corridor: An Economic Perspective. Denver, CO. November 1995. Page III-2:6.

estimate was not based on a specific boundary for the corridor but rather on the general understanding of a corridor to the northwest of the Plateau. The implication, nonetheless, is that a 25% increase in emissions within the corridor could be considered a level of growth that would not impact visibility.

Using one of the proposed corridor alignments examined by the Meteorology Subcommittee – a corridor that would protect the 30% cleanest days on the Colorado Plateau, adjusted to account for emissions density and IAS region boundaries – BBC Research & Consulting conducted an economic and demographic assessment of the corridor to determine whether emissions would increase 25% by 2040. The assessment found that emissions are not expected to increase 25% by 2040.[7] Specifically, BBC used a weighting scheme defined in the IAS model to account for the varying effects of different pollutants on visibility. Total weighted emissions of elemental carbon, nitrogen oxides, organic carbon, particulate matter, reactive organic gases, and sulfur oxides in 1990 were 52,073 VEEU tons.[8] A 25% increase would yield 65,092 VEEU tons. BBC projected that emissions in the corridor would increase to 55,047 VEEU tons by 2040, thus leaving an ample margin of safety of 10,054 VEEU tons.[9]

As a result of these analyses, the Commission recommended that no targeted policies or regulatory programs to control emissions growth were needed at that time, but that a regional tracking and accounting system be implemented to make sure that the frequency of clear days does not decrease at the 16 Class I areas and that the Commission's assumptions about increased emissions are proven reliable. The Commission recommended that, within areas that are sources of clean air, the tracking and accounting system should identify patterns of growth that have a negative impact on visibility and that, in areas outside the clean air corridors, the tracking and accounting system should identify significant emissions growth that begins to impair the quality of air in the corridor.

IV. WRAP Policy

A. EMISSIONS TRACKING – §309(d)(3)

> *The WRAP directs its Technical Oversight Committee (TOC) to track emissions and to describe the tracking process in such a way that can be included in state and tribal implementation plans. At a minimum, using the most recent state emission inventories available, the TOC should produce a report for each five-year implementation plan revision on the current and projected emissions in the clean air corridor and in areas outside the corridor and compare these emissions to a 1996 baseline for purposes of this section.*

The tracking described above is intended to ensure that any unexpected changes are identified. This tracking would coincide with the periodic SIP revisions required in 2008, 2013, and 2018. States and tribes already prepare inventories at least every three years to meet federal

[7] BBC report, page III-5
[8] Visibility Equivalency Emission Units
[9] BBC report, page III-6.

requirements and will prepare detailed inventories annually for sources of sulfur dioxide of 100 tons per year or greater for compliance with the stationary source provisions of §309.[10] The WRAP will use these state and tribal data for tracking emissions in general and can summarize emissions for the counties and tribal lands within the corridor and for areas outside the corridor for use by states and tribes as they revise their regional haze SIPs every five years. Further information on tracking point sources and area sources is provided below.

POINT SOURCES. Any new, large source will be required to undergo a Prevention of Significant Deterioration review and an Air Quality Related Values analysis before receiving an air quality permit and will also be subject to New Source Performance Standards and other requirements, giving the public, states, tribes, and federal land managers ample opportunity to evaluate any possible visibility impacts on the 16 Class I areas. Thus, it is unlikely that point sources will lead to a 25% increase and even less likely that a trend in that direction would go unnoticed.

AREA AND MOBILE SOURCES. Population and economic growth is expected to be slow in the corridor, holding down emissions from area and mobile sources within the corridor. Federal standards recently promulgated for on-road sources and additional ones pending for non-road sources are expected to reduce emissions from both of these source categories during the first planning period of the implementation plans (2018). However, emissions from prescribed burning are expected to increase and, depending on the location of the burns, could affect visibility in the 16 Class I areas. It is hard to predict how great the effect will be on clean days, but it is not expected to be severe. For one, prescribed fires generally occur in the spring and fall, whereas most clear days occur in the winter. In addition, prescribed fires are much less intense than wild fires. Nonetheless, careful fire emissions tracking is warranted and is being developed under separate WRAP policy and technical efforts.

B. BOUNDARY OF THE CLEAN AIR CORRIDOR – §309(d)(3)(i)

> *The WRAP identifies one clean air corridor as shown in **Figure 1**. The counties within the corridor are listed in **Table 1**. For ease of administration, the corridor's boundary follows county lines.*

The WRAP adopts this boundary based on a balancing of demographic, economic, and air quality impact analyses performed on this corridor and their subsequent review and consensus-based approval by the Commission. The boundary identified is a slight modification of the boundary defined in the BBC report described above. The grid cells in the air quality analyses did not follow state or county boundaries, and for ease of administration the WRAP has removed small areas of southern Washington and southwestern Montana from the corridor. These small areas are far from the Colorado Plateau and unlikely to affect the Class I areas on the Plateau. In contrast, counties have been added to the corridor that were not originally included in the boundary defined in the BBC report. These include Box Elder, Tooele, and Grand Counties in Utah, Wasco and Sherman Counties in Oregon, and Cassia and Lemhi Counties in Idaho.

[10] Also see Western Regional Air Partnership. Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program, An Annex to the Report of the Grand Canyon Visibility Transport Commission. Denver, CO. September 29, 2000.

C. IDENTIFICATION OF EMISSIONS INCREASES – §309(d)(3)(ii) and (iii)

> *Pursuant to 40 CFR 51.309(d)(3)(ii), the WRAP has examined patterns of growth in the corridor and finds that they are not causing significant emission increases that could have or are having visibility impacts at one or more of the 16 Class I areas. Nor, at this time, are such emission increases expected during the first planning period (2003-2018). Analyses performed by the Grand Canyon Visibility Transport Commission found that an increase of 25% in weighted emissions would result in a 0.7 dv reduction in visibility, whereas the weighted emission increase expected by 2018 is only 4%.*

Patterns of growth in the corridor are first examined by comparing 1990 emissions (those used in the Commission's final report) to 1996 emissions (the most recent comprehensive data set). This comparison is not easily made because emissions were aggregated into different categories. Nonetheless, it appears that emissions in 1996 were only slightly higher than in 1990. In the clean air corridor 73,637 tons of SO_2 were emitted in 1990 and 73,756 were emitted in 1996; 232,704 tons of NO_x were emitted in 1990 and 256,762 were emitted in 1996. In addition, the WRAP examined data from IMPROVE monitors and found that none of the seven long-term sites showed any significant decrease in visibility on the cleanest days for the period from 1988 through 1998.[11]

The WRAP is recommending, as part of this policy, that future clean air corridor analyses use a baseline year of 1996 to quantify emission increases. The first reason for this recommendation is that the 1996 inventory has been more carefully assembled than the 1990 inventory. The second reason is that future inventories are more likely to be structured like the 1996 inventory, thereby facilitating comparison. In addition, the most recent and comprehensive projection of emissions (discussed below) is based on the 1996 inventory, not the 1990 inventory.

The WRAP also examined emission projections. These are used as a means to identify potential future increases that should be more carefully tracked and to identify preventive measures that could be implemented in a timely fashion. **Table 2** summarizes the projected change in emissions between 1996 and 2018. PM_{10} and $PM_{2.5}$ emissions are expected to increase about 7% and 18%, respectively. NOx and VOC emissions, however, are expected to decrease about 15% and 26%, respectively. SO_2 emissions are expected to increase about 5% within the corridor, even with the declining milestones of the backstop emissions trading program. Overall, SO_2 emissions are expected to decline by 17% in the 13-state contiguous WRAP region by 2018,[12] and the fact that the projections show a 5% increase in SO_2 within the clean air corridor is a result of non-road mobile sources using high-sulfur diesel fuel. This source of sulfur dioxide is expected to be drastically reduced (e.g., from a fuel sulfur content of 3,000 ppm to 15 ppm) before 2018 according to announcements by EPA to develop new engine certification and fuel standards for non-road vehicles and equipment. Thus, 5% should be viewed as an upper bound on the possible increase of SO_2.

[11] EPA. Visibility in Mandatory Federal Class I Areas (1994-1998), A Report to Congress. EPA-452/R-01-008.
[12] WRAP Emissions Inventory Forum. 2018-1996 Difference: Actual to Control Spreadsheet. WRAP Web Site. September 25, 2002.

Since different pollutants have different impacts on visibility, the WRAP estimated a weighted emissions increase according to the VEEU system used by the Commission. As shown in **Table 3**, the weighted increase is expected to be 4%, substantially less than the 25% increase thought to be necessary to achieve an impact that may be perceptible. It is also worth noting the safety margins included within this analysis – the fact that the BBC corridor protects 30% of the clean days, not 20%; the benefits of new non-road mobile source standards; and the uncertainty in where additional electricity generating capacity will be located.

> *Pursuant to 40 CFR 51.309(d)(3)(iii), the WRAP has examined emissions growth in areas outside the corridor and finds that significant emissions growth is not occurring that could begin or is beginning to impair the quality of the air in the corridor and thereby lead to visibility degradation for the least impaired days in one or more of the 16 Class I areas.*

The WRAP sees two purposes for emissions tracking in areas outside the corridor: first, to determine if such emissions are degrading visibility in the corridor, which may potentially affect one or more of the 16 Class I areas; and second, to compensate for any uncertainties in establishing the boundary of the corridor, such as those relating to computed airmass trajectories or introduced by aligning the corridor with county boundaries. Again, SO_2 emissions are expected to decline throughout the WRAP region. Emissions of other pollutants are also expected to decline. All visibility-impairing pollutants from on-road mobile sources, with the exception of some minor ammonia emissions, are expected to decline substantially. And all visibility impairing pollutants from non-road mobile sources are expected to decline, especially in areas upwind of the corridor. This decline would be greatly enhanced if the EPA promulgates stricter standards for non-road engines and fuel, as it has announced to do. Also, NOx and PM from existing stationary sources remains to be addressed in future implementation plans by 2008 under Sections 308 and 309 of the regional haze rule. Finally, all states will have to implement measures to achieve reasonable progress in other Class I areas by 2008. Such measures are likely to "overlap" the clean air corridor and areas outside the corridor in such a way that provide further protection to the 16 Class I areas on the 20% cleanest days.

D. IF IMPAIRMENT OF AIR QUALITY IN THE CORRIDOR IS IDENTIFIED – §309(d)(3)(iv)

> *Since impairment of air quality in clean air corridors has not been identified pursuant to 40 CFR 51.309(d)(3)(ii) and (iii), the WRAP finds no requirement under 40 CFR 51.309(d)(3)(iv) for further visibility impact analysis or additional emission reduction measures until at least the next SIP revision (2008). However, the WRAP encourages its appropriate technical activities – such as the Causes of Haze report – to take into account the assessment and protection of clean air corridors.*

The rule specifies that if impairment of air quality in the clean air corridor is identified, the plan must include "an analysis of the effects of increased emissions, including provisions for the identification of the need for additional emission reduction measures, and implementation of the

additional measures if necessary." For reasons stated above, the WRAP finds no need at this time for additional emission reduction measures.

The periodic WRAP inventories to be produced by the TOC, as instructed above, will identify growth in emissions, and the periodic updates to the WRAP Causes of Haze report will help identify any effect on visibility that may result from such emissions increases. Should any effects be identified, the WRAP will conduct an analysis to determine the sources of impairment within six months of completion of the inventory indicating the increase. Additional control measures that may be warranted would be developed within another six months. The criteria the states and tribes would follow in making this determination are (a) the location of the significant emissions growth, (b) type of source activity causing the emissions growth, and (c) the appropriate control measure for the source(s) based on feasibility, cost, and anticipated visibility benefits. Any necessary additional control measures would be added in the next five-year SIP revision.

E. DO OTHER CORRIDORS EXIST? – §309(d)(3)(v)

*The WRAP finds no other clean air corridors beyond the corridor identified in **Figure 1**.*

The regional haze rule requires that implementation plans identify whether any other clean air corridors exist for any of the 16 Class I areas. The WRAP finds no such areas other than the corridor to the northwest of the Colorado Plateau identified in **Figure 1**. The WRAP recognizes, however, that additional work to identify clean air corridors may be needed. For example, several monitors have recently been installed at Class I areas on the Plateau which were not previously monitored. These may generate a slightly different set of 20% cleanest days and a slightly different set of back trajectories on those days, especially at sites furthest to the north and east. This may result in a broader or separate corridor. Such analysis should be performed when sufficient data are available. Adequate monitoring data could be available by 2004, and analysis of those data could be published by the WRAP as part of its Causes of Haze report.

V. Conclusion

The bottom line is that, while the area to the northwest of the Colorado Plateau delivers clean air to the Plateau on the cleanest days, emissions from throughout much of the region affect the Class I areas on the Plateau. Thus, emissions throughout the WRAP region will be tracked carefully. Ongoing WRAP efforts to improve the quality of inventories and the models used to make projections, and to produce a periodic Causes of Haze report, will bring increased understanding of the role that clean air corridors play in protecting the cleanest days. In the final analysis, the indicator of success or failure will be whether the measured light extinction at the Class I areas on the Colorado Plateau improves or declines on the cleanest days. Any indication of deterioration on the cleanest days should trigger an immediate investigation of the cause, as well as efforts to correct the problem.

Figure 1. Clean Air Corridor Endorsed by the WRAP.

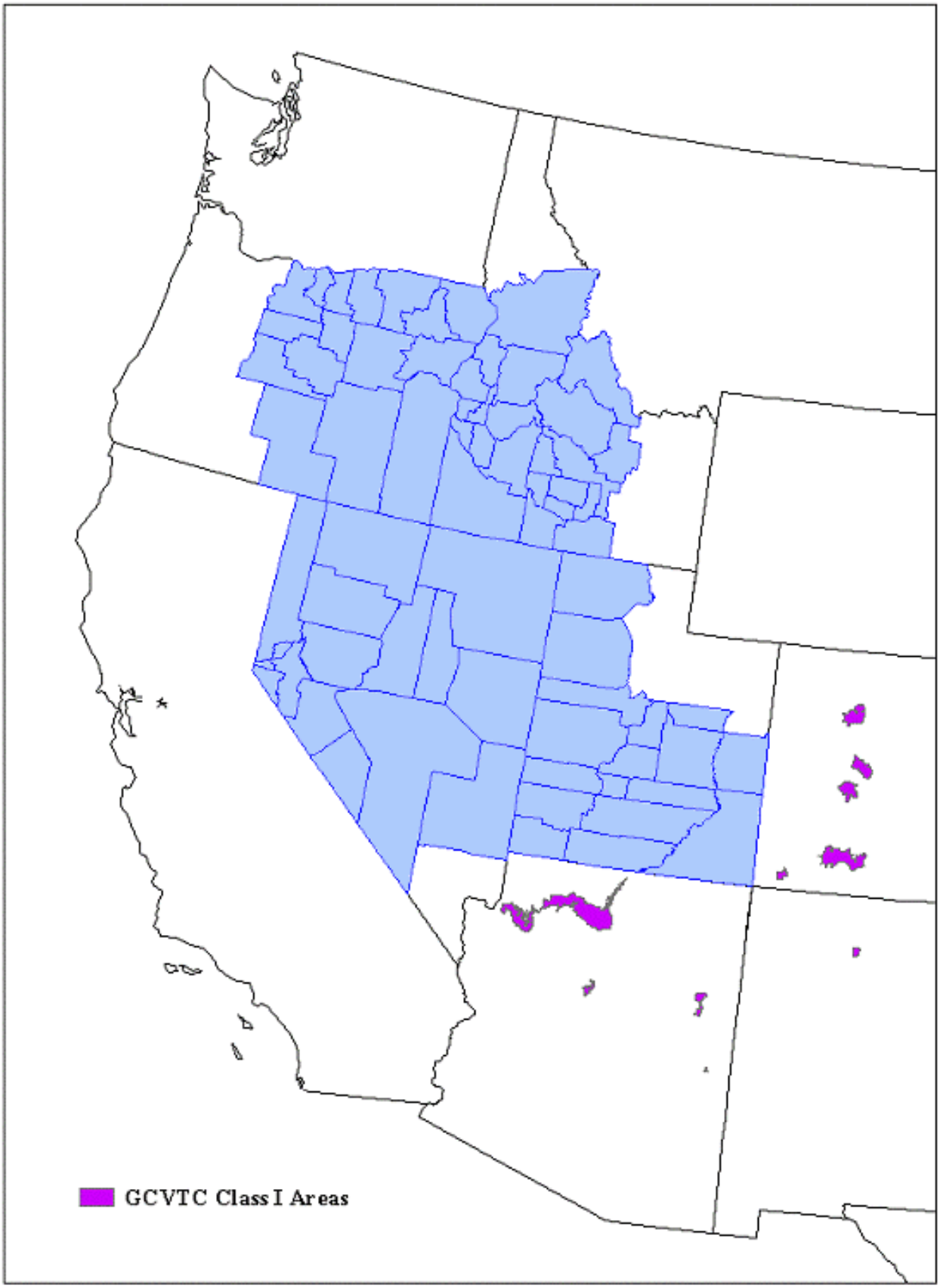

Table 1. Counties Within the Clean Air Corridor Endorsed by the WRAP.

State	County
Idaho	Ada
Idaho	Adams
Idaho	Blaine
Idaho	Boise
Idaho	Butte
Idaho	Camas
Idaho	Canyon
Idaho	Cassia
Idaho	Custer
Idaho	Elmore
Idaho	Gem
Idaho	Gooding
Idaho	Idaho
Idaho	Jerome
Idaho	Lemhi
Idaho	Lincoln
Idaho	Minidoka
Idaho	Owyhee
Idaho	Payette
Idaho	Twin Falls
Idaho	Valley
Idaho	Washington
Nevada	Churchill
Nevada	Douglas
Nevada	Elko
Nevada	Esmeralda
Nevada	Eureka
Nevada	Humboldt
Nevada	Lander
Nevada	Lincoln
Nevada	Lyon
Nevada	Mineral
Nevada	Nye
Nevada	Pershing
Nevada	Storey
Nevada	Washoe
Nevada	White Pine
Nevada	Carson City
Oregon	Baker
Oregon	Crook
Oregon	Deschutes
Oregon	Gilliam
Oregon	Grant
Oregon	Harney
Oregon	Jefferson
Oregon	Lake
Oregon	Malheur
Oregon	Morrow
Oregon	Sherman
Oregon	Umatilla
Oregon	Union
Oregon	Wallowa
Oregon	Wasco
Oregon	Wheeler
Utah	Beaver
Utah	Box Elder
Utah	Carbon
Utah	Emery
Utah	Garfield
Utah	Grand
Utah	Iron
Utah	Juab
Utah	Kane
Utah	Millard
Utah	Piute
Utah	San Juan
Utah	Sanpete
Utah	Sevier
Utah	Tooele
Utah	Washington
Utah	Wayne

Table 2. Changes in Clean Air Corridor Emissions (Assuming SO_2 Milestones Are Met).

		Point	Area	On Road	Non Road	Paved	Unpaved	Total
SO_2	1996	51,413	9,260	2,065	10,838	0	0	73,576
	2018	45,330	10,614	413	21,596	0	0	77,954
	2018-1996	-6,082	1,354	-1,652	10,758	0	0	4,378
NOx	1996	85,782	12,935	93,581	64,462	0	0	256,762
	2018	109,863	17,576	28,692	62,557	0	0	218,689
	2018-1996	24,080	4,641	-64,889	-1,905	0	0	-38,072
PM_{10}	1996	27,055	142,776	3,872	5,952	5,740	47,733	233,128
	2018	32,748	154,966	2,640	6,763	12,402	38,828	248,347
	2018-1996	5,692	12,190	-1,232	811	6,662	-8,904	15,219
$PM_{2.5}$	1996	11,987	41,595	3,495	5,487	1,435	7,160	71,160
	2018	14,583	52,069	2,058	6,228	3,101	5,824	83,863
	2018-1996	2,595	10,474	-1,438	740	1,665	-1,336	12,702
VOC	1996	5,993	95,921	69,899	38,535	0	0	210,349
	2018	7,921	95,515	22,651	29,233	0	0	155,321
	2018-1996	1,927	-406	-47,248	-9,301	0	0	-55,029

Table 3. Total Change in Emissions Weighted to Reflect Relative Impact on Visibility.

	SO2	NOx	PM10	PM2.5	VOC	EC*	OC*	Total	Change
1996 VEEU	5,445	1,746	1,958	932	294	902	856	12,133	--
2018 VEEU	5,769	1,487	2,086	1,099	217	985	935	12,578	4%

* Estimates of elemental and organic carbon, EC and OC, were not available to the CAC Work Group for the 1996 and 2018 emission inventories. Values for this analysis were derived from the estimates of EC and OC for the 1990 inventory of the 9 GCVTC states. The method used was to take the proportion of EC to fine and coarse particulates (PM2.5 + PM10) in the 1990 inventory and use that same proportion to calculate an EC value for the 1996, 2018, and 2018 milestone inventories. The same method was used for OC.

**** VEEU – Visibility Equivalency Emission Units** (Used in the GCVTC IAS Model.)

VEEU weights

PM2.5	PM10	NOx	VOC	SO2	EC	OC
0.0131	0.0084	0.0068	0.0014	0.0740	0.6497	0.2466

Each category in the inventory is multiplied by these factors to create the VEEU-weighted inventory.

Appendix A-6b. WRAP Emission Tracking System and Assessment Process for the Clean Air Corridor

FINAL

NEEDS ASSESSMENT FOR EVALUATION AND DESIGN OF AN EMISSIONS DATA REPORTING, MANAGEMENT, AND TRACKING SYSTEM

Prepared for

Western Governor's Association
Western Regional Air Partnership
1515 Cleveland Place
Suite 200
Denver, Colorado 80202

Prepared by

EA Engineering, Science, and Technology
15 Loveton Circle
Sparks, MD 21152

July 25, 2003

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1.0 INTRODUCTION

1.1 Regional Haze

Regional haze is defined as air pollution that is transported long distances and reduces visibility in national parks and wilderness areas. The pollutants that create this haze are sulfates, nitrates, organic carbon, elemental carbon, and soil dust. Human-caused haze sources include industry, motor vehicles, agricultural and forestry burning, and windblown dust from roads and farming practices.

In 1999, the US Environmental Protection Agency (EPA) issued regulations that address regional haze in one hundred fifty six (156) national parks and wilderness areas across the country. The goal of the Regional Haze Rule (RHR) is to eliminate human-caused visibility impairment in national parks and wilderness areas across the country. It contains strategies to improve visibility over the next sixty (60) years, and requires states to adopt implementation plans.

The RHR provides two paths to address regional haze. One is 40 CFR 51.308 (Section 308), and requires most states to develop long-term strategies out to the year 2064. These strategies must be shown to make "reasonable progress" in improving visibility in Class I areas inside the state and in neighboring jurisdictions. The other is 40 CFR 51.309 (Section 309), and is an option for nine states - Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming - and the two hundred eleven (211) Tribes located within those States to adopt regional haze strategies for the period from 2003 to 2018. These strategies are based on recommendations from the Grand Canyon Visibility Transport Commission (GCVTC), for protecting the sixteen (16) Class I areas in the Colorado Plateau area (GCTVC, 1996). Adopting these strategies constitutes reasonable progress until 2018. These same strategies can also be used by the nine western states and tribes to protect the other Class I areas within their own jurisdiction.

The RHR specifically requires comprehensive emissions tracking and reporting for clean air corridors (CAC), sulfur dioxide (SO_2) stationary sources, fire sources, mobile sources, and windblown dust sources among other requirements.

1.2 Consolidated Emission Reporting Rule

One of the recent EPA's rules that will affect the data submission requirements of the RHR is the Consolidated Emission Reporting Rule (CERR) (67 FR 39602-39616) issued in 2002. The CERR will simplify and consolidate emissions inventory reporting requirements to a single location within the CFR and establish new reporting requirements related to particulate matter with aerodynamic size less than 2.5 µm ($PM_{2.5}$), regional haze, and statewide reporting of area and mobile source emissions. In fact, new inventories will add $PM_{2.5}$ and ammonia (NH_3). Currently area and mobile sources are reported by nonattainment area, and under the CERR, inventories will include all sources statewide by county. Moreover, there will be an option to report smaller point sources once every three years or one-third of the sources every year.

1.3 RPO Data Exchange Protocol

The RPO data exchange protocol will also affect the data submission and reporting requirements. The goal of the RPO data exchange protocol is to facilitate the sharing of databases for emissions modeling in a regionally consistent and model-independent nature. Therefore, it seeks to develop data exchange formats and naming conventions so that emissions modelers from the five RPOs and states and tribes have common datasets from which to pursue regulatory modeling of ozone (O_3), regional haze, and PM. It includes nine different protocols:

- Industrial point source protocol
- Area source protocol
- Temporal allocation and profile assignment protocol
- On-road mobile sources protocol
- Off-road mobile sources protocol
- Continuous emissions monitoring and day-specific protocol
- Spatial surrogate protocol
- Speciation profile protocol
- Growth and control factors protocol

The data sources, data formats, and issues associated with each of these protocols are further detailed in the Midwest RPO's *Draft RPO Data Exchange Protocol* (Pechan, 2003).

1.4 Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is a regional planning organization (RPO) that was established in 1997 as the successor organization of the GCVTC. The WRAP is a collaborative effort of tribal governments, state governments, and various federal agencies to implement the recommendations of the GCVTC and to develop the technical and policy tools needed by western states and tribes to comply with the RHR. The WRAP Emissions Forum (EF) oversees the development of a comprehensive emissions tracking and forecasting system which can be utilized by the WRAP or its member entities to monitor the trends in actual emissions, and forecast the anticipated emissions which will result from current regulatory requirements and alternative control strategies. In addition, this forum is responsible for the oversight of the assembly and quality assurance of the emissions inventories and forecasts to be utilized by the WRAP forums.

1.5. Regulatory Framework for Tribal Visibility Implementation Plans

The RHR explicitly recognizes the authority of tribes to implement the provisions of the rule, in accordance with principles of federal Indian law, and as provided by the Clean Air Act (CAA) Section 301(d) and the tribal authority rule (TAR) (40 CFR 49.1–11). Those provisions create the following framework:

- Absent special circumstances, reservation lands are not subject to state jurisdiction.
- Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable"

elements of such programs (40 CFR 49.3, 49.7). The mechanism for this delegation is a tribal implementation plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.

- The RHR expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64 FR 35756), and that the authority to implement Section 309 TIPs extends to all tribes within the GCVTC region (40 CFR 51.309(d)(12)).
- The EPA has indicated that under the TAR, tribes are not required to submit Section 309 TIPs by the end of 2003. Rather, they may choose to opt-in to Section 309 programs at a later date (67 FR 30439).
- Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a federal implementation plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR 49.11). EPA is committed to consulting with tribes on a government-to-government basis in developing tribe-specific or generally applicable TIPs where necessary (63 FR 7263-64).

The amount of modification, if any, needed for this report to fulfill tribal needs may vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes, which are not present under existing law.

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board. Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred (400) federally recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members, Forum and Committee members, and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, it is anticipated that the tribal participants will join the state, federal, and private stakeholder interests in approving this report as a consensus document.

1.6 Objectives

The EF is currently seeking to implement a comprehensive internet web-based air pollution emissions data reporting, management, and tracking system to support state and tribal regional

haze implementation plan (SIP/TIP) development. The system is to be capable of receiving and storing emissions data in EPA-compliant emissions reporting formats commonly used by various agencies and sources with little or no additional effort, producing user-specified reports, performing user-selected quality control and assurance tests, allowing data queries and graphic display, and presenting this information in geographic information system (GIS) format.

The EF contracted with EA Engineering, Science, and Technology, Inc (EA) to assess the needs of the WRAP emissions database management system (WRAP EDMS). The overall approach of this needs assessment consists of the following tasks.

- Task 1: Determine the emissions data to be reported, managed and tracked.
- Task 2: Conduct a comparative analysis of existing emissions data management systems approved and in use by EPA and state air quality agencies.
- Task 3: Prepare a report addressing issues associated with developing a new system, long-term system maintenance and operation of the recommended data management system, by integrating information gathered in Tasks 1 and 2.

This report presents the results of Task 3 and represents the final technical report of the project. It provides the documentation from the two workshops and questionnaires, the findings based on the input received from the two workshops and questionnaires, an evaluation of existing EDMS, and the system recommendations.

2.0 WORKSHOP AND QUESTIONNAIRE FINDINGS

2.1 Description of the Workshops

The WRAP EDMS needs assessment survey consisted of two interview workshops. The first workshop took place in Santa Fe, New Mexico, on March 20th, 2003. It was intended for members of the WRAP Forums. Thirty-five (35) people attended the meeting. The workshop lasted approximately three hours, and included a presentation by the EA team covering the project overview and timeline, the goals and roles of the WRAP EDMS, a comparative summary of existing systems, a straw man presentation of the conceptual WRAP EDMS, and the conceptual timeline of the development and population of the WRAP EDMS. The presentation was followed by specific discussions on the WRAP EDMS needs. Appendices A1, A2, and A3 present the EA presentation, a summary of the discussion points, and the list of the workshop participants respectively.

The second workshop took place in Denver, Colorado, on May 7th, 2003 and was planned in order to provide an opportunity for state, tribe, and local (STL) air pollution control agencies staff and other stakeholders to participate in the project. Prospective attendees were notified by email several weeks prior to the meeting, and via an online questionnaire. Thirteen (13) people attended this day long workshop. The session included a presentation by the EA team that covered the project overview and timeline, the goals and roles of the WRAP EDMS, a summary of the RHR and CERR, a comparative summary of existing systems, a straw man presentation of the conceptual WRAP EDMS, the conceptual timeline of the development and population of the WRAP EDMS, and the summary of the Santa Fe workshop. This was followed by an oral presentation of the special needs of the Fire Emission Joint Forum (FEJF) and specific discussions on the WRAP EDMS needs were brought up during and after the presentations. Appendices B1, B2, and B3 present the EA presentation, a summary of the discussion points, and the list of the workshop participants respectively.

2.2 Description of Questionnaire

As mentioned above, in addition to the interview workshop, a web-based questionnaire was posted on http://wrap.eaest.com for a period of three months. All potential users of the WRAP EDMS, stakeholders, and interested parties were invited to fill it out. The questionnaire comprised thirty-four (34) questions designed to collect ideas on all the possible needs of the WRAP EDMS. Overall, twenty (20) peoples responded to the web-based questionnaire. Appendix C shows the results of this questionnaire. Furthermore, one person responded to this questionnaire via email before it was posted on the internet. Appendix C also shows these responses.

2.3 Findings

The workshop interviews and questionnaire results underscored the emerging project consensus that the WRAP EDMS needs to be different from any of the other existing systems (including the national emissions inventory (NEI)) because of its architecture, technical capabilities, and contents. The system needs to be developed with all possible users in mind, and with the intent

to accommodate several distinct user groups. The WRAP EDMS will not only be a repository of the WRAP regional emissions inventories but will also be able to be used to implement the emissions tracking and reporting requirements of the RHR. The WRAP EDMS would be located either at the WRAP regional modeling center (RMC) or at a university center as is the monitoring database. Moreover, it will be made publicly accessible through the internet and will contain online training manuals.

The WRAP EDMS will track all the visibility-impairing pollutants: volatile organic compounds (VOC), nitrogen oxides (NOx), SO_2, PM_{10}, $PM_{2.5}$, elemental carbon (EC), organic carbon (OC), carbon monoxide (CO), and NH_3 and all the necessary activity data for all the sources and emission factors needed to calculate their emissions.

A metadata describing and characterizing all of the emissions data will be developed. Furthermore, The WRAP EDMS will be linked to other related external databases. These databases will contain related surrogate and activity data used to estimate some of the emissions such as mobile, biogenic, and windblown dust sources emissions as well as speciation profiles for VOC and PM data. The WRAP EDMS will also adopt the RPO data exchange protocol in order to capture all the necessary external data.

The emissions data will primarily be submitted by STL agencies. Emissions from mobile, biogenic, and windblown dust sources may be estimated through modeling using activity data submitted by STL agencies and other surrogate data. The estimated emissions will be sent to STL agencies for review and approval before inclusion in the final database. Fire source emissions data that are not generated by STL agencies will be estimated by the WRAP EDMS based on fire activity data submitted by STL agencies, federal agencies, private entities, or generated by WRAP. Some STL agencies may estimate fire emissions themselves. These emissions would be submitted by the STL agencies along with all the activity and surrogate data used for the estimation. WRAP will obtain and process the international (Canada and Mexico) data.

The large majority of participants in both workshops felt that the WRAP EDMS should be developed and populated in two phases. In Phase I, the system will include the core database architecture, including all of the functioning modules and all of the reporting and queries capabilities (see Section 4). It will be used primarily to store emissions data that will be used to implement the tracking and reporting requirements of both Sections 308 and 309. The focus will be on the implementation of the emissions tracking and reporting requirements of the CAC, fire sources, stationary SO_2 sources, and mobile sources. The minimum spatial resolutions of the emissions data will be the county and reservation levels. The submittal temporal resolution of the activity data would be variable (i.e. hourly, daily, seasonal, and annual) depending on the source category. However, the emissions will be reported and tracked on an annual resolution basis.

In Phase II, the system could be expanded to incorporate new and updated technical functionality that would allow for storage, tracking, and reporting of hourly, daily, seasonal, and annual emissions data as necessary. The system would include others pollutants (e.g. methane (CH_4), mercury (Hg), etc) and their emissions data. It may be used to track other RHR requirements

(e.g. annual emission goals) and other regulations (e.g. Clear Skies, Greenhouse Gas, etc) requirements.

There was general agreement that the WRAP EDMS will be built and tested by the end of 2003 and will be live on the web in early 2004. This first version of the WRAP EDMS will be populated with the 2002 comprehensive emissions data. The collection, processing, and quality assurance/quality control (QA/QC) of these data from the STL agencies will start in early 2004 and will continue throughout 2004. At the same time, the 2002 base and 2018 projection years' emissions files that will be used by RMC will be produced. The system will also produce the emission reports as needed for both Sections 308 and 309. From 2005 to 2007, annual emissions will be generated from the 2002 comprehensive emissions data in order to satisfy the tracking and reporting requirements of the RHR. At the same time, refined emissions inventories representing the effect of control strategies in 2018 will be developed, and the 2005 comprehensive emissions data will be collected from STL agencies, processed, and QA/QC'd. It should be noted that the emissions data submitted by tribal agencies may be from any given inventory year. Moreover, wherever tribal emissions data are available, the state should adjust its inventory taking into account these tribal data. The conceptual development timeline of the WRAP EDMS is as follow.

- Mid 2003: finish needs assessment project
- Late 2003:
  1. WRAP contractor builds and alpha tests Phase I of WRAP EDMS
  2. Beta test of the WRAP EDMS
- Early 2004:
  1. Initiate live Phase I of the WRAP EDMS on the web
  2. Provide training and user support
- Throughout 2004: begin collection, processing, and QA/QC of 2002 emissions from STL agencies
- Late 2004:
  1. Implement Phase II of the WRAP EDMS
  2. Provide training and user support
  3. Produce emissions reports as needed for Section 308 and 309 requirements
  4. Prepare 2002 base and 2018 projection years' emissions files for use by RMC
- 2005-2007: ongoing operation of the WRAP EDMS
  1. Track emissions as needed for Section 308 and 309
  2. Develop refined emissions inventories representing the effect of control strategies in 2018
  3. Provide training and user support
  4. Populate the WRAP EDMS with annual emissions data to meet Section 308 and 309 regulatory requirements
  5. Collection, processing, and QA/QC of 2005 emissions from STL agencies

There was also consensus that the WRAP EDMS should be built in a modular fashion, to allow for easy expansion and improvement. It will include six major modules representing the sources (point, area, fire, mobile, windblown dust, and biogenic) in addition to the GIS, QA/QC, and database administrator (DBA) modules. The submission formats will be similar to that of the

NEI format (NIF) and the minimum submission cycle would coincide with the submission cycle of the NEI (annual and triennial cycles). However, the WRAP EDMS will have an open submittal process, where STL agencies' emissions data will be submitted at different times. Currently, state submit the NIF in several file formats including ASCII Text (Text), Microsoft Access database (MS Access), and eXtended Markup Language (XML). The results of the questionnaire indicated that, across the WRAP region, states are using Text, MS Access, in-house developed systems, and other systems (i.e. AMS Tempo) that need to be converted to the NIF. Therefore, the WRAP EDMS will accept all the file formats already accepted by NEI.

The WRAP EDMS will be managed by a DBA whose functions could include QA/QC, some emission calculations, data gap filling, data archiving, and data version management among others.

3.0 COMPARATIVE ANALYSIS

3.1 Conceptual WRAP EDMS

The conceptual WRAP EDMS was developed based on the findings of the interview workshops and the web-based questionnaire.

3.1.1 Data Tracking

The WRAP EDMS should contain all visibility-impairing pollutants: VOC, NO_x, SO_2, PM_{10}, $PM_{2.5}$, EC, OC, CO, and NH_3. The WRAP EDMS should also track all necessary activity data for all the sources and emission factors needed to calculate emissions. These pollutants and related activity data should be tracked for the following sources: point, area, mobile, biogenic, windblown dust, and fire sources. The data will be tracked at the county and reservation level for all sources and also individually for point and fire sources. The emissions data will be submitted to the WRAP EDMS by STL agencies, except for biogenic, mobile, windblown dust, and certain fire sources emissions data that will be calculated by WRAP using emissions estimation models. The submissions will be in a standard format similar to the NIF and done at the NEI minimum cycle but STL agencies may submit emissions data frequently.

3.1.2 Data QA/QC

The WRAP EDMS should include a QA/QC module to perform two levels of QA/QC. The first level of QA/QC should include a validation of the format of the submitted data files. This will ensure that the submitting entity supply all data to WRAP in the expected format and also identify any errors. The submittal check will be at the point of entry to the WRAP EDMS in order to minimize the DBA work and encourage STL agencies to submit clean data. The second level of QA/QC should consist of checks of the data that is submitted to WRAP, and include checking reference values and acceptable data ranges for specific data points. The data should also be checked for completeness, ensuring that all data exists for all sources and geographic areas.

3.1.3 Data Reporting

The WRAP EDMS should include a series of standard summary reports broken down by source type, geographic location, and pollutant. It should also include a series of reports designed specifically to meet the RHR emissions tracking and reporting requirements. The RHR reports will include special reports for CAC, pre-trigger SO_2 stationary sources, mobile sources, fire sources, and windblown dust sources. The WRAP EDMS should also include a series of data export formats for inclusion in external systems including emissions modeling programs such as SMOKE (MCNC, 1999).

3.1.4 GIS Components

The WRAP EDMS should include a fully functioning GIS module that provides multiple tools to display data over the internet. The inclusion of a GIS module will provide a means for users to

select data that is of importance to them and display the data in a fashion that is easily understood. The WRAP EDMS should include the following GIS functionality: pan, zoom, query layer information, ability to add/remove multiple layers of data, point and click, measure distances, buffer, print multiple sizes of maps, and select map features by line, rectangle, or polygon.

The WRAP EDMS GIS module should include the following layers of data: county, state and country polygons, tribal reservation polygons, roadways and railroad line features, CAC polygons, international polygons, metropolitan statistical areas polygons, nonattainment area polygons, class I areas polygons, bodies of water polygons, census data polygons, other federal land polygons (i.e. national parks, monuments, forest, and refuges), and WRAP modeling domain grid system. It should have the ability to select and display emissions sources and associated emissions data by geographical area.

3.1.5 User Access and Preferences

All reporting features of the WRAP EDMS should be available to the public via the internet. STL agencies will have a separate, non-public interface for submitting their data to a central submission area. The user interface for the WRAP EDMS should be easy and intuitive to use while providing all necessary functionality.

3.2 Comparison

Five existing EDMS were evaluated and compared each to the conceptual WRAP EDMS. Each system was evaluated in terms of meeting the design and functionality requirements of the conceptual WRAP EDMS. As expected, none of the individual systems included all of the required elements for the conceptual WRAP EDMS. This was due in part to the fact that none of the systems tracked all of the required pollutants or included emissions data from all of the required, individual sources. In some instances, individual systems included most or all of the required functionality, such as a GIS module or the ability to export data, but did not track emissions data for all of the required pollutants or sources. Without all of the required data available, the output of these systems will be incomplete. Appendix D illustrates the overall comparison between the conceptual WRAP EDMS and the selected existing systems and Section 3.3 below describes these systems further.

3.3 Existing EDMS

This section lists each of the selected five existing database management systems, provides a brief description and background information for each, and highlights any elements from each system that could be utilized by the WRAP EDMS.

3.3.1 National Emissions Inventory – NEI

The EPA's Emission Factor and Inventory Group (EFIG) maintains a national emissions inventory containing information on air emissions and their sources for each state in the U.S., the U.S. Virgin Islands, Puerto Rico and the District of Columbia. The NEI has a public website

(http://www.epa.gov/air/data/index.html) where users can query the emissions database and produce reports based on their specific needs.

3.3.1.1 System Details

The NEI tracks seven pollutants: VOC, NO_x, SO_2, PM_{10}, $PM_{2.5}$, CO, and NH_3. The pollutants are tracked for four source types: point, area, mobile, and biogenic sources. All data is tracked at the county level for all sources, and also individually for point sources. The data is submitted on an annual and triennial basis to EPA by state and tribal agencies. The data is submitted in the EPA's standard submission format, the NIF.

The NEI includes a QA/QC process that performs multiple levels of QA/QC checks. The first level consists of a validation of the format of the submitted data files, which ensures that the submitting entity supplied all data to NEI, in the expected format, and also identifies any errors with the submitted format. The second level of QA/QC checks includes checks of the data that is submitted to NEI. Reference values are checked against standard lists and data points are checked against acceptable data ranges. The data is also checked for completeness, ensuring that all data exists for all sources and geographic areas. If data points are missing, the NEI will replace the missing values with national averages or previous year data for the particular data point.

The NEI includes a series of standard summary reports broken down by source category, geographic location, and pollutant. The NEI also includes a data export feature to allow data to be extracted from the NEI database for inclusion in external systems.

The NEI includes a basic mapping capability to display emissions data over the internet. The NEI mapping functionality includes the ability to pan, zoom, and displays county, state and country boundaries.

All reporting features of the NEI are available to the public via the internet. The NEI user interface is easy to use and navigate to reach the desired data.

3.3.1.2 Key System Elements

The NEI has three key elements that should be utilized in the WRAP EDMS. First, the NEI requires a standard submission format (NIF) for all data submitted to the system. The WRAP EDMS could utilize this same submission format for all data sources, except for fire sources. The submission format captures the required emissions and activity data for all pollutants except OC and EC, which can be calculated by the WRAP system, based on the $PM_{2.5}$ data. Also, since STL agencies are already required to submit their data in the NIF format, no additional work will be necessary on their part to create submissions for the WRAP EDMS. See Appendix E for the recent version of the NIF submission formats.

Second, the NEI has a well-established and defined QA/QC process for all submitted emissions data. This process does a thorough analysis of the submission format and data content to identify all possible issues before the data is included in the system. The WRAP EDMS could adopt a

modified version of this QA/QC Process to ensure that all data submitted to the WRAP EDMS is accurate. However, instead of automatically replacing missing or erroneous data with a default set of data, WRAP could make recommendations for replacing missing data or supplementing existing data to STL agencies while leaving the final approval for all data included in the WRAP EDMS with them. See Appendix F for a detailed explanation of the NEI QA/QC process.

Finally, the NEI includes an adequate set of standard reports for users to utilize when accessing the NEI database. The set of reports is not exhaustive, but does provide an excellent basis for data reporting and gathering to serve the public's data needs. The NEI report interface is also very easy to use and intuitive, making the data gathering process easy for the user. The WRAP EDMS could adopt this report functionality and design for the general data gathering and reporting capabilities of its system.

3.3.2 Tribal Emissions Inventory Software Solution – TEISS

Northern Arizona University is currently developing an air emissions inventory for all western region tribes. The Tribal Emissions Inventory Software Solution (TEISS) will be a desktop application where users can query the emissions database and produce reports based on their specific needs.

3.3.2.1 System Details

The TEISS tracks seven pollutants: VOC, NO_x, SO_2, PM_{10}, $PM_{2.5}$, CO, and NH_3. The pollutants are tracked for three source types: point, area, and mobile sources. All data is tracked at the reservation level for all sources, and also individually for point sources. The data is collected from the tribes on a continuing basis. The data is submitted in multiple formats and can also be hand-entered through data entry screens.

The TEISS includes a series of standard reports broken down by source category, geographic location, and pollutant. The TEISS also includes a data export feature to allow data to be extracted from the TEISS database for inclusion in external systems, including the NEI and modeling programs such as SMOKE.

The TEISS includes a fully functioning GIS module that provides multiple tools to display data geographically. The TEISS includes several advanced GIS features including: pan, zoom, query layer information, ability to add/remove multiple layers of data, measure distances, buffer, print multiple sizes of maps, and select map features by line, rectangle, or polygon. The TEISS GIS module includes several static layers of data, such as county, state and country, and tribal reservation boundaries, and the ability to select and display emissions sources and associated emissions levels by geographical area.

The TEISS utilizes an advanced user interface, since it is a desktop application and not accessible via the internet.

3.3.2.2 Key System Elements

The TEISS has two key elements that should be utilized in the WRAP EDMS. First, the TEISS has a fully functioning GIS module embedded in the system. This allows TEISS users to display map features in conjunction with relevant emissions and activity data on a real-time basis. The TEISS GIS module includes a full set of tools for manipulation of any map created in the system. The WRAP EDMS could include a majority of this functionality in its GIS module to provide its users a complete internet GIS capability. However, since current web GIS capabilities are limited compared to desktop capabilities, the WRAP EDMS will not be able to implement all of the features of the TEISS GIS module.

Second, the TEISS has a flexible set of exporting functions to allow for multiple data export formats. The WRAP EDMS could include a comparable set of exporting features to accommodate the need of multiple formats for the system's users.

3.3.3 California Air Resources Board Emissions Inventory – CARBEI

The California Air Resources Board maintains an emissions inventory (CARBEI) containing information on air emissions and their sources for the state of California. The CARBEI has a public website (http://www.arb.ca.gov/emisinv/eib.htm) where users can query the emissions database and produce reports based on their specific needs.

3.3.3.1 System Details

The CARBEI tracks five pollutants: NO_x, SO_2, PM_{10}, $PM_{2.5}$, and CO. The pollutants are tracked for three sources types: point, area, and mobile sources. All data is tracked at the county level for all sources, and also individually for point sources. The data is submitted by local agencies in the California Air Resources Board's standard submission format, the California Emission Inventory Development and Reporting System (CEIDARS).

The CARBEI includes a QA/QC process that performs multiple levels of QA/QC checks. The first level consists of a validation of the format of the submitted data files, which ensures that the submitting entity supplied all data to CARBEI, in the expected format, and also identifies any errors with the submitted format. The second level of QA/QC checks includes checks of the data that is submitted to CARBEI. Data points are checked against acceptable data ranges to ensure the submitted data are accurate and reasonable.

The CARBEI includes standard summary reports broken down by source category, geographic location, and pollutant. The CARBEI also includes a data export feature to allow data to be extracted from the CARBEI database for inclusion in external systems.

All reporting features of the CARBEI are available to the public via the internet. The CARBEI user interface is easy to use and navigate for the user to reach the desired data.

3.3.3.2 Key System Elements

The CARBEI has one key element that should be utilized in the WRAP EDMS. The CARBEI report interface is very easy to use and intuitive, making the data gathering process easy for the user. The WRAP EDMS could adopt this report functionality and design for the general data gathering capabilities of its system.

3.3.4 Colorado Department of Health Air Pollution Inventory – CAPI

The Colorado Department of Health maintains an Air Pollution Inventory (CAPI) containing information on air emissions and their sources for the state of Colorado. The CAPI has a public website (http://emaps.dphe.state.co.us/APInv/viewer.htm) where users can query the emissions database and produce reports based on their specific needs. It should be noted that CAPI is not the Colorado primary emissions inventory system. It is included in this analysis because of its internet capabilities.

3.3.4.1 System Details

The CAPI tracks five pollutants: VOC, NO_x, SO_2, PM_{10}, and CO. The pollutants are tracked for three source types: point, area, and mobile sources. All data is tracked at the county level for all sources, and also individually for point sources. The data is submitted by local agencies on a continuing basis.

The CAPI includes standard summary reports broken down by source category, geographic location, and pollutant.

The CAPI includes a fully functioning GIS module that provides multiple tools to visually display data. The CAPI includes several advanced GIS features including: pan, zoom, query layer information, ability to add/remove multiple layers of data, measure distances, buffer, print, and select map features by line, rectangle, or polygon. The CAPI GIS module includes several static layers of data, such as county and state boundaries, and various attainment area boundaries.

All reporting features of the CAPI are available to the public via the internet. The CAPI user interface is easy to use and navigate for the user to reach the desired data.

3.3.4.2 Key System Elements

The CAPI includes a functioning, internet-based GIS module. The CAPI GIS module includes a full set of tools for manipulation of any map created in the system. Although the CAPI does not have the capability of mapping data from the emissions database, it does represent a good example of internet-based GIS functionality. The WRAP EDMS could include this functionality in its GIS module to provide its users internet-based GIS capability.

3.3.5 Delaware Environmental Navigator – DEN

The Delaware Department of Natural Resources and Environmental Control maintains a database of information for all aspects of environmental monitoring and control. The Delaware Environmental Navigator (DEN) has a public website (http://www.dnrec.state.de.us/dnreceis/) where users can query the database and produce reports based on their specific needs.

3.3.5.1 System Details

At the air emissions level, the DEN tracks five pollutants: VOC, NO_x, SO_2, PM_{10}, and CO. The pollutants are tracked for three source types: point, area, and mobile sources. All data is tracked at the county level for all sources, and also individually for point sources. The data is submitted by local agencies on a continuing basis.

The DEN includes a limited QA/QC process that performs quality checks of all submitted data.

The DEN includes standard summary reports broken down by source category, geographic location, and pollutant.

The DEN includes a fully functioning GIS module that provides multiple tools to display data geographically. The DEN includes several advanced GIS features including: pan, zoom, query layer information, ability to add/remove multiple layers of data, measure distances, print, and select map features by line, rectangle or polygon. The DEN GIS module includes several static layers of data, such as county, state and country boundaries, interstate and highway line features, and the ability to select and display data by geographical area.

All reporting features of the DEN are available to the public via the internet. The DEN user interface is easy to use and navigate to reach the desired data.

3.3.5.2 Key System Elements

The DEN has a fully functioning, internet-based GIS module included in the system. This allows DEN users to display map features in conjunction with relevant emissions and activity data on a real-time basis. The DEN GIS module includes a full set of tools for manipulation of any map created in the system. The DEN was included in this comparison due to its advanced internet-based GIS functionality and its ability to map user defined data queried from the DEN database on a real time basis. The WRAP EDMS could include this functionality in its GIS module to provide its users internet-based GIS capability.

4.0 RECOMMENDATIONS

4.1 Flow Chart of the WRAP EDMS

Appendix G presents the flow chart of the WRAP EDMS that shows the information needs, from the emissions data submission to the report generations, data queries, graphic display, and GIS presentation. The sections below explain the different parts of this flow chart.

4.2 Point Source Module

For point sources, at a minimum, the emissions data listed below should be submitted, stored, and tracked for each inventory. The data file should be organized into records for the submitting format. In the NIF Version 3, the point source file contains eight records with specific key fields represented by these emissions data (see Appendix E).

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) Facility ID code
9) Point ID code
10) Process ID code
11) Stack ID code
12) Site name
13) Physical address
14) SCC code
15) Heat content (fuel) (annual average)
16) Ash content (fuel) (annual average)
17) Sulfur content (fuel) (annual average)
18) Pollutant code
19) Activity/throughput (annual)
20) Activity/throughput (daily)
21) Work weekday emissions
22) Annual emissions
23) Emission factor
24) Winter throughput (%)
25) Spring throughput (%)
26) Summer throughput (%)
27) Fall throughput (%)
28) Hours/day in operation
29) Start time (hour)
30) Day/week in operation
31) Weeks/year in operation

32) X stack coordinate (latitude)
33) Y stack coordinate (longitude)
34) Stack height
35) Stack diameter
36) Exit gas temperature
37) Exit gas velocity
38) Exit gas flow rate
39) SIC code
40) Design capacity
41) Maximum nameplate capacity
42) Primary control efficiency (%)
43) Secondary control efficiency (%)
44) Control device type
45) Rule effectiveness (%)

Emissions from point sources will be estimated by STL agencies using emission factors published in AP-42 (EPA, 1998) or from stack test data and submitted at the individual source level on an annual temporal resolution basis. According to the CERR, the minimum point source reporting thresholds are 100 tons per year (tpy) for VOC, NOx, SO_2, PM_{10}, $PM_{2.5}$, and NH_3 and 1000 tpy for CO. Many states have different reporting thresholds tied to other state environmental regulations and would like to be able to retrieve data from the EDMS as they are submitted. Therefore, the WRAP EDMS will allow different point source cutoff level submissions and will check for these discrepancies in order to avoid double counting emissions.

4.3 Area Source Module

Based on input and discussion, it appears that area sources represent all other stationary sources not included in the point source category, excluding fire and windblown dust sources. These sources also include open burning activities on residential, commercial, and industrial properties.

For area sources, at a minimum, the emissions data listed below should be submitted, stored, and tracked for each inventory. Similar to the point sources, the data file should be organized into records. The area source file contains five records in the NIF version 3 (see Appendix E).

1) Inventory year
2) Inventory start date
3) Inventory end date,
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Emission factor
10) Activity/throughput level (annual)
11) Total capture/control efficiency (%)
12) Rule effectiveness (%)

13) Rule penetration (%)
14) Pollutant code
15) Summer/winter work weekday emissions
16) Annual emissions
17) Winter throughput (%)
18) Spring throughput (%)
19) Summer throughput (%)
20) Fall throughput (%)
21) Hours/day in operation
22) Days/week in operation
23) Weeks/year in operation

Emissions from area sources will be estimated by STL agencies using mostly emission factors published in AP-42 (EPA, 1998) and submitted at the county level on an annual temporal resolution basis. The area source definitions are different from STL to STL. For example, some STL define gas stations or dry cleaners as point sources while others do as area sources. Therefore, the WRAP EDMS will allow different source category submissions and will check for these discrepancies in order to avoid double counting emissions.

4.4 Mobile Source Module

Mobile sources are divided into two main categories: onroad and nonroad mobile sources. Onroad mobile sources are motor vehicles licensed for use on highways or roadways (i.e. automobiles, trucks, etc). Onroad mobile source emissions are the product of emission factors obtained through the execution of the latest EPA's MOBILE model (EPA, 2002) or the California EMFAC model (CARB, 2002) and activity levels represented by the vehicle mile traveled (VMT). Dust from paved and unpaved roads may be estimated by using either the method in AP-42, Section 11 (EPA, 1998) or the EPA's PART5 model (EPA, 1995).

Nonroad mobile sources are the other mobile sources represented for instance by construction equipment, lawn and garden equipment, snowmobiles, boats, trains, and airplanes. Their emissions can be estimated using the EPA's NONROAD model (EPA, 2000) and/or published emission factors, especially for boats and trains. Emissions of airplanes and associated ground support equipment and auxiliary power units are estimated using the Federal Aviation Administration (FAA) Emission and dispersion Modeling System model (FAA, 2002). It is not anticipated that the WRAP EDMS will contain these models.

Most mobile emissions will be submitted at the county level on an annual temporal resolution basis. However, many mobile source emissions data are seasonal in nature. Therefore, the WRAP EDMS may store applicable seasonal mobile emissions data as well. For unsubmitted and/or missing mobile source emissions data for a given area, the WRAP EDMS DBA will estimate the inventories using available mobile emissions models and area-specific data or national average data. These inventories will be submitted to STL agencies for review and approval before inclusion in the final database.

For mobile sources, the emissions data listed below should be submitted, stored, and tracked for each inventory. Similar to the point sources, the data file should be organized into records. The onroad and nonroad mobile source files contain three and five records respectively in the NIF version 3 (see Appendix E).

For on-road mobile sources,

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Emission factor
10) Activity (VMT by roadway class)
11) Pollutant code
12) Summer/winter work weekday emissions
13) Annual emission
14) Refueling emissions classification

For non-road mobile sources,

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Emission factor
10) Activity/throughput level (annual)
11) Total capture/control efficiency (%)
12) Rule effectiveness (%)
13) Rule penetration (%)
14) Pollutant code
15) Summer/winter work weekday emissions
16) Annual emissions
17) Winter throughput (%)
18) Spring throughput (%)
19) Summer throughput (%)
20) Fall throughput (%)
21) Hours/day in operation
22) Days/week in operation

23) Weeks/year in operation

4.5 Biogenic Source Module

The latest EPA's Biogenic Emissions Inventory System (BEIS) model (EPA, 1998) will be used to generate the region-wide biogenic emissions using activity data submitted by STL agencies and other surrogate land use and meteorological data. The emission inventories will then be submitted to STL agencies for review and approval before inclusion in the final database. The reporting spatial resolution will be the county level and the temporal resolution will be annual for the biogenic emissions data in Phase I. In phase II, hourly, daily, or seasonal temporal resolutions may be tracked. The biogenic emissions are currently being generated at RMC on a 36-km grid system for each hour. Therefore, they will need to be converted to a county level and aggregate on an annual temporal resolution basis before being sent to STL agencies for review and subsequent inclusion in the WRAP EDMS.

For biogenic sources, at a minimum, the emissions data listed below should be submitted, stored, and tracked for each inventory. Similar to the point sources, the data file should be organized into records. The biogenic source file contains two records in the NIF version 3 (see Appendix E).

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Pollutant code
10) Summer/winter work weekday emissions
11) Annual emissions

4.6 Windblown Dust Source Module

Windblown dust emissions will be generated region-wide through modeling. The emission inventories will then be submitted to STL agencies for review and approval before inclusion in the final database. The spatial resolution will be the county level and the temporal resolution will be annual for the windblown dust source data in Phase I. In phase II, hourly, daily, or seasonal temporal resolutions may be tracked. The dust emissions (PM_{10} and $PM_{2.5}$) are currently being estimated using wind data as emissions per grid square. Therefore they will need to be converted to a county level before being sent to STL agencies for review and subsequent inclusion in the WRAP EDMS.

For windblown dust sources, at a minimum, the emissions data listed below should be submitted, stored, and tracked for each inventory. Windblown dust source is not included in the NEI as a

separate source category. Therefore, the data file needs to be created and the records defined. A definition based on the NIF biogenic source file should suffice.

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) Country code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Pollutant code
10) Summer/winter work weekday emissions
11) Annual emissions
12) Natural or anthropogenic classification

4.7 Fire Source Module

There are four types of fire emissions sources - wildfire, prescribed fire, wildland fire use, and agricultural burning - that will be included in the fire source module of the WRAP EDMS. It should be noted that wildfire, prescribed fire, wildland fire use include rangeland. Fire sources such as open burning activities on residential, commercial, and industrial properties will be included in the area source module. The WRAP Fire Tracking System (FTS) (WRAP, 2001) identified seven essential data (9 – 17) that will provide the basis for calculating the emissions for fire through the use of an emissions calculation mechanism, such as the WRAP emissions inventory system, to integrate the appropriate emissions factors and emission calculation techniques. The FTS also identified optional data (18 – 21) that are equally important in calculating fire emissions. Note that for fire sources, the WRAP EDMS will calculate the emissions. However, some STL agencies may estimate fire emissions themselves. These emissions will be submitted by the STL agencies with all the activity and surrogate data used for the estimation.

For fire sources, at a minimum, the emissions data listed below should be submitted, stored, tracked, and also used to calculate fire emissions when necessary. In the NEI, fire sources are contained in the area source category. Therefore, a data file which records are similar to the NIF area source file may define the fire source file.

1) Inventory year
2) Inventory start date
3) Inventory end date
4) Inventory type
5) County code
6) State and county FIPS code
7) Tribal code
8) SCC code
9) Date of burn

10) Duration of burn
11) Burn location latitude
12) Burn location longitude
13) Area of burn
14) Fuel type
15) Pre-burn fuel loading
16) Type of burn
17) Anthropogenic or natural classification
18) Daily tracking components
19) Fuel consumption
20) Non-burning techniques
21) Additional fire tracking information
22) Pollutant code
23) Emission factor
24) Daily emissions
25) Annual emissions

4.8. Standard Reports and Queries

The EDMS should have the capability to produce the following standard reports in tabular and simple plots (i.e. bar graph and pie chart) formats and allow queries of the same information including presentation in GIS format.

- A summary report of the annual WRAP emission inventory, compiled at the county and reservation levels and totaled for each state, tribe, and the WRAP region, for all pollutants, broken down by point, area, mobile, fire, biogenic, and windblown dust source categories, and by summed total emissions for all six source categories.
- A summary report of the annual WRAP emissions from the stationary point sources in each county and reservation and the stationary point sources for each state, tribe and the entire region (broken down by plant name), for each pollutant.
- A summary report of the annual WRAP emissions from the stationary point sources in each county and reservation and the stationary point sources for each state, tribe and the entire region (broken down by SCC code), for each pollutant.
- A summary report of the annual WRAP emissions from the area sources in each county and reservation and the area sources for each state, tribe and the entire region (broken down by SCC code), for each pollutant.
- A summary report of the annual WRAP emissions from the “Top 10” stationary point sources in each county and reservation and the “Top 10” stationary point sources for each state, tribe and the entire region (broken down by plant name), for each pollutant.
- A summary report of the annual WRAP emissions from the “Top 10” stationary point sources in each county and reservation and the “Top 10” stationary point sources for each state, tribe and the entire region (broken down by SCC code), for each pollutant.
- A summary report of the annual WRAP emissions from the “Top 10” area sources in each county and reservation and the “Top 10” area sources for each state, tribe and the entire region (broken down by SCC code), for each pollutant.

- A summary report of the annual WRAP emissions from on-road mobile sources in each county and reservation and on-road mobile sources for each state, tribe and the entire region (broken down by the sixteen (16) mobile source categories), for each pollutant and dust from paved and unpaved road.
- A summary report of the annual WRAP emissions from non-road mobile sources in each county and reservation and non-road mobile sources for each state, tribe, and the entire region (broken down by SCC code), for each pollutant.
- A summary report of the annual WRAP emissions from fire sources in each county and reservation and fire sources for each state, tribe, and the entire region (broken down by the 3 fire categories (wildfire, prescribed wild land burning, and agricultural burning activities), for each pollutant.
- A summary report of the annual WRAP emissions from biogenic sources in each county and reservation and biogenic sources for each state, tribe, and the entire region (broken down by emission source name).
- Data reports in the NEI Input Format Version 3.0 (NIF V3.0) for submittal to the EPA under the CERR.
- For stationary point sources, data reports for all emission points on site by text description name and by Stack ID, for NEI file format stack parameters (STKHGT, STKDIAM, STKTEMP, STKFLOW, STKVEL), production rates (BOILCAP, CAP_UNITS, THRUPUT, MAXRATE, NETDC), fuel parameters (HEATCON, SULFCON, ASHCON), standard industrial classification code (SIC), location (LATC, LONG), and emission controls ("pollutant"_CE, "pollutant"_CPRI, "pollutant"_CSEC).
- For stationary point sources, data reports for all emission points on site by text description name and by Stack ID, for actual emission rates of each pollutant, on an annual (tpy) and on a short term (pounds per hour) basis. This emission data will be summed for a cumulative total of emissions from each stationary point source.
- In addition to these standard reports, the EDMS will produce regional emission model (SMOKE)-ready emissions input files for the regional visibility modeling efforts.

4.9. Special Section 309 Tracking

Section 309 of the RHR requires that the first SIP be submitted by December 31, 2003 and that SIP must be effective until December 2018. Section 309 also specifically requires comprehensive emissions tracking and reporting for the clean air corridors (CAC), stationary SO_2 sources, mobile sources, fire sources, and windblown dust based on annual emissions.

4.9.1 Clean Air Corridors (CAC)

The preamble of the RHR defines a CAC as “a region that generally brings clean air to a receptor region”. The preamble also says, “the requirement to track emissions will enable states to quickly determine if changes in patterns of emissions will reduce the number of clean air days (defined as the average of the 20% clearest days) in any of the 16 Class I areas.” The actual requirements state that the Section 309 SIP/TIP must describe and provide for implementation of comprehensive emission tracking strategies for CAC to ensure that the visibility does not degrade on the least-impaired days at any of the 16 Class I areas. The strategy must include:

- An identification of CAC.
- Within areas that are CAC, an identification of patterns of growth or specific sites of growth that could cause, or are causing, significant emissions increases that could have, or are having, visibility impairment at one or more of the 16 Class I areas.
- In areas outside of CAC, an identification of significant emissions growth that could begin, or is beginning, to impair the quality of air in the corridor and thereby lead to visibility degradation for the least-impaired days in one or more of the 16 Class I areas.
- If impairment of air quality in CAC is identified, an analysis of the effects of increased emissions, including provisions for the identification of the need for additional emission reduction measures, and implementation of the additional measures where necessary.
- A determination of whether other clean air corridors exist for any of the 16 Class I areas. For any such CAC, an identification of the necessary measures to protect against future degradation of air quality in any of the 16 Class I areas.

WRAP identified one CAC as shown in Appendix H. Using the most recent state emission inventories available through the WRAP EDMS, WRAP will produce a report for each five-year implementation plan revision (2008, 2013, and 2018) on the current and projected emissions in the CAC and in areas outside the corridor and compare these emissions to a 1996 baseline emissions.

WRAP has examined patterns of growth in the CAC and found that they are not causing significant emission increases that could have or are having visibility impacts at one or more of the 16 Class I areas. Nor, at this time, are such emission increases expected during the first planning period (2003-2018). WRAP also has examined emissions growth in areas outside the corridor and found that significant emissions growth is not occurring that could begin or is beginning to impair the quality of the air in the corridor and thereby lead to visibility degradation for the least impaired days in one or more of the 16 Class I areas.

Since impairment of air quality in clean air corridors has not been identified, WRAP finds no requirement under for further visibility impact analysis or additional emission reduction measures until at least the next SIP revision (2008). WRAP finds no other clean air corridors beyond the corridor identified in Appendix H.

Consequently, the EDMS should have the capability to produce the following special reports in tabular and simple plots (i.e. bar graph and pie chart) formats and allow queries of the same information including presentation in GIS format, in addition to the standard reports.

- A summary report of the annual summed total emissions for all six source categories and all of the pollutants by county/state and tribal lands, as well as for the entire CAC.
- A summary report of the annual summed total emissions for all six source categories and all of the pollutants for the same types of political boundaries surrounding the CAC.
- A summary report of the comparison of the annual summed total emissions for all six source categories and all of the pollutants for the same types of political boundaries, as well as the entire CAC and the corresponding base year total emissions.

4.9.2 Pre-Trigger SO_2 Annex

The SO_2 Annex program, as proposed by WRAP and adopted by EPA, requires the tracking of SO_2 emissions from eligible stationary sources within states or tribal reservations participating in Section 309, to determine if the regional SO_2 emissions cap has been exceeded. This is known as "pre-trigger" tracking. Beginning with the 2003 calendar year and continuing through 2018, each state and tribe participating in the program will submit an annual SO_2 emissions report to the WRAP EDMS for the sources covered by the program. These annual reports will contain the following information:

- Identification and explanation for new/additional SO_2 sources which emissions are greater than100 tpy that were not contained in the previous year's emissions report.
- Explanation for sources shut down or removed from the previous year's emissions report.
- Explanation for emissions variations at any covered source that exceeds +/- 20% from the previous year.
- Identification and explanation of new emissions reporting methods at any source.

WRAP will compile the annual emissions reports submitted by the states and tribes participating in the program into a regional emission report for SO_2 using the WRAP EDMS. By December 31 of the year following the applicable compliance year, WRAP will prepare a regional emission report that will include the following information:

- Summary of regional SO_2 emissions (tpy).
- Identification of any paper emission increases and decreases that have occurred due to changes in emission inventory techniques since the last SIP revision for the regional haze SIP. The report will contain a running regional total, as well as supporting documentation identifying the specific changes that have occurred at individual sources.
- Average emissions for the last three years (if applicable) for comparison to the regional milestone.
- Regional milestone for the compliance period.
- Draft determination that the milestone has either been met, or has been exceeded thereby triggering the backstop trading program.

Consequently, The EDMS should have the capability to produce the following special reports in tabular and simple plots (i.e. bar graph and pie chart) formats and allow queries of the same information including presentation in GIS format, in addition to the standard reports.

- A summary report of the annual WRAP emissions from the stationary sources emitting more than 100 tpy of SO_2 in the base year for each state, tribe and the entire region.
- A summary report of the new stationary sources emitting more than 100 tpy of SO_2 that were not contained in the previous year's inventory for each state, tribe and the entire region.
- A summary report of the stationary sources emitting more than 100 tpy of SO_2 that are retired compared to the previous year's inventory for each state, tribe and the entire region.

- A summary report of the regional average SO_2 emissions from stationary sources emitting more than 100 tpy of SO_2 for the last three years and comparison to the regional milestone for the compliance period.
- A summary report of the stationary sources emitting more than 100 tpy of SO_2 which emissions exceed +/- 20% compared to the previous year's inventory for each state, tribe and the entire region.
- A summary report identifying all the stationary sources emitting more than 100 tpy of SO_2 that choose to opt in the program for each state, tribe and the entire region.
- A summary report identifying all the stationary sources emitting more than 100 tpy of SO_2 that were not included in the base year for each state, tribe and the entire region.

4.9.3 Mobile Emissions

For mobile sources, the SIP/TIP submissions must provide for statewide inventories of on-road and non-road mobile source emissions of VOC, NO_X, SO_2, $PM_{2.5}$, EC, OC, and paved and unpaved road dust for the years 2003, 2008, 2013, and 2018. The inventories must demonstrate a continuous decline in total mobile source emissions for the aforementioned pollutants, evaluated separately. This means that the statewide mobile source emissions of each pollutant in 2008, 2013, and 2018 must be less than the estimated emissions of that pollutant for the previous period.

Consequently, the EDMS should have the capability to produce the following special report in tabular and simple plots (i.e. bar graph and pie chart) formats and allow queries of the same information including presentation in GIS format, in addition to the standard reports.

- A summary report of the comparison of annual WRAP total (on-road plus nonroad) emissions from the mobile sources (VOC, NOx, SO_2, $PM_{2.5}$, EC, OC, and paved and unpaved road dust) for each state, tribe and the entire region and the corresponding previous period total emissions, for each pollutant.

4.9.3 Fire Emissions

For fire emissions, Section 309 of the RHR specifically calls for a statewide inventory and emissions tracking system (spatial and temporal) of VOC, NO_X, EC, OC, and $PM_{2.5}$ emissions from fire. The WRAP inventory will add SO_2, PM_{10}, CO, and NH_3 emissions.

Under Section 309, states and tribes must identify a method or a timeline to develop a method to track fire activity data and calculate the resulting required emissions inventory in their SIP/TIP. Tracking of fire activity data and calculation of the resulting emissions through the WRAP EDMS will provide information critical to the successful implementation of other requirements under Section, including the development, adoption, and implementation of enhanced smoke management programs, the establishment of annual emission goals, and future projections of fire emissions.

The WRAP EDMS will track activity data as reported by states and tribes participating in Section 309, as well as the same type of data provided by other WRAP region state, tribal, and

local air agencies, and federal/state/private sources using prescribed and/or agricultural burning techniques. The WRAP EDMS will calculate the resulting emissions for fire source types including prescribed fire, wildfire, wildland fire use, and agricultural burning.

The EDMS should have the capability to produce a special report in tabular and simple plots (i.e. bar graph and pie chart) formats and allow queries of the same information including presentation in GIS format in the standard report style presented in Section 3.8 of this report.

4.10 GIS Module

GIS provides users with the ability to display and analyze data that is related to a geographic location. GIS provides a means for an organization to display data that is easily read and understood. The WRAP EDMS should include a fully functioning GIS module that provides multiple tools to display data over the internet. The inclusion of a GIS module will provide a means for users to select data that is of importance to them and display the data in a fashion that is easily understood.

During Phase I of development, the WRAP EDMS should include the following GIS Functionality.

- Pan and zoom
- Query layer information
- Ability to add/remove multiple layers of data
- Point and click
- Measure distances
- Buffer
- Print – multiple sizes of maps
- Select map features by line, rectangle or polygon

Phase II development of the WRAP EDMS could include some of the following additional functionality.

- Export selected maps shape files
- Generate polygons/layers from coordinates stored in the WRAP EDMS (e.g. create polygons for fire burn areas)

The WRAP EDMS GIS module should include the following layers of data for Phase I development.

Static layers

- County, state and country polygons
- Tribal reservation polygons
- Metropolitan statistical areas polygons
- Nonattainment area polygons
- Class I areas polygons

- Interstate and highway line features
- Other roadways and railroad line features
- Bodies of water polygons
- Census data polygons
- Other federal land polygons (i.e. national parks, monuments, forest, and refuges)
- CAC polygons
- International area polygons
- WRAP modeling domain grid system

Dynamic/Data driven layers

- Select and display emissions sources and associated emissions levels by geographical area.

4.11 DBA Module

All major applications and systems include an administrative section or module that allows the application administrator(s) to perform general system maintenance as well as application specific system maintenance. These maintenance routines consist of tasks that are routinely performed by the application or system administrator(s) and can easily be automated through a graphical user interface. Often times there are tasks that administrators need to perform that cannot easily be automated, due to the complexity or changing nature of the task, and would not be included in the administrative module of the application.

The WRAP EDMS will require a DBA Module, which will provide the necessary functionality required to perform several administrative tasks. During Phase I of development, the WRAP EDMS should include the following DBA Functionality.

- User account maintenance – maintain the list and permissions for users of the WRAP EDMS.
- Lookup table maintenance (unit conversions, threshold values, etc.) – maintain the multiple lookup tables and associated data that will be included in the WRAP EDMS.
- Versioning/maintenance of submitted data – ability to version submitted data and determine current version of all data.
- Data gap filling triggered from a QA/QC check, following specific methods that will be developed by WRAP.
- International data maintenance – maintain the tables and data for all international data necessary for the WRAP EDMS.
- Opt-in options for individual states, tribes, and sources – maintain list of states and tribes with associated emissions sources that decide to opt-in for Sections 308 and 309 tracking, after 2003.
- Others – other DBA module functionality requirements as determined necessary.

During Phase II development, the WRAP EDMS should include the following DBA Functionality.

- Data warehousing/archiving – ability to move historical data out of the production database and into a WRAP data warehouse.
- Historical data retrieval – ability to generate reports and data sets from the WRAP data warehouse.

4.12 QA/QC Module

The WRAP EDMS will include a QA/QC module to perform two levels of QA/QC. The QA/QC protocol will be similar to that of NEI with some modifications (see Appendix F for the NEI QA/QC process). The first level of QA/QC should include a validation of the format of the submitted data files at the submission point of entry. This would ensure that the submitting entity supplied all data to the WRAP EDMS in the expected format and also identify any errors. The second level of QA/QC should consist of checks of the data that was submitted to WRAP. This should include checking reference values and acceptable data ranges for specific data points.

The WRAP EDMS QA/QC module should perform the following types of format checks.

- Does the file conform to the format specification? - The initial checks performed on each submitted data set will verify that the file format is correct, and therefore readable for further processing (e.g., field widths, begin/end position, data types).
- Are mandatory data elements reported? - The presence or absence of mandatory data elements will be confirmed. Some of the mandatory data fields are the primary keys (i.e. FIPS codes and SCC Codes) in each record that help relate and maintain the individual records together in a file for subsequent processing.
- Does the data set contain what the STL agency said they are submitting? - The data in the file will be compared to the Inventory Submittal Form (ISF) that was provided with the file to verify the noted and intended coverage for geographic area, pollutants, source categories, and temporal information.

WRAP will keep a log of errors and problems encountered with each of the data submissions, and will provide those to the STL agency when communicating with the agency.

The WRAP EDMS QA/QC for data content will consist of two areas of QA/QC. First, the data will be checked for completeness, ensuring that all data exists for all sources and geographic areas. Second, the data integrity will be checked, ensuring that supplied values are within acceptable ranges and all codes are valid. The QA/QC module should perform the following types of data content checks for completeness.

- Add records to fill in missing facilities or source categories, or to fill in for missing geographic areas (e.g., where data were not reported for entire counties).
- Add, or solve for, data elements missing in existing records.

Additionally, the QA/QC module will perform the following data augmentation processes:

- Calculate EC and OC emissions.

- Aggregate dust and biogenic source data from the supplied grid and hourly levels to county/reservation and annual levels.
- Modify county data to exclude sources and emissions from tribal reservations that are within the county's boundaries.

The QA/QC module should perform the following types of data integrity checks.

- Conditional fields - fields required by other fields in the same table. For example, if there is a PCT Capture Efficiency in the Control Equipment (CE) table, then there should also be a Primary Device Type in the CE Table.
- Acceptable codes - the Pollutant Code (and all acceptable codes) should be consistent.
- Numeric values in acceptable range - For example, the annual average days per week in the Emission Point (EP) table should be less than seven.
- Inter-File Format - fields required by other fields in different tables. If there is an Emission Record in the Emission (EM) table, then there should be an associated activity record in the Activity Code (AC) table.
- Inter-source relationships
- Inter-pollutant relationships
- Advance point source diagnostic – check of largest sources, out of range stacks, stack location.

5.0 CONCLUSIONS

Under contract with the WRAP EF, EA performed an EDMS needs assessment that included two interview workshops, a web-based questionnaire, and an evaluation of selected existing systems. Five existing database management systems were evaluated and compared to the conceptual WRAP EDMS developed from the findings of the workshops and web-based questionnaire.

The workshops and questionnaire results indicated that the WRAP EDMS should be used as the repository of WRAP regional emissions data, and as a tool that can help in the implementation of the emissions tracking and reporting requirements of the RHR. The WRAP EDMS will be able to track all the visibility-impairing pollutants. The emissions data will primarily be submitted by STL agencies in an EPA-compliant format according to an open submittal process. Furthermore, the WRAP EDMS will contain six major sources representing the emissions sources: point, area, mobile, fire, biogenic, and windblown dust sources in addition to a QA/QC module, a GIS module, and a DBA module. Finally, the WRAP EDMS will produce user-specified standard and RHR-special reports and will allow data queries and graphical display, and presentation of this information in GIS format.

The results of the comparative analysis showed that the conceptual WRAP EDMS has a unique set of requirements that are not fully implemented in any existing EDMS. Therefore, a new individual EDMS needs to be developed to meet the requirements for the conceptual WRAP EDMS. Also, this new system could utilize some of the features incorporated in several of the existing systems to accomplish some of the WRAP EDMS requirements.

6.0 REFERENCES

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APPENDIX A-7. STATIONARY SOURCES

This appendix contains work products and references relied upon by Arizona in the development of Chapter 7 of the Regional Haze SIP.

Appendix A-7a. Arizona Draft Western Backstop SO_2 Trading Program Rule

DRAFT RULE

<u>NOTE</u>: This draft rule has been included in Arizona's Regional Haze State Implementation Plan in order to give the reader an opportunity to see how Arizona has currently interpreted the Model Rule for state-specific rulemaking. This draft rule will go through revisions prior to its submission to Arizona's Secretary of State, after the public comment period, and is subject to the final review of the Governors' Regulatory Review Council.

TITLE 18. ENVIRONMENTAL QUALITY
CHAPTER 2. DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR POLLUTION CONTROL

ARTICLE 16. VISIBILITY; REGIONAL HAZE

Section		
R18-2-1610	Western Backstop SO_2 Trading Program; Definitions ……	New Section
R18-2-1611	Pre-trigger Applicability; Monitoring, Recordkeeping and Reporting ……..……..…….	New Section
R18-2-1612	WEB Trading Program Trigger ……. ……	New Section
R18-2-1613	WEB Trading Program Applicability ……	New Section
R18-2-1614	Account Representative for WEB Sources ……	New Section
R18-2-1615	Registration ……	New Section
R18-2-1616	Allowance Allocations ……..……	New Section
R18-2-1617	Establishment of Accounts ……..……	New Section
R18-2-1618	Monitoring, Recordkeeping and Reporting ……	New Section
R18-2-1619	Allowance Transfers ……	New Section
R18-2-1620	Use of Allowances from a Previous Year ……	New Section
R18-2-1621	Compliance ……	New Section
R18-2-1622	Special Penalty Provisions for the 2018 Milestone ……	New Section

ARTICLE 16. VISIBILITY; REGIONAL HAZE

R18-2-1607. Reserved

R18-2-1608. Reserved

R18-2-1609. Reserved

R18-2-1610. Western Backstop SO_2 Trading Program; Definitions

A. This rule implements the Western Backstop SO_2 Trading Program ("WEB Trading Program") provisions required under the federal Regional Haze Rule, 40 CFR 51.309, and the SO_2 Milestones and Backstop Trading Program.

1. All applicable sources as described in Sections 1611 and 1613 of this Rule shall meet the pre-trigger monitoring, recordkeeping and reporting requirements as outlined in Section 1611 of this Rule.
2. Nothing in this Rule waives any requirement otherwise in effect or subsequently required under another program, including rules governing new sources.

B. The definitions in this part apply only to this Rule.

1. "Account Certificate of Representation" means the completed and signed submission required to designate an Account Representative for a WEB source or an Account Representative for a general account.
2. "Account Representative" means the individual who is authorized through an Account Certificate of Representation to represent owners and operators of the WEB source with regard to matters under the WEB Trading Program or, for a general account, who is authorized through an Account Certificate of Representation to represent the persons having an ownership interest in allowances in the general account with regard to matters concerning the general account.
3. "Act" means the federal Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.*
4. "Actual Emissions" means total annual sulfur dioxide emissions determined in accordance with Section 1618 of this Rule, or determined in accordance with [refer to state or tribal inventory rule] for sources that are not subject to Section 1618 of this Rule.
5. "Allocate" means to assign allowances to a WEB source.
6. "Allowance" means the limited authorization under the WEB Trading Program to emit one ton of SO_2 during a specified control period or any control period thereafter subject to the terms and conditions for use of unused allowances as established by this Rule.
7. "Allowance limitation" means the tonnage of SO_2 emissions authorized by the allowances available for compliance deduction for a WEB source for a control period under Section 1621(A) of this Rule on the allowance transfer deadline for that control period.

8. “Allowance Tracking System” means the system developed by the Director where allowances under the WEB Trading Program are recorded, held, transferred and deducted.
9. “Allowance Tracking System” account means an account in the Allowance Tracking System established for purposes of recording, holding, transferring, and deducting allowances.
10. “Allowance transfer deadline” means the deadline established in Section 1619(B) of this Rule when allowances must be submitted for recording in a WEB source’s compliance account in order to demonstrate compliance for that control period.
11. “Compliance account” means an account established in the Allowance Tracking System under Section 1617(A) of this Rule for the purpose of recording allowances that a WEB source might hold to demonstrate compliance with its allowance limitation.
12. “Compliance certification” means a submission to the Director by the Account Representative as required under Section 1621(B) of this Rule to report a WEB source’s compliance or noncompliance with this Rule.
13. “Control period” means the period beginning January 1 of each year and ending on December 31 of the same year, inclusive.
14. “Emissions tracking database” means the central database where SO_2 emissions for WEB sources as recorded and reported in accordance with this Rule are tracked to determine compliance with allowance limitations.
15. “Emission unit” means any part of a stationary source that emits or would have the potential to emit any pollutant submitted to regulations under the Clean Air Act.
16. “Existing source” means a stationary source that commenced operation before the Program Trigger Date.
17. “Fugitive emissions” means those emissions that could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.
18. “General account” means an account established in the Allowance Tracking System under Section 1617 of this Rule for the purpose of recording allowances held by a person that are not to be used to show compliance with an allowance limitation.
19. “Milestone” means the maximum level of stationary source regional sulfur dioxide emissions for each year from 2003 to 2018.
20. “New WEB Source” means a WEB source that commenced operation on or after the Program Trigger Date.

21. “New Source Set-aside” means a pool of allowances that are available for allocation to new sources.
22. “Owner or operator” means any person who is an owner or who operates, controls or supervises a WEB source, and includes but is not be limited to any holding company, utility system or plant manager.
23. “Potential to emit” means the maximum capacity of a stationary source to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is enforceable by the EPA Administrator.
24. “Program trigger date” means the date that the Director determines that the WEB Trading Program has been triggered.
25. “Program trigger years” means the years for the applicable milestone if the WEB Trading Program is triggered.
26. “Renewable Energy Resource” means a resource that generates electricity by non-nuclear and non-fossil technologies that results in low or no air emissions. The term includes electricity generated by wind energy technologies; solar photovoltaic and solar thermal technologies; geothermal technologies; technologies based on landfill gas and biomass sources, and new low-impact hydropower that meets the Low-Impact Hydropower Institute criteria. Biomass includes agricultural, food and wood wastes. The term does not include pumped storage or biomass from municipal solid waste, black liquor, or treated wood.
27. “Retired source” means a WEB source that has received a retired source exemption as provided in Section 1613(C) of this Rule. Any retired source resuming operations under Section 1613(C)(4) of this Rule, must submit its exemption as part of its registration materials.
28. “Serial number” means, when referring to allowances, the unique identification number assigned to each allowance by the Tracking Systems Administrator, in accordance with Section 1616(B) of this Rule.
29. “SO_2 emitting unit” means any equipment that is located at a WEB source and that emits SO_2.
30. “Stationary source” means any building, structure, facility or installation that emits or may emit any air pollutant subject to regulation under the Clean Air Act.
31. “Submit” means sent to the appropriate authority under the signature of the Account Representative. For purposes of determining when something is

submitted, an official U.S. Postal Service postmark, or equivalent electronic time stamp, shall establish the date of submittal.

32. "Ton" means 2000 pounds and, for any control period, any fraction of a ton equaling 1000 pounds or more shall be treated as one ton and any fraction of a ton equaling less than 1000 pounds shall be treated as zero tons.

33. "Tracking System Administrator" means the person designated by the Director as the administrator of the Allowance Tracking System and the emissions tracking database.

34. "WEB source" means a stationary source that meets the applicability requirements of Section 1613 of this Rule.

35. "Western Backstop SO_2 Trading Program ("WEB Trading Program")" means in reference to this Rule, the program triggered as a backstop, if necessary, to ensure that regional SO_2 emissions are reduced.

R18-2-1611. Pre-trigger Applicability; Monitoring, Recordkeeping and Reporting

A. Applicable sources are described in Section 1613 of this Rule.

B. All applicable sources shall follow the provisions for monitoring, recordkeeping and reporting as outlined in R18-2-304, R18-2-306, R18-2-327, or R18-2-715.01, and, in addition, shall:

1. Submit an annual inventory of SO_2 emissions, beginning with the 2003 emission inventory.
   a. A source that emits 100 tons per year or more of SO_2 in a later year shall continue to submit an SO_2 inventory for tracking compliance with the regional SO_2 milestones until 2018 or until the WEB Trading Program has been fully implemented and emissions tracking is occurring, whichever is earlier.
   b. Smelters shall submit an annual report of sulfur input in tons per year with the submission of the annual emissions inventory.
2. Utilize appropriate emission factors and estimating techniques, and document the emissions monitoring or estimation methodology used.
3. Include emissions from start up, shut down, and upset conditions in the annual total inventory.
4. Utilize, if subject to the federal acid rain program, methods from 40 CFR Part 75 to report emissions from all sources.
5. Include the rate and period of emissions, the specific installation that is the sources of the air pollution, composition of air contaminant, type and efficiency of

the air pollution control equipment, and other information necessary to quantify operation and emissions, and to evaluate pollution control.

6. Retain records for a minimum of 10 years from the date of creation, or if the record was the basis for an adjustment to a milestone, 5 years from the date of a state implementation plan revision, whichever is longer.

R18-2-1612. WEB Trading Program Trigger

A. Except as provided in 1612(B), Sections 1613 through 1621 of this Rule shall become effective on the program trigger date that is established in accordance with the procedures outlined in the 40 CFR 51.309(4)(h).

B. Section 1622 of this Rule, Special Penalty Provisions for Year 2018, shall become effective on January 1, 2018 and shall remain effective until the provisions of Section 1622 of this Rule have been fully implemented.

R18-2-1613. WEB Trading Program Applicability

A. General Applicability. This Rule applies to any stationary source or group of stationary sources that are located on one or more contiguous or adjacent properties and which are under the control of the same person or persons under common control, belonging to the same industrial grouping, and that are described in paragraphs (1) through (4) of this subsection. A stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (i.e., all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987.

B. The following are WEB sources:

1. All BART-eligible sources as defined in 40 CFR 51.301 that are BART-eligible due to SO_2 emissions.
2. All stationary sources not meeting the criteria of 1613(A) of this Rule that have actual SO_2 emissions of 100 tons or more per year in the Program Trigger Years or any subsequent year. The fugitive emissions of a stationary source shall not be considered in determining whether it is a WEB source unless the source belongs to one of the following categories of stationary source:
   a. Coal cleaning plants (with thermal dryers);
   b. Kraft pulp mills;
   c. Portland cement plants;
   d. Primary zinc smelters;

e. Iron and steel mills;

f. Primary aluminum ore reduction plants;

g. Primary copper smelters;

h. Municipal incinerators capable of charging more than 250 tons of refuse per day;

i. Hydrofluoric, sulfuric, or nitric acid plants;

j. Petroleum refineries;

k. Lime plants;

l. Phosphate rock processing plants;

m. Coke oven batteries;

n. Sulfur recovery plants;

o. Carbon black plants (furnace process);

p. Primary lead smelters;

q. Fuel conversion plants;

r. Sintering plants;

s. Secondary metal production plants;

t. Chemical process plants;

u. Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;

v. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;

x. Taconite ore processing plants;

y. Glass fiber processing plants;

z. Charcoal production plants;

aa. Fossil-fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input; or

bb. Any other stationary source category, which as of August 7, 1980 is being regulated under Section 111 or 112 of the Act.

3. A new source that begins operation after the Program Trigger Date and has the potential to emit 100 tons or more of SO_2 per year.

4. The Director may determine on a case-by-case basis, with concurrence from the EPA Administrator, that a source defined in Section 1613(B)(2) of this Rule is not a WEB source if the source:

a. In each of the previous five years had actual SO_2 emissions of less than 100 tons per year; and

b. Had actual SO_2 emissions of 100 tons or more in a single year due to a

temporary emission increase that was caused by a sudden, infrequent and not reasonably preventable failure of air pollution control equipment, failure of process equipment, or a failure to operate in a normal or usual manner;

c. Took timely and reasonable action to minimize the temporary emission increase; and

d. Has corrected the failure of air pollution control equipment, process equipment, or process by the time of the Director's determination under this section; or

e. Had to switch fuels or feedstocks on a temporary basis and as a result of an emergency situation or unique and unusual circumstances besides cost of such fuels or feedstocks.

f. A temporary emission increase due to poor maintenance or careless operation does not meet the criteria of this section.

C. Duration of Program Participation. Except as provided for in Section 1613(D) of this Rule, once a source is subject to the WEB Trading Program, it will remain in the program every year thereafter.

D. Application for Retired Source Exemption. Any WEB that is retired shall apply for a retired source exemption. The WEB source may only be considered retired if all SO_2 emitting units at the source are retired. The application shall contain the following information:

1. Identification of the WEB source, including plant name and an appropriate identification code in a format specified by the Director.
2. Name of Account Representative.
3. Description of the status of the WEB source, including the date that the WEB source was retired.
4. Signed certification that the WEB source is retired and will comply with the requirements of Sections 1613(D) through (H) of this Rule.
5. Verification that the WEB source has a general account where any unused allowances or future allocations will be recorded.

E. Notice of Retired Source Exemption. The retired source exemption becomes effective When the Director, or control officer with jurisdiction over the source, notifies the source that the retired source exemption has been granted.

F. Responsibilities of Retired Sources:

1. A retired source shall be exempt from Sections 1618 and 1621 of this Rule, except as provided below.
2. A retired source shall not emit any SO_2 after the date the retired source exemption is effective.
3. A source shall submit SO_2 emissions reports, as required by Section 1618(H) of this Rule for any time period the source was operating prior to the effective date of the retired source exemption. The retired source shall be subject to the compliance provisions of Section 1621 of this Rule, including the requirement to hold allowances in the source's compliance account to cover all SO_2 emissions prior to the date the source was permanently retired.
4. A retired source that is still in existence but no longer emitting SO_2 shall, for a period of five years from the date the records are created, retain records demonstrating the effective date of the retired source exemption for purposes of this Rule.

G. Resumption of Operations. Should a retired source desire to resume operation, the retired source must submit registration materials as follows:

1. If the source is required to obtain a new source review permit or operating permit under [refer to applicable new source permitting rule] prior to resuming operation, then registration information as described in Section 1615(A) of this Rule and a copy of the retired source exemption must be submitted with the application required under [refer to applicable new source permitting rule];
2. If the source is not required to obtain a new source review permit or operating permit under [refer to applicable new source permitting rule] prior to resuming operation, then registration information as described in Section 1615(A) of this Rule and a copy of the retired source exemption must be submitted to the Director at least ninety days prior to resumption of operation.
3. The retired source exemption shall automatically expire on the day the source resumes operation.

H. Loss of Future Allowances.

1. A WEB source that is retired and that does not apply to the Director for a retired source exemption within ninety days of the date that the source is retired shall forfeit any unused and future allowances. The abandoned allowances shall be retired by the Tracking System Administrator.

Note to Reviewer: This is not intended to be a punitive action, but a method to correct the number of allowances being tracked by the state.

The Director will need to establish due process procedures for forfeiting these "abandoned" allowances in a manner that is consistent with the administrative procedures process. This provision is intended to address sources that go out of business, leave no forwarding address, and truly abandon their allowances. It is assumed that the Director will have a process to notify sources that their allowances may be forfeited so this provision does not lead to forfeiture just because the deadline was missed Arizona will draft the appropriate notification language for this section.

R18-2-1614. Account Representative for WEB Sources

A. Each WEB source must identify one Account Representative and may also identify an alternate Account Representative who may act on behalf of the Account Representative. Any representation, action, inaction or submission by the alternate Account Representative will be deemed to be a representation, action, inaction or submission by the Account Representative.

B. Identification and Certification of an Account Representative.

1. The Account Representative and any Alternate Account Representative shall be appointed by an agreement that makes the representations, actions, inactions or submissions of the Account Representative and any alternate binding on the owners and operators of the WEB source.
2. The Account Representative shall submit to the Director and the Tracking System Administrator a signed and dated Account Certificate of Representation (Certificate) that contains the following elements:
   a. Identification of the WEB source by plant name, state and an appropriate identification code in a format specified by the Director;
   b. The name, address, e-mail (if available), telephone and facsimile number of the Account Representative and any alternate;
   c. A list of owners and operators of the WEB source;
   d. Information to be part of the emission tracking system database in accordance with the Implementation Plan. The specific data elements shall be as specified by the Director to be consistent with the data system structure, and may include basic facility information that may appear in other reports and notices submitted by the WEB source, such as county location, industrial classification codes, and similar general facility information.
   e. The following certification statement:

"I certify that I was selected as the Account Representative or alternate Account Representative, as applicable, by an agreement binding on the owners and operators of the WEB source. I certify that I have all the necessary authority to carry out my duties and responsibilities under the WEB Trading Program on behalf of the owners and operators of the WEB source and that each such owner and operator shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Director regarding the WEB Trading Program."

3. Upon receipt by the Director of the complete Certificate, the Account Representative and any alternate Account Representative represents and, by his or her representations, actions, inactions, or submissions, legally binds each owner and operator of the WEB source in all matters pertaining to the WEB Trading Program. The owners and operators shall be bound by any decision or order issued by the Director regarding the WEB Trading Program.
4. No WEB Allowance Tracking System account shall be established for the WEB source until the Tracking System Administrator has received a complete Certificate. Once the account is established, the Account Representative shall make all submissions concerning the account, including the deduction or transfer of allowances.

C. Requirements and Responsibilities of the Account Representative.

1. The responsibilities of the Account Representative include, but are not limited to, the transferring of allowances, and the submission of monitoring plans, registrations, certification applications, SO_2 emissions data and compliance reports as required by this Rule, and representing the source in all matters pertaining to the WEB Trading Program.
2. Each submission under this program shall be signed and certified by the Account Representative for the WEB source. Each submission shall include the following truth and accuracy certification statement by the Account Representative:
"I am authorized to make this submission on behalf of the owners and operators of the WEB source for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I amaware that there are

significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

D. Changes to the Account Representative; Owners and Operators.

1. Changes to the Account Representative or the alternate Account Representative.
   a. The Account Representative or alternate Account Representative may be changed at any time by sending a complete superseding Certificate to the Director and the Tracking System Administrator under Section 1614(B) of this Rule, with the change taking effect upon receipt of such Certificate by the Director.
   b. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Account Representative or alternate prior to the time and date when the Tracking System Administrator receives the superseding Certificate shall be binding on the new Account Representative and the owners and operators of the WEB source.
2. Changes in Owners and Operators.
   a. Within thirty days of any change in the owners and operators of the WEB source, including the addition of a new owner or operator, the Account Representative shall submit a revised Certificate amending the list of owners and operators to include such change.
   b. In the event a new owner or operator of a WEB source is not included in the list of owners and operators submitted in the Certificate, such new owner or operator shall be deemed to be subject to and bound by the Certificate, the representations, actions, inactions, and submissions of the Account Representative of the WEB source, and the decisions, orders, actions, and inactions of the Director as if the new owner or operator were included in such list.

R18-2-1615. Registration

A. Deadlines.

1. Each source that is a WEB source on or before the Program Trigger Date shall register by submitting the initial Certificate required in Section 1614(B) of this Rule to the Director no later than 180 days after the Program Trigger Date.
2. Any existing source that becomes a WEB source after the Program Trigger Date shall register by submitting the initial Certificate required in Section 1614(B) of this Rule to the Director by September 30 of the year following the inventory year

in which the source exceeded the emission threshold.

3. Any new WEB source shall register by submitting the initial Certificate required in Section 1614(B) of this Rule to the Director prior to the commencement of operation.

B. Integration into Permits

1. Any allocation, transfer or deduction of allowance to or from the compliance account of a WEB source shall not require revision of the WEB source's operating permit.
2. Any WEB source that is not required to have a permit under [state's New Source Review Rule] at any time after this Rule becomes effective must at all times possess a permit that includes the requirements of this Rule. If it does not possess a Title V permit under [state's Title V rule], it may do so by obtaining or modifying a permit under [state or tribe's New Source Review Rule] to incorporate the requirements of this Rule. The source must at all times possess a permit that includes these requirements.

R18-2-1616. Allowance Allocations

A. The Tracking System Administrator will record the allowances for each WEB source in the compliance account for a WEB source once the allowances are allocated by the Director. If applicable, the Tracking System Administrator will record a portion of the SO_2 allowances for a WEB source in a special reserve account assigned to the Director to account for any allowances to be held by the Director in accordance with Section 1618(A)(2) of this Rule.

B. The Tracking System Administrator will assign a serial number to each allowance.

C. All allowances shall be allocated, recorded, transferred, or used as whole allowances. To determine the number of whole allowances, the number of allowances shall be rounded down for decimals less than 0.50 and rounded up for decimals of 0.50 or greater.

D. An allowance is not a property right, and is a limited authorization to emit one ton of SO_2 valid only for the purpose of meeting the requirements of this Rule. No provision of this WEB Trading Program or other law should be construed to limit the authority of the Director to terminate or limit such authorization.

E. Early Reduction Bonus Allocation.

1. Any WEB source that reduces permitted annual SO_2 emissions to a level that is below the floor level allocation established for that source between 2003 and the program trigger year may apply to the Director for an early reduction bonus allocation.

2. The application must be submitted no later than ninety days after the Program Trigger Date. Any WEB source that applies and receives early reduction bonus allocations must retain the records referenced below for a minimum of five years after the early reduction bonus allowance is certified.

3. The application for an early reduction bonus allocation must contain the following information:

   a. Copies of all permits or other enforceable documents that include annual SO_2 emissions limits for the WEB source during the period the WEB source was generating the early reductions. Such permits or enforceable documents require monitoring for SO_2 emissions that meets the requirements in Sections 1618(A)(1) and 1618(A)(3) of this Rule.

   Note to reviewer: The early reduction bonus allocation needs to address sources that are not using Part 75 equipment monitoring. This is under discussion.

   b. Copies of emissions monitoring reports, for the period the WEB source was generating the early reductions, that documents the actual annual SO_2 emissions and demonstrates that the actual annual SO_2 emissions were below the floor level allocation established for that source.

   c. Demonstration that the floor level established for the source was calculated using data consistent with the new monitoring methodology. If new monitoring techniques change the floor level for the source, then a demonstration of the new floor level based on new monitoring techniques should be included in the application.

F. Request for allowances for new WEB sources or modified WEB Sources.

1. A new WEB source or an existing WEB source that has increased production capacity through a permitted change in operations [refer to state's NSR Rules] may apply to the Director for an allocation from the new source set-aside.

   a. A new WEB source is eligible to apply for an annual allocation equal to the permitted annual SO_2 emission limit for that source after the source has commenced operation.

   b. An existing WEB source is eligible to apply for an annual allocation equal to the permitted annual SO_2 emission limit for that source that is attributable to any amount of production capacity that is greater than the permitted production capacity for that source as of January 1, 2003.

c. A source that has received a retired source exemption under Section 1613)D of this Rule is not eligible to apply for an allocation from the new source set-aside.

2. The application for an allocation from the new source set-aside must contain the following information:

a. Demonstration that shows the permitted production capacity of the source before and after the new permit;

b. For new WEB sources, documentation of the actual date of the commencement of operation and a copy of the permit.

R18-2-1617. Establishment of Accounts

A. Allowance Tracking System Accounts.

1. All WEB sources are required to open a compliance account. Any person may open a general account for holding and transferring allowances. To open either type of account, an application that contains the following information shall be submitted:

a. The name, mailing address, e-mail address, telephone number, facsimile number of the Account Representative. For a compliance account, include a copy of the Account Certificate of Representation of the Account Representative and any alternate as required in Section 1614(B)(2) of this Rule. For a general account, include the Account Certificate of Representation of the Account Representative and any alternate as required in Section 1617(C)(2) of this Rule.

b. The WEB source or organization name;

c. The type of account to be opened; and

d. A signed certification of truth and accuracy by the Account Representative according to Section 1614(C) of this Rule for compliance accounts and for general accounts, certification of truth and accuracy by the Account Representative according to Section 1617(D) of this Rule.

B. Account Representative for General Accounts.

1. For a general account, one Account Representative must be identified and an alternate Account Representative may be identified and may act on behalf of the Account Representative. Any representation, action, inaction or submission by the alternate Account Representative will be deemed to be a representation, action, inaction or submission by the Account Representative.

C. Identification and Certification of an Account Representative for General Accounts.

1. The Account Representative shall be appointed by an agreement that makes the representations, actions, inactions or submissions of the Account Representative binding on all persons who have an ownership interest with respect to allowances held in the general account.

2. The Account Representative shall submit to the Director and the Tracking System Administrator a signed and dated Account Certificate of Representation (Certificate) that contains the following elements:

   a. The name, address, e-mail (if available), telephone and facsimile number of the Account Representative and any alternate;

   b. The organization name;

   c. The following certification statement:

      "I certify that I was selected as the Account Representative or alternate Account Representative, as applicable, by an agreement binding on all persons who have an ownership interest in allowances in the general account with regard to matters concerning the general account. I certify that I have all the necessary authority to carry out my duties and responsibilities under the WEB Trading Program on behalf of said persons and that each such person shall be fully bound by my representations, actions, inactions, or submissions and by any decision or order issued to me by the Director regarding the general account."

3. Upon receipt by the Director of the complete Certificate, the Account Representative represents and, by his or her representations, actions, inactions, or submissions, legally binds each person who has an ownership interest in allowances held in the general account with regard in all matters concerning the general account. Such persons shall be bound by any decision or order issued by the Director.

4. No WEB Allowance Tracking System general account shall be established until the Tracking System Administrator has received a complete Certificate. Once the account is established, the Account Representative shall make all submissions concerning the account, including the deduction or transfer of allowances.

D. Requirements and Responsibilities.

1. Each submission for the general account shall be signed and certified by the Account Representative for the general account. Each submission shall include the following truth and accuracy certification statement by the Account Representative:

   "I am authorized to make this submission on behalf of all person

who have an ownership interest in allowances held in the general account. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

E. Changing the Account Representative.

1. The Account Representative or alternate Account Representative may be changed at any time by sending a complete superseding Certificate to the Director and the Tracking System Administrator under Section 1617(C)(2) of this rule, with the change taking effect upon receipt of such Certificate by the Director. Notwithstanding any such change, all representations, actions, inactions, and submissions by the previous Account Representative or alternate prior to the time and date when the Director receives the superseding Certificate shall be binding on the new Account Representative and all person having ownership interest with respect to allowances held in the general account.

F. Changes to the Account.

1. Any change to the information required in the application for an existing account under Section 1617(A) of this Rule shall require a revision of the application.

R18-2-1618. Monitoring, Recordkeeping and Reporting

Note to Reviewer: Theses provisions will be reviewed and compared to the revised provisions prepared by the Western Regional Air Partnership (WRAP) and EPA on August 13, 2003. Revisions to this section of the rule may be necessary. References within this section are to the Model Rule versus this Rule. The Model Rule is available on WRAP's Web page at www.wrapair.org.

A. General Requirements.

1. For each SO_2 emitting unit at a WEB source the owner or operator shall comply with the following, as applicable, to monitor and record SO_2 mass emissions:
   a. If a unit is subject to 40 CFR Part 75 under a requirement separate from the WEB Trading Program, the unit shall meet the requirements contained

in Part 75 with respect to monitoring, recording and reporting SO_2 mass emissions. [As necessary, insert state rule language to address changes to 40 CFR Part 75.]

b. If a unit is not subject to 40 CFR Part 75 under a requirement separate from the WEB Trading Program, a unit shall use one of the following monitoring methods, as applicable:

i. A continuous emission monitoring system (CEMS) for SO_2 and flow that complies with all applicable monitoring provisions in 40 CFR Part 75;

ii. If the unit is a gas- or oil-fired combustion device, the excepted monitoring methodology in Appendix D to 40 CFR Part 75, or, if applicable, the low mass emissions (LME) provisions (with respect to SO_2 mass emissions only) of section 75.19 of 40 CFR Part 75;

iii. One of the optional WEB protocols, if applicable, in Appendix A to this Rule (attached); or

iv. A petition for site-specific monitoring that the source submits for approval by the Director, and approval by the U.S. Environmental Protection Agency in accordance with Section I8(e) of this Rule (relating to petitions).

c. A permanently retired unit shall not be required to monitor under this Section if such unit was permanently retired and had no emissions for the entire period for which the WEB source implements this paragraph (3) and the Account Representative certifies in accordance with Section L2 of this Rule that these conditions were met.

2. Notwithstanding paragraph (a) of this Section, the owner or operator of a unit that meets one of the conditions of paragraph (b)(1) may elect to have the provisions of this paragraph (b) apply to that unit.

a. Any of the following units may implement this paragraph (b):

i. Any smelting operation where all of the emissions from the operation are not ducted to a stack; or

ii. Any flare, except to the extent such flares are used as a fuel gas combustion device at a petroleum refinery.

iii. Any other type of unit without add-on SO_2 control equipment, if no control level was assumed for the WEB source in establishing the floor level (and reducible allocation).

b. For each unit covered by this paragraph (b), the Account Representative shall submit a notice to request that this paragraph (b) apply to one or more SO_2 emitting units at a WEB source. The notice shall be submitted in accordance with the compliance dates specified in Section I6(a) of this Rule, and shall include the following information (in a format specified by the Director with such additional, related information as may be requested):

i. A notice of all units at the applicable source, specifying which of the units are to be covered by this paragraph (b);

ii. Consistent with the emission estimation methodology used to determine the floor level (and reducible allocation) for the source in accordance with Section C1 of the Implementation Plan, the portion of the WEB source's overall allowance allocation that is attributable to any unit(s) covered by this paragraph; and

iii. An identification of any such units that are permanently retired.

c. For each new unit at an existing WEB source for which the owner or operator seeks to comply with this paragraph (b) and for which the Account Representative applies for an allocation under the new source set-aside provisions of Section G6 of this Rule, the Account Representative shall submit a modified notice under paragraph (b)(2) that includes such new SO_2 emitting unit(s). The modified notice shall be submitted in accordance with the compliance dates in Section I6(a) of this Rule, but no later than the date on which a request is submitted under Section G6 of this Rule for allocations from the set-aside.

d. The Director shall evaluate the information submitted by the WEB source in paragraphs (b)(2) and (b)(3), and may issue a notice to the source to exclude any units that do not qualify under this paragraph (b) or to adjust the portion of allowances attributable to units that do qualify to be consistent with the emission estimation methodology used to establish the floor level (and reducible allocation) for the source. Any such notice shall be provided within 180 days after the date on which the notice from the WEB source was received.

e. The Director shall hold allowances equal to the adjusted portion of the WEB source's allowances under paragraphs (b)(2), (b)(3), and (b)(4) in an account maintained by the Director, provided that no such hold back of the WEB source's allocation will be required for any unit that is

permanently retired.

f. The Account Representative for a WEB source shall submit an annual emissions statement for each unit under this paragraph (b). The WEB source shall maintain operating records sufficient to estimate annual emissions in a manner consistent with the emission estimation methodology used to establish the floor level (and reducible allocation) for the source. The Director will retire the allowances held under paragraph (b)(5) to account for the emissions from such units. In addition, if the estimated emissions from all such units at the WEB source are greater than the allowances held under paragraph (b)(5) for the WEB source, the Account Representative will report the excess amount as part of the cumulative annual emissions report for the WEB source and be required to use other allowances in the compliance account for the WEB source to account for such emissions, in accordance with Section I8 of this Rule.

g. The remaining provisions of this Section 1618 shall not apply to units covered by this paragraph except where otherwise noted.

h. A WEB source may opt to modify the monitoring for an SO_2 emitting unit to use monitoring under Section I1(a) of this Rule, but any such monitoring change must take effect on January 1 of the next compliance year. In addition, the Account Representative must submit an initial monitoring plan at least 180 days prior to the date on which the new monitoring will take effect and a detailed monitoring plan in accordance with Section I2 of this Rule. The Account Representative shall also submit a revised notice under paragraph (b)(2) at the same time that the initial monitoring plan is submitted.

3. For any monitoring method that the owner or operator uses under this Section (including paragraph (b)), the owner or operator (and, as applicable, the Account Representative) shall implement, certify, and use such method in accordance with this Section, and record and report the data from such method as required in this Section. In addition, the owner or operator (and, as applicable, the Account Representative) may not:

a. Use an alternative monitoring system, alternative reference method or another alternative for the required monitoring method without having obtained prior written approval in accordance with Section I8(e) of this Rule (relating to petitions);

b. Operate an SO_2 emitting unit so as to discharge, or allow to be discharged, SO_2 emissions to the atmosphere without accounting for these emissions in accordance with the applicable provisions of this Section;

c. Disrupt the approved monitoring method or any portion thereof, and thereby avoid monitoring and recording SO_2 mass emissions discharged into the atmosphere, except for periods of recertification or periods when calibration, quality assurance testing or maintenance is performed in accordance with the applicable provisions of this Section; or

d. Retire or permanently discontinue use of an approved monitoring method, except under one of the following circumstances:

i. During a period when the unit is exempt from the requirements of this Section, including retirement of a unit as addressed in Section I1(a)(3);

ii. The owner or operator is monitoring emissions from the unit with another certified monitoring method approved under this Section for use at the unit that provides data for the same parameter as the retired or discontinued monitoring method; or

iii. The Account Representative submits notification of the date of certification testing of a replacement monitoring system in accordance with this Section, and the owner or operator recertifies thereafter a replacement monitoring system in accordance with the applicable provisions of this Section.

B. Monitoring Plan.

1. General Provisions. The owner or operator of an SO_2 emitting unit that uses a monitoring method under Section I1(a)(2) of this Rule shall meet the following requirements:

a. Prepare and submit to the Director an initial monitoring plan for each monitoring method that the owner or operator uses to comply with this Section. In accordance with paragraph I2(C) of this Rule, the plan shall contain sufficient information on the units involved, the applicable method, and the use of data derived from that method to demonstrate that all unit SO_2 emissions are monitored and reported. The plan shall be submitted in accordance with the compliance dates specified in Section I5 of this Rule.

b. Prepare, maintain and submit to the Director a detailed monitoring plan at least 45 days prior to the first day of certification testing. The plan will

contain the applicable information required by paragraph I2(d) of this Rule. the Director may require that the monitoring plan (or portions thereof) be submitted electronically. The Director also may require that the plan be submitted on an ongoing basis in electronic format as part of the quarterly report submitted under Section I8(a) of this Rule or resubmitted separately within 30 days after any change is made to the plan in accordance with the following paragraph (a)(3).

c. Whenever the owner or operator makes a replacement, modification, or change in one of the systems or methodologies provided for in Section I1(a)(2), including a change in the automated data acquisition and handling system or in the flue gas handling system, that affects information reported in the monitoring plan (e.g., a change to serial number for a component of a monitoring system), then the owner or operator shall update the monitoring plan.

2. The owner or operator of an SO_2 emitting unit that uses a method under Section I1(a)(1) of this Rule (a unit subject to 40 CFR Part 75 under a program other than this WEB Trading Program) shall meet the requirements of Section I2(a)-(f) by preparing, maintaining and submitting a monitoring plan in accordance with the requirements of 40 CFR Part 75, provided that the owner or operator also shall submit the entire monitoring plan to the Director upon request.

3. Initial Monitoring Plan. The Account Representative shall submit an initial monitoring plan for each SO_2 emitting unit (or group of units sharing a common methodology) that, except as otherwise specified in an applicable provision in Appendix A, contains the following information:

a. For all SO_2 emitting units involved in the monitoring plan:

i. Plant name and location;

ii. Plant and unit identification numbers assigned by the Director;

iii. Type of unit (or units for a group of units using a common monitoring methodology);

iv. Identification of all stacks or pipes associated with the monitoring plan;

v. Types of fuel(s) fired (or sulfur containing process materials used in the SO_2 emitting unit), and the fuel classification of the unit if combusting more than one type of fuel and using a 40 CFR Part 75 methodology;

vi. Type(s) of emissions controls for SO_2 installed or to be installed,

including specifications of whether such controls are pre-combustion, post-combustion, or integral to the combustion process;

vii. Maximum hourly heat input capacity, or process throughput capacity, if applicable;

viii. Identification of all units using a common stack; and

viv. Indicator of whether any stack identified in the plan is a bypass stack.

b. For each unit and parameter required to be monitored, identification of monitoring methodology information, consisting of monitoring methodology, monitor locations, substitute data approach for the methodology, and general identification of quality assurance procedures. If the proposed methodology is a site-specific methodology submitted pursuant to Section I1(a)(2)(D) of this Rule, the description under this paragraph shall describe fully all aspects of the monitoring equipment, installation locations, operating characteristics, certification testing, ongoing quality assurance and maintenance procedures, and substitute data procedures.

c. If the WEB source intends to petition for a change to any specific monitoring requirement otherwise required under this Section, such petition may be submitted as part of the initial monitoring plan.

d. The Director may issue a notice of approval or disapproval of the initial monitoring plan based on the compliance of the proposed methodology with the requirements for monitoring in this Section. Except for any petition contained in the initial monitoring plan, if such notice is not issued within 180 days after the date on which the Director received the initial monitoring plan, the plan shall be deemed approved.

4. Detailed Monitoring Plan. The Account Representative shall submit a detailed monitoring plan that, except as otherwise specified in an applicable provision in Appendix A, shall contain the following information:

a. Identification and description of each monitoring component (including each monitor and its identifiable components, such as analyzer and/or probe) in a CEMS (e.g., SO_2 pollutant concentration monitor, flow monitor, moisture monitor), a 40 CFR Part 75, Appendix D monitoring system (e.g., fuel flowmeter, data acquisition and handling system), or a protocol in Appendix A, including:

i. Manufacturer, model number and serial number;

ii. Component/system identification code assigned by the facility to each identifiable monitoring component, such as the analyzer and/or probe;

iii. Designation of the component type and method of sample acquisition or operation (e.g., in situ pollutant concentration monitor or thermal flow monitor);

iv. Designation of the system as a primary or backup system;

v. First and last dates the system reported data;

vi. Status of the monitoring component; and

vii. Parameter monitored.

b. Identification and description of all major hardware and software components of the automated data acquisition and handling system, including:

i. Hardware components that perform emission calculations or store data for quarterly reporting purposes (provide the manufacturer and model number); and

ii. Software components (provide the identification of the provider and model/version number).

c. Explicit formulas for each measured emissions parameter, using component/system identification codes for the monitoring system used to measure the parameter that links the system observations with the reported concentrations and mass emissions. The formulas must contain all constants and factors required to derive mass emissions from component/system code observations and an indication of whether the formula is being added, corrected, deleted, or is unchanged. The owner or operator of a low mass emissions unit for which the owner or operator is using the optional low mass emissions excepted methodology in section 75.19(c) of 40 CFR Part 75 is not required to report such formulas.

d. Inside cross-sectional area (ft^2) at flow monitoring location (for units with flow monitors, only).

e. If using CEMS for SO_2 and flow, for each parameter monitored: scale, maximum potential concentration (and method of calculation), maximum expected concentration (if applicable) (and method of calculation), maximum potential flow rate (and method of calculations), span value, full-scale range, daily calibration units of measure, span effective

date/hour, span inactivation date/hour, indication of whether dual spans are required, default high range value, flow rate span, and flow rate span value and full scale value (in scfh) for each unit or stack using SO_2 or flow component monitors.

f. If the monitoring system or excepted methodology provides for use of a constant, assumed, or default value for a parameter under specific circumstances, then include the following information for each value of such parameter:

   i. Identification of the parameter;
   ii. Default, maximum, minimum, or constant value, and units of measure for the value;
   iii. Purpose of the value;
   iv. Indicator of use during controlled/uncontrolled hours;
   v. Types of fuel;
   vi. Source of the value;
   vii. Value effective date and hour;
   viii. Date and hour value is no longer effective (if applicable); and
   viv. For units using the excepted methodology under section 75.19 of 40 CFR Part 75, the applicable SO_2 emission factor.

g. Unless otherwise specified in section 6.5.2.1 of Appendix A to 40 CFR Part 75, for each unit or common stack on which hardware CEMS are installed:

   i. The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of Appendix A to 40 CFR Part 75), or thousand of lb/hr of steam, or ft/sec (as applicable);
   ii. The load or operating level(s) designated as normal in section 6.5.2.1 of Appendix A to 40 CFR Part 75, or thousands of lb/hr of steam, or ft/sec (as applicable);
   iii. The two load or operating levels (i.e., low, mid, or high) identified in section 6.5.2.1 of Appendix A to 40 CFR Part 75 as the most frequently used;
   iv. The date of the data analysis used to determine the normal load (or operating) level(s) and the two most frequently-used load (or operating) levels; and
   v. Activation and deactivation dates when the normal load or operating level(s) change and are updated.

h. For each unit that is complying with 40 CFR Part 75 for which the optional fuel flow-to-load test in section 2.1.7 of appendix D to 40 CFR Part 75 is used:

i. The upper and lower boundaries of the range of operation (as defined in section 6.5.2.1 of Appendix A to 40 CFR Part 75), expressed in thousand of lb/hr of steam;

ii. The load level designated as normal, pursuant to section 6.5.2.1 of Appendix A to 40 CFR Part 75, expressed in thousands of lb/hr of steam; and

iii. The date of the load analysis used to determine the normal load level.

i. Information related to quality assurance testing, including (as applicable): identification of the test strategy; protocol for the relative accuracy test audit; other relevant test information; calibration gas levels (percent of span) for the calibration error test and linearity check; calculations for determining maximum potential concentration, maximum expected concentration (if applicable), maximum potential flow rate, and span;

j. If applicable, apportionment strategies under sections 75.10 through 75.18 of 40 CFR Part 75.

k. Description of site locations for each monitoring component in a monitoring system, including schematic diagrams and engineering drawings and any other documentation that demonstrates each monitor location meets the appropriate siting criteria. For units monitored by a continuous emission monitoring system, diagrams shall include:

i. A schematic diagram identifying entire gas handling system from unit to stack for all units, using identification numbers for units, monitor components, and stacks corresponding to the identification numbers provided in the initial monitoring plan and paragraphs (d)(1) and (3). The schematic diagram must depict the height of any monitor locations. Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common stack.

ii. Stack and duct engineering diagrams showing the dimensions and locations of fans, turning vanes, air preheaters, monitor components, probes, reference method sampling ports, and other equipment that affects the monitoring system location,

performance, or quality control checks.

l. A data flow diagram denoting the complete information handling path from output signals of CEMS components to final reports.

5. In addition to supplying the information in paragraphs (c) and (d) above, the owner or operator of an SO_2 emitting unit using either of the methodologies in paragraph I.1(a)(2)(B) of this Section shall include the following information in its monitoring plan for the specific situations described:

a. For each gas-fired or oil-fired SO_2 emitting unit for which the owner or operator uses the optional protocol in appendix D to 40 CFR Part 75 for SO_2 mass emissions, the Account Representative shall include the following information in the monitoring plan:

i. Parameter monitored;

ii. Type of fuel measured, maximum fuel flow rate, units of measure, and basis of maximum fuel flow rate (i.e., upper range value or unit maximum) for each fuel flowmeter;

iii. Test method used to check the accuracy of each fuel flowmeter;

iv. Submission status of the data;

v. Monitoring system identification code;

vi. The method used to demonstrate that the unit qualifies for monthly GCV sampling or for daily or annual fuel sampling for sulfur content, as applicable;

vii. A schematic diagram identifying the relationship between the unit, all fuel supply lines, the fuel flowmeter(s), and the stack(s). The schematic diagram must depict the installation location of each fuel flowmeter and the fuel sampling location(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

viii. For units using the optional default SO_2 emission rate for “pipeline natural gas” or “natural gas” in appendix D to 40 CFR Part 75, the information on the sulfur content of the gaseous fuel used to demonstrate compliance with either section 2.3.1.4 or 2.3.2.4 of appendix D to 40 CFR Part 75;

ix. For units using the 720 hour test under section 2.3.6 of appendix D to 40 CFR Part 75 to determine the required sulfur sampling requirements, report the procedures and results of the test; and

x. For units using the 720 hour test under section 2.3.5 of appendix

D to 40 CFR Part 75 to determine the appropriate fuel GCV sampling frequency, report the procedures used and the results of the test.

b. For each SO_2 emitting unit for which the owner or operator uses the low mass emission excepted methodology of section 75.19 to 40 CFR Part 75, the designated representative shall include the following information in the monitoring plan that accompanies the initial certification application:

i. The results of the analysis performed to qualify as a low mass emissions unit under section 75.19(c) to 40 CFR Part 75. This report will include either the previous three years actual or projected emissions. The following items should be included:

(1) Current calendar year of application;

(2) Type of qualification;

(3) Years one, two, and three;

(4) Annual measured, estimated or projected SO_2 mass emissions for years one, two, and three; and

(5) Annual operating hours for years one, two, and three.

ii. A schematic diagram identifying the relationship between the unit, all fuel supply lines and tanks, any fuel flowmeter(s), and the stack(s). Comprehensive and/or separate schematic diagrams shall be used to describe groups of units using a common pipe;

iii. For units which use the long term fuel flow methodology under section 75.19(C)(3) to 40 CFR Part 75, a diagram of the fuel flow to each unit or group of units and a detailed description of the procedures used to determine the long term fuel flow for a unit or group of units for each fuel combusted by the unit or group of units;

iv. A statement that the unit burns only gaseous fuel(s) and/or fuel oil and a list of the fuels that are burned or a statement that the unit is projected to burn only gaseous fuel(s) and/or fuel oil and a list of the fuels that are projected to be burned;

v. A statement that the unit meets the applicability requirements in sections 75.19(a) and (b) to 40 CFR Part 75 with respect to SO_2 emissions; and

vi. Any unit historical actual, estimated and projected SO_2 emissions data and calculated SO_2 emissions data demonstrating that the

unit qualifies as a low mass emissions unit under sections 75.19(a) and (b) to 40 CFR Part 75.

c. For each gas-fired unit the Account Representative shall include the following in the monitoring plan: current calendar year, fuel usage data as specified in the definition of gas-fired in section 72.2 of 40 CFR Part 72, and an indication of whether the data are actual or projected data.

6. An operating permit for a WEB source issued in accordance with Title V of the Clean Air Act shall require a source to maintain a detailed monitoring plan in accordance with this Part, but the specific elements of the plan shall not be part of the permit, and modifications to the elements of the plan shall not require a permit modification.

C. Certification/Recertification.

1. All monitoring systems are subject to initial certification and recertification testing as specified in 40 CFR Part 75 or Appendix A to this Rule, as applicable. Certification or recertification of a monitoring system by the U.S. Environmental Protection Agency for a WEB source that is subject to 40 CFR Part 75 under a requirement separate from this Rule shall constitute certification under the WEB Trading Program.

2. The owner or operator of an SO_2 emitting unit not otherwise subject to 40 CFR Part 75 that monitors SO_2 mass emissions in accordance with 40 CFR Part 75 to satisfy the requirements of this Section shall perform all of the tests required by that regulation and shall submit the following:

a. A test notice, not later than 21 days before the certification testing of the monitoring system, provided that the Director may establish additional requirements for adjusting test dates after this notice as part of the approval of the initial monitoring plan under paragraph I2(C) of this Rule; and

b. An initial certification application within 45 days after testing is complete. A monitoring system will be considered provisionally certified while the application is pending, and the system shall be deemed certified if the Director does not approve or disapprove the system within six months after the date on which the application is submitted.

D. Ongoing Quality Assurance and Quality Control.

1. The WEB source shall satisfy the applicable quality assurance and quality control requirements of Part 75 or, if the WEB source is subject to a WEB protocol in Appendix A, the applicable quality assurance and quality control requirements in Appendix A on and after the date that certification testing commences.

E. Substitute Data Procedures.

1. For any period after certification testing is complete in which valid data are not being recorded by a monitoring system specified in this Rule, missing or invalid data shall be replaced with substitute data in accordance with 40 CFR Part 75 or, if the WEB source is subject to a WEB protocol in Appendix A of this rule, with substitute data in accordance with Appendix A of this rule.
2. For an SO_2 emitting unit that does not have a certified (or provisionally certified) monitoring system in place as of the beginning of the first control period for which the unit is subject to the WEB Trading Program, the owner or operator shall:
   a. If the owner or operator will use a CEMS to comply with this Section, substitute the maximum potential concentration of SO_2 for the unit and the maximum potential flow rate, as determined in accordance with 40 CFR Part 75. The procedures for conditional data validation under section 75.20(b)(3) may be used for any monitoring system under this Rule that uses these 40 CFR Part 75 procedures, as applicable;
   b. If the owner or operator will use the 40 CFR Part 75 Appendix D methodology, substitute the maximum potential sulfur content, density or gross calorific value for the fuel and the maximum potential fuel flow rate, in accordance with section 2.4 of Appendix D to 40 CFR Part 75;
   c. If the owner or operator will use the 40 CFR Part 75 LME methodology, substitute the SO_2 emission factor required for the unit as specified in 40 CFR 75.19 and the maximum rated hourly heat input, as defined in 40 CFR 72.2; or
   d. If using a protocol in Appendix A to this Rule, follow the procedures in the applicable protocol.

F. Compliance Dates.

1. The initial monitoring plan shall be submitted by the following dates:
   a. For each source that is a WEB source on or before the Program Trigger Date, the monitoring plan shall be submitted 180 days after such Program Trigger Date.
   b. For any existing source that becomes a WEB source after the Program

Trigger Date, the monitoring plan shall be submitted by September 30 of the year following the inventory year in which the source exceeded the emissions threshold.

c. For any new WEB source, the monitoring plan shall be included with the permit application for New Source Review. [State shall modify the language as necessary to conform with state's new source review rules.]

2. Emission monitoring systems shall be installed, operational and shall have met all of the certification testing requirements of this Section I (including any referenced in Appendix A) by the following dates:

a. For each source that is a WEB source on or before the Program Trigger Date, two years prior to the start of the first control period as described in Section L of this Rule.

b. For any existing source that becomes a WEB source after the Program Trigger Date, one year after the due date for the monitoring plan under I1(C)(2) of this Rule.

c. For any new WEB source, the earlier of 90 unit operating days or 180 calendar days after the date the new source commences operation.

G. Recordkeeping.

1. Except as provided in Section I7(b), the WEB source shall keep copies of all reports, registration materials, compliance certifications, sulfur dioxide emissions data, quality assurance data, and other submissions under this Rule for a period of five years. Unless otherwise requested by the WEB source and approved by the Director, the copies shall be kept on site.

2. The WEB source shall keep all Account Certificates of Representation on site at the source through the year 2018.

3. The WEB source shall keep records of all operating hours, quality assurance activities, fuel sampling measurements, hourly averages for SO_2, stack flow, fuel flow, or other continuous measurements, as applicable, and any other applicable data elements specified in this Section or in Appendix A to this Rule. The WEB source shall maintain the applicable records specified in 40 CFR Part 75 for any SO_2 emitting unit that uses a Part 75 monitoring method to meet the requirements of this Section.

H. Reporting.

1. Quarterly Reports. For each SO_2 emitting unit, the Account Representative shall submit a quarterly report within thirty days after the end of each calendar quarter. The report shall be in a format specified by the Director and shall be submitted in

a manner compatible with the emissions tracking database designed for the WEB Trading Program. the Director may require the WEB source to submit hourly and quality assurance activity information comparable to quarterly reports under 40 CFR Part 75. If the owner or operator submits a quarterly report under 40 CFR Part 75 to the U.S. EPA Administrator, no additional report under this paragraph (a) shall be required, provided, however, that the Director may require that a copy of that report (or a separate statement of quarterly and cumulative annual SO_2 mass emissions) be submitted separately to the Director.

2. Annual Report. Based on the quarterly reports, each WEB source shall submit an annual statement of total annual SO_2 emissions for all SO_2 emitting units at the source. The annual report shall contain four elements: total emissions for all units monitored in accordance with Section I1(a) of this Rule; total emissions for all units with emissions estimated in accordance with Section I1(b) of this Rule; the number of tons, if any, of SO_2 emissions estimated under Section I1(b) of this Rule that are subject to deduction of allowances from the source's compliance account in accordance with Section I1(b)(6); and the total number of SO_2 tons subject to deduction of allowances from the source's compliance account in accordance with Section 1621 of this Rule. The annual report shall be submitted within 30 days after the end of a control period.
3. The Director may direct that any monitoring plan, report, certification/recertification, or emissions data required to be submitted under this Section be submitted to the Tracking System Administrator.
4. The Director may review and reject any report submitted under this Section I7 that contains errors or fails to satisfy the requirements of this Section, and the Account Representative shall resubmit the report to correct any deficiencies.
5. Petitions. A WEB source may petition for an alternative to any requirement specified in Section I1(a)(2). The petition shall require approval of the Director and the U.S. EPA Administrator. Any petition submitted under this paragraph shall include sufficient information for the evaluation of the petition, including, at a minimum, the following information:
    a. Identification of the WEB source and applicable SO_2 emitting unit(s);
    b. A detailed explanation of why the proposed alternative is being suggested in lieu of the requirement;
    c. A description and diagram of any equipment and procedures used in the proposed alternative, if applicable;
    d. A demonstration that the proposed alternative is consistent with the

purposes of the requirement for which the alternative is proposed and is consistent with the purposes of this Rule and that any adverse effect of approving such alternative will be *de minimis*; and

e. Any other relevant information that the Director may require.

6. For any monitoring plans, reports, or other information submitted under Section 1618 of this Rule, the Account Representative shall ensure that, where applicable, identifying information is consistent with the identifying information provided in the most recent certificate of representation for the WEB source submitted under Section 1614 of this Rule.

R18-2-1619. Allowance Transfers

A. Procedure.

1. To transfer allowances, the Account Representative shall submit the following information to the Tracking System Administrator:

a. The transfer account number(s) identifying the transferor account;

b. The transfer account number(s) identifying the transferee account;

c. The serial number of each allowance to be transferred; and

d. The transferor's Account Representative's name and signature and date of submission.

B. Deadline.

1. The allowance transfer deadline is midnight Pacific Standard Time March 1 of each year (or if this date is not a business day, midnight of the first business day thereafter) following the end of the control period. By this time, the transfer of the allowances into the WEB source's compliance account must be correctly submitted to the Tracking System Administrator in order to demonstrate compliance under Section 1621(A) of this Rule for that control period.

C. Retirement of Allowances.

1. To transfer allowances for the purpose of retirement, the Account Representative shall submit the following information to the Tracking System Administrator:

a. The transfer account number(s) identifying the transferor account;

b. The serial number of each allowance to be retired; and

c. The transferor's Account Representative's name and signature and date of submission accompanied by a signed statement acknowledging that each retired allowance as no longer available for future transfers from or to any account.

R.18-2-1620. Use of Allowances from a Previous Year

A. Any allowance that is held in a compliance account or general account will remain in such an account unless and until the allowance is deducted in conjunction with the compliance process, or transferred to another account.

B. In order to demonstrate compliance under Section 1621(A) of this Rule for a control period, WEB sources shall only use allowances allocated for that current control period or any previous year.

C. If flow control procedures for the current control period have been triggered, then the use of allowances that were allocated for any previous year will be limited as follows:

1. The number of allowances that are held in each compliance account and general account as of the allowance transfer deadline for the immediately previous year and that were allocated for any previous year will be determined.
2. The number determined in (1) will be multiplied by the flow control ratio to determine the number of allowances that were allocated for a previous year that can be used without restriction for the current control period.
3. Allowances that were allocated for a previous year in excess of the number determined in (2) may also be used for the current control period. If such allowances are used to make a deduction, two allowances must be deducted for each deduction of one allowance required under Section 1621 of this Rule.

D. Special provisions for the year 2018. After compliance with the 2017 allowance limitation has been determined in accordance with Section 1621(A) of this Rule, allowances allocated for any year prior to 2018 shall not be used for determining compliance with the 2018 allowance limitation or any future allowance limitation.

R18-2-1621. Compliance

A. Compliance with Allowance Limitations.

1. The WEB source must hold allowances, in accordance with Section 1620 and Section 1621(A)(2) of this Rule, as of the allowance transfer deadline in the WEB source's compliance account (together with any current control year allowances held for the WEB source by the Director under Section 1618(A)(2) of this Rule) in an amount not less than the total SO_2 emissions for the control period from the WEB source, as determined under the monitoring and reporting requirements of Section 1618 of this Rule.
   a. For each source that is a WEB source on or before the Program Trigger Date, the first control period is the calendar year that is six years following the calendar year for which SO_2 emissions exceeded the

milestone.

b. For any existing source that becomes a WEB source after the Program Trigger Date, the first control period is the calendar year that is four years following the inventory year in which the source exceeded the SO_2 emissions threshold.

c. For any new WEB source after the Program Trigger Date the first control period is the first full calendar year that the source is in operation.

d. If the WEB Trading Program is triggered in accordance with the 2013 review, the first control period for each source that is a WEB source on or before the Program Trigger Date is the year 2018.

2. Allowance transfer deadline. An allowance may only be deducted from the WEB source's compliance account if:

a. The allowance was allocated for the current control period or meets the requirements in Section 1620 of this Rule for use of allowances from a previous control period, and

b. The allowance was held in the WEB source's compliance account as of the allowance transfer deadline for the current control period, or was transferred into the compliance account by an allowance transfer correctly submitted for recording by the allowance transfer deadline for the current control period.

3. Compliance with allowance limitations shall be determined by comparing the following two numbers:

a. The monitored SO_2 emissions data reported by the source to the Director, in accordance with Section 1618 of this Rule, and recorded in the emissions tracking database and

b. The allowance allocations and transfers recorded in the Allowance Tracking System, adjusted in accordance with Section 1620 of this Rule.

4. To the extent consistent with Section 1620 of this Rule, allowances shall be deducted for a WEB source for compliance with the allowance limitation as directed by the WEB source's Account Representative. Deduction of any other allowances as necessary for compliance with the allowance limitation shall be on a first-in, first-out accounting basis in the order of the date and time of their recording in the WEB source's compliance account, beginning with the allowances allocated to the WEB source and continuing with the allowances transferred to the WEB source's compliance account from another compliance account or general account. The allowances held by the Director for compliance at

a WEB source pursuant to Section 1618(A)(2) of this Rule shall be deducted as specified in that Section.

B. Certification of Compliance.

1. For each control period in which a WEB source is subject to the allowance limitation, the Account Representative of the source shall submit to the Director a Compliance Certification report for the source.
2. The Compliance Certification report shall be submitted no later than the allowance transfer deadline of each control period, and shall contain the following:
   a. Identification of each WEB source;
   b. At the Account Representative's option, the serial numbers of the allowances that are to be deducted from a source's compliance account for compliance with the allowance limitation; and
   c. The Compliance Certification report according to subpart 3 of this section.
3. In the Compliance Certification report, the Account Representative shall certify, based on reasonable inquiry of those persons with primary responsibility for operating the WEB source in compliance with the WEB Trading Program, whether the WEB source for which the compliance certification is submitted was operated during the control period covered by the report in compliance with the requirements of the WEB Trading Program applicable to the source including:
   a. Whether the WEB source operated in compliance with the SO_2 allowance limitation;
   b. Whether SO_2 emissions data has been submitted to [states or tribe] in accordance with Section 1618(A) of this Rule and other applicable guidance, for review, revision as necessary, and finalization for forwarding to the SO_2 Allowance Tracking System for recording;
   c. Whether the monitoring plan that governs the WEB source has been maintained to reflect the actual operation and monitoring of the source, and contains all information necessary to attribute SO_2 emissions to the source, in accordance with Section 1618(A) of this Rule;
   d. Whether all the SO_2 emissions from the WEB source if applicable, were monitored or accounted for either through the applicable monitoring or through application of the appropriate missing data procedures;
   e. If applicable, whether any SO_2 emitting unit for which the WEB source is not required to monitor in accordance with Section 1618(A)(1)(c) of this

rule remained permanently retired and had no emissions for the entire applicable period; and

f. Whether there were any changes in the method of operating or monitoring the WEB source that required monitor recertification. If there were any such changes, the report must specify the nature, reason, and date of the change, the method to determine compliance status subsequent to the change, and specifically, the method to determine SO_2 emissions.

C. Penalties for any WEB source exceeding its allowance limitations.

1. Allowance deduction penalties.

a. If emissions from a WEB source exceed the allowance limitation for a control period, as determined in accordance with Section 1621(A) of this Rule, the source's allowances held in its compliance account will be reduced by an amount equal to two times the source's tons of excess emissions.

b. If the compliance account does not have sufficient allowances allocated for that control period, the required number of allowances will be deducted from the WEB source's compliance account regardless of the control period for which they were allocated, once allowances are recorded in the account.

c. Any allowance deduction required under this Section shall not affect the liability of the owners and operators of the WEB source for any fine, penalty or assessment or their obligation to comply with any other remedy, for the same violation, as ordered under the Clean Air Act, implementing regulations or applicable state or tribal law..

2. A financial penalty of $5,000 per ton of SO_2 emissions in excess of the WEB source's allowance limitation shall be levied.

3. WEB Source liability for non-compliance

a. Separate and regardless of any automatic penalties assessed for allowance deduction penalty and financial penalty, a WEB source that violates any requirement of this Rule, including monitoring record keeping and reporting requirements, is subject to civil and criminal penalties under the Director law and the Clean Air Act. Each day of the control period is a separate violation, and each ton of SO_2 emissions in excess of a source's allowance limitation is a separate violation.

R18-2-1622. Special Penalty Provisions for the 2018 Milestone

A. If the WEB Trading Program is triggered and the first control period will not occur until after the year 2018, the following provisions shall apply for the 2018 emissions year.

1. All WEB sources shall register, and open a compliance account within 180 days after the Program Trigger Date, in accordance with Sections 1615(A)and 1617 of this Rule.
2. The Tracking System Administrator will record the allowances for the 2018 control period for each WEB source in the source's compliance account once the Director allocates the 2018 allowances.
3. The allowance transfer deadline is midnight Pacific Standard Time on May 30, 2021. WEB sources may transfer allowances as provided in Section 1619(A) of this Rule until the allowance transfer deadline.
4. A WEB source must hold allowances allocated for 2018 including those transferred into the compliance account by an allowance transfer correctly submitted by the allowance transfer deadline, in an amount not less than the WEB source's total SO_2 emissions for 2018. Emissions are determined using the pre trigger monitoring provisions in Section 1611 of this rule.
5. An allowance deduction penalty and financial penalty shall be assessed and levied in accordance with Sections 1620(D), 1621(A)(4) and 1621(C) of this Rule, except that SO_2 emissions shall be determined under Section 1622(A)(4) of this Rule.

B. If the program has been triggered and provision 1622(A) is implemented, the provisions of 1622(C) of this Rule shall apply for each year after the 2018 emission year until:

1. The first control period under the WEB trading program; or
2. The Director determined that the 2018 SO2 milestone has been met.

C. If provision in Section 1622(A) has been implemented, the following shall apply to each emissions year after the 2018 emissions year:

1. The Tracking System Administrator will record the allowances for the control period for the specific year for each WEB source in the source's compliance account once the Director allocates the allowances.
2. The allowance transfer deadline is midnight Pacific Standard Time on March 1 of each year (or if this date is not a business day, midnight of the first business day thereafter) following the end of the specific emissions year. WEB sources may transfer allowances as provided in Section 1619(A) of this Rule until the allowance transfer deadline.
3. A WEB source must hold allowances allocated for that specific emissions year, or any year after 2018, including those transferred into the compliance account by an

allowance transfer correctly submitted by the allowance transfer deadline, in an amount not less than the WEB source's total SO_2 emissions for the specific emissions year. Emissions are determined using the pre-trigger monitoring provisions in Section 1611 of this rule.

4. An allowance deduction penalty and financial penalty shall be assessed and levied in accordance with Sections 1620(D), 1621(A)(4) and 1621(C) of this Rule, except that SO_2 emissions shall be determined under Section 1622(C)(3) of this Rule.

NOTE: Appendix A follows.

APPENDIX A: WEB MODEL RULE MONITORING PROTOCOLS

Protocol WEB-1: SO_2 Monitoring of Fuel Gas Combustion Devices

1. Applicability

   (a) The provisions of this protocol are applicable to fuel gas combustion devices at petroleum refineries.

   (b) Fuel gas combustion devices include boilers, process heaters, and flares used to burn fuel gas generated at a petroleum refinery.

   (c) Fuel gas means any gas which is generated and combusted at a petroleum refinery. Fuel gas does not include (1) natural gas, unless combined with other gases generated at a petroleum refinery, (2) gases generated by a catalytic cracking unit catalyst regenerator, (3) gases generated by fluid coking burners, (4) gases combusted to produce sulfur or sulfuric acid, or (5) process upset gases generated due to startup, shutdown, or malfunctions.

2. Monitoring Requirements

   (a) Except as provided in paragraphs (b) and (c) of this Section 2, fuel gas combustion devices shall use a continuous fuel gas monitoring system (CFGMS) to determine the total sulfur content (reported as H_2S) of the fuel gas mixture prior to combustion, and continuous fuel flow meters to determine the amount of fuel gas burned.

      (1) Fuel gas combustion devices having a common source of fuel gas may be monitored for sulfur content at one location, if monitoring at that location is representative of the sulfur content of the fuel gas being burned in any fuel gas combustion device.

      (2) The CFGMS shall meet the performance requirements in Performance Specification 2 in Appendix B to 40 CFR Part 60, and the following:

         (i) Continuously monitor and record the concentration by volume of total sulfur compounds in the gaseous fuel reported as ppmv H_2S.

         (ii) Have the span value set so that the majority of readings fall between 10 and 95% of the range.

         (iii) Record negative values of zero drift.

         (iv) Calibration drift shall be # 5.0% of the span, for initial certification and daily calibration error tests.

         (v) Methods 15A, 16, or approved alternatives for total sulfur, are the reference methods for the

relative accuracy test. The relative accuracy test shall include a bias test in accordance with paragraph 4.(c) of this section.

(3) All continuous fuel flow meters shall comply with the provisions of section 2.1.5 of Appendix D to 40 CFR Part 75.

(4) The hourly mass SO_2 emissions rate for all the fuel gas combustion devices monitored by this approach shall be calculated using the following equation:

$$E_t = (C_S)(Q_t)(K)$$

where: E_t = Total SO_2 emissions in lb/hr from applicable fuel gas combustion devices
C_S = Sulfur content of the fuel gas as H_2S(ppmv)
Q_t = Fuel gas flow rate to the applicable fuel gas combustion devices (scf/hr)
$K = 1.660 \times 10^{-7}$ (lb/scf)/ppmv

(b) In place of a CFGMS in paragraph (a) of this Section 2, fuel gas combustion devices having a common source of fuel gas may be monitored with an SO_2 CEMS, a flow CEMS, and (if necessary) a moisture monitoring system at only one location, if the CEMS monitoring at that location is representative of the SO_2 emission rate (lb SO_2/scf fuel gas burned) of all applicable fuel gas combustion devices. Continuous fuel flow meters shall be used in accordance with paragraph (a), and the fuel gas combustion device monitored by a CEMS shall have separate fuel metering.

(1) Each CEMS for SO_2, flow, and (if applicable) moisture, shall comply with the operating requirements, performance specifications, and quality assurance requirements of 40 CFR Part 75.

(2) All continuous fuel flow meters shall comply with the provisions of section 2.1.5 of Appendix D to 40 CFR Part 75.

(3) The SO_2 hourly mass emissions rate for all the fuel gas combustion devices monitored by this approach shall be determined by the ratio of the amount of fuel gas burned by the CEMS-monitored fuel gas combustion device to the total fuel gas burned by all applicable fuel gas combustion devices using the following equation:

$$E_t = (E_m)(Q_t)/(Q_m)$$

where: E_t = Total SO_2 emissions in lb/hr from applicable fuel gas combustion devices
E_m = SO_2 emissions in lb/hr from the CEMS-monitored fuel gas combustion device, calculated using Equation F-1 or (if applicable) F-2 in Appendix F to 40 CFR Part 75 Q_t = Fuel gas flow rate (scf/hr) to the applicable fuel gas combustion devices
Q_m = Fuel gas flow rate (scf/hr) to the CEMS-monitored fuel gas combustion device

(c) In place of a CFGMS in paragraph (a) of this section, fuel gas combustion devices having a common source of fuel gas may be monitored with an SO_2 - diluent CEMS at only one location, if the CEMS monitoring at that location is representative of the SO_2 emission rate (lb SO_2/mmBtu) of all applicable fuel gas combustion devices. If this option is selected, the owner or operator shall conduct fuel gas sampling and analysis for gross calorific value (GCV), and shall use continuous fuel flow metering in accordance with paragraph (a) of this Section 2, with separate fuel metering for the CEMS-monitored fuel gas combustion device.

(1) Each SO_2-diluent CEMS shall comply with the applicable provisions for SO_2 monitors and diluent monitors in 40 CFR Part 75, and shall use the procedures in section 3 of Appendix F to Part 75 for determining SO_2 emission rate (lb/mmBtu) by substituting the term SO_2 for NO_x in that section, and using a K factor of 1.660×10^{-7} (lb/scf)/ppmv instead of the NO_x K factor.

(2) All continuous fuel flow meters and fuel gas sampling and analysis for GCV to determine the heat input rate from the fuel gas shall comply with the applicable provisions in sections 2.1.5 and 2.3.4 of Appendix D to 40 CFR Part 75.

(3) The SO_2 hourly mass emissions rate for all the fuel gas combustion devices monitored by this approach shall be calculated by using the following equation:

$$E_t = (E_m)\ (Q_t)(GCV)/10^6$$

where:

E_t = Total hourly SO_2 mass emissions in lb/hr from the applicable fuel gas combustion devices
E_m = SO_2 emission rate in lb/mmBtu from the CEMS - monitored fuel gas combustion device
Q_t = Fuel gas flow rate (scf/hr) to the applicable fuel gas combustion devices
GCV = Fuel Gross Calorific Value (Btu/scf)
10^6 = Conversion from Btu to million Btu

(d) Calculate total SO_2 mass emissions for each calendar quarter and each calendar year based on the emissions in lb/hr and Equations F-3 and F-4 in Appendix F to 40 CFR Part 75, Appendix F.

3. Certification/Recertification Requirements

All monitoring systems are subject to initial certification and recertification testing as follows:

(a) The owner or operator shall comply with the initial testing and calibration requirements in Performance Specification 2 in Appendix B to 40 CFR Part 60 and paragraph 2 (a)(2) of this section for each CFGMS.

(b) Each CEMS for SO_2 and flow or each SO_2-diluent CEMS shall comply with the testing and calibration requirements specified in 40 CFR Part 75, section 75.20 and Appendices A

and B, except that each SO_2-diluent CEMS shall meet the relative accuracy requirements for a NO_x-diluent CEMS (lb/mmBtu).

(c) A continuous fuel flow meter shall comply with the certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 to Appendix D to 40 CFR Part 75.

4. Quality Assurance/Quality Control Requirements

(a) A quality assurance/quality control (QA/QC) plan shall be developed and implemented for each CEMS for SO_2 and flow or the SO_2-diluent CEMS in compliance with sections 1, 1.1, and 1.2 of Appendix B to Part 75.

(b) A QA/QC plan shall be developed and implemented for each continuous fuel flow meter and fuel sampling and analysis in compliance with sections 1, 1.1, and 1.3 of Appendix B to 40 CFR Part 75.

(c) A QA/QC plan shall be developed and implemented for each CFGMS in compliance with sections 1 and 1.1 of Appendix B to 40 CFR Part 75, and the following:

(i) Perform a daily calibration error test of each CFGMS at two gas concentrations, one low level and one high level. Calculate the calibration error as described in Appendix A to 40 CFR Part 75. An out of control period occurs whenever the error is greater than 5.0% of the span value.

(ii) In addition to the daily calibration error test, an additional calibration error test shall be performed whenever a daily calibration error test is failed, whenever a monitoring system is returned to service following repairs or corrective actions that may affect the monitor measurements, or after making manual calibration adjustments.

(iii) Perform a linearity test once every operating quarter. Calculate the linearity as described in Appendix A to 40 CFR Part 75. An out of control period occurs whenever the linearity error is greater than 5.0 percent of a reference value, and the absolute value of the difference between average monitor response values and a reference value is greater than 5.0 ppm.

(iv) Perform a relative accuracy test audit once every four operating quarters. Calculate the relative accuracy as described in Appendix A to 40 CFR Part 75. An out of control period occurs whenever the relative accuracy is greater than 20.0% of the mean value of the reference method measurements.

(v) Using the results of the relative accuracy test audit, conduct a bias test in accordance with Appendix A to 40 CFR Part 75, and calculate and apply a bias adjustment factor if required.

5. Missing Data Procedures

(a) For any period in which valid data are not being recorded by an SO_2 CEMS or flow CEMS specified in this section, missing or invalid data shall be replaced with substitute data in accordance with the requirements in Subpart D of 40 CFR Part 75.

(b) For any period in which valid data are not being recorded by an SO_2-diluent CEMS specified in this section, missing or invalid data shall be replaced with substitute data on a rate basis (lb/mmBtu) in accordance with the requirements for SO_2 monitors in Subpart D of 40 CFR Part 75.

(c) For any period in which valid data are not being recorded by a continuous fuel flow meter or for fuel gas GCV sampling and analysis specified in this section, missing or invalid data shall be replaced with substitute data in accordance with missing data requirements in Appendix D to 40 CFR Part 75.

(d) For any period in which valid data are not being recorded by the CFGMS specified in this section, hourly missing or invalid data shall be replaced with substitute data in accordance with the missing data requirements for units performing hourly gaseous fuel sulfur sampling in section 2.4 of Appendix D to 40 CFR Part 75.

6. Monitoring Plan and Reporting Requirements

In addition to the general monitoring plan and reporting requirements of Section I of this Rule, the owner or operator shall meet the following additional requirements:

(a) The monitoring plan shall identify each group of units that are monitored by a single monitoring system under this Protocol WEB-1, and the plan shall designate an identifier for the group of units for emissions reporting purposes. For purpose of submitting emissions reports, no apportionment of emissions to the individual units within the group is required.

(b) If the provisions of paragraphs 2.(b) or (c) are used, provide documentation and an explanation to demonstrate that the SO_2 emission rate from the monitored unit is representative of the rate from non-monitored units.

Protocol WEB-2: Predictive Flow Monitoring Systems for Kilns with Positive Pressure Fabric Filter

1. Applicability

The provisions of this protocol are applicable to cement kilns or lime kilns that (1) are controlled by a positive pressure fabric filter, (2) combust only a single fuel, no fuel blends, and (3) have operating conditions upstream of the fabric filter that the WEB source documents would reasonably prevent reliable flow monitor measurements. This protocol does not modify the SO_2 monitoring requirements in section I of this Rule.

2. Monitoring Requirements

(a) A cement or lime kiln with a positive pressure fabric filter shall use a predictive flow monitoring system (PFMS) to determine the hourly kiln exhaust gas flow.

(b) A PFMS is the total equipment necessary for the determination of exhaust gas flow using process or control device operating parameter measurements and a conversion equation, a graph, or computer program to produce results in cubic feet per hour.

(c) The PFMS shall meet the following performance specifications:

(1) Sensors readings and conversion of sensor data to flow in cubic feet per hour must be automated.

(2) The PFMS must allow for the automatic or manual determination of failed monitors. At a minimum a daily determination must be performed.

(3) The PFMS shall have provisions to check the calibration error of each parameter that is individually measured. The owner or operator shall propose appropriate performance specifications in the initial monitoring plan for all parameters used in the PFMS comparable to the degree of accuracy required for other monitoring systems used to comply with this Rule. The parameters shall be tested at two levels, low: 0 to 20% of full scale, and high: 50 to 100% of full scale. The reference value need not be certified.

(4) The relative accuracy of the PFMS must be $\leq$ 10.0% of the reference method average value, and include a bias test in accordance with paragraph 4(c) of this section.

3. Certification Requirements

The PFMS is subject to initial certification testing as follows:
(a) Demonstrate the ability of the PFMS to identify automatically or manually a failed monitor.

(b) Provide evidence of calibration testing of all monitoring equipment. Any tests conducted within the previous 12 months of operation that are consistent with the QA/QC plan for the PFMS are acceptable for initial certification purposes.

(c) Perform an initial relative accuracy test over the normal range of operating conditions of the kiln. Using the results of

the relative accuracy test audit, conduct a bias test in accordance with Appendix A to 40 CFR Part 75, and calculate and apply a bias adjustment factor if required.

4. Quality Assurance/Quality Control Requirements

A QA/QC plan shall be developed and implemented for each PFMS in compliance with sections 1 and 1.1 of Appendix B of 40 CFR Part 75, and the following:

(a) Perform a daily monitor failure check.

(b) Perform calibration tests of all monitors for each parameter included in the PFMS. At a minimum, calibrations shall be conducted prior to each relative accuracy test audit.

(c) Perform a relative accuracy test audit and accompanying bias test once every four operating quarters. Calculate the relative accuracy (and bias adjustment factor) as described in Appendix A to 40 CFR Part 75. An out of control period occurs whenever the flow relative accuracy is greater than 10.0% of the mean value of the reference method.

5. Missing Data

For any period in which valid data are not being recorded by the PFMS specified in this section, hourly missing or invalid data shall be replaced with substitute data in accordance with the flow monitor missing data requirements for non-load based units in Subpart D of 40 CFR Part 75.

6. Monitoring Plan Requirements

In addition to the general monitoring plan requirements of Section I of this Rule, the owner or operator shall meet the following additional requirements:

(a) The monitoring plan shall document the reasons why stack flow measurements upstream of the fabric filter are unlikely to provide reliable flow measurements over time.

(b) The initial monitoring plan shall explain the relationship of the proposed parameters and stack flow, and discuss other parameters considered and the reasons for not using those parameters in the PFMS. The [state or tribe] may require that the subsequent monitoring plan include additional explanation and documentation for the reasonableness of the proposed PFMS.

Appendix A-7b. Proposed WRAP 309 Coordinating Committee Charter

WRAP Board of Directors

Proposal to form a standing 309 Coordinating Committee
October 15, 2003

Background:

Section 309 of the Regional Haze Rule provides that the 9 western "transport region" states and Indian tribes within those states may opt to develop regional haze SIPs following the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC). If implemented, the GCTVC recommendations satisfy the requisite showing of "Reasonable Progress" toward meeting the national visibility goal. Transport states electing to submit 309 SIPs must incorporate the GCVTC recommendations, and submit their initial SIPs by December 31, 2003. Eligible tribes are not subject to this deadline and may submit 309 TIPs at later dates. Over the last several years the WRAP has performed most of the technical analyses and policy recommendations to support the states on a regional scale.

Five transport region states have declared their intent to submit 309 SIPs. These states are AZ, NM, OR, UT, and WY. To date, no tribe has announced its intention to submit a 309 TIP.

As these 309 states have moved through their individual planning processes following the work of the WRAP, it is clear they would benefit greatly through continuing the cooperative relationships already established under the WRAP. Likewise, tribes that choose 309 would also benefit greatly from this ongoing collaboration. This would better enable each participant to take advantage of the work done by the other participants on their initial submittals, with higher assurance that the SIPs and TIPs would meet all requirements of the Regional Haze Rule and the Annex. Over the longer term, a coordinated approach provides a forum to facilitate ongoing communications among the participants, and a mechanism to meet particular implementation requirements, such as milestone tracking, monitoring information and data exchange.

Proposal:

The 309 states propose that the WRAP board create a standing committee, called the "309 Coordinating Committee." This committee would be formed according to the WRAP Bylaws, II. E., which allows the formation of additional standing committees (see attachment). The committee would be organized as follows:

Membership –

One designated representative from each state and tribe that submits a plan under §309 (in the case of tribes, a declaration of intent to move ahead with submission of a plan would warrant membership). Additional state and tribal staff may participate in meetings of the committee, as appropriate. The WRAP will appoint Co-Chairs from the membership.

Additional members –

If issues arise which require participation of federal agencies or stakeholders, the committee at its discretion will extend membership to such federal representatives and stakeholders as appropriate. The WRAP will make these appointments for limited duration as long as the issue requiring federal or stakeholder membership is active.

Charge of the Committee –

To provide an ongoing forum for 309 states and tribes to facilitate communications and information exchange.

To provide a mechanism to achieve consistency in implementing requirements of §309 of the regional haze rule, including but not limited to implementation of: the emissions tracking system to evaluate stationary source compliance with the SO_2 milestones; the backstop market-trading program for stationary sources, if required; and emission tracking in clean air corridors, for fire and enhanced smoke management programs, and for mobile and area sources.

The committee will also make recommendations to the WRAP Board, as needed, toward improving implementation of programs contained in SIPs and TIPs adopted under §309, and evaluate the value and appropriateness of WRAP involvement in resolving disagreements between states or between states and tribes on 309 matters.

ATTACHMENT

(From WRAP bylaws, revised 7/23/02)

...

I. GENERAL GUIDELINES FOR STANDING COMMITTEES REPORTING DIRECTLY TO THE WRAP.

A. All meetings shall be open to the public, and should include an opportunity for those members of the public who are observing the meeting to comment on or provide suggestions relevant to the committee's work.

B. Whenever processes are directed to be stakeholder based, membership should represent a wide range of social, cultural, economic, geographic, relative population and technical viewpoints. To meet this goal, the following categories of representatives should be considered.

* Industry (focused on production sector but excluding the mobile source sector)

* Small business (focused on the service sector, including "green industry")

* Mobile sources (including vehicle manufacturers and transportation planners)

* Federal government

* Tribal government

* State government

* Local government

* Academia

* Environmental groups

* General public

In all cases it may not be possible or appropriate to include each of the categories in stakeholder processes. However, whenever a category is not included, an explanation for the exclusion should be recorded.

In selecting members for committees, both technical expertise and diversity of viewpoints must be considered in balancing committee membership to provide equity. It

is not expected that each member of a committee be a technical expert in all aspects of the committee's work but rather, that all can contribute to the committee's overall goals.

II. TECHNICAL OVERSIGHT COMMITTEE (TOC), INITIATIVES OVERSIGHT COMMITTEE (IOC), AND OTHER COMMITTEES

...

E. Other Committees

1. The WRAP may establish other standing committees, forums or work groups. Membership on such standing committees, forums, or work groups shall consist of state and tribal representatives from the applicable region.

2. The committee shall extend membership to other regional stakeholders as appropriate. Members will be selected by the WRAP from letters of interest. Duration of the appointment shall coincide with the duration of the air quality issue.

3. The WRAP will appoint co-chairs of any standing committees. The co-chairs of any standing committees established will be members of the Coordinating Group.

Appendix A-7c. WRAP Report on Assessment of NOx/PM Strategies

Stationary Source NOx and PM Emissions in the WRAP Region:

An Initial Assessment of Emissions, Controls, and Air Quality Impacts

Final Report of the WRAP Market Trading Forum

October 1, 2003

Western Governors' Association
1515 Cleveland Place, Suite 200
Denver, CO 80202

NOTE: Section VI of this report is bound separately and available on the WRAP Web site at http://www.wrapair.org/forums/mtf/nox-pm.html

PREFACE

Regulatory Framework for Tribal Visibility Implementation Plans

The regional haze rule explicitly recognizes the authority of tribes to implement the provisions of the rule, in accordance with principles of federal Indian law, and as provided by the Clean Air Act §301(d) and the tribal authority rule (TAR) (40 CFR §§49.1– .11). Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.
2. Federally recognized tribes may apply for and receive delegation[1] of federal authority to implement CAA programs, including visibility regulation, or "reasonably severable" elements of such programs (40 CFR §§49.3, 49.7). The mechanism for this delegation is a tribal implementation plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.
3. The regional haze rule expressly provides that tribal visibility programs are "not dependent on the strategies selected by the state or states in which the tribe is located" (64. Fed. Reg. 35756), and that the authority to implement §309 TIPs extends to all tribes within the GCVTC region (40 CFR §51.309(d)(12)).
4. The EPA has indicated that under the TAR tribes are not required to submit §309 TIPs by the end of 2003. Rather, they may choose to opt-in to §309 programs at a later date (67 Fed. Reg. 30439).
5. Where a tribe does not seek delegation through a TIP, EPA, as necessary and appropriate, will promulgate a federal implementation plan (FIP) within reasonable timeframes to protect air quality in Indian country (40 CFR §49.11). EPA is committed to consulting with tribes on a government-to-government basis in developing tribe-specific or generally applicable TIPs where necessary (See, e.g., 63 Fed. Reg. 7263-64).

The amount of modification, if any, needed for this report to fulfill tribal needs may vary considerably from tribe to tribe. The authors have striven to ensure that all references to tribes in the document are consistent with principles of tribal sovereignty and autonomy as reflected in the above framework. Any inconsistency with this framework is strictly inadvertent and not an attempt to impose requirements on tribes which are not present under existing law.

Tribal Participation in the WRAP

Tribes, along with states and federal agencies, are full partners in the WRAP, having equal representation on the WRAP Board as states. Whether Board members or not, it must be remembered that all tribes are governments, as distinguished from the "stakeholders" (private interest) which participate on Forums and Committees but are not eligible for the Board.

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[1] Tribes also possess a more fundamental source of authority to regulate their environments, based on their inherent authority as sovereign nations, which predates the formation of the United States. However, in the context of air pollution regulation and visibility planning in particular, tribal authority will more likely be based on delegation of federal authority.

Despite this equality of representation on the Board, tribes are very differently situated than states. There are over four hundred federally-recognized tribes in the WRAP region, including Alaska. The sheer number of tribes makes full participation impossible. Moreover, many tribes are faced with pressing environmental, economic, and social issues, and do not have the resources to participate in an effort such as the WRAP, however important its goals may be. These factors necessarily limit the level of tribal input into and endorsement of WRAP products.

The tribal participants in the WRAP, including Board members Forum and Committee members and co-chairs, make their best effort to ensure that WRAP products are in the best interest of the tribes, the environment, and the public. One interest is to ensure that WRAP policies, as implemented by states and tribes, will not constrain the future options of tribes who are not involved in the WRAP. With these considerations and limitations in mind, the tribal participants have joined the state, federal, and private stakeholder interests in approving this report as a consensus document.

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Prepared by WRAP Staff

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Prepared by WRAP Staff

Section III: Nitrate and PM Ambient Concentrations

Prepared by WRAP Staff

Section IV: A Conceptual Model of Regional Haze in the West and the Role of Stationary Source NOx and PM Emissions

Prepared by Armistead Russell, Georgia Institute of Technology

Section V: Summary of Air Quality Modeling Results

Prepared by WRAP Staff, the University of California at Riverside, and ENVIRON Corporation

Section VI: Summary of Emission Controls Available for Large Stationary Sources of NOx and PM

Prepared by Reaction Engineering Incorporated and Energy & Environmental Strategies

Section VI Bound separately and available at ***http://www.wrapair.org/forums/mtf/nox-pm.html***

SECTION I:
EXECUTIVE SUMMARY

Background and Purpose

The primary purpose of this report is to provide the information necessary for western states and tribes to fulfill the requirements of Section 309(d)(4)(v) of the U.S. Environmental Protection Agency's (EPA) regional haze rule (40 CFR 51.309). Specifically, the rule states:

> *Provisions for stationary source NOx and PM. The plan submission must include a report which assesses emissions control strategies for stationary source NOx and PM, and the degree of visibility improvement that would result from such strategies. In the report, the State must evaluate and discuss the need to establish emission milestones for NOx and PM to avoid any net increase in these pollutants from stationary sources within the transport region, and to support potential future development and implementation of a multipollutant and possibly multisource market-based program. The plan submission must provide for an implementation plan revision, containing any necessary long-term strategies and BART requirements for stationary source PM and NOx (including enforceable limitations, compliance schedules, and other measures) by no later than December 31, 2008.*

The regional haze rule provides the nine western states within the Grand Canyon Visibility Transport Region (GCVTR) an opportunity to submit state implementation plans (SIPs) containing policies and programs recommended in the final report of the Grand Canyon Visibility Transport Commission (June 1996). Such plans must be submitted by December 31, 2003. GCVTR states electing not to submit SIPs under Section 309 must submit SIPs under Section 308 of the regional haze rule in the 2005-07 time frame. Indian tribes have the option to submit tribal implementation plans (TIPs) under either section at any time. Moreover, the TIPs may include reasonably severable elements of the rule. A map of the WRAP region, mandatory federal Class I areas addressed by the regional haze rule, and WRAP state and tribal members is provided in **Figure I-1**.

A major provision of Section 309 is the control of stationary source sulfur dioxide (SO_2) emissions. The provision quoted above – for a report on stationary sources of NOx and PM – is to ensure that states begin the process of evaluating other pollutants from stationary sources. Hence, this report is meant as a starting point for a potentially multi-year process of evaluating stationary sources and designing further control strategies where appropriate. At a minimum, this process must include the determination of best available retrofit technology (BART) for certain sources[1] and the resulting visibility improvements and may include an alternative (e.g., emissions trading) program achieving greater reasonable progress towards the national visibility goal of no man-made impairment.

[1] BART-eligible sources are those which belong to one of 26 industrial categories, have the potential to emit at least 250 tons per year of a visibility-impairing pollutant, and were put into place between 1962 and 1977.

Organization of Report

This report is required for the GCVTR states choosing to submit SIPs under Section 309 of the region haze rule, but since all states must ultimately address stationary source NOx and PM emissions from BART-eligible and potentially other stationary sources, the scope of this report goes somewhat beyond the nine states in the GCVTR and the limited number of BART-eligible sources in the WRAP region. For example, the air quality modeling evaluates the impact of emission changes within the GCVTR, but at all Class I areas within the contiguous WRAP region. Also, emission control technologies evaluated in Section VI were chosen on the basis of source types throughout the WRAP region, which do not differ substantially from those types within the GCVTR. They were also chosen on the basis of all existing source types, not just BART-eligible source types, partly because sources eligible for BART as a result of pollutants other than SO_2 have not yet been identified[2] and partly because an alternative program to BART could apply to a much broader universe of sources. By extending the scope of this report beyond the nine GCVTR states and beyond the BART-eligible stationary sources, it not only becomes applicable to a wider range of WRAP members and potential control strategies but serves to coordinate regional development of such strategies. It is also a more cost-effective approach than dealing with the nine GCVTR states separately.

As noted above, this report contains analyses and information to initiate a process for evaluating stationary sources of NOx and PM – a process required of all states and open to Indian tribes as well. The Executive Summary contains highlights of the report, but it is also where specific issues raised in Section 309(d)(4)(v), such as interpollutant trading, are directly and succinctly discussed. This is intended to help Section 309 states and tribes address the literal requirements of the rule.

Table I-1 shows how analyses within this report were designed to address the specific requirements of the rule. Emissions data can be used to assess emission control strategies and to evaluate the need for milestones by illustrating the relative significance of different source categories to total NOx and PM emissions, both now and in the future. Ambient monitoring data can be used to assess emission control strategies by illustrating where and how much nitrate and primary PM may contribute to actual visibility impairment. The conceptual model is intended to support this entire assessment and to provide a common, scientifically-founded understanding of western haze and the role of stationary sources in anticipation of a multi-year assessment of their importance and control options. The conceptual model is intended to provide a more complete framework than what can be provided alone by the air quality modeling and other assessments. Air quality modeling is used in a "sensitivity capacity" to assess emission control strategies, their degree of visibility improvement, and the need for milestones to prevent any future increase in emissions. A summary of current NOx and PM control technologies and their costs, trends, and secondary and multi-pollutant impacts can be used to assess emission control technologies and the need for milestones to support multisource and multipollutant programs. This summary is also a useful starting point for addressing the BART requirements in Section 308 SIPs and Section 309 SIP revisions. All these analyses are expected to be updated and improved by the WRAP before such SIPs are adopted.

[2] The full universe of BART-eligible sources does not need to be identified until SIPs and SIP revisions are due in 2005-08, although this identification process is expected to begin in 2003.

Table I-1. Analyses Contained in this Report and Their Relation to the Requirements in Section 309(d)(4)(v) of the Regional Haze Rule.

Requirements of 309(d)(4)(v)	Emissions Data	Ambient Data	Conceptual Model	Air Quality Model	Control Technologies
Assess emission control strategies	X	X	X	X	X
Assess degree of visibility improvement that would result from such strategies		X	X	X	
Evaluate and discuss the need to establish milestones to avoid any net increase	X		X	X	
Evaluate and discuss the need for milestones to support potential future development of multipollutant and multisource market-based programs			X		X
Implementation plan revision by December 31, 2008					

Finally, emissions in Alaska are not presented because resources did not permit examination of a second emissions inventory database, nor are air quality modeling results presented for Alaska because the visibility modeling system for Alaska is currently under development. However, ambient monitoring data for Alaska are presented, and the conceptual model and control technology information are applicable as well.

Summary of Findings

Analysis of current and future emissions, ambient monitoring data, and very limited modeling results indicates that stationary source emissions of PM probably cause less than 2 percent of the region's visibility impairment, whereas stationary source NOx emissions result in nitrates[3] that probably cause about 2 to 5 percent of the impairment on the Colorado Plateau[4] and about 10 percent of the impairment in some areas of the Northern Plains, Pacific Northwest, and southern California. These findings may change as emission projections are updated and as ambient monitoring data from new sites is collected and analyzed, and especially as modeling capabilities are improved and as more data become available for the best and worst visibility days.

[3] NOx emissions may also increase other PM species.
[4] Some of the 20 percent haziest days, however, are dominated by nitrate.

Regardless of this or future regional technical analyses, the remedy embodied in reasonably attributable visibility impairment requirements under the regional haze rule is still available where BART-eligible sources of NOx and PM are found to have direct impact on specific mandatory federal Class I areas. Furthermore, when considering NOx and PM milestones, attention should be given to the reasonable progress goals in the regional haze rule, which generally entail steady and continuing emission reductions and no degradation on the best visibility days. Where stationary source NOx emission reductions are appropriate, substantial reduction may be feasible with commercially-available technologies for about $300 to $1,200 per ton.

Assessment of Emission Control Strategies for Stationary Sources of NOx and PM

Since this report is primarily a starting point for addressing stationary source NOx and PM emissions, the control of which would not be determined until the 2005-08 timeframe, specific emission control strategies including such elements as level of control, applicability, and emissions trading are not addressed. Rather, this report identifies significant issues in assessing and designing such control strategies and provides some preliminary emissions, monitoring, and modeling results.

Stationary source NOx emissions comprise about 25 percent of the WRAP NOx emission inventory. One byproduct of NOx emissions is nitrate aerosols. As described in Section III, during the 20 percent worst days on the Colorado Plateau, nitrate aerosols are responsible for about 6 to 18 percent of the man-made visibility impairment, although on some of these days they are responsible for as much as 40 to 60 percent. At some sites in the Northern Plains, Pacific Northwest, and southern California, nitrate aerosols are responsible for about 40 percent of the man-made visibility impairment during the 20 percent worst days. Assuming the contribution of stationary sources to nitrate is roughly equal to their proportion of the NOx emission inventory, then stationary source NOx emissions might be expected to contribute to about 2-5 percent of the Plateau's light extinction and to about 10 percent of the extinction in the Northern Plains, Pacific Northwest, and southern California.

Potentially increasing these contributions is the fact that stationary sources have unique emission characteristics which may disproportionately impact visibility (e.g., stack heights, transport distances, and proximity to Class I areas). Also, NOx is known to influence the formation of non-nitrate secondary fine particles, to alter the characteristics of primary coarse particles, and its future significance may depend on future changes in sulfur and ammonia emissions. On the other hand, total NOx emission in the WRAP region are expected to decrease by over 25 percent,[5] primarily as a result of federal controls on mobile sources, and NOx reductions may, in isolated instances, lead to local increases in nitrate concentrations.

To determine the effectiveness of stationary source NOx controls, it is therefore important to have an air quality model that can account for the processes above. The WRAP's current modeling system, while sufficient for analyzing the regional impact of some emission changes, is not predicting nitrate concentrations well enough to support a decision on whether or not

[5] Future NOx emissions will, of course, depend on uncertain activity levels (e.g., oil and gas development) and regulatory developments (e.g., new source review reforms).

stationary source NOx controls are an effective way at achieving reasonable progress – the results are simply too uncertain. Several improvements to the modeling system are underway, but until the model produces better nitrate results, other means of assessment will be necessary to determine the appropriate level of NOx control in future SIPs.

Given the model's current performance, its use in this report is limited to the summer months (July through September), when it is performing best for nitrate, but also when nitrate concentrations are lowest. Furthermore, its use is limited to two "sensitivity analyses" – a 50 percent stationary source NOx reduction and a 50 percent stationary source PM_{10} reduction. The purpose of the sensitivity analyses is to gauge how nitrate and other atmospheric constituents might respond to significant changes in emissions, albeit such responses may be conservative given the model's limited application to the July – September time period. Results are summarized in the next part of this Executive Summary and discussed in more detail in Section V of the report.

As advancements are made towards understanding the air quality impacts of stationary source NOx emissions, it is appropriate to investigate the potential level of control that can be achieved, and at what cost. Section VI of this report identifies 34 NOx control technologies. Most of these are commercially available, while others are near-available. Those for coal-fired boilers (by far the largest category of stationary source NOx emissions) typically achieve 30 to 50 percent NOx control at a cost of about $300 to $1,200 per ton.[6] Actual costs and emission reductions are highly dependent on boiler type, vintage, and configuration, fuel burned, and existing controls. For these reasons, it is important to have recent, extensive, and reliable data on the emission source population, some of which are lacking in the WRAP inventory, such as current control information, utility boiler heat rates, information on the process producing the emissions (e.g., from natural gas compressor stations), and utilization rates (e.g., from industrial internal combustion engines). Future WRAP emission inventories should include such information.

Visibility impairment may occur when a high portion of the NOx emissions are in the form of (or converted to) nitrogen dioxide gas (NO_2). This may be important in urban hazes and in some coherent plumes, but is typically negligible for regional haze.[7] For this reason, NO_2 is not included in the light extinction budget in the EPA's guidance for tracking reasonable progress.

Stationary source PM_{10} emissions[8] are currently 6 percent of the WRAP PM_{10} inventory and may grow slightly to 7 percent by 2018. However, the WRAP inventory does not yet include wind-blown fugitive dust emissions (currently under development), which will tend to decrease the apparent contribution of stationary source PM_{10} emissions. PM_{10} accounts for nearly all the man-made light extinction, but the amount attributable to primary stationary source emissions is difficult to determine. Since most of the coarse fraction (between 2.5 and 10 microns) is believed to be primary and only some of the fine fraction is believed to be primary, the percent of visibility impairment attributable to coarse particles should approximate the contribution of

[6] One exception is selective catalytic reduction (SCR), which is capable of achieving 70 to 90+ percent control at costs of approximately $1,200 to $2,000 per ton.
[7] See, for example, Watson J., Visibility: Science and Regulation, J. of Air and Waste Manage. Assoc. 52:628.
[8] As explained in Section II of this report, the term "PM" used in Section 309(d)(4)(v) of the regional haze rule is construed as primary PM_{10} emissions.

primary PM_{10} emissions from all sources. As shown in Section III, this is approximately 10 to 20 percent (on average) across most of the WRAP region, with generally lower percentages in the Pacific Northwest and higher percentages in the southeast part of the region. Assuming the contribution of stationary sources to ambient primary PM_{10} is roughly equal to their proportion of the PM_{10} emission inventory, then stationary source PM_{10} emissions might be expected to contribute to less than 2 percent of the region's light extinction. Coupled with the fact that stationary source PM_{10} emissions are relatively well controlled in the West, there does not appear to be much potential in a stationary source PM control strategy for purposes of regional haze. PM_{10} emissions, however, appear to have a greater visibility impact per ton than NOx emissions, as shown in Section V. Also, some PM_{10} emission co-benefits may result from multi-pollutant technologies described in Section VI, so reductions in stationary source PM_{10} emissions could conceivably be part of a broader air quality management strategy and/or part of a broader strategy to achieve reasonable progress under the visibility regulations – e.g., to prevent degradation on the cleanest days.

Finally, the appropriate level of stationary source NOx and PM control, if any, should be informed by a comprehensive assessment, which may include some non-visibility impacts (to the extent they can be estimated within WRAP resources and with the WRAP's visibility-based tools) and the full costs and benefits of controls, not just those associated with facility compliance and visibility improvements. To this end, the WRAP is completing work on an economic analysis framework to conduct such analyses in a consistent and technically sound manner.

Degree of Visibility Improvement Resulting from Emission Control Strategies for Stationary Sources of NOx and PM

Due to the complex role of NOx emissions in the atmosphere, a regional-scale modeling effort is underway to more carefully assess the visibility improvement from potential control strategies. Given the model's current performance, its application in this report is limited to the June-September timeframe – when nitrate performance is best, but also when nitrate concentrations are lowest – and it is only used in a "sensitivity analysis mode", meaning two scenarios were modeled to gauge how nitrate and other atmospheric constituents might respond to significant changes in emissions: one in which emissions of NOx are reduced by 50 percent (412,000 tpy) from stationary sources in the GCVTR with emissions of NOx greater than 100 tpy, and an identical scenario for PM_{10} (98,000 tpy).

Current modeling results indicate that the stationary source NOx and PM_{10} emission reductions described above would reduce regional haze (in Mm^{-1}) by 0.5 percent and 0.4 percent, respectively, when averaged across all sites in the GCVTR over the June-September time period, although some areas would see an improvement of 2 to 5 percent on some days.[9] On a purely ton-per-ton basis, reductions in stationary source PM_{10} emissions appear to yield greater regional haze benefits than reductions in NOx emissions, since they produced almost the same visibility benefit at one-fourth the emission change.

[9] These results are similar to the more general assessment made in Section IV (see page IV-21).

The NOx emission reductions had the greatest impact in southern CA, where ammonium nitrate concentrations in Class I areas are predicted to decrease by 0.15 to 0.25 ug/m^3. A second area of reductions is predicted in the central-east Rocky Mountains, especially in north-central CO. Although the reductions are not as large as in southern CA (0.04 to 0.11 ug/m^3), they are larger than average across the domain and exhibit the largest percentage reduction (10 to 20 percent).

It is interesting to compare these results with those simulating the effects of the SO_2 backstop emissions trading program, or Annex. In the case of the Annex, an SO_2 emission reduction of 15 percent (132,000 tons) in the GCVTR produced a sulfate reduction of 4 percent averaged across all Class I areas in the GCVTR on the 20% worst modeled days. In the case of the NOx sensitivity run, a NOx emission reduction of 15 percent (412,000 tons) in the GCVTR produced a nitrate reduction of 5 percent averaged across all Class I areas in the GCVTR on the July-September modeled days. The nitrate reduction does not produce as much visibility benefit at most Class I areas because its concentrations are much smaller than the sulfate concentrations, but the response of nitrate to NOx reductions is similar in proportion to the response of sulfate to SO_2 reductions.

NOx changes appear to have very little effect on aerosol concentrations beyond changes in nitrate. Other species that could be indirectly affected – e.g., ozone concentrations and subsequent oxidation of SO_2 and organic gases into the particulate phase – do not appear influenced by the levels of NOx reductions (16 percent of the total inventory) assumed in this analysis.

The PM_{10} emission reductions had a maximum impact of about 0.1 to 0.5 ug/m^3, or about 4 to 8 percent. Compared to the NOx reduction scenario, reductions in ambient PM_{10} are more dispersed, with a greater number of local maximums. This may reflect the fact that there are a fewer number of large PM_{10} sources than large NOx sources and that much of the PM_{10} emissions are coarse particles, with shorter transport distances.

All modeling results in this report are subject to change after the modeling improvements described in Section V are implemented. Results may also change when compiled for the best and worst visibility and nitrate days throughout the year, as opposed to a three-month summer average. For reasons described in Section V, the three-month summer average probably tends to reduce the apparent impact of emission changes.

The Need to Establish Milestones to Avoid Any Net Increase in NOx and PM Emissions from Stationary Sources

Sensitivity modeling was also done to evaluate the impacts of a 25 percent simultaneous increase in stationary source NOx and PM_{10} emissions. The increase in nitrate formation was approximately half the magnitude of the decrease resulting from the NOx reduction scenario. However, the increase in PM_{10} (nitrates and primary particulates) and visibility impairment were about the same in the 25 percent increase scenario as in the two 50 percent decrease scenarios because both pollutants were increased simultaneously.

The need to establish milestones to avoid any net increase in NOx and PM emissions from stationary sources should be determined when more complete and accurate modeling results (and ambient data analyses) are available, prior to submittal of the Section 309 SIP revisions in 2007-08. In addition to the modeling results per se, consideration should be given to meeting the reasonable progress goals of the regional haze rule, which generally imply a steady and continuous reduction in emissions and a prevention of degradation on the best visibility days.

The Need for Milestones to Support Potential Future Development of Multipollutant and Multisource Market-Based Program

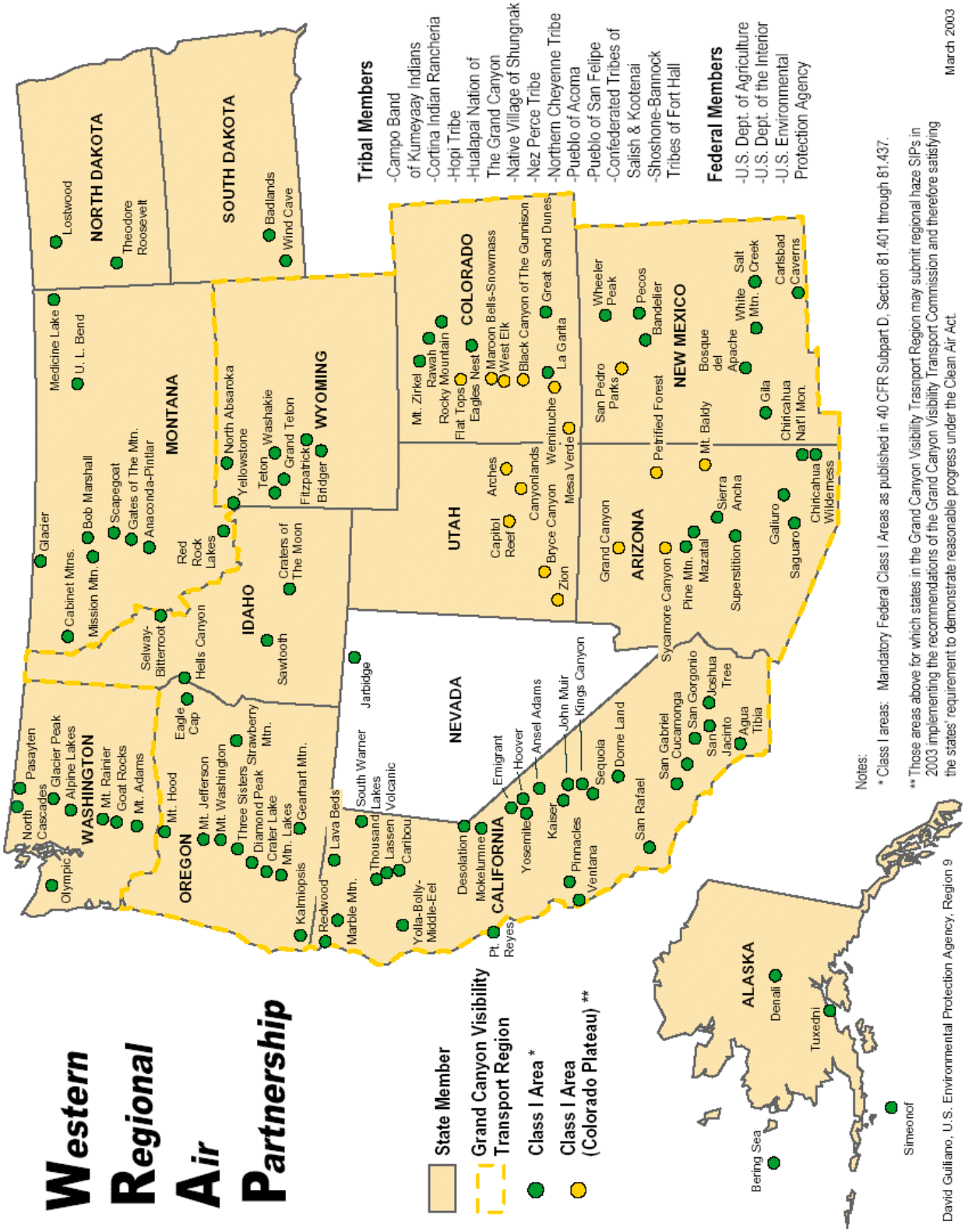
Milestones are not absolutely necessary to support potential multipollutant and multisource market-based programs. For example, a group of sources could theoretically comply with an SO_2 milestone by reducing emissions of other pollutants, and/or in other sectors, for which no milestones exist. Regardless, the key issues raised by such programs do not involve the milestones as much as the uncertainties associated with such emissions trading.

As discussed in Section IV, there are a number issues that must be addressed. Most of these relate to the visibility-improvement value of eliminating a ton of emissions. Different pollutants have different impacts on visibility on a per ton basis. Establishing an "equivalency ratio" to allow X tons of one pollutant to be reduced in lieu of Y tons of another would require significant analysis, and the certainty of such values may be suspect (especially for NOx) or insufficient to ensure a specific level of visibility improvement. Moreover, the equivalency ratio between two pollutants may vary across the region, between seasons, and possibly over time as the composition of the atmosphere changes. These same uncertainties (involving trades among pollutants) also pertain to trades among a single pollutant, most notably NOx, as nitrate concentrations are highly variable by season and location.

Trading across emission source categories poses a couple of additional issues. First, all categories would have to have sufficient emissions monitoring to validate emission credits, and monitoring of non-stationary sources is generally less accurate and verifiable than monitoring of stationary sources. Second, concentrated emissions from stacks may have different impacts than diffuse emissions at ground-level.

The uncertainties identified above could be reduced through further research, and the remaining uncertainties could be further addressed by limiting the emission trading markets to certain subregions, pollutants, or seasons where the equivalency ratios are fairly certain and stable. However, such market restrictions could limit the economic benefits the market is intended to provide. In short, some level of multipollutant and/or multisource market based program could be a feasible way of meeting the long-term national visibility goal, and several of the technologies described in Section VI of this report are capable of multipollutant reductions, but substantially more research should be performed before committing to such programs, especially in the 2007-08 timeframe.

Figure I-1. Map of the WRAP Region, Members, and Mandatory Federal Class I Areas.



SECTION II:
NOx AND PM EMISSIONS FROM STATIONARY SOURCES

Data Sources

The data presented in this section are based on "Version 1" of the WRAP stationary source emission inventory, downloaded from the WRAP website in June 2002 (filename wga_pt96.dbf). A second version of the inventory was released in October 2002, which contained a couple dozen corrections to point source coordinates, stack parameters, and source classification codes among the 214,000 records in the database. There were also some corrections to the NOx and PM emissions, which reduced the regional point source totals by two percent and six percent, respectively. A third version of the inventory was released in March 2003. This version contained minor NOx and PM emission changes in Pima and Navajo Counties (less than one percent of state-wide point sources) and NOx emission reductions in Nevada amounting to a 4,400 ton (or nine percent) decrease in the state-wide point source inventory. Discrepancies noted in Maricopa, Pima, and Pinal Counties by stakeholders in Arizona have not yet been incorporated into the WRAP database.

For the purposes of this regional-scale characterization of NOx and PM sources, the changes made to Version 1 of the stationary source inventory are essentially insignificant. The analysis, therefore, was not repeated. However, the analysis presented in Section VI is based on the most recent inventory since the analysis was begun after the Version 3 was available. This may cause slight discrepancies between the data presented here and in Section VI, but the conclusions are unaffected.

The term "PM" used in Section 309(d)(4)(v) of the regional haze rule has been construed in this report as primary PM_{10} emissions. Precursor emissions are not considered "PM" because they are explicitly referenced where appropriate throughout the rule, as is done with NOx in 309(d)(4)(v). PM_{10} was chosen over $PM_{2.5}$ because PM_{10} includes $PM_{2.5}$ and because all particles less than 10 microns have visibility impairing attributes. Moreover, many of the $PM_{2.5}$ emission estimates are derived from PM_{10} emission factors as opposed to direct $PM_{2.5}$ measurements – i.e., a certain fraction of the PM_{10} is assumed to be $PM_{2.5}$.

Emissions Summary

Table II-1 provides a summary of air pollutant emissions in the 13-state contiguous WRAP region (including Nevada but not Alaska). NOx emissions from stationary sources are expected to increase slightly, but due to decreases from other sources, their percentage of the total inventory is expected to grow from 22 percent to 33 percent to become the single largest source category. Stationary source PM_{10} emissions appear less important than NOx emissions, but they may contribute more to haze on a per ton basis, partly because not all NOx emissions are converted to particles and partly because stationary source PM emissions contain some elemental carbon, which is a highly-efficient light absorber. Compared to other source categories, stationary sources do not emit a large amount of PM_{10}, but their emissions may contribute more to haze on a per ton basis than other source categories because they emit particles primarily in

the fine mode (less than 2.5 microns) and often through stacks, making them more likely to be transported to Class I areas. Future work should examine available information on the dispersion characteristics, size distribution, and chemical and optical properties of primary PM emissions from stationary sources relative to other types of sources.

Table II-1. Air Pollutant Emissions in the 13-State WRAP Region.

	1996				2018			
	NOx		PM10		NOx		PM10	
Emissions Category	tons	%	tons	%	tons	%	tons	%
Point	1,059,985	22%	196,005	6%	1,118,460	33%	247,071	7%
Area	352,623	7%	1,921,389	54%	449,559	13%	1,981,060	54%
On-Road Mobile	1,755,573	37%	59,098	2%	485,270	14%	46,139	1%
Off-Road Mobile	1,368,663	29%	103,069	3%	950,414	28%	91,412	2%
Wildfire	166,703	4%	755,537	21%	59,641	2%	270,307	7%
Prescribed Fire	16,688	0%	50,057	1%	338,627	10%	525,393	14%
Agricultural Fire	*	*	*	*	3,504	0%	8,894	0%
Paved Road Dust	0	0%	91,322	3%	0	0%	165,106	5%
Unpaved Road Dust	0	0%	370,762	10%	0	0%	326,042	9%
Total	4,720,236	100%	3,547,239	100%	3,405,475	100%	3,661,423	100%

* Not available

Figure II-1 shows the location and relative magnitude of stationary source NOx emissions in the WRAP region with emissions of NOx greater than 100 tons per year (tpy) on a plant-wide basis. The WRAP 1996 inventory contains over 6,700 point sources of NOx. Approximately 11 percent of these plants (763) emitted 100 tpy or more of NOx and were responsible for 94 percent of total stationary source NOx emissions. Approximately 150 of the plants are electric power plants.

Figure II-2 shows the location and relative magnitude of stationary source PM_{10} emissions in the WRAP region with emissions of PM_{10} greater than 100 tpy on a plant-wide basis. The WRAP 1996 inventory contains over 6,500 point sources of PM_{10}. Approximately 5 percent of these (338 plants) emitted 100 tpy or more of PM_{10} and were responsible for 82 percent of total stationary source PM_{10} emissions.

Figures II-3 and **II-4** identify and compare emissions from the major stationary source categories of NOx and PM_{10}, respectively. External combustion boilers (utility and industrial) are the largest source categories for both NOx and PM_{10}. Industrial internal combustion engines (mostly natural gas fired) is another substantial source of NOx emissions. This category may warrant more attention since it is not inventoried with the same rigor as electric utility sources. The major source categories of PM_{10} are more diverse in character than those for NOx, including such broad categories as mineral products, chemical manufacturing, and primary metal production. This part of the inventory may also warrant further investigation since many of the emissions might be fugitive. Categorization of fugitive emission, in addition to source classifications, may vary across states. Further information on stationary source emissions, especially on the largest sources (boilers and internal combustion engines), is provided in Section VI.

Figure II-1. Stationary Source NOx Emissions > 100 tpy in the WRAP Region (1996).

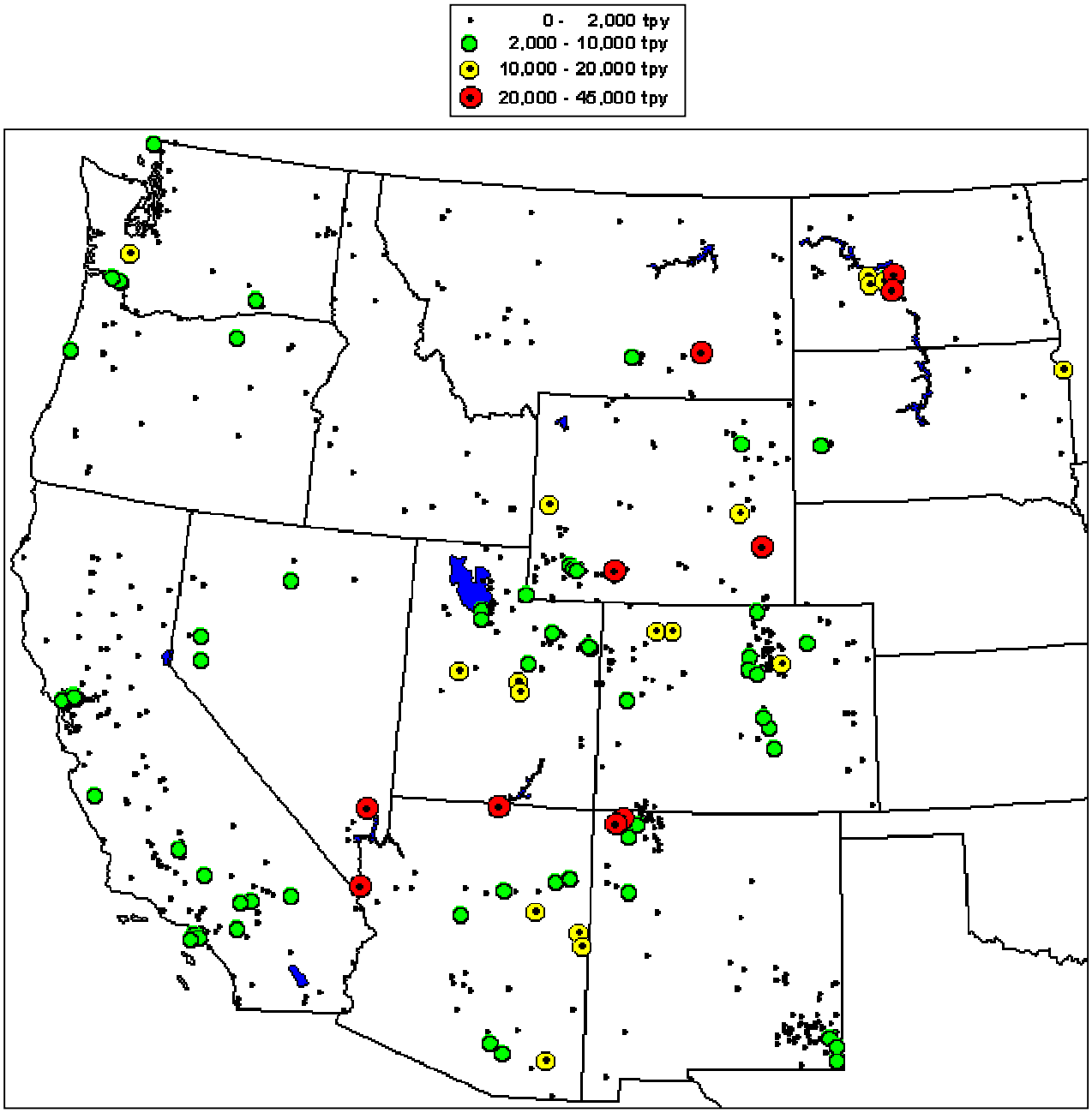


Figure II-2. Stationary PM_{10} Emissions > 100 tpy in the WRAP Region (1996).

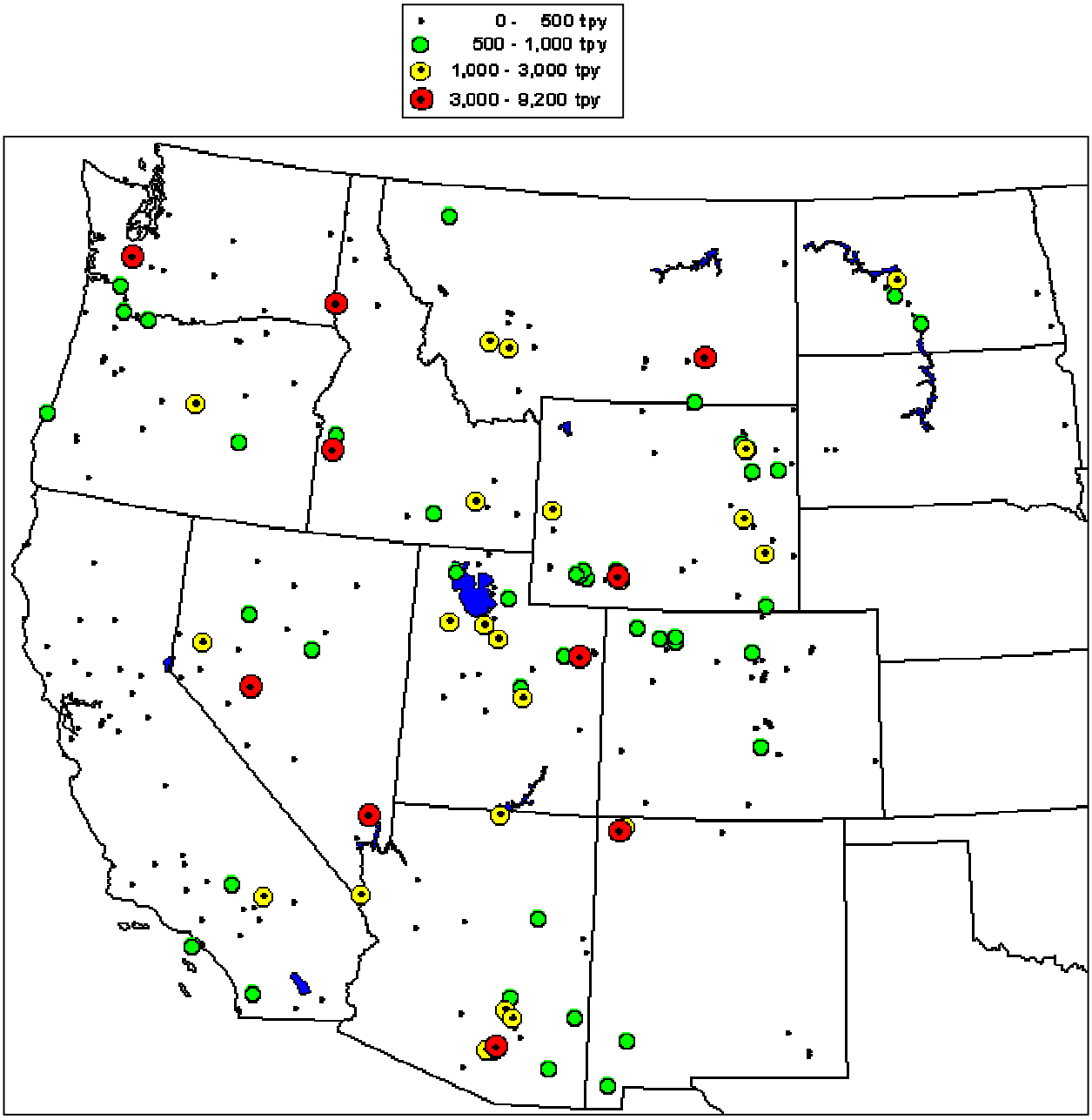


Figure II-3. Categorization of Stationary Source NOx Emissions > 100 tpy in the WRAP Region (1996).

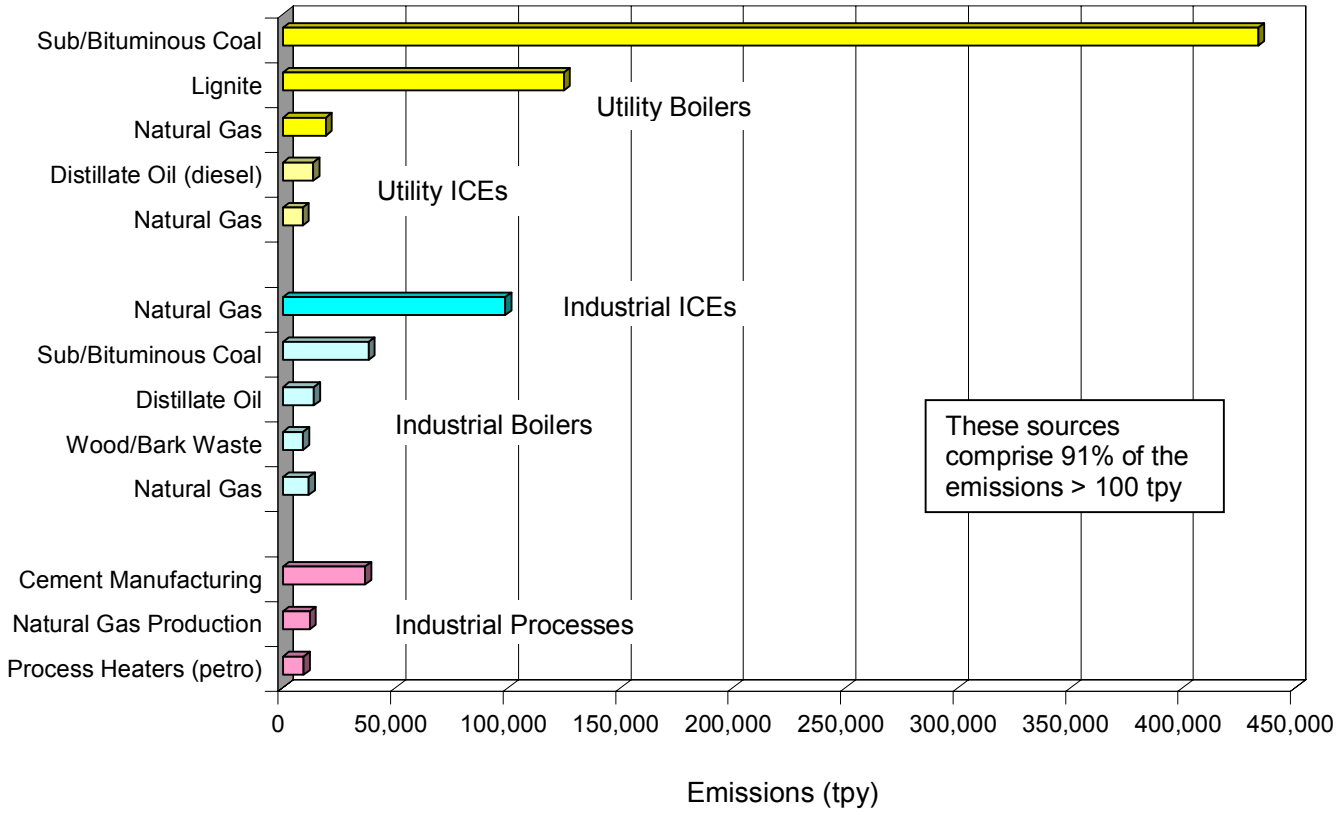
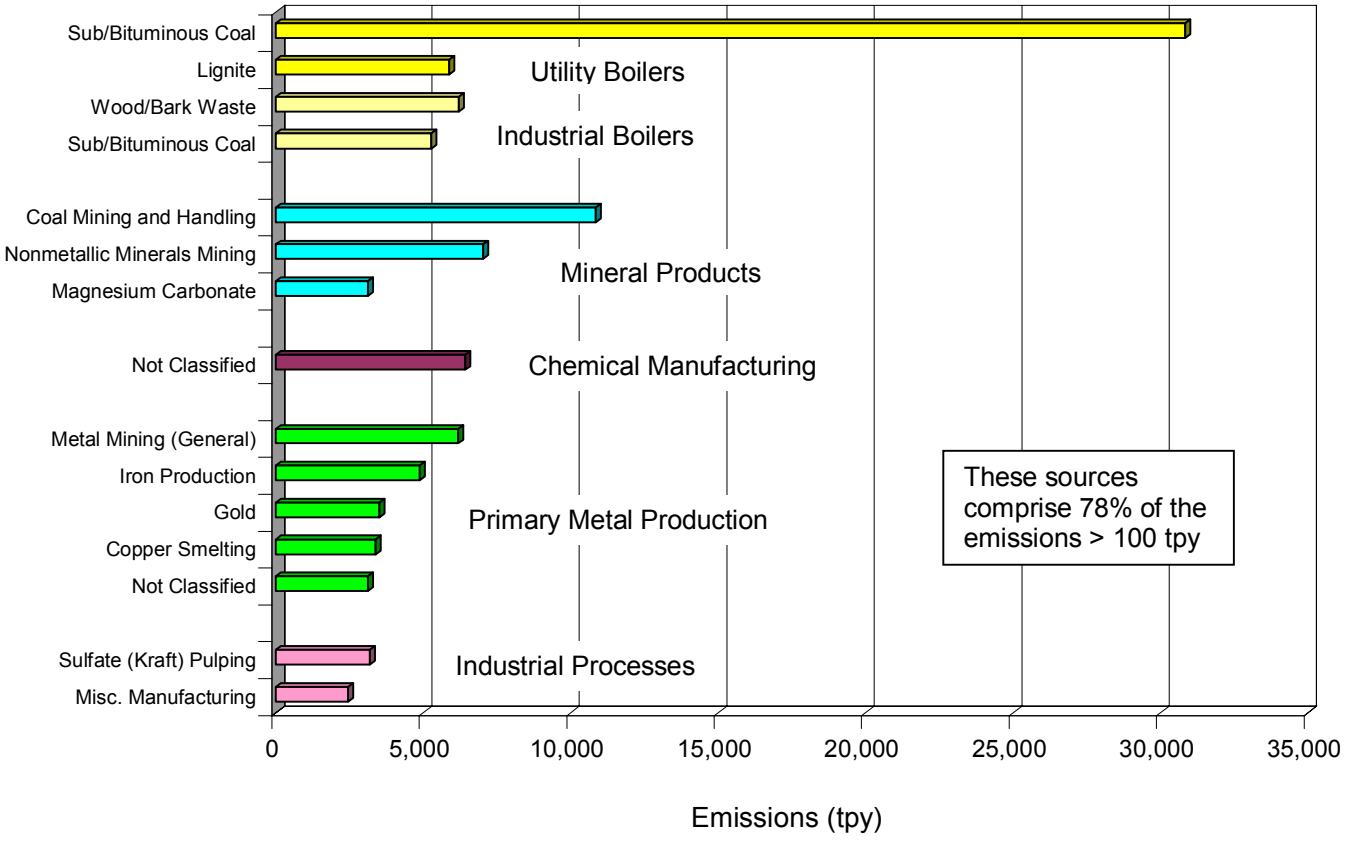


Figure II-4. Categorization of Stationary Source PM_{10} Emissions > 100 tpy in the WRAP Region (1996).



SECTION III:
NITRATE AND PM AMBIENT CONCENTRATIONS

Figures III-1 through III-11 show spatial patterns of ammonium nitrate (NH4NO3) and PM and historical trends in PM at IMPROVE monitoring sites in 1996 and 2001. The maps and data were downloaded from the VIEWS website (http://vista.cira.colostate.edu/views) on May 20, 2003. At that time, maps were only available for annual and seasonal averages, but some are now available for the best and worst visibility days. Hence, all the maps in this section except one indicate annual averages. Also, because the legends are auto-scaled, they are not the same in each map. For example, the value indicated by a yellow contour in Figure III-1 (1996) is not the same as the value indicated by a yellow contour in Figure III-2 (2201).

IMPROVE sites are located in rural settings, typically within Class I areas. They are not representative of more heavily polluted urban areas and tend to represent air quality at regional scales. Due to the size of the IMPROVE monitoring network, the maps for 1996 include data from less than a third of the western Class I areas. The maps for 2001 include data from about two-thirds of the western Class I areas, and additional monitors have been established since then.

Figures III-1 and III-2 show the annual average NH4NO3 concentrations in 1996 and 2001, respectively. Concentrations are typically less than 0.6 ug/m^3, with some areas in southern CA and the Columbia River Gorge exceeding 1.5 ug/m^3.

Figures III-3 and III-4 show the percent of aerosol-caused[10] annual average light extinction due to NH4NO3 in 1996 and 2001, respectively. This percent is typically less than 14, with some higher areas in the Pacific Northwest and Northern Plains, and especially in southern CA (exceeding 20 percent). Since some aerosols – principally organic carbon and "soil" and "coarse" aerosols – have substantially strong natural sources, the percent contribution of NH4NO3 to *man-made* haze is somewhat greater than indicated in Figures III-3 and III-4. A rough estimate of the contribution to man-made impairment can be obtained by assuming half the organic carbon, soil, and coarse aerosols are naturally caused. Removing these natural contributions from the light extinction budgets would raise the percent contribution of NH4NO3 by approximately 20 percent in each of the regions noted above (Colorado Plateau, Pacific Northwest, Northern Plains, and southern California).[11] For example, where NH4NO3 may contribute to 15 percent of the aerosol-caused light extinction in these areas, it would contribute to about 18 percent of the man-made light extinction.

Data recently provided on the VIEWS website indicates that the percent contribution of NH4NO3 to light extinction on the 20 percent worst days, as shown in **Figure III-5**, is slightly greater than the percent contribution on average, as shown in Figure III-4. Moreover, a cursory examination of daily data collected on the Colorado Plateau in 2001 indicates that some of the 20 percent worst days are dominated by NH4NO3. Some examples are provided in **Table III-1**. Such episodes should be quantified and studied more thoroughly in future WRAP work.

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[10] Aerosol-caused light extinction excludes natural (Rayleigh) scattering by air molecules.

[11] See Table 3.3 in Malm, William C. et al., Spatial and Seasonal Patterns and Temporal Variability of Haze and Its Constituents in the United States, Colorado State University, May 2000.

Table III-1. A Sample of Hazy Days in 2001 Dominated by NH4NO3 on the Colorado Plateau.

Class I Area	Date	Light Extinction[a] (Mm^{-1})	NH4NO3 Contribution	2001 Average Light Extinction[a] (Mm^{-1})	2001 Average NH4NO3 Contribution
Bryce Canyon	01/16/01	35	55 %	16	11 %
	01/28/01	28	49 %		
Canyonlands	01/04/01	23	55 %	14	15 %
	01/19/01	31	48 %		
	01/22/01	33	55 %		
San Pedro	01/07/01	16	50 %	11.5	10 %
	02/09/01	14	31 %		
	12/21/01	13	36 %		

[a] Over and above natural (Rayleigh) scattering by air molecules (10 Mm^{-1}).

Finally, NH4NO3 exhibits a strong seasonal pattern. When averaged across the 32 IMPROVE sites operating in 1996-1999, the light extinction due to NH4NO3 is about 10 percent on an annual basis and about 17 percent in the winter.

Figures III-6 and III-7 show the annual average PM_{10} concentrations in 1996 and 2001, respectively. Specifically, the values are reconstructed total mass – that is, speciated fine mass plus gravimetrically-determined coarse mass (PM_{10} - $PM_{2.5}$). (Gravimetric PM_{10} was not available from the VIEWS website.) PM_{10} concentrations are typically below 8 ug/m^3, with some areas in the Columbia River Gorge, Northern Plains, and southern CA exceeding 10 ug/m^3.

Figures III-8 and III-9 show the percent of aerosol-caused annual average light extinction due to coarse particulate matter (between 2.5 and 10 microns) in 1996 and 2001, respectively. Since most of the coarse fraction is believed to be primary and only some of the fine fraction is believed to be primary, the percent of visibility impairment attributable to coarse particles should approximate the contribution of primary PM_{10} emissions from all sources to visibility impairment. As shown in the figures, this is approximately 10 to 20 percent across most of the WRAP region, with generally lower percentages in the Pacific Northwest and higher percentages in the southeast part of the region.

Figure III-10 shows trends in (gravimetric) PM_{10} concentrations during average visibility days at 27 western IMPROVE sites. Data for the best and worst visibility days are available, but only data for average visibility days are shown for comparability with the maps in Figures III-1 through III-7. The values shown are 5-year rolling averages, meaning that the value shown for 1993 represents data collected from 1989-1993. The full names of the sites shown in Figure III-10 are provided in **Table III-2**.

At most sites, there appears to be a gradual decline in PM_{10} concentrations on days with average visibility, with exceptions at Chiricahua, Grand Canyon, and Guadalupe Mountain. On the worst visibility days, however, there is less of a decline, if any, at most sites. Compare, for example, the trend at the sites shown in **Figure III-11** with the first trend chart shown in Figure III-10.

Note that the trends, even when averaged over 5-year periods, can sometimes be affected by one or two extremely high events, typically associated with wildfires or dust storms. Trends in NH4NO3 concentrations and the percent of light extinction due to NH4NO3 are not available because of a measurement bias in data collected prior to June 1996. These data, however, are sufficient for showing the spatial patterns in Figures III-1 through III-7.

Figure III-1. Annual Average NH4NO3 Concentrations at IMPROVE Sites (1996).

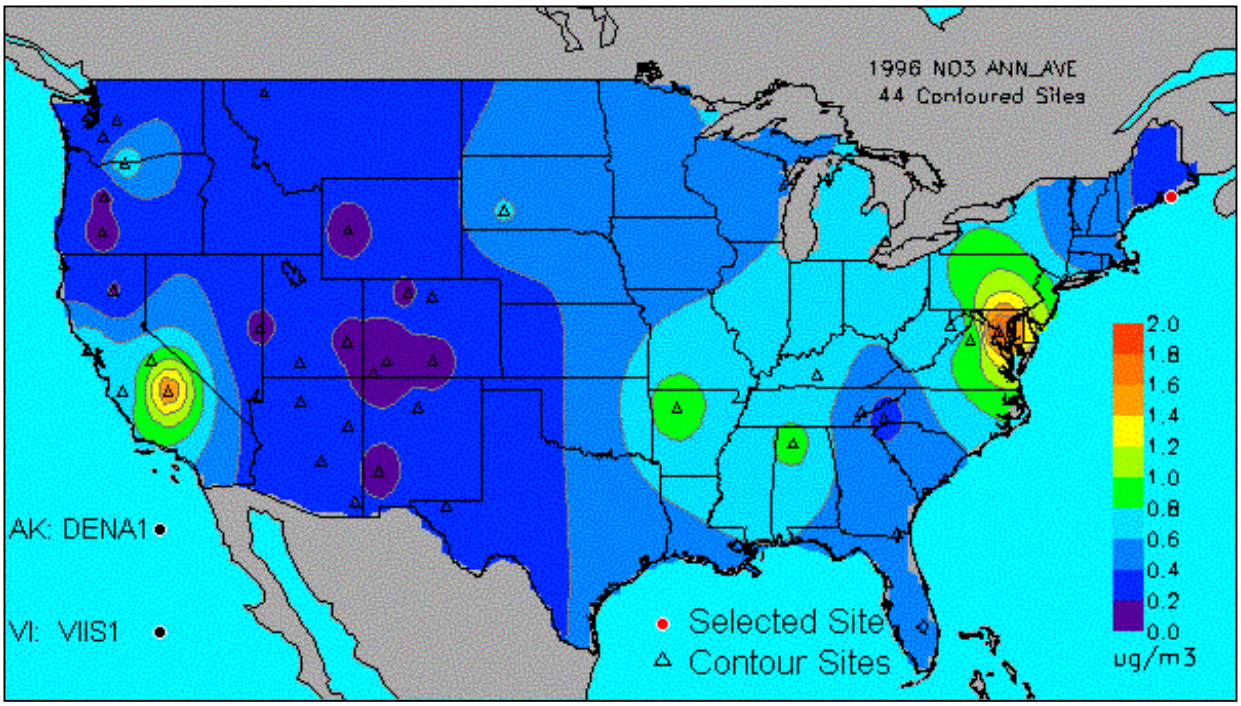


Figure III-2. Annual Average NH4NO3 Concentrations at IMPROVE Sites (2001).

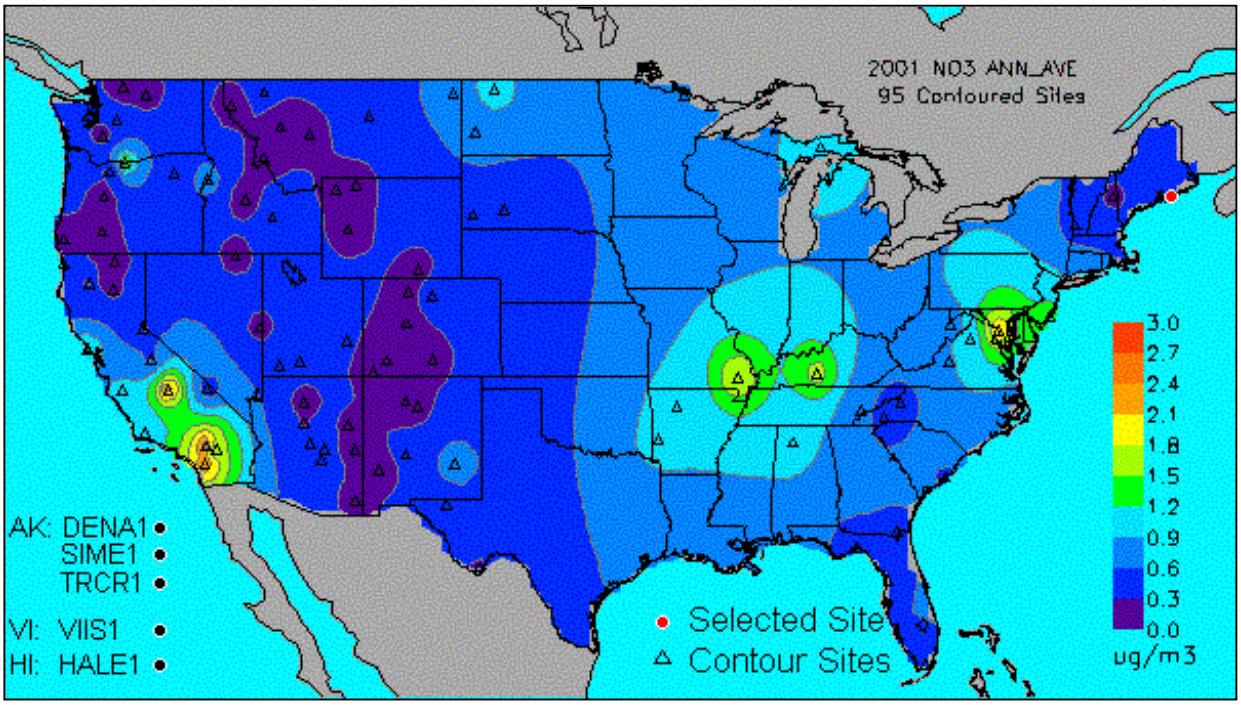


Figure III-3. Percent of Annual Average Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites (1996).

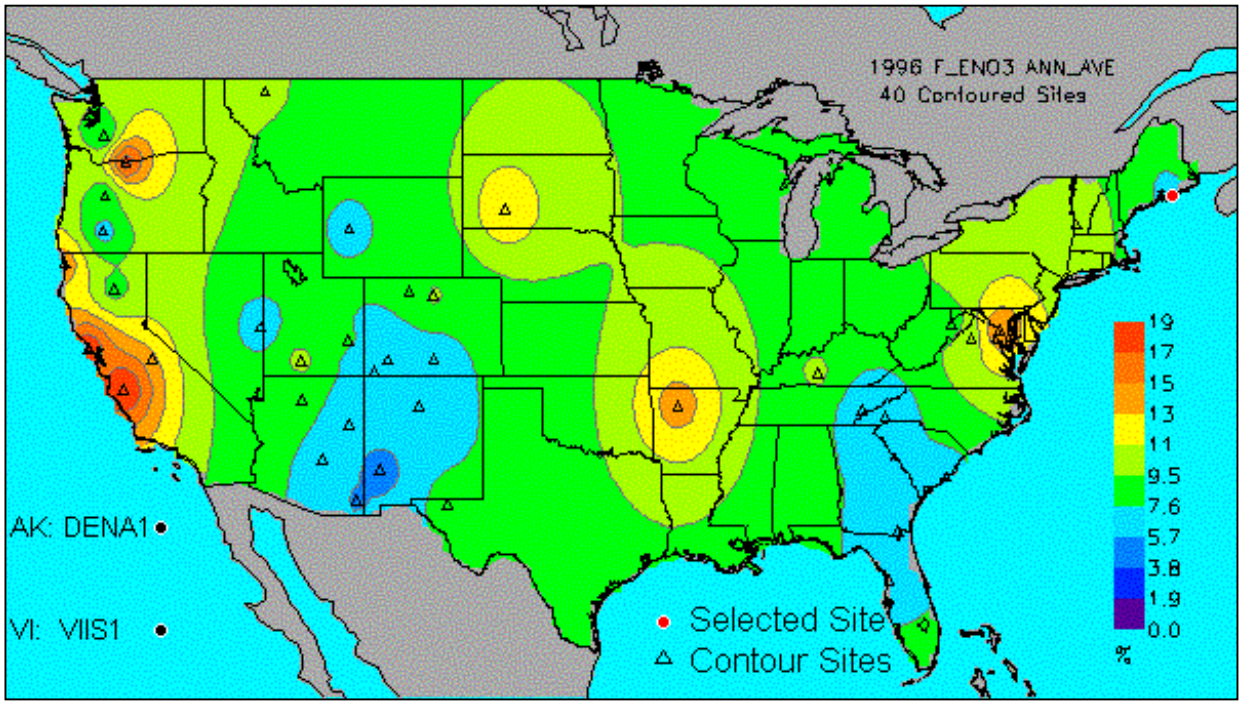


Figure III-4. Percent of Annual Average Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites (2001).

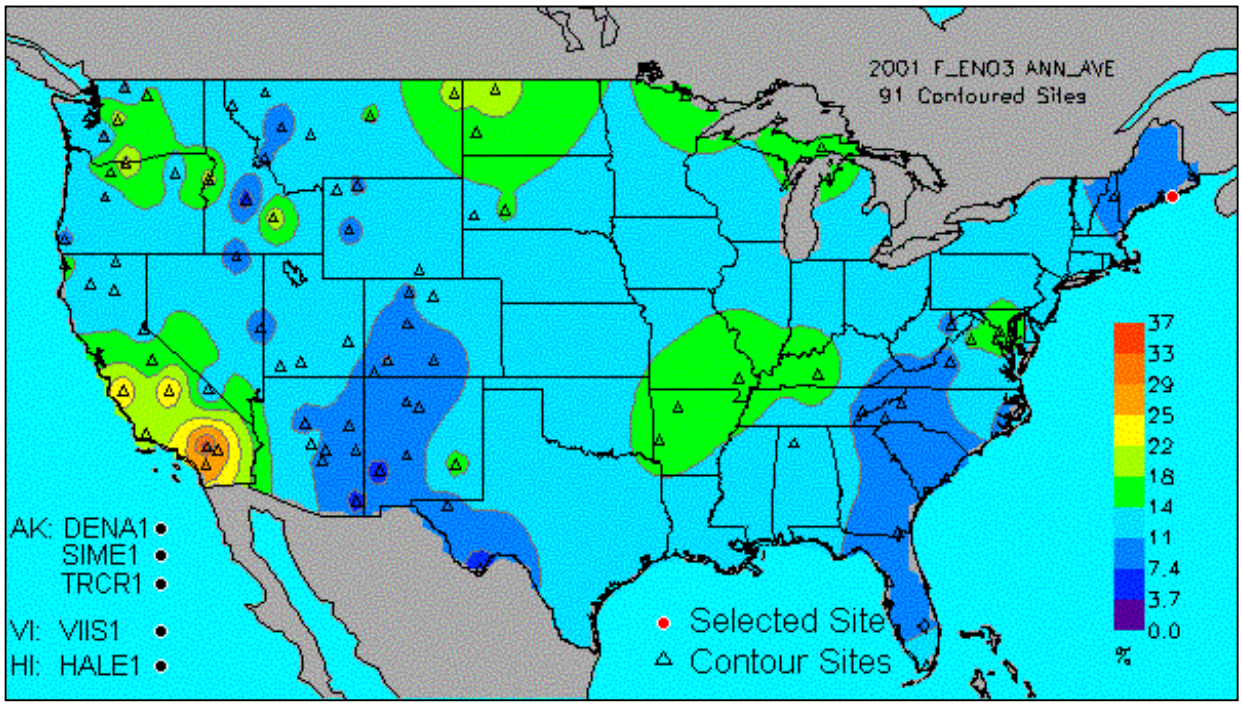


Figure III-5. Percent of Aerosol Light Extinction Due to NH4NO3 at IMPROVE Sites on the 20 Percent Worst Days (2001).

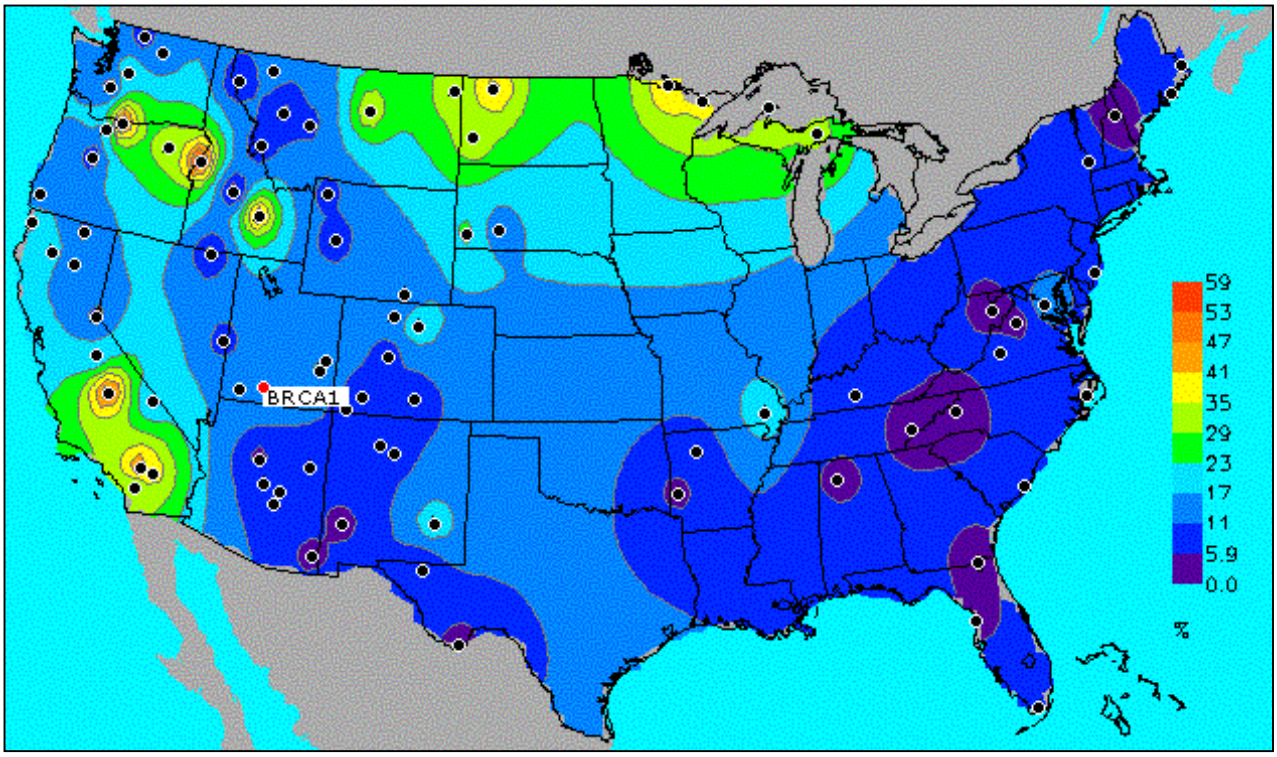


Figure III-6. Annual Average PM_{10} Concentrations at IMPROVE Sites (1996).

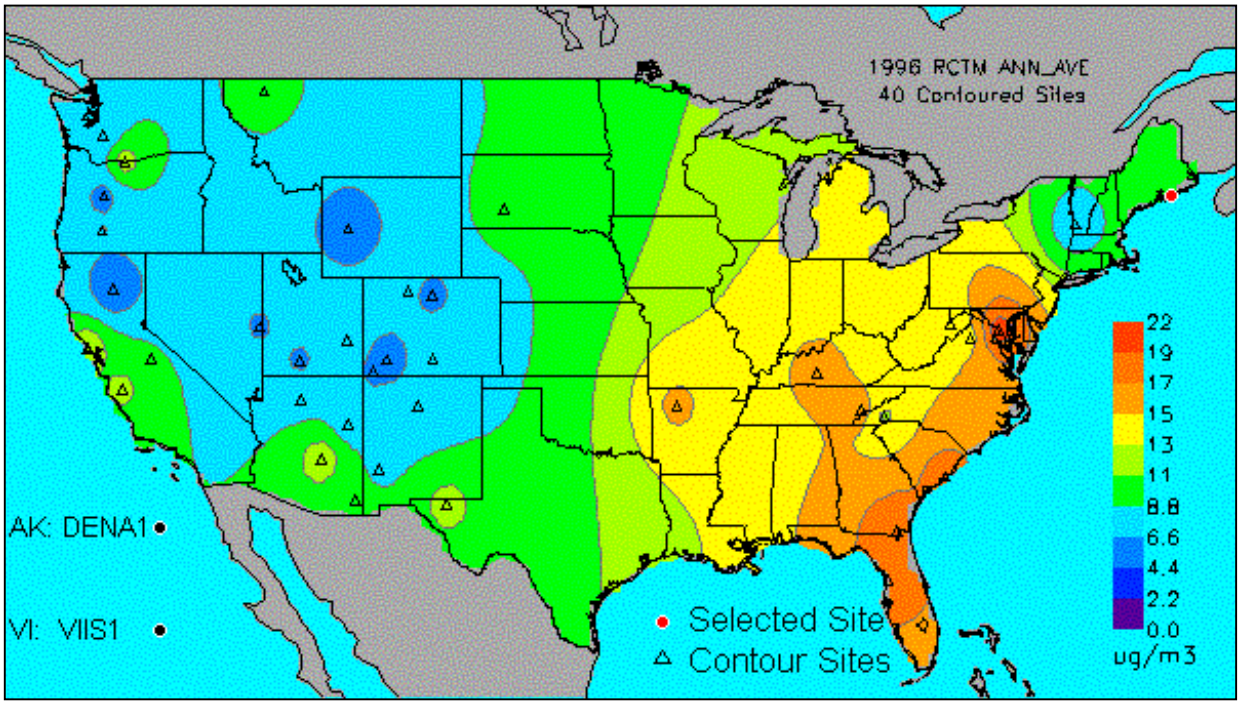


Figure III-7. Annual Average PM_{10} Concentrations at IMPROVE Sites (2001).

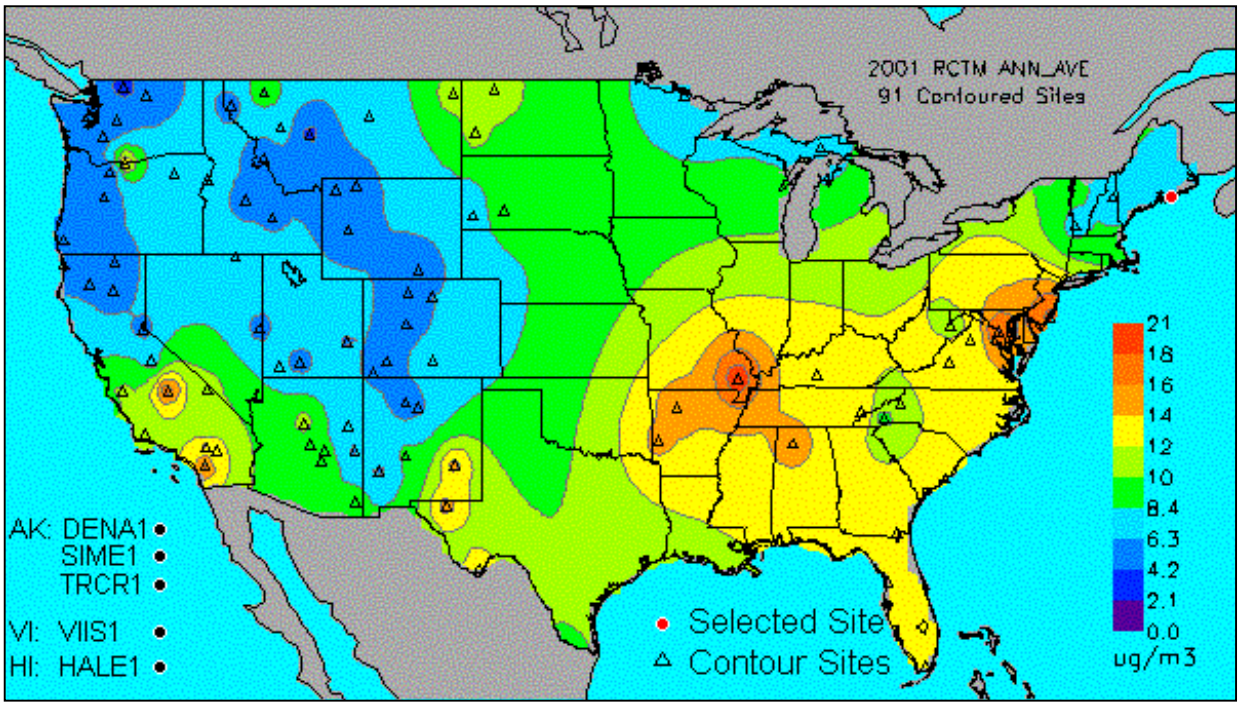


Figure III-8. Percent of Annual Average Light Extinction Due to Coarse Particulate Matter at IMPROVE Sites (1996).

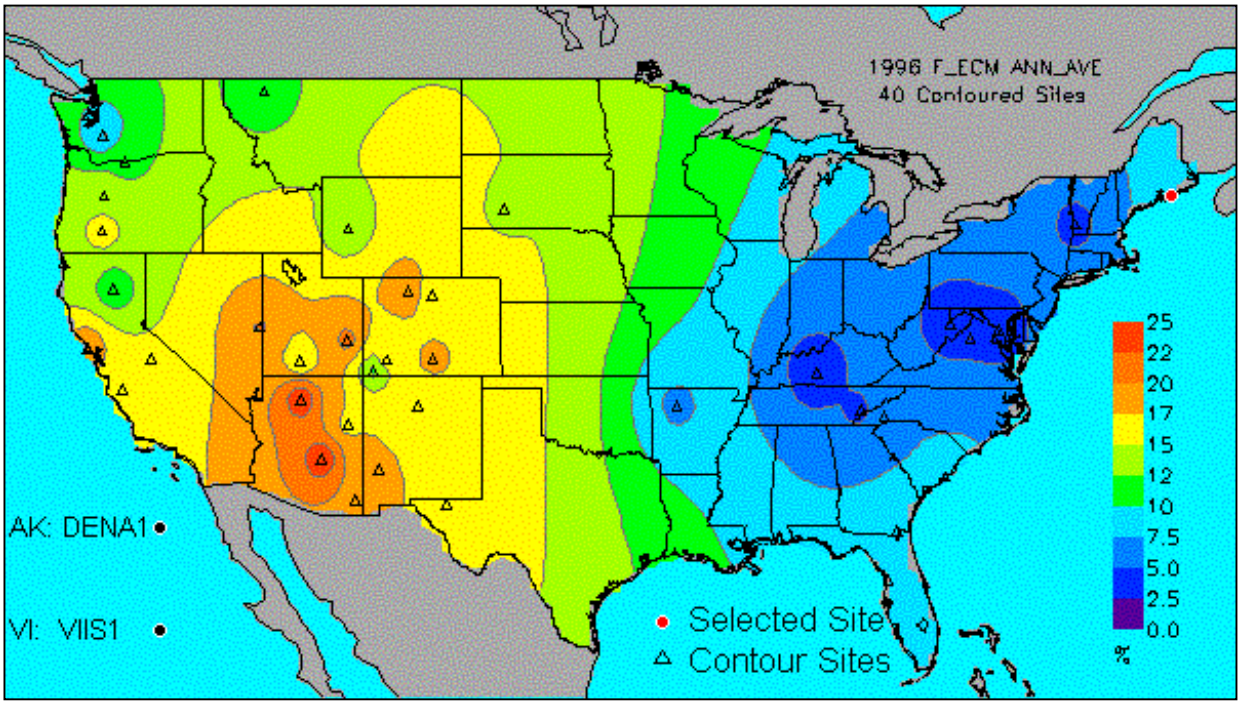


Figure III-9. Percent of Annual Average Light Extinction Due to Coarse Particulate Matter at IMPROVE Sites (2001).

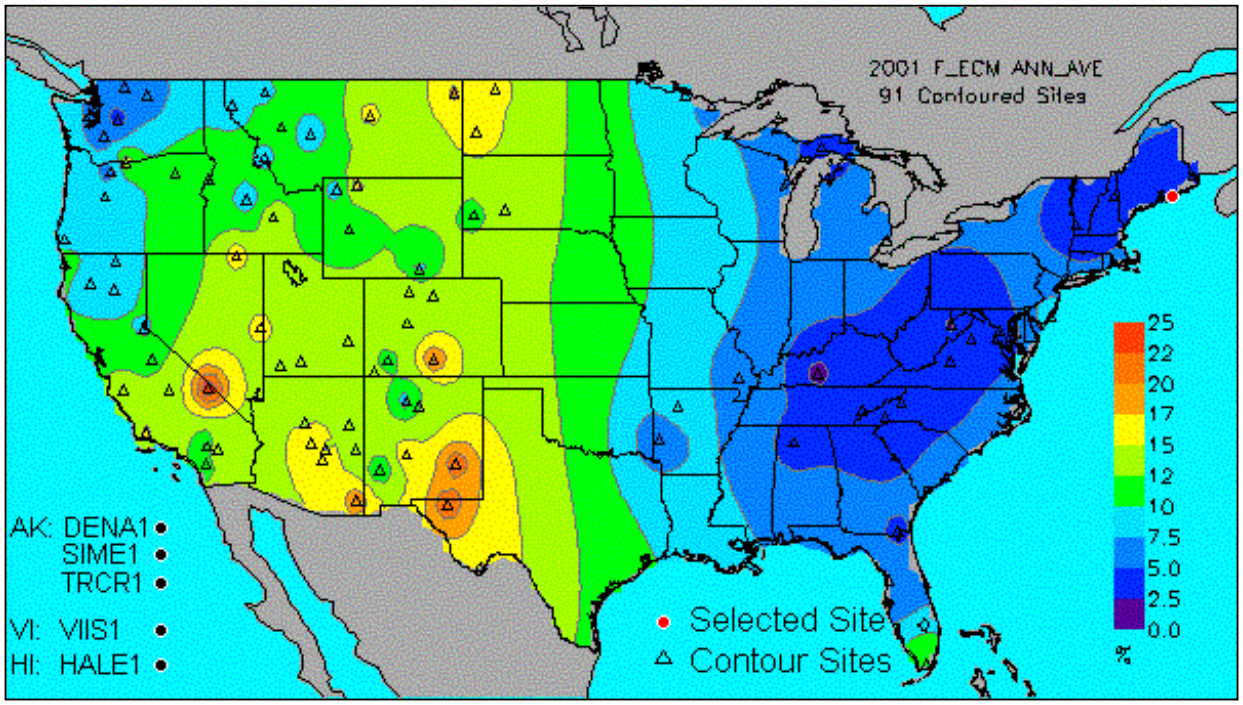
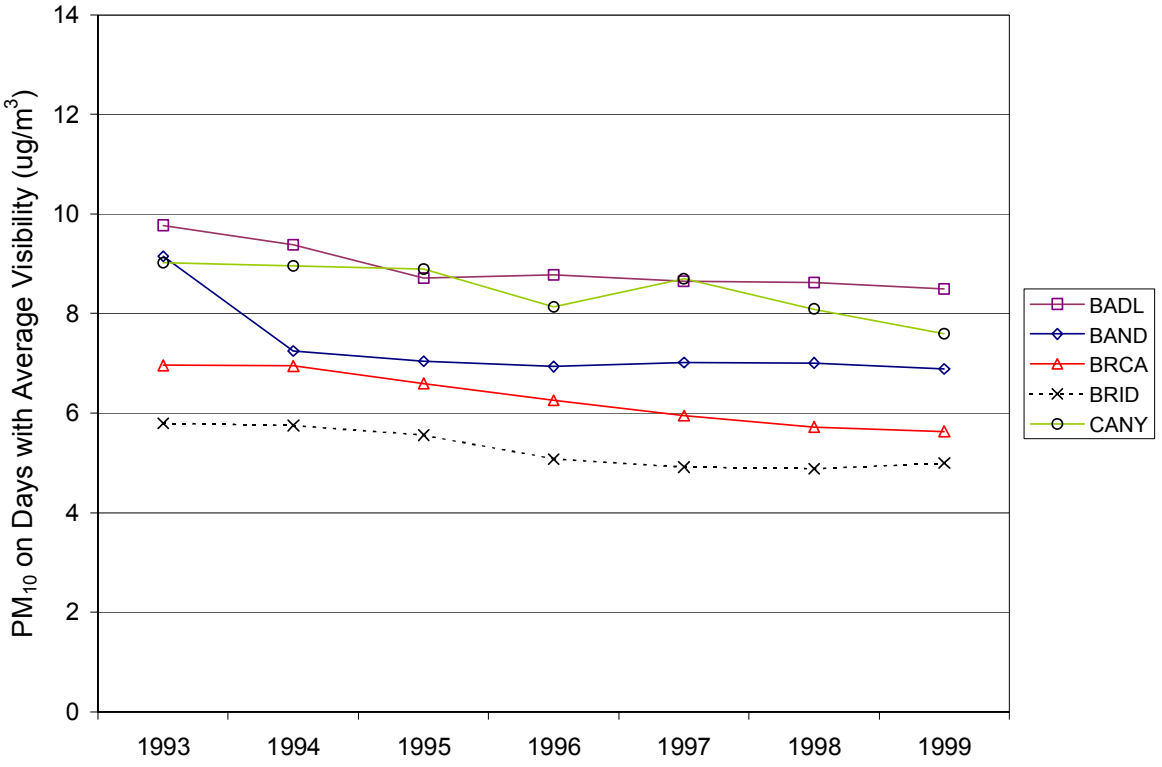
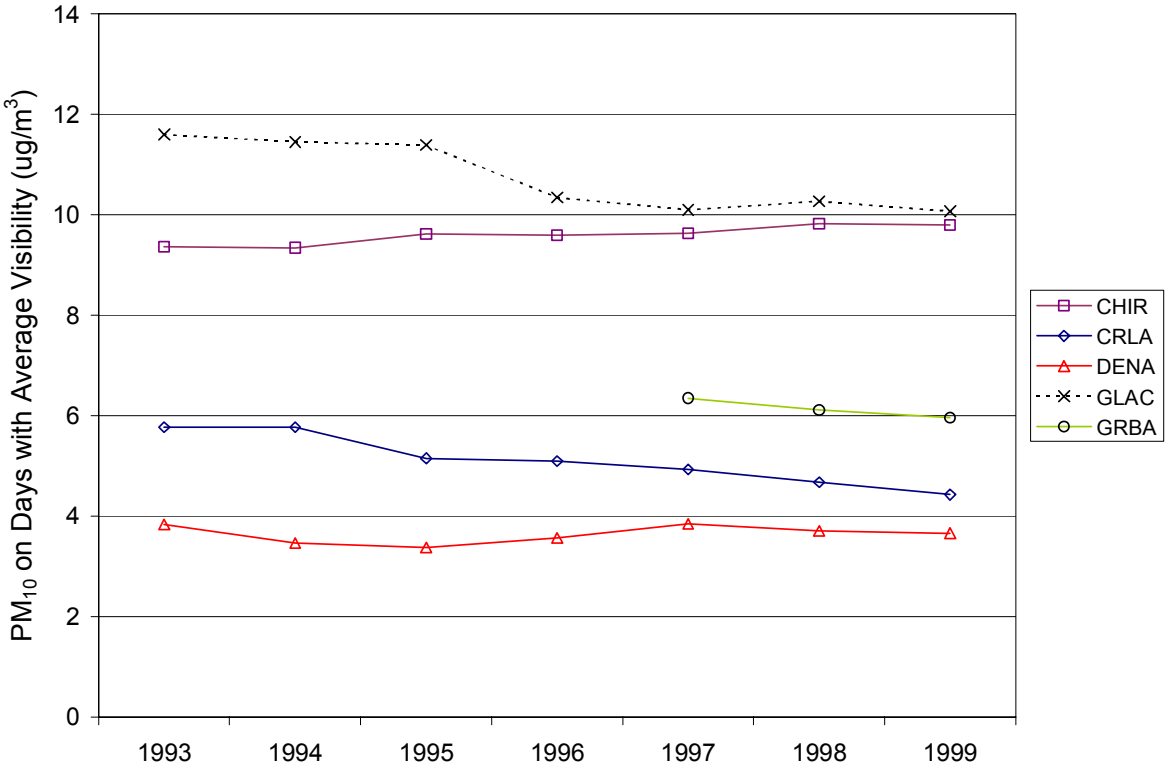


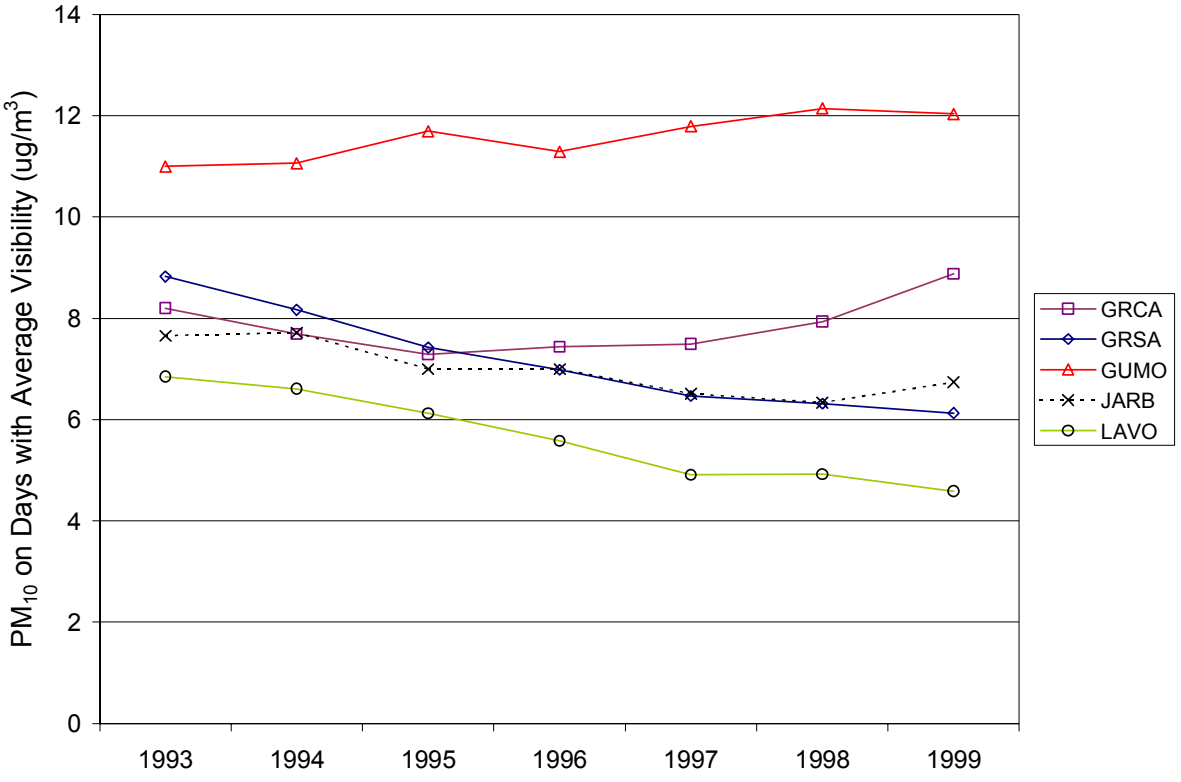
Table III-2. Name of IMPROVE Sites Shown in Figure III-9.

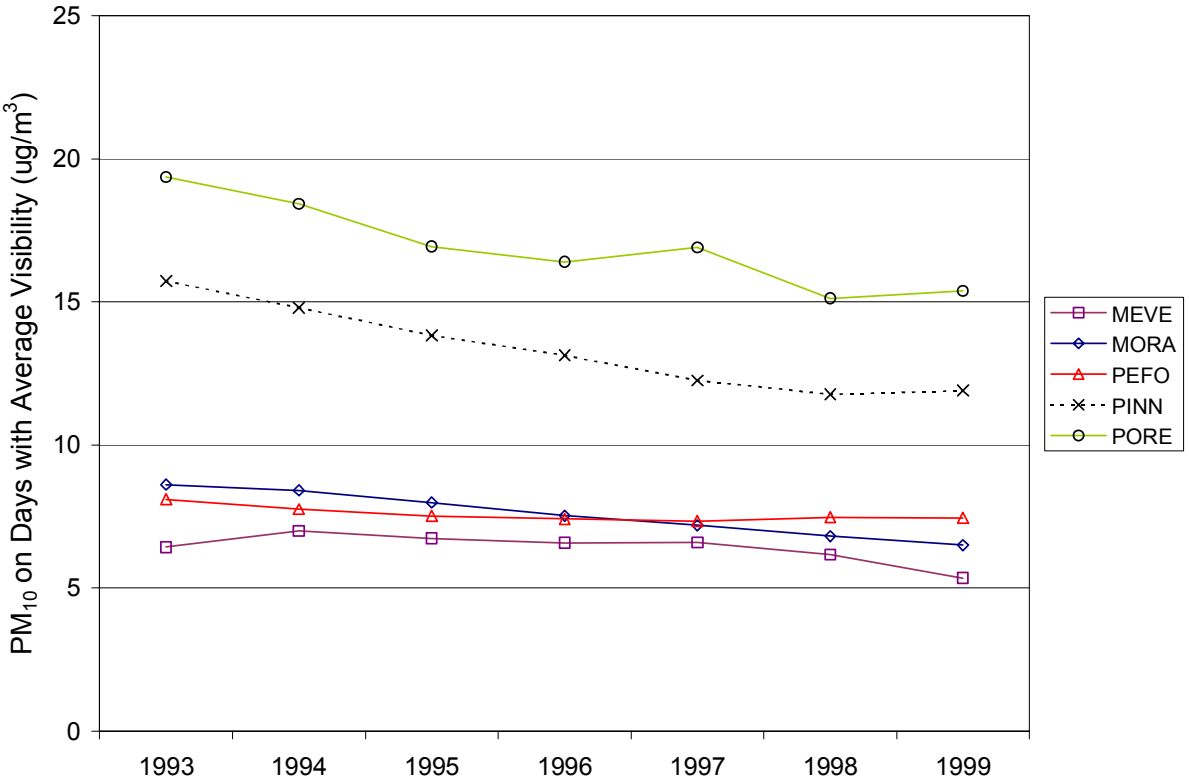
Code	Site Name	Code	Site Name
BADL	Badlands	LAVO	Lassen Volcanic
BAND	Bandalier	MEVE	Mesa Verde
BRCA	Bryce Canyon	MORA	Mount Ranier
BRID	Bridger	PEFO	Petrified Forest
CANY	Canyon Lands	PINN	Pinnacles
CHIR	Chiricahua	PORE	Point Reyes
CRLA	Crater Lake	REDW	Redwood
DENA	Denali	ROMO	Rocky Mountain
GLAC	Glacier	SAGO	San Gorgonio
GRBA	Great Basin	TONT	Tonto
GRCA	Grand Canyon	WEMI	Weminuche
GRSA	Great Sand Dunes	YELL	Yellowstone
GUMO	Guadalupe Mountain	YOSE	Yosemite
JARB	Jarbidge		

Figure III-10. Trends in PM_{10} Concentrations at Western IMPROVE Sites on Days with Average Visibility.




14
12
10
8
6
4
2
0
PM10 on Days with Average Visibility (ug/m3)
1993
1994
1995
1996
1997
1998
1999
CHIR
CRLA
DENA
GLAC
GRBA


14
12
10
8
6
4
2
0
PM10 on Days with Average Visibility (ug/m3)
1993
1994
1995
1996
1997
1998
1999
GRCA
GRSA
GUMO
JARB
LAVO


25
20
15
10
5
0
PM10 on Days with Average Visibility (ug/m3)
1993
1994
1995
1996
1997
1998
1999
MEVE
MORA
PEFO
PINN
PORE

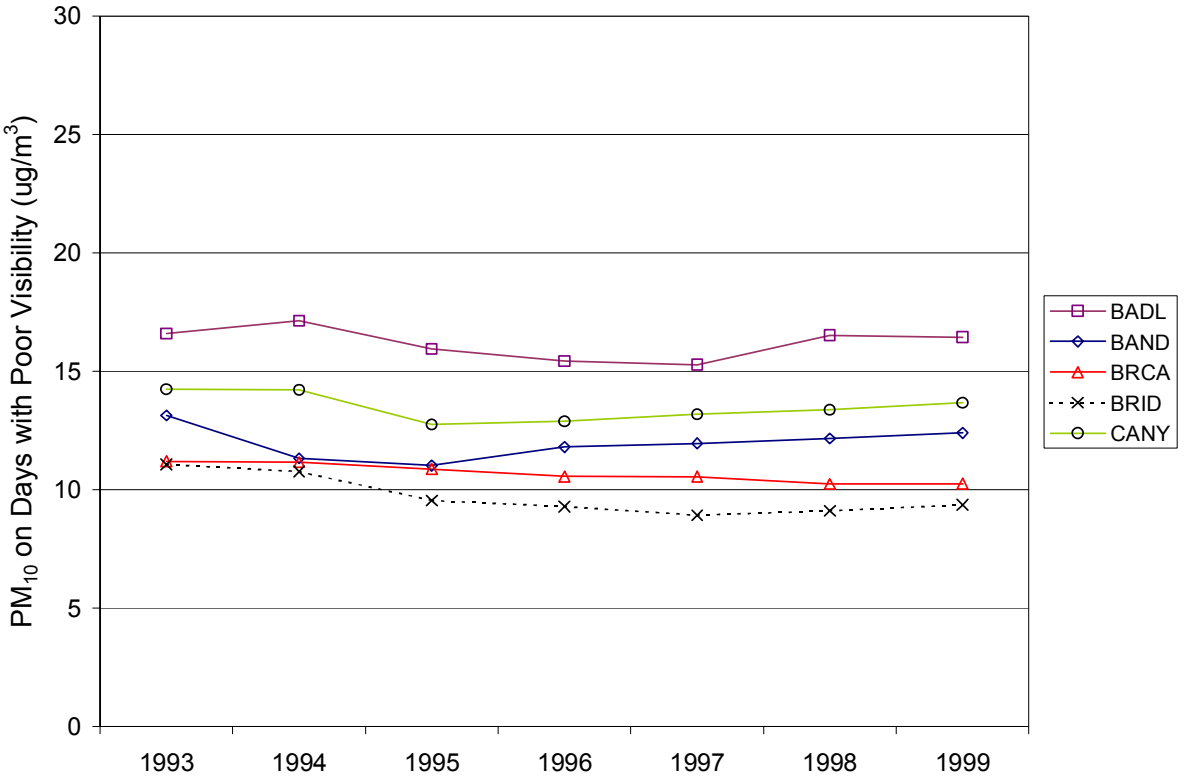
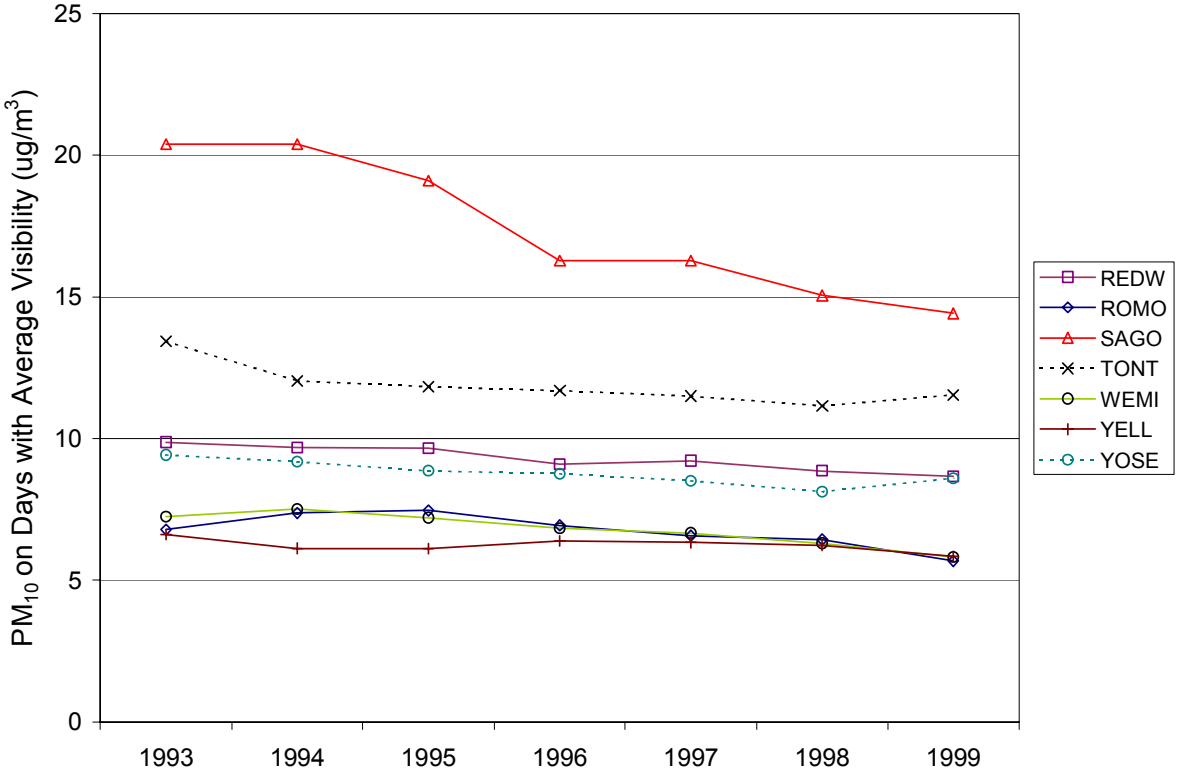

30
25
20
15
10
5
0
PM10 on Days with Poor Visibility (ug/m3)
1993
1994
1995
1996
1997
1998
1999
BADL
BAND
BRCA
BRID
CANY

Figure III-11. Trends in PM_{10} Concentrations at Western IMPROVE Sites on Days with Poor Visibility (Worst 20 Percent).



SECTION IV:
A CONCEPTUAL MODEL OF REGIONAL HAZE IN THE WEST AND THE ROLE OF STAITIONARY SOURCE NOx AND PM EMISSIONS

Introduction

The objective of this report is to provide a foundation for better understanding the dynamics of PM in the West, with particular attention to the nitrate and primary component that may be due to point source emissions. Further, the report explores how stationary source NOx and primary PM controls might impact FPM levels. As part of that, the utilization of a trading system is discussed. The report sets up a detailed framework to understand the issues by developing a conceptual model of PM formation, atmospheric dynamics, and impacts in the West. Next, the report discusses the likely effectiveness of PM and NOx controls on PM levels in the West and the relationship with visibility. This section also deals with issues involving emission trading. The final two sections discuss potentially useful computer simulations and a summary.

Overview of PM in the West

The area covered by the Western Regional Air Partnership (WRAP) includes a large fraction of the continental United States. In an air quality management context, this area has very different air quality characteristics. In part, this is due to the diversity in the source characteristics of the region, ranging from large coastal California cities to very sparsely populated and isolated regions. In the former, the emissions are dominated by mobile sources, disperse human activities, and a variety of industries. In the latter, natural sources (e.g., fire, dust, and biogenic emissions) and large point sources (e.g., electricity generating units) can dominate. Similarly important are the meteorological and topographical differences: e.g., rainy and cool coastal areas in the Northwest, dry mountainous regions further inland, and deserts in the Southwest. Pollutant levels and characteristics vary accordingly. Not only do the relative levels of pollutants vary, but the composition and source contributions change as well. This is especially seen in the particulate matter composition. In Los Angeles, nitrate (and the associated ammonia) is a major contributor. Outside of California, nitrate is usually a relatively minor contributor, though the Columbia Gorge and Seattle areas find somewhat elevated levels (Malm et al., 2003).

Unlike gases, particulate matter is characterized not only by its composition, but by the particle size as well. From a regulatory standpoint, particulate matter is divided in to three fractions: fine, coarse and very coarse. To a degree, these capture how the particulate mater size distribution is considered from a scientific perspective, which is broken in to four modes of ascending size: nucleation, Aitken, accumulation and coarse modes. The nucleation mode is the very fine fraction where new particles are formed from nucleation of vapors. Recently, as part of the Supersite experiments, regional nucleation events have been seen. These particles then grow into the Aitken mode, which also contains primary emissions from combustion sources, and finally the accumulation mode. The accumulation mode is aptly named as the smaller particles grow in to this mode, but the growth out of accumulation mode particles into the coarse mode is very slow. Recent interest has grown over another possible division of PM: ultrafines (having

particle diameters less than about 0.1 um). There is relatively less information about ultrafine PM.

Fine particulate matter (FPM) is often measured as PM2.5, or particulate matter with an aerodynamic diameter less than 2.5 micrometers (um). Some measurements of FPM have used other cut points, but there is a natural cut point at 2.5 um between the accumulation and coarse modes. On a mass basis, FPM is dominated by PM in the accumulation mode. Thus, coarse particulate matter is the fraction with particle diameters greater than 2.5 um. Given the historical measurements of PM10, coarse PM is often taken as the fraction between 2.5 and 10 um. The fraction above 10 um can be considered as very coarse, and is included (along with the other fractions) in total suspended particulate matter (TSP) measurements. The reasons for using these ranges have to do with the somewhat distinct dependence of the various size fractions on source, their atmospheric dynamics and impacts. Also, if one looks at a size distribution of PM, these modes become apparent. Characteristics of the coarse fraction are that the particles are mechanically generated (e.g. from road dust, construction, mining, etc.) and have relatively shorter atmospheric lifetimes due to settling and deposition, particularly for the very coarse particles. FPM can be mechanically generated (FPM can be present as the tail end portion of emissions that are mostly coarse) or from chemical conversion (SO2 oxidation to sulfate, combustion generation of soot, etc.), the latter often dominating. FPM also has a longer lifetime in the atmosphere as it deposits relatively slowly, though rain can rapidly remove much of the FPM. Ultrafines are due to emissions from combustion sources and chemical reactions in the atmosphere. Like FPM, ultrafines deposit slowly, but have a limited atmospheric lifetime as ultrafines because they grow due to condensation and coagulation.

While size differences are important, so are species differences. Sulfate is almost solely a secondary species, formed from the oxidation of SO2 (e.g., from coal-fired EGUs and other combustion processes). This may take place in the gas phase or from heterogeneous reactions. Sulfate is found in the fine fraction. Sulfate tends to be one of the largest components of FPM in the rural West, and still a major fraction in urban areas. Average levels are about 1 ug/m^3 in rural western areas. Nitrate is also a secondary component, resulting from the oxidation of NOx to form nitric acid gas, which then undergoes gas-to-particle conversion. NOx emissions are dominated by combustion sources, though there is a small fraction from biogenic emissions. Nitrate is also primarily in the FPM range, though tends to have a somewhat larger average particle diameter than the sulfate. A fraction of the nitrate is found in the coarse mode, indicative of gaseous nitric acid reacting with preexisting CPM (Malm et al., 2003). In the West, typical levels of measured nitrate outside of and not downwind of urban areas and central California tend to be low, averaging well less than 1 ug/m^3. In the Los Angeles basin, nitrate levels can exceed 25 ug/m^3, and significantly impact areas downwind. Care should be taken in interpreting measured nitrate levels as the techniques used are subject to artifacts (both positive and negative).

Organic carbon (OC) is the most complex part of the PM in many ways. First, it is comprised of many different species. Further, it can be primary or secondary, and biogenic and anthropogenic in origin. Again, OC is primarily FPM. Levels are highest in the cities or in areas with biomass burning (e.g., due to wild or planned fires), and there is growing evidence of the importance of secondary OC (Brown et al., 2000).

Elemental carbon (EC), or black carbon, is due to incomplete combustion, and appears to be primarily from wood burning and diesel vehicle emissions, though other sources contribute, and the actual fraction due to diesel vehicles is under study. Given the sources, EC is highest in urban areas, and a relatively small component of FPM in rural locations. While small on a mass basis, EC does absorb light, so can contribute more significantly to visibility degradation.

Metals, metal oxides and other crustal materials are due to a wide variety of sources, largely wind blown dust, as well as combustion, cement manufacture, etc. These are largely in the coarse mode, though a fraction is found as FPM, generally as the tail end of the size distribution of the coarse PM, or from combustion sources. In the non-coastal states of the West, the soil fraction is between about 20-30% of the FPM (Malm et al., 2003).

FPM has come to attention as an important fraction of the total particulate matter because of its potential impacts. FPM has been suspect of impacting human health, and recent and continuing studies tend to provide further support. (Less information is available for ultrafines). FPM also exists in a size range (e.g., similar to the wavelength of visible light) that effectively scatters and absorbs light, decreasing visibility, which is of particular concern in the West with its many national parks, forests and wilderness areas. Coarse particulate matter is of less concern (though still some) due to its shorter lifetimes, apparently reduced health effects and it is less effective, on a mass basis, of scattering light.

FPM levels in the West go from very low, with some of the lowest annual averages found in the US, to very high, with the Los Angeles area experiencing some of the highest. Other areas in the West experience isolated events of high PM (e.g., due to dust storms and fires) but annual average levels tend to be low. In much of the West and other parts of the country, the FPM is dominated by organic carbon and sulfate, while nitrate is typically a more minor constituent. While levels of these components, as well as FPM in general, are usually lower than in the east, the sources appear to be similar: sulfate comes from fuel combustion, particularly coal fired power plants and organic carbon comes from biomass burning and secondary formation. Of interest, recent results from the BRAVO study using molecular markers (Brown et al, 2002) suggest that a significant fraction of the organic FPM is secondary, as do similar studies in the Southeast. Carbon 14 dating of the organic matter in the Southeast (Edgerton, 2002) further suggest that the secondary organic is biogenic, which, given the emissions in the Big Bend area, would likely be the case there. Unlike most other areas, in Los Angeles and the Central Valley of California nitrate is a significant contributor, along with organic carbon and some sulfate.

Literature Review

Particulate matter dynamics has been an on-going research topic for decades. In-depth treatments of atmospheric particulate matter are contained in Seinfeld and Pandis (1998) and Friedlander (1977). The impact of PM on visibility has likewise been studied for years, with early work by van de Hulst (1957), and on-going study from the IMPROVE (Interagency Monitoring of Protected Visual Environments) program begun in 1985 (e.g., http://vista.cira.colostate.edu/improve/, and Malm, 2000, and references there in). Early studies

of nitrate dynamics and response to emissions controls include Stelson and Seinfeld (1982) and Russell and Cass (1984).

In the WRAP area, particulate matter studies have been conducted for years. One could group them in to urban vs. pristine area studies, or a second split could be California studies and the rest of the west. The urban vs. pristine area consideration is typified by studies with different considerations, e.g., in urban areas health and attaining the National Ambient Air Quality Standards are often the drivers, while in pristine areas, visibility is of primary importance. The latter distinction, between California and other areas in the west, is made on a couple of bases. First, California has been very active in conducting air quality studies, in part because of the severe air quality problems in that state. Second, as presented in the regional conceptual model discussion below, particulate matter in regions in California is compositionally distinct from what is found over much of the West.

Outside of California, the primary information that is available concerning PM in the West is derived from the IMPROVE program (e.g., Malm, 2000), and a number of studies focusing on specific areas. IMPROVE is an ongoing study of visibility in Class I areas in the U.S. most notably national parks. Amongst its objectives are to monitor the composition of particulate matter in protected environments and identify sources. Other, more regionally focused studies include the Big Bend Regional Aerosol and Visibility Observational (BRAVO) study (see Green et al., 2000, Brown et al., 2002) those associated with the Grand Canyon and Colorado Plateau (e.g., Grand Canyon Visibility Transport Commission, 1996 and project MOHAVE: Lowenthal et al., 2000), Mt. Zirkel (e.g., Watson et al., 2001), the Denver Brown Cloud, which included the Northern Front Range Air Quality Study (NFRAQS) (e.g., Watson et al., 1998). The Grand Canyon studies were directed primarily at assessing how nearby power plants (in particular, the Navajo Generating station) impact visibility in areas on the Colorado Plateau, which includes a number of Class I areas, including the Grand Canyon, which had experienced days with decreased visibility. BRAVO is assessing the sources of particulate matter and visibility degradation in the Big Bend area of Texas, and NFRAQS studied visibility in the area around Denver. While not focused on PM in the West, the Southern Appalachians Mountains Initiative (SAMI) study (SAMI, 2002) is relevant here because it addressed many of the same issues, except for the focus on Class I areas in the southeastern United States.

Within California, a number of programs are available for providing information on particulate matter in various regions. First, a number of Class I areas in the state do have IMPROVE monitors, which provide both a long term record of PM composition, as well as a means of comparing, directly, levels in California with those in other states. In addition, California has conducted a number of additional, intensive efforts, most notably in the Los Angeles area and the Central Valley. In the Los Angeles (or South Coast) Basin, two studies are of particular note: the Southern California Air Quality Study (SCAQS) and the Southern California Ozone Study, 1997 (SCOS97). There have been a number of additional studies as well, notably those by Cass and coworkers (e.g., Hildemann et al., (1984); Gard et al., 1998), and the current studies associated with the Supersite (e.g., Sioutas et al., 2003). In the Central Valley, the San Jaoquin Valley/Atmospheric Utility Signature Prediction Experiment (SJV/AUSPEX), the California Regional Particulate Matter Air Quality Study (CRPAQS) and the Fresno Supersite are providing

detailed information on the air quality and sources in that region. The two Supersite studies, however, are more focused on urban air quality, and less focused on visibility in protected areas.

A number of publications and reports discuss the results of the IMPROVE program, documenting the composition and trends and their relationship to visibility. A recent manuscript by Malm et al. (2003) presents the annual average fine particulate matter composition in each of 30 IMPROVE regions. In general, sulfate levels in the West are significantly below those in the East. Ammonium nitrate is high in southern California and the Lower Central Valley, with very low concentrations most other locations in the West (generally less than 0.5 ug/m^3 except in isolated spots, Malm et al, 2003). It should be noted that ammonium nitrate is actually not measured, but inferred from the nitrate measurements. As they note, nitrate can also be found in other forms, some of which are thermally stable (e.g., from the reaction of nitric acid with soil or sea salt, Malm et al., 1994; Gard et al., 1998). Organic carbon, regionally, typically runs between 0.5 and 2 ug/m^3. Elemental carbon levels are low, typically below 0.5 ug/m^3 on average, but can be an important component in terms of visibility reduction. A recent trends report from IMPROVE (Malm, 2000, also see Sisler et al., 2000 and Malm et al., 2002) shows that trends in PM levels are mixed throughout the West. For example, Sisler et al., (2000) found that of the western sites where a significant trend was found, not quite two thirds reported improvements. In some cases, decreases of one component (e.g., sulfate) were off set by another (e.g., organic carbon), as found at Jarbridge Wilderness area. At the Guadalupe Mountains NM, organics are going down, but nitrate and fine soil are going up, with no real change in visibility.

In the Mt. Zirkel Visibility Study (Watson et al., 2001), the major components that impaired visibility were found to be sulfate, organic carbon and crustal material, similar to the results form IMPROVE monitors in the region. Nitrate was a small contributor. Greater amounts of nitrate were found during the NFRAQS study, presumably because of the more concentrated sources of oxidized nitrogen in an urban area, and the proximity of confined animal operations.

Given the use of regional PM modeling, it is instructive to compare the modeling conducted here with similar studies, in particular BRAVO and SAMI, as well as other applications of PM regional models. In the SAMI study, the Urban-to-Regional, Multiscale (URM) model was used (Odman et al., 2002), and used the Decoupled, Direct Method (Yang et al., 1997) to assess source impacts and response to controls. They also assessed the response of PM levels to emissions changes corresponding to varying levels of controls. Results of their modeling was used to calculate the expected changes in visibility, stream health and ozone damage (SAMI, 2002). Model simulations led to FPM mass having an normalized error of under 50%. Sulfate and elemental and organic carbon simulations also found errors on the same order, but nitrate predictions were high. Seigneur (2003) recently completed a report discussing regional modeling applications of CMAQ and REMSAD, two of the more commonly used regional PM models. The focus of this review was the model performance in the BRAVO, WRAP, Southeast US and various EPA studies. In general, model performance in the studies outside of the WRAP found PM predictions with a normalized error of 35-90%. Nitrate predictions had the largest error.

SAMI air quality modeling dealt with many of the same issues being addressed currently by the WRAP (Odman et al., 2002). Specific issues addressed were quantifying the relationship

between emissions and various air quality endpoints, including PM levels, deposition and ozone. PM results, which were by species, were used for visibility calculations. Specific results of relevance here include:

- PM reductions were sub-linear to controls, and that the degree of sub-linearity increased as PM concentrations decreased. For example, when sulfate concentrations were highest, a 10% reduction in SO2 emissions resulted in an approximately 8-9% reduction in sulfate. At lower sulfate levels, the same 10% reduction led to a smaller percentage change. For nitrate, the sub-linear response was greater. A 10% reduction in NOx led to about a 5% reduction in nitrate, averaged over the year.

- Reductions in sulfate led to an increase in nitrate levels.

- Increases in ammonia led to an increase in nitrate.

- Nitrate formation was generally ammonia-limited.

These findings are important both individually and collectively. Over the next few years, SO2 emissions are expected to decrease and ammonia emissions are expected to increase, both leading to increases in nitrate. SAMI results suggest that these increases will be relatively small, but non-zero. However, in many locations, they offset the 27-63% reductions in NOx, such that nitrate actually increased. It is difficult to translate how similar changes will impact the WRAP regions, particularly since the WRAP regions are more heterogeneous. However, the preliminary results from the CMAQ modeling suggest that nitrate formation is ammonia-limited in a large part of the West. The sub-linear response suggests that controls will not get as much reduction as might originally be expected. However, the greatest fractional improvements will occur on the most heavily impacted days.

A final reference that provides a good overview of the issue is the NARSTO Assessment (NARSTO, 2003). It provides a more thorough discussion of many of the issues contained here, as well as conceptual models of PM dynamics in a number of areas of the United States.

Conceptual Model of Primary PM and Nitrate Dynamics in Western Airsheds

Here, conceptual models are developed to help elucidate the dynamics of both primary and nitrate PM in various western airsheds, starting with primary coarse and fine PM, which are not as involved with gas-to-particle conversion and less complicated. Note, secondary species can condense on primary PM, so even primary species can impact the formation and properties of secondary material.

Coarse PM is typically emitted by mechanical processes, e.g., grinding operations, transport of solid materials, road dust and wind blown dust. Further, CPM is typically emitted near the ground, not from tall stacks. In part, this is due to controls on large point sources. CPM has a relatively short lifetime, on the order of a few hours, though particles at the upper end of the coarse mode will have very short lifetime. For wind blown dust, this is much of the mass. Primary CPM can be attacked by nitric acid, and because of the shorter lifetime, act as a sink of

nitrate PM. Given total primary CPM emissions of 70 tons per year (tpy) (1/2 of the total PM10 emissions), one can develop a first order estimate of the contribution to total PM in the region by dividing by the approximate volume of the boundary layer in the WRAP area (~10^{15} m^3), and multiply (~1 hr) by the lifetime. This leads to an average contribution of large point sources to PM of 0.005 ug/m^3, a small fraction, again, on average. However, high levels of CPM are often very episodic (dust storms) or very local: i.e., within a few km of the source. Further downwind, the emissions have deposited and been diluted.

A portion of the CPM can be secondary, e.g., due to reaction of nitric acid on the surface of the aerosol, or condensation. Measurements suggest that a non-insignificant fraction of the nitrate in the regions outside of the California valleys is coarse. As discussed below, the existence of CPM nitrate is important from a control point of view. CPM nitrate is less likely to be reduced from reductions in ammonia as compared to FPM nitrate.

From this conceptual model of CPM, driving points are:

- CPM is predominantly primary, with a fraction due to gas-to-particle conversion, e.g., by the reaction of nitric acid with pre-existing particles,
- CPM has a relatively short lifetime,
- CPM can act as a sink for nitrate, and
- CPM is typically episodic, often occurring during periods with large amounts of windblown dust.

Primary FPM is emitted, often as a combustion by-product, in to the atmosphere, where it undergoes transport, growth, deposition, rain-out and a variety of other processes. The size of such emissions are typically in the ultrafine region, though from some processes the average particle size can be larger, e.g., as fine and coarse PM (e.g., cement manufacture). If emitted as an ultrafine, the small particles will likely grow in to the accumulation mode via condensation of other compounds to it (primarily) and coagulation with other particles, staying as FPM.

Primary FPM is transported very efficiently, essentially as a gas, since its sedimentation velocity (the rate at which it falls due to gravity) is very slow. As such, it will follow the prevailing winds and be distributed vertically and horizontally due to atmospheric turbulence. Removal of FPM occurs due to wash-out (e.g., rain and snow) and dry deposition. Dry deposition is slow, slower than many gases, due to the slow transport of FPM across the fluid dynamic boundary layer near solid surfaces (gases diffuse much more rapidly than particles) and low sedimentation velocities. As an example, for a 1 um particle, the deposition velocity is on the order of $5x10^{-4}$ m s^{-1}. Using a boundary layer height (e.g., the well mixed portion of the atmosphere near the earth's surface) of 1000m, this leads to an atmospheric lifetime of about 3 weeks, and the particles will be transported out of the region before depositing. Larger particles will deposit somewhat faster as their sedimentation velocity is higher (the particles are heavier), and very small particles will as well since they diffuse faster. With such long lifetimes, wash-out can be very important, particularly in areas that have frequent rains. Depending on the intensity of the

rain, FPM can be very effectively removed, such that the lifetime of the FPM is very directly linked to the frequency of rain. Without rain, FPM is generally transported out of the airshed or, as will be discussed for nitrate, be lost due to some other process. The lifetime due to transport in the region is on the order of 10 days. Using this, along with assuming that one half of the primary PM emissions from stationary sources (Seignuer et al., 2003) are fine, one calculates that the average primary FPM levels would be on the order of 1 ug/m^3. This is somewhat above what is measured as crustals in most locations, and more in line with the measured organic carbon. However, organic carbon would be due more to wood boilers and internal combustion engines. Using just those emissions, the average contribution to the organics would be less than 0.1 ug/m^3. This is in line with source apportionments that suggest a large fraction of the organic carbon is due to biomass burning and other processes (e.g. Maykut et al., 2003). The stationary source emissions estimates would suggest that primary FPM from stationary sources may have a regionally significant impact, though this calculation is conservative and does not take in to account rainout and other loss processes.

If the primary FPM is emitted from the stack of a large point source, it will be transported in the plume with the gaseous pollutants and can undergo somewhat more rapid growth due to the concentration of condensable compounds. It may also be transported above the well mixed boundary layer, delaying the dry deposition loss mechanism, at least temporarily. When the mixed layer grows to capture the plume, the FPM will be diffused downwards. Given the cloud heights relative to the typical effective plume height, washout will typically remove FPM from plumes.

During transport, primary FPM can grow. Growth will depend upon the particle size and composition. Of particular importance is the hygroscopicity of the compounds in the particles. Some compounds will readily absorb water, such that in a humid environment, they will grow significantly, e.g., doubling in size. If the compound is hydrophobic, they will undergo more slow growth due to condensation of other compounds. Water is not the only compound that will be selective as to which particles are most readily absorbed. Semi-volatile organic gases can have a preference for particles with similar-structured organic matter already present. $SO_2(g)$ can be absorbed in to particles that already contain water, and then oxidized to form sulfate. Nitric acid will prefer non-acidic particulate matter. Important here is to recognize that a primary particle will interact with its environment, and end up as having both primary and secondary components. From a visibility standpoint, this is important since the growth can make the particles more efficient at degrading visibility. While the argument could be made that the condensable species would find some other process to form particulate matter without direct emissions (e.g., nucleation, followed by condensation), there is an abundance of water that would not necessarily do so. Further, as compounds such as sulfate condense on primary FPM, they can become more hygroscopic. Since primary emissions of FPM can undergo atmospheric growth, it is not directly apparent that decreases in FPM emissions will lead to the same level of decrease in FPM in the atmosphere. Indeed, greater reductions may be realized if the nuclei provided by the primary FPM is a limiting factor in the formation of secondary FPM. On the other hand, the observed effects may not be as enhanced since the condensable species will find other particles.

From this conceptual model of primary FPM, driving points are:

- FPM has potentially long lifetimes in the atmosphere,
- Wash-out is an important loss mechanism,
- Ultrafine primary FPM can grow in to a size range that is efficient at scattering light,
- Hygroscopic FPM can pick up water and become diffusive, and
- Even if emitted from tall stacks, primary FPM can be diffused downwards to the surface.

Particulate nitrate dynamics is significantly more complex than for primary PM because of the added chemistry and gas-to-particle/particle-to-gas conversion. While there is a small amount of primary nitrate emissions, most of the particulate nitrate in the troposphere starts out as NO_x which was emitted from a combustion process. NO_x, which is well known for its role in the formation of ozone, can be oxidized to nitric acid via two important pathways. During the day, NO_2 is oxidized by the hydroxyl radical:

$$NO_2 + OH \longrightarrow HNO_3$$

This reaction is responsible for most of the nitric acid formation. A second route takes place mostly at night. First, NO_2 is oxidized by ozone to the nitrate radical, NO_3:

$$NO_2 + O_3 \longrightarrow NO_3 + O_2$$

(The nitrate radical should not be confused with the nitrate ion, NO_3^-). Next, the nitrate radical reacts with NO_2 to form dinitrogen pentoxide, N_2O_5:

$$NO_2 + NO_3 \longrightarrow N_2O_5$$

N_2O_5 then reacts with water to form two nitric acid molecules:

$$N_2O_5 + H_2O \longrightarrow 2HNO_3$$

This reaction is slow in the gas phase, but can occur rapidly on the surface of a particle that contains water. However, the rate of this reaction is very uncertain, and it is believed that the rate used by CMAQ in the past may be too high (Dennis, 2003, personal communication), leading to an over prediction of PM nitrate. NO_3 photolyzes very rapidly, and during the daytime it is found at very, very low levels, blocking this formation route when the sun is up.

The nitric acid gas formed from the above reactions can dry-deposit out, be washed out, or undergo gas-to-particle conversion. Nitric acid reacts very rapidly with surfaces, and deposits out rapidly. It's lifetime to dry deposition is on the order of a few hours. Nitric acid is also very soluble, and is removed effectively by rain.

In terms of particulate matter formation, nitric acid is a strong gas and can attack pre-existing particles, being adsorbed or displacing other compounds present. For example, nitric acid gas can displace chlorine in a sea salt-derived particle, leading to sodium nitrate and HCl(g). Likewise, it can react with alikilinic crustal material to form PM nitrate (e.g., Malm et al., 2003). In both such cases, the particulate nitrate formed is in the coarse fraction because the original particle was in the coarse mode. In many regions, the route to forming FPM nitrate is via the gas phase reaction between nitric acid and ammonia (NH_3):

$$HNO_3(g) + NH_3(g) \longrightarrow NH_4NO_3(\text{aerosol})$$

followed by gas to particle conversion. The reaction is reversible, and the ammonium nitrate can thermally decompose. The forward and backward reactions are fast enough such that the two reactions are often considered to be in equilibrium:

$$HNO_3(g) + NH_3(g) \xleftrightarrow{K} NH_4NO_3(\text{aerosol})$$

where K is the equilibrium constant. Thus, the fraction of nitrate formed is very sensitive to the abundance of ammonia available, as probed later. In areas with substantial quantities of ammonia, large amounts of nitrate can be formed (e.g., in areas with confined animal operations). In areas with relatively little ammonia, or where the ammonia available is bound as ammonium sulfate (or ammonium bisulfate), very little nitrate is present. Another factor is that the equilibrium constant is very temperature dependent, and at higher temperatures, the gas phases of the two compounds is preferred. The equilibrium makes the formation of ammonium nitrate very nonlinear. In some cases, e.g., in an environment rich in ammonia but with little nitric acid, the ammonium nitrate levels are governed almost solely by the available nitrate (e.g., nitric acid formation), and ammonia reductions will have little impact. If ammonia is low, it is the controlling species

Surprisingly, nitrate levels, locally, may go up when NOx emissions are decreased. This is analogous to the disbenefit found in the response of ozone to NOx emissions. Regionally, NO_x reductions will reduce ozone because NO2 is needed to form ozone. However, locally, reducing NO_x can lead to local increases in ozone for two reasons. The most easily understood is that NO_x is primarily emitted as NO, which titrates ozone. This is important at night. During the day, NO_2 reacts with the hydroxyl radical, significantly lowering OH levels. This decreases the rate of VOC oxidation, which reduces the rate of NO oxidation to NO_2, which reduces ozone formation. Most of the hydroxyl radical formed comes from ozone photolysis, so lower ozone reduces OH formation. Thus, there is a positive feedback. NO_x emissions increases decrease ozone, decrease OH, and decrease the rate at which NO_2 is oxidized to nitrate, locally. Regionally, more nitric acid will be formed. In the SAMI study, this appeared to be a second order effect.

Complicating the nitrate formation issue is the presence of other condensed phase species, in particular sulfate. As noted above, ammonium nitrate formation is very sensitive to the availability of ammonia. SO_2 oxidation, which is faster in the summer when hydroxyl levels are highest, leads to the formation of sulfuric acid, H_2SO_4. Sulfuric acid reacts with ammonia to form ammonium bisulfate [$(NH_4)HSO_4$], and if enough ammonia is present, ammonium sulfate

[$(NH_4)_2SO_4$]. Ammonia will preferentially react with sulfate to form the above two species before reacting with nitric acid to form ammonium nitrate. As such, the presence of sulfate will reduce the amount of ammonia available to form ammonium nitrate. In many cases, there is so little free ammonia that ammonium nitrate is not formed. On the other hand, nitric acid that has reacted with sea salt or crustal material to form sodium/calcium nitrate does not require ammonia, so there can be some aerosol nitrate even in high sulfate areas, though typically not as much as in high ammonia/low sulfate areas.

The interaction between sulfate, nitric acid and ammonia has implications for the "lifetime" of nitrate in the atmosphere as sulfate is reduced: decreasing sulfate will make more ammonia available to form PM nitrate, reducing nitric acid gas levels. The PM nitrate deposits much less rapidly than nitric acid, so the total abundance of nitrate in the atmosphere will increase. Thus, decreasing sulfate levels may lead to somewhat more nitrate than is expected from just considering the amount of nitric acid currently available to form PM nitrate.

Sulfur dioxide reductions will lead to the reduction of sulfate particulate matter, and hence, can lead to more ammonium being available to form ammonium nitrate, leading to what is referred to as the "rebound effect". In this case, the sulfur dioxide controls will not lead to the expected (or desired) reductions in particulate matter because as sulfate decreases, nitrate increases due to the availability of ammonia in a condition where nitrate formation was ammonia limited. This was found to be true in the SAMI study to a limited degree.

One issue that should be addressed is the impact of certain NOx controls on increasing ammonia emissions, e.g., SCR and SNCR. Compared to other sources of emissions, such controls would represent a very small fraction of the total ammonia emissions. However, in the plume, the ammonia emissions might be high enough to lead to an increase in ammonium nitrate, and hence impact visibility in concentrated plumes.

Washout is very important to nitrate levels. Not only will rain remove the nitrate aerosol, but will also remove nitric acid gas and ammonia very effectively. Clouds can also increase the oxidation of SO2 to sulfate, which captures ammonia, and is also washed out. Some of the lowest FPM levels are found following a rain storm.

From this conceptual model of PM nitrate, driving points are:

- PM nitrate formation is due to both gas and heterogeneous reactions forming nitric acid from nitrogen oxide emissions, followed by gas-to-particle conversion,

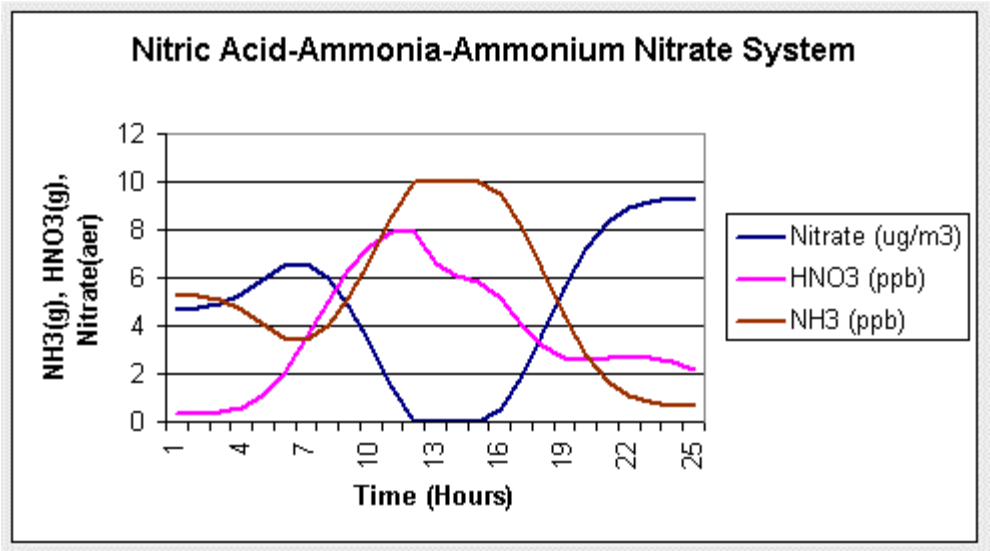
- FPM nitrate is largely due to reaction with ammonia, while CPM nitrate is due to reactions of nitric acid on a preexisting particle,

- Reducing ammonia can reduce nitrate formation in areas that are "ammonia limited", but may have little impact in areas where there is an abundance of ammonia, and

- NOx controls can reduce nitrate in areas where ammonium nitrate formation is nitrate limited, as well as areas where nitrate is formed from the reaction of nitric acid on pre-existing particles.

This conceptual model is diagrammed in the figure below. It should be noted that this figure, or the discussion above, does not have all of the complexities leading to nitrate formation. The atmospheric chemistry involves hundreds of compounds, and thousands of reactions. Describing the physical processes is equally complex. The systems of equations governing the pollutant evolution are non-linear. Pollutants evolve spatially and temporally. For such reasons, complex computer models are generally used to study the details of the pollutant dynamics. However, a good picture of the system dynamics, and an understanding of the importance of various processes can be developed from a simplified, zero-dimensional model.

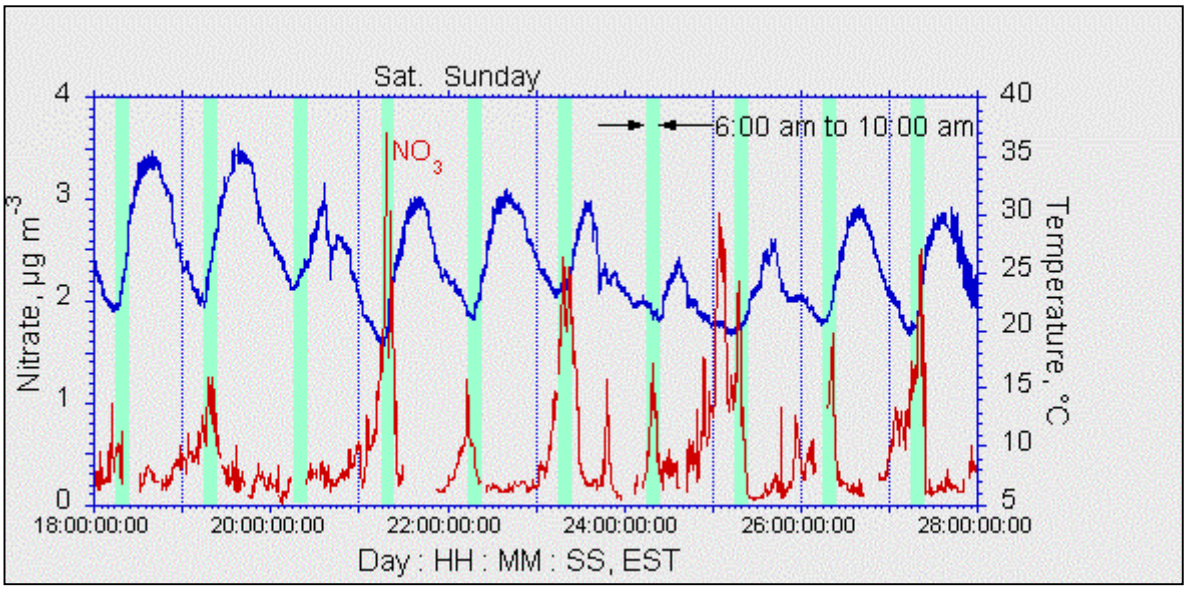
While very simplified, a zero-dimensional model can be used to demonstrate the important features and resulting formation and loss of particulate nitrate. In this case, the model includes the formation of nitric acid, peaking during the day, an increase in temperature during the day, going from 10 to 30 C, the increase in the equilibrium constant with temperature, deposition of nitric acid, and a constant level of ammonia/ammonium. The result is that the highest levels of PM nitrate occur at night and the early morning, going to zero during the hottest parts of the day. Nitric acid peaks during the day when all of the ammonium nitrate has dissociated. Most of the nitrate deposits during the day since nitric acid is so reactive with surfaces. In the SAMI project, the deposition of oxidized nitrogen due to nitric acid was about an order of magnitude higher than for PM nitrate, due both to the higher nitric acid levels and deposition velocities.



One of the important features of this system is that while ammonium nitrate does not deposit rapidly, nitric acid does. Thus, an ammonium nitrate aerosol will disappear relatively rapidly in a continual, two-step process: the nitric acid gas deposits rapidly as a gas. The ammonium nitrate will thermally decompose to replace the lost nitric acid. The nitric acid released will then deposit out, etc.. At higher temperatures, i.e., when a significant amount of the nitrate is in the

gas phase, this process can be rapid. In cold areas, almost all of the nitrate will be bound as ammonium nitrate, and the thermal decomposition is slow, so the process is inhibited.

A multi-day observation of aerosol nitrate levels is shown in Figure 2, along with the temperature trace. As shown, nitrate goes up in the morning due to NOx oxidation along with low temperatures. As the temperature increases, the nitrate decreases and goes to near zero during the day. While not shown, sulfate also increases during the day, scavenging ammonia and further decreasing nitrate levels.



Particles and Visibility

As noted previously, particles can degrade visibility. The three primary mechanisms are Mie, Rayleigh and Geometric scattering, and absorption. Only a few types of particles absorb visible light effectively. Most notably is elemental carbon. Mie scattering occurs from a complex interaction between light waves and particles of a size similar to the wavelength of light (visible light ranges from about 0.2 to 0.8 um). Larger particles scatter and block light. Air molecules also scatter light (Rayleigh scattering), limiting visibility on even the cleanest days.

Visibility, or visual range, x_v, is often calculated using the Koschmeider formula:

$$x_v = \frac{3.912}{b_{ext}}$$

where b_{ext} is called the extinction coefficient, and is generally given in Mm^{-1}. The extinction coefficient is calculated by accounting for all of the processes scattering and absorbing light. While very complex formulas have been derived, a useful parameterization that corresponds to he air quality data usually available from IMPROVE and other sites is:

$$b_{ext} = 3 f_T(RH)([Sulfate]+[Nitrate]) + 4 f_{org}(RH)[Organic] + [Soil] + 0.6[CPM] + 10[LAC]$$

where $f_T(RH)$ is a function to account for sulfate and nitrate absorbing water ($f_{org}(RH)$ is a similar function for organic material), [Sulfate], [Nitrate], [Organic] and [Soil], are the measured masses of the corresponding fine PM constituents, and [LAC] is the measured mass of the "light absorbing carbon" similar to EC, (depending on measurement technique). The latter term accounts for absorption. At relative humidities (RH) above 40%, $f_T(RH)$ is greater than one, going up to above 5. However, $f_{org}(RH)$ is taken as one. Given this, one sees that, on a mass basis, sulfate and nitrate are usually more effective at scattering light than organics, soil and CPM. LAC is very effective at absorbing light, and a small amount can lead to significant light extinction. Another measure of visibility impairment is the deciview (Pitchford and Malm, 1993). It is proportional to the log of the extinction coefficient and relates to the perception of haziness. Given the non-linear nature of the relationship between deciviews and extinction coefficient, but the linear relationship between extinction and PM composition, for the purposes of this report, it is easier to consider extinction.

Regional Conceptual Models

The above description of the formation and fate of primary FPM and nitrate was done for a general case, without consideration of regional differences in either the processes impacting primary FPM and nitrate. In the West, many such regions exist. To provide a better understanding of how such differences manifest themselves, four sub-regions of the WRAP are identified based on their meteorological and FPM characteristics. The four regions are: wet coastal, dry mountainous, southwest desert, and California valleys. Wet coastal regions include the coastal regions starting in northern California to the Olympic Peninsula, and include the coastal mountains. The dry mountainous sub-region includes the Rockies, the Sierras, and other drier mountainous areas. The southwest desert region would include non-mountainous areas in Arizona, New Mexico, Colorado and Nevada. California valleys include the Los Angeles basin and the surroundings (including the mountainous and desert areas downwind) and the Central Valley and surrounding mountains. A fifth case, considered separately, but not as a separate region, "in-and-near,"., i.e., those regions that have significant sources of PM either directly within or nearby. For example, a Class I area near a major city or facility with very large emissions, or if the activities within a Class I area led to significant emissions. The IMPROVE investigators have dissected the west in to 15 regions, which is more than is needed for developing the conceptual models as done below. However, which "IMPROVE" regions fall in to each of the four given below are noted.

Wet, Coastal Subregion

This subregion occurs along the Pacific coast and the Puget Sound, in to the coastal mountains and the Cascades. As such, it includes the IMPROVE Pacific Coastal and Cascade Mountains. As the name implies, this region tends to be wet, and is known for rain, and can also experience intense coastal storms. The temperatures tend to be cool. There are a few population centers in this region (e.g., Portland and Seattle).

PM levels in the coastal region tend to be low, e.g., on the order of a 3-4 ug/m^3 average over the year (Malm et al., 2003). Average levels of nitrate and primary FPM are very low: 0.2-0.8 ug/m^3, though nitrate is higher in the Puget Sound and Columbia Gorge areas (Malm et al.,

2003). The rain removes FPM and its precursors and coastal winds ventilate the region. The cloudiness of the area inhibits the rate of oxidation of NO2 to nitric acid. There are relatively fewer sources of FPM and precursors in the region. Higher levels of FPM are experienced in the population centers. In the Class I areas, FPM tends to be primarily sulfate and OC, with little nitrate and primary material. Biomass burning (e.g., forest fires) appears to be a major contributor in some areas, as suggested by high OC levels, particularly during some very high events. In terms of the general conceptual model, discussed above, particulate nitrate can be formed from the reaction of nitric acid with sea salt. Ammonium nitrate formation in the area appears to be limited by the presence of both free nitrate and ammonium. On the other hand, the cool temperatures promote converting what little available nitric acid and ammonia is available in to ammonium nitrate. Without further investigation (e.g., longer term, detailed modeling) it is difficult to tell how nitrate will respond to controls, but it is likely that the formation is limited by NOx emissions, not ammonia. Results from the WRAP modeling suggest that part of Oregon is ammonia sensitive (Tonneson, 2003).

The days with the most severe visibility impairment appear to be impacted most heavily by organics (particularly during severe episodes) and sulfate.

Dry, Mountainous Subregion

This region includes the more inland mountains, and would contain the Sierra Nevada, Wasatch, Northern Rocky, Sierra-Humboldt and Central Rocky Mountain IMPROVE regions. These areas are much drier than the coastal mountains. While not immune to rain and storms, they are less frequent, particularly during the summer. Temperatures tend to get hotter during the summer. During the winter, temperatures can get quite low. The area has a relatively low population density, and few major source regions, though is relatively agricultural. Major point sources include utility boilers, and smelting operations. Confined animal operations can lead to areas of very high ammonia. Forest fires, particularly in the northern mountainous areas (e.g., Montana and Idaho) and the Sierras can lead to very large PM concentrations during episodes. In such cases, OC dominates mass.

FPM levels in this region are low, around 2-5 ug/m^3 in Class I areas. Again, cities have higher levels. Nitrate and primary FPM levels are a small fraction of the total (0.1 to 0.4 ug/m^3, except in the regions of the Sierra Nevada that are influenced by emissions in the Central Valley), particularly during the some of the most polluted events that are dominated by sulfate. Given the low levels of nitrate, and the likely higher ammonia emissions, nitrate formation is likely limited by nitric acid formation from NO_2. Simulations by UCR tend to suggest a mixture of sensitivities (Tonneson, 2003).

The days with the most severe visibility impairment appear to be impacted most heavily by organic matter or sulfate, though some events have very high levels of coarse mass as well. Nitrate tends to be a relatively small contributor, which is to be expected when sulfate is high. Because the measurements can not distinguish as to the source of primary PM, it is not immediately apparent as to the source of the coarse mass, but given the episodic nature, it is likely that the primary PM is natural in origin.

Southwest

This region includes the far eastern part of southern California, Arizona, New Mexico, southern Colorado and Nevada. IMPROVE regions corresponding to this region are the Great Basin of Nevada, the Colorado Plateau and Sonoran Desert. The Southwest has features similar to the Dry Mountainous subregion, being dry and having low FPM levels. It differs in that temperatures tend to be higher, and there is a greater abundance of major point sources of NOx and FPM. Biogenic sources in much of the southwest are very small, but appear to be a major component of the OC nonetheless (Brown et al., 2000). Ammonia emissions are less dense, though crustal material can be higher from wind blow dust as this area finds higher soil concentrations than the others (Malm et al., 2003).. While more detailed modeling is needed, it would appear that the higher levels of sulfate measured, and the apparently lower levels of ammonia emissions, would make this area ammonia limited much of the time.

The days with the most severe visibility impairment appear to be impacted most heavily by sulfate, OC and nitrate, though some of the events with the lowest visibility have very high levels of coarse mass, likely associated with dust storms. There are periods with very high levels of OC, indicative of major biomass burning events (forest fires).

California Valleys

This subregion is the most distinct of the four, and includes California's Los Angeles Basin and the Central Valley, and the areas most directly impacted by transport from these regions (e.g., downwind of Los Angeles and the mountains directly along the valley, including part of the Sierra Nevada). This region is relatively dry and warm. There are periods of significant stagnation. Most importantly, this region has greater emission densities of the pollutants impacting nitrate PM, in particular both NOx and ammonia. These characteristics lead to substantially higher FPM levels, especially for nitrate. Nationally, this region has the highest nitrate levels.

Of all the regions, most is known about the dynamics of PM here due to a history of studies being sponsored by the state of California, industries and others. In Los Angeles, the high nitrate levels are due to the large emissions of NOx, e.g., from mobile sources, confined animal operations leading to high ammonia emissions, low ventilation rates concentrating both sets of emissions, and plentiful sun, oxidizing the NO2. In parts of the basin, e.g., before the air masses pass over the confined animal operations, nitrate formation is ammonia limited. Further downwind, the formation becomes nitrate-limited as there are plentiful ammonia emissions and the nitric acid continues to deposit out. The highest nitrate levels are found in the fall when the sunlight still leads to rapid oxidation of NO2, winds are light, there is little rain, and the temperatures are lower favoring the formation of ammonium nitrate. On hot summer days, the ammonium nitrate thermally decomposes, though large amounts of nitrate can be present during the cooler hours.

The Central valley shares some of the characteristics of the LA basin, but has some unique features. First, the sources of NOx differ, having a larger non-mobile component, and being less dense. There are widespread agricultural and animal operations leading to ammonia emissions

throughout the valley. There can be long stagnation events with fog and very little ventilation. During these stagnation events, nitrate levels can build.

An interesting study of the NOx-nitrate relationship was recently completed for the San Joaquin Valley using a box model (Stockwell et al., 2000). They found that for each gram of NOx emission, approximately 0.6 grams of nitrate is formed. This is a high ammonia region, so while those results are in general agreement with field measurements in the region, the extrapolation of those results elsewhere is limited.

For both areas, the days with the greatest visibility impairment are high in nitrate, OC and sulfate, with episodes of coarse material.

In and Near

A few Class I areas lie very near a major source region (e.g., a city) or specific source (e.g., a major highway, mining operation or power plant). In this case, the PM levels can be higher than experienced by the rest of the region, and have a different composition. Examples that are near source regions include San Gorgonio (downwind of Los Angeles) and Casa Grande and Tonto National Monuments near Phoenix. In this case, the PM takes on a characteristic that is a blend between these in the urban area and the regional background. For example, this can lead to elevated nitrate, as particularly found in San Gorgonio, and organic and elemental carbon. For areas near major sources, the PM can be enriched in the compounds being directly emitted by the source. Secondary pollutants, particularly sulfate, take longer to form, so there is less of a direct impact, but some enrichment is likely (e.g. Grand Canyon Visibility Transport Commission, 1996; Pitchford et al., 1999). Pollutant dispersion reduces the apparent source impact relatively rapidly, so after a few 10s of km, the impact from that source is reduced by an order of magnitude or so. This is particularly true for CPM which also deposits rapidly. Also, human activities within a protected area (e.g., driving, fires, etc.) can contribute to locally higher PM levels. However, these sources are outside of the subject of this study, do not appear to be a significant contributor to visibility degradation regionally, and are not dealt with further here.

Particulate Matter Modeling

Currently, the most scientifically well-founded approach to assessing how future emissions changes will impact air quality is to use a physically and chemically comprehensive air quality model that describes the evolution of pollutants in the atmosphere. Such models (actually, multiple models are used) are complex, and are run on fast computers. The WRAP is now using such an approach. In particular, the WRAP is using the Models-3 suite of models, including SMOKE for emissions, MM5 for meteorology and CMAQ for air quality, including particulate matter. MM5 is one of the most widely used meteorological models, and CMAQ is an increasingly popular air quality model.

MM5 solves the equations governing the motions of the atmosphere. These equations are very complex and non-linear, and sensitive to boundary and initial conditions. The model uses a variety of parameterizations to simulate various processes. For some processes, MM5 has more than one choice of parameterization since no one approach appears to be universally best. This,

in part, shows the complexity of meteorological models, and that modeling errors can be expected. Errors can grow with time, degrading performance in longer simulations if nothing is done to constrain the growth. For this reason, data assimilation is used where observations are used to adjust the results as the fields evolve. As such, the model results are sensitive to model inputs (including initial and boundary conditions), model parameterizations and errors in the data used in the assimilation. While MM5 often achieves very good performance, there are events where good performance is elusive.

CMAQ is a comprehensive chemical transport model, developed primarily by the US EPA and funding from that agency. It represents the state-of-the-science in most aspects, and has been developed for use by the modeling community. Its use by the community is, in part, to help it evolve and continuously improve. CMAQ contains processes describing gas phase chemistry, aerosol dynamics, dry and wet deposition, pollutant transport and more. A common configuration of CMAQ uses CB-IV, a rather older, simplified chemical mechanism, though versions exist with RADM-II and SAPRC-99, two of the newer, most comprehensive and well tested mechanisms.

All three models have been used in a variety of efforts in the past. MM5 and CMAQ, the two predictive models, have been able to show good performance, at least for some species, though performance can vary from site to site and study to study. Since CMAQ uses the results from MM5, poor performance by MM5 can lead to similarly poor performance from CMAQ. However, even with ostensibly good performance from MM5, CMAQ may not perform well due to poor emissions inputs and/or problems with CMAQ itself, e.g., how it treats various processes. Further, here, CMAQ is being applied using a 36 km grid resolution. Such large grids are not appropriate for assessing the impact of a point source of CPM on nearby areas because of the rapid deposition of the larger particles, and the artificially large dilution of the emissions over the 36x36 km grid.

Model Performance Issues

Confidence in using such a model is derived from successful evaluation of the results. What constitutes good model performance varies by pollutants, and for FPM there is no standard criteria. Recent modeling efforts have found errors for sulfate to be within about 50%, OC within a similar range, and nitrate within about 100% (Seignuer, 2003).
However, current model performance found for the WRAP effort suggests poor model performance for some species, particularly nitrate (up to a factor of 10 high in the winter, but some days with essentially no nitrate formation simulated in regions where nitrate is monitored to be present). It is difficult to assess the model performance for primary FPM from stationary sources since the measurements and the model results are not able to support such an evaluation. How does poor model performance affect the use of the results, in particular for quantifying the likely impact of emissions changes?

First, it is important to understand the likely reasons for the poor nitrate performance. It is unlikely that the NOx emissions estimates are very far off, so other problems likely exist. Ammonia emissions are much more uncertain, and can be part of the problem. Also suspect is the deposition rate used for nitric acid (too low) and the nighttime, heterogeneous oxidation of

NOx to nitric acid (too high), both leading to higher levels of nitrate. The reasons for having too little nitrate during the summer (e.g., no nitrate is sometimes predicted when some is observed) may be because the nitrate present is particulate nitrate formed from nitric acid attacking pre-existing particles to form a thermally stable form of particulate nitrate (e.g., soil material and salt), slight overestimates in the amount of sulfate formed or underestimates in the ammonia emissions. Monitoring has found that a significant amount of the nitrate in Class I areas outside of southern California is larger FPM or coarse, suggesting that it is formed from nitric acid attacking pre-existing aerosol forming a thermally stable form of nitrate. If this is the reason for the discrepancy, and that ammonium nitrate is not present, then the modeled sensitivity to emissions reductions will be very different than would occur. In particular, an area that might appear to be ammonia limited from the modeling, may be nitrate-limited, and most sensitive to NOx emissions.

A large error indicates that either the sensitivity to emissions changes is in error, or there is a large error in the emissions. If the latter were true, the model results could be used to scale observed levels to get a reasonably good approximation of how the ambient levels would respond. The decision was made, in advance, in SAMI to use scaling, even for the species where very good performance was found. Note, if performance is perfect, the same results are found if one uses scaling or the model results directly. Thus, the approach is asymptotically correct.

If model performance is poor, scaling the observations with model results becomes more questionable. Given the very large errors found for nitrate, the low correlation between observed and simulated levels, and that NOx emissions are relatively well known (probably well within a factor of two), the modeled sensitivity of nitrate levels to NOx emissions could be well off. Indeed, the very low observed nitrate, versus that simulated, suggest that much of the time the model is in a different regime than the actual atmosphere (e.g., the case where the two species, ammonia and nitric acid, are in sufficient supply to form aerosol nitrate vs. the case where one or both are at concentrations low enough to negate ammonium nitrate formation, and what little nitrate found is due to reactions of nitric acid with a crustal material or sea salt). Performance is worst during the winter, but during the summer there are days where no nitrate is predicted, though some is observed. In this case, NOx controls will not lead to any change in predicted nitrate, so scaling will not show any benefit. Given the performance problems, it is difficult to suggest if the sensitivity of either the annual nitrate levels, or the nitrate levels on the days with the most limited visibility, is adequately represented by the model.

One issue concerning the use of scaling is that it does not account for spatial inhomogeneities in the controls. For example, control at a specific source, even though it is a very small fraction of the total inventory, will have an enhanced local impact, though little impact further away. This issue can be dealt with by using the model to develop source-receptor relationships, and use those results to help guide the scaling.

For primary fine and coarse PM, the response of ambient PM is likely to be quite linear (though not totally due to particle growth), so scaling should work relatively well, as long as the issue of spatial inhomogeneities in the emissions controls is adequately addressed. This can be relatively easily tested using a single model simulation.

At present, the simulations have not been conducted to provide a complete source apportionment of the PM. By this, one means exercising the model to show how each source (or group of sources) impacts PM at specific receptors (e.g., the Class I areas). Such a calculation can be very helpful in suggesting controls. Further, it is important to understand the magnitude of the problem with which we are dealing, and how to interpret model results and observations. In particular, this is important for primary PM. At most Class I areas, FPM is dominated by secondary species (nitrate, ammonium, sulfate and a fraction of the OC), and primary EC and OC. Other compounds are a relatively small contributor to both FPM mass and visibility. One question, for which the model can be used to help understand, is if a significant fraction of the PM is from stationary sources. If not, i.e., that stationary sources are a small fraction of the primary PM at Class I areas, and that primary PM is a small fraction of the total PM, reductions in primary PM emissions will have a rather small impact.

Effectiveness of PM and NOx Controls on PM levels and Visibility in the West

As discussed above, nitrate is a major contributor to PM levels and visibility extinction in a few areas of the West, notably in California, and to a lesser amount the Columbia Gorge. In the southern half of California, nitrate can be the major constituent. In most other areas, nitrate is found at relatively small concentrations, around 5-20% of the total FPM. Likewise, point source primary emissions of PM, both coarse and fine, are a small contributor, regionally, as well. Thus, controls on point source emissions of NOx and PM will have a relatively limited effect on both PM and visibility in much of the West, <u>all else being equal</u>. The latter clause is important because, as SO2 emissions are reduced, and ammonia emissions increase (as is forecast in many areas), aerosol nitrate may become a more significant contributor, as was found in SAMI.

In and around the California valleys, nitrate formation appears to be nitrate limited. As noted above, Stockwell et al., (2000) found that one gets, roughly, about 0.6 grams of nitrate (as ammonium nitrate) per gram of NOx emissions. This would suggest that, in these areas, NO_x controls will reduce nitrate levels. The exact level of benefit will have to come from either analysis of the measurements or modeling after performance improves. The California inventory suggests that about 478 tons per day (tpd), or about 14% of the 3441 tpd statewide, of NOx come from stationary sources. Assuming that stationary sources have a similar impact on nitrate formation (SAMI results suggest this is not totally true, Odman et al., (2002)), this puts an upper bound on the likely benefits of around 15%, and the results of the SAMI study suggest that the actual impact on nitrate mass is more around 7%. This translates in to approximately 2% of the total FPM in areas around Los Angeles where nitrate makes up about 30% of the total FPM and 1% in areas of California, such as the Sierras east of the Central Valley where nitrate is about 15% of the total FPM. In other areas, the stationary source contribution, on average, would be smaller, on average. Three considerations would increase the importance somewhat: on days with the worst visibility in these areas, nitrate makes up a larger fraction of the total (in some cases, over 50%) on days with the highest levels of nitrate, a greater fractional response to NOx reductions is suggested and if the receptor is directly downwind of a major point source, the impact would be increased. The first two considerations might lead to an increased impact of up to 5%. The latter consideration would be very site and meteorology dependent.

Elsewhere in the West, nitrate levels are relatively small: usually less than a ug/m^3, and from 5-10% of the total PM. The days with the worst visibility tend to be dominated by one of three cases: high CPM and crustal (indicative of dust storms), high organic and elemental carbon (which can indicate forest fires) or high sulfate, which tends to be elevated much of the time, and increases during stagnation. Thus, unless the increasing ammonia and decreasing sulfate lead to significant nitrate increases, stationary point sources will lead to only about 2% (or less) of the visibility extinction, except in areas significantly impacted by major sources. SAMI modeling suggested that there will be small additional benefits of NOx controls in reducing sulfate due to decreased sulfur dioxide oxidation. Thus, NOx controls will have a relatively small impact on PM and visibility in the West.

The impacts of primary PM controls on point sources are more difficult to assess at this time since the available data is less specific as to the fraction of PM from point sources. As noted above, CPM has such a short lifetime that reductions will have a small impact on PM levels and visibility, except very near the source. Primary stationary source FPM, while longer lived, still appears to be relatively minor, contributing less than 0.1 ug/m^3, so controls on FPM would also have a minor impact on PM levels and visibility. This is in line with the results from studies such as those conducted at Mt. Zirkel (Watson et al., 1996). Total removal would lead to a decrease in extinction of about 0.4 Mm-1, or less than about 0.5% of the total extinction on a day with relatively bad visibility of about 20 miles.

The above analysis suggests that primary PM and NOx controls will have limited impact on visibility in the West in the near term, except in areas of California and areas directly impacted by specific stationary sources being controlled. Near-field impacts of sources needs to be conducted on a site-by-site basis. However, as sulfate levels come down, the impact of NOx controls will increase, both because nitrate levels will increase and due to the non-linear relationship between visibility and extinction. Locations whose visibility is currently dominated by sulfate may find that nitrate becomes the species of concern. Looking towards the future, it is prudent to identify the types of controls and mechanisms to increase their cost effectiveness.

Emissions Trading

Emissions trading is viewed as an economically efficient approach to air quality management, as has been experienced through the acid rain program. However, when trading pollutant emissions, the economic efficiencies tend to decrease as limits are placed on trading, e.g., spatially, temporally, across sectors, and across pollutants. There are issues associated with each. Allowing spatially diverse trades can shift emissions reductions and the resulting air quality improvements.

Temporal trading can lead to decreased (or enhanced) benefits. For example, sulfate tends to be higher in the summer due to more rapid oxidation. If the trading results in greater reductions during the winter, average sulfate levels may decrease less than if the reductions were more uniform. On the other hand, if the SO2 reductions are greater in the summer, the benefits could be enhanced. This may be more critical for nitrate which, as discussed above, is very sensitive to temperature, and is thus found predominantly in the winter. Primary emissions would not be affected as much.

Trading across source sectors may be impacted by (1) the spatial and temporal trading concerns identified above, (2) that sources can emit at different elevations above the ground, and (3) that different sectors do not have the same PM characteristics. Emissions from a tall stack are in to a very different environment than a more dispersed ground level source. First, elevated emissions, e.g., from utilities, tend to be very concentrated in NOx, and the plumes can stay very NOx rich for significant distances. Ground level sources tend to be more disperse and in to environments with higher levels of VOCs. In recent field experiments, this has been found to have an impact on ozone formation efficiencies (e.g., Ryerson et al., 2001). Recent modeling has also found this to be the case for ozone and acid deposition, and nitrate FPM (Odman et al., 2002), though the differences were not as large as that measured for ozone. For primary FPM, this is likely a small impact, though ground level FPM emitted in populated areas would likely lead to a greater exposure than if emitted higher up. It is likely that the spatial and temporal issues are of greater concern. A final concern is that trading primary PM emissions between sectors can lead to a different type (e.g., predominant size) of PM being emitted. For example, utility emissions are likely going to be more fine than, say, cement production or mining emissions (as well as being emitted at different levels). CPM deposits faster, and impacts visibility less. Thus, removing a ton of CPM would not have the same benefit as removing a ton of FPM, all else equal. In this way, trading primary PM emissions between sectors is much like trading pollutant types, with the issues discussed below.

Scientifically, the most challenging type of trade is across pollutant types, e.g., SO2 for NOx, primary PM for NOx, etc. This is because it is difficult to quantify how much of one pollutant can be traded for another and have equal air quality benefits. The possibility of displacement reactions further clouds how such trades can be weighted. For example, reducing SO2 will lead to sulfate aerosol reductions. However, this can free up ammonium to react with nitric acid, leading to increased nitrate. While this was found to be the case in SAMI modeling, the "rebound effect" was not large. Finally, the different species will have different impacts, e.g., in terms of visibility reduction. For example, each fraction of the PM has a different impact on visibility per mass. Nitrate and sulfate have a greater impact, on a per mass basis, than soil or CPM. Further, sulfate and nitrate both have a greater impact on visibility at higher humidities, other constituents do not, generally leading those two constituents to have a bigger impact on visibility on a per mass basis than (say) organics. Conversely, elemental carbon is very effective at absorbing light. If one can correctly account for the relationships between emissions and the resulting concentrations, it is straightforward to account for the visibility impairment differences, though the relationships can change with time. For example, as SO2 emissions are reduced in the future, and ammonia emissions increase, the area could become more sensitive to NOx emissions. Thus, one ton of NOx reduction may become more valuable in relationship to one ton of primary FPM.

A final issue is that reducing NOx emissions will impact both secondary sulfate and OC formation. This is because NOx is central to the formation of ozone and increasing the oxidizing capacity of the atmosphere. Modeling as part of SAMI suggested that this secondary effect is small, but non-zero, impacting mainly the formation of sulfate. Typically, reducing NOx also reduced sulfate formation slightly, but in some locations NOx reductions led to small sulfate increases due to increasing H2O2 formation and the heterogeneous oxidation of SO2, as well as

increasing OH levels. In general, these secondary impacts will slightly enhance the effects of NOx emissions reductions, but can be ignored for now due to the larger uncertainties in quantifying the NOx-aerosol nitrate system response.

Given the complexities, the question arises is, if emissions trading is to be done, how should trading equity be established. If the trades are somewhat restricted to the point that there are no obvious resulting inequities (e.g., limited spatially and not across pollutants, and that there is little likelihood that there would be little temporal or elevation differences), policy makers could likely proceed without the use of some more extensive approach. However, this would severely restrict the market and the associated economic benefits. Dealing with the issues identified is ideally tackled using a comprehensive air quality modeling effort, such as is being done by the WRAP. In this case, the model could be exercised to identify the appropriate trading ratios and the inequities resulting from various trades.

A major problem at this time, as discussed above, is that confidence in a model's use can only be developed through successful evaluation and good model performance for the species of interest. In the case of the WRAP modeling, nitrate performance was poor, and it would be difficult to use such results to assess how to make trades equitable, e.g., to develop trading ratios across pollutants. While less of an issue, using the model to assess trading SO2 for FPM is also difficult because of the rebound effect. When model performance is such that the WRAP is comfortable that the model is adequately capturing the physics and chemistry affecting pollutant evolution of the compounds of interest, then the model, presumably, can be used to determine how to make trades equitable. Note, this does not mean that performance for all species has to be good. Having poor performance for crustal species would not significantly impact the use of the model for comparing SO2 and NOx trades.

Given the successes achieved from emissions trading, it is important to identify model performance problems such that trading guidelines can be established in a sound fashion. None of the issues identified above are "show stoppers". However, given the level of uncertainty in the modeling results at present, inter-pollutant trading would have the potential to jeopardize visibility improvements in the region.

Suggested Model Simulations

At present, a few sensitivity simulations have been conducted using CMAQ. While conducted, in part, to understand model performance, they are providing insight into PM dynamics in the West. In particular, the cases where NH_3 emissions are being changed to find areas that are most sensitive to NH_3 emissions. Such sensitivity calculations are key to addressing trading issues and identifying effective control strategies.

After model performance is judged to be adequate, a number of calculations are suggested. A first set of calculations is to conduct a comprehensive source apportionment by source type (e.g., point, area and mobile), pollutant (SO2, NO_x, NH_3, CPM and FPM), and location (e.g., state or region). The resulting matrix (a total of about 45 sensitivities) can be used to guide trading, assessing the impact of transport, identifying important source regions to pristine areas, and guiding control simulations. While 45 simulations may appear prohibitive, various tools exist to

facilitate the process. For example, SAMI used DDM-3D. The results of these sensitivities should be stratified into days with very good and poor visibility, and the annual average. The aggregation of days will tend to suggest a more local impact of sources than looking at a typical day.

A second set of simulations would be to explore specific control issues, e.g., the imposition of certain sets of controls. A particular interest would be to explore future PM levels as the NO_x and SO2 emissions are decreased, but NH_3 emissions increase. The interest would be to assess if there is the possibility of increased nitrate formation due to the higher NH_3 and lower sulfate in spite of lower NOx emissions, as was found in the SAMI study. In some areas, this may lead to nitrate replacing sulfate as the major contributor to visibility reduction, greatly increasing the impact of NO_x controls on visibility.

A third calculation would look at how SCR or SNCR controls would impact visibility in a point source plume. The ammonia in such a plume might lead to locally increased ammonium nitrate formation. While, regionally, ammonia emissions from such control technologies are small compared to animal waste decomposition and fertilizer, on a very local scale there may be increased PM formation. Such a calculation may require a finer grid being employed in locations to capture the finer scale impacts of the plume where, presumably, both NO_x and NH_3 would be elevated.

Summary

The states that are part of the WRAP have a very diverse chemical/PM "climatology", represented by extremes ranging from the dry, high nitrate areas in Southern California to the wet, low PM northern coastal mountains, to the dry mountains and deserts inland. Typically, the major constituents of the visibility-impairing PM are fine PM sulfate, OC and, at times, nitrate, though there are episodes of high coarse material.

Doing a simple, approximate, mass-lifetime balance on coarse PM emissions from primary sources suggests that, on average, primary CPM emissions from point sources will contribute a very small fraction of the total PM. This is borne out in the observations. Near the source (within a few 10s of km), however, the sources may be significant. FPM is much longer lived than CPM, and is predominantly secondary, being composed primarily of sulfate, OC and nitrate.

Primary FPM from point sources is estimated to be a small contributor to FPM mass and light extinction on a regional basis. First, the total amount is small relative to other components of the FPM. Second, it has a lower impact, on a per mass basis, than other constituents. Third, periods of highest extinction do not appear to have significant amounts of point source-derived, primary FPM as compared to the other components, particularly CPM during dust storms, organic and elemental carbon during fires, sulfate during stagnation events, and nitrate in areas of high ammonia.

Nitrate is formed from emissions of NO_x that react to form nitric acid, which then can undergo gas-to-particle conversion. Much, but not all, of the nitrate is fine, and higher observed concentrations are formed from the reaction between nitric acid and ammonia to form

ammonium nitrate. A fraction of the nitrate will be formed from nitric acid attacking pre-existing PM (coarse or fine). Ammonium nitrate levels can be reduced by either reducing nitric acid formation or ammonia emissions, with the greatest sensitivity to reducing the precursor that is least abundant (on a mole basis). Thus, some parts of the region will be ammonia-limited, others will be nitrate-limited (e.g., areas with high ammonia, such as near confined feeding and intense agricultural operations). The fraction that is formed from nitrate attacking pre-existing PM will not be very ammonia sensitive, responding more to NO_x controls. Modeling currently suggests that much of the domain is ammonia-limited (in terms of nitrate formation). However, CMAQ does not include the capability to simulate the nitric acid attacking pre-existing PM, so this may be an artifact. What this suggests is that it is important to get model performance to the point where one is confident that the nitrate formation mechanisms are quantitatively reliable.

In areas where nitrate formation is nitric acid-limited, NO_x controls will generally reduce PM (with a few local exceptions). However, one ton of emissions reductions will not lead to one less ton of PM being formed. NO, NO_2 and nitric acid all deposit out (dry or wet). Indeed, nitric acid deposits very rapidly, and simulations suggest that most of the mass will be removed this way. The WRAP model can develop the response of nitrate PM to NOx emissions.

Trading emissions of primary FPM from one source to another would be relatively straightforward compared to other types of trades. The relative height of emission will have little impact on far downwind receptors. As with trading any type of emissions, trades across sources in very different locations may lead to one area receiving greater air quality benefits than another. Trading emissions of point source CPM would be especially sensitive to location in that the major impact is very near the source, dropping dramatically within 10 km.

NOx emissions trading to reduce PM formation would be more complex. First, as noted above, some (if not most) regions are likely ammonia-limited, so NOx controls will have relatively smaller impacts on nitrate than might be expected. Second, the oxidation of NOx to nitric acid will depend on emission height and the intensity of emissions (e.g., the concentration of NOx in a plume). Third, reducing NOx will slightly impact the formation of sulfate and OC. Further complicating the issue is that an equitable trade (in terms of visibility) today may not be equitable in the future. Again, trading across large spatial areas may lead to issues in terms of which areas benefit most.

Trading between pollutants is more involved yet, and a major concern is that the relationship between NOx emissions and nitrate formation is not well quantified at present. As model performance improves, there is no reason that it would not be practical to use the model to set trading relationships between pollutants. In so doing, one must account for the differing impact on visibility on a mass basis and the response to humidity.

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SECTION V:
SUMMARY OF AIR QUALITY MODELING RESULTS

Context

The modeling performed for this report is best described as a "sensitivity analysis." The intent is to get a preliminary assessment of the general atmospheric response to changes in NOx and PM emissions from stationary sources. A secondary objective is to "practice" this type of modeling to get a better understanding of the key technical issues and to identify the most effective ways at evaluating and displaying model results. The results presented here are the best available predictions at this time, but forthcoming improvements to the modeling system may affect the results in ways that alter the policy implications. For this reason, results are discussed in a fairly broad and qualitative manner – i.e., spatial patterns and relative changes. As the modeling system improves and specific strategies are contemplated, additional emission scenarios will be designed and modeled.

Modeling System

The WRAP's regional-scale air quality modeling system used to support other aspects of the Section 309 plans was also used to provide information for this report. A description of the modeling system – in addition to model performance statistics, input files, and detailed model results – is available at http://pah.cert.ucr.edu/rmc.

Emission Scenarios

Three emission scenarios were simulated:

- A 50 percent decrease in NOx emissions from plants with NOx emissions > 100 tpy,
- A 50 percent decrease in PM_{10} emissions from plants with PM_{10} emission > 100 tpy, and
- A 25 percent increase in NOx and PM_{10} emissions from all stationary sources.

The first two scenarios are meant to address the regional haze rule's requirement to "assesses emissions control strategies for stationary source NOx and PM, and the degree of visibility improvement that would result from such strategies." As discussed in Section VI of this report, many commercially-available technologies (and various combinations of such technologies) are capable of achieving a 50% or greater NOx emission reduction without having to switch fuels. Hence, the 50% reduction, although intended primarily to gauge the general atmospheric response to NOx reductions, is not an unreasonable level of control to assume for this exercise in terms of technical feasibility. Again with technical (and administrative) feasibility in mind, emission reductions were limited to plants with emissions greater than 100 tpy, similar to the approach in the Annex. The third scenario is meant to address the rule's requirement to "evaluate and discuss the need to establish emission milestones for NOx and PM to avoid any net increase in these pollutants from stationary sources within the transport region." Hence, a 25 percent increase from all stationary sources was assumed to simulate potential growth in the

economy and/or disproportionate growth in high-emitting sectors such as energy development, fossil-fueled electricity generation, and mineral processing.

For reasons implied in the rule, the emission changes in the scenarios described above were limited to the nine-state GCVTR[12]. Also, the emission changes were applied to the 2018 inventory, which includes reductions expected from full implementation of the Annex. This provides a basis for comparing results to other strategies being modeled by the WRAP.

Model Performance and Future Improvements

Nitrate concentrations are poorly predicted by the current modeling system, especially in the winter. For this reason, results for nitrate (and all other species) for the NOx and PM sensitivity runs are only presented for the three month period of July – September.

Several aspects of the modeling system are being improved and evaluated, which should improve confidence in future model predictions, both in the summer and winter. These improvements and evaluations involve the chemical mechanisms, the ammonia inventory, a more robust meteorological database (2002 vs 1996), enhanced grid resolution (12 km vs 36 km), plume-in-grid capabilities, the introduction of an inventory for wind-blown dust emissions, and better temporal allocation and chemical speciation of point and area source emissions. A source apportionment mechanism is also expected to be included with the model.

Model Results

As stated above, results are presented in a fairly broad and qualitative manner – i.e., spatial patterns and relative changes. Relative (percent) changes are of particular interest because their errors are believed to be smaller than those of the absolute concentrations. It is not clear how the seasonal limitation of this analysis (July – September) may affect the relative changes, but it is likely to reduce them to some extent. First, nitrate concentrations tend to be lower in the summer than in the winter, especially in areas where nitrate concentrations are highest and the potential for change the greatest. Second, results are averaged over a full three-month period. Typically, visibility effects are measured by averaging conditions over the worst 20 percent of the days observed per year at an ambient monitoring site, which is approximately 22 days. But in this analysis, because it is limited to the July-September timeframe, the results are averaged over 92 consecutive days and do not represent a measure of the worst conditions, again when the potential for change is the greatest. Thus, while there are many uncertainties surrounding the model's nitrate predictions, the limitation of this study to July – September will tend to limit the apparent impacts from the NOx (and to some extent) PM_{10} emission changes.

On a ton-per-ton basis, reductions in stationary source PM_{10} emissions appear to yield greater regional haze benefits than reductions in NOx emissions. For instance, when stationary source PM_{10} emissions are reduced by 98,000 tpy (a 50 percent reduction from GCVTR facilities > 100 tpy), the average summer-time visibility improvement across all Class I areas in the GCVTR (in Mm^{-1}) is about 0.4 percent. When stationary source NOx emissions are reduced by

[12] In 1996, stationary sources in the GCVTR emitted about 75 percent and 83 percent of the NOx and PM_{10} emissions, respectively, in the13-state WRAP region.

412,000 tpy (a 50 percent reduction from GCVTR facilities > 100 tpy), the visibility improvement is only somewhat greater, at 0.5 percent.[13] Hence, on a purely technical basis (without considering existing controls, costs, or other implementation issues), reductions in PM emissions might be more effective at improving regional haze than reductions in NOx emissions.

Nevertheless, the 50 percent NOx reduction scenario tends to produce slightly greater regional haze benefits than the 50 percent PM_{10} reduction scenario. This is because stationary sources comprise 33 percent of the total NOx inventory but only 7 percent of the total PM_{10} inventory. So even though much of the NOx is never converted to the particulate phase, the sheer volume of NOx emission reductions relative to PM_{10} reductions and the fact that nitrate (mostly in the fine mode) scatters light more efficiently than primary PM (mostly in the coarse mode) make the NOx reduction scenario more meaningful in terms of regional haze benefits than the PM_{10} reduction scenario. The fact that stationary source NOx emissions are not as well controlled as stationary source PM_{10} emissions in the West actually lends some relevance to the outcome that NOx emissions are altered more in the sensitivity analysis than PM_{10} emissions.

For the three-month summer period examined in this analysis, NOx changes have very little effect on aerosol concentrations beyond changes in nitrate. Other species that could be indirectly affected – e.g., ozone concentrations and subsequent oxidation of SO_2 and organic gases into the particulate phase – do not appear influenced by the levels of NOx reductions (16 percent of the total inventory) assumed in this analysis. This finding may change after implementing all the model improvements noted above, but since nitrate currently appears as the largest responder to NOx changes, and given the information above regarding the NOx and PM scenarios, the maps, tables, and discussion below place somewhat more emphasis on nitrate and the results of the 50 percent NOx reduction scenario than on other species and scenarios.

Figures V-1 and V-2 show the model-predicted 2018 base case (Annex included) surface-layer concentrations of ammonium nitrate (NH4NO3) and $PM_{10,}$ respectively, averaged over the three month period of July-September. The values in these maps should not be construed as the *expected* ammonium nitrate and PM_{10} concentrations in 2018, which are determined by scaling the ambient monitoring data by the relative changes predicted by the model. Rather, these maps are intended to provide a sense of the spatial variability and span of concentrations, which are useful for interpreting the following maps of relative (percent) changes – e.g., a high percentage change in a low-concentration area may be less meaningful than a moderate percentage change in a high concentration area.

Figures V-3 and V-4 show the absolute and percentage change, respectively, in NH4NO3 concentrations from a 50 percent reduction in stationary source NOx emissions from facilities in the GCVTR greater than 100 tpy. The largest absolute changes occur in southern CA, where concentrations in Class I areas are predicted to decrease by 0.15 to 0.25 ug/m^3. A second area of reductions is predicted in the central-east Rocky Mountains, especially in north-central CO. Although the reductions are not as large as in southern CA (0.04 to 0.11 ug/m^3), they are larger than average across the domain and exhibit the largest percentage reduction (10 to 20 percent).

[13] In some Class I areas, the visibility improvement can be two to five percent on some days.

It is interesting to compare these results with those simulating the effects of the SO_2 backstop emissions trading program, or Annex. In the case of the Annex, an SO_2 emission reduction of 15 percent (132,000 tons) in the GCVTR produced a sulfate reduction of 4 percent averaged across all Class I areas in the GCVTR on the 20% worst modeled days. In the case of the NOx sensitivity run, a NOx emission reduction of 15 percent (412,000 tons) in the GCVTR produced a nitrate reduction of 5 percent averaged across all Class I areas in the GCVTR on the July-September modeled days. The nitrate reduction does not produce as much visibility benefit at most Class I areas because its concentrations are much smaller, but the response of nitrate to NOx reductions is similar in proportion to the response of sulfate to SO_2 reductions.

Figures V-5 and V-6 show the absolute and percentage change, respectively, in NH4NO3 concentrations from a 25 percent increase in stationary source NOx and PM_{10} emissions from all stationary sources in the GCVTR. The spatial pattern of changes is very similar to that in the 50 percent NOx reduction scenario, although the magnitude of changes are about half. Again, it is interesting to see some proportionality in the modeling results – i.e., an emission change that is half as large produces aerosol changes that are about half as large. The percent increase in NH4NO3 concentrations and visibility impairment (in Mm^{-1}) in this scenario is 2 percent and 0.5 percent, respectively, when averaged over all Class I areas in the GCVTR for July-September.

Figures V-7 and V-8 show the absolute and percentage change, respectively, in PM_{10} concentrations from a 50 percent reduction in stationary source PM_{10} emissions from facilities in the GCVTR greater than 100 tpy. Maximum reductions in PM_{10} are about 0.1 to 0.5 ug/m^3, or about 4 to 8 percent. Compared to the NOx reduction scenario, reductions in ambient PM_{10} are more dispersed, with a greater number of local maximums. This may reflect the fact that there are a fewer number of large PM_{10} sources than large NOx sources and that much of the PM_{10} emissions are coarse particles, with shorter transport distances.

Figures V-9 and V-10 show the absolute and percentage change, respectively, in PM_{10} concentrations from a 25 percent increase in stationary source NOx and PM_{10} emissions from all stationary sources in the GCVTR. The spatial pattern of changes reflects where both relatively large NH4NO3 changes (southern CA and central-east Rockies) and PM_{10} changes (additional areas) are predicted. The largest PM_{10} increases are about 0.1 to 0.3 ug/m^3, or 2 to 3 percent. Less than half of this is NH4NO3.

Table V-1 shows the predicted change in light extinction and NH4NO3 at each Class I area in the GCVTR averaged over the July-September period as a result of reducing NOx emissions by 50 percent from stationary sources with emissions greater than 100 tpy in the GCVTR.[14] As shown in the maps, the greatest impacts occur in southern CA, followed by areas in CO. The average improvements in light extinction in these areas is about 0.3 to 1.5 Mm^{-1} (1 to 2.5 percent). The average improvement in NH4NO3 is about 0.05 to 0.25 ug/m^3 (3 to 20 percent).

[14] Tabular, site-specific data for other scenarios is available upon request. Tabulay presentation of results was limitted to this scenario since others tend to produce smaller changes in visibility.

Figure V-1. Base Case Ammonium Nitrate Concentrations (μg/m^3) – for purposes of illustrating spatial patterns, not magnitudes.

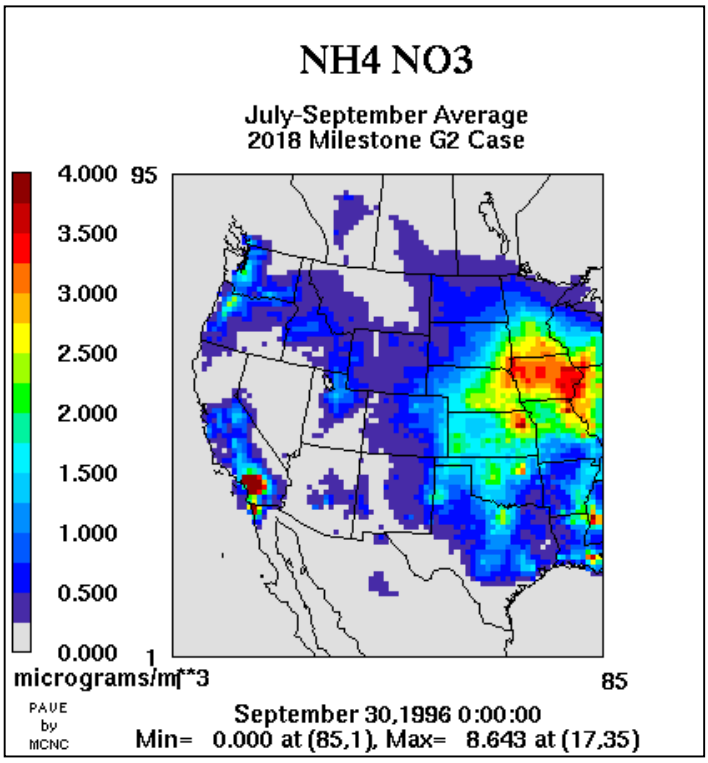

Figure V-2. Base Case PM_{10} Concentrations (μg/m^3) – for purposes of illustrating spatial patterns, not magnitudes.

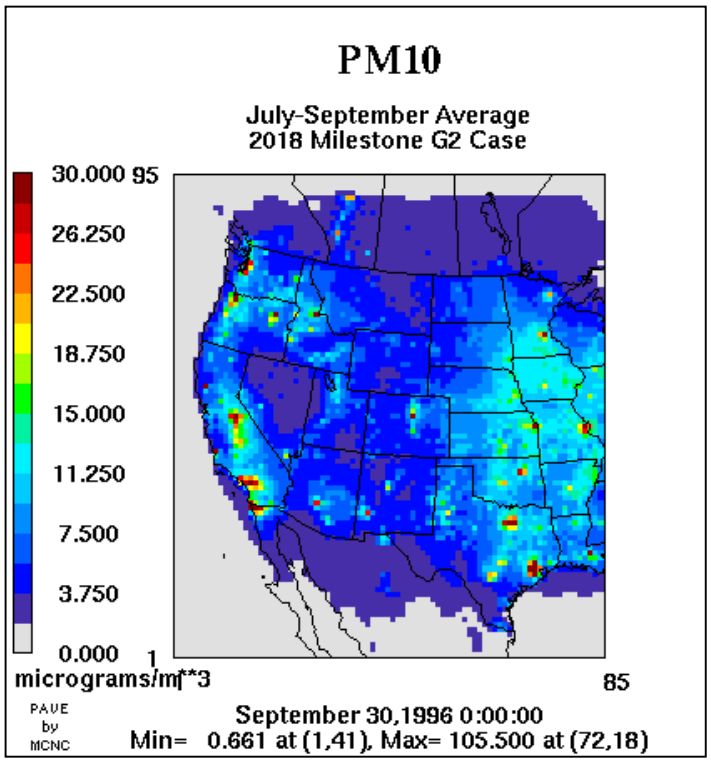

Figure V-3. Change in Ammonium Nitrate Concentrations Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy.

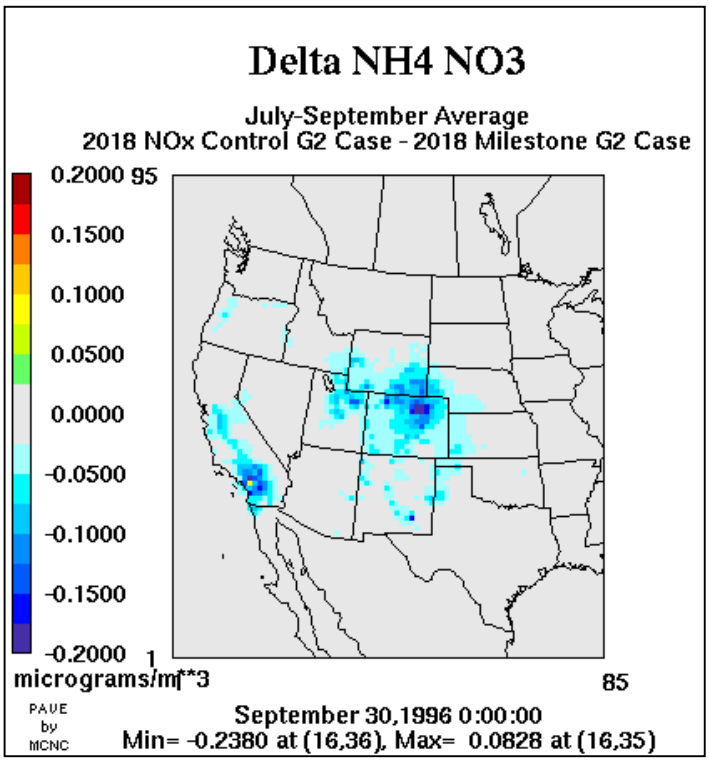

Figure V-4. Relative Change in Ammonium Nitrate Concentrations Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy.

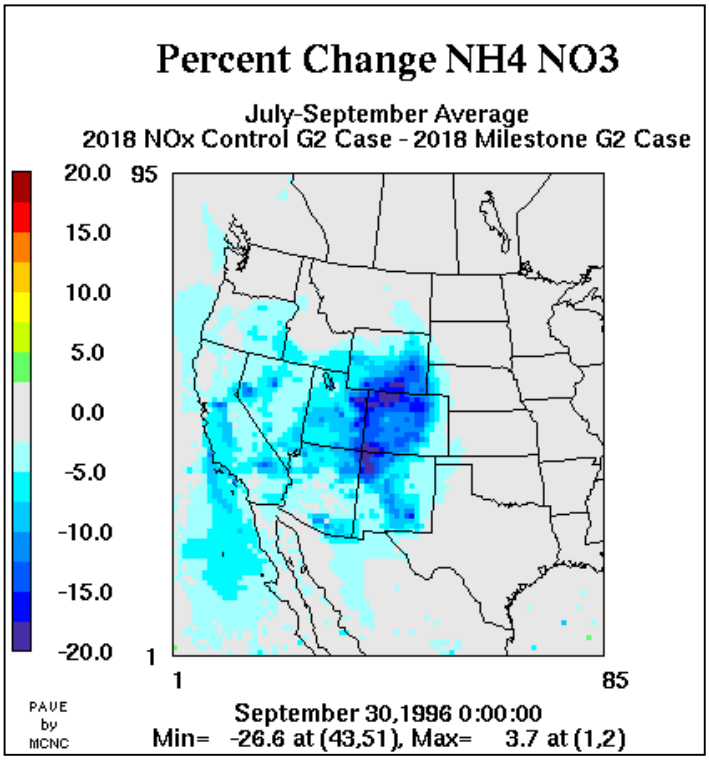

Figure V-5. Change in Ammonium Nitrate Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

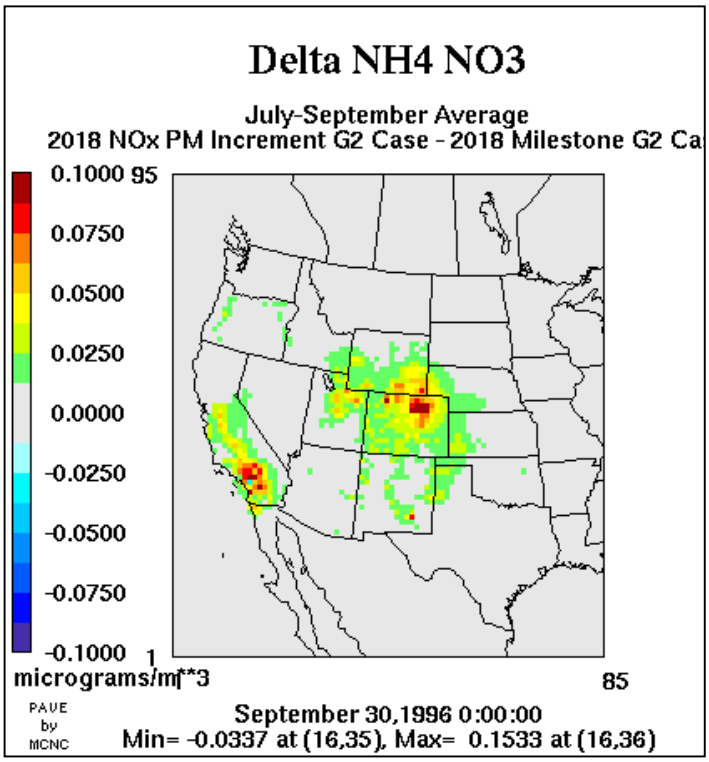

Figure V-6. Relative Change in Ammonium Nitrate Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

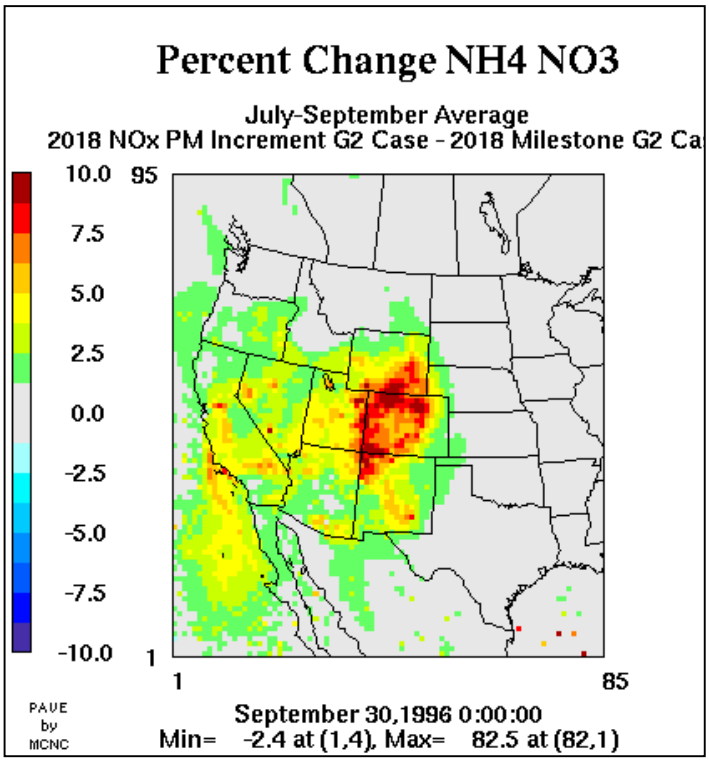

Figure V-7. Change in PM_{10} Concentrations Resulting from a 50% Reduction in Stationary Source PM_{10} Emissions > 100 tpy.

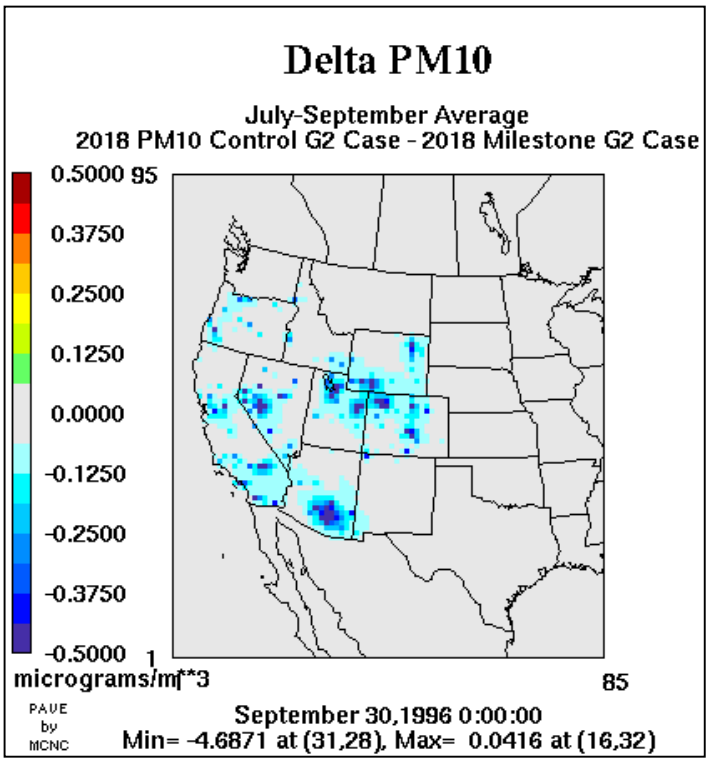

Figure V-8. Relative Change in PM_{10} Concentrations Resulting from a 50% Reduction in Stationary Source PM_{10} Emissions > 100 tpy.

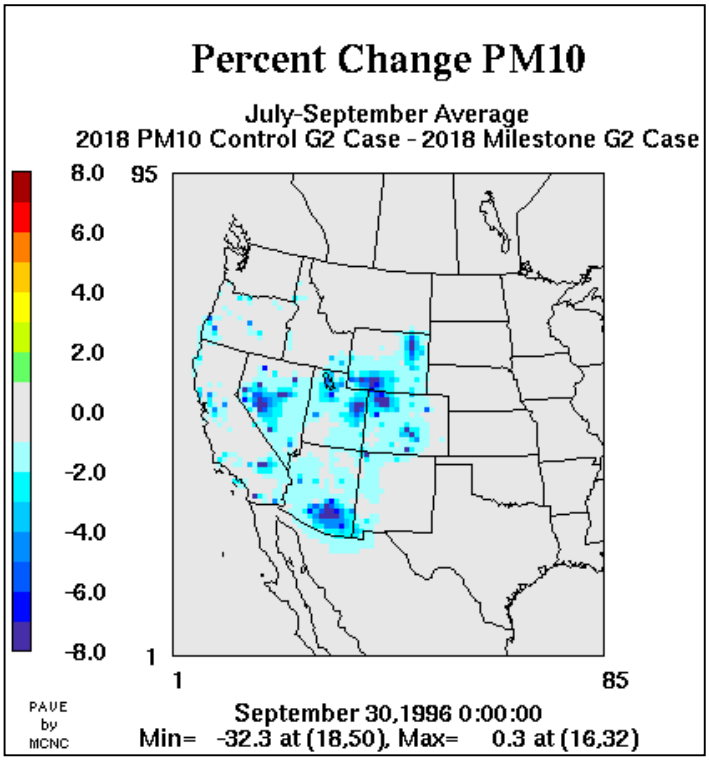

Figure V-9. Change in PM_{10} Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

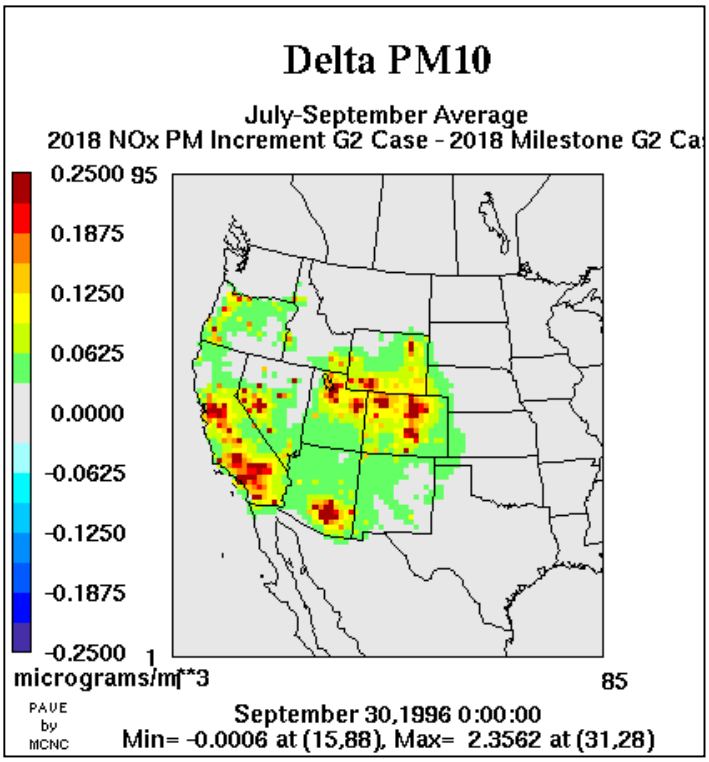

Figure V-10. Relative Change in PM_{10} Concentrations Resulting from a 25% Increase in Stationary Source NOx and PM_{10} Emissions.

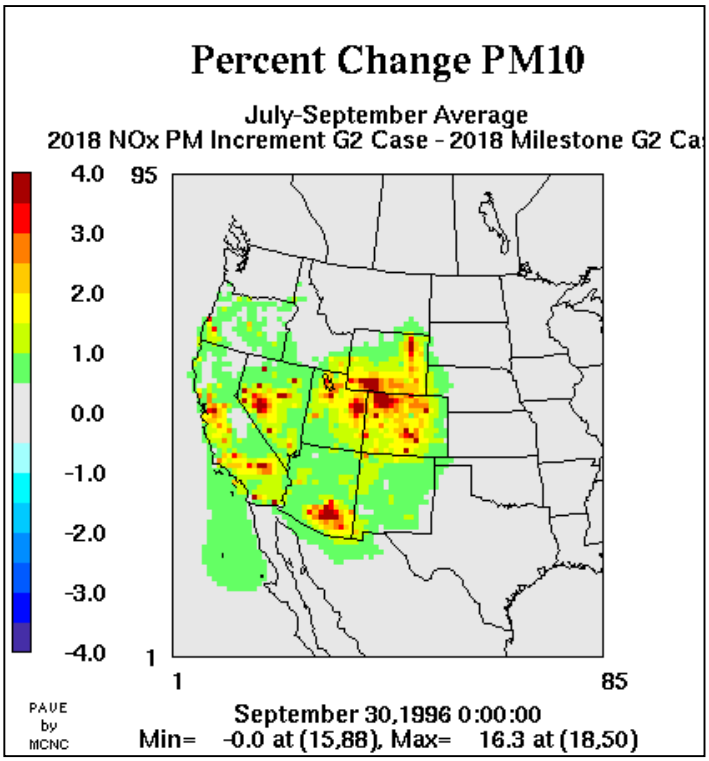

Table V-1. Light Extinction and Ammonium Nitrate Changes Resulting from a 50% Reduction in Stationary Source NOx Emissions > 100 tpy, Sorted by Average Light Extinction.

		Light Extinction		NH4NO3	
State	GCVTR Class I Area	Δ Mm^{-1}	Δ %	Δ $\mu g/m^3$	Δ %
CA	Cucamonga Wilderness	-1.59	-1.37	-0.25	-3.25
CA	San Jacinto Wilderness	-1.13	-1.18	-0.19	-2.97
CA	San Gabriel Wilderness	-0.83	-0.82	-0.13	-3.06
CA	Agua Tibia Wilderness	-0.81	-1.05	-0.12	-2.77
CA	San Gorgonio Wilderness	-0.80	-0.93	-0.16	-2.65
CO	Rawah Wilderness	-0.69	-2.41	-0.11	-16.84
CO	Mount Zirkel Wilderness	-0.61	-2.28	-0.09	-20.86
CO	Rocky Mountain NP	-0.57	-1.68	-0.09	-14.14
CA	Joshua Tree NP	-0.47	-0.77	-0.13	-3.69
CO	Eagles Nest Wilderness	-0.45	-1.41	-0.07	-11.97
CO	Great Sand Dunes NM	-0.43	-1.57	-0.06	-13.87
NM	White Mountain Wild.	-0.36	-1.11	-0.05	-10.51
CO	Flat Tops Wilderness	-0.34	-1.28	-0.05	-13.82
CO	La Garita Wilderness	-0.34	-1.27	-0.05	-12.15
CO	West Elk Wilderness	-0.33	-1.19	-0.05	-12.09
CO	Black Canyon of Gunnison	-0.31	-0.97	-0.04	-14.83
CO	Weminuche Wilderness	-0.29	-1.14	-0.04	-13.02
CO	Maroon Bells-Snowmass	-0.29	-1.00	-0.04	-10.62
CA	Dome Land Wilderness	-0.27	-0.46	-0.04	-4.48
CA	Pinnacles NM	-0.26	-0.86	-0.04	-5.93
NM	Wheeler Peak Wilderness	-0.24	-0.91	-0.03	-8.94
AZ	Mount Baldy Wilderness	-0.22	-0.64	-0.03	-6.25
NM	Salt Creek Wilderness	-0.22	-0.71	-0.02	-7.75
AZ	Petrified Forest NP	-0.21	-0.73	-0.01	-6.88
WY	Bridger Wilderness	-0.20	-0.77	-0.03	-7.51
CA	Hoover Wilderness	-0.20	-0.19	-0.04	-2.60
CA	Emigrant Wilderness	-0.19	-0.25	-0.03	-3.08
NM	Gila Wilderness	-0.18	-0.34	-0.02	-3.81
CA	Minarets	-0.18	-0.23	-0.03	-2.71
OR	Mount Jefferson Wild.	-0.17	-0.28	-0.02	-2.59
NM	San Pedro Parks Wild.	-0.17	-0.64	-0.02	-10.43
NM	Bandelier NM	-0.17	-0.58	-0.02	-7.42
AZ	Superstition Wilderness	-0.16	-0.40	-0.02	-2.04
OR	Mount Washington Wild.	-0.16	-0.30	-0.02	-2.55
OR	Mount Hood Wilderness	-0.14	-0.22	-0.03	-1.83
CA	Kaiser Wilderness	-0.14	-0.19	-0.02	-2.63
CA	Kings Canyon NP	-0.14	-0.22	-0.02	-2.83
CA	John Muir Wilderness	-0.14	-0.23	-0.02	-2.69
CA	San Rafael Wilderness	-0.14	-0.32	-0.01	-5.40
AZ	Sierra Ancha Wilderness	-0.13	-0.35	-0.01	-1.76
CA	Sequoia NP	-0.13	-0.24	-0.02	-4.56
CA	Yosemite NP	-0.13	-0.17	-0.02	-2.63
UT	Arches NP	-0.13	-0.51	-0.01	-14.82

		Light Extinction		NH4NO3	
State	GCVTR Class I Area	Δ Mm^{-1}	Δ %	Δ $\mu g/m^3$	Δ %
NM	Pecos Wilderness	-0.12	-0.44	-0.03	-7.29
WY	Fitzpatrick Wilderness	-0.12	-0.46	-0.02	-4.83
NM	Bosque del Apache Wild.	-0.12	-0.44	-0.01	-8.65
OR	Kalmiopsis Wilderness	-0.11	-0.34	-0.01	-3.05
OR	Eagle Cap Wilderness	-0.11	-0.31	-0.02	-4.29
OR	Three Sisters Wilderness	-0.11	-0.24	-0.02	-2.55
AZ	Grand Canyon NP	-0.11	-0.40	-0.01	-7.36
UT	Capitol Reef NP	-0.11	-0.45	-0.01	-8.21
WY	Grand Teton NP	-0.11	-0.36	-0.02	-3.47
WY	Teton Wilderness	-0.10	-0.36	-0.02	-3.56
OR	Crater Lake NP	-0.10	-0.21	-0.01	-2.09
ID	Hells Canyon Wilderness	-0.10	-0.13	-0.02	-3.87
OR	Strawberry Mountain Wild.	-0.10	-0.15	-0.01	-2.89
AZ	Sycamore Canyon Wild.	-0.10	-0.32	-0.01	-5.25
CA	Marble Mountain Wild.	-0.10	-0.23	-0.01	-2.57
AZ	Chiricahua NM	-0.10	-0.36	0.00	-6.65
AZ	Chiricahua Wilderness	-0.10	-0.36	0.00	-6.65
AZ	Galiuro Wilderness	-0.10	-0.30	-0.01	-4.30
UT	Canyonlands NP	-0.09	-0.42	-0.01	-10.61
OR	Diamond Peak Wild.	-0.09	-0.18	-0.01	-2.20
AZ	Saguaro Wilderness	-0.09	-0.28	-0.01	-6.84
UT	Bryce Canyon NP	-0.08	-0.32	-0.01	-6.14
AZ	Pine Mountain Wild.	-0.08	-0.24	-0.01	-2.82
AZ	Mazatzal Wilderness	-0.08	-0.23	-0.01	-2.82
NM	Carlsbad Caverns NP	-0.08	-0.26	-0.01	-4.03
OR	Mountain Lakes Wild.	-0.07	-0.18	-0.01	-2.43
UT	Zion NP	-0.07	-0.21	-0.01	-7.22
CO	Mesa Verde NP	-0.07	-0.21	-0.03	-17.68
CA	Lava Beds Wilderness	-0.06	-0.15	-0.01	-2.09
WY	Yellowstone NP	-0.06	-0.20	-0.01	-2.50
CA	South Warner Wilderness	-0.06	-0.19	-0.01	-3.77
ID	Selway-Bitterroot Wild.	-0.05	-0.12	-0.01	-2.19
WY	North Absaroka Wild.	-0.05	-0.19	-0.01	-2.43
WY	Washakie Wilderness	-0.05	-0.19	-0.01	-2.43
CA	Point Reyes NS	-0.05	-0.15	0.00	-2.80
ID	Craters of The Moon Wild.	-0.04	-0.14	-0.01	-3.89
OR	Gearhart Mountain Wild.	-0.04	-0.13	0.00	-2.24
CA	Caribou Wilderness	-0.04	-0.11	0.00	-3.38
CA	Thousand Lakes Wild.	-0.03	-0.09	0.00	-2.30
CA	Lassen Volcanic NP	-0.03	-0.07	0.00	-2.28
CA	Yolla Bolly Middle Eel Wild.	-0.03	-0.09	0.00	-1.13
NV	Jarbridge Wilderness	-0.03	-0.13	0.00	-4.49
CA	Ventana Wilderness	-0.02	-0.12	0.00	-5.24
CA	Redwood NP	-0.02	-0.06	0.00	-2.92
	Average	-0.21	-0.51	-0.03	-5.79

SECTION VI:
SUMMARY OF EMISSION CONTROLS AVAILABLE FOR LARGE STATIONARY SOURCES OF NOx AND PM

Final Report

Prepared for:

Lee Alter
Western Governors' Association
1515 Cleveland Place, Suite 200
Denver, CO 80202-5114

Prepared by:

Constance Senior, Brooke Shiley, Bradley Adams
Reaction Engineering International
77 West 200 South, Suite 210
Salt Lake City, UT 84101

Rui Afonso
Energy & Environmental Strategies
50 Old Faith Road
Shrewsbury, MA 01545

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LIST OF ACRONYMS, ABBREVIATIONS AND SYMBOLS

ACFM	Actual cubic feet per minute
AFBC	Atmospheric fluidized bed combustor
BART	Best available retrofit technology
DLN	Dry Low NO_x
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
GCVTC	Grand Canyon Visibility Transport Commission
GCVTR	Grand Canyon Visibility Transport Region
FGR	Flue Gas Recirculation
Hg	Mercury
ICE	Internal Combustion Engine
LEC	Low Emission Combustion
LNB	Low-NO_x burner
MBtu	Millions of British Thermal Units
MTF	Market Trading Forum
NG	Natural Gas
NO_x	Nitrogen oxides
NSCR	Non-selective catalytic reduction
NSPS	New Source Performance Standard
O&M	Operating and Maintenance
OFA	Overfire air
PM	Particulate matter
PM10	Particulate matter less than 10 microns
PM2.5	Particulate matter less than 2.5 microns
SCC	Source Classification Code
SCR	Selective catalytic reduction
SIP	State Implementation Plan
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership

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We are grateful to Dr. Praveen Amar for providing help in locating the most recent sources of information on control technologies, as well as for external review of the report from the perspective of making it relevant to readership in the state governments/regional entities.

1 INTRODUCTION

1.1 Background

The Western Regional Air Partnership (WRAP) has undertaken a program to assess emissions control technologies and strategies for large stationary sources of NO_x and PM emissions in the western states region. The WRAP is a collaborative effort of tribal governments, state governments, and various federal agencies to implement the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC) and to develop the technical and policy tools needed by western states and tribes to comply with the U.S. Environmental Protection Agency's (EPA) Regional Haze Rule.

The WRAP established the Market Trading Forum (MTF), in large part, to develop and recommend emission control strategies for stationary sources of air pollution. A major focus of the MTF has been the establishment of regional emission milestones for sulfur dioxide (SO_2) and a regional backstop cap-and-trade program for SO_2 to be triggered if the milestones are not met voluntarily.

The MTF is also responsible for generating a report required in 40 CFR 51.309(d)(4)(v) of the Regional Haze Rule. The report must assess emission control technologies and strategies for stationary source NO_x and PM emissions and the degree of visibility impairment that would result from such strategies. It must also evaluate the need for NO_x and PM milestones to avoid any net emissions increase and to support possible multi-pollutant and multi-source control programs. Finally, this year several states must submit state implementation plans (SIPs) to EPA and must commit to a 2008 revision containing any necessary long-term strategies and Best Available Retrofit Technology (BART) requirements for stationary source NO_x and PM.

This project is essentially a starting point for addressing stationary source NO_x and PM emission sources over the next four years, at which point local and/or regional emission control program(s) may be implemented. Future work by the WRAP will investigate these issues further and will attempt more detailed cost estimates and emission reductions achievable in the WRAP region given the nature of its sources and existing controls.

1.2 Objectives

The main objectives of this project are to identify and briefly describe for large stationary sources in the western United States:

- The universe of modern commercially-available or near-available stationary source NO_x and PM controls (either technologies or best management practices);
- Trends in such controls;
- Their approximate capital and operating costs, control efficiencies, and cost effectiveness;
- Secondary environmental impacts, such as control of other air pollutants and generation of solid or hazardous waste;
- Real-world experience at facilities implementing or testing such controls;

- Future opportunities for improvements and demonstrations; and
- Recommendations for future work.

1.3 Definitions and Methodology

The work plan for the project consisted of the following tasks:

Task 1. Inventory of Stationary Sources in the WRAP Region. This task involved a review of the 1996 WRAP stationary source emissions inventory (version 3, in MS Access format), as well as other recent and relevant databases to determine the number/type of stationary sources with emissions greater than 100 tons per year (TPY) and the type and performance of air pollution control devices installed on those sources. Two subsets were created for NO_x and PM emissions, respectively, based on the following criteria:

- Sources (defined as emission units, or records, in the database) having annual emissions of the pollutant of interest greater than 100 TPY; and
- Sources located in the thirteen-state region: AZ, CA, CO, ID, MT, ND, NM, NV, OR, SD, UT, WA, WY (See Figure 1).

Table 1 lists the fields extracted from the WRAP database.

Figure 1. Thirteen-state region considered in the technology assessment.

Table 1. WRAP database fields used in the technology assessment.

Field	Description
FIPST	FIP State Code
POINTID	NAPAP Point ID Code
STACKID	Stack Number
BLRID	Boiler ID Code Code (utility only)
SEGMENT	Segment Number
ORISID	ORIS Plant ID (utility only)
PLANT	Plant Name
SCC	Source Classification Code
SCC1_DESC	General category (e.g., External Combustion Boiler)
SCC3_DESC	Major industrial group within general category
SCC6_DESC	Specific industry or emission source
SCC8_DESC	Particular emitting process or fuel type
NOX_ANN	Annual NO_x Emissions, tons per year
PM10_ANN	Annual PM Emissions, tons per year
CO_ANN	Annual CO Emissions, tons per year
SO2_ANN	Annual SO_2 Emissions, tons per year
NOX_CPRI	Primary Control Equipment Code - NO_x
PM_CPRI	Primary Control Equipment Code - PM
CONTROL_DEVICE_DESC	Control Device Description (either NO_x or PM)

Note: Codes taken from the 1996 National Emission Trends (NET) PC Inventory File Format

The source classification codes (SCCs) used to categorize sources served as general guidelines for choosing the categories in Task 1. The similarities (or differences) in the control technologies applicable to specific SCCs were also factors in grouping sources. For example, a category called "Coal-fired boilers" was created containing emissions data from utility and industrial boilers (of different boiler types) burning coal because the same NO_x and PM control technologies can be applied to most of these sources. With this in mind, Table 2 gives the categories created for characterization of the WRAP emissions and a description of the WRAP categories (i.e., SCC codes) used to define the categories in this report.

For electric utility point sources, additional databases were used to determine boiler capacity (MBtu/yr), enhance and update information on control technologies in place, and verify other source information. These databases were: EPA CEMs database for 1996 and 2001 [1], EPA E-GRID database for 1996 and 2000 [2] and the EIA-767 database for 1996 [3].

The results of Task 1 are discussed in Section 2 of this report.

Table 2. List of Categories Used to Characterize Point Sources

Category	**WRAP Sources (based on SCC Codes contained with the category)**
Coal-Fired Boilers	All coal-fired external combustion boilers
Reciprocating Engines *NG* *Diesel* *Process Gas*	All reciprocating ICE's *Natural gas-fired ICE's, including 2- and 4-cycle* *Diesel-fired ICE's, including large-bore engines* *Unspecified process gas-fired ICE's*
Cement Kilns	All cement kilns (wet and dry process)
Oil/NG Boilers	External combustion boilers firing oil or natural gas
Turbines *NG* *Diesel*	All fired turbines *Natural gas-fired turbines* *Diesel-fired turbines*
Mineral Processing	Cement crushing, grinding and drying, asphalt, other drying applications
Petrochemical	Flares, cat.crackers, nitric acid plants, unspecified process gas operations, *does not include process heaters*
NG Compressor	Technology (reciprocating engine or turbine) not specified
Pulp and Paper	Recovery boilers, lime kilns, drying and smelting
Wood Boilers	Wood waste and/or bark boilers, technology unspecified
Refinery Process Heaters	Process heaters
Glass Manufacture	Glass melting furnaces
Primary Metal Production	Electric arc furnaces, reheat furnaces, material handling and unspecified
Waste Combustion	Liquid waste (Dakota gasifier) and solid waste (WTE)
Refinery	Unspecified refinery emissions
In-process Fuel Use	Unspecified combustion systems at glass and cement plants
Jet Engine Testing	Jet engine testing
Oil and Gas Production	Flares and unspecified processes
Smelting Operations	Copper and aluminum smelting
Sugar Beet Processing	Sugar beet processing
Secondary Metal Production	Steel foundries
Turbines, Steam	Geothermal power production

Task 2. Survey and Documentation of Emission Control Technologies. In this task, we focused on the identification and compilation of control technologies for NO_x and PM (main focus) and for SO_2 and Hg (secondary focus). Sources identified in Task 1 that represented minor contributions to the emissions profile of the region, either due to their small number, uniqueness, or size, were considered in a more cursory fashion if their control technology options fell outside of the range of the more common/available technologies. This effort consisted mainly of literature reviews, on-line searches and personal (telephone) contacts and interviews.

The following information was collected on each technology or process:

- Type and fundamentals of technology or process;
- Projected performance;
- Costs (capital and O&M or cost effectiveness in $/ton of pollutant removed) or cost projections;
- Status of development and opportunities for or barriers to further development; and
- Applicability to category (or categories) of WRAP sources identified in Task 1.

The results of this task are presented in Sections 3 and 4.

Task 3. Control Technology Analysis and Discussion. This task was the main focus of the project, in which a thorough evaluation and discussion of the many identified technologies was conducted. A summary containing the following information was created for each technology:

- Process name
- For each source category to which the technology was applicable, the following information was tabulated:
    - Total annual NO_x or PM emissions from sources greater than 100 TPY
    - Percentage NO_x and PM reduction
    - Cost ($/ton or $/ACFM)
    - Development status
- Detailed descriptions were prepared for the following:
    - Process description
    - Achievable NO_x or PM reduction
    - Cost information
    - Development status
    - Practical considerations
    - Compatibility with other air pollution control technologies
    - Secondary environmental impacts
- References

The results of this task are presented in Appendices C and D.

Task 4. Final Report. The draft version of the final report was submitted to WRAP on 25 April 2003. The final report was submitted on 30 June 2003.

2 NO_x AND PM SOURCES IN THE WESTERN UNITED STATES

2.1 Characterization of NO_x Sources

Table 3 gives the annual NO_x emissions in the GCVTR as well as in thirteen-state region for sources (defined as emission units, or records, in the WRAP database) exceeding 100 TPY. The cut-off of 100 TPY captures 84% of the stationary source NO_x emissions in the WRAP database for the thirteen-state region. Figure 2 shows the distribution of annual NO_x emissions (greater than 100 TPY) as a function of state.

The largest source category by far in the thirteen-state region is coal-fired boilers (69%); the top five categories (coal-fired boilers, internal combustion engines, cement kilns, turbines and oil and natural gas boilers) account for almost 90% of the NO_x emissions. Therefore, this report concentrates on control technologies applicable to these major process categories.

The states with the largest NO_x emissions are AZ, CA, ND, NM, UT, and WY. Since all these states except ND are in the GCVTR, it is not surprising that emissions from the nine states in the GCVTR (AZ, CA, CO, ID, NM, NV, OR, UT, WY) account for 75% of the thirteen-state emissions greater than 100 TPY. Appendix A contains NO_x emissions by process category and by state.

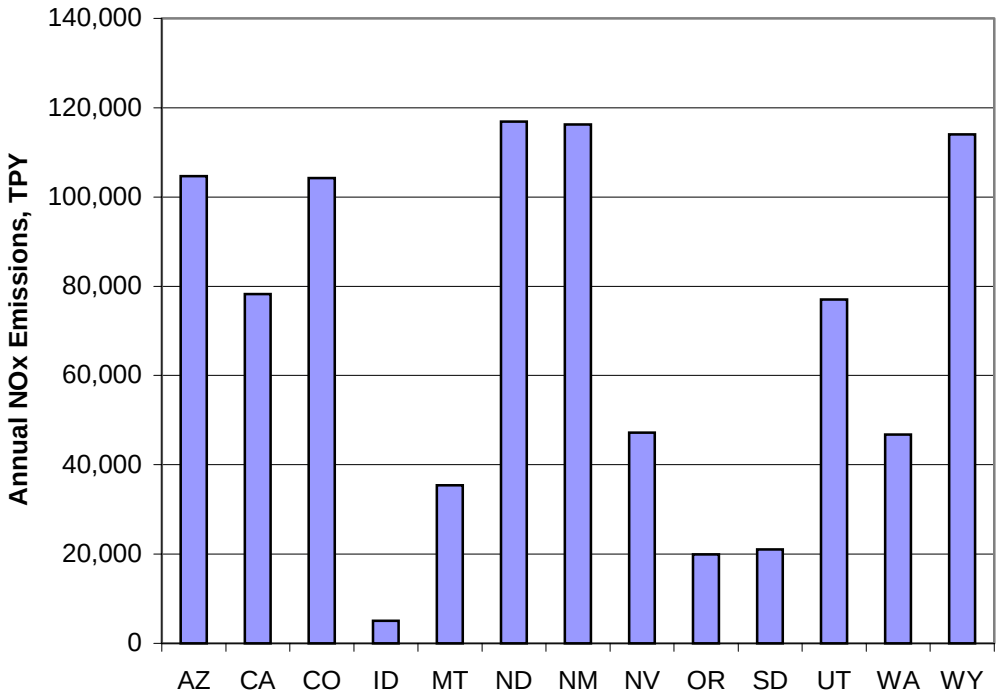

Figure 2. Annual NO_x emissions from sources with emissions greater than 100 TPY for the thirteen-state region.

Table 3. A comparison of annual emissions of NO_x from sources with emissions greater than 100 TPY between the thirteen-state region and the GCVTR.

Category	13-States		GCVTR		
	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	% NO_x in GCVTR
Coal-Fired Boilers	151	607,748	117	436,882	72%
Reciprocating Engines	423	86,210	394	78,092	91%
Cement Kilns	39	41,009	31	32,503	79%
Oil/NG Boilers	112	32,910	80	26,116	79%
Turbines	86	25,278	78	23,955	95%
Mineral Processing, Other	34	16,250	25	13,342	82%
Petrochemical	48	13,719	31	8,326	61%
NG Compressor	16	10,959	16	10,959	100%
Pulp and Paper	39	10,010	20	4,619	46%
Wood Boilers	48	9,776	36	6,864	70%
Refinery Process Heaters	38	9,311	29	7,302	78%
Glass Manufacture	14	5,033	12	4,379	87%
Primary Metal Production	17	3,476	16	3,360	97%
Waste Combustion	6	3,309	2	339	10%
Fugitive	8	3,256	8	3,256	100%
In-process Fuel Use	9	2,605	8	2,016	77%
Fixed Wing Aircraft	4	2,297	4	2,297	100%
Oil and Gas Production	7	1,140	5	792	70%
Smelting Operations	3	961	2	852	89%
Food and Agriculture	3	730	1	111	15%
Secondary Metal Production	4	507	0	0	0%
Turbines, Steam	1	165	1	165	100%
Total (> 100 TPY)	**1,110**	**886,659**	**916**	**666,527**	**75%**

With few exceptions, the distribution of NO_x sources is similar in the thirteen-state region as compared to the GCVTR. ICE's (reciprocating engines and turbine) are predominantly in the GCVTR, while pulp and paper emissions are mostly outside the GCVTR. As a result of this similarity, the scope of this project was expanded to include additional WRAP states at minimal cost.

The achievable NO_x emission rate depends on the fuel type. For coal-fired boilers, lower NO_x emission rates are obtained when firing subbituminous coal as compared to bituminous coal. Thus, it is useful to look at the distribution of coals in use in the thirteen-state region. Figure 3 shows the distribution of coals burned in utility boilers as a function of boiler type and coal rank. Most coal burned in the West is burned close to the mine; this distribution of coal rank reflects the native coals in the West.

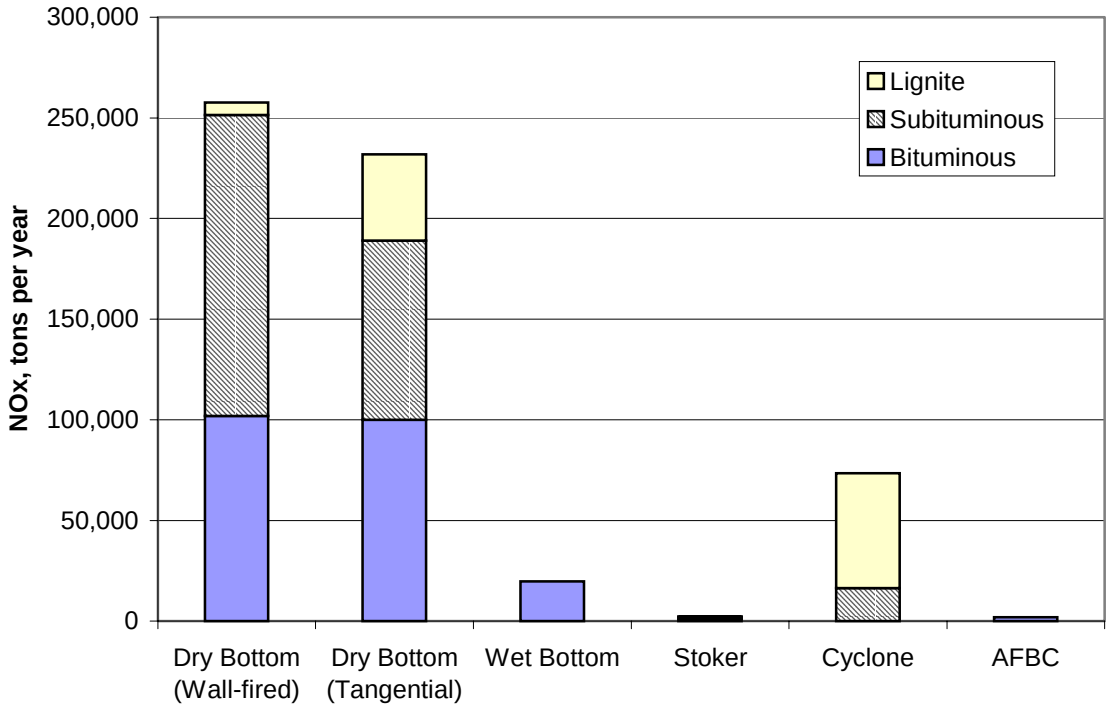

Figure 3. NO_x emissions from coal-fired utility boilers as a function of boiler type and coal rank for thirteen-state region from WRAP 1996 database.

For ICE's, the application of NO_x control technology can depend on the type of fuel. More so than with utility boilers, the design and operation of the engine is often determined by the primary fuel. Most of the stationary ICE's with annual emissions greater than 100 TPY burn natural gas, as shown in Figure 4.

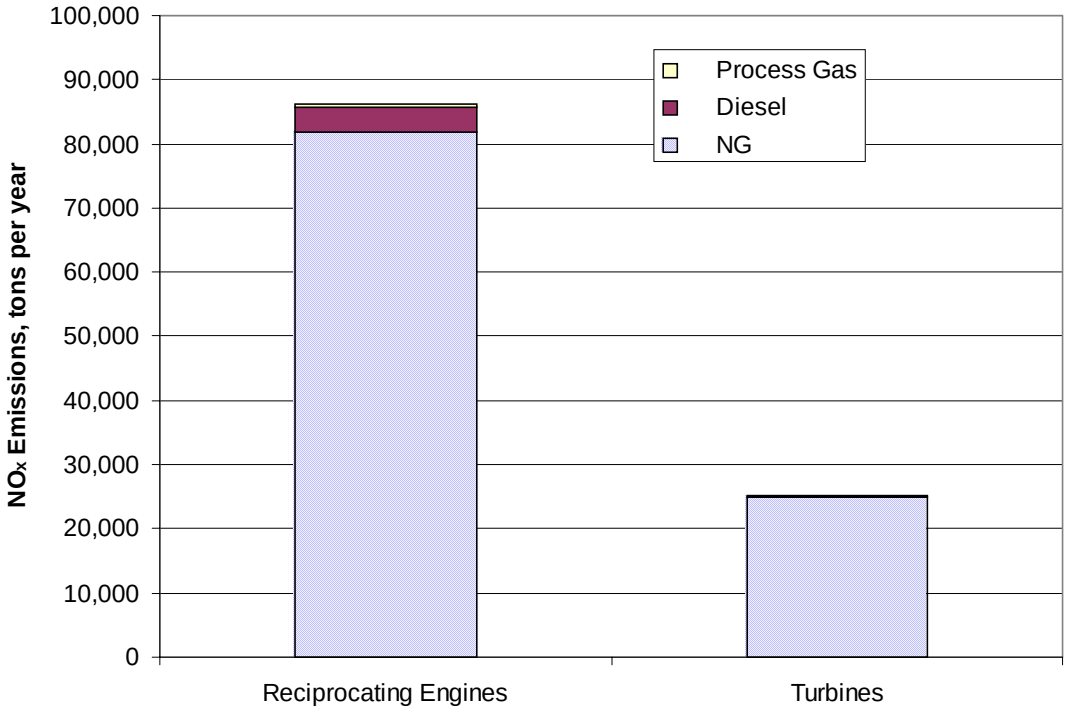

Figure 4. NO_x emissions from Internal Combustion Engines as a function of engine type and fuel for thirteen-state region from WRAP 1996 database.

As long as a source category consists of primarily large sources, the cut-off of 100 TPY will include most of the NO_x emission sources. The 100-TPY cut-off captures 84% of the NO_x emissions in the WRAP database as a whole. However, certain source categories contain a very large number of small sources. For ICE's (reciprocating engines and turbines) the 100-TPY cut-off only captures about 56% of the emissions as shown in Figures 5 and 6, although this is by far the second largest source category of stationary source NO_x emissions. Thus, NO_x control programs for sources in this category will require careful consideration of population attributes (e.g., controlling a large number of small sources).

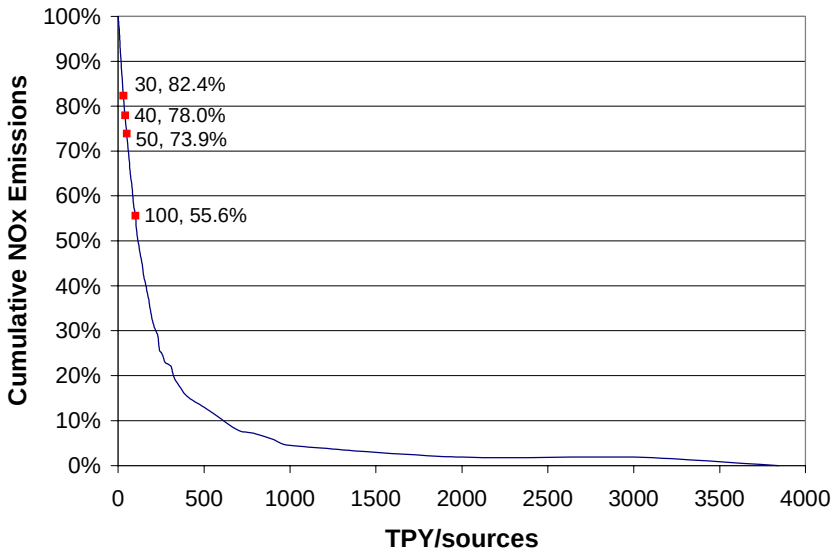

Figure 5. Cumulative NO_x emissions from ICE's in the thirteen-state region as a function of annual emission per source.

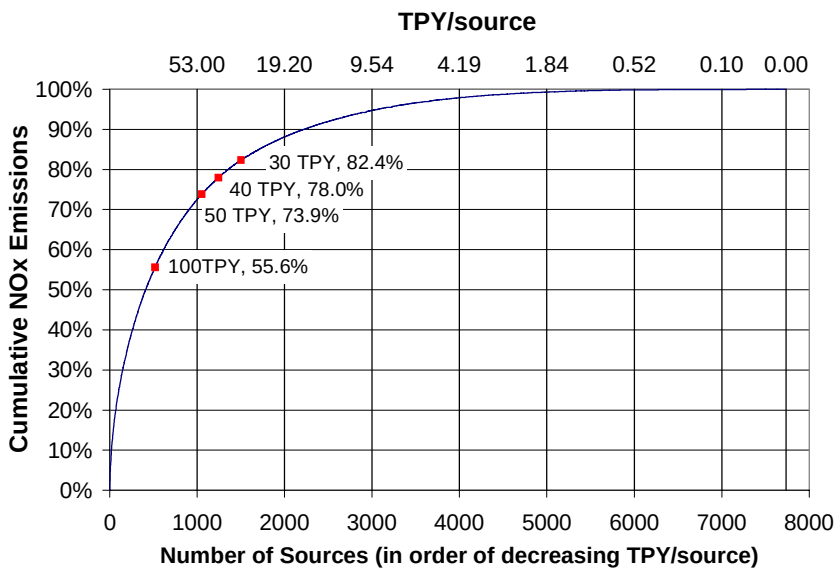

Figure 6. Cumulative NO_x emissions from ICE's in the thirteen-state region as a function of number of sources (in order of decreasing annual emission per source.)

The 1996 WRAP database contains information on control technologies for the pollutants of interest. According to the 1996 data for sources greater than 100 TPY, few sources had NO_x controls, as shown in Table 4. Overall, just above 4% of the NO_x sources greater than 100 TPY in the WRAP 1996 database had installed controls. Coal-fired boilers were the most frequently controlled (15% of the units), followed by petrochemical processes (about 13% of the units). Note that control technologies listed in the right-hand column are as reported in the WRAP database. In a few cases, the description of the control technology does not seem correct (e.g., fabric filter or electrostatic precipitator) for NO_x control; this is a limitation of the data available and it is outside the scope of this program to determine the accuracy of the data in the WRAP database.

Table 4. NO_x Control Technologies in use in 1996 on Sources Greater than 100 TPY from 1996 WRAP database.

Category	**# Units**	**Units Controlled**	**Total NO_x TPY**	**Avg NO_x TPY/Unit**	**NO_x Control Technology** (number of applications in parentheses)
Coal-Fired Boilers	151	23	607,748	4,025	Ammonia Injection(2), Fluid Bed Dry Scrubber(1), Low Excess Air Firing(3) , Modified Furnace Or Burner Design(13), Misc.(4)
Reciprocating Engines	423	3	86,210	204	Catalytic Reduction(1), Process Change(2)
Cement Kilns	39	2	41,009	1,052	Electrostatic Precipitator – High Efficiency(2)
Oil/NG Boilers	112	4	32,910	294	Low Excess Air Firing(3), SNCR(1)
Turbines	86	5	25,278	294	Steam Or Water Injection(5)
Mineral Processing	34	1	16,250	478	Fabric Filter - High Temperature, i.e. T>250F(1)
Petrochemical	48	6	13,719	286	Catalytic Afterburner(1), Catalytic Afterburner With Heat Exchanger(1), Catalytic Reduction(1), Staged Combustion(2), Tray-Type Gas Absorption Column(1)
NG Compressor	16	0	10,959	685	None
Pulp and Paper	39	0	10,010	257	None
Wood Boilers	48	1	9,776	204	Ammonia Injection(1)
Refinery Process Heaters	38	0	9,311	245	None
Glass Manufacture	14	0	5,033	360	None
Primary Metal Production	17	1	3,476	204	Process Enclosed(1)
Waste Combustion	6	0	3,309	552	None
Refinery	8	0	3,256	407	None
In-process Fuel Use	9	0	2,605	289	None
Jet Engine Testing	4	0	2,297	574	None
Oil and Gas Production	7	0	1,140	163	None
Smelting Operations	3	0	961	320	None
Sugar Beet Processing	3	0	730	243	None
Secondary Metal	4	0	507	127	None
Turbines, Steam	1	0	165	165	None
Total	**1,110**	**46**	**886,660**	**799**	

2.2 Comparison with Other Databases for NO_x Control Technologies

The level of control for coal-fired boilers in the WRAP database seemed low, even for 1996. Therefore, the 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for NO_x control technologies. The E-GRID database should contain the information in the other two databases since it contains data from 24 different federal data sources, including EIA data and other EPA data. Only coal-fired utility boilers were included in this comparison, not all coal-fired boilers. However, only 3% of the WRAP NO_x emissions from coal-fired boilers in the thirteen-state region were from non-utility boilers.

It is worthwhile to take a closer look at utility boilers for two reasons. First, they are by far the largest source of NO_x emissions, accounting for 68% of the emissions from sources greater than 100 TPY. Second, the effectiveness of NO_x control technologies on boilers depends on the type of the boiler as well as on the fuel burned.

For this exercise, the EPA databases (CEMs and E-GRID) were queried to obtain information on capacity (MBtu per year) and control technologies. Data from 1996 was used in order to compare with the WRAP 1996 database. EPA and WRAP records were matched using ORIS Plant ID numbers and plant names. For matching records, control technologies not listed in the WRAP database were added, capacity (MBtu) entries were added, and NO_x emissions were replaced from the EPA databases.

A comparison of Tables 5 and 6, which contain, respectively, the WRAP data and the WRAP data augmented by the other databases, shows that the combination of the WRAP data and the EPA and EIA data suggests that 44% of the utility boilers had NO_x control (in 1996), as compared to only 12% when considering only the WRAP data by itself. The EPA databases probably undergo a more thorough QA/QC procedure than was used to create the WRAP database. Thus, the E-GRID and other federal databases might be expected to have more complete information.

Table 5. NO_x Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	99	14	489,580	4,945	Modified Furnace/Burner Design (13), Low Excess Air Firing(1)
Cyclone	5	1	73,468	14,694	Low Excess Air Firing(1)
Wet Bottom	2	0	19,688	9,844	None
NG Boiler	48	3	18,813	392	Low Excess Air Firing(3)
Stoker	6	0	1,779	296	None
Coal-fired AFBC	2	1	1,954	977	None
Wood Boiler	2	0	598	299	None
Oil Boilers					None
Total	**164**	**19**	**605,881**	**3,694**	

Table 6. NO_x Emissions and NO_x Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database Combined with EPA and EIA Databases.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	100	45	538,003	5,380	Modified Furnace/Burner Design(13) , Low Excess Air Firing(1), Low NOx Burner(21), OFA(3), Misc.(7)
Cyclone	5	1	73,528	14,706	Low Excess Air Firing(1)
Wet Bottom	3	3	23,409	7,803	Low NOx Burner(3)
NG Boiler	47	22	19,917	424	Low Excess Air Firing(3), SCR(2), SNCR(3), Misc.(14)
Stoker	6	0	3,987	665	None
Coal-fired AFBC	2	2	1,954	977	Low Excess Air Firing(1), Misc.(1)
Wood Boiler	3	0	957	319	None
Oil Boilers	1	0	110	110	None
Total	**167**	**73**	**661,866**	**3,963**	

The achievable NO_x emission rate depends on the boiler-fuel combination. The largest general class of utility boilers (in terms of number and capacity) is the dry bottom boiler. Dry bottom boilers can further be subdivided into wall-fired and tangential. Natural gas boilers emit less NO_x than coal-fired boilers per unit of fuel consumed. Of coal-fired boilers, tangential-fired units have the lowest emission rate and cyclones have the highest. The controls in the WRAP database are almost entirely low-NO_x burners or other combustion modifications. Figure 7 compares the range of NO_x emission rates for all boilers and fuels.

Application of low-NO_x burners and other combustion modifications can reduce NO_x emissions significantly; this can be seen in the large range of NO_x emission that is due, in part, to the use of NO_x controls on some of the boilers in each subset. Substantial NO_x reductions can also be achieved on coal-fired boilers just with combustion modifications.

Since 1996, low-NO_x burners have continued to improve; currently there are vendors who will guarantee NO_x emissions as low as 0.15 lb/MBtu from low-NO_x burners or low-NO_x firing systems. Furthermore, options have been developed for other combustion modifications, and SCR has begun to be applied to coal-fired boilers. Thus, the potential for NO_x control on coal-fired boilers is significantly better today than in 1996.

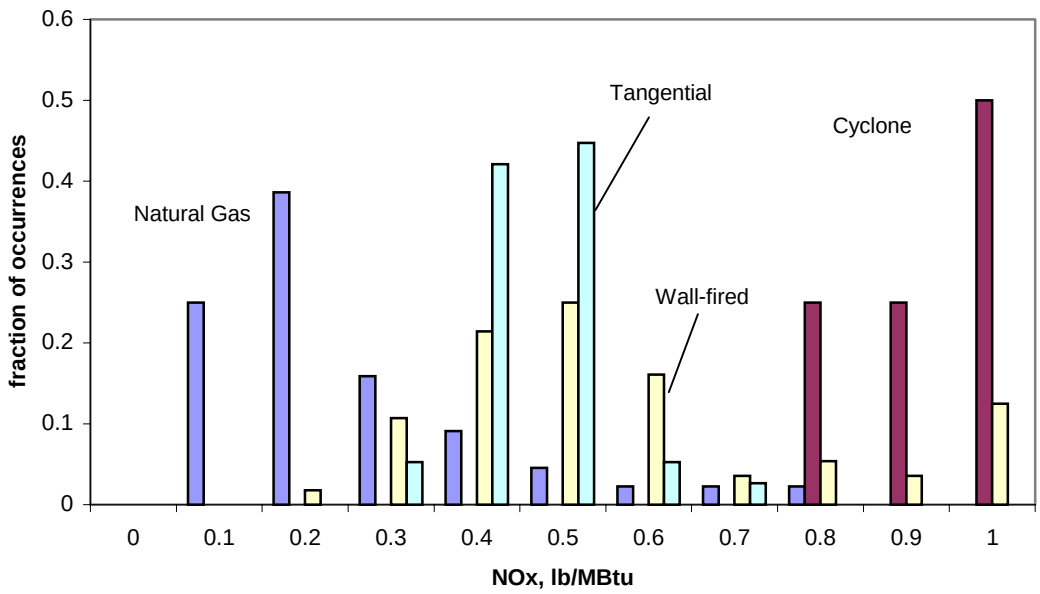

Figure 7. Distribution of NO_x emission rates for utility boilers in the thirteen-state region, combination of WRAP and EPA/EIA databases for 1996.

2.3 Trends in NO_x Emissions and Controls for Coal-Fired Utility Boilers, 1995-2000.

The most recent data available from the EPA databases for electric utility boilers are from 2000. In this section, we compare the 1996 data on NO_x emissions and controls discussed in the previous section with data from 2000.

Table 7 presents the data for 2000 derived from the EPA E-GRID and CEMS databases; this should be compared with Table 6 for 1996. The capacity of electric utility boilers increased by 37%, from 3,019,873,933 MBtu/yr in 1996 to 4,130,818,353 MBtu/yr in 2000, but the total NO_x emissions decreased by 7%. Figure 9 shows that the average annual emissions from dry bottom coal boilers (the largest category) decreased. Overall there was a decrease in emissions and an increase in the number of units that were controlled.

The number of sources increased, particularly the number of natural gas boilers, which increased from 47 to 82. The percent of natural gas boilers having NO_x controls decreased from 47% to 30%. During the time from 1996 to 2000, low-NO_x burners were added to natural gas units; there was also a small increase in SCR and SNCR on these types of boilers.

NO_x control on dry-bottom boilers increased from 47% to 71% from 1996 to 2000, resulting in a 9% decrease in total NO_x emissions from these boilers. The number of units with low-NO_x burners doubled. Overfire air (OFA) installations, though small in number, tripled. There were no SCR or SNCR installations on coal-fired boilers in 2000.

Thus, there was a modest reduction in NO_x emissions from electric utility boilers from 1996 to 2000, accompanied by a substantial increase in generating capacity. NO_x control increased, particularly on coal-fired boilers. The added NO_x control technologies were primarily low-NO_x burners and OFA.

Table 7. NO_x Emissions and NO_x Control Technologies for Utility Boilers in the Thirteen-State Region combined with EPA and EIA Databases for 2000.

	Number of Units	Controlled Units	NOx Emissions (TPY)	Average Emissions (Tons/Source)	NO_x Control Technology
Dry Bottom	96	68	489,680	5,101	Modified Furnace/Burner Design(13), Low Excess Air Firing(1), Low NOx Burner(41), OFA(9), Misc.(4)
Cyclone	5	2	66,013	13,203	Low Excess Air Firing(1), OFA(1)
NG Boiler	82	25	39,381	480	Low Excess Air Firing(4), Low NOx Burner(8), OFA(4), SCR(5), SNCR(4)
Wet Bottom	2	2	14,159	15,519	Low NOx Burner(2)
Coal-fired AFBC	2	2	2,118	1,059	Low Excess Air Firing(1), Misc.(1)
Wood Boiler	2	0	598	299	None
Stoker	1	0	335	335	None
Oil Boilers	1	0	216	216	None
Total	**191**	**99**	**612,500**	**3,207**	

2.4 Characterization of Sources of Particulate Matter (PM)

Table 8 gives the annual PM emissions for all PM sources in the thirteen-state region with emissions greater than 100 TPY. The cut-off of 100 TPY captures 60% of the PM emissions in the 1996 WRAP database for the thirteen-state region. With few exceptions, the distribution of PM sources is similar in the thirteen-state region as compared to the GCVTR. (Primary metal production emissions are mostly outside the GCVTR.) As a result of this similarity, the scope of this project was expanded to include additional WRAP states at minimal cost.

The largest source category (for those sources with emissions greater than 100 TPY) in the thirteen-state region is coal-fired boilers (40%); the top eight categories account for 92% of the PM emissions. Therefore, this report will focus on control technologies applicable to these process categories.

The state with the largest PM emissions is WY, followed by AZ, ID, and NM (Figure 9). Since all these states are in the GCVTR, it is not surprising that emissions from the nine states of the GCVTR (AZ, CA, CO, ID, NM, NV, OR, UT, WY) account for 83% of the total stationary source emissions greater than 100 TPY, as shown in Figure 10. Appendix B contains PM emissions by process category and by state.

Table 8. Annual Emissions of PM from Sources with Greater than 100 TPY.

Category	13-States		GCVTR		
	# Units	Total PM TPY (>100 TPY)	# Units	Total PM TPY (>100 TPY)	% PM in GCVTR
Coal-Fired Boilers	88	46,010	67	35,137	76%
Mineral Processing	85	24,499	75	21,824	89%
Petrochemical	42	10,836	37	9,716	90%
Wood Boilers	24	5,718	20	5,210	91%
Refinery Emissions	11	5,631	7	5,011	89%
Primary Metal Production	20	4,697	11	2,244	48%
Pulp and Paper	15	4,476	13	4,119	92%
Smelting Operations	8	3,555	7	3,397	96%
Miscellaneous	1	2,456	1	2,456	100%
Oil/NG Boilers	5	1,379	5	1,379	100%
Sugar Beet Processing	5	1,150	3	750	65%
Cooling Tower	4	932	4	932	100%
Cement Kilns	4	641	3	524	82%
Turbines	2	838	2	838	100%
Secondary Metal Production	1	537	1	537	100%
Jet Engine Testing	2	535	2	535	100%
Reciprocating Engines	3	525	3	525	100%
Refinery Process Heaters	1	176	1	176	100%
Total	**321**	**114,589**	**262**	**95,308**	**83%**

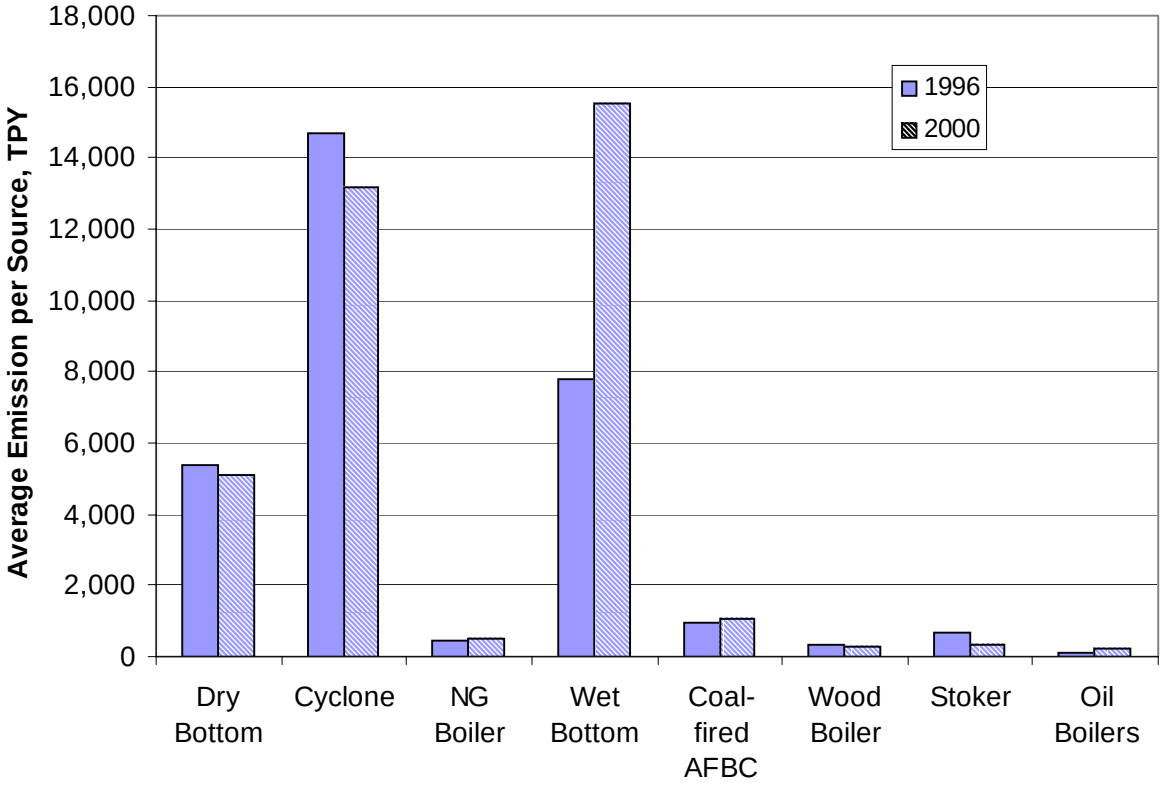

Figure 8. Average Annual NO_x Emissions (greater than 100 TPY) from Electricity Generating Boilers: Comparison of 1996 and 2000 data from EPA Databases.

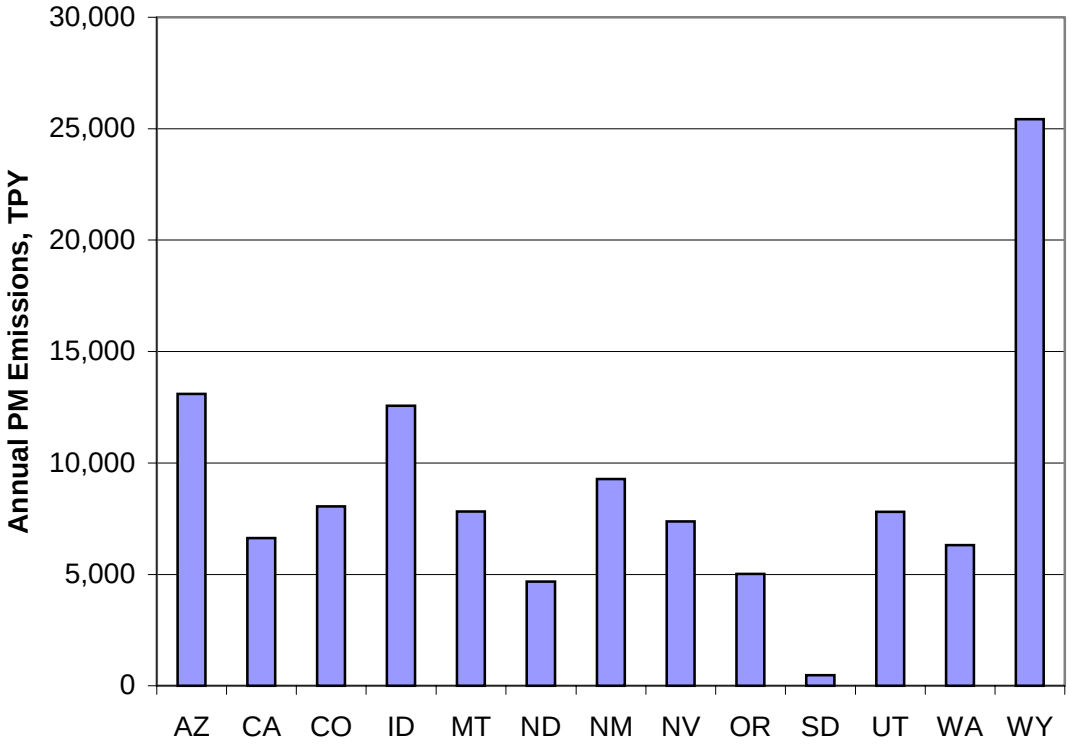

Figure 9. Annual PM Emissions from Sources with Emissions Greater than 100 TPY for the Thirteen-State Region.

Table 9 lists the control technologies in use in the 1996 WRAP database for particulate matter. 72% of coal-fired boilers, the largest category of emissions, had some form of PM control. Overall, though, only 38% of sources with emissions greater than 100 TPY had controls.

Table 9. PM control technologies in use on sources greater than 100 TPY from 1996 WRAP database.

	Number of Units	Controlled Units	Total PM (TPY)	Avg PM (TPY/Source)	PM Control Technology
Coal-Fired Boilers	88	64	46,010	523	Centrifugal Collector (Cyclone)(2), Electrostatic Precipitator(35), Fabric Filter(12), Multiple Cyclone(4), Multiple Cyclone/Electrostatic Precipitator(2), Multiple Cyclone/Wet Scrubber(1), Wet Scrubber(8)
Mineral Processing	85	29	24,499	288	Centrifugal Collector (Cyclone)(2), Dust Suppression by Chemical Stabilizers or Wetting(5), Dust Suppression by Water Sprays(16), Fabric Filter(1), Water Curtain(1), Wet Scrubber(4)
Petrochemical	42	7	10,836	258	Centrifugal Collector (Cyclone)(3), Sulfuric Acid Plant - Contact Process(2), Wet Scrubber(2)
Wood Boilers	24	3	5,718	238	Centrifugal Collector (Cyclone)(1), Wet Scrubber(1)
Refinery Emissions	11	3	5,631	512	Dust Suppression by Water Sprays(2), Fabric Filter(1)
Primary Metal Production	20	7	4,697	235	Alkalized Alumina(2), Dust Suppression by Water Sprays(1), Wet Scrubber(3), Misc.(1)
Pulp and Paper	15	3	4,476	298	Centrifugal Collector (Cyclone)(1), Wet Scrubber(1)
Smelting Operations	8	0	3,555	444	None
Miscellaneous	1	0	2,456	2,456	None
Oil/NG Boilers	5	4	1,379	276	Electrostatic Precipitator(4)
Sugar Beet Processing	5	1	1,150	230	Centrifugal Collector (Cyclone)(1)
Cooling Tower	4	0	932	233	None
Turbines	2	0	838	419	None
Cement Kilns	4	1	641	160	Electrostatic Precipitator(1)
Secondary Metal Production	1	0	537	537	None
Jet Engine Testing	2	0	535	267	None
Reciprocating Engines	3	0	525	175	None
Refinery Process Heaters	1	0	176	176	None
Total	**321**	**122**	**114,590**	**357**	

2.5 Comparison with Other Databases for PM Control Technologies

The 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for PM control technologies. The E-GRID database should contain the information in the other two databases since it contains data from 24 different federal data sources, including EIA data and other EPA data.

EPA and WRAP records for 1996 were matched using ORIS Plant ID numbers and plant names. For matching records, control technologies not listed in the WRAP database were added, capacity (MBtu) entries were added, and PM emissions were replaced from the EPA databases. The EIA-767 database reported PM emissions as lb PM/MBtu, from which we calculated PM emissions in tons per year.

PM emissions data in the EPA databases do not agree with data in the WRAP database, suggesting that the data were obtained from different measurement and/or estimation methods. The differences, illustrated by a few sample records in Table 10, follow no general trend from plant to plant.

Table 10. Sample PM Records from WRAP 1996 and EPA 1996 databases.

Boiler	Capacity (MBtu/yr)	PM Emissions Rate, EPA (PM/MBtu)	PM Emissions Rate, WRAP (PM/MBtu)	PM Emissions, EPA (TPY)	PM Emissions, WRAP (TPY)
Four Corners 1 (NM)	16,530,550	0.03	0.13	248	1,048
Four Corners 2 (NM)	9,369,730	0.03	0.13	141	618
Four Corners 3 (NM)	18,823,220	0.03	0.13	282	1,243
Four Corners 4 (NM)	58,100,720	0.01	0.03	291	883
Four Corners 5 (NM)	52,759,010	0.01	0.03	264	789
Reid Gardner 1 (NV)	9,599,371	0.05	0.05	240	222
Reid Gardner 2 (NV)	23,152,788	0.05	0.01	579	128
Reid Gardner 3 (NV)	30,579,084	0.05	0.02	764	278
Reid Gardner 4 (NV)	42,514,192	0.05	0.01	1,063	245

A comparison of Tables 11 and 12, which contain, respectively, the WRAP data and the WRAP data augmented by the other databases, shows that the combination of the WRAP data and the EPA and EIA data suggests that about 94% of the utility boilers had PM control (in 1996), as compared to only 53% when considering only the WRAP data by itself. The EPA databases probably undergo a more thorough QA/QC procedure than was used to create the WRAP database. Thus, the E-GRID and other federal databases might be expected to have more complete information.

Table 11. PM Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database.

	Number of Units	Controlled Units	PM Emissions (TPY)	Average Emissions (TPY/Source)	PM Control Technology
Dry Bottom	60	30	36,889	615	Multiple Cyclone(3), Fabric Filter(8), Wet Scrubber(7), Electrostatic Precipitator(12)
NG Boiler	4	4	1,235	309	Electrostatic Precipitator(4)
Cyclone	3	3	702	234	Electrostatic Precipitator(3)
Stoker	3	0	571	190	None
Coal-fired AFBC	1	1	381	381	Multiple Cyclone(1)
Wet Bottom	1	0	102	102	None
Total	**72**	**38**	**39,880**	**554**	

Table 12. PM Emissions and Control Technologies for Utility Boilers in the Thirteen-State Region from WRAP 1996 Database Combined with EPA and EIA Databases.

	Number of Units	Controlled Units	PM Emissions (TPY)	Average Emissions (TPY/Source)	PM Control Technology
Dry Bottom	77	75	84,140	1,093	Multiple Cyclone(3), Fabric Filter(15), Wet Scrubber(8), Electrostatic Precipitator(44), Multiple Cyclone/Electrostatic Precipitator(3), Multiple Cyclone/Wet Scrubber(2),
Cyclone	5	5	1,633	327	Electrostatic Precipitator(4), Fabric Filter(1)
NG Boiler	4	4	1,235	309	Electrostatic Precipitator(4)
Wet Bottom	3	2	697	232	Fabric Filter(2)
Stoker	3	0	571	190	None
Coal-fired AFBC	2	2	274	137	Multiple Cyclone/Electrostatic Precipitator(1), Fabric Filter(1)
Total	**94**	**88**	**88,549**	**942**	

3 NO_x CONTROL TECHNOLOGIES

3.1 Overview

As discussed in Section 2, the NO_x emissions greater than 100 TPY in the thirteen-state region come predominantly from coal-fired boilers. We have concentrated on obtaining detailed information on NO_x control technologies for the top five categories, which account for 90% of the emission, although in some cases, where information was readily available, we have collected information for other source categories (refinery process heaters, glass melters, and wood-fired boilers). Table 13 shows that these source categories together account for 92% of the NO_x emissions greater than 100 TPY.

Table 13. Annual NO_x emissions greater than 100 TPY from major source categories.

Category	# Units	Total NO_x TPY	% of NO_x Emissions
Coal-Fired Boilers	151	607,748	68%
Reciprocating Engines	423	86,210	10%
Cement Kilns	39	41,009	5%
Oil/NG Boilers	112	32,910	4%
Turbines	86	25,278	3%
Wood Boilers	48	9,776	1%
Refinery Process Heaters	38	9,311	1%
Glass Manufacture	14	5,033	1%
Others	199	69,385	8%
Total	**1,110**	**886,660**	

In this section, the information is organized in two formats. First, Table 14 lists all the technologies considered. For the most part, these are commercial technologies, in that vendors are offering these technologies. Not all technologies listed in Table 14 have demonstrated long-term operation, however. Table 14 gives the following information about each technology:

- Name of the technology
- Source categories to which the technology can be applied
- Was a summary prepared? (Yes/No). If yes, technology summaries are contained in Appendix C.

Second, Tables 15 through 22 summarize the NO_x control options for major source categories for ease of comparison. More detailed information, particularly on the range of cost and NO_x control, is given in Appendix C. These tables contain the following information:

- Name of Technology
- Process Description
- Applicability to units in the source category
- Range of performance (NO_x removal efficiency)
- Range of costs ($/ton of NO_x removed, levelized annual cost)
- Commercial status

Table 14. NO_x Control Technologies.

	Technology	Applicability	Summary in Appendix C (Y/N)
1	Air or fuel staging	Coal-fired boilers, Cement kilns	Y
2	Batch/Cullet Preheating	Glass Melters	Y
3	Biosolids injection	Cement kilns	N (not common)
4	Burner Modifications	Coal-fired boilers	N (see LNB)
5	Catalytic combustion	Gas Turbines	Y
6	DLN (fuel-lean combustion)	Gas Turbines	Y
7	Electric Boost	Glass Melters	N (too expensive)
8	Flue Gas Recirculation (FGR)	Oil/Nat'l Gas Boilers	Y
9	Fuel Reburn	Coal-fired boilers, Wood/biomass boilers, Glass Melters	Y
10	High Energy Ignition	Reciprocating Engines	Y
11	High-Pressure Fuel Injection	Reciprocating Engines	Y
12	Hybrid Reburn + SNCR	Coal-fired boilers	N (see Reburn, SNCR)
13	Hybrid SNCR + SCR	Coal-fired boilers	N (see SNCR, SCR)
14	Hydrocarbon-enhanced SNCR	Coal-fired boilers	N (see SNCR)
15	Intelligent controls	Coal-fired boilers, Oil/NG boilers, Wood/biomass boilers	Y
16	Iron addition (CemStar)	Cement kilns	Y

	Technology	Applicability	Summary in Appendix C (Y/N)
17	Kiln dust insufflation	Cement kilns	N (see O_2-enhanced combustion)
18	Kiln temperature control	Cement kilns	Y
19	LNB + FGR	Coal-fired boilers, Oil/NG boilers, Process heaters, Pyrolysis furnaces	N (see LNB, FGR)
20	Low-Emission Combustion (LEC)	Reciprocating Engines	Y
21	Low NO_x Burners	Coal-fired boilers, Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Process heaters, Cement kilns	Y
22	Low-NO_x Calciner	Cement kilns	Y
23	Mid-kiln or tower tire injection	Cement kilns	Y
24	Non-Selective Catalytic Reduction (NSCR)	Reciprocating Engines	Y
25	NOxTech	Reciprocating Engines	Y
26	Overfire Air	Coal-fired boilers, Wood/Biomass boilers. Oil/Nat'l Gas Boilers	Y
27	Oxy-Fuel Firing	Glass Melters	Y
28	Oxygen-enhanced Combustion Modifications	Coal-fired boilers, Cement kilns, Glass Melters	Y
29	Pre-stratified Charge	Reciprocating Engines	Y
30	Rich Reagent Injection (RRI)	Coal-fired boilers	N (see SNCR)
31	SCONOX	Oil/Nat'l Gas Boilers, Reciprocating Engines, Gas Turbines	Y
32	SCR	Coal-fired boilers, Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Process heaters, Reciprocating Engines, Gas Turbines	Y

	Technology	Applicability	Summary in Appendix C (Y/N)
33	SNCR	Coal-fired boilers, Wood/Biomass boilers Oil/NG boilers, Glass Melters, Pyrolysis furnaces, Cement kilns, Reciprocating Engines, Gas Turbines	Y
34	Tempering (Steam, water or air injection)	Gas turbines, Process heaters, Pyrolysis furnaces	Y

Table 15. Coal-Fired Boilers.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Burner Modifications	Burner air and/or fuel modifications to improve air/fuel interaction	Most units.	10 to 30% NO_x reduction	100-200	Y
Fuel Reburn	Inject portion of the fuel into the furnace downstream of burner zone. Usually requires OFA to complete combustion	Most units. Furnace height (residence time) may restrict some applications	20 to 30% NO_x reduction for Fuel-Lean Gas Reburning (no OFA), and 30 to 60% reduction for conventional reburning.	500-2000 (Highly dependent on cost of reburn fuel)	Y
Hybrid Reburn + SNCR	Co-inject reburning fuel and SNCR reagent.	Same as individual technologies.	50-70%	300-600	Y
Hybrid SNCR + SCR	Overfeed reagent into the furnace, and allow ammonia carryover to further reduce NO_x over a catalyst downstream.	Same as individual technologies.	50 to 90% NO_x reduction, de-pending on how much catalyst is installed.	800-2000	Y
Hydrocarbon-enhanced SNCR	Inject small amount of natural gas to create radicals that enhance SNCR effectiveness at 1700 to 2000 °F. Emerging technology.	Most units. Can use more NH_3 with less slip.	40 to 60% NO_x reduction	500-1000	Y
"Intelligent" Controls	Sensors and software optimize air-fuel ratio to burners.	Available for all units	0 to 30% NO_x reduction.	<100-300	Y
Low-NO_x burners (LNB)	Burners designed to produce lower NO_x emissions – "staged" combustion	Most boilers already have LNB.	30-50% NO_x reduction.	200-1000	Y
Overfire air (OFA)	Form of "staged" combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.	Most units. Furnace height may restrict some applications	20 to 40% NO_x reduction.	250-600	Y

Table 15. Coal-Fired Boilers (Continued).

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Oxygen-enhanced combustion modification	Improve effectiveness of OFA operation by injecting O_2 into fuel-rich flames. Operate more fuel-rich without the problems. Emerging technology.	Best applied with new OFA system designed to achieve stoichiometric air-fuel ratio < 0.8.	30-50% beyond OFA	1000-2000	Y
Rich Reagent Injection (RRI)	SNCR applied to fuel-rich region of OFA system.	Most units. Modeling required to determine injection locations.	20 to 30% additional NO_x reduction beyond OFA.	800-1500	Y
Selective Catalytic Reduction (SCR)	Ammonia added upstream of catalytic reactor installed upstream of air preheater (conventional), downstream of a hot ESP (low dust), or downstream of the cold ESP (tail end).	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70 to 90+% NO_x reduction	1500-2000	Y
Selective Non-catalytic Reduction (SNCR)	Inject ammonia-based reagent into upper furnace (1700-2000 degrees F) to destroy NO_x.	Most. Residence time and temperature characteristics are important.	25 to 50% NO_x reduction, depending on the furnace temperature and time for reaction.	800-1500	Y

Table 16. Reciprocating Engines.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
High Energy Ignition	Provide continuous electrical discharge at the spark plug gap for 10 to 90 ^{o} of crankshaft rotation. This extended energy delivery ensures combustion in the leanest of conditions.	For lean-burn engines (to support ignition under very lean conditions)	80% NO_x reduction. Use of plasma ignition is new, so there is limited operating experience.	115-200+	Y
High-Pressure Fuel Injection	Enhance mixing of fuel and air under lean conditions	Same as LEC	~80%	Not available, but less than LEC.	Y
Low-Emission Combustion (LEC)	Retrofit kits available to implement lean burn for new engines as well as retrofit.	Not available for all engines, some fuel efficiency decrease. Requires turbo-charging or inter-cooling upgrades.	80-90% NO_x reduction	190-700, depending on engine BHP. $6500 for 80 BHP.	Y
Non-Selective Catalytic Reduction (NSCR)	Install oxidation-reduction catalyst that uses hydrocarbons in exhaust to destroy NO_x.	Requires rich-burn engine to produce hydrocarbons used for NO_x reduction.	40-98% NO_x reduction, depending on engine speed. Average of 95% reduction is achievable.	<500	Y
NOxTech	Inject chemical reagent into exhaust at temperatures of 1400 to 1500 °F.	Applicable to all engines, but exhaust must be heated for most engines.	90-95% NO_x reduction, 60-80% particulate removal, 50-70% CO removal, 90% hydrocarbon removal.	~ 1000	Y
Pre-stratified Charge	Inject air into intake manifold so that the piston initially draws in air, followed by a fuel-rich air-fuel mixture.	For carbureted, rich-burn engines.	80-95% NO_x reduction.	< 500	Y

Table 16. Reciprocating Engines (Continued).

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Theoretically works for all engines. Catalyst regeneration is difficult. Little operating data available.	95% reduction of NOx, CO, and hydrocarbons.	Not available	Y
SCR	Inject ammonia upstream of a catalyst that operates at 300-900 °F.	All engine types (especially diesel), but difficult to control if load range is wide.	75-90% NOx reduction	< 1000	Y

Table 17. Cement Kilns.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Air or fuel staging	Inject portion of the fuel downstream of the main flame to create locally reducing conditions where NO_x can be destroyed. Sometimes includes installing a "NO_x fan" to increase burnout.	More easily implemented in tower kilns.	0 to 50% NO_x reduction, depending on existing equipment.	1000-2000	Y
Biosolids injection	Add sewerage sludge to mid-kiln or tower for combined SNCR and fuel-staging affect.	Tried in long kilns and preheater/precalciner kilns, but effectiveness is limited by poor combustion and increased hydrocarbon or SO_2 emissions.	20 to 30% NO_x reduction, but can reduce kiln capacity due to high moisture content.	100-500	Y
Iron addition (CemStar)	Change cement formulation by adding waste iron to lower clinkering temperature and suppress NO_x.	Applicable to all kiln types, but may affect cement quality.	20 to 30% NO_x reduction, depending on cement specifications	0-100	Y
Kiln dust insufflation	Re-inject cement kiln dust (CKD) into flame zone to lower peak temperatures and increase clinker production.	Applicable to long kilns.	0 to 20% NO_x reduction in conjunction with a 0-5% kiln capacity increase.	100-300	Y
Kiln temperature control	Add temperature-monitoring device to kiln controls to minimize high-temperature excursions where more NO_x is emitted.	Applicable to all kiln types, but risks unacceptable cement quality.	0 to 20% NO_x reduction, and requires less operator attention.	200-500	Y
Low-NO_x Burner (LNB)	Replace open pipe burner with multi-annular design. Usually accompanied by installation of an indirect coal feed system to reduce coal transport airflow.	Applicable to all kiln types. Can reduce cement quality on some kilns.	0 to 20% NO_x reduction; production may increase.	500-1000	Y

Table 17. Cement Kilns (Continued).

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Low-NO_x calciners	Replace calciner with new low-NO_x design.	Applicable only to preheater/precalciner kilns.	30-50% NO_x. Little experience	1000-5000	Y
Mid-kiln or tower tire injection	Inject whole tires or shredded tires downstream of the flame to reduce NO_x formed in the burner.	Injected mid-kiln in long kilns, and into lower tower for preheater/precalciner kilns.	15 to 30% NO_x reduction; generate revenues.	0-1000	Y
Oxygen enrichment	O_2 lance to decrease fuel requirement for clinker formation.	Cement quality could be more difficult to control.	0 to 20% NO_x reduction and potential for additional capacity.	200-1000	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000°F) to destroy NO_x.	Applicable to preheater/precalciner kilns.	30 to 70% NO_x reductions, depending on access to temperatures in 1600-1800 °F range.	200-1000	Y

Table 18. Oil/Natural Gas-Fired Boilers.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Flue Gas Recirculation (FGR)	Recycle 15-25% of the flue gas to the windbox to reduce flame temperature. Can use eductors for induced FGR	Most units, but could affect heat balance. Induced FGR requires pressure part changes.	40-80% NO_x reduction	500-3000	Y
Low-NO_x Burners	Burners designed to produce lower NO_x emissions – "staged" combustion	Most boilers.	30-60% NO_x reduction	200-1000	Y
Overfire Air (OFA)	Form of "staged" combustion. Divert portion of the air from the windbox to OFA ports installed above	Most units. Furnace height may restrict some applications	40-80% NO_x reduction	1000-2000	Y
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Steam-hydrogen regeneration gas not practical for some boilers. Limited testing to date.	70-99% NO_x reduction claimed.	Not available	Y
SCR	Ammonia added upstream of catalytic reactor.	Most units. Space availability may constrain some options. High sulfur fuels more challenging	70-90+% NO_x reduction	2000-10000	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000°F) to destroy NO_x.	Most. Residence time and temperature characteristics are important.	30-60% NO_x reduction	1300-3000	Y

Table 19. Turbines.

Technology	Description	Applicability	Performance	Cost,$/T	Commercial
Catalytic combustion	Catalytic combustor reduces combustion temperature below thermal NO_x limit.	Limited experience.	0.05 lb/MBtu (80% reduction) has been measured.	> 500	Y
DLN (fuel-lean combustion)	Low NO_x combustor is GT "equivalent" of LNB.	Most turbines. Flame instability a problem for some gas fuels.	0.1 lb/MBtu (70% reduction) can be guaranteed on new units.	1000-2000	Y
SCONOX	Add chemical reactor for NO_x sorption, followed by regeneration.	Reliability of system not yet proven.	0.02 lb/MBtu (> 90% reduction) claimed.	> 7000	Y
SCR	Add catalyst section to HRSG to destroy NO_x at temperatures of 600 to 900 °F.	Applied to most turbines	90 % reduction down to 0.03 lb/MBtu.	500-10000+	Y
Tempering (Water/ Steam Injection)	Spray water or steam into combustor to suppress flame temperature.	Can be applied to most turbines, but some will experience slight efficiency loss.	0.15 lb./MBtu (50% reduction) can be achieved.	2000-7000	Y

Table 20. Wood or Biomass-Fired Boilers.

Technology	Description	Applicability	Performance	Cost, $/T	Commercial
Fuel Reburn	Inject portion of the fuel into the furnace downstream of burner zone. Usually requires OFA to complete combustion	Stoker, water tube	40-60% NO_x reduction	300-3000	Y
"Intelligent" Controls	Sensors and software optimize air-fuel ratio to burners.	Watertube boilers	0-20 % NO_x reduction	200-500	Y
Overfire air (OFA)	Form of “staged” combustion. Divert portion of the air from the windbox to OFA ports installed above the burners.	Stoker, watertube	20-60% NO_x reduction	200-2000	Y
Selective Non-Catalytic Reduction (SNCR)	Inject ammonia-based reagent into upper furnace (1700-2000° F) to destroy NO_x.	Stoker, FBC, watertube	40-80 % NO_x reduction reported	900-2200	Y

Table 21. Process Heaters.

Technology	Description	Applicability	Performance	Cost, $/Ton	Commercial
LNB + FGR	Staged firing with flue gas mixed with pre-combustion air	Oil/gas fired, MD only	50-60%	Gas: 1,720-2,480 Oil: 2,390-2,910	Y
Low-NO_x Burners, Ultra Low-NO_x Burners	Staged firing; Combines staged firing with induced flue gas recirculation	Oil/gas fired	30-50% Ultra-LNB: 50-80%	Gas: 1,210-1,820 Oil: 1,200-2,340 Gas: 810-1,280 Oil: 400-1,440	Y
SCR	Ammonia added upstream of catalytic reactor.	Oil/gas fired	75-90%	Gas: 5,130-10,600 Oil: 3,710-6,490	Y
SNCR	Inject ammonia-based reagent into upper furnace (1700-2000° F) to destroy NO_x.	Oil/gas fired	50-70%	Gas: 1,470-2,640 Oil: 1,230-2,350	Y

Table 22. Glass Melting Furnaces.

Technology	Description	Applicability	Performance	Cost, $/Ton	Commercial
Batch/Cullet Preheating	Residual heat of waste gas used to preheat batch materials/cullet (recycled glass)	Any glass melting furnace w/ >50% cullet in batch	5-25%	890-1,040	Y
Electric Boost			10-30%	2,600-9,900	Y
Low-NO_x Burners	Burners designed to produce lower NO_x emissions – "staged"		40%	790-1,680	Y
Natural Gas Reburn	Inject portion of the fuel into the furnace downstream of burner zone.		50-65%	moderate	Y
Oxy-Fuel Firing	Oxygen used instead of air; requires different furnace design	Oil/gas fired furnaces	80-85%	2,150-4,400	Y

The formation of NO_x is a byproduct of the combustion of fossil fuels. Nitrogen contained in fuels such as coal and oil, as well as the harmless nitrogen in the air, will react with oxygen during combustion to form nitrogen oxides (NO_x). The degree to which this formation evolves is dependent on many factors, including both the combustion process itself and the properties of the particular fuel being burned. This explains why similar boilers firing different fuels or similar fuels burned in different boilers will yield different NO_x emissions.

As a result of these complex interactions in the formation of NO_x, an equally large number of approaches to minimize or reduce its emissions into the atmosphere have been and continue to be developed. A relatively simple way of understanding the many technologies available for NO_x emission control is to divide them into two major categories: (1) those that minimize the formation of NO_x during the combustion process (e.g., smaller quantities of NO_x are formed); and (2) those that reduce NO_x after the combustion process. It is common to refer to the first approach as “combustion modifications” whereas technologies in the second category are termed "post-combustion controls."

Within each of these categories, several technologies and variations of the same technology exist. Finally, combinations of some of these technologies are not only possible but often desirable as they may produce more effective NO_x control than the application of a stand-alone technology.

The following summaries describe the major technologies in each category.

3.2 Coal-Fired Boilers

Combustion modifications can vary from simple "tuning" or optimization efforts (similar to a "tune-up" of a car) to the deployment of dedicated technologies such as low-NO_x burners (LNB), Overfire air (OFA), or Reburn. All combustion modification approaches face a common challenge: that of striking a balance between NO_x reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower efficiency (more fuel needed for the same electrical output) and which may contaminate the fly ash itself, possibly making it unsuitable for reutilization (e.g., cement and concrete production).

<u>Combustion Optimization</u>

Combustion optimization efforts can lead to reductions in NO_x emissions of 5%-15% or even higher in cases where a unit may be poorly "tuned." It is important to remember that optimization results are truly a function of the "pre-optimization" condition of the power plant or unit, and as such have limited opportunity for drastic emission reductions. Recent development of "intelligent controls" - software-based systems that "learn" to operate a unit and then maintain its performance during normal operation may go a long way towards keeping plants well-tuned as they age.

<u>LNB’s and OFA</u>

LNB’s and OFA represent practical approaches to minimizing the formation of NO_x during combustion. Simply, this is accomplished by controlling the quantities and the way in which

fuel and air are introduced and mixed in the boiler (usually referred to as "fuel or air staging"). These technologies are the most prevalent in the power industry at present. For example, plants that have had to comply with Phase I of Title IV of the CAAA of 1990 have largely used these technologies for compliance. (Phase II of the Title IV has required the use of post-combustion technologies to meet more stringent requirements for both Group 1 and Group 2 boilers.) Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies. LNB's and OFA, which can be used separately or as a system, are capable of NO_x reductions of 40% - 60% from uncontrolled levels. Again, the type of boiler (e.g., dry vs. wet-bottom, wall- vs. tangential-fired, NSPS vs. pre-NSPS) and the type of fuel (e.g., bituminous vs. sub-bituminous) will influence the actual performance achieved. NO_x emission rates on the order of 0.15 lb/MBtu can be achieved with low NO_x burners under circumstances, particularly in dry-bottom boilers burning low-rank coals.

LNB's/OFA have little or no impact on operating costs, other than those noted above. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from $10-$40/kW, with the lower range reflecting easier "plug-in" application, whereas the higher costs are typically associated with more difficult and involved retrofits (e.g., where new controls or other systems may be replaced as part of the LNB retrofit).

From the standpoint of scheduling retrofits for existing units, LNB/OFA retrofit projects have "lead" times of 10-14 weeks and can require outages of 6-10 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Reburn

Reburn, while generically included in the "Combustion Modification" category, is different from the other technologies in this group (LNBs/OFA) in that it "destroys" NO_x through chemically reducing conditions shortly after it is formed rather than minimizing its formation as discussed previously. From a practical standpoint, this is accomplished by introducing the reburn fuel (theoretically any fossil fuel can be used, but natural gas is the most common) into the boiler above the main burner region. Subsequently, this "fuel-rich" environment reacts with and "destroys" the NO_x formed in the main burners. This technology has been implemented in the U.S. and overseas, and while not as common as LNB/OFA, it is commercial at this time. Owing to stricter compatibility criteria, reburn is not as universal as LNB/OFA in its applicability to the overall boiler population. Specific criteria such as boiler size, availability of natural gas, type and quality of the main fuel are all important in determining the suitability of a unit for this technology. One important feature of reburn is its compatibility with cyclone boilers, for which the previously mentioned technologies are not particularly well suited. Cyclones boilers represent over 25,000 MW of capacity in the U.S.

Reburn performance has been shown to range from 35%-60% depending on such factors as reburn fuel type and quantity, initial NO_x level, boiler design, etc. Reburn can be thought of as a "dial-in" NO_x technology in that NO_x reductions are a function of the amount of reburn fuel. This feature may provide strategic value in compliance scenarios.

With respect to cost, systems using natural gas as the reburn fuel range from $15/kW to $30/kW whereas those using coal for reburn range from $30/kW to $60/kW. Operating costs are primarily driven by the fuel cost differential in the case of gas reburn, while for coal or oil reburn fuel preparation costs (pulverization and atomization, respectively) represent the dominating O&M costs. Countering these costs, particularly in the gas reburn case, are SO_2, particulates, and CO_2 co-benefits proportional to the fraction of gas used.

Project retrofit schedules for this technology are on the order of 15 to 20 weeks with 6 to 10 weeks of outage time likely.

Recently, reburn technology has evolved into several variations of the original approach. One of these is “Fuel Lean Gas Reburn" (FLGR) developed for specific applications where NO_x reductions of around 30%-40% may be required. FLGR uses less gas than conventional reburn (3%-7% vs 15%-20%), and its capital cost is less than $10/kW, making it a potentially effective option in specific applications.

SCR and SNCR

Readily available post-combustion NO_x controls are limited to selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). They are fundamentally similar in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler and convert it to nitrogen and water. SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x.

While this difference between the two technologies may seem minor, it results in significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "makeshift" reactor, which is not what it was originally designed to be), while in the SCR case, a dedicated reactor and the reaction-promoting catalyst ensure a highly controlled, efficient reaction. In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_x); and finally, has limited NO_x reduction capability (typically 30%-40%, with some cases achieving reductions in the 50% range). SCR, on the other hand, has higher capital costs but offers lower operating costs and the opportunity for very high NO_x reductions (up to 90%).

Capital costs range from $10 to $15/kW and $60 to $100/kW for SNCR and SCR, respectively. Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR and ammonia for SCR, which in turn is dependent upon the efficiency of the process (usually referred to in terms of reagent utilization) as well as the initial NO_x level and the desired percent reduction. Two additional parameters important in the overall operating costs are (1) the potential contamination of fly ash by ammonia, making it unusable and (2) the life cycle of the catalyst due to fly ash.

Combined Approaches

In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the "economics" of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific.

However, several such combinations of technology are considered attractive and have or are gaining acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical (SNCR) and capital costs (SCR – smaller reactor/catalyst) due to lower NO_x levels entering the SCR/SNCR system. Another example is the combination of Reburn with SNCR, driven by the synergisms between the two (similar location, temperatures in the boiler). This application may yield NO_x reductions of 60%-70% with capital costs in the $20-$30/kW range, but has a relatively high operating cost due to reagent and reburning fuel consumption.

3.3 Reciprocating Engines

Several control technologies are available for ICE's, 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, 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 ICE's. 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 ICE's. 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 ICE's 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 ICE's 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%.

3.4 Cement Kilns

As with other combustion systems, modifying the combustion process is one strategy for reducing NO_x in cement kilns. However, the quality of the clinker produced by the kiln can be affected by combustion modifications so these must be undertaken carefully.

Monitoring temperature and excess air in the combustion zone increases the efficiency of the cement-making process and can result in reduced NO_x emissions. Combustion modifications include staged combustion of air or fuel. Specifically designed low-NO_x burners are sometimes used. Even without low-NO_x burners, staging can be achieved by adding some of the fuel mid-kiln, as in mid-kiln injection of tires. Mid-kiln injection of fuel (most often tires) was in practice in twenty kilns in the U.S. in 2000.

Iron addition (CemStar process) has been used at about a dozen facilities in the U.S. This reduces the temperature needed in the kiln for formation of clinker and allows the combustion zone to operate cooler (and thus reducing NO_x).

Post-combustion (post-kiln) NO_x controls include SCR and SNCR. SCR has not been used on cement kilns in the U.S.; pilot studies have been conducted in Europe. SNCR technology requires a specific temperature window and residence time; these are not attainable in all cement kilns. SNCR can be applied to preheater/precalciner kilns. SNCR is widely practiced in Europe on cement kilns, but to date there have been only a handful of demonstrations in the U.S.

3.5 Natural Gas and Oil Fired Boilers

The menu of NO_x control options for gas and oil-fired boilers is essentially the same as for coal-fired boilers. One noted exception is the use of Flue Gas Recirculation (FGR), which is not effective in coal applications and hence, is not mentioned there.

While the control technologies are common to the coal-fired options, application issues require different considerations and analyses. Examples range from differences in the inherent NO_x formation amongst the fuels (thermal NO_x vs. "fuel"-NO_x), which dictate that combustion-based technologies are designed accordingly for each fuel, to the fact that gas produces no PM or SO_2/SO_3 and hence can afford some design changes from coal and oil applications. Equally important are the economics of the different fuels, which may favor different technology approaches.

In summary it can be said that the available menu of technologies is the same as for coal applications, but that (at least for gas), deployment of these technologies tends to be less constraining than for coal.

3.6 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. The baseline NO_x level significantly affects 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 DLN 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.

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).

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. A 75 MW turbine at a high capacity factor 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 SCONOx) offer the potential for very low NO_x emission levels. Because there is much less experience with these technologies, available cost information is limited.

4 PM CONTROL TECHNOLOGIES

4.1 Overview

As discussed in Section 2, 8 source categories make up about 92% of the PM emissions and are summarized in Table 23. Detailed information on PM control technologies has been obtained for industrial processes that generate particulate matter. We have not provided cost information on fugitive emissions, however, since costs of fugitive dust control are highly variable and it is difficult to find an adequate metric for costs and then quantify them.

Table 23. PM emissions from top eight source categories.

	# Units	Total PM TPY	% PM Emissions
Coal-Fired Boilers	88	46,010	40%
Mineral Processing	85	24,499	21%
Petrochemical	42	10,836	9%
Wood Boilers	24	5,718	5%
Refinery Emissions	11	5,631	5%
Primary Metal Production	20	4,697	4%
Pulp and Paper	15	4,476	4%
Smelting Operations	8	3,555	3%
Others	28	9,168	8%
Total (>100 TPY)	**321**	**114,589**	

Table 24 lists all the technologies considered. These are commercial technologies, in that vendors are offering these technologies with demonstrated operating experience in a wide range of applications. Table 24 gives the following information about each technology:

- Name
- Source categories to which the technology can be applied
- Summary prepared? (Y/N)

Technology summaries are contained in Appendix D.

Table 24. PM Control Technologies

	Technology	Applicability	Summary (Y/N)
1	Cyclones	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns, Smelting	Y
2	Electrostatic precipitator (ESP)	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns	Y
3	Fabric Filter	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns	Y
4	PM Scrubber	Coal-fired boilers, Oil/NG boilers, Wood/Biomass boilers, Cement kilns, smelting	Y
5	Surface modification • Water • Surfactants • Shape	Fugitive Emissions, Mineral Products	N
6	Traffic operations	Fugitive Emissions, Mineral Products	N

4.2 PM Control for Coal-Fired Boilers and Other Combustion Sources

Particulate matter is generated by a variety of physical and chemical processes. It is emitted to the atmosphere through combustion, industrial processes, fugitive emissions and natural sources. In combustion processes, the mineral matter (inorganic impurities) is converted to ash. The particles suspended in the flue gas are known as fly ash. Fly ash constitutes the primary particulate matter, which enters the particulate control device. Particulate matter is in general referred to as "PM", "PM10", "PM2.5" (particulate matter (PM) with an aerodynamic equivalent diameter of 10 microns or less and 2.5 microns or less, respectively).

Quantity and characteristics of the fly ash and particle size distribution depend on the mineral matter content of the fuel, combustion system, and operating conditions. Combustion technique mainly determines the particle size distribution in the fly ash and hence the final particulate emissions. Common combustion systems in pulverized coal firing include dry bottom, wall (front, opposed) and corner (tangential) burners and wet bottom furnaces. In dry bottom boilers, 10-20% of the ash is discharged as dry, bottom ash. In wet bottom boilers, 50-60% of the ash is discharged at the bottom of the boiler as slag. Stokers or grate-fired boilers are used to burn coal, wood and waste. The majority of the ash falls through the grate and is discharged as bottom ash. Mineral composition of the coal and the amount of carbon in the fly ash determine the quantity, resistivity and cohesivity of the fly ash.

PM emissions from other point source processes involve similar phenomena where particulate matter is carried with the flue gas, in suspension to the stack. Hence, the general technologies applicable to one source are typically suitable for the others as well. Factors such as type and

quantity of PM, characteristics of the process gas (temperature, moisture, other contaminants) will have a major influence on the selection and design of the PM control technology.

Without getting into the details of the various technologies, the following four major types of particulate controls technologies are common for a variety of applications:

- Wet scrubbers – scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the "venturi scrubber" is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber. Venturi scrubbers are effective devices for particulate control. However, for higher collecting efficiencies and a wider range of particulate sizes, higher pressures are required. High-energy scrubbers refer to designs operating at pressure losses of 50-70 inches of water. Of course, higher pressure translates to higher energy consumption. Performance of scrubbers varies significantly across particle size range with as little as 50% capture for small (<2 microns) sizes to 99% for larger (>5 microns) sizes.

- Electrostatic Precipitators (ESP) –ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charged plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates. In gases with high moisture content, dry ESP's are not suitable because the wet gas would severely limit the ability to collect the "sticky" particulates from the plates. The wet ESP technology is capable of very high removal efficiencies and is well-suited for the wet gas environments. Both types of ESP's are capable of 99+% removals for particle sizes above 1 micron.

- Fabric Filters – These are essentially "giant" vacuum cleaners. As in the case of the dry ESP, Fabric Filters are not well suited for wet gas applications. However FFs are extremely efficient in collecting PM including fine (submicron) size fractions.

- Cyclones – Cyclones are devices that separate particulates from the gas stream through aerodynamic/centrifugal forces. However, the technology is only effective in removing larger size particulates (greater than about five microns).

4.3 Other Developments

While the technologies above represent the major available options for particulate control from point sources, it is relevant to note that advancements and innovative application of these technologies have and will continue to occur. Examples of these can vary from simple retrofits (e.g. new filter bag materials for Fabric Filters or newer spark control electronics on ESPs) to innovations including electrostatically- enhanced fabric filtration and hybrid concepts that combine attributes of various technologies.

The Electric Power Research Institute's (EPRI) COHPAC process and the University of North Dakota Energy and Environmental Research Center's Advanced Hybrid Particulate Collector

(AHPC) are examples of hybrid particulate collectors. In COHPAC, an ESP is followed by a pulse-jet Fabric Filter either immediately following it or actually integrated into the original casing of the ESP (in the case of larger older ESP's), where the FF acts as a "polishing" device significantly increasing the overall and fine particulate collection efficiency of the ESP alone. The AHPC technology can be described as an ESP with alternating rows of electrode plates and highly efficient membrane filter bags. In this case, the technology benefits from good synergism between the ESP and FF during bag cleaning resulting in very high performance levels, small sizes and operational flexibility.

4.4 Costs

As with most control technologies, the costs of PM controls involve both capital and operating costs. A cost-effectiveness indicator such as $/ton as is typically used for other technologies (e.g. NO_x and SO_2) is very difficult to address for generic PM control costs, as the range of PM reductions for different fuels and processes is wide that cost ranges become useless. An attempt to summarize costs in terms of capital and O&M components is presented below.

Capital

While it is customary to indicate capital costs on a $/kW basis for power generation applications, this is not relevant for non-power applications since no electricity is generated. However, one of the main parameters dictating the "sizing" and hence, the costs of a PM control device, is the quantity of flue gas it must handle. As a result, it is more appropriate to generalize capital costs on a "$/ACFM" basis. The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Dry ESPs - $15 - $40/ACFM
- Wet ESPs - $15 - $40/ACFM
- Reverse Air Fabric Filter - $17 - $40/ACFM
- Pulse Jet Fabric Filter - $12 - $40/ACFM
- Venturi Scrubber - $5 - $20/ACFM
- Cyclone - $1 - $5/ACFM

O&M

O&M costs are difficult to generalize for such a variety of technologies and applications, as they are affected by many parameters that include type of fuel, type of process, local ash disposal options, local cost of power, etc. O&M costs include fixed costs (FOM) and variable costs (VOM). The costs provided below are presented in $/year-ACFM and reflect costs for coal based fuels but should reasonably apply to other sources as well.

Fixed O&M

- Dry ESPs - $0.25 - $0.65/yr-ACFM
- Wet ESPs - $0.15- $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM

- Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM
- Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Cyclone – Not applicable

Variable O&M

- Dry ESPs - $0.45 - $0.60/yr-ACFM
- Wet ESPs - $0.25 - $0.50/yr-ACFM
- Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM
- Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM
- Venturi Scrubber - $1.2 - $1.8/yr-ACFM
- Cyclone – Not applicable

5 MULTI-POLLUTANT CONTROL TECHNOLOGIES

Emerging environmental issues and proposed federal legislation (President's Clear Skies Initiative, Carper Bill, Jeffords' Bill) as well as state legislation (examples include MA, NY, NC, NH, CT) have driven interest in multi-pollutant (as opposed to single pollutant) control technologies capable of addressing air pollutant emissions more comprehensively with greater flexibility and ultimately lower cost. Multi-pollutant control technologies integrate in-situ and/or post-combustion controls of at least two of the following pollutants: SO_2, NO_x, and Hg (and other hazardous air pollutants including cadmium, arsenic, and nickel), and CO_2. Multi-pollutant controls are intended primarily for large utility coal-fired boilers since the complexity of some of these processes as well as regulatory drivers often limit them to larger, utility boilers. Since coal-fired boilers represent the single largest source category for both NO_x (as well as SO_2 and Hg) and PM in the thirteen-state region, it is worth considering some of these technologies.

5.1 Proposed Multi-pollutant Emission Regulations from Utility Boilers

In 2002 and 2003 three "multi-pollutant" bills were introduced in the US Congress that call for coordinated reductions in NO_x, SO_2, and Hg from coal-fired power plants [26]. Some of the bills also include emission limits for CO_2. The three bills are briefly summarized here.

- The Clean Power Act (CPA, Jeffords) would amend the CAA to require electric power generation sources greater than 15 MW. It is the most stringent of the three proposals. It will cap SO_2 emissions at 2.26 mm TPY in 2008 (0.28 mm TPY in the western region that includes WRAP states and MT, WY and CA; and 1.98 mm TPY in the eastern region). For NO_x, the cap of 1.51 mm TPY is to be met by 2008. The cap on Hg is at 5 TPY, also to be met by 2008. In addition, this bill sets a cap of 2.08 billion TPY for CO_2 to be met by 2008 (roughly 1990 levels). Except for Hg, national trading will be allowed to meet the caps.

- The Clear Skies Act (CSA) has been proposed by the Bush administration. It is the least stringent of the three proposals. It would cap SO_2 emissions at 4.5 mm TPY in 2010 and at 3 mm TPY in 2018. The corresponding limits for NO_x are 3 mm TPY (in 2008) and 1.7 mm TPY in 2018. For Hg, the proposed national caps are at 26 TPY in 2010 and 15 TPY in 2018. There are no limits for CO_2. A national trading program similar to the existing trading program for SO_2 emissions under Title IV of the Clean Air Act will be the implementation mechanism to achieve these caps. All electric generation sources greater than 25 MW would fall under this program.

- The Clean Air Planning Act (CAPA, Carper,Breaux, Baucus, and Chafe)) was intended as middle ground between the CPA and CSA. For SO_2, the caps are 4.5 mm TPY by 2008, 3.5 mm TPY by 2012, and 2.25 mm TPY by 2015. The caps for NO_x are 1.87 mm TPY by 2008 and 1.7 mm TPY by 2012. The Hg cap limits are 24 TPY by 2008, and a potential cap of 5-16 TPY by 2012 (this cap to be set by EPA and implies a control in the range of 79 to 93% from current Hg emission level). Cap and trade program will be the implementation mechanism for all four pollutants, except trading for Hg will be limited. In a "hybrid" approach, limited trading for Hg would be allowed (each plant will be required to reduce its Hg emissions at site by at least 50% in 2008 and by 75% in 2012). For CO_2, CAPA proposes to stabilize CO_2 emissions at 2005 levels (approximately 2.6 billion TPY) by 2008, and then stabilize to 2001 levels (approximately 2.4 billion TPY) by 2012.

All three bills recognize and incorporate the WRAP SO_2 trading program by setting separate caps on SO_2 emissions in the West. The CPA and CAPA allow nationwide trading of NO_x, while the CSA divides the country into two zones for NO_x trading. The western zone includes the ND, SD, NE, OK, KS, western TX, the eleven states west of the Rockies, AK, HI and the U.S. territories. The largest differences among the three bills are in the Hg emissions reduction requirements. The first-phase Hg emissions caps under CSA and CAPA are about the same, but compliance would come two years earlier under CAPA. CPA has the most stringent Hg reduction requirement: a cap of 5 TPY or about 90% control. The CSA would allow nationwide Hg trading, while the CAPA would allow partial trading. There is no trading under CPA.
Both CSA and the first phase of CAPA have modest Hg emission reduction targets; these would make it possible in some cases to achieve reduction of Hg as a "co-benefit" of other control technologies, for example, from the combination of an SCR and wet scrubber. If one of these bills were enacted, there might be some additional incentive to install an SCR and/or FGD on plants for which there might not be justification on the basis of a single pollutant.
In terms of Hg co-benefits, the West is at a disadvantage as compared to the East. In the latter region, more utilities burn bituminous coals that are high in chlorine (which tends to increase the amount of oxidized Hg in flue gas) and in sulfur. Wet scrubbers are effective for the removal of oxidized Hg, but ineffective for removal of the elemental Hg that is the predominant form of Hg in many western power plants. If all coal-fired power plants must reduce Hg emissions by upwards of 70%, the West will have a more difficult job than the East, owing to differences in coal composition. The bills that allow Hg trading (CSA and CAPA) would allow western power plants to deploy Hg control technology at plants were the highest emissions reductions are likely to be achieved.

If the CPA is enacted or if none of the three bills are enacted this year, it is likely that EPA will continue with the MACT process for Hg control, which does not allow trading and which will probably impose a Hg emission reduction target in the range of 70% to 90% (or an emission limit in the range of 0.2 to 0.6 pound of Hg per trillion Btu input). In this case, coal-fired power plants will have to look at application of activated carbon injection, the most mature technology for Hg control currently, or one of the multi-pollutant processes under development. Activated carbon injection may require adding additional particulate control equipment (such as a polishing baghouse with high cloth to air ratio), which will lower PM as well as the emissions of other hazardous pollutants including arsenic, chromium, lead, manganese, and nickel) as a consequence.

5.2 Multi-pollutant Control Technologies

A multi-pollutant control technology may be one integrated process or a combination of synergistic processes. In addition to in-situ and post-combustion control processes, options such as advanced power generation technologies, power plant rehabilitation-upgrading-repowering, fuel switching or blending and power plant optimization are sometimes included in the multi-pollutant control category. Emerging and commercial processes for multi-pollutant control for coal-fired boilers are summarized in Table 25, which is largely taken from Reference 4, with more recent information from the DOE-EPRI-U.S. EPA -A&WMA Combined Power Plant Air Pollutant Control Symposium in Washington, D.C., May 19-22, 2003.

Approximately half of the options listed in Table 25 are in commercial and early commercial stages. However, nearly all the options in commercial stage are proven SO_2 control technologies, which also remove Hg, advanced power generation options and power plant upgrading-fuel switching options. Nearly all in-situ and post-combustion controls (SO_2-NO_x or SO_2-NO_x-Hg) are either in demonstration or pilot-scale. Some technologies (e.g., SNO_X, SNRB, Advacate and CZD) have been tested either in pilot or demonstration scale in the early phase of the U.S. Department of Energy's Clean Coal Technology (CCT) program, but have not been adopted by the industry. Some of these technologies may become more cost-effective if additional controls are required. Most of the environmental control processes increase the auxiliary power requirements of the plant (some up to 5%, but mostly in the range of 1 to 2%), increasing proportionally the CO_2 emissions.

Emerging post-combustion, multi-pollutant control technologies are being developed by a number of companies. The Electro-Catalytic Oxidation (ECO) system is a four-stage pollution control process that integrates established technologies to remove SO_2, NO_x, Hg and PM2.5. The system also produces a valuable fertilizer byproduct. The AIRborne process removes SO_2 and NO_x from plant emissions while turning the leftover material into a high-quality granular fertilizer. EnviroScrub is a dry scrubbing system that results in control of SO_2, NO_x, and possibly mercury and results in a byproduct that can be sold into the fertilizer, chemical, and/or explosives industry. None of these technologies controls emissions of CO_2.

Capital costs of options controlling two pollutants (either SO_2-NO_x or SO_2-Hg) are projected to be in the 50-315 $/kW range, but there is significant uncertainty associated with these estimates because of their early stage of development. Also, lack of information, especially associated with O&M costs, makes it difficult to compare their cost-effectiveness. Further monitoring and updating of cost-related information is needed. For reference, the costs of the combined commercial technologies, FGD and SCR are above 200-250 $/kW.

Advanced power generation technologies such as circulating fluidized bed (CFB), pressurized fluidized bed (PFBC) and integrated gasification combined cycle (IGCC) are potentially attractive options because they are revenue-generating options, while reducing significantly SO_2 and NO_x, and to a lesser extent CO_2. These options are available mainly for new power plants. Also, supercritical pulverized coal boiler provides an attractive alternative to subcritical pulverized coal boiler for nearly the same investment and results in an additional 4-12% reduction of all emissions. While this may not seem to be a significant percentage, their cost-effectiveness is attractive; also, the amount of CO_2 reduction (in tons or tons per year) is significant.

Of particular interest are options such as power plant optimization, fuel blending or switching and power plant upgrading. These options may play an important role in a flexible compliance regulatory framework and may result in significant savings for the utility industry compared to the implementation of control technology options. Optimization involves only operating changes, and while it results in only minor emission reductions, its costs are very low and therefore it is an attractive option and should be pursued in all power plants. Fuel blending or switching, and power plant upgrading provide significant opportunities for emission control, but their site-specific nature makes it difficult to generalize regarding their emission reduction potential and cost-effectiveness. A more site-specific assessment is recommended to assess the potential for these options in a typical utility system.

Table 25. Commercial and Emerging Multi-Pollutant Control Technologies for External Combustion Boilers.

Technology	Status	Emissions Reductions	Applicability	Issues
SO_2/Mercury Control				
Dry Scrubbers (conventional)	C	SO_2: >95%; NO_x: NA; Hg: 5-85%	Low to medium sulfur coals	Hg removal can vary significantly with coal type, operating conditions
SO_2 sorbents, low temperature	P/C	SO_2: 40-85%; NO_x: NA; Hg: 0-90%	Units with ESP or FF for particulate control	Potential impacts on ESP or FF
SO_2 sorbents, furnace injection	C/D	SO_2: 65-70%; NO_x: NA; Hg: 65-90%	Existing plants, especially older units less than 300 MW	Demonstration on long-term basis needed
Activated carbon with SO_2 sorbent processes	P/C	SO_2: 40-85%; NO_x: NA; Hg: 50-90%	Units with ESP or FF for particulate control	Not used commercially, potential impacts on ESP or FF
Wet FGD with mercury oxidation processes	P	SO_2: 95%; NO_x: NA; Hg: 80+%	Wet Scrubber Plants	Full scale demonstration underway, insufficient information at present
Wet FGD with wet ESP	C/P	SO_2: 99%; NO_x: NA; Hg: 80+%	Integration with wet scrubbers, retrofit dry ESPs, new units	Few application in power industry, potentially expensive alloys required
Advanced Dry FGD	P/C	SO_2: 90-98%; NO_x: NA; Hg: <90%	NOX-Hg control for low to medium sulfur coals(same as Spray Dryers)	Hg removal may vary significantly with coal type, operating conditions (similar to Spray Dryers)
SO_2/NO_x Control				
E-BEAM	C/D	SO_2: 95+%; NO_x: 50-90%; Hg: NA	New and retrofit	High costs and auxiliary power requirements
SNOX	C	SO_2: 90+%; NO_x: 50-90%; Hg: 0%	New and retrofit	Cost-effectiveness
SNRB	P	SO_2: 80-90%; NO_x: 50-90%; Hg: 0%	New and retrofit	Requires demonstration
AIRborne	D	SO_2: 90->99%; NO_x: 50-60%; Hg: 30-75%	New and retrofit	Demonstration in progress; capital cost comparable to FGD-SCR
Thermal NOX	D	SO_2: 90-95%; NO_x: 80-90%; Hg: NA	New and retrofit	In demonstration

Status: P = pilot stage; C = commercial; D = demonstration

Table 25. Commercial and Emerging Multi-Pollutant Control Technologies for External Combustion Boilers. [Continued]

Technology	Status	Emissions Reductions	Applicability	Issues
SO_2/NO_x/Mercury Control				
Activated Coke	C	SO_2: 90-98%; NO_x: 60-80%; Hg: 90-99%	New and retrofit	High costs, especially operating costs due to high activated coke costs
Activated carbon with particulate controls	P/C	Hg: 50-90%	Retrofit and new units with ESP an/or FF	Not widely demonstrated at full scale, ash salability, ESP/FF performance, impact of mercury speciation
Electro Catalytic Oxidation	D	SO_2: 95-98%; NO_x: 90%; Hg: 70+%	New and Retrofit	Demonstration required
EnviroScrub	D	SO_2: 99+%; NO_x: 99%; Hg: 60-70%	New and retrofit.	Demonstration required; costs estimated to be 30-50% lower than FGD-SCR
Wet FGD and SCR	C	SO_2: 95%; NO_x: 90-95%; Hg: 0-80%	Plants with SCR and Wet scrubber technologies	Depends on Hg speciation in flue gas.

Status: P = pilot stage; C = commercial; D = demonstration

6 SUMMARY AND RECOMMENDATIONS

6.1 NO_x and PM Sources

The main objectives of this project were to identify and briefly describe the available (or emerging) technologies for control of NO_x and PM emissions that could be applied to sources in the western United States. The starting point for this work was an analysis of large (greater than 100 TPY) sources from the WRAP 1996 Emission Inventory (Version 3). Sources were limited to those from the thirteen-state region: AZ, CA, CO, ID, MT, ND, NM, NV, OR, SD, UT, WA, and WY.

The source profile from the thirteen-state region was compared with that from the nine-state GCVTR: AZ, CA, CO, ID, NM, NV, OR, UT, and WY. The GCVTR accounted for 75% of the NO_x emissions and 83% of the PM emissions within the thirteen-state region. Generally, the distribution of sources was the same in the GCVTR as compared to the thirteen-state region. Thus, conclusions based on the thirteen-state region should therefore be valid for the GCVTR while achieving broader applicability to WRAP members.

The cut-off of 100 TPY captures 84% of the NO_x emissions in the 1996 WRAP database for the thirteen-state region. For ICE's (reciprocating engines and turbines) the 100 TPY cut-off only captures about 56% of the emissions, though this category is the second largest category and responsible for 10% of stationary source emissions. Thus, NO_x control programs for sources in this category will require careful consideration of population attributes (e.g., a large number of small sources).

The largest source category for NO_x by far in the thirteen-state region is coal-fired boilers (68%); the top five categories (coal-fired boilers, internal combustion engines, cement kilns, turbines and oil and natural gas boilers) account for 90% of the NO_x emissions. The states with the largest stationary source NO_x emissions according to the 1996 WRAP database were AZ, CA, ND, NM, UT, and WY.

According to the WRAP 1996 (Version 3) stationary source emissions database, about 4% of the NO_x sources greater than 100 TPY had at least one type of control. Coal-fired boilers had the highest level of control (15%), followed by petrochemical processes (13%). The level of control for coal-fired boilers seemed low, even for 1996. Therefore, the 1996 WRAP database was compared with the data available for utility boilers in the 1996 CEMS and E-GRID databases. The EIA-767 database was also searched for NO_x control technologies. This comparison only looked at coal-fired utility boilers and not all coal-fired boilers. However, only 3% of the WRAP NO_x emissions from coal-fired boilers in the thirteen-state region were from non-utility boilers. WRAP data augmented by these other databases suggested that 44% of the utility boilers had at least one type of NO_x control in 1996, mostly low-NO_x burners.

The NO_x emission rate from external combustion boilers that is achievable with combustion modification depends on the fuel type. For coal-fired boilers, lower NO_x emission rates are obtained when firing subbituminous coal as compared to bituminous coal. Considering the

amount of subbituminous coal in the West, there is a fairly even split between bituminous and subbituminous coals as fuels for utility boilers. This may have shifted since 1996, however.

The cut-off of 100 TPY captures 60% of the PM emissions in the 1996 WRAP database for the thirteen-state region. The largest source category in the thirteen-state region is coal-fired boilers (40%); the top eight categories account for 92% of the PM emissions (greater than 100 TPY): coal-fired boilers, mineral processing, petrochemical, wood boilers, fugitive, primary metal production, pulp and paper, and smelting operations. The state with the largest PM emissions is WY, followed by AZ, ID, and NM.

In the 1996 WRAP database, 72% of coal-fired boilers, the largest category of emissions, had PM controls. Overall, though, only 38% of units had PM controls.

6.2 Controls for NO_x and PM

Many commercially available technologies exist for control of NO_x and PM emissions from stationary sources. Twenty-five NO_x control technologies and four PM control technologies were summarized. Cost and performance information was obtained for most technologies.

There are a lot more technologies available for NO_x control because of the different ways in which NO_x can be prevented or destroyed. In contrast, PM control on industrial processes is often done only at the back end of the process. This is not to say that process modification cannot be used to reduce PM emissions. Fugitive emissions, for example, can sometimes be controlled by process modification. Further work should be done to look into the details of important industrial processes to determine where process modification will yield significant reductions in PM.

Most of the NO_x emissions from stationary sources are generated by combustion or by high temperature thermal processing. NO_x control technologies fall broadly into two categories: combustion modifications and post-combustion removal or destruction. Combustion systems differ, from internal combustion engines to external combustion boilers. Thus, there are many different strategies for modifying the combustion process. Deciding on an appropriate NO_x control technology is highly dependent on the process conditions and on the type of fuel. The existing NO_x control technology on a particular source will also influence what additional NO_x controls can be added successfully. Post-combustion NO_x controls are not truly “back-end” technologies, like ESPs and baghouses for PM control; some degree of process integration is required. Thus, not all post-combustion control processes can be applied to a given source.

There is no “one size fits all” solution for NO_x control. Deciding which technology to apply to a certain source depends on:

- The fuel type;
- The specific combustion process;
- Post-combustion characteristics: temperature, residence times, etc.;
- The type of NO_x control technology already in use; and
- The target NO_x emission rate.

Emerging environmental issues and regulatory changes have driven interest in multi-pollutant (as opposed to single pollutant) control technologies capable of addressing air pollutant emissions more comprehensively with greater flexibility and ultimately lower cost. Multi-pollutant control technologies integrate in-situ and/or post-combustion controls of at least two of the following: SO_2, NO_x, and mercury pollutants, and CO_2 emissions. Multi-pollutant controls are intended primarily for external combustion boilers, particularly coal-fired boilers. The complexity of some of these processes as well as regulatory drivers often limit them to larger, power-generation boilers.

Emerging post-combustion, multi-pollutant control technologies are being developed for SO_2, NO_x, and mercury that could be applied to stationary combustion sources in the western U.S. in the next five or ten years. These processes generally produce a saleable byproduct and have SO_2 removal rates of greater than 50%, and NO_x removal rates of greater than 70%. Several of these processes are currently in pilot or full-scale demonstration. Costs of options controlling two pollutants (either SO_2-NO_x or SO_2-Hg) are projected to be in the 50-315 $/kW range, but there is significant uncertainty associated with these estimates because of their early stage of development. Also, lack of information, especially associated with O&M costs, makes it difficult to compare their cost-effectiveness. Further monitoring and updating of cost-related information is needed. For reference, the costs of the combined commercial technologies, FGD and SCR are above 200-250 $/kW.

6.3 What's on the horizon? What trends will influence emissions and control technologies?

- The rate of advancement and use of multi-pollutant technologies (NO_x/Hg, SO_2/Hg, PM/Hg, etc.) will depend on the levels of future mercury emissions reduction.

- Significant enhancements have been made in the ability of combustion modifications to reduce NO_x formation, but they may be reaching their maximum potential given the theoretical limits within the combustion process and given the nitrogen content of some fuels (e.g., coal). Determining how much NO_x emissions can be reduced in the West through this type of technology will require closer examination of the types and vintages of combustion modifications already in place.

- There is (and always will be) uncertainty in the future mix of fuels for some combustion processes (e.g. electricity production). This influences the retirement of existing sources and the investment in new sources, which, in turn requires that a range of projections be made for future source distribution scenarios.

- Historically new technologies have had one major evaluation criteria in common: their performance improvement over the existing technology (e.g. SCR capable of 90% reductions over SNCR). As technologies push the potential control levels to 90% or more, we need to view them from a new perspective, one which includes greater emphasis on overall impacts, costs, inter-pollutant compatibility, etc.

6.4 Recommendations for Future Work

Further work must be done in order to generate both accurate costs and reasonable control scenarios to be used in both regional-scale atmospheric models and in evaluating regional control strategies, particularly in light of the multi-pollutant control legislation currently under consideration in Congress. This includes the following:

- Accurate cost information (generally available now);
- Details of the emission-generating processes;
- NO_x and PM control technologies already in place; and
- Accurate estimates of the current emissions.

Better use could be made of existing EPA databases; in addition, the WRAP database should be updated to give a more accurate description of sources and existing control technology.

In this work, we found that the EPA databases (CEMs and E-GRID) were easy to use and provided what appeared to be a fairly complete picture of current emissions and control technologies for NO_x and PM. Since much has changed in the West since the 1996 WRAP stationary source inventory, these databases are useful for getting more current information on utility boilers, which generate a significant amount of the emissions in the western U.S. It would be worthwhile now to look at trends in emissions and NO_x control technologies in the West by analyzing the most recent CEMs and E-GRID databases.

Sufficient detail about the configuration and process of the sources is generally not available in the EPA databases and these databases are only for utility boilers. The next WRAP inventory should be used to collect the information needed to make estimates of costs for control. Better identification of sources is important; there are instances in the 1996 WRAP database in which there is insufficient information on the type of source and/or the fuel in use. Obviously, better identification of existing air pollution control technology is critical. For combustion sources, particularly utility boilers, the capacity, in terms of MBtu/yr should also be included in the WRAP database.

Consideration should also be given to selecting a subset of sources for detailed characterization and calculate ranges of costs and expected emissions reductions. The subset should be a representative distribution of those sources within the most important source categories.

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APPENDIX A : Breakdown of NO_x Emissions by State

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State

Category	13-States		AZ*		CA*		CO*	
	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)
Coal-Fired Boilers	151	607,748	15	75,018	3	1,544	31	82,927
Reciprocating Engines	423	86,210	16	6,441	58	10,274	56	11,328
NG	*404*	*81,786*	*14*	*5,731*	*54*	*9,436*	*56*	*11,328*
Diesel	*16*	*4,021*	*2*	*709*	*3*	*708*		
Process Gas	*3*	*403*			*1*	*130*		
Cement Kilns	39	41,009	2	4,662	16	15,886	4	4,470
Oil/NG Boilers	112	32,910	4	1,092	40	12,290	9	2,643
Turbines	86	25,278	8	1,918	37	8,990	9	1,655
NG	*83*	*24,821*	*7*	*1,795*	*37*	*8,990*	*9*	*1,655*
Diesel	*3*	*457*	*1*	*123*				
Mineral Processing	34	16,250	4	2,861	4	3,263		
Petrochemical	48	13,719	1	101	13	3,978	4	730
NG Compressor	16	10,959	14	10,686				
Pulp and Paper	39	10,010			3	602		
Wood Boilers	48	9,776			14	2,430		
Refinery Process Heaters	38	9,311			28	7,096		
Glass Manufacture	14	5,033			11	4,128	1	251
Primary Metal Production	17	3,476	2	1,009			2	244
Waste Combustion	6	3,309						
Refinery Emissions	8	3,256			8	3,256		
In-process Fuel Use	9	2,605			7	1,906		
Jet Engine Testing	4	2,297			4	2,297		
Oil and Gas Production	7	1,140						
Smelting Operations	3	961	2	852				
Sugar Beet Production	3	730			1	111		
Secondary Metal Production	4	507						
Turbines, Steam	1	165			1	165		
Total (> 100 TPY)	1,110	886,659	68	104,639	248	78,217	116	104,249

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	ID*		MT		ND		NM*	
	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)
Coal-Fired Boilers	6	2,218	6	25,452	17	108,007	10	70,193
Reciprocating Engines			14	4,357	8	2,569	201	37,755
NG			*4*	*2,056*	*8*	*2,569*	*201*	*37,755*
Diesel			*10*	*2,301*				
Process Gas								
Cement Kilns			1	1,662			1	1,000
Oil/NG Boilers			1	128	3	909	10	3,389
Turbines	1	139	0	0	3	564	12	2,947
NG	*1*	*139*			*3*	*564*	*12*	*2,947*
Diesel								
Mineral Processing	1	117	3	428			1	145
Petrochemical	3	1,449	5	842	1	915	1	124
NG Compressor								
Pulp and Paper	3	377	4	920				
Wood Boilers	4	708	4	1,057			1	360
Refinery Process Heaters							1	206
Glass Manufacture								
Primary Metal Production								
Waste Combustion					4	2,971		
Refinery Emissions								
In-process Fuel Use			1	589				
Jet Engine Testing								
Oil and Gas Production					2	348	1	140
Smelting Operations								
Sugar Beet Production					2	619		
Secondary Metal Production								
Turbines, Steam								
Total (> 100 TPY)	18	5,008	39	35,436	40	116,901	239	116,258

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	NV*		OR*		SD		UT*	
	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)	# Units	Total NO_x TPY (>100 TPY)
Coal-Fired Boilers	8	39,040	1	4,195	3	17,268	15	66,600
Reciprocating Engines							15	2,074
NG							*14*	*1,772*
Diesel							*1*	*303*
Process Gas								
Cement Kilns	2	3,789	2	687	3	2,718	2	565
Oil/NG Boilers	6	3,727	6	2,155			1	267
Turbines	1	191	3	5,372	2	435	3	772
NG			*2*	*5,229*	*2*	*435*	*3*	*772*
Diesel	*1*	*191*	*1*	*143*				
Mineral Processing	2	218			2	577	5	4,542
Petrochemical							2	324
NG Compressor							2	273
Pulp and Paper			14	3,641				
Wood Boilers			17	3,366				
Refinery Process Heaters								
Glass Manufacture								
Primary Metal Production	1	125	3	514			7	1,263
Waste Combustion							2	339
Refinery Emissions								
In-process Fuel Use	1	109						
Jet Engine Testing								
Oil and Gas Production								
Smelting Operations								
Sugar Beet Production								
Secondary Metal Production								
Turbines, Steam								
Total (> 100 TPY)	21	47,199	46	19,929	10	20,998	54	77,020

*** GCTVR State**

Table A-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	WA		WY*	
	# Units	Total NOx TPY (>100 TPY)	# Units	Total NOx TPY (>100 TPY)
Coal-Fired Boilers	8	20,138	28	95,148
Reciprocating Engines	7	1,191	48	10,219
NG	*5*	*918*	*48*	*10,219*
Diesel				
Process Gas	*2*	*273*		
Cement Kilns	4	4,126	2	1,444
Oil/NG Boilers	28	5,758	4	553
Turbines	3	324	4	1,971
NG	*3*	*324*	*4*	*1,971*
Diesel				
Mineral Processing	4	1,904	8	2,197
Petrochemical	11	3,635	7	1,619
NG Compressor				
Pulp and Paper	15	4,471		
Wood Boilers	8	1,856		
Refinery Process Heaters	9	2,009		
Glass Manufacture	2	654		
Primary Metal Production	1	116	1	205
Waste Combustion				
Refinery Emissions				
In-process Fuel Use				
Jet Engine Testing				
Oil and Gas Production			4	652
Smelting Operations	1	109		
Sugar Beet Production				
Secondary Metal Production	4	507		
Turbines, Steam				
Total (> 100 TPY)	105	46,798	106	114,009

***GCVTR State**

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APPENDIX B : Breakdown of PM Emissions by State

Table B-1. WRAP PM Emissions for sources > 100 TPY by State

Category	13-States		AZ*		CA*		CO*	
	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY
Coal-Fired Boilers	88	46,010	9	2,657	1	699	3	684
Mineral Processing	85	24,499	14	4,932	5	710	18	4,700
Petrochemical	42	10,836			5	834	4	757
Wood Boilers	24	5,718			3	471		
Refinery Emissions	11	5,631	2	3,949	1	104	3	843
Primary Metal Production	20	4,697	3	529	1	139	1	232
Pulp and Paper	15	4,476			2	272		
Smelting Operations	8	3,555	1	137				
Miscellaneous	1	2,456			1	2,456		
Oil/NG Boilers	5	1,379						
Sugar Beet Processing	5	1,150	1	210	1	110	1	430
Cooling Tower	4	932						
Cement Kilns	4	641			1	132		
Turbines	2	838	1	590			1	248
Diesel	1	590	1	590				
NG	1	248					1	248
Secondary Metal Production	1	537						
Jet Engine Testing	2	535			2	535		
Reciprocating Engines	3	525	1	104			1	169
Diesel	2	273	1	104			1	169
NG	1	252						
Refinery Process Heaters	1	176			1	176		
Total	**321**	**114,589**	**32**	**13,107**	**24**	**6,638**	**32**	**8,063**

*** GCTVR State**

Table B-1. WRAP PM Emissions for sources > 100 TPY by State [continued]

Category	ID*		MT		ND		NM*	
	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY
Coal-Fired Boilers	8	5,180	4	3,990	11	3,679	9	7,285
Mineral Processing	5	1,864	9	2,565	1	110	2	270
Petrochemical	4	688	2	274	1	590	1	307
Wood Boilers	6	1,683	2	242				
Refinery Emissions								
Primary Metal Production			1	477				
Pulp and Paper	6	2,949						
Smelting Operations			1	158			4	1,242
Miscellaneous								
Oil/NG Boilers								
Sugar Beet Processing					1	297		
Cooling Tower								
Cement Kilns	1	216	1	117			1	176
Turbines Diesel NG								
Secondary Metal Production								
Jet Engine Testing								
Reciprocating Engines Diesel NG								
Refinery Process Heaters								
Total	**30**	**12,579**	**20**	**7,825**	**14**	**4,676**	**17**	**9,280**

*** GCTVR State**

Table B-1. WRAP PM Emissions for sources > 100 TPY by State [continued]

Category	NV*		OR*		SD		UT*	
	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY	# Units	Total PM TPY
Coal-Fired Boilers	8	5,688	1	108	2	236	8	2,436
Mineral Processing	2	244					11	2,510
Petrochemical								
Wood Boilers			11	3,056				
Refinery Emissions					1	233		
Primary Metal Production	1	211	1	276			4	857
Pulp and Paper			5	898				
Smelting Operations							2	2,017
Miscellaneous								
Oil/NG Boilers	4	1,235	1	144				
Sugar Beet Processing								
Cooling Tower								
Cement Kilns								
Turbines Diesel NG								
Secondary Metal Production			1	537				
Jet Engine Testing								
Reciprocating Engines Diesel NG								
Refinery Process Heaters								
Total	**15**	**7,379**	**20**	**5,019**	**3**	**469**	**25**	**7,820**

*** GCTVR State**

Table B-1. WRAP NO_x Emissions for sources > 100 TPY by State [continued]

Category	WA		WY*	
	# Units	Total PM TPY	# Units	Total PM TPY
Coal-Fired Boilers	4	2,968	20	10,400
Mineral Processing			18	6,594
Petrochemical	2	255	23	7,130
Wood Boilers	2	266		
Refinery Emissions	3	386	1	115
Primary Metal Production	8	1,976		
Pulp and Paper	2	357		
Smelting Operations				
Miscellaneous				
Oil/NG Boilers				
Sugar Beet Processing	1	103		
Cooling Tower			4	932
Cement Kilns				
Turbines				
Diesel				
NG				
Secondary Metal Production				
Jet Engine Testing				
Reciprocating Engines			1	252
Diesel				
NG			1	252
Refinery Process Heaters				
Total	**22**	**6,311**	**67**	**25,423**

***GCVTR State**

APPENDIC C: NO_x Control Technology Summaries

Process: Air or Fuel Staging				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	0 to 50%	1000-2000	Commercial

Process Description:

Inject portion of the fuel downstream of the main flame to create locally reducing conditions where NO_x can be destroyed. Sometimes includes installing a "NO_x fan" to increase burnout. Most commonly applied to preheater/precalciner kilns in which part of the coal is already being fired in the calciner. In this case, airflow is rerouted downstream of the calciner fuel injector.

Air and Fuel Staging as commonly applied to large industrial/utility boilers is discussed under the more commonly referred names technologies Overfire Air and Fuel Reburn

NO_x Reduction:

NO_x reduction is achieved by creating two separate combustion zones. The burner zone is fired fuel-lean to create the high temperatures needed for clinker formation. Limestone calcination, which takes place at temperatures in the range of 1600 to 1800 °F, is accomplished in the second combustion zone in the tower. NO_x reductions as high as 50% can be achieved by controlling the size of the fuel-rich region in the second combustion zone. Conversely, if combustion is fuel-lean or well-mixed in the second zone, NO_x would not be reduced. The ideal stoichiometric ratio in the calciner is 0.7 to 0.8. Some systems do not perform well because the second combustion zone is too fuel-rich (SR < 0.6), causing significant NO_x production when the staging air is added.

Cost Information:

Capital cost for the technology includes additional ductwork and controls. This should run between $200,000 and 500,000 depending on the length of new ductwork required. Operating cost should not change unless lower temperatures or locally reducing conditions adversely affect cement quality.

Development Status:

Commercially available.

Practical Considerations:

The technology is easier to implement on preheater/precalciner kilns since special injectors are required to introduce fuel or air into the middle of a rotating kiln. In either case, there must be sufficient residence time at high temperature to complete burnout.

Compatibility with other air pollution control technologies:

Reducing conditions may increase sulfur emissions or require additional SO_2 emission controls.

Process: Air or Fuel Staging
Secondary Environmental Impacts: None expected.
References: Dusome D. (1993). "Staged Combustion for NO_x Control at the Calaveras Tehachapi Plant", presented to the Portland Cement Association. Nielsen, P.B. et al. (1990). "An Overview of the Formation of SO_X and NO_X in Various Pyroprocessing Systems", IEEE Cement Industry Technical Conference. Johnson, S.A. and Haythornthwaite, S., "Summary of Available NO_x Control Techniques for the Cement Industry", submitted to the Portland Cement Association, Skokie, IL, 1998.

Process: Batch/Cullet Preheating				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Glass Manufacturing	5,033	5-25%	890-1,040	Commercial

Process Description:

Batch and cullet (recycled glass) preheating can be applied by direct preheating, indirect preheating and Edmeston EGB Filter. Direct preheating requires direct contact between the flue gas and the raw material in a cross-counter flow and incorporates a bypass that allows furnace operation to continue when preheater use is either inappropriate of impossible. The indirect preheater is in principle a cross-counter flow, plate heat exchanger. The Edmeston electrified granulate bed (EGB) filter system is a hybrid between an electrostatic precipitator for dust removal and a direct cullet preheater.

NOx Reduction:

Cullet preheating is primarily an energy saving technique (savings between 10-20%), but its practice reduces NO_x emissions due to lower fuel requirements and lower furnace temperatures.

Cost Information:

Capital costs generally range from $42K-110K. Economics are strongly dependent on the capacity of the furnace and the preheater.

Development Status:

Commercially available

Practical Considerations:

Cullet preheating systems can be installed at any existing glass melting furnace with greater than 50% cullet in the batch. For economic reasons, the temperature of the waste gas available should be at least 400-450°C, and a cooling of the flue gases by at least 200-250°C is needed. To prevent material agglomeration, the maximum entry temperature of the flue gases should not exceed 600°C.

The design and implementation of the preheating unit should be evaluated with the over-all system configuration. Many technical issues, such as monitoring of the preheating temperature, should be carefully reviewed prior to the implementation.

Compatibility with other air pollution control technologies:

Cullet preheating is compatible with combustion modification techniques and post-combustion technologies.

Secondary Environmental Impacts:

- The use of a direct preheater causes increased emissions of particulate matter (up to 2000 mg/Nm^3) and secondary particulate abatement is necessary.
- Direct preheating reduces acidic compounds, SO_2, HF, and HCl by up to 60%, 50%, and 90% respectively (difference before and after cullet bed).

References

European IPPC Bureau. "Reference Document on Best Available Techniques in the Glass Manufacturing Industry." Seville, Spain, October, 2000.

Process: Catalytic Combustion				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Combustion or Gas Turbines	25,278	> 80%	> 500	Commercial

Process Description:

Catalytic combustion reduces NO_x formed from the combustion process by reducing the combustion temperature to reduce thermal NO_x. The fuel and air are premixed into a fuel-lean mixture (fuel/air ratio of approximately 0.02) and then pass into a catalyst bed. In the bed, the mixture oxidizes without forming a high-temperature flame font. Peak combustion temperatures can be limited to below 2800 °F, which is below the temperature at which significant amounts of thermal NOx begin to form. Catalytic combustors can also be designed to operate in a rich/lean configuration. In this case, the air and fuel are premixed to form a fuel-rich mixture, which passes through a first stage catalyst where combustion begins. Secondary air is then added to produce a lean mixture, and combustion is completed in a second stage catalyst bed.

NO_x Reduction:

According to one developer of the technology, catalytic combustion has been demonstrated to achieve 3 ppm NO_x on a 1.5 MW gas turbine. NO_x level of 3.3 ppm was achieved on a General Electric Frame 9 test stand.

Cost Information:

Costs referenced above are preliminary and based on DOE reference below.

Development Status:

Commercially available.

Practical Considerations:

Catalytic combustion techniques apply to all combustor types and are effective on both diesel- and gas-fired turbines. The technology has a limited operating range, and thus cannot be applied to gas turbines subject to rapid load changes.

Compatibility with other air pollution control technologies:

Compatible with post-combustion technology.

Secondary Environmental Impacts:

None expected.

References:

NESCAUM, " Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and Internal Combustion Engines: Technologies and Cost Effectiveness," December 2000

U.S. Environmental Protection Agency. "Alternative Control Techniques Document-NO_x Emissions from Stationary Gas Turbines." EPA-453/R-93-007, Research Park Triangle, NC, January 1993.

DOE, "Cost Analyses of NO_x Control Alternatives for Stationary Gar Turbines", November 1999.

Process: DLN (Fuel-lean combustion)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Turbines	25,278	70%	1,000-2,000	Commercial

Process Description:

Dry Low NO_x (DLN) is a combustion technology for gas turbines that enables gas-turbine combustors to produce low NO_x emission levels without diluents (such as water or steam) or catalysts. DLN technology utilizes a lean, premixed flame as opposed to a turbulent diffusion flame, a gas turbine equivalent of the LNB.

NO_x Reduction:

Engines from 3-10 MW retrofit with DLN achieved 42 ppm NO_x emissions, corresponding to reductions in the range of 60-83%. New and retrofit turbines in the larger, power plant sizes (over 50 MW) have been retrofitted to below 9 ppm of NO_x.

Cost Information:

The cost of NO_x reduction by DLN is very sensitive to the capacity factor of the turbine. There is also substantial variation in capital cost measured in terms of dollars/horsepower ($/hp) due to different turbine types and variations in turbine design. Reported costs in case studies show capital costs ranging from $750K-1,950K (4,700 hp at $160/hp and 13,000 hp at $150/hp). These are total project costs that owners attributed to the project, which may include project management or other charges associated with the project beyond the equipment and installation.

Development Status:

Commercially available

As of August 2000, about 50 turbines had been retrofitted and over 500 new turbines were operating with DLN technology.

Practical Considerations:

Because DLN 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. Manufacturers have developed improved electronic turbine controls to address this problem. Some early experience has also found combustor liners failing after only about 5,000 hours compared to over 20,000 hour lifetime for conventional technology. Similarly, manufacturers have developed improved liners to address this problem.

Other considerations are:

- DLN is achievable with fuels that can be premixed and are low in fuel nitrogen content, such as natural gas. Turbines that must maintain low NOx levels while operating on fuel oil may not be compatible with DLN.
- Achieving low NO_x across the full load range requires a sophisticated combustor design, often with variable operating modes in order to maintain flame stability.

Process: DLN (Fuel-lean combustion)
• The DLN combustor is typically larger than a conventional combustor and can have more limited operating ranges.
Compatibility with other air pollution control technologies: Compatible with post-combustion technology (SCR, SNCR).
Secondary Environmental Impacts: None expected.
References: NESCAUM, " Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and Internal Combustion Engines: Technologies and Cost Effectiveness" December 2000.

Process: Flue Gas Recirculation (FGR)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Oil/Natural gas boilers	32,910	40-80%	500-3,000	Commercial
Refinery Process Heaters	9,311	(combined with LNB)	5,900	Commercial

Process Description:

Flue Gas Recirculation (FGR) simply refers to a NO_x reduction approach that involves reintroducing some flue gas (5% to 15%) into the combustion air (or directly into the burner) to suppress flame temperatures and minimize NOx formation.

This technology usually involves a dedicated FGR fan to recirculate the flue gas back to the burner front and it is most applicable to gas fired applications. This is because its main benefit is in the minimization of thermal NO_x (NO_x formed from nitrogen in the combustion air), as opposed to fuel-NO_x (NO_x formed from fuel-bound nitrogen). Since in oil and coal sources a significant fraction of NO_x comes from "fuel-NO_x", FGR is less effective in such applications

NO_x Reduction:

NO_x reductions from FGR on gas-fired sources can be in the range of 40% to 80%.
FGR is often used in combination with LNBs and discriminating between the relative NOx reduction contributions is difficult in some cases.

Cost Information:

The main costs associated with FGR involve the retrofit of the FGR fan(s) and required ductwork to route the flue gas to the burner front. Costs in the range of $10 - $20/kW are expected for power generation sources

Development Status:

FGR is a well-proven technology in commercial operations for many years. Variations of the general concept include Induced FGR where the gas recirculated to the burner zone through an eductor, as well as recirculated to individual burners as opposed to the combustion air windbox for mixing with the combustion air prior to entering the burners.

Practical Considerations:

As mentioned above, FGR is mostly appropriate for gas-fired applications. Its effectiveness on oil and coal reduce its "appeal" to such sources

Care is necessary to ensure that the amount of FGR does not compromise boiler safety by diluting oxygen concentration in the combustion air to unsafe levels

Process: Flue Gas Recirculation (FGR)
Compatibility with other air pollution control technologies: FGR is used in combination with LNB's and OFA. FGR is also compatible with post combustion NO_x technologies although the overall cost effectiveness needs to be addressed case-by-case.
Secondary Environmental Impacts: None expected.
References: EPRI, "Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers", Final Report, December 1993. Poole, L., "Houston Galveston Area NO_x Abatement Industries Perspective," present at the Council of Industrial Boiler Owners, NO_x Control XV Conference, Houston, TX, August 2002.

Process: Fuel Reburn				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired boilers	607,748	30-60%	500-2,000	Commercial
Wood/Biomass boilers	9,776	40-60%	300-3,000	Commercial
Glass Melters	5,033	50-65%	"moderate"	Commercial

Process Description:

Reburning, while generically included in the "Combustion Modification" category of NO_x control technologies, differs from the others (BCM, LNB and OFA) by "destroying" NO rather than by minimizing its formation. Fuel is introduced above the main burner zone in the furnace, creating a fuel-rich (reducing) atmosphere in which NO_x formed in the main burner zone is destroyed by reacting with hydrocarbon and nitrogen compounds. The hardware needed for reburning includes reburn fuel burners or nozzles and overfire or burnout air ports (see discussion on fuel-lean reburn for deviations from this). The level of complexity of a particular system depends mostly on the choice of the reburn fuel itself (gas, coal, oil, orimulsion), as well as on the status and capability of the existing boiler (e.g., the burner/boiler control system).

NO_x Reduction:

Full load NO_x reductions with reburning can be expected to range from 35% to 60% depending on factors such as:

- reburn fuel type and quantity; typically the reburn fuel needs to provide 15-20% of the total heat input if it is gas or 25-30% if coal to obtain 50-60% ΔNO_x
- initial NO_x level
- "tolerance" of negative impacts (e.g., efficiency loss, ash quality)

At low loads, NO_x reduction may fall to the 20-40% range, depending on the burner zone stoichiometry and low load operating characteristics of the boiler (e.g., operating at high excess air to control reheat temperature). Reburning, like SNCR and SCR, may be thought of as a "dial-in" technology in that NO_x reductions will be a function of the amount of reburn fuel (or the amount of nitrogen compound reagent in the case of SNCR and SCR). This feature may make it particularly attractive for compliance scenarios based on seasonal use, averaging and/or trading.

Cost Information:

In general, the capital costs range from $15/kW to $30/kW for gas reburn and $30/kW to $60/kW when using coal as the reburn fuel. Operating costs are mainly driven by fuel cost differential (certainly gas vs coal). For other fuels (e.g. coal/orimulsion reburning), fuel preparation costs become more important (micronization, atomization) as there is little or no fuel cost differential.

Retrofit schedules are directly related to the scope of the retrofit requirements. In most cases, 3-6 weeks are adequate for a reburn retrofit.

Process: Fuel Reburn
Development Status: Commercial While reburning does not account for a significant fraction of installed NO_x reduction technologies compared to LNBs, SNCR and SCR worldwide, it is gaining acceptance, and a number of recent activities suggest it has become a viable strategic option for $_{NOx}$ control. This increase in interest is due to two key factors, among others: (1) increased experience and encouraging results, which increase the level of comfort with the technology; and (2) the "proliferation" of advanced reburn technologies, each with its own features, advantages and disadvantages. These "advanced" reburning options involve enhancements of the conventional approach, with features ranging from combinations with SNCR to the outright avoidance of overfire air, as in fuel-lean gas reburn (FLGR).
Practical Considerations: Boilers with the following design and operating characteristics are expected to be more suitable candidates for reburning: • firing low-sulfur coals (e.g., less propensity for waterwall corrosion) • low baseline unburned carbon (e.g., to minimize ash salability impacts). • favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness). • gas availability, very efficient/effective coal pulverizers (e.g., approaching micronization) or access to orimulsion for the reburn fuel Of major importance is the choice of reburn fuel. The increasing experience with coal and orimulsion dictates that these must be considered in light of cost, availability, deliverability and overall project objectives. However, the use of natural gas provides benefits from lower maintenance costs (e.g., less demand on pulverizers) and lower emissions of other pollutants (particulate, SO_x, CO_2).
Compatibility with other air pollution control technologies: Reburn Technology can be implemented with both Low NO_x combustion approaches (e.g. LNBs) and post combustion technologies (SNCR/SCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.
Secondary Environmental Impacts: Reburn technology has the potential to effect both positive and negative secondary environmental impacts depending on factors such as the reburn fuel, main combustion and reburn zone stoichiometries, boiler physical characteristics, etc. The following are potential impacts that must be analyzed on an individual unit basis • CO may increase due to stoichiometry in the reburn zone • LOI may increase due to stoichiometries and OFA design

Process: Fuel Reburn
• SO_2/CO_2 benefits when reburn fuel is gas (proportional to gas input)
References: NESCAUM, "Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers", June 1998. EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update", EPRI Final Report, December 2000. Folsom, B. "Field Experience with Reburn NOx Control", ICAC Forum 2000, Arlington, VA. March 2000.

Process: High Energy Ignition System (HEIS)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	50% - 80%	115 - 200+	Commercial

Process Description:

HEIS technology, also known as plasma ignition, provides a continuous electrical discharge at the gap of a conventional spark plug for 10 to 90 degrees of crankshaft rotation as opposed to traditional spark ignition where the life of the spark is only a fraction of a degree of crankshaft rotation. The extended energy ensures that ignition will occur even in the leanest of conditions. A rich mixture is ignited in a small ignition cell located in the cylinder head. The ignition cell flame passes to the cylinder where it provides a uniform ignition source.

NO_x Reduction:

Laboratory tests and case studies have shown NO_x emissions in the range of 2.5 to 3.0 g/bhp-hr while maintaining acceptable engine operation. Emissions of 2.5 b/bhp-hr were achieved on a 2,750-bhp engine, amounting to an 84% reduction from the uncontrolled level.

Cost Information:

Cost information was not widely reported. Cost range indicated above was taken from the NESCAUM reference below.

Development Status:
Commercially available

HEIS has been installed on numerous engines to meet NO_x RACT requirements in the range of 2.5 to 3.0 g/bhp-hr in the Eastern United States. Several users have reported over 80% reduction in NO_x emissions.

Practical Considerations:

HEIS technology can be used only in lean-burn, natural gas-fired spark ignition engines. This technique can be retrofit to turbocharged 2- and 4-cycle engines.

Compatibility with other air pollution control technologies:

Compatible with post-combustion NO_x technologies (SCR, NSCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

In most cases, NO_x reductions have been accompanied by increased power output and increased fuel economy.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

NESCAUM, " Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers and

Process: High Energy Ignition System (HEIS)
Internal Combustion Engines: Technologies and Cost Effectiveness," December 2000. State of New Jersey Department of Environmental Protection. "State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines." Trenton, NJ, July, 1997. Alternative Control Techniques Document: NO_x Emissions from Stationary Reciprocating Internal Combustion Engines. EPA Document No. EPA-453/R-93-032, July 1993.

Process: High-Pressure Fuel Injection				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	~80%	N/A (less than LEC)	Commercial

Process Description:

High-Pressure Fuel Injection represents a "second generation" Low Emission Combustion (LEC), according to one vendor of NO_x control equipment and retrofit services. The technology uses high pressure to enhance the mixing of air and fuel in the combustion cylinder under fuel lean conditions. This technique reduces the quantity of excess air in comparison to LEC, diminishing the turbocharging and intercooling retrofit requirements.

NO_x Reduction:

Tests from a large (~5,000 bhp) turbocharged Clark engine showed 80% NOx reduction. May be comparable to LEC reductions.

Cost Information:

Less than LEC because the technology does not require pre-combustion chambers or as much excess air, thus reducing the degree of turbocharging and intercooling required.

Development Status:
Commercially available

Considered emerging in 2000.

Practical Considerations:

An LEC retrofit vendor stated that NO_x emissions cannot be reduced to 2 g/bhp-hr through the use of a high-pressure fuel system alone. Less stringent regulatory requirements cans be met with a combination of ignition timing adjustment, high-pressure fuel injectors, and improve A/F ratio and ignition system controls.

Compatibility with other air pollution control technologies:

Compatible with post-combustion NO_x technologies (SCR, NSCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

None expected.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

National Center for Environmental Research, U. S. EPA Office of Research and Development. "1994 Phase II Abstracts: Plasma Ignition Retard for NO(x) Reductions." http://es.epa.gov/ncerqa_abstracts/sbir/94/topics43.html.

Process: "Intelligent" Combustion Controls				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-Fired Boilers	607,748	0-30%	100-300	Commercial
Oil/Gas Boilers	32,910	0-30%	100-500	Commercial
Wood/Biomass Boilers	9,776	0-20%	200-500	Commercial

Process Description:

Sensors and computer software programs are used to control air-fuel ratio to individual burners. Conventional combustion systems provide measured airflow to the windbox (that feeds all burners) and to each pulverizer (that feeds from two to eight burners). However, coal flow to individual burners may deviate by as much as 50%, while airflow to each burner may deviate by over 20%. Measuring and controlling (using existing or new control valves) these quantities at each burner allows the boiler to operate with lower excess air or slightly staged. Sensors are also available to monitor post-combustion processes. Online measurements of unburned carbon and CO provide feedback for burner adjustments. Other sensors evaluate flame quality, furnace temperature, or boiler heat transfer. Software can be rule-based or neural net. Usually the new software resides on the operator's digital control system (DCS).

NO_x Reduction:

Full -load NO_x reductions with combustion monitoring and tuning can be expected to range from 0% to 30% depending on factors such as:

- Current state of "out of tune" combustion system.
- Initial NO_x level.
- Operational flexibility of the burner/furnace design.

The highest NO_x reductions are usually found on boilers that are able to bias their fuel input to lower burners and bias the airflow to upper burners. At low loads where there may be more operating flexibility, NO_x reduction may improve to the 20-40% range, depending on the burner zone stoichiometry and low load operating characteristics of the boiler (e.g., operating at high excess air to control reheat steam temperature).

Cost Information:

In general, the capital costs for combustion monitoring and tuning are less than $1M per boiler. Operating costs are mainly driven by additional labor to maintain the new equipment. Often the installation of this technology is driven by the potential to reduce boiler operational expenses. For example, if total airflow is minimized, boiler efficiency can be increased. Reducing unburned carbon in the ash residue will not only increase boiler efficiency but also could improve salability of this byproduct to the cement industry.

An outage is generally not required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service.

Process: "Intelligent" Combustion Controls
Development Status: Commercially available. Many of the sensors, however, are relatively new and do not have a track record for reliability and dependability. Since each application of the technology is custom-engineered, there may be a steep learning curve for every user. For now, each installation also requires onsite presence (for a few weeks) from the supplier or other combustion expert to achieve best results.
Practical Considerations: Boilers with the following design and operating characteristics are expected to be more suitable candidates for combustion monitoring and tuning: • Combustion equipment must be in good operating condition. The technology will not be able to overcome such factors as poor coal fineness or failure of burner parts. • Favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness). • Excess coal pulverizer capacity so that fuel biasing can be maximized. Of major importance is acceptance from boiler operators. If operators want to stick with old procedures and operating conditions, the effectiveness of the technology may not be realized.
Compatibility with other air pollution control technologies: Combustion monitoring and tuning can be implemented with both Low NO_x combustion approaches (e.g. LNBs) and post combustion technologies (SNCR/SCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.
Secondary Environmental Impacts: Combustion monitoring and tuning has the potential to affect both positive and negative secondary environmental impacts depending on factors such as the fuel, burner stoichiometries, boiler physical characteristics, etc. The following are potential impacts that must be analyzed on an individual unit basis • CO may increase due to stoichiometry in the burner zone • LOI may increase due to increased staging • ESP performance may degrade with increased LOI
References: Power Plant Optimization Guidelines, EPRI Report, December 1998 Alternative Control Techniques Document: NO_x Emissions from Industrial/Commercial/Institutional (ICI) Boilers. EPA Document No. EPA-453/R-94-022, July 1994. Alternative Control Techniques Document: NO_x Emissions from Utility Boilers. EPA Document No.

Process: "Intelligent" Combustion Controls
EPA-453/R-94-023, July 1994. Fuller, T., "Field Experience with the Flame Doctor™ System", EPRI/DOE/EPA Mega Symposium, Washington, May 2003 Kohn, D. "Combustion Optimization Case Studies & Emerging Applications", EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Iron Slag Addition (CemStar)				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	12-30%	0-100	Commercial

Process Description:

Change cement formulation by adding waste iron to lower clinkering temperature and suppress NO_x. The iron waste is usually supplied from local steel production facilities, which limits the technology to certain geographical areas.

NO_x Reduction:

NO_x reduction is achieved by reducing clinkering temperature as well as the required heat input to produce a ton of clinker. The technology reduces total NO_x emissions by about 20 to 30%, and also may increase clinker production.

Cost Information:

Iron addition provides an overall economic benefit while reducing total NO_x emissions. The technology is currently being used at several cement plants for its original purpose of increasing production capacity. There are no capital costs for installing the technology. Operating and maintenance costs depend on the cost of the iron (shipping can be a large portion of this cost).

Development Status:

Commercially available.

Practical Considerations:

There is a limit to how much iron that can be incorporated into the clinker. Cement product specifications may limit or prevent use of this technology for some products.

Compatibility with other air pollution control technologies:

Should not affect other control systems.

Secondary Environmental Impacts:

None expected.

References:

NESCAUM, "Status Report on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness." December 2000.

Process: Kiln temperature control				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	0 to 20%	200-500	Commercial

Process Description:

Add temperature-monitoring device to kiln controls to minimize high-temperature excursions where more NO_x is emitted.

NO_x Reduction:

NO_x reduction is achieved by measuring a characteristic flame-zone temperature and then controlling heat input to maintain that temperature. Without direct temperature measurement, temperatures fluctuate within a wide range since clinker formation is an exothermic reaction. When clinker formation slows down or stops, temperatures fall. Operators respond with a large burst of fuel that sends temperature up by as much as 500 °F. Then they back off the fuel input. Temperature measurement helps operators avoid losing clinker formation and thus maintain relatively steady kiln temperatures.

Cost Information:

Capital cost for the technology includes installation of a continuous temperature monitor along with control system upgrades to tie the temperature signal into the coal feed rate. Operating cost should not change unless lower temperatures adversely affect cement quality.

Development Status:

Commercially available.

Practical Considerations:

The dynamics of a cement kiln are very difficult to control, even with direct temperature measurement and control. Each kiln will react differently. It will require considerable operator experience to minimize the temperature on each kiln.

Compatibility with other air pollution control technologies:

Should not affect other control systems.

Secondary Environmental Impacts:

None expected.

Process: Kiln temperature control
References: U.S. Environmental Protection Agency. "Alternative Control Techniques Document: NO_x Emissions from Cement Manufacturing." EPA Document No. EPA-453/R-94-004, January 1994. Johnson, S.A. and Haythornthwaite, S., "Summary of Available NO_x Control Techniques for the Cement Industry", submitted to the Portland Cement Association, Skokie, IL, 1998.

Process: Low-Emission Combustion (LEC)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	80-90%	190-700	Commercial

Process Description:

NO_x formation from a spark-ignited engine is highest when the mixture is slightly fuel-lean. LEC enhances the effectiveness of the air/fuel ratio method by enabling much deeper leaning without the adverse effects associated with lean mixtures. Additional combustion air acts as a heat sink, lowering the temperature in the cylinder and reducing NO_x formation. Deeper leaning can be achieved by relocating the spark plug to a precombustion chamber (may use High-Energy Ignition, see associated description) where the mixture is somewhat richer than in the cylinder. Early sparking avoids problems associated with ignition and misfiring that can result form leaning the mixture. Some smaller engines use an "open chamber" LEC design instead of a precombustion chamber. These designs typically incorporate improved air-fuel mixing systems to achieve stable combustion under very lean conditions.

NO_x Reduction:

Large, stationary spark-ignition engines usually achieve 80% NOx reduction through a LEC Retrofit. A NOx emission level of 125 ppm (at 15% oxygen) is an achievable exhaust NOx value. Up to 90% reduction can be achieved in natural gas engines, and about 60-70% for landfill gas engines (probably due to lower initial NOx from the lower heating-value landfill gas).

Engines with open-chamber LEC technology typically are designed for excess air levels only slightly above 50%, while engines with precombustion chambers typically are designed for excess air levels of 75-100%. Consequently, prechambered engines have generally lower NOx emissions than do open-chamber models.

Cost Information:

The capital cost of retrofitting these engines depends on the engine BHP. For engines firing a single fuel, retrofits have been implemented costing $340/hp for 3400hp engines. A lower capital cost is expected for smaller, medium-speed engines, about $200/hp. Dual-fuel engines have much greater capital costs. For these engines (larger than 1,000 hp), the capital cost can be estimated by

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

Retrofitting a 2,500 hp engine is projected to cost $615/hp.

Development Status:

Commercially available

The California Air Resources Board considers LEC Retrofit a Reasonably Available Control Technology (RACT) for large spark-ignition engines. LEC based on precombustion chamber technology has been in use for over 20 years. All major manufacturers of lean-burn spark ignition engines offer LEC-equipped models. Retrofit kits are also available.

Process: Low-Emission Combustion (LEC)
Practical Considerations: Available for spark-ignition engines fired with gaseous fuels including dual-fuel engines operating in dual-fuel mode (as opposed to firing only diesel fuel). LEC can cause some fuel efficiency decrease. A reasonable fuel efficiency penalty is estimated to be on the order of 0.5%. Turbocharging and intercooling are required to avoid derate. In retrofit situations, this typically involves upgrading or replacing the turbocharger and intercooler, or adding this equipment. Other equipment associated with increased air flows may also need to be modified for LEC, such as the air intake and filtration system, the intercooler radiator, and the exhaust system and muffler. To maintain the optimum A/F ratio, an automated A/F ratio controller typically is used. The challenge with very lean combustion is to achieve proper ignition and stable combustion. Vendors of LEC technology (i.e., engine manufacturers and third-party retrofitters) have met these requirements with some combination of improved combustion chamber design, enhanced air-fuel mixing, and improved ignition systems.
Compatibility with other air pollution control technologies: Compatible with post-combustion NOx technologies (SCR, NSCR). However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.
Secondary Environmental Impacts: Emissions of products of incomplete combustion can increase.
References: Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000. NESCAUM. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness." December, 2000. 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. State of New Jersey Department of Environmental Protection. "State of the Art (SOTA) Manual for Reciprocating Internal Combustion Engines." Trenton, NJ, July, 1997. 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. Cooper-Bessemer. Facsimile from J. W. Hibbard to W. Neuffer, U. S. EPA. Information on Low Emission Combustion. Cooper-Bessemer, Cooper Energy Services, Mount Vernon, OH. March 3, 1999. 4pp. Dresser-Rand. Facsimile from C. F. Willke to W. Neuffer, U. S. EPA. Information on Low Emission Combustion. Dresser-Rand Services, Painted Post, NY. May 7, 1999. 2pp.

Process: Low-NO_x Burners				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-Fired Boilers	607,748	30 to 60%	200-1000	Commercial
Cement Kilns	41,009	0 to 20%	500-1000	Commercial
Oil/NG Boilers	32,910	30 to 60%	200-1000	Commercial
Glass Manufacturing	5,033	~ 40%	790-1,680	Commercial
Refinery Process Heaters	9,311	30 to 60%	5,900 (with FGR)	Commercial

Process Description:

LNB's operate on the principal of carefully controlling the rate of mixing of air and fuel within the flame so that peak flame temperatures are low and fuel-bound nitrogen is released in a region where the concentration of oxygen is very low. This inhibits the formation of both fuel and thermal NOx by reducing the concentration of oxygen in the flame zone. Most LNB's work by limiting the amount of air in the primary flame creating a central fuel-rich flame core. Additional air is introduced to surround the primary flame where the temperature is lower, limiting thermal NO_x formation. A few low-NO_x burners split the coal flow into two or more streams to create multiple fuel-rich regions. One Japanese burner concentrates the coal-primary air mixture, and introduces the dilute coal stream downstream of the burner while air is introduced only to the primary flame. The fuel introduced into the primary flame zone results in a high temperature fuel rich central flame. The balance of coal is added outside the primary flame where it burns at a lower temperature.

NO_x Reduction:

Full load NO_x reductions with Low-NO_x Burners can be expected to range from 30% to 60% depending on factors such as:

- Fuel type.
- Initial NO_x level.
- Excess air
- Operational flexibility of the boiler or furnace.

For coal-fired boilers, NO_x emissions rates as low as 0.15 lb/MBtu are achievable, particularly when burning low rank coals. However, the fuel nitrogen content of coal is such that significantly lower emission rates are probably not possible with coal. Lower emission rates can be achieved with natural gas. Installing Low-NO_x burners is usually the first step taken to reduce NO_x emissions.

Cost Information:

In general, the capital costs for burners range from $10,000 to 50,000 per burner plus installation. The lower end of this range applies when existing burners are modified instead of replaced to achieve lower NO_x. Operating costs are negligible unless increased unburned carbon results in lost revenues from ash sales. An outage is generally required when implementing this technology, but coal-flow sensors and adjustable orifices are best installed when a mill is out of service.

Process: Low-NO_x Burners
Development Status: Commercially available.
Practical Considerations: Since low-NO_x Burners usually produce longer flames, the size and shape of the furnace could cause problems for some installations. Flame impingement on sidewalls or rear wall can result in ash deposits, corrosion, or unacceptable unburned carbon in the flue gas. Most burners have optional configurations to shape the flame at the expense of less NO_x reduction.
Compatibility with other air pollution control technologies: Low-NO_x burners can be implemented with other NO_x-control technologies such as OFA, SNCR, or SCR. In general, the NO_x reduction achieved with LNB make post-combustion NO_x control technologies more cost-effective.
Secondary Environmental Impacts: Low-NO_x burners can cause both positive and negative secondary environmental impacts depending on factors such as the fuel, burner stoichiometries, boiler physical characteristics, etc. The following are potential impacts that must be analyzed on an individual unit basis • CO may increase due to stoichiometry in the burner zone • LOI may increase due to increased staging • ESP performance may degrade with increased LOI or finer particulate.
References: EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update", EPRI Final Report, December 2000 EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 1996 Update Addendum", May 1997

Process: Low-NO_x Calciners				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	30 to 50%	1000-5000	Commercial

Process Description:

Replace the riser duct in existing preheater/precalciner kilns with new equipment designed for staged combustion. The new duct has separated air and fuel injection points, and extended residence time downstream of the final air addition point to assure acceptable burnout and minimize CO or hydrocarbon emissions.

NO_x Reduction:

NO_x reduction is achieved by creating two separate combustion zones. The burner zone is fired fuel-lean to create the high temperatures needed for clinker formation. Limestone calcination, which takes place at temperatures in the range of 1600 to 1800 °F, is accomplished in the second combustion zone in the tower. NO_x reductions as high as 50% can be achieved by controlling the size of the fuel-rich region in the second combustion zone. Conversely, if combustion is fuel lean or well mixed in the second zone, NO_x will not be reduced. The ideal stoichiometric ratio in the calciner is 0.7 to 0.8. Some systems do not perform well because the second combustion zone is too fuel-rich (SR < 0.6), causing significant NO_x production when the staging air is added.

Cost Information:

Capital cost for the technology includes additional injectors, ductwork and controls. In some cases, the cyclones used to improve gas-solids contact are also replaced. Capital cost range from $500,000 and 5,000,000 depending on how much of the existing tower is replaced. Operating costs should not change unless cement quality degrades due to lower temperatures or locally reducing conditions. An outage is required to install the new equipment.

Development Status:

Commercially available.

Practical Considerations:

Space to fit the newer larger equipment may not be available in all kilns.

Compatibility with other air pollution control technologies:

Reducing conditions may increase sulfur emissions or require additional SO_2 emission controls.

Secondary Environmental Impacts:

None expected.

Process: Low-NO_x Calciners
References: Rother, R. and Kupper, D., "Staged Fuel Supply – An Effective Way of Reducing NO_x Emissions", Zement-Kalk-Gips, No. 9. 1989.

Process: Mid-Kiln or Tower Tire Injection				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Cement Kilns	41,009	15-30%	0-1000	Commercial

Process Description:

Cement kilns are normally fired with a single open-pipe burner fueled by coal or natural gas. However, a portion of the main fuel may be replaced by a waste fuel injected in the mid-kiln region of long, wet or dry kilns, or in the calcining region of tower kilns. Special injectors have been designed to time the introduction of two to four tires into the mid-kiln region as the kiln rotates. Due to rotation, tires can only fall into the kiln once per revolution when the door is on top. Alternately, tires can be dropped into the tower where temperatures are high enough to support combustion.

Mid-kiln tire injection is attractive because it not only reduces NO_x but also generates revenue in the form of tipping fees and reduced fuel requirements. Cadence Environmental Energy, a subsidiary of Ash Grove Cement, offers an automated whole-tire injection system, including a fork that picks up the tires and drops them into the kiln through a gate assembly. A second option is to set up a tire shredding operation on site and inject tire flake into the kiln.

NO_x Reduction:

NO_x is lowered by burning some of the fuel at a lower temperature, and by creating pockets of fuel-rich gas as the tires decompose. Hydrocarbons from tire destruction can reduce NO_x formed in the burner flame. Results to date have varied from 15 to 30% NO_x reduction, depending on:

- Kiln type.
- Number of tires injected.
- Injection temperature.

In some installations, a booster fan has been mounted on the kiln downstream of the tire injection point to provide additional burnout air. This "NO_x fan" gets rid of the high CO or smoke emissions caused by the tires, and may allow operation at higher tire injection rates.

Cost Information:

The capital costs for installing a mid-kiln tire injection system are about $2 to 4M. Operating and maintenance costs should not be affected. Often the installation of this technology is driven by the tipping fee revenue generation. If this is possible, injector costs can be recovered within a few years.

An outage is required when implementing this technology, but downtime can be minimized at sites where space is sufficient for installing the injection system ahead of time (without getting in the way of kiln operation).

Development Status:

Commercially available.

Process: Mid-Kiln or Tower Tire Injection
Practical Considerations: The main purpose of a cement kiln is to produce as much high-quality clinker as possible at the lowest energy cost. Over-feeding tires creates locally reducing conditions that cause smoke, soot, and spoil the naturally occurring sulfur capture in the clinker resulting in higher SO_2 emissions. The practical limit on tire injection is replacement of about 10 to 30% of the fuel, depending on the kiln design. Also, since tires are injected every two minutes, the NO_x emissions rise and fall erratically, making control very difficult.
Compatibility with other air pollution control technologies: High airflows from the NO_x fans can cause increased carryover of cement kiln dust (CKD) into the exhaust. Reducing conditions in the flame zone increase SO_2 emissions.
Secondary Environmental Impacts: Combustion monitoring and tuning has the potential to effect both positive and negative secondary environmental impacts depending on factors such as the fuel, burner air-fuel ratio, kiln design, etc. The following are potential impacts that must be analyzed on an individual unit basis • CO, hydrocarbons and soot emissions may increase due to tire byproducts escaping the secondary combustion zone. • SO_2 may increase due to increased staging. • ESP performance may degrade with increased CKD.
References: U.S. Environmental Protection Agency, "Alternative Control Techniques Document: NO_x Emissions from Cement Manufacturing." EPA Document No. EPA-453/R-94-004, January 1994. "Stick a Fork in It". Product Brochure from Cadence Inc., 1997.

Process: Non-Selective Catalytic Reduction (NSCR)				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
IC Engines, rich-burn only	111,488	40-98%	< 500	Commercial

Process Description:

In NSCR, the engine exhaust is routed to a catalyst bed across which NO_x is reduced to nitrogen gas. At the same time, VOC and carbon monoxide are oxidized to water and carbon dioxide. Because the catalyst reduces emissions all three of these pollutants, NSCR is often referred to as a "three-way catalyst" system. These systems are similar to the catalytic converters used on automobiles.

For an NSCR system to operate optimally (i.e., to minimize NO_x emissions), the inlet exhaust stream must have very low oxygen content, as well as proper concentrations of NO_x, hydrocarbons, and carbon monoxide. This requires initial engine adjustments, followed by careful monitoring of oxygen content in the exhaust. For this reason, an automatic air-fuel (A/F) ratio controller typically is used to regulate the exhaust oxygen content entering the catalyst bed. The controller adjusts the A/F ratio based on input from an oxygen sensor upstream from the catalyst bed.

Because of the requirement for low oxygen content, NSCR systems are limited to rich-burn SI engines.

NO_x Reduction:

This source indicates that these catalyst systems reduce NO_X emissions by over 98 percent, while reducing VOC by 80 percent and carbon monoxide by over 97 percent. NO_x levels in the range of 0.1 to 1.0 g/bhp-hr have been achieved.

Cost Information:

Capital cost for NSCR includes the catalyst as well as the addition of oxygen sensors and controls. Catalyst replacement generally occurs after about 20,000 hours of operation.

Development Status:

Commercial. Information from vendors of NSCR systems indicates that NSCR three-way catalysts have been installed on over 1,000 IC engines in the United States and have been in use for over 10 years. .

Practical Considerations:

The engine adjustments required to optimize NSCR systems typically reduce the efficiency of the engine, harming fuel economy. The biggest operational problem associated with NSCR has been damage to the catalyst caused by excessive temperature. This is caused when the exhaust stream is too fuel rich. In this situation, the uncombusted natural gas is rapidly oxidized in the catalyst bed, burning it out. At about 1,300 ^{o}F, the catalyst sustains damage.

Compatibility with other air pollution control technologies:

Enhanced removal of CO and VOC can be achieved.

Process: Non-Selective Catalytic Reduction (NSCR)
Secondary Environmental Impacts: None expected.
References: Manufacturers of Emission Controls Association. "Emission Control Technology for Stationary Internal Combustion Engines." Status Report, July 1997. Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

Process: NOxTech				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	90-95%	~ 1000	Commercial

Process Description:

According to product literature, the NOxTech® emission control system, developed by NOxTech Inc., NOxTech is an automated system in which exhaust gases are chemically treated with a nonhazardous liquid chemical. The technology involves replacing the engine exhaust silencer with a reaction chamber where NO_x and reagent react to form nitrogen, water vapor, and carbon dioxide. The non-catalytic chemical reagent is injected into the exhaust at temperatures between 1,400 and 1,500 °F.

NO_x Reduction:

The vendor states that NOxTech has been proven to remove 90-95% of NOx, as seen in the 4,000-bhp diesel-powered generator on Catalina Island.

Cost Information:

Based on vendor literature, self-sustained, gas-phase autocatalysis reduces emissions of NO_x are reduced at costs as low as $1,000/ ton.

Development Status:

Commercially available

As of August 2000, the system has been installed and is operating on several diesel generators in California. Based on commercial performance in these engines, NOxTech has been demonstrated as BACT for some diesel engines.

Practical Considerations:

The exhaust gas must be heated to achieve the temperatures necessary for the NOxTech system reactions. A heat exchanger should be placed downstream from the reactor to reclaim and reuse this heat energy.

Compatibility with other air pollution control technologies:

Compatible with low-NO_x combustion approaches (LNB, combustion modification). Can be used to augment LEC.

Secondary Environmental Impacts:

Technology also potentially removes 60-80% of particulate matter, 90% of VOC, and 50-70% of carbon monoxide from the exhaust, as seen in the 4,000-bhp diesel-powered generator on Catalina Island.

The process produces trace ammonia emissions of less than 2 to 5 ppmv.

Process: NOxTech
References: Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NO_x Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000. NOxTech Inc. "NOxTech® Technology." website. www.noxtechinc.com/products.htm. NOxTech Inc. Letter and attachments from E. Cazzola to Mary Jo Krolewsky, U. S. EPA Acid Rain Division. April 12, 1999.

Process: Overfire Air (OFA)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired boilers	607,748	20-40%	250-600	Commercial
Oil/NG boilers	32,910	40-80%	1,000-2,000	Commercial
Wood/Biomass boilers	9,776	20-60%	200-2,000	

Process Description:

OFA, like LNB's, represents practical approaches to minimizing the formation of NO_x during combustion. Simply, this is accomplished by "controlling" the quantities and the way in which fuel and air are introduced and mixed in the boiler (referred to as staging).

In the case of OFA, the approach consists of diverting some of the combustion air (typically up to about 30%) to dedicated injection nozzles (called OFA ports) located some distance above the burner or main combustion zone. Variations include the design and location of the OFA ports, the supply of air to the OFA (either directly from the windbox, or from a dedicated booster fan).

NO_x Reduction:

OFA, which can be used separately or as a system with LNBs, is capable of NO_x reductions of 20% - 40% from uncontrolled levels, when used alone. The type of boiler (e.g., dry vs. wet-bottom, wall- vs. tangential-fired, NSPS vs. pre-NSPS, etc.) and the type of fuel will influence the actual performance achieved.

Cost Information:

OFA technologies have little or no impact on operating costs (other than the potential for an increase in unburned carbon - efficiency loss -, and the resulting impact on ash disposal options). Retrofit costs are site-specific. As such, the economics of these technologies are driven by capital/retrofit costs which typically range from $5-$10/kW, with the lower range reflecting easier application whereas the higher costs are typically associated with more difficult and involved retrofits.

From a schedule standpoint, OFA retrofit projects can require outages of 3 – 6 weeks, depending on factors such as scope of work, integration with other plant outage requirements, etc.

Development Status: Commercial

OFA and LNB's are the most prevalent in the power industry at present. Plants that have had to comply with Title IV of the CAAA of 1992 have largely used these technologies for compliance. Competing manufacturers have proprietary designs, geared towards application in different boiler types, as well as reflecting their own design philosophies.

Practical Considerations:

Boilers with the following design and operating characteristics are expected to be more suitable candidates for OFA applications:

- firing lower-sulfur fuels (e.g., less propensity for waterwall corrosion)
- low baseline unburned carbon (e.g., to minimize ash salability impacts).

Process: Overfire Air (OFA)
• favorable cross-section/height profiles (e.g., tall boilers which provide for adequate mixing/residence time to maximize effectiveness). • units with existing burners in good operating condition, • Potential O&M impacts due to combustion NOx controls include: • Change in optimum excess air level: 0.5-1.5 percentage points increase in excess O_2 is possible • 3-5 percentage points increase in LOI is possible; in general, as higher NO_x reduction is being sought, the higher the probability for increased LOI (NO_x vs. LOI trade-off) • Changes in reheat and superheat steam temperatures (typically lower by 20-50 degrees F) are possible in some applications.
Compatibility with other air pollution control technologies: OFA technologies are often used in conjunction with LNB's. As a main combustion based NO_x control approach, OFA is fully compatible with other NOx controls including LNB's, reburning (OFA is an integral component of reburning), as well as the post combustion technologies such as SNCR and SCR
Secondary Environmental Impacts: OFA, like all combustion modification approaches face a common challenge: that of "striking a balance" between NO_x reduction and fuel efficiency. The concern is exemplified by the typically higher carbon levels in the fly ash, which reflect lower combustion efficiency but also the contamination of the fly ash itself possibly making it unsuitable for reutilization (e.g., cement industry).
References: EPRI, "Retrofit NO_x Control Guidelines for Gas- and Oil-Fired Boilers", Final Report, December 1993. EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 1996 Update Addendum", May 1997. EPRI, "Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update", EPRI Final Report, December 2000

Process: Oxy-Fuel Firing				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Glass Manufacturing	5,033	80-85%	2,150-4,400	Commercial

Process Description:

Oxy-fuel melting involves the replacement of the combustion air with oxygen (>90% purity). The technique can be used with either natural gas or oil as the fuel, although the use of gas is more common. The elimination of the majority of the nitrogen form the combustion atmosphere reduces the volume of the waste gases (composed mainly of CO_2 and water vapor) by 70-85 % depending on oxygen purity. In general, oxy-fuel furnaces have the same basic design as recuperative melters, with multiple lateral burners and a single waste gas exhaust port. In the most modern furnaces the geometry is optimized for oxy-fuel firing and minimization. Furnaces designed for oxygen combustion do not currently utilize heat recovery systems to pre-heat the oxygen supply to the burners, due to safety concerns; however, the technique potentially involves substantial energy savings because it is not necessary to heat the atmospheric nitrogen to the temperature of the flames. The formation of thermal NO_x is greatly reduced because the main source of nitrogen in the furnace is much lower.

NO_x Reduction:

Compared to air-fuel fired furnaces, NO_x emissions are generally reduced by 70-90%. This reduction equates to:

- <1 kg/ton glass for fiber and container glass furnaces
- 1-2 kg/ton glass for special glass (without nitrate addition)

The latest versions of oxy-fuel burners combined with optimized furnace design and operation can in some cases reduce emissions to 0.3-0.8 kg NO_x/ton of glass melted. No information is available for emissions from flat glass production, but emissions of 0.5 to 1.5 kg/ton of glass melted are considered likely.

Cost Information:

In general, capital costs for oxy-fuel firing are $1,930K-$9,810K. An important factor in the capital cost is that oxy-fuel furnaces do not have a conventional combustion gas preheat system and so the capital cost is generally lower than for a regenerative or recuperative furnace of comparable pull-rate. In most applications, the determining factor regarding cost effectiveness of oxy-fuel firing will be the difference between the energy savings and the costs of the oxygen compared with the costs of alternative NO abatement techniques.

Development Status:

Commercially available

It is estimated that 5-10% of the world's glass production is made with oxy-fuel melting, but this figure varies between the sectors. There are several examples of oxy-fuel furnaces operating successfully in the following sectors: container glass, glass wool, special glass (particularly TV glass), continuous filament glass fiber, and frits. Trials have been carried out in the domestic glass sector resulting in good NO_x reduction, but problems occurred with severe foaming. The problems encountered in domestic glass production are similar to those initially encountered in other applications e.g. container glass. Similar

Process: Oxy-Fuel Firing
solutions are likely to be possible but the higher quality requirements make them more difficult to apply. There are several examples of the technique operating successfully for domestic glass production worldwide. Considerable development work is being undertaken and the number of plants and the level of operating experience are increasing.
Practical Considerations: The merits of oxy-fuel firing vary greatly from case to case depending on furnace size and availability of pure oxygen. The technique is most effectively installed during furnace rebuild. Hot installation may lead to energy savings and to an increased pull rate; however, it is unlikely to result in lower NO_x emissions, and there is a danger of accelerated refractory wear. Furnace waste-gas temperature can be very high, 1200-1300 °C and will usually require cooling. Due to high water content and concentration of corrosive species, cooling is usually by dilution with air. The higher temperatures associated with the technique can result in higher refractory wear. Oxygen required for combustion can be supplied either by delivery to the site or by on-site production. Except for very small applications, the amounts of oxygen required usually make it more economical to produce the oxygen on-site.
Compatibility with other air pollution control technologies: Addition of a cullet preheating system, which can also reduce NO_x and other emissions by reducing the amount of fuel required, can add to the energy savings of oxy-fuel firing by recovering heat from the waste gases. See cullet preheating description.
Secondary Environmental Impacts: Oxy-fuel firing can also help to reduce overall emissions of volatile materials form the furnace (particulates, fluorides, chlorides etc.), due to reduces gas flow over the melt and in some cases reduced turbulence. • Particulate emissions in soda-lime glass can be reduced to 0.2-0.3 kg/ton. • Particulate emissions most effectively reduced for boron containing glasses (up to 50%). • Reduction in fuel usage leads to lower SO_2 emissions for oil-fired furnaces. Concentrations of all pollutants may actually be higher due to reduced gas volume, although the absolute emission is reduced. Dilution with cooling air usually brings the concentrations closer to more normal levels.
References: European IPPC Bureau. "Reference Document on Best Available Techniques in the Glass Manufacturing Industry." Seville, Spain, October, 2000.

Process: Oxygen-Enhanced Combustion Modifications				
Category	**NO_x, TPY (WRAP 1996)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired Boilers	607,748	30 to 80%	1,000-2,000	Near Commercial
Cement kilns	41,009	0-20%	100-1000	Commercial

Process Description:

In coal-fired boilers, O_2 injection is used to improve effectiveness of OFA operation. Small amounts of oxygen are introduced into the burner zone through specially designed lances. The added O_2 creates a local hot spot that increases the rate of coal volatile release, encourages more NO_x reduction, and enables more fuel-rich operation where less NO_x is formed. The technology has been demonstrated on a 44-MW coal-fired boiler.

In cement kilns, oxygen lances are used to create a hot spot in the flame zone and achieve higher kiln throughput (increase clinker production). In doing so, NO_x is not reduced but NO_x emission rates (lb. NO_x/ton of clinker) goes down in proportion to the increase in production. O_2 injection achieves even higher production when cement kiln dust (CKD) is co-injected. The CKD also quenches peak flame temperature to achieve some reduction in thermal NO_x formation.

NO_x Reduction:

In the coal-fired boiler demonstration, conventional OFA reduced NO_x to around 0.35 to 0.40 lb./MBtu. O_2 injection lowered the NO_x further to around 0.22 to 0.25 lb./MBtu, while also decreasing LOI and opacity, and allowing better steam temperature control when firing bituminous coal. NO_x reductions down to 0.16-0.19 lb./MBtu were achieved when the unit switched to a blend of 90% sub-bituminous and 10% bituminous coal.

In the cement industry, oxygen injection has achieved 0 to 20% NO_x reduction in conjunction with a 0-5% kiln capacity increase. Increased capacity (when it occurs) is the primary cause of the NO_x reduction.

Cost Information:

The primary cost of all these applications of oxygen-enhanced combustion is the cost of the oxygen. Oxygen required for combustion can be supplied either by delivery to the site or by on-site production. Except for very small applications, the amounts of oxygen required usually make it more economical to produce the oxygen on-site. Capital cost for oxygen storage and delivery systems range from $100,000 when pipeline gas is used, to $1,500,000 when on-site storage is required. In general, capital costs are $1,930K-9,810K when on-site generation is chosen.

An important factor for the capital cost of oxy-fuel firing is that oxy-fuel furnaces do not have a conventional combustion gas preheat system and so the capital cost is generally lower than for a regenerative or recuperative furnace of comparable pull-rate. In most applications, the determining factor regarding cost effectiveness of oxy-fuel firing will be the difference between the energy savings and the costs of the oxygen compared with the costs of alternative NO_x abatement techniques.

Process: Oxygen-Enhanced Combustion Modifications
Development Status: The coal-fired boiler technology needs to be demonstrated over several months to show effectiveness, reliability, and safety. Such a demonstration is expected to begin during the summer of 2003. The technologies are commercially available for application to cement and glass manufacturing.
Practical Considerations: Using oxygen enrichment results in less flue gas flow since it eliminates the nitrogen in the air it replaces. The merits of oxy-fuel firing vary greatly from case to case depending on furnace size and availability of pure oxygen. The technique is most effectively installed during furnace rebuild. Hot installation may lead to energy savings and to an increased pull rate; however, it is unlikely to result in lower NO_x emissions, and there is a danger of accelerated refractory wear. Furnace waste-gas temperature can be very high, 1200-1300 °C and will usually require cooling. Due to high water content and concentration of corrosive species, cooling is usually by dilution with air. The higher temperatures associated with the technique can result in higher refractory wear. Many potential users do not want to own and operate an air-separation plant. Oxygen suppliers offer to build, own, and operate the air separation system in return for a long term contract for oxygen sales.
Compatibility with other air pollution control technologies: Oxygen-enhanced combustion on coal-fired boilers can only be effective when implemented with OFA. If O_2 is added to an unstaged flame, NO_x emissions will increase. The technology can also be combined with SNCR or SCR for greater NO_x reductions. O_2 can also be used with post-combustion NO_x control technologies in cement kilns and glass melters.
Secondary Environmental Impacts: Oxygen-enhanced combustion may lessen the impacts of staged combustion. The following are potential impacts that must be analyzed on an individual unit basis: • CO may increase due to stoichiometry in the burner zone • LOI may increase due to increased staging • ESP performance may degrade with increased LOI or finer particulate. Oxy-fuel firing can also help to reduce overall emissions of volatile materials from the kiln or furnace (particulates, fluorides, chlorides etc.), due to reduced gas flow and in some cases reduced turbulence. • Particulate emissions in soda-lime glass can be reduced to 0.2-0.3 kg/ton. • Particulate emissions most effectively reduced for boron containing glasses (up to 50%). • Reduction in fuel usage leads to lower SO2 emissions for oil-fired furnaces. Concentrations of all pollutants may actually be higher due to reduced gas volume, although the absolute emission is reduced. Dilution with cooling air usually brings the concentrations closer to more normal levels.
References: U.S. Environmental Protection Agency, “Alternative Control Techniques Document: NO_x Emissions from

Process: Oxygen-Enhanced Combustion Modifications
Utility Boilers". EPA Document No. EPA-453/R-94-023, July 1994. Bool, L., "NO_x Reduction from a 44MW Wall-Fired Boiler Utilizing Oxygen-enhanced Combustion", EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Pre-Stratified Charge				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	80-95%	<500	Commercial

Process Description:

Air is injected into the intake manifold so that during the intake stroke, the piston initially draws in air, followed by a fuel-rich air-fuel mixture. Thus, the mixture near the spark plug is fuel rich, promoting good combustion, while the mixture away form the spark plug is very lean, acting a s a heat sink and suppressing NO_x formation.

NO_x Reduction:

From tests for ten engine models ranging from 100 to 800 bhp, NO_x emissions ranged from about 0.1 g/bhp-hr to 9.5 g/bhp-hr, with a mean of 0.6 g/bhp-hr. Engines ranging from 300 to 800 bhp averaged 95% reduction, while tests on engines less than 50 bhp showed NO_x reductions averaging 77%.

Vendors guarantee the achievable NO_x emission level of 2.0 g/bhp-hr.

Cost Information:

See EPA Report below.

Development Status:

Commercially available. In commercial use since 1980s.

Practical Considerations:

Applicable only to carbureted (i.e. non-fuel-injected) rich-burn engines. May cause some power derating; 20% has been observed. While the PSC system itself requires very little maintenance, the engines require more frequent overall maintenance.

Compatibility with other air pollution control technologies:

Compatible with exhaust gas recirculation (EGR), with air injected by PSC system coming form the engine's exhaust. May also be used in conjunction with post-combustion technologies. However, the overall NO_x reductions are not strictly additive and careful evaluation is required to ensure cost effective strategies.

Secondary Environmental Impacts:

Possible increase in CO and VOC emissions.

References:

Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000.

Process: SCONOx Technology				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Reciprocating Engines	86,210	95%	Not available	Commercial
Oil/NG boilers	32,910	70-99%	Not available	Commercial
Turbines	25,278	>90%	>7,000	Commercial

Process Description:

The SCONOx system adds a chemical reactor for NO_x sorption using a catalyst/sorbent to remove NO_x, carbon monoxide, and VOC. NO_x is oxidized in the presence of a platinum-based catalyst and the resulting NO_2 is adsorbed onto a potassium carbonate sorbent, forming potassium nitrites. The sorbent must be regenerated periodically by passing a controlled mixture of regeneration gases across its surface in the absence of oxygen. Regeneration gases react with the nitrites to form water and elemental nitrogen. The system is installed as a bed of sorbent/catalyst. 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.

NO_x Reduction:

The first commercial installation in gas turbines achieved NO_x emissions below 2 ppm, a reduction of over 90%.

Vendor testing shows SCONOx reduced NO_x emissions in natural gas-fired reciprocating engines up to 95%. Preliminary testing in diesel engines found the technology reduced NOx by 98.9% to 0.4 g/bhp-hr.

Cost Information:

Cost for Gas Turbine application is preliminary and from DOE reference below.

Development Status:

Commercially available

First commercial installations in gas turbines commenced in 1999. Commercial applications for natural gas-fired reciprocating engines went online in 2000. Diesel applications were sold in 2000, but further information is unavailable.

Practical Considerations:

The technology was initially applied only to gas turbines, but variations have been developed for natural-gas and diesel-fired reciprocating engines.

Regeneration gas flow is about 1 percent of exhaust gas flow. Typically, natural gas is converted to hydrogen in a reformer at 600-900 °F to produce the regeneration gas. The regeneration step is complicated and the reformer requires additional labor and maintenance.

Exhaust temperatures should be controlled at 600-700 °F for best NO_x reduction. Performance also improves as exhaust gas oxygen levels approach zero. Temperature and O_2 control may be difficult at some sites. The catalyst is de-activated by soot or sulfur species, so catalyst must be cleaned every 20,000 hours.

Process: SCONOx Technology
SCOSOx is required to remove SO_2, which would otherwise poison the SCONOx catalyst. SCOSOx requires regeneration similar to SCONOx.
Compatibility with other air pollution control technologies: Due to the emerging nature of the technology, little is discussed about compatibility with other technologies. Based on tests with LEC engines, issues regarding increases in CO/VOC may be of concern
Secondary Environmental Impacts: Carbon monoxide and VOC are also reduced up to 95%.
References: Edgerton, S. W., Lee-Greco, J., and Walsh, S. "Stationary Reciprocating Internal Combustion Engines Updated Information on NOx Emissions and Control Techniques (Final Report)." EPA contract No. 68-D98-026, EC/R Incorporated, Chapel Hill, NC, August 29, 2000. Amar, K.P., Staudt, J. "Status Report on NOx Controls for Gas Turbines, Cement Kilns, Industrial Boilers, Internal Combustion Engines; Technologies and Cost Effectiveness." Northeast States for Coordinated Air Use Management, Boston, MA, January, 2001. Goal Line Environmental Technology News. "Cummins Engine Co. Tests SCONOx® for Diesel IC Engines." Oct 1999. Vol 1, Issue 3.

Process: Selective Catalytic Reduction (SCR)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired boilers	607,748	70-90%	1,500-2,000	Commercial
Reciprocating Engines	86,210	75-90%	<1,000	Commercial
Oil/NG boilers	32,910	70-90%	2,000-10,000	Commercial
Turbines	25,278	~90%	500-10,000	Commercial
Refinery Process Heaters	9,311	75-90%	3,700-11,000	Commercial
Glass Melters	5,033	75-90%	---	Commercial

Process Description:

Post-combustion NO_x controls include **Selective Non-Catalytic Reduction** (SNCR) and **Selective Catalytic Reduction** (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700ºF-2000ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF to 750°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x. High temperature catalysts, sometimes used in gas turbine applications can operate at temperatures up to ~1100°F

Conventional SCR incorporates a reactor located typically between the economizer and the air preheater. The reactor housing is sized to provide optimum flue gas velocity and catalyst volume.

In about one-quarter to one-third of the German SCR installations, the SCR reactor is located downstream of the flue gas desulfurization (FGD) system. This is called a “tail-end” configuration. Because the catalyst operates at temperatures of at least 600+°F, the flue gas temperature needs to be increased between the FGD and tail-end SCR. This reheating the flue gas before it enters the SCR. This extra equipment makes the capital and energy costs higher than in a conventional SCR. On the other hand, the tail-end SCR uses less catalyst, experiences a longer catalyst life, and can be built without impacting plant operations, with tie-in typically occurring during a normal two-week outage.

An ammonia injection system is located upstream of the catalyst typically in a grid configuration to inject and disperse the ammonia uniformly into the flue gas.

NO_x Reduction:

NO_x reductions of 90+% are capable with SCR. NO_x reduction levels are typically limited by the need to control residual ammonia to low levels (2-5ppm), and by cost effectiveness considerations (higher cost-to-NOx reduction ratio for deeper reductions. SCR applications typically represent a balance between the percentage NOx reduction requirement, residual ammonia limit, SO_2 to SO_3 oxidation rate, and ability to continuously maintain a uniform, stable NH_3/NO_x distribution across the entry plane into the catalyst.

Cost Information:

Capital costs for retrofit SCR systems to power generation sources are mostly within the range of $60/kW to about $140/kW. The lower end of this range applies to retrofits with nominal difficulty. The high end of the range would typically be associated with retrofits having significantly impeded construction access, extensive relocations, and difficult ductwork transitions.

Process: Selective Catalytic Reduction (SCR)
Operating costs are mainly driven by cost of reagent, energy penalty (pressure loss, ammonia vaporization), catalyst replacement and dedicated O&M costs
Development Status: Commercially available SCR is widely used oversees (Germany and Japan represent over 50,000 MW of installed capacity. In the US, significant activity has recently occurred with SCR installations on coal fired units. Projections for over 100 new installations in the US in the next 5 years have been made.
Practical Considerations: From a technical perspective, SCR can be used many different applications and sources. However, the cost can vary considerably depending on retrofit difficulty and plant layout, fuel, or unit operating characteristics. The performance of an SCR system is dependent on the size and arrangement of the catalysts, the fuel burned, gas flow conditions at the catalyst entrance, and the type and amounts of reagent used. A number of factors should be considered when installing an SCR system. They include: • Operating temperature window temperature which is a function of the catalyst formulation but typically ranges between 600°-750°F for sulfur bearing fuels, • Ammonia injection system design to ensure good distribution in proportion to the mass flux of NO_x for optimized performance (maximum NO_x reduction and minimum NH_3 slip) • Flue gas pressure drop which is dependent upon flue gas velocity, catalyst configuration, and quantity of catalyst required to achieve specified NO_x reduction • Flue gas flow/temperature distribution, as catalyst guarantees are typically predicated upon predetermined conditions • Fouling potential of catalyst and/or APH surfaces. Reaction of excess ammonia with SO_3 generated in the furnace when firing sulfur bearing fuels will form ammonium bisulfate/sulfate that deposits on the cold end sections of the air heater to cause corrosion and increased pressure drop • Flue gas contaminants - alkaline compounds, halogens, and heavy metals can cause catalyst poisoning. • Decreased heat rate at low load if economizer bypass is needed to maintain the required flue gas temperature in the SCR reactor.
Compatibility with other air pollution control technologies: SCR applications are fully compatible with combustion NOx controls (LNBs, OFA, reburn, etc.) and can be used with other amine-based controls (e.g. SNCR) in hybrid configurations. In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the "economics" of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific. However, several such combinations of technology are considered attractive and have or are gaining acceptance. For example, the combination of LNB/OFA with either SCR or SNCR is more prevalent than the application of the post-combustion technologies alone. The economics of this approach are justified by the reduced chemical and capital costs due to lower NO_x levels entering the SCR system.

Process: Selective Catalytic Reduction (SCR)
When combining SCR with NO_x control technologies whose performance depends on mixing characteristics in the upper furnace (i.e., OFA, reburn, or SNCR), potential stratification of inlet NO_x levels to the SCR becomes a key design issue that can impact SCR performance.
Secondary Environmental Impacts: Potential impacts arising from the application of SCR include: • Increased corrosion downstream of the SCR from SO_3 formed on the catalysts • Air heater fouling due to ammonia bisulfate formation in the cold end • Ammonia contamination of fly ash affecting its salability or disposal • Increased system pressure drop • FGD waste management, if located downstream of SCR These impacts are mostly relevant to applications with sulfur and other contaminants-bearing fuels (e.g. coal/oil). Applications with natural gas are more benign both with respect to catalyst choice and life, as well as other plant impacts.
References: EPRI, **"**Retrofit NO_x Controls for Coal-Fired Utility Boilers – 2000 Update", EPRI Final Report, December 2000 NESCAUM, "Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers", June 1998. Cichanowicz, J., "100 GW of SCR: Installation Status and Implications of Operating Performance on Compliance Strategies", EPRI/DOE/EPA Mega Symposium, Washington, May 2003 McIlvaine, R., "SCR Operating Experience of German Power Plant Owners as Applied to Challenging US High Sulfur Service", EPRI/DOE/EPA Mega Symposium, Washington, May 2003

Process: Selective Non-Catalytic Reduction (SNCR)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Coal-fired boilers	607,748	25-50%	800-1,500	Commercial
Cement Kilns	41,009	30-70%	200-1,000	Commercial
Oil/NG boilers	32,910	30-60%	1,300-3,000	Commercial
Wood/Biomass boilers	9,776	40-80%	900-2,200	Commercial
Refinery Process Heaters	9,311	50-70%	1,200-2,700	Commercial
Glass Melters	5,033	~40%	---	Commercial

Process Description:

Post-combustion NO_x controls include **Selective Non-Catalytic Reduction** (SNCR) and **Selective Catalytic Reduction** (SCR). They are fundamentally similar, in that both use an ammonia-containing reagent to react with the NO_x produced in the boiler, and convert it to harmless nitrogen and water, SNCR accomplishes this at higher temperatures (1700ºF-2100ºF) in the upper furnace region of the boiler, while SCR operates at lower temperatures (about 600ºF to 750°F) and hence needs a catalyst to produce the desired reaction between ammonia and NO_x.

While this difference between the two technologies may seem minor, it yields significant difference in performance and costs. This is because in the case of SNCR, the reaction occurs in a somewhat uncontrolled fashion (e.g., the existing upper furnace becomes the "reactor"). In practice, this means that SNCR has lower capital costs (no need for a reactor/catalyst); higher operating costs (lower efficiency means that more reagent is needed to accomplish a given reduction in NO_x); and limited NO_x reduction capability (typically 30%-40%, with some cases achieving reductions in the 50% range).

With SNCR, the reagent is introduced directly into the upper furnace, within the temperature window above. Typical applications may include multiple injection nozzles at various elevations (temperature points). in the furnace to optimize the distribution of reagent as well as to allow for operation at various load points.

NO_x Reduction:

SNCR technology is typically capable of NO_x reductions in the range of 25% to 80% depending on many design and operating characteristics of the specific application.

Cost Information:

Capital cots range from $10 to $20/kW for power generation boilers.
Operating costs are driven primarily by the consumption of the chemical reagent – usually urea for SNCR - which in turn is dependent upon the efficiency of the as well as the initial NO_x level and the desired percent reduction. These are typically in the range of $500-$700/ton of NO_x.
An additional consideration important in the overall operating costs is the potential contamination of fly ash by ammonia making it potentially unsalable.

Development Status: Commercial
SNCR is a fully commercial technology widely employed in various industries and applications. Urea-based applications are the predominant approach, as urea seems to have several advantages over ammonia in large-scale applications.

Process: Selective Non-Catalytic Reduction (SNCR)

Practical Considerations:

SNCR applications must be considered on a site –specific basis as several design and operating characteristics will affect the suitability of the technology. Some key issues include

- Available temperature window
- Size (cross-section/height) of the furnace for appropriate distribution and mixing of the reagent
- Sulfur content of the fuel (SO_3 and NH_3 form ammonium salts which can have negative impacts on the downstream equipment)
- Operational profile of the unit (rapid swings in flows/temperatures often result in poor performance in terms of NO_x reduction and ammonia slip)

Compatibility with other air pollution control technologies:

SNCR applications are compatible with combustion NO_x controls (LNBs, OFA, reburn, etc.) and can be used with other amine-based controls (e.g. SCR) in hybrid configurations. In theory, most of these technologies can be used together. However, NO_x reductions are not necessarily additive, and more importantly, the "economics" of the combined technologies may or may not be cost-effective. Such analyses are highly site- and strategy-specific.

The application of SNCR with reburn has yielded several developments by different companies. Various approaches are available commercially. Essentially they all revolve around the ability to combine the injection the reburn fuel and the amine reagent in the upper furnace region. NO_x reductions are not additive but better than the individual technology. While these combined approaches have not gained extensive commercial deployment reductions of 60%-70% have been reported. Economic effectiveness needs to be properly addressed on an individual basis as both the cost of reagent and reburn fuel contribute to the overall cost analyses

Other variations of SNCR-based technology include the use of hydrocarbon injection to promote NH_3 reduction reactions, as well as reagent injection into a fuel rich zone of the OFA system. These variations while offered commercially are still under demonstration

Secondary Environmental Impacts:

SNCR has some of the same issues associated with SCR. The two most likely to warrant consideration are

- NH_3 slip (emissions and impacts on ash)
- Formation of nitrous oxide (N_2O – a green house gas). This is mostly associated with urea, as opposed to ammonia, and may become a larger concern from the perspective of global climate issues

References:

NESCAUM, "Status Report on NO_x Control Technologies and Cost Effectiveness for Utility Boilers", June 1998.

EPRI, "Retrofit NOx Controls for Coal-Fired Utility Boilers – 2000 Update, Final Report", December 2000.

Himes, R., "A Fresh Look at SNCR", EPRI/DOE/EPA Mega Symposium, Washington, May 2003

EPRI, "Sate of the Art Assessment of SNCR Technology", September 1993.

EPRI, "SNCR Feasibility and Economic Evaluation Guidelines for Fossil-Fired Utility Boilers", May 1994

Process: Tempering (Water, air, steam injection)				
Category	**NO_x, TPY (WRAP 1996>100 TPY)**	**%NO_x reduction**	**Cost, $/ton**	**Status**
Turbines	25,278	~50%	2,000-7,000	Commercial
Refinery Process Heaters	9,311	---	---	Commercial

Process Description:

Tempering is a combustion control using water, air, or steam to lower the combustion temperatures, which reduces thermal NO_x formation. Water or steam, treated to quality levels comparable to boiler feedwater, is injected into the combustor and acts as a heat sink to lower flame temperatures.

NO_x Reduction:

Controlled NO_x emission levels range form 25 to 42 ppmv for natural gas fuel and from 42 to 75 ppmv for distillate oil fuel.

Cost Information:

Capital costs for wet injection include a mixed bed demineralizer and reverse-osmosis water treatment system and an injection system. All costs are based on availability of the injection medium on site. Capital costs range from $388K for a 4,430 hp turbine ($89/hp) to $4,830K for a 216,000 hp turbine ($22/hp). For steam injection, capital costs are slightly higher than for water injection.

Development Status:

Commercially available

Practical Considerations:

This technique is available for all new turbine models and can be retrofitted to most existing installations. The decision of which injection medium to use for NO_x reduction depends on many factors including the availability of steam injection nozzles and controls from the turbine manufacturer, the availability and cost of steam at the site, and turbine performance and maintenance impacts. This decision is usually driven by site-specific environmental and economic factors.

Compatibility with other air pollution control technologies:

None.

Secondary Environmental Impacts:

None expected.

References:

Alternative Control Techniques Document: NO_x Emissions from Stationary Gas Turbines. EPA Document No. EPA-453/R-93-007, January 1993.

U.S. Environmental Protection Agency. "Alternative Control Techniques Document – NO_x Emissions form Stationary Reciprocating Internal Combustion Engines." EPA-453/R-93-032, July, 1993.

Process: Tempering (Water, air, steam injection)
Poole, L., "Houston Galveston Area NO_x Abatement Industries Perspective," present at the Council of Industrial Boiler Owners, NO_x Control XV Conference, Houston, TX, August 2002.

APPENDIX D: PM Control Technology Summaries

Process: Cyclones				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost**	**Status**
Mineral Processing	24,499	50 – 90%	See below	Commercial
Petrochemical	10,836	50 – 90%	See below	Commercial
Wood/Biomass boilers	5,718	50 – 90%	See below	Commercial
Primary metal production	4,697	50 – 90%	See below	Commercial
Pulp & Paper	4,476	50 – 90%	See below	Commercial

Process Description:

Cyclones use centrifugal force to separate particulate from gas streams, and belong to the broader family of mechanical collectors, which use a variety of mechanical forces to collect particulate. A multiple cyclone is an array of a large number of small (several inch diameter) cyclones in parallel.

PM Reduction:

Multiple cyclones have overall mass removal efficiencies of 70-90%. However, cyclone collection efficiencies fall off rapidly with particle size, so that control of fine particulate (PM-2.5) is limited. While collection efficiency is a function of the cyclone design and particle properties, cyclone removal efficiencies will be 90% or greater for 10 micron particles, dropping to perhaps 70% for 2.5 micron particles, and 50% for 1 micron particles. Addition of a second multiple cyclone in series with the first will allow for increased removal efficiency.

The efficiency of a cyclone increases with the gas flow rate through the cyclone. Cyclones are therefore most effective at high boilers loads, where flue gas flow rates are highest, with collection efficiency decreasing at lower loads.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM).

- Capital - $1 - $5/ACFM
- O&M - NA

Development Status:

Commercial.

Cyclones have been used extensively in various particulate collection applications over the years. In the past, industrial plants used mainly cyclones. Cyclones are robust technologies that can deal with the cyclic operation and load changes. However, their efficiency is moderate when compared with ESP or fabric filtration

Practical Considerations:

Cyclones are best suited for applications of relatively large particle sizes as their effectiveness on smaller particles is limited

Cyclones are less expensive than other PM controls and have no costs beyond the initial capital cost.

Process: Cyclones
Multiple cyclones have no moving parts, but do require regular cleaning to avoid plugging, and preventive maintenance to avoid leaks, which can disrupt flow patterns and thus lower collection efficiency.
Compatibility with other air pollution control technologies: Cyclones are compatible with other PM controls and may be desirable in selected applications to minimize PM loadings into downstream controls such as an ESP, FF or PM scrubber
Secondary Environmental Impacts: None expected.
References: http://www.icac.org http://www.IEA-coal.org.UK/ http://www.croll.com

Process: Electrostatic Precipitator (ESP)				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost**	**Status**
Coal-fired boilers	46,010	90%-99+%	See below	Commercial
Wood/Biomass boilers	5,718	90%-99+%	See below	Commercial
Oil/NG boilers	1,379	90%-99+%	See below	Commercial
Cement kilns	641	90%-99+%	See below	Commercial

Process Description:

ESP's operate on the principle of electrophoresis, by imparting a charge to the particulates and collecting them on opposed charges plates. Dry vs. wet refers to whether the gas is water cooled and saturated prior to entering the charged plate area, or is collected dry on the plates.

Electrostatic precipitators (ESPs), have been in use for particulate control since the early 1920's, use electrical fields to remove particulate from boiler flue gas.

In an electrostatic precipitator, an electric field is maintained between high-voltage discharge electrodes, typically wires or rigid frames, and grounded collecting electrodes, typically plates. A corona discharge from the discharge electrodes ionizes the gas passing through the precipitator, and gas ions subsequently ionize particulates. The electric fields impart electrostatic forces to the negatively charged particles, "driving" them to the collecting electrodes. Particulates are collected from the electrode plates either by mechanical rapping (Dry ESP) or by using a water spray to remove this particulate. (Wet ESP).

In a typical electrostatic precipitator, collecting plates are arranged parallel to the gas flow, normally 9-18 inches apart, with discharge electrodes between them. Most precipitators have 3-5 independent electrical sections, i.e., sets of discharge and collecting electrodes with independent power supplies called Transformer/Rectifier (TR) sets, in series. Each independent section removes a fraction of the particulate in the gas stream. This arrangement allows the use of lower power (higher voltages, but lower current) in the first sections of the precipitator, where there is more particulate to be removed. Higher power is needed in the later sections, to collect the smaller particles.

A typical wet ESP configuration uses cylindrical collecting electrodes, with discharge electrodes located in the centers of the cylinders. Wet ESPs are useful in obtaining low opacities through the removal of acid gases and mists in addition to fine particulate. In addition, these devices have no rapping re-entrainment losses, and no back corona.

PM Reduction:

Many factors determine electrostatic precipitator removal efficiency. ESP size is an important one. Size determines residence time (longer particle residence times help collection efficiency)
Precipitator size is related to and usually referred to as the specific collection area (SCA), the ratio of the surface area of the collection electrodes to the gas flow. Higher collection areas lead to better removal efficiencies. Collection areas normally are in the range of 200-800 ft^2/1000 acfm. In order to achieve collection efficiencies of 99.5%, specific collection areas of 350-400 ft^2/1000 acfm are typically used.

Electrostatic precipitator collection efficiencies can exceed 99.9%, and efficiencies in excess of 99.5% are common. Precipitators with high overall collection efficiencies will have high collection efficiencies for particles of all sizes. Good control of PM-10 and PM-2.5 can be achieved with well-designed and operated electrostatic precipitators.

Process: Electrostatic Precipitator (ESP)

Precipitator collection efficiencies decreases for very small particles (less than 1 micron). The reason for lower efficiency for submicron particles is that both particle charge and the resistance of the gas to particle motion increase with particle size. As particles get smaller, the particle charge is lower, while the resistance to particle motion is higher resulting in poor collection. In practice this effect means that an ESP precipitator with a 99.9% overall mass collection efficiency may only collect over 90% of submicron particles, and over 97-98% of the 0 to 5 micron particles.

Some older precipitators on utility boilers are small, with SCAs below 200 ft^2/1000 acfm and correspondingly short treatment times.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM))

- Capital: $15 - $40/ACFM
- Fixed O&M: Dry ESP's - $0.25 - $0.65/yr-ACFM
  Wet ESP's - $0.15- $0.50/yr-ACFM
- Variable O&M: Dry ESP's - $0.45 - $0.60/yr-ACFM
  Wet ESP's - $0.25 - $0.50/yr-ACFM

Development Status:

Commercial

ESP's have been in use for over 75 years and are a widely recognized technology option for PM control

Practical Considerations:

Maximizing electric field strength will maximize precipitator collection efficiency.

Other actors limiting precipitator performance include flow non-uniformity and particle re-entrainment. Uniform flow distribution helps ensure that there are no high gas velocity, short treatment time paths through the precipitator.

Re-entrainment of collected particles may occur during rapping. Proper rapper design and timing will minimize rapper re-entrainment. Maintenance of appropriate hopper ash levels and of flow uniformity will minimize re-entrainment of ash from the hoppers.

A major consideration of ESP collection efficiency is the electrical resistivity of the particles to be collected. Particles with resistivities in the range of 10^7-10^{10} ohm-cm are more easily collected with ESPs: these particles are easy to charge, and loose their charge slowly once deposited on a collecting electrode. Particles with low resistivities (less than 10^7 ohm-cm), on the other hand, loose their charge to a collecting electrode rapidly and tend not to adhere to the electrode, causing high re-entrainment losses. (Carbon black is an example of a low resistivity material).

Particles with high resistivity (greater than 10^{10} ohm-cm) can be difficult to remove with a precipitator: such particles are not easily charged, and thus are not easily collected. High-resistivity particles also form ash layers with very high voltage gradients on the collecting electrodes. Electrical breakdowns in these ash layers lead to injection of positively charged ions into the space between the discharge and collecting

Process: Electrostatic Precipitator (ESP)
electrodes ("back corona"), thus reducing the charge on particles in this space and lowering collection efficiency. Fly ash from the combustion of low-sulfur coal typically has a high resistivity, and thus is difficult to collect. Flue gas treatment options exist to address both high and low resistivity problems and include the injection of ammonia, SO_3 and other proprietary additives.
Compatibility with other air pollution control technologies: ESP's are compatible with other PM controls and may be desirable in selected applications to minimize PM loadings into downstream controls such as a FF or PM scrubber
Secondary Environmental Impacts: None expected.
References: EPRI, "Economic Evaluation of Particulate Control Technologies", Final Report, September 1992. Staehle, R., "The Past, Present and Future of Wet ESPs in Power plant Applications", EPRI/DOE/EPA Mega Symposium, Washington, May 2003. IEA Coal Research, "Particulate control Handbook", Final report, July 1997. IEA Coal Research, "Prevention of Particulate Emissions", Final report, December 2000. ICAC, "ESPs vs. Fabric Filters: A Symposium and Debate", March 1994. http://www.icac.org http://www.IEA-coal.org.UK/ http://www.croll.com

Process: Fabric Filter				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost,**	**Status**
Coal-fired boilers	46,010	99+%	See below	Commercial
Mineral Processing	24,499	99+%	See below	Commercial
Wood/Biomass boilers	5,718	99+%	See below	Commercial
Fugitive	5,631	99+%	See below	Commercial
Oil/NG boilers	1,379	99+%	See below	Commercial
Cement kilns	641	99+%	See below	Commercial

Process Description:

Fabric filter (FF) collectors (also referred to as baghouses) are the industrial equivalent of very large vacuum cleaners: by passing flue gas through a tightly woven fabric, particulate in the flue gas will be collected on the fabric by sieving and other mechanisms. The dust cake which forms on the filter from the collected particulate can contribute significantly to the overall collection efficiency.

FF types are usually defined by the type of bag cleaning utilized. Major types include: (1) the "reverse-air" baghouse, where the flue gas flows upward through the insides of vertical bags, which open downward. The fly ash thus collects on the insides of the bags, and the gas flow keeps the bags inflated. To clean the bags, a compartment of the FF is taken off-line, and the gas flow is reversed. This causes the bags to collapse, and collected dust to fall from the bags into hoppers. (Shaking or other method may be necessary to dislodge the dust from the bags.); and (2) the pulse-jet fabric filter, where the dirty gas flows from the outside of the bags inward, and the bags are mounted on cages to keep them from collapsing. Dust that collects on the outsides of the bags is removed by a reverse pulse of high-pressure air. This cleaning does not require isolation of the bags from the flue gas flow, and thus may be done on-line.

PM Reduction:

FF's are capable of 99.9% removal efficiencies. In addition removal efficiency is relatively level across the particle size range, making FF's good alternatives for very small particle sizes

.

Key performance factors include the fabric of the bag, the cleaning frequency and methods, and the particulate characteristics. Fabrics can be chosen for different applications, and some fabrics are specialty-coated for enhanced removal of submicron particulate.

Cleaning intensity and frequency are also important variables in determining removal efficiency. Because the dust cake can provide a significant fraction of the fine particulate removal capability of a fabric, cleaning which is too frequent or too intense will lower the removal efficiency. On the other hand, if removal is too infrequent or too ineffective, then pressure drop will increase rapidly and impact overall operation.

Process: Fabric Filter
Cost Information: FF's have been used extensively for many years in different industries. The power generation sector while predominantly dominated by ESP's has started to utilize FF's in the last 20 years. • Capital: Reverse Air Fabric Filter - $17 - $40/ACFM Pulse Jet Fabric Filter - $12 - $40/ACFM • Fixed O&M: Reverse Air Fabric Filter - $0.35 - $0.75/yr-ACFM Pulse Jet Fabric Filter - $0.50 - $0.90/yr-ACFM • Variable O&M: Reverse Air Fabric Filter - $0.70 - $0.80/yr-ACFM Pulse Jet Fabric Filter - $.90 - $1.1/yr-ACFM
Development Status: Commercial. FF's have been used extensively for many years in different industries. The power generation sector while predominantly dominated by ESP's has started to utilize FF's in the last 20 years.
Practical Considerations: FF size is determined by the choice of air-to-cloth ratio (A/C), or the ratio of air flow to cloth area, typically expressed in feet per minute (cubic feet per minute of flow divided by square feet of fabric area). The selection of air-to-cloth ratio depends on the particulate loading and characteristics, and the cleaning method used. A high particulate loadings will require the use of a larger FF (lower A/C) in order to avoid forming too heavy a dust cake, resulting in an excessive pressure drop Pulse-jet FF's are smaller (higher A/C) than reverse-air FFs due to the higher cleaning intensity and resulting bags being cleaner
Compatibility with other air pollution control technologies: FF's are compatible with other PM controls. FF's are also choices for applications downstream of dry SO2 controls (e.g. spray dryers) as well as in combination with sorbent injection techniques for SO2 and/or Hg control Adding a FF downstream from an existing electrostatic precipitator is a strategy gaining some acceptance in the power industry. Because the ESP removes the bulk of the particulate, the baghouse can be relatively small, and thus less expensive. One commercial approach to this is the installation of a small pulse-jet fabric filter downstream of an ESP, known as a Compact Hybrid Particulate Collector (COHPAC). Physically, it may be separate from the precipitator, or even fully integrated into the last field of the existing ESP, further reducing the over cost and space requirements.
Secondary Environmental Impacts: As mentioned above FF's can represent a complementary option to sorbent injection technologies where they enhance the contact (reaction) times between the sorbent and the flue gas contaminant of interest. This results in enhanced collection efficiency for the pollutant (e.g. mercury), as well as reduced quantities of sorbent needed

Process: Fabric Filter
References: EPRI, “Economic Evaluation of Particulate Control Technologies”, Final Report, September 1992. Staehle, R., “Particulate Control Options for Dry FGD Systems”, EPRI/DOE/EPA Mega Symposium, Washington, May 2003. IEA Coal Research, “Particulate control Handbook”, Final report, July 1997. IEA Coal Research, “Prevention of Particulate Emissions”, Final report, December 2000. ICAC, “ESPs vs. Fabric Filters: A Symposium and Debate”, March 1994. http://www.icac.org http://www.IEA-coal.org.UK/ http://www.croll.com

Process: PM Scrubber				
Category	**PM, TPY (WRAP 1996 >100 TPY)**	**%PM reduction**	**Cost,**	**Status**
Mineral Processing	24,499	50%-99+%	See below	Commercial
Petrochemical	10,836	50%-99+%	See below	Commercial
Wood/Biomass boilers	5,718	50%-99+%	See below	Commercial
Primary Metal production	4,476	50%-99+%	See below	Commercial
Pulp & Paper	4,476	50%-99+%	See below	Commercial

Process Description:

Scrubbers work on the principle of rapid mixing and impingement of the particulate with the liquid droplets and subsequent removal with the liquid waste. For particulate controls the "venturi scrubber" is an effective technology whose performance is directly related to the pressure loss across the venturi section of the scrubber.

Venturi scrubbers are one type of the more commonly used "scrubbers" for particulate collection. As the name implies, the scrubbing liquid and flue gases accelerate through a converging section into a narrow throat. In the throat, very high gas velocity shears the scrubbing liquid into many very fine droplets, which collect particles through numerous "collisions".

PM Reduction:

Scrubbers have varying PM reduction capabilities based on deign operating conditions and particle characteristics. Performance can range 50% for the small size fraction (< 2microns) to over 99% for the larger sizes.

Higher collecting efficiencies and a wider range of particulate sizes, require higher operating pressures. . High-energy scrubbers refer to designs operating at pressure drop of 50-70 inches of water. Of course, higher pressure translates to higher energy consumption.

Cost Information:

The following values represent typical costs for several of these technologies (these numbers reflect unit sizes ranging from utility-size units up to about 2,000,000 ACFM to smaller process down to about 10,000 ACFM)

- Capital: Venturi Scrubber - $5 - $20/ACFM
- Fixed O&M: Venturi Scrubber - $0.25 - $0.65/yr-ACFM
- Variable O&M: Venturi Scrubber - $1.2 - $1.8/yr-ACFM

Development Status:

Commercial

Wet scrubbers are widely used in various industries. One advantage of scrubbers is their ability to treat wet gases which are not conducive to other technologies such as dry ESPs and FFs.

Practical Considerations:

For applications where variation in flow require throat velocity compensation to maintain specified scrubbing efficiencies, automatic and manually variable throat designs are available.

Process: PM Scrubber
The automatic throat is used where flow conditions vary widely and frequent adjustments are required. When occasional variations occur, a manually controlled throat is generally sufficient.
Compatibility with other air pollution control technologies: Scrubbers are compatible with other PM controls. However, dry ESP's and FF's would not be deployed downstream of a scrubber without prior reheating of the flue gas which would make such application economically questionable in general
Secondary Environmental Impacts: Liquid waste disposal requires consideration on a case-by-case basis. Since scrubbers have the capability to reduce acid gases, applications where this is important must be considered.
References: IEA Coal Research, "Particulate control Handbook", Final report, July 1997. http://www.icac.org http://www.IEA-coal.org.UK/ http://www.croll.com

APPENDIX A-8. SO2 MILESTONES/BACKSTOP

This appendix contains work products and references relied upon by Arizona in the development of Chapter 8 of the Regional Haze SIP.

Appendix A-8a. WRAP Market Trading Forum Non-Utility Sector Allocation Final Report from the Allocations Working Group (November 2002)

MARKET TRADING FORUM NON-UTILITY SECTOR ALLOCATION

FINAL REPORT FROM THE ALLOCATIONS WORKING GROUP

PECHAN

5528-B Hempstead Way
Springfield, VA 22151

703-813-6700 telephone
703-813-6729 facsimile

3622 Lyckan Parkway
Suite 2002
Durham, NC 27707

919-493-3144 telephone
919-493-3182 facsimile

P.O. Box 1575
Shingle Springs, CA 95682

530-672-0441 telephone
530-672-0504 facsimile

Prepared for:

Western Governors' Association
1515 Cleveland Place
Denver, CO 80202

Prepared by:

E.H. Pechan & Associates, Inc.
5528-B Hempstead Way
Springfield, VA 22151

November 2002

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ACRONYMS AND ABBREVIATIONS

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
BLS	Black liquor solids
CAA	Clean Air Act
CWPB	center-worked prebake cells
DCE	Direct contact evaporator
dscf	dry standard cubic foot
ESPs	electrostatic precipitators
FCCU	fluid catalytic cracking unit
GCVTC	Grand Canyon Visibility Transport Commission
H_2S	hydrogen sulfide
HSS	horizontal stud Soderberg
ICI	industrial, commercial, and institutional
kg	kilogram
LAER	Lowest Achievable Emission Reduction
lbs/MMBtu	pounds per million British thermal units
Mg	megagram
MTF	Market Trading Forum
NO_x	oxides of nitrogen
NSPS	New Source Performance Standards
ppm	parts per million
ppmv	parts per million volume
PTE	potential to emit
RECLAIM	Regional Clean Air Incentives Market
SCC	Source Classification Code
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SRU	Sulfur Recovery Unit
SWPB	side-worked prebake cells
tpy	tons per year
VSS	vertical stud Soderberg
WGA	Western Governors' Association
WRAP	Western Regional Air Partnership

EXECUTIVE SUMMARY

This study was performed for a Working Group of the Western Regional Air Partnerships' (WRAP) Market Trading Forum. It provides a current, best estimate of the floor allocation for non-utility sources in the region that would be established if western States and tribes adopt a regional, backstop trading program for sulfur dioxide (SO_2) to meet the requirements of Section 309 of the regional haze rule. The major SO_2 emitting non-utility source categories evaluated in this study include the following: petroleum refineries, lime manufacturing, industrial boilers and co-generators, pulp and paper manufacturing, cement manufacturing, natural gas processing and oil and gas production, elemental phosphorus production, glass manufacturing, aluminum smelters, sulfuric acid plants, and coke production. Of these industry sectors, phosphorus, aluminum smelters, sulfuric acid plants, and coke production plants were not considered in the original source categories for the Market Trading Forum. The floor control technology (or emission rate or SO_2 control effectiveness) was determined by evaluating the emissions performance of other sources in that source category in the western States. The floor is defined to be best available control technology (BACT), best available retrofit technology (BART), or lowest achievable emission rate (LAER) for existing sources. For some sources, EPA has not determined what these levels of emissions are. SO_2 floor allocations were computed for each of about 200 major non-utility sources in the western States, where major is defined as those sources emitting greater than 100 tons per year (tpy).

While this analysis uses plant and process-level information to estimate floor allocations, if the backstop trading program is triggered, SO_2 allowances under the trading program will be allocated by the participating transport region States and Tribes at that time. This study is only an approximation of how the allocations might be made based upon the limited information that we have today. It is expected that the States and Tribes would be able to obtain more detailed information about current emissions and controls for these non-utility sources than has been available for the current project.

The floor allocation analysis has been performed separately for each of the 12 major non-utility source categories in the west. The text below summarizes the key findings for each source category.

To simplify the analysis, it was determined that California SO_2 sources are already highly controlled. The California floor allocation of 27,335 tpy is based on the opt-in/out 2018 SO_2 allocation that has been estimated previously by the WRAP Market Trading Forum.

Petroleum Refining: There are ten petroleum refineries outside California in the WRAP transport region. Data were received from all of these refineries for the allocation process. These floor allocations were computed for each of the four major SO_2 emitting processes at refineries: sulfur plants, fluidized catalytic cracking units (FCCUs), fuel combustion units, and flares. The SO_2 floor allocation for these ten refineries is 11,418 tpy, or about 5,400 tpy less than historic emissions during 1996 to 2000. This is one of the best characterized source categories.

Cement Manufacturing: The control technology analyses for cement kilns showed that there was no demonstrated SO_2 control technique at western State sources that could be applied to reduce SO_2 across the source population. There are widely varying SO_2 emissions rates from these kilns, and the process itself removes sulfur from the off gas. As a result, this sector's floor allocation of 7,761 tpy was based on recent historic emissions. *The analysis for lime manufacturing reached the same conclusion as that for cement.* The lime manufacturing floor allocation is 2,103 tpy.

Boilers and Co-generators: The floor for boilers and co-generators at industrial facilities was estimated by applying the equivalent of 85 percent SO_2 control to coal and oil-fired sources not already at, or near, this control level. Average capacity factors were used to estimate boiler utilization for estimating the floor with a 5 percent growth margin. This assumption is consistent with that used in the utility boiler floor allocations. Some non-utility boilers are operating at low utilization rates. The industrial boiler and cogenerator floor allocation is 7,910 tpy.

Pulp and Paper Industry: Recovery furnaces and lime kilns are the SO_2 sources at the Kraft pulp mills in the west. Most of these mills are in Oregon. Floor allocations for recovery furnaces and lime kilns are based on standard U.S. Environmental Protection Agency (EPA) emission factors and 100 percent capacity utilization (or recent annual throughput, if capacity estimates were not available). The pulp and paper floor allocation is 7,184 tpy.

Natural Gas Processing Plants and Oil and Gas Production: SO_2 emissions from natural gas processing plants result from combustion of sour gases. It was decided that the current New Source Performance Standard (NSPS) would serve as the floor. The NSPS requires a variable sulfur removal efficiency based on the hydrogen sulfide (H_2S) content of the acid gas and the amount of sulfur in the gas. If a facility had current control levels higher than the assumed floor, the actual average emissions over the past three years were used to estimate the floor. Since emissions from flaring operations both in the plant and the well field are not amenable to control, floor emissions are assumed to be the average of the emissions in three recent years. Data availability was a significant issue in determining the floor allocations for some gas plants. The floor allocation for this source category is 28,884 tpy.

Elemental Phosphorus Production: One of the two U.S. elemental phosphorus production facilities is in Idaho. Because of the uniqueness of this facility, no floor control technology was identified. The floor allocation is set at year 2000 SO_2 emissions, which were 15,861 tpy. It is expected that the State of Idaho will perform a more detailed evaluation of this facility during preparation of its regional haze State Implementation Plan (SIP).

Glass Manufacturing: The major source of SO_2 emissions in the glass industry is the glass melting operation. There are only two active glass manufacturing facilities in the 8 non-California WRAP States. With a lack of information about SO_2 control techniques in practice, the floor allocation for glass manufacturing plants was set according to historical SO_2 emissions. The glass manufacturing floor allocation is 368 tpy.

Copper Smelters: Because of the uniqueness of the existing copper smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. A double contact acid plant is considered the appropriate retrofit control equipment. All copper smelters in the western States are currently equipped with double contact acid plants. The current year SO_2 allocation for the six copper smelters in the 9-State region is 86,000 tons. This allocation is reduced to 78,000 tons by 2013 and is the same in 2018.

Aluminum Production: There are only 2 primary aluminum plants in the study region and both are located in Oregon. The primary SO_2 source in aluminum production is the sulfur in the coke, and the coal tar pitch binder used to produce the anodes. The floor control technology for aluminum smelters was determined by evaluating the emissions performance at the two Oregon facilities. One facility uses a wet scrubber to achieve a 70 percent SO_2 emission reduction. Therefore, a wet scrubber with a 70 percent SO_2 reduction was selected as the floor technology for aluminum smelters. The aluminum smelter floor allocation is 2,076 tpy.

Sulfuric Acid Plants: The only significant source of air emissions from a contact sulfuric acid plant is the tail gas leaving the final absorbing tower. This gas contains small amounts of SO_2 and even smaller amounts of sulfur trioxide, sulfuric vapor, and sulfuric

acid mist. Based on the information available for the 4 sulfuric acid plants in the west, it was decided that the floor allocation should be estimated by applying the NSPS requirements to each sulfuric acid plant. Achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent SO_2 collection mechanism in a controlled facility. However, recent historical SO_2 emissions for these facilities were lower than the NSPS emission rate times capacity estimated values, so the sulfuric acid plant floor was estimated using these historical SO_2 emission values. The resulting floor allocation for these sulfuric acid plants is 5,386 tpy.

Metallurgic Coke Production: SO_2 emissions from coke oven operations primarily result from combustion of the byproduct coal gas in the oven. There were three coke production facilities operating in the west during the 1990s. Coke production has recently ceased at two of these facilities. The only facility that continues to operate is a rotary calciner in Wyoming. Because of the uniqueness of this operation, the floor allocation is based on recent historic SO_2 emissions, and is 631 tpy.

There are two benchmarks that can be used to put the floor allocations in perspective. One is year 2000 historic emissions and the other is the non-utility SO_2 emissions forecast for 2018. The floor allocation estimate in this report is about 2,500 tons higher than year 2000 historical emissions. However, this comparison of the respective emission totals is skewed by the fact that year 2000 copper smelter emission were about one-half of the 78 thousand ton allocation for this sector. When copper smelters are removed from the totals, the floor allocation is about 45 thousand tons lower than year 2000 emissions. A comparison of the floor allocation with the SO_2 emissions in the 2018 opt-in/out emission allocations shows that the floor allocation is approximately the same.

CHAPTER I
INTRODUCTION

This report describes an analysis that was prepared for a Working Group of the Western Regional Air Partnership's (WRAP) Market Trading Forum (MTF). It provides the current best estimate of the floor allocation for non-utility sources in the region that would be established if western States and tribes adopt a regional, backstop trading program for sulfur dioxide (SO_2) to meet the requirements of Section 309 of the regional haze rule. Note that this does not establish final allocations for sources in the region. Each State and tribe will determine the appropriate floor level for sources within their jurisdiction, and will include this information in their State or tribal implementation plan. The program is voluntary for western States and tribes. Information is provided to assist eligible States and tribes evaluate the impacts of the program, but decisions to participate in the program will be made by each separate jurisdiction.

The distribution of regional SO_2 allowances to existing sources in the nine Commission Transport States is composed of two portions: floor and reducible allocation. There are two components of the floor allocation - an allocation for the California Regional Clean Air Incentives Market (RECLAIM) program, and source-specific floor allocations for non-RECLAIM sources. The floor allocation is a minimum allocation for all existing sources, which will be calculated to ensure that well-controlled sources will receive a full allocation.

California RECLAIM Program: 3,462 SO_2 allowances will be included in the California budget for RECLAIM sources. These credits will be a subset of the existing source pool for the State of California and, hence, will not consume any extra credits from the total credit pool.

Source-specific Floor Allocation: A floor allocation will be calculated for all existing sources in the region based on some specified level of control (e.g., Best Available Control Technology [BACT], Best Available Retrofit Technology [BART], Lowest Achievable Emission Reduction [LAER]) for non-utility sources.

The sources affected by the backstop trading programs are all those stationary sources in participating States and tribes that emit SO_2 in an amount greater than or equal to 100 tons per year (tpy). The 100 ton cut off will be assessed at the plant level to correspond with the methodology used in the 1990 emissions inventory. Among the source types covered by this definition are utility and industrial boilers, refineries, smelters, pulp and paper mills, cement and lime kilns, and all of the other source categories listed in section 169(g)(7) of the Clean Air Act (CAA).

In this report, the geographic area of analysis is defined to be the nine Commission Transport Region States, which are Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming. Facilities included in the analysis are those that emitted 100 tpy or more of SO_2 sometime during the period 1990 to 2000. Plants that are electric utilities are excluded from this analysis.

A. ANALYSIS METHODS

The floor allocation analysis for the non-utility sector was performed using the following steps:

1. It was assumed that the SO_2 sources in the State of California are already at the floor. This is expected because of the stringency of the air emission regulations in that State.

2. Because copper smelter allocations for 2018 have already been determined, no additional analyses were performed for copper smelters. Smelter allocations are presented in Chapter X.

3. The focus of the analysis was on non-California, non-smelter facilities that had at least 100 tpy of SO_2 emissions during at least one year in the period 1990 to 2000. States included in this analysis were Arizona, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming.

4. The major SO_2 emitting non-utility source categories evaluated in this study included the following: petroleum refineries, lime manufacturing, industrial boilers and co-generators, pulp and paper manufacturing, cement manufacturing, natural gas processing and oil and gas production, elemental phosphorus production, glass manufacturing, aluminum smelting, sulfuric acid production, and metallurgical coke production.

5. The floor control technology or emission rate or SO_2 control effectiveness was determined by evaluating the emissions performance of other sources in that source category in the western States. The floor is defined to be BACT, BART, or LAER for *existing* sources. The floor for each of the major source categories is summarized in Table I-1.

6. The primary source of emissions information for the western States is the 1996 WRAP point source inventory. The 1996 emission estimates were prepared under contract to the Western Governors' Association (WGA) by Pacific Environmental; Services and Eastern Research Group, Inc. under contract to the WGA (PES, 2001). However, this data set was not sufficient for providing all of the information needed to compute the floor allocation for each source. The State air pollution control agencies in each of the 8 States were contacted to obtain supplementary data. For most source categories, this additional information included estimates of unit capacities. This could be either the design capacity for boilers, or the production capacity for industrial processes.

7. Once data was received from the State agencies, it was used to estimate the floor allocation by source and facility based on the control technologies listed in Table I-1 and the unit or plant-specific information about existing capacities and SO_2 control techniques.

The chapters that follow explain the floor allocation analyses for each of the key industrial sector source categories in the western United States.

Table I-1
Methodology for the Calculation of the Floor Allocations for Non-Utility Sources

Source Category	Technologies or Standard for Floor	
Copper Smelters	Due to the uniqueness of the existing smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. Currently, the Hidalgo smelter is the only BART-eligible source on the list in this category. A double-contact acid plant will be considered the appropriate retrofit control equipment (all smelters in the region are currently equipped with double-contact acid plants). On August 21, 2000, New Mexico completed an engineering analysis that verified earlier determinations by the MTF that the fugitive SO_2 capture system at Hidalgo satisfies BART at 96% overall capture.	
Refineries	There are four sources of SO_2 emissions at the refinery level. Floor based upon New Source Performance Standards (NSPS) where applicable.	
	Description	Assumed Average Control Level
	Sulfur Recovery Unit (SRU)	Meet NSPS Subpart J or the equivalent of 3-stage Claus units with a tail gas unit (NSPS and the tail gas unit does not apply to Claus units smaller than 20 long tons/day or less).
	Fuel gas combustion units	Fix at the NSPS emission limit rate of 0.027 pounds per million British thermal units (lbs/MMBtu) assuming fuel gas input and not fuel oil.
	Catalytic crackers	NSPS (J) selected 9.8 lbs of SO_2 per 1,000 lbs of coke burned.
	Flares	Based upon average of the last 5 years' emission, AP42 factors for calculated. No additional controls.
Natural Gas Processing	Description	Assumed Average Level of Control
	Process Emissions	Reduction to satisfy NSPS. Variable reduction depending on hydrogen sulfide (H_2S) content and plant size.
	Flaring	Based upon average of the last 5 years' emission.
Oil & Gas Production	Description	Assumed Average Level of Control
	Flaring	Based upon average of the last 5 years' emission.
Lime Plants	No additional reduction. Approximately 50% control inherent in the process. Additional SO_2 controls are not in place at lime plants in the western States.	

Table I-1 (continued)

Source Category	Technologies or Standard for Floor
Industrial Boilers (Cogens)	Technology determination dependent upon current level of control. Description — Assumed Average Level of Control Uncontrolled Units — 85% Units controlled at less than 70% — Treat as uncontrolled (see above). Units controlled between 70-80% — Increase reductions by 5% (i.e., if a unit is at 72%, would be assumed to control to 77%). Units controlled greater than 80% — No additional reductions.
Pulp and Paper	Sulfur sources are recovery furnaces and boilers. Boiler discussions covered with industrial boilers. Recovery Furnaces: No additional reduction. Low emissions coupled with lack of more than one example of scrubbing.
Cement Plants	No additional reduction. Approximately 70-90 percent control inherent in the process. Additional SO_2 controls are not typically applied to these levels of processes.
Aluminum Smelters	A wet scrubber with a 70 percent SO_2 emission reduction selected as the floor based on achieved control levels at NW Aluminum in Oregon.
Sulfuric Acid Plants	No additional reduction. Existing units are already controlled to NSPS levels (4 lbs per ton of 100% acid produced).
Coke Production	Only one facility is still operating. Because of the uniqueness of this rotary calciner, the floor allocation is established at historic SO_2 emission levels.

CHAPTER II
PETROLEUM REFINING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The petroleum refining industry involves numerous processes that convert crude oil into more than 2,500 products, including gasoline, liquefied petroleum gas, kerosene, jet fuel, diesel fuel, other fuel oils, lubricating oils, and feed stock for the petrochemical industry. Petroleum refinery activities include the storage of crude oil at the refinery, petroleum handling and refining operations, and storage of the refined products prior to shipment. As of January 1990, there were 189 operating refineries in the United States with a total crude capacity of 15.4 million barrels per calendar day.

Removal of sulfur from refinery streams is a part of refining. It would be desirable to remove all sulfur compounds before any crude processing begins, but because this is impractical, sulfur is removed throughout the refining process. There are several reasons, besides air pollution control, for removing sulfur from intermediate fractions and products of crude oil. Sulfur removal reduces corrosion, odor, breakdown frequency, catalyst poisoning, and gum formation and improves octane rating, color, and lube oil life.

B. FLOOR ALLOCATION ESTIMATION METHODS

There are four possible unit types (SO_2 emission points) within a refinery, as noted in the methodology for the calculation of the floor allocations for non-utility sources. These four SO_2 sources are: (1) the SRU; (2) fuel gas combustion units; (3) catalytic crackers; and (4) flares. The approach for estimating SO_2 floor allocations is unique for each of these four SO_2 source types within the refinery. Floor calculation methods are presented below for each of these four source types.

1. Sulfur Recovery Units

Sulfur recovery refers to conversion of H_2S to elemental sulfur. H_2S is a by product of processing natural gas and refining high sulfur crude oils. The most common conversion method used is the Claus process. Approximately 90 to 95 percent of recovered sulfur is produced by the Claus process. The Claus process typically recovers 95 to 97 percent of the H_2S feed stream.

The average production rate of a sulfur recovery plant in the United States varies from 51 to 203 megagrams (Mg) (56 to 224 tons) per day. Some of the small to mid-sized refineries in the western States have sulfur plant capacities that are lower than these average values.

The SO_2 floor allocation for SRUs depends on the size of the sulfur plant. For sulfur plants of 20 long tons per day or larger, the NSPS require a 3-stage Claus unit with a tail gas unit. Existing NSPS limit sulfur emissions from Claus sulfur recovery plants of greater than 20.32 Mg (22.40 tons) per day capacity to 0.025 percent by volume (250 parts per million volume [ppmv]). The NSPS and tail gas unit do not apply to Claus units smaller than 20 long tons per day or less. For these smaller sulfur plants, the SO_2 floor allocations are estimated as 95 percent SO_2 control.

Table 8.13-1 in AP-42 provides the following SO_2 emission factors for modified Claus Recovery Plants:

Emission Factors for Modified Claus Sulfur Recovery Plants

		SO_2 Emissions	
Number of Catalytic Stages	**Average % Sulfur Recovery**	**Kilograms (kg)/Mg of Sulfur Produced**	**lbs/ton of Sulfur Produced**
1, Uncontrolled	93.5	139	278
3, Uncontrolled	95.5	94	188
4, Uncontrolled	96.5	73	145
2, Controlled	98.6	29	57
3, Controlled	96.8	65	129

The SO_2 emission factor for 99.8 percent sulfur recovery is 8 lbs/ton and for 96.8 percent sulfur recovery is 132 lbs/ton of sulfur produced. This emission factor value is multiplied by the sulfur plant capacity in tons per day, 365 days per year, and 1 ton per 2,000 lbs to arrive at an annual SO_2 emissions floor estimate. Equation (1) below shows the above description as a formula:

$$Sulfur\ plant\ capacity\left(\frac{tons}{day}\right) * \frac{lbs\ SO_2}{ton} * \frac{365\ days}{year} * \frac{1\ ton}{2{,}000\ lbs} = \frac{SO_2\ tons}{year} \qquad (1)$$

For refineries with sulfur plants smaller than 20 long tons per day, and lower H_2S contents in their acid gas, an SO_2 control level of 96.8 percent may not be achievable. In that situation, an alternative way to calculate the floor is to use the sulfur feed rate and the H_2S content of the acid gas of the affected facility to compute the appropriate minimum SO_2 reduction efficiency using the relationships shown in Table II-1. This table is from the NSPS for onshore natural gas production.

Table II-1
Sulfur Plants - Required Minimum SO_2 Emission Reduction Efficiency

H_2S Content of Acid Gas (Y), %	Sulfur Feed Rate (x), Long Tons per Day			
	$2.0 \le X \le 5.0$	$5.0 < X \le 15.0$	$15.0 < X \le 300.0$	$X > 300.0$
$Y \ge 50$	74.0	. . . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . . or 99.8, whichever is smaller		
$20 \le Y < 50$	74.0	. . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . or 97.5, whichever is smaller		97.5
$10 \le Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

2. Fuel Gas Combustion Units

Fuel gas combustion units in refineries were defined to include all process heaters and boilers, and their combined oil and gas combustion capacity. SO_2 floor allocations are estimated as the combined oil and gas combustion capacity multiplied by 0.027 lbs/MMBtu. This emission rate is an approximation of the SO_2 emission factor for a fuel gas combustion unit meeting the NSPS of 0.10 grains H_2S per dry standard cubic foot (dscf) as required by 40 CFR 60 Subpart J.

This H_2S value is converted to an SO_2 emission rate in lbs/MMBtu using the equation below:

$$SO2\left(\frac{lb}{MMBtu}\right) = \frac{010\ grains\ H2S}{dscf}\ x\ \frac{1\ lb}{7{,}000\ grains}\ x\ \frac{64\ lb\ moles\ SO2}{34\ lb\ moles\ H2S}\ x\ \frac{1000\ scf}{MMBtu} = \frac{0.027\ lb}{MMBtu}$$

In the floor allocation estimates for fuel gas combustion units, the fuel gas combustion capacity is based on reported values for the refineries in Colorado, New Mexico, and Utah as well as for Wyoming Refining and Frontier Refining in Wyoming. Where this value has not been reported, it is estimated to be 5 percent of the crude oil processing capacity at that refinery. The industry norm is reported to be in the range of 5 to 10 percent. The 5 percent value was used because it is the average value for the western State refineries for which data on fuel gas combustion capacity were provided.

3. Catalytic Crackers

The SO_2 floor allocation for catalytic crackers at petroleum refineries is computed using the NSPS for fluid catalytic cracking units (FCCUs). The NSPS for FCCUs without add-on controls is 9.8 kg SO_x per 1,000 kg coke burn-off. For FCCUs without add-on control devices, EPA decided that the regulated pollutant should be SO_x, because SO_3 could constitute a significant portion of the total SO_2 emissions from FCCUs using SO_x reduction catalysts. The standard for FCCUs without add-on controls requires the use of Method 8 to determine the total SO_x emissions from affected facilities.

One of the issues in applying the NSPS emission rate to estimate the SO_2 floor allocation is the availability of information about the amount of coke burn-off for each FCCU. The Source Classification Code (SCC) units used in emission inventories, and AP-42 SO_2 emission factors, are expressed as lbs/1,000 barrels of fresh feed. Therefore, it is necessary to develop a conversion factor to go from an emission limit expressed as an SO_x emission rate per 1,000 kg coke burn-off to an emission limit expressed in AP-42 or SCC units if the coke burn rate is not available for a refinery.

In order to apply the NSPS SO2 emission rate to estimate the floor allocation for FCCUs, information about the coke burn rate was needed for each refinery. For 10 of the Western State refineries listed in Table II-1, estimates of the coke burn rate in pounds per hour were available from a data set that the American Petroleum Institute provided to EPA as part of the MACT standard setting process. These coke burn rates are based on 1997 operations. For the refineries with FCCUs and no coke burn rate available, the coke burn rates were estimated using the relationship between the FCCU feed capacity in barrels per calendar day and the coke burn rate (pounds per hour) for the 10 western refineries with reported values. The relationship used was 16 pounds coke per barrel of oil. Refineries where this default value was applied included the two Colorado refineries and Flying J, Inc. in Utah. Wyoming Refining provided a design coke burn rate for its FCCU.

4. Flares

Flares are commonly used for the disposal of waste gases during process upsets and emergencies. They are basically safety devices that are also used to destroy organic constituents in waste emission streams. The AP-42 SO_2 emission factor for a vapor recovery system and flaring is 26.9 lbs per 1,000 barrels refinery feed. This emission factor is applied to estimate the SO_2 emissions floor for flares at each refinery.

C. FLOOR ALLOCATION RESULTS

Table II-2 includes the floor allocation calculation for the refineries in the 8 non-California Western Regional Air Partnership (WRAP) States. The *Oil & Gas Journal Worldwide Refining Survey for 2000* provided the values for sulfur plant capacity, catalytic cracking unit capacity, and crude capacity listed in Table II-2 where they were not otherwise provided by State air agencies or refinery companies. Fuel gas combustion capacities in MMBtu/hour (hr) are estimated using information provided by State air pollution control agencies. Sinclair Corporation provided data for its two Wyoming refineries (Greene, 2002).

Table II-2
Petroleum Refining Floor Allocation Calculation

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
Conoco Inc.	Commerce City	CO	Sulfur Recovery Unit	70	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	102.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	112.9
			Oil		MMBtu/hr			
			Total	955	MMBtu/hr			
			FCCU	12,666	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	554.8
			Flares	57,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	282.3
			All Sources Combined					1,052.2
Colorado Refining	Denver	CO	Sulfur Recovery Unit	4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	96.4
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	60.2
			Oil		MMBtu/hr			
			Total	509	MMBtu/hr			
			FCCU	5,333	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per coke burn off	233.6
			Flares	35,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	171.8
			All Sources Combined					562.0
Giant Refining Co.	Bloomfield	NM	Sulfur Recovery Unit	2	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	48.2
			Fuel Gas Combustion					
			Gas	328	MMBtu/hr	0.027	lbs of SO_2 per million Btu	38.8
			Oil		MMBtu/hr			

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Total	328	MMBtu/hr			
			FCCU	5,400	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	236.5
			Flares	18,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	90.8
			All Sources Combined					414.3
Giant Refining Co.	Gallup	NM	Sulfur Recovery Unit	2	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	48.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	37.3
			Oil		MMBtu/hr			
			Total	315	MMBtu/hr			
			FCCU	8,200	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	359.2
			Flares	32,200	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	158.1
			All Sources Combined					602.7
Navajo Refining Co.	Artesia	NM	Sulfur Recovery Unit	140	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	204.4
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	109.3
			Oil		MMBtu/hr			
			Total	924	MMBtu/hr			
			FCCU	13,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	569.4
			Flares	70,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	343.6

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			All Sources Combined					1,226.7
BP/now Tesoro Petroleum	Salt Lake City	UT	Sulfur Recovery Unit	17.4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	419.2
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	100.0
			Oil		MMBtu/hr			
			Total	846	MMBtu/hr			
			FCCU	14,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	613.2
			Flares	52,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	255.3
			All Sources Combined					1,387.7
Chevron Products Co.	Salt Lake City	UT	Sulfur Recovery Unit	22.4	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	539.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	145.9
			Oil		MMBtu/hr			
			Total	1,234	MMBtu/hr			
			FCCU	6,500	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	284.7
			Flares	55,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	270.0
			All Sources Combined					1,240.3
Silver Eagle Refining Inc.	Woods Cross	UT	Sulfur Recovery Unit	0	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	0.0
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	15.6

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Oil		MMBtu/hr			
			Total	132	MMBtu/hr			
			FCCU	0	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	0.0
			Flares	12,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	61.4
			All Sources Combined					77.0
Flying J Inc.	Salt Lake City	UT	Sulfur Recovery Unit	7	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	168.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	57.8
			Oil		MMBtu/hr			
			Total	489	MMBtu/hr			
			FCCU	7,533	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn	329.9
			Flares	24,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	117.8
			All Sources Combined					674.2
Phillips Petroleum Co.	Woods Cross	UT	Sulfur Recovery Unit	14	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	337.3
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	83.4
			Oil		MMBtu/hr			
			Total	705	MMBtu/hr			
			FCCU	5,000	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	219.0
			Flares	25,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	122.7

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			All Sources Combined					762.4
Frontier Refining Inc.	Cheyenne	WY	Sulfur Recovery Unit	110	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	160.6
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	155.5
			Oil		MMBtu/hr			
			Total	1,315	MMBtu/hr			
			FCCU	7,330	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	321.1
			Flares	46,000	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	225.8
			All Sources Combined					863.0
Sinclair Oil Corp.	Casper	WY	Sulfur Recovery Unit	21.7	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	522.8
			Fuel Gas Combustion					
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	77.1
			Oil		MMBtu/hr			
			Total	652	MMBtu/hr			
			FCCU	7,590	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	332.4
			Flares	22,000	Based on 2001 operations (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	108.0
			All Sources Combined					1,040.3
Sinclair Oil Corp.	Sinclair	WY	Sulfur Recovery Unit	52.6	Sulfur plant capacity tons sulfur per day	8	lbs of SO_2 per ton sulfur produced	76.8
			Fuel Gas Combustion					

Table II-2 (continued)

Plant Name	City	State	Source Type	Plant/Unit Capacity	Capacity Notes	Floor Allocation Emission Rate	Emission Rate Units	Floor allocation tons/year
			Gas		MMBtu/hr	0.027	lbs of SO_2 per million Btu	119.9
			Oil		MMBtu/hr			
			Total	1,014	MMBtu/hr			
			FCCU	13,120	Coke Burn Rate (lbs/hr)	20	lbs of SO_2 per ton coke burn off	574.7
			Flares	60,000	Based on 2001 operations (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	294.6
			All Sources Combined					1,066.0
Wyoming Refining Co.	Newcastle	WY	Sulfur Recovery Unit	3	Sulfur plant capacity tons sulfur per day	132	lbs of SO_2 per ton sulfur produced	72.3
			Fuel Gas Combustion					
			Gas	0	MMBtu/hr	0.027	lbs of SO_2 per million Btu	51.6
			Oil	0	MMBtu/hr			
			Total	436.6	MMBtu/hr			
			FCCU	6,028.5	Data provided by Wyoming Refining (lbs/hr) design coke burn rate	20	lbs of SO_2 per ton coke burned	264.0
			Flares	12,500	From the December 2000 Oil and Gas Journal (bbls/cd)	26.9	lbs/1,000 bbl refinery feed	61.4
			All Sources Combined					449.3
Total Floor Allocation (CO, NM, UT, WY)								**11,418**

D. COMPARISON WITH HISTORICAL EMISSIONS

Table II-3 summarizes historical SO_2 emissions from petroleum refineries located in the 9 WRAP States. California refineries are included in this table. This table provides a point of comparison with the floor allocations shown in Table II-2.

E. EXAMPLE CALCULATION

This section provides an example calculation of the refinery floor allocation using the data provided for this project by Wyoming Refining. This refinery is located in Newcastle, Wyoming. This same information can be found in Table II-2 in condensed form.

1. Sulfur Recovery Unit

The SO_2 floor allocation for the SRU is based on the capacity of the unit. Because the capacity of the Wyoming Refining sulfur plant is less than 20 long tons per day, a sulfur recovery efficiency of 96.8 percent is applied in the floor calculation. (If the sulfur plant was larger than 20 long tons per day, a 99.8 percent sulfur recovery value would be applied.)

The SO_2 emission factor for 96.8 percent sulfur recovery is 132 lbs SO_2 per ton of sulfur produced as shown below:

$$\frac{3.2\ tons\ S\ emitted}{96.8\ tons\ S\ removed} * \frac{2000\ lbs}{ton} x \frac{64\ lbs\ moles\ SO_2}{32\ lbs\ moles\ S} = \frac{132\ lbs\ SO_2}{ton\ S\ produced}$$

Then, the SO_2 floor allocation is the sulfur plant capacity (3 short tons per day) multiplied by the SO_2 emission factor and 365 days per year, as follows:

$$SO_2\ Floor\ (tons\ per\ year) = Sulfur\ plant\ capacity\ (tons\ /\ day) * SO_2\ emission\ factor\ (lbs\ /\ ton) * \frac{1\ ton}{2000\ lbs}\ x\ 365\ days\ /\ year$$

$$= (3.0)\ (132)\ (365) \div 2000 = 72.3$$

2. Fuel Gas Combustion

The SO_2 floor allocation for fuel gas combustion is based on the combined boiler and process heater combustion capacity with each refinery. Wyoming Refining estimates that its total boiler plus process heater fired duty capacity at the refinery is 436.6 MMBtu per hour. The SO_2 floor allocation is estimated to be the combined oil and gas combustion capacity multiplied by 0.027
lbs/MMBtu.

$$SO_2\ Floor\ (tons\ per\ year) = Combustion\ Capacity\ (MMBtu\ /\ hr) * SO_2\ emission\ factor\ (lbs\ /\ MMBtu) * \frac{1\ ton}{2000\ lbs} * \frac{8760\ hrs}{year}$$

$$= (436.6)\ (0.027)\ (5 \times 10^{-4})\ (8760)$$

$$= 51.6$$

Table II-3
Petroleum Refineries – Historical Emissions – 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	005	0001	42	2911	6	Oil/Gas	Intermountain Refining		803	0	0	0
CA	6	037	800012	14	2911	6	Oil/Gas	ARCO (NSR USE ONLY)	ARCO PRODUCTS CO	1,919	2,359	1,706	2,315
CA	6	037	800030	14	2911	6	Oil/Gas	CHEVRON U.S.A. INC (EIS USE) - EL SEGUNDO	CHEVRON PRODUCTS CO.	833	1,795	938	1,208
CA	6	013	10	11	2911	6	Oil/Gas	CHEVRON USA INC - RICHMOND	CHEVRON PRODUCTS COMPANY	1,291	1,018	1,413	1,244
CA	6	095	15	11	2911	6	Oil/Gas	EXXON CORPORATION - BENICIA		4,922	6,042	5,779	5,779
CA	6	029	37	13	2911	6	Oil/Gas	KERN OIL & REFINING CO.		319	425	443	364
CA	6	037	800089	14	2911	6	Oil/Gas	MOBIL OIL CORP (EIS USE) - TORRANCE	MOBIL OIL CORP (EIS USE)	256	807	725	1,018
CA	6	013	32	11	2911	6	Oil/Gas	PACIFIC REFINING COMPANY	NOW PLANT ID 11587	278	290	0	0
CA	6	029	25	13	2911	6	Oil/Gas	SAN JOAQUIN REFINERY	SAN JOAQUIN REFINING COMPANY	337	313	138	0
CA	6	013	11	11	2911	6	Oil/Gas	SHELL OIL COMPANY - MARTINEZ	MARTINEZ REFINING COMPANY	2,790	2,518	2,374	1,159
CA	6	037	800223	14	2911	6	Oil/Gas	TEXACO REFINING & MARKETING IN - WILMINGTON		546	727	590	953
CA	6	029	33	13	2911	6	Oil/Gas	TEXACO REFINING AND MARKETING - BAKERSFIELD	EQUILON ENTERPRISES LLC	471	190	94	72
CA	6	013	12758	11	2911	6	Oil/Gas	TOSCO CORP AVON REFINERY		7,661	4,459	5,422	5,422
CA	6	037	800026	14	2911	6	Oil/Gas	ULTRAMAR INC (NSR USE ONLY)		341	959	669	620
CA	6	037	800144	14	2911	6	Oil/Gas	UNION OIL CO OF CAL (NSR USE O	TOSCO REFINING COMPANY	724	1,005	806	806
CA	6	079	4	13	2911	6	Oil/Gas	UNOCAL CARBON	TOSCO SANTA MARIA REFINERY	0	0	0	0
CA	6	079	4	13	2911	6	Oil/Gas	UNOCAL CHEM DIV-UNOCAL CORP - ARROYO GR	TOSCO	3,034	3,950	0	0
CA	6	013	16	11	2911	6	Oil/Gas	UNOCAL CORPORATION - RODEO	TOSCO RODEO REFINERY	584	728	675	615
CA	6	037		14	2911	6	Oil/Gas	UNOCAL REFINING & MARKETING CO	TOSCO REFINING (L.A.)	0	343	508	587
CA	6	079	13	13	2911	6	Oil/Gas	UNOCAL- SANTA MARIA REFINERY	TOSCO SANTA MARIA REFINERY	647	225	3,501	3,727
CA	6	037	800047	14	2911	6	Oil/Gas	FLETCHER OIL & REF CO (EIS USE		107	0	0	0
CA	6	037	800184	14	2911	6	Oil/Gas	GOLDEN WEST REF CO (EIS USE)		232	0	0	0
CA	6	037	800103	14	2911	6	Oil/Gas	POWERINE OIL CO (EIS USE)		196	0	1	1
CA	6	037	800115	14	2911	6	Oil/Gas	SHELL OIL CO (EIS USE) - CARSON	SHELL OIL PRODUCTS	778	0	0	0
CO	8	001	0004	53	2911	6	Oil/Gas	COLO REFINING		632	664	526	545
CO	8	001	0003	53	2911	6	Oil/Gas	CONOCO DENVER		2,336	2,610	2,496	1,972
CO	8	077	0001	55	2911	6	Oil/Gas	LANDMARK PETROLEUM		157	0	0	0
NM	35	045	0023	60	2911	6	Oil/Gas	GIANT INDUSTRIES/BLOOMFIELD REF		676	772	920	920
NM	35	031	0008	61	2911	6	Oil/Gas	GIANT REFINING/CINIZA REFINERY		1,346	1,115	1,779	1,779
NM	35	015	0010	65	2911	6	Oil/Gas	NAVAJO REFINING/ARTESIA REFINERY		1,549	1,552	969	980
UT	49	035	0004	32	2911	6	Oil/Gas	Amoco Petroleum Products	TESORO PETROLEUM	6,701	983	1,116	1,368
UT	49	011	0003	31	2911	6	Oil/Gas	Chevron Products Company		2,424	1,116	845	1,242
UT	49	011	0008	31	2911	6	Oil/Gas	Flying J Incorporated		312	574	225	300
UT	49	011	0013	31	2911	6	Oil/Gas	Phillips 66 Company		5,672	864	862	601
WY	56	021	0001	9	2911	6	Oil/Gas	FRONTIER OIL & REFINING - CHEYENNE		1,521	1,769	1,422	1,396
WY	56	025	0001	9	2911	6	Oil/Gas	LITTLE AMERICA REFINING COMPANY	SINCLAIR - CASPER	1,899	1,629	1,305	1,458
WY	56	007	0011	9	2911	6	Oil/Gas	SINCLAIR @ SINCLAIR		5,917	3,990	3,524	3,407
WY	56	045	0001	9	2911	6	Oil/Gas	WYOMING REFINING CO	WYOMING REFINING - NEWCASTLE	630	930	804	876
WY	56	025	0002	9	2911	6	Oil/Gas	AMOCO REFINERY		1,153	0	0	0
Totals										**61,994**	**46,721**	**42,575**	**42,734**

3. Catalytic Crackers

The SO_2 floor allocation for catalytic crackers is based on the coke burn rate at the FCCU and the NSPS SO_2 emission rate. The FCCU for Wyoming Refining has a design feed rate of 5,300 barrels per day, or 6,029 lbs per hour. The NSPS SO_2 emission rate is 20 lbs SO_2 per ton coke burn-off.

$$SO_2\ Floor\ (tons\ per\ year) = Coke\ burn\ rate\ (lbs/hr) * \frac{1\ ton}{2000\ lbs} * SO_2\ emission\ factor\ (lbs/ton) * \frac{1\ ton}{2000\ lbs} * \frac{8760\ hrs}{year}$$

$$= (6029)(5 \times 10^{-4})(20)(5 \times 10^{-4})(8760)$$

$$= 264.0$$

4. Flares

The SO_2 floor allocation for the flares at Wyoming Refining is estimated according to the total crude processing capacity of the facility. The estimated crude processing capacity for Wyoming Refining is 12,500 barrels per calendar day. This capacity value is multiplied by the AP-42 SO_2 emission factor for a vapor recovery system and flaring of 26.9 lbs per 1,000 barrels refinery feed.

$$SO_2\ Floor\ (tons\ per\ year) = refinery\ capacity \left(\frac{1000\ bbls}{cd}\right) * 26.9 \left(\frac{lbs}{1000\ bbls}\right) * \left(\frac{1\ ton}{2000\ lbs}\right) * \left(\frac{365\ days}{year}\right)$$

$$= (12.5)\ (26.9)\ (5 \times 10^{-4})\ (365)$$

$$= 61.4$$

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CHAPTER III
LIME MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Lime is the high temperature product of the calcination of limestone. Although limestone deposits are found in every State, only a small portion is pure enough for industrial lime manufacturing. The Standard Industrial Classification (SIC) code for lime manufacturing is 3274. The six-digit SCC for lime manufacturing is 3-05-016.

The heart of a lime plant is the kiln. The prevalent type of kiln is the rotary kiln, accounting for about 90 percent of all U.S. lime production. This kiln is a long, cylindrical, slightly inclined, refractory-lined furnace, through which the limestone and hot combustion gases pass concurrently. Coal, oil, and natural gas may all be fired in rotary kilns. Product coolers and kiln feed preheaters of various types are commonly used to recover heat from the hot lime product and hot exhaust gases, respectively.

The next most common type of kiln in the United States is the vertical, or shaft, kiln. This kiln can be described as an upright heavy steel cylinder lined with refractory material. The limestone is charged at the top and is calcined as it descends slowly to discharge at the bottom of the kiln. A primary advantage of vertical kilns over rotary kilns is higher average fuel efficiency. The primary disadvantages of vertical kilns are their relatively low production rates and the fact that coal cannot be used without degrading the quality of the lime produced. There have been few recent vertical kiln installations in the United States because of high product quality requirements.

Other, must less common, kiln types include rotary hearth and fluidized bed kilns. Both kiln types can achieve high production rates, but neither can operate with coal. The "calcimatic" kiln, or rotary hearth kiln, is a circular kiln with a slowly revolving doughnut-shaped hearth. In fluidized bed kilns, finely divided limestone is brought into contact with hot combustion air in a turbulent zone, usually above a perforated grate. Because of the amount of lime carryover into the exhaust gases, dust collection equipment must be installed on fluidized bed kilns for process economy.

SO_2 emissions are influenced by several factors, including the fuel sulfur content, the sulfur content and numeralogical form (pyrite or gypsum) of the stone feed, the quality of lime being produced, and the type of kiln. The dominant source of SO_2 emissions is the kiln's fuel, and the vast majority of the fuel sulfur is not emitted because of reactions with calcium oxides in the kiln. SO_2 emissions may be further reduced if the pollution equipment uses a wet process or if it brings calcium oxides and SO_2 into intimate contact.

Table III-1 provides SO_2 emission factors for lime manufacturing. This table shows that there is a wide range of SO_2 emissions performance depending on the kiln type, pollution control equipment, feedstock, and fuel.

Because of differences in the sulfur content of the raw material and fuel and in process operations, a mass balance on sulfur may yield a more representative emission factor for a specific facility than AP-42 emission factors.

B. FLOOR ALLOCATION ESTIMATION METHODS

With the wide range of SO_2 emission factors for lime manufacturing, the SO_2 control that is inherent in the lime manufacturing process, and additional controls are not typically applied to lime plants, the SO_2 floor allocation for lime plants will be based on historical

emissions. The historical emissions for the 1990 to 2000 period are listed in Table III-2. The calendar year 2000 SO_2 emission total for lime manufacturing is 2,316 tons.

REFERENCES

AWMA, 2000: Air & Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, edited by Wayne T. Davis, 2000.

EPA, 1998: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, AP-42, Section 11:17: Lime Manufacturing," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

Table III-1
Emission Factors for Lime Manufacturing[a]

Source	SO_2[b]	Emission Factor Rating
Coal-fired rotary kiln (SCC 3-05-016-18)	5.4	D
Coal-fired rotary kiln with fabric filter (SCC 3-05-016-18)	1.7	D
Coal-fired rotary kiln with wet scrubber (SCC 3-05-016-18)	0.30	D
Gas-fired rotary kiln (SCC 3-05-016-19)	ND	
Coal- and gas-fired rotary kiln with venturi scrubber (SCC 3-05-016-20)	ND	
Coal- and coke-fired rotary kiln with venturi scrubber (SCC 3-05-016-21)	ND	
Coal-fired rotary preheater kiln with dry PM controls (SCC 3-05-016-22)	2.3	E
Coal-fired rotary preheater kiln with multiclone, water spray, and fabric filter (SCC 3-05-016-22)	6.4	E
Gas-fired calcimatic kiln (SCC 3-05-016-05)	ND	
Gas-fired parallel flow regenerative kiln with fabric filter (SCC 3-05-016-23)	0.0012	D
Product cooler (SCC 3-05-016-11)	ND	

NOTES: [a]Factors represent uncontrolled emissions unless otherwise noted. Factors are lbs/ton of lime produced unless noted. ND = no data. Classification Code.
[b]Mass balance on sulfur may yield a more representative emission factor for a specific facility.

Table III-2
Lime Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Allocation*
AZ	4	025	0011	41	3274	10	Metals/Mining/Minerals	CHEMICAL LIME (CHEMSTAR)	CHEMICAL LIME CO - NELSON PLANT	141	122	562	702	632
AZ	4	003	0003	47	3274	10	Metals/Mining/Minerals	CHEMICAL LIME (DOUGLAS)	CHEMICAL LIME CO - DOUGLAS PLANT	212	634	724	742	733
CA	6	053	12	12	3274	10	Metals/Mining/Minerals	NATIONAL REFRACTORIES&MINERALS	CHEMICAL LIME CO - NATIVIDAD PLANT	243	<100	69	82	76
NV	32	003	0003	22	3274	10	Metals/Mining/Minerals	CHEMSTAR APEX	CHEMICAL LIME CO - APEX PLANT	783		175	210	193
NV	32	007	0261		3274	10	Metals/Mining/Minerals	CONTINENTAL LIME INC., PILOT PEAK PLANT	GRAYMONT WESTERN US INC, PILOT PEAK PLANT	<100	136	235	249	242
UT	49	027		35	3274	10	Metals/Mining/Minerals	CONTINENTAL LIME INC., CRICKET MOUNTAIN PLANT	GRAYMONT WESTERN US, INC., CRICKET MOUNTAIN PLANT	115	297	275	331	303
Totals										**1,594**	**1,289**	**2,040**	**2,316**	**2,179**

NOTE: *Based on 1998 and 2000 historical SO_2 emission estimates.

CHAPTER IV
INDUSTRIAL BOILERS AND COGENERATORS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Industrial, commercial and institutional (ICI) boilers produce steam or heat water for use in industrial processes, electrical/mechanical power generation, or space heating. Some have a dual functionality such as the cogeneration of steam and electricity. Auxiliary boilers provide backup power and power for startup/shutdown of large units. Large boilers (≥150 MMBtu/hr) are generally field-erected units while small boilers are preassembled, packaged units. The design of an individual ICI boiler is often dependant on the application of steam and the space limitations in a particular plant.

ICI boilers generate steam at lower temperatures and pressures than utility boilers, therefore, their heat inputs are smaller. Industrial boilers generally have heat input rates ranging from 30 to 250 MMBtu/hr, but may be as high as 1,500 MMBtu/hr (EPA, 1994). Commercial and institutional boilers typically have heat input rates ranging from 0.4 to 12 MMBtu/hr, but may be as high as 100 MMBtu/hr (EPA, 1994). The overall population of ICI boilers have small heat inputs, with 80 percent of the population operating at less than 5 MMBtu/hr per boiler (STAPPA, 1994). Over 80 percent of the ICI boilers burn oil and gas. The remaining boilers burn primarily coal, with a small number burning biomass, waste or other non-fossil fuel. ICI combustion units often burn a mixture of conventional fuels and biomass or waste. Pulverized coal-fired units account for approximately 1 percent of the total ICI boiler population. However, they have large heat inputs, greater than 100 MMBtu/hr, therefore, they represent 14 percent of the total ICI boiler capacity. Oil and gas fired ICI boilers are smaller in size than coal-fired boilers, typically less than 250 MMBtu/hr.

The use of ICI boilers varies with the industrial application. In addition, the application of steam from an industrial boiler can change with the seasons, and can vary through the course of a day as well, depending on the processes and activities underway at a given moment and their demand for steam. Therefore, ICI boilers may have a much lower annual operating load or capacity factor than a typical utility boiler.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to facilities which emit greater than 100 tpy of SO_2 in total, and/or individual units which emit greater than 25 tpy of SO_2. In addition, only coal and oil fired units were analyzed. Auxiliary boilers were included in the floor allocation estimation if the unit had a potential to emit (PTE) greater than 25 tpy. This includes boilers larger than 5 MMBtu/hr firing fossil fuel with a sulfur content of 1 percent or more.

The air pollution agencies for each WRAP State provided information for each ICI boiler being analyzed. This information included the boiler design capacity, annual fuel consumption for recent calendar years, fuel type (coal or oil), fuel sulfur content, SO_2 control device information, and the control device SO_2 control efficiency, or permitted SO_2 emissions limit for each unit.

The SO_2 floor allocations are calculated for each facility based on the current level of control. An average level of control is then assumed for each facility, according to Table IV-1 below:

Table IV-1
Assumed Level of Control for SO_2 Floor Allocation

Current Facility Level of Control	Assumed Average Level of Control for Estimating the Floor
Uncontrolled, 0%	85% Reduction
Units controlled at 0% to <70%	85% Reduction
Units controlled at 70% to 80 %	Increase reduction by 5%
Units controlled at 80% or greater	No additional reduction

Floor allocations for industrial boilers/cogenerators were also based on the average capacity utilization during the most recent calendar years. Some States were able to provide as many as five years worth of boiler utilization data. The recent years of boiler utilization (fuel consumption) data were used to estimate an average capacity factor for each unit. This average capacity factor was used, along with a 5 percent margin for growth, in the SO_2 floor allocation calculation for each boiler/cogenerator.

1. Coal Fired Units

Coal fired units were assumed to fire subbituminous coal with a heating value of 9,000 Btu/lb (18 MMBtu/ton) of coal burned, unless a specific coal type or heating value was reported (AWMA, 2000). The ICI boilers in the WRAP States were assumed to burn subbituminous coal since it has a low sulfur content. In addition, a lower grade of subbituminous coal, class C coal, was assumed to be used for ICI applications. The fuel sulfur content used to calculate the floor allocation was facility-specific, where available. For facilities that did not report sulfur content, an average sulfur content (1 percent) for the type of coal being fired was used (AWMA, 2000).

The SO_2 emission factor for subbituminous coal fired boilers in pounds of SO_2 emitted per ton of coal burned is given in AP-42 as:

$$EF_{SO2}\left(\frac{\text{lb of SO2}}{\text{ton}}\right) = 35 \times S$$

where S is the percentage sulfur content of the coal burned by each combustion unit (EPA, 1998a).

2. Oil Fired Units

Oil fired units were assumed to have a heating value of 0.15 MMBtu/gal unless a specific oil type or heating value was reported (AWMA, 2000). The fuel sulfur content used to calculate the floor allocation was facility-specific. For facilities not reporting sulfur content, an average sulfur content for the type of oil being fired was used (AWMA, 2000).

The SO_2 emission factor for No. 2 and No. 6 oil fired boilers in pounds of SO2 emitted per 1,000 gallons of oil burned is given in AP-42 as:

$$EF_{oil}\left(\frac{\text{lb of SO2}}{\text{1,000 gal}}\right) = 157 \times S$$

where S is the percentage sulfur content of the oil burned by each combustion unit (EPA 1998b).

Units that burn natural gas and oil are assumed to burn natural gas as a primary fuel, if the emission data indicated SO_2 emission < 5 tpy. If natural gas is the primary fuel, no allocations are computed.

C. FLOOR ALLOCATION RESULTS

Table IV-2 summarizes the floor allocation calculation for the ICI boilers in the 8 non-California Western Regional Air Partnership (WRAP) States.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table IV-3 summarizes historical SO_2 emissions from industrial boilers located in Arizona, Colorado, Idaho, Oregon, Utah, and Wyoming. This table provides a point of comparison with the floor allocations shown in Table IV-2 and historical emissions at each facility. Note that the historical emissions are the total plant emissions, not just those resulting from operation of the boiler. In general, boilers which currently have a scrubber are able to meet their SO_2 floor allocations based on historical emissions.

E. EXAMPLE USE OF CAPACITY UTILIZATION DATA FOR FLOOR ALLOCATION ESTIMATES

The floor allocation estimation method for boilers and cogenerators takes into account utilization of these fuel combustion units in the most recent historical years. This section provides an example of how the capacity factor calculation was performed for one boiler at Abitibi Consolidated in Arizona.

In order to estimate the average annual capacity factors of each unit, Pechan requested the actual fuel throughput data for the last 5 years for each boiler. The data was supplied by the air pollution agencies for each WRAP State. The fuel throughput data supplied by the Arizona DEQ for Abitibi Consolidated is listed in Table IV-4.

Fuel throughput for all fuel types, coal, oil and natural gas were used to estimate the annual heat input for each unit using the following equation:

$$Q_{annual} = \left(T_{coal} \times HC_{coal}\right) + \left(T_{oil} \times HC_{oil}\right) + \left(T_{gas} \times HC_{gas}\right)$$

where:

Q_{annual} = annual heat input for each boiler (MMBtu/yr),
T = throughput for given fuel type, and
HC = heat content for a given fuel type.

Most States did not specify the heat content for each fuel, therefore, the following default values were used:

Coal	Heat content = 18.0 MMBtu/ton
Oil	Heat content = 0.15 MMBtu/gal
Natural Gas	Heat content = 1,020 MMBtu/MMscf

The boiler design capacity at Abitibi Power boiler #2 is 1,132 MMBtu per hour. In this exercise, the annual fuel consumption is compared with this boiler design capacity to estimate the percentage of total capacity that is used in each year. The Arizona DEQ was able to provide fuel throughput, or fuel consumption, estimates for four calendar years: 1998 through 2001. This particular unit burns coal and oil, but not natural gas. Fuel consumption estimates were provided by the State in tons for coal and gallons for oil. The average heat contents of these two fuels are listed in Table IV-4 and are used to compute an *All Fuels Combined Throughput* value in column J. Column K contains the boiler design capacity value converted to an annual equivalent. The capacity factor for each calendar year is computed (in column L) as the ratio of column J to column K. For Abitibi Power boiler #2, these capacity factors range from 60 to 70 percent, with an average capacity

factor of 64 percent. The 64 percent average capacity factor value is used in the floor allocation estimate. (Note that during a leap year (2000), the potential hours of operation are greater.)

This average capacity factor is used to calculate the SO_2 floor allocation. This value is multiplied by 1.05 to provide some margin for future increases in operations. Only the primary fuel (coal in this example) is assumed to burned by the boiler in the floor allocation estimation. The SO_2 allocations are calculated using the assumed control efficiency (85 percent) as specified in Table IV-1. The SO_2 floor allocation is calculated using the following equation:

$$SO_2 = \frac{Q_{design}}{HC_{prime}} \frac{EF_{SO2}}{2000 \frac{\text{lb}}{\text{ton}}} \left(1.05 \times CF\right) \left(\frac{100 - \text{CE}}{100}\right)$$

where:

SO_2	=	SO_2 floor allocation (tons/yr),
Q_{design}	=	annual heat input (MMBtu/yr),
HC_{prime}	=	heat content of primary fuel (MMBtu/ton, MMBtu/gal),
EF	=	SO_2 emissions factor (lb/ton, lb/gal),
CF	=	average capacity factor (%), and
CE	=	required control efficiency (%).

For Abitibi Power boiler #2, the appropriate values for the above equation are:

Q_{design}	=	9,916,320
HC_{prime}	=	18
EF	=	35
CF	=	0.64
CE	=	85

As is shown in column P of Table IV-4, the SO_2 floor allocation estimate for Abitibi Power boiler #2 is 978 tpy.

REFERENCES

AWMA, 2000: Air and Waste Management Association, Davis, Wayne T. ed., "Air Pollution Engineering Manual," Second Edition, John Wiley and Sons, Inc., New York, 2000.

EPA, 1994: U.S. Environmental Protection Agency, "Alternative Control Techniques Document – NO_x Emissions from Industrial/Commercial/Institutional Boilers," EPA-453/R-94-022, Emission Standards Division, Office of Air Quality Planning and Standards, Research Triangle Park, NC, March 1994.

EPA, 1998a: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42), Section 1.1 Bituminous And Subbituminous Coal Combustion," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

EPA, 1998b: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42), Section 1.3 Fuel Oil Combustion," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

STAPPA, 1994: State and Territorial Air Pollution Program Administrators (STAPPA) and Association of Local Air Pollution Control Officials (ALAPCO), "Controlling Nitrous Oxides," July 1994.

Table IV-2
Facility SO_2 Floor Allocation Estimation for ICI Boilers

Facility	Unit	Capacity in MMBtu/hr	Fuel	Sulfur Content	Current SO_2 Controls	Percent Reduction	SO_2 Limit	Average Capacity Factor (%)	Assumed Percent Reduction	Floor Allocation (tpy)
Arizona										
Abitibi Consolidated	No. 2 Power Boiler	1,132	Coal	1.0	None	0		64	85	978
Colorado										
TRIGEN - Colorado Energy Corp	Boiler #3	225	Coal	0.39		0		43	85	
TRIGEN - Colorado Energy Corp	Boiler #4	360	Coal	0.38		0		62	85	
TRIGEN - Colorado Energy Corp	Boiler #5	650	Coal	0.43		0		59	85	387
Idaho										
Amalgamated Sugar, Nampa	S-B1	105	Coal	1.0	None	0		34	85	
Amalgamated Sugar, Nampa	S-B2	105	Coal	1.0	None	0		35	85	
Amalgamated Sugar, Nampa	S-B3	250	Coal	1.0	None	0		43	85	242
Amalgamated Sugar Company, Paul	S-B1	200	Coal	1.0	None	0		35	85	
Amalgamated Sugar Company, Paul	S-B2	200	Coal	1.0	None	0		23	85	155
Amalgamated Sugar Company, Twin Falls	P-B1	280	Coal	1.0	None	0		30	85	
Amalgamated Sugar Company, Twin Falls	P-B2	285	Coal	1.0	None	0		24	85	203
Oregon										
Boise Cascade [c]	Power Boiler 6-9	N/A	Oil	2.0	No	0	4125 tpy	--	85	411
Amalgamated Sugar	B&W Boilers	204	Coal	1.5	Wet Scrubber	45	200 tpy	12	85	
Amalgamated Sugar	Foster Riley Boiler	136	Coal	1.5		0	265 tpy	20	85	
Amalgamated Sugar	Foster Wheeler Boiler	300	Coal	1.5		0	775 tpy	21	85	74
Georgia Pacific West	Power Boiler #1	Unknown	Oil	2.0	None	0	429.6 tpy	--	85	143
Pope & Talbot	Power Boiler #1	Unknown	Oil	2.0	None	0	391 tpy	--	85	107
West Linn Paper Co.	Boilers 1 & 2		Oil	2.0	None	0	492.74 tpy	46	85	211
Georgia-Pacific Wauna	Power Boiler	Unknown	Oil	2.0	None	0	641.1 tpy	--	85	
Georgia-Pacific Wauna	Package Boiler	Unknown	Oil	2.0	None	0	0.5 tpy	0	85	277
Weyerhaeuser Springfield	Power Boiler	Unknown	Oil	2	None	0	590 tpy	--	85	
Weyerhaeuser Springfield	Package Boiler	Unknown	Oil	0.55	None	0	73 tpy	--	85	
Weyerhaeuser Springfield	Package Boiler	16	Oil	2	None	0	39 tpy	0	85	362
Utah										
Sunnyside Cogeneration Associates	FBC Boiler #1	700	Coal	1.0	Scrubber	86	462 lbs/hr	84	86	1,270
Kennecott Utah Copper Corp N. Concentator	Unit 1	431	Coal	0.68	None [a]	0	1258 tpy	41	85	
Kennecott Utah Copper Corp N. Concentator	Unit 2	431	Coal	0.68	None [a]	0	1258 tpy	33	85	
Kennecott Utah Copper Corp N. Concentator	Unit 3	431	Coal	0.68	None [a]	0	1258 tpy	28	85	
Kennecott Utah Copper Corp N. Concentator	Unit 4	838	Coal	0.68	None [a]	0	2445 tpy	39	85	700
Brigham Young University	Units #2, #3, and #5	128	Coal	0.70	None [a]	0	217 tpy	0	85	
Brigham Young University	Auxiliary #7	5	Oil	1.5		0		6	85	0
Brush Wellman Incorporated	S-11 - Main Boiler	81.2	Oil	1.5	None	46	0.85 lb/MBtu	32	85	
Brush Wellman Incorporated	S-10 Backup Boiler	12.66	Oil	1.5	None	46	0.85 lb/MBtu	19	85	23

Table IV-2 (continued)

Facility	Unit	Capacity in MMBtu/hr	Fuel	Sulfur Content	Current SO_2 Controls	Percent Reduction	SO_2 Limit	Average Capacity Factor (%)	Assumed Percent Reduction	Floor Allocation (tpy)
Geneva Steel	Power Boiler 1	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 2	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 3	411	Coal/Gas	1.0	None	0		4		
Geneva Steel	Power Boiler 4	205	Coal/Gas	1.0	None	0		0		
Geneva Steel	Power Boiler 5	205	Coal/Gas	1.0	None	0	520.2 tpy	0	96	17
Wyoming										
Solvay Minerals, Inc.	Boiler #18	350	Coal	0.7	Scrubber	85	0.2	62	85	
Solvay Minerals, Inc.	Boiler #19	350	Coal	0.7	Scrubber	85	0.2	61	85	294
General Chemical	Boiler C	534	Coal	0.5	No	0	1.2	74	85	
General Chemical	Boiler D	880	Coal	0.5	No	0	1.2	71	85	750
Holly Sugar-Torrington Plant		221.2	Coal	0.7	No	0	None	17	85	23
FMC Corp - Green River Plant	Boiler #6	887	Coal	0.5	Scrubber [b]	0	1.2	70	85	
FMC Corp - Green River Plant	Boiler #7	887	Coal	0.5	Scrubber [b]	0	1.2	70	85	956
University of Wyoming Central Heating Plant	Boiler #2	73.1	Coal	0.5	No	0	1.2	18	85	
University of Wyoming Central Heating Plant	Boiler #3	73.1	Coal	0.5	No	0	1.2	25	85	22
University of Wyoming Central Heating Plant	Boiler #4	73.1	Coal					20		
FMC Granger	Boiler #1	358	Coal	1.0	Scrubber	99	0.2 lb/MMbtu	48	99	
FMC Granger	Boiler #2	358	Coal	1.0	Scrubber	99	0.2 lb/MMbtu	48	99	305
Total Floor Allocation										**7,910**

NOTES: [a]Natural gas is fired during winter months per SIP requirements.
[b]Scrubber is for the entire plant not just the boiler.

Table IV-3
Comparison of SO_2 Floor Allocation with Historical Emissions for ICI Boilers

Facility	Unit	Capacity (MMBtu/hr)	SO_2 Floor Allocation (tpy)	Historical SO_2 Emissions			
				1990 (tpy)	1996 (tpy)	1998 (tpy)	2000 (tpy)
Arizona							
Abitibi Consolidated	Power Boiler #2	1,132	978		2,455	2,448	1,893
Colorado							
TRIGEN - Colorado Energy Corp [b]	Boiler #3	225					
TRIGEN - Colorado Energy Corp [b]	Boiler #4	360					
TRIGEN - Colorado Energy Corp [b]	Boiler #5	650	387	2,675		3,708	2,583
Idaho							
Amalgamated Sugar, Nampa	S-B1	105					
Amalgamated Sugar, Nampa	S-B2	105					
Amalgamated Sugar, Nampa	S-B3	250	242	1,008	1,660	1,787	1,697
Amalgamated Sugar Company, Paul	S-B1	200					
Amalgamated Sugar Company, Paul	S-B2	200	155	608	306	217	1,322
Amalgamated Sugar Company, Twin Falls	P-B1	280					
Amalgamated Sugar Company, Twin Falls	P-B2	268	203	599	1,364	1,053	1,053
Oregon							
Boise Cascade [c]	Power Boiler 6-9	N/A	411	2,453	685	746	1,834
Amalgamated Sugar [c]	B&W Boilers	204					
Amalgamated Sugar [c]	Foster Riley Boiler	136					
Amalgamated Sugar [c]	Foster Wheeler Boiler	300	74	594	625	1,235	987
Georgia Pacific West [c]	Power Boiler #1	Unknown	143				
Pope & Talbot [c]	Power Boiler #1	Unknown	107			39	161
West Linn Paper Co. [a]	Boilers 1 & 2	365	211				
Georgia-Pacific - Wauna [c]	Power Boiler	Unknown					
Georgia-Pacific - Wauna [c]	Package Boiler	18	277			254	165
Weyerhaeuser Springfield	Power Boiler	Unknown	297				
Weyerhaeuser Springfield	Package Boiler	Unknown	65				
Weyerhaeuser Springfield	Package Boiler	16	0				
Utah							
Sunnyside Cogeneration Associates [b]	FBC Boiler #1	700	1,270	0	1,006	970	1,054
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 1	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 2	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 3	431					
Kennecott Utah Copper Corp, N. Concentator [b]	Unit 4	838	700	2,905	2,141	2,200	2,534
Brigham Young University	Units 2, 3, and 5	128					
Brigham Young University	Auxiliary #7	5	0	248	90	158	125
Brush Wellman Incorporated	S-11 Main Boiler	81.2					
Brush Wellman Incorporated	S-10 Back-up Boiler	12.66	23	161	175	208	179

Table IV-3 (continued)

Facility	Unit	Capacity (MMBtu/hr)	SO_2 Floor Allocation (tpy)	Historical SO_2 Emissions			
				1990 (tpy)	1996 (tpy)	1998 (tpy)	2000 (tpy)
Geneva Steel	Power Boiler 1	411					
Geneva Steel	Power Boiler 2	411					
Geneva Steel	Power Boiler 3	411					
Geneva Steel	Power Boiler 4	205					
Geneva Steel	Power Boiler 5	205	17	8,473	2,020	881	979
Wyoming							
Solvay Minerals, Inc. [b]	Boiler #18	350					
Solvay Minerals, Inc. [b]	Boiler #19	350	294		101	72	52
General Chemical [b]	Boiler C	534					
General Chemical [b]	Boiler D	880	750	4,196	5,651	4,538	5,000
Holly Sugar-Torrington Plant [b]		221.2	23	374	266	154	178
FMC Corp - Green River Plant [b]	Boiler #6	887					
FMC Corp - Green River Plant [b]	Boiler #7	887	956	4,795	5,256	4,533	4,901
University of Wyoming Central Heating Plant [a]	Boiler #2	73.1					
University of Wyoming Central Heating Plant [a]	Boiler #3	73.1	22	152	154	223	193
University of Wyoming Central Heating Plant [a]	Boiler #4	73.1					
FMC Granger	Boiler #1	358					
FMC Granger	Boiler #2	358	305	475	473	149	212

NOTES: [a]Facility with boilers as only SO_2 source.
[b]Facility has multiple sources, emissions are total plant.
[c]Facility has multiple sources, emissions are boilers only.

Table IV-4
Example Use of Capacity Utilization Data for Floor Allocation Estimates

A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
			Coal		Oil		Natural Gas								
Facility	Unit	Year	Throughput (ton/yr)	Heat Value (MMBtu/ton)	Throughput (gal/yr)	Heat Value (MMBtu/gal)	Throughput (MMcf/yr)	Heat Value (MMBtu/ft^3)	Throughput All Fuels Combined (MMBtu/yr)	Design Capacity (MMBtu/yr)	Capacity Factor	Primary Fuel Sulfur Content (%)	SO_2 EF (lb/ton)	SO_2 Reduction (%)	SO_2 Allocation (tons)
Arizona															
Abitibi Consolidated	Power Boiler # 2	1998	387,532	18.0	44,000	0.15	0.0		6,982,176		70%				
	1,132 MMBtu/hr	1999	353,163	18.0	-	0.15	0.0		6,356,934		64%				
		2000	350,531	18.0	29	0.15	0.0		6,309,562		64%				
		2001	327,428	18.0	193,000	0.15	0.0		5,922,654		60%				
				18.0						**9,916,320**	**64%**	**1.00**	**35.0**	**85.0**	**978**

NOTE: Throughput is the annual fuel consumption in the calendar year.

CHAPTER V
PULP AND PAPER INDUSTRY

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The processing of wood for a variety of products is one of the ten largest industries in the United States. To produce paper or paperboard, wood must be pulped first. In general, the pulp and paper production processes can be divided into three steps: pulp making, pulp processing, and paper/paperboard processing. The three basic types of pulping processes, which are the major sources of SO_2, are chemical pulping, mechanical pulping, and semi-chemical pulping. Chemical wood pulping involves cooking wood chips or sawdust in an aqueous chemical solution to dissolve the lignin that binds the cellulose fibers together. There are two major types of chemical pulping used: Kraft/soda pulping and sulfite pulping. Kraft pulping accounts for over 80 percent of the chemical pulp produced in the United States.

Sources of SO_2 in a Kraft mill include: (1) boilers generating steam for power and heat, using coal, oil, natural gas, or bark/wood waste as fuel; (2) recovery furnaces where SO_2 emissions occur from the oxidation of reduced sulfur compounds; and (3) lime kilns when fuel oil is being combusted.

Allocations for boilers are discussed in Chapter IV, "Industrial Boilers and Cogenerators." Floor allocations for recovery furnaces and lime kilns are described in this chapter. Note that the calculations for these sources are the same as those for like configurations set forth in other chapters.

1. Recovery Furnaces

After the cooking period, the pulp and the liquor in which it cooked are separated, the spent liquor (black liquor) is evaporated and concentrated to about 65 percent solids. Concentrated black liquor is then sprayed into the furnace and the organic compounds are combusted. The combustion of black liquor in a recovery furnace results in SO_2 emissions that vary with liquor properties (i.e., sulfidity, heat value), combustion air and liquor firing patterns, furnace design and operational patterns.

SO_2 reduction is achieved by altering the process, rather than applying control technology. Strategies to lower liquor sulfidity and optimize combustion and firing patterns in such way that yields maximum and uniform temperatures in the lower furnace are used to minimize SO_2 emissions. Flue gas desulfurization is energy intensive and its efficiency uncertain, considering the generally low concentrations and fluctuating levels of SO_2 in the furnace flue gases.

2. Lime Kilns

In a pulp and paper lime kiln, the inorganic molten smelt that forms and collects at the bottom of the furnace is withdrawn through spouts into a smelt-dissolving tank where jets of water are used to quench the molten smelt, forming green liquor. The green liquor is then combined with quicklime (CaO), resulting in a white liquor solution containing NaOH, Na_2S and lime mud precipitate (mainly $CaCO_3$). This lime mud is washed, dried and calcined in the lime kiln to regenerate quicklime. The regenerated quicklime in the kiln acts as an in-situ-scrubbing agent and the Venturi scrubber that usually follows the kiln further reduces SO_2 levels. Emissions from smelt-dissolving tanks and lime kilns are generally negligible.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to pulp and paper facilities that emit greater than 100 tpy of SO_2 from all processes. There are seven pulp and paper facilities evaluated – six located in the State of Oregon and one in Idaho. The Oregon Department of Environmental Quality provided data on the unit capacity for each Oregon facility. However, the data given were the permitted SO_2 emission levels and the design capacity of production of each recovery furnace or kiln.

Abitibi in Navajo County, Arizona no longer operates a recovery furnace. They are no longer pulping and have converted to recycled paper processing. Therefore, they receive no floor allocation for recovery furnace operation.

1. Recovery Furnaces

The floor allocation for recovery furnaces is determined assuming that the process provides sufficient SO_2 reductions. No further SO_2 reductions will be required when estimating the floor allocations. Pechan estimated the floor allocation using the emission factor given in AP-42 in lbs/air-dried ton of pulp (ADT) and the designed pulp production capacity. The SO_2 floor allocations are given by the equation:

$$A_F(tpy) = EF_{SO_2}\left(\frac{lb}{ADT\ of\ pulp}\right) x\ capacity\left(\frac{ADT\ of\ pulp}{day}\right) x\ \%\ capacity\ x\ \frac{1\ ton}{2{,}000\ lb}\ x\ \frac{365\ days}{1\ year}$$

where:

A_F = SO_2 allocation for recovery furnaces in the facility, and
EF_{SO2} = AP-42 emission factor = 7 lbs/ADT.

For facilities where pulp production capacity was not given, but fuel throughput was reported in its place, SO_2 allocations are estimated as the fuel throughput multiplied by the EPA AP-42 SO_2 emission factor.

2. Lime Kilns

The floor allocation for lime kilns is determined in the same manner as recovery furnaces. The floor allocation for lime kilns assumes no further SO_2 reductions will be required when estimating the floor allocations. Using the emission factor for lime kilns given in AP-42, the SO_2 floor allocation equation for lime kilns is given by:

$$A_K(tpy) = EF_{SO_2}\left(\frac{lb}{ADT\ of\ pulp}\right) x\ capacity\left(\frac{ADT\ of\ pulp}{day}\right) x\ \%\ capacity\ x\ \frac{1\ ton}{2000\ lb}\ x\ \frac{365\ days}{1\ year}$$

where:

A_K = SO_2 allocation for lime kilns in the facility, and
EF_{SO2} = AP-42 emission factor = 0.3 lbs/ADT.

For facilities where pulp production capacity was not given, but fuel throughput was reported in its place, SO_2 allocations are estimated as the fuel throughput multiplied by the EPA AP-42 SO_2 emission factor.

C. FLOOR ALLOCATION RESULTS

Table V-1 presents the floor allocation calculations for pulp and paper plants in Oregon based on the permitted capacity of the recovery furnaces and kilns. Unit capacity values were given in air-dried tons of pulp per day. For the floor calculations, it was assumed that the furnace was operated 365 days per year at 100 percent capacity.

Table V-2 presents the floor allocation for facilities where the pulp production capacity was not given, but fuel throughput was reported instead. The Potlatch facility listed in Table V-2 is located in Idaho. All other pulp and paper mills listed in Tables V-1 and V-2 are in Oregon. Therefore, the computed floor allocations by State are 1,807 tpy for Idaho, and 5,377 tpy for Oregon. The California allocation for pulp/paper is based on the 1996, 1998, and 2000 historical SO_2 emissions data in Table V-3, and is 324 tpy.

Table V-1
Facility SO_2 Floor Allocation Estimation for Pulp and Paper Facilities Based on Unit Capacity Values

Facility	Unit	Capacity* (ADTP/day)	SO_2 Allocations (tpy)
Boise Cascade Corporation	Recovery Furnace#2	450	575
	Recovery Furnace#3	700	894
	Lime Kiln#4	1,150	63
Georgia-Pacific (Wauna Mill)	Recovery Furnace	1,015	1,297
	Lime Kiln	1,174	64
Weyerhauser Springfield	#3 Recovery Boiler	1,150	760
	#4 Recovery Boiler	1,150	790
	Lime Kilns	2,156	118

NOTE: *Design and actual capacity are unknown, the values given are the permitted levels.

Table V-2
Facility SO_2 Floor Allocation Estimation for Pulp and Paper Facilities Based on Fuel Throughput

Facility	Unit	Fuel	Throughput	SO_2 Allocations (tpy)
Georgia-Pacific West, Inc.	Recovery Furnace#1	DCE-BLS	242,725 tpy	129
		Nat. gas		
	Recovery Furnace#2	DCE-BLS	242,725 tpy	129
		Nat. gas		
	Lime Kiln#2	Nat. gas	553.7*10E6 ft³/y	0
		RFO		
		#6 oil		
	Lime Kiln#3	Nat. gas	553.7*10E6 ft³/y	0
		RFO		
		#6 oil		
Willamette Industries, Inc.	Recovery Furnace#5	BLS	495,000 tpy	235
		Nat. gas	350 MMft³	0
		No.2 fuel oil	1E06 gal/y	39
	Lime Kiln #3	Oil/nat.gas/LPG	1.35E05 ton lime mud/y	36
Pope & Talbot, Inc.	Recovery Furnace	BLS	461,081 tpy	67
		Oil	1.2E06 gal/y	173
	Lime Kiln	CaO	55,536 tpy	0
		Oil	1.8E06 gal/y	1
		NCG/CaO	5,662 tpy	7
Potlatch	#4 Recovery Boiler	BLS	117,113 tpy	410
	#5 Recovery Boiler	Pulp	393,548 tpy	1,377
	#2 Lime Kiln	CaO	10,247 tpy	2
	#3 Lime Kiln	CaO	61,467 tpy	9
	#4 Lime Kiln	CaO	60,147 tpy	9

D. COMPARISON WITH HISTORICAL EMISSIONS

Table V-3 summarizes historical SO_2 emissions from pulp and paper facilities. This table provides a point of comparison with the floor allocations shown in Tables V-1 and V-2 and historical emissions at each facility. Note that the historical emissions are the total plant emissions, not just those resulting from operation of the recovery furnace and lime kiln.

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 18 -Wood Processing Industry, 2000.

EPA, 1998: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors, AP-42, Fifth Edition, Volume I: Stationary Point and Area Source, Section 10.2 Chemical Wood Pulping," Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

Table V-3
Pulp and Paper - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	017	0007	43	2611	3	Wood/Paper/Pulp	STONE CONTAINER	ABITIBI	8,536	2,455	2,448	1,893
CA	6	023	21	10	2611	3	Wood/Paper/Pulp	SIMPSON PAPER COMPANY	SIMPSON PAPER CO	1,021	315	315	
CA	6	089	23		2611	3	Wood/Paper/Pulp	SHASTA PAPER-ANDERSON					216
CA	6	013	3257	11	2611	3	Wood/Paper/Pulp	GAYLORD CONTAINER CORPORATION		263	0	0	
CA	6	023	37	10	2611	3	Wood/Paper/Pulp	LOUISIANA-PACIFIC CORP.		302	<100	42	42
CA	6	077	191	11	2621	3	Wood/Paper/Pulp	NEWARK SIERRA PAPERBOARD CORP.		270	0	0	
ID	16	045			2611	3	Wood/Paper/Pulp	BOISE CASCADE - EMMETT					252
ID	16	069	0001	3	2621	3	Wood/Paper/Pulp	POTLATCH		1,379	700	700	1,694
OR	41	009	1849	6	2621	3	Wood/Paper/Pulp	Boise Cascade Company		2,453	685	746	1,834
OR	41	041	0005	5	2631	3	Wood/Paper/Pulp	Georgia-Pacific West, Inc.		56	207	322	452
OR	41	019	0036	5	2631	3	Wood/Paper/Pulp	International Paper		874	602	1,006	0
OR	41	007	0004	5	2621	3	Wood/Paper/Pulp	James River II, Inc.	Georgia- Pacific (Wauna Mill)	331	573	617	643
OR	41	043	3501	5	2621	3	Wood/Paper/Pulp	Pope & Talbot Pulp, Inc.		485	133	92	293
OR	41	071	6142	5	2621	3	Wood/Paper/Pulp	Smurfit Newsprint Corporation 2		592	368	461	519
OR	41	043	0471	5	2631	3	Wood/Paper/Pulp	Willamette Industries, Inc.		396	54	485	327
OR	41	039	8850	5	2631	3	Wood/Paper/Pulp	Collins Products LLC	Weyerhaeuser Co. (Particleboard)	202	0	3	1,721
OR	41	047	5398	5	2621	3	Wood/Paper/Pulp	Ogden Martin Systems of Marion, Inc.	Covanta Marion, Inc.	127	18	22	
										17,287	**6,210**	**7,259**	**9,886**

CHAPTER VI
CEMENT MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The cement industry involves the calcining of limestone in clinker and the subsequent crushing of the clinker into cement. Cement manufacturing activities include the process the mining and mixture of raw materials such as limestone and other materials, the pryoprocessing of the raw materials into a clinker, and the grinding of the clinker and other materials such as silicates into the final cement. As of December 2000, there were 201 kilns with a total capacity of 84 million tpy. The kiln is a predominate source of SO_2 emissions. The SO_2 emissions result from the combustion of the sulfur in the fuel and the sulfur (generally in the form of pyrite) that can occur in the feedstock.

Kilns generally take five forms:

- wet (where the feedstock contains up to 43 percent water);
- dry;
- semi-dry;
- dry with a pre-heater;
- and dry with a pre-calciner.

SO_2 emissions vary by kiln type generally based on how effectively the kiln type mixes the SO_2 containing gases with the alkaline calcium compounds. The pre-heater and pre-calciner kilns can remove 90+ percent of the SO_2 in the gas stream while the dry process kiln removes about 70 percent. In addition, the type of particulate control devices can impact the amount of SO_2 removed in the process. Fabric filters, both because they mix the SO_2 containing gases with the particles collected on the filter, and because they operate at a generally lower temperature then electrostatic participators (ESPs), collect more SO_2 than ESPs.

B. FLOOR ALLOCATION ESTIMATION METHODS

Estimation of the floor allocation procedure for the cement industry poses several difficulties. First, there is no demonstrated control technology for control of SO_2 emissions from cement kilns. Second, emissions from kilns vary considerably due to numerous variables including kiln type and sulfur content of feedstock. According to EPA AP-42 emission factors, emissions can vary by as much as a factor of 20. Emission data from two similar kilns in Utah shows that changes in feedstock can cause a change in emissions up to a factor of 100. Because of this variability and lack of predictability of emissions, the floor allocation was based on the average emissions from each plant over the past several years.

C. FLOOR ALLOCATION RESULTS

Table VI-1 shows the allocation results of the emissions to each plant. As discussed above, the data are based on the emissions reported in State inventories unless otherwise indicated (See Table VI-2). Several of the sources added new kilns in the past several years. For these sources only emission data after the new kiln were included. Permit

Table VI-1
Floor Allocations

State	Plant Name	SO_2 Floor Allocation (tpy)	State Totals (tpy)
AZ	Phoenix Cement Portland Cement Plant	320[1]	
			320
CO	Holcim Portland	3,374	
CO	Holcim Laporte	1,402	
CO	Cemex	160	
			4,936
ID	Ash Grove Inkom	522	
			522
NV	Nevada Cement	305	
NV	Royal Cement	143[2]	
			448
NM	Rio Grande	1,103[3]	
			1,103
UT	Holcim	267[2]	
			267
WY	Centex	165[4]	
			165
TOTAL		**7,761**	**7,761**

NOTES: [1]Permit limited potential to emit.
[2]Only two years after new kiln included.
[3]Only one year of data available.
[4]New kiln in 1997.

Table VI-2
Cement Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
AZ	4	019			3241	4	Cement/Concrete	Arizona Portland Cement		101	13	10	8
AZ	4	025		41	3241	4	Cement/Concrete	Phoenix Cement		<100	197	339	539
CA	6	029	9	13	3241	4	Cement/Concrete	CAL PORTLAND CEMENT CO.		429	245	245	245
CA	6	029	20	13	3241	4	Cement/Concrete	CALAVERAS CEMENT CO		286	286	286	286
CA	6	085	17	11	3241	4	Cement/Concrete	KAISER CEMENT CORPORATION	HANSON PERMANENTE CEMENT	474	464	416	474
CA	6	087	11	11	3241	4	Cement/Concrete	LONE STAR INDUST CEMENT PLANT	RMC PACIFIC MATERIALS	250	286	393	314
CA	6	071	7000000	15	3241	4	Cement/Concrete	MITSUBISHI CEMENT		28	574	946	298
CA	6	071	1200003	15	3241	4	Cement/Concrete	RIVERSIDE CEMENT COMPANY		0	527	527	164
CA	6	071	100005	15	3241	4	Cement/Concrete	CEMEX-CALIFORNIA CEMENT		0	0	0	427
CA	6	071		15	3241	4	Cement/Concrete	SOUTHWESTERN PORTLAND CEMENT C	SOUTHDOWN-VICTORVILLE PLANT	108	0	0	0
CO	8	069	0002	52	3241	4	Cement/Concrete	HOLNAM LAPORTE	HOLCIM	623	623	375	404
CO	8	043	0001	58	3241	4	Cement/Concrete	HOLNAM PORTLAND	HOLCIM	4,069	3,615	3,219	3,288
CO	8	013	0003	53	3241	4	Cement/Concrete	SOUTHWEST PORTLAND	CEMEX-LYONS PLT.	967	160	160	50
ID	16	005	0004	7	3241	4	Cement/Concrete	ASHGROVE CEMENT		790	200	200	1,327
NV	32	019	0387	20	3241	4	Cement/Concrete	NEVADA CEMENT COMPANY	FERNLEY PLANT	360	340	346	172
NM	35	001			3241	4	Cement/Concrete	RIO GRANDE PORTLAND CEMENT		0	0	0	1,103
UT	49	029	0001	31	3241	4	Cement/Concrete	Holnam Incorporated	HOLCIM	911	3	247	288
										9,496	**7,533**	**7,709**	**9,387**

limits were selected, since the kiln is under construction and there was no actual emission data. Table VI-3 provides an example of this calculation.

Table VI-3
Example Calculation

Facility	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Estimate[1]
Nevada Cement	340	346	172	286
Holcim Laporte	632	375	404	470

[1]Floor estimate based on the average of these 3 years.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table VI-2 shows a comparison of emissions to the historical emissions based on State emissions inventories. Since the floor is based on historical emissions, the general match is very close, but for any individual plant, the floor may be higher or lower than recent emissions.

REFERENCES

EPA, 1995: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors (AP-42)," Chapter 11.6, Cement Manufacturing, Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1995.

PCA, 2001: Portland Cement Association, U.S. and Canadian Portland Cement Industry Plant Information Summary, Data as of December 31, 2000, Portland Cement Association, Economic Research Department, 2001.

CHAPTER VII
NATURAL GAS PROCESSING PLANTS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

SO_2 emissions from natural gas processing plants result from the combustion of sour gases. Sour gases may contain less than 1 percent H_2S to over 20 percent H_2S.

H_2S is removed from the natural gas by scrubbing with an amine solution. The amine solution is heated to regenerate the amine solution. Heating the amine also produces a very concentrated H_2S stream. This H_2S stream can be treated to produce sulfur. The most common treatment is by using a Claus plant. The Claus plant can convert about 80-98.6 percent of the H_2S to sulfur depending on the number of stages and the concentration of H_2S. The average recovery percentage for a 3-stage Claus plant would be about 96 percent, on average. The residual H_2S after the Claus plant is either flared or converted to additional sulfur in a "tail gas" treatment plant like the SCOT or Stretford-Beavon process. H_2S conversion efficiencies of up to 99.9 percent are possible. Residual H_2S may be flared.

In addition to the plant tail gas flare, SO_2 emissions also result from upset conditions at the plant, or in the well field, or emissions when new wells are brought in. Upsets at the plant cause the sulfur recovery plant to be bypassed and the H_2S is flared to produce SO_2. Upsets in the well field may result in sour natural gas being flared as a safety precaution to reduce exposure to toxic levels of H_2S.

B. FLOOR ALLOCATION ESTIMATION METHODS

The requirements for, and the economics of, sour gas control are a function of a number of variables, including the amount of H_2S in the offgas, the size and age of the facility, and the air pollution control requirements in existence at the time the facility was built. Existing sour gas processing plants may have been built in situations where no regulations existed, under the 1987 NSPS, or under a BACT review under prevention of significant deterioration regulations.

It was decided that the current NSPS would serve as the floor. The NSPS requires a variable sulfur removal efficiency based on the H_2S content of the acid gas and the amount of sulfur in the gas. The required emission reduction for each facility was based on the equations in Table VII-1 since these are the long term reductions called for in the NSPS. If a facility had current control levels higher than the assumed floor, the actual average emissions over the past three years were assumed to be the floor. Since emissions from flaring operations, both in the plant and the well field, are not amenable to control, floor emissions will be assumed to be the average of three years emissions, whenever the data is available.

Table VII-1
Sulfur Plants - Required Minimum SO_2 Emission Reduction Efficiency

H_2S Content of Acid Gas (Y), %	Sulfur Feed Rate (x), Long Tons per Day			
	$2.0 \leq X \leq 5.0$	$5.0 < X \leq 15.0$	$15.0 < X \leq 300.0$	$X > 300.0$
$Y \geq 50$	74.0	. . . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . . or 99.8, whichever is smaller		
$20 \leq Y < 50$	74.0	. . . . $85.35X^{0.0144}Y^{0.0128}$ . . . . or 97.5, whichever is smaller		97.5
$10 \leq Y < 20$	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
$Y < 10$	74.0	74.0	74.0	74.0

Data availability was a significant issue in determining the floor allocation for some plants. The data from New Mexico was not adequate to distinguish between process plant, upset flare, and well field emissions.

C. FLOOR ALLOCATION RESULTS

1. General Plants

Table VII-2 shows the floor allocation calculation for the natural gas processing plants in the 8 non-California Western Regional Air Partnership (WRAP) States.

In Table VII-2, the plant name and SCC code are those provided in the State inventory. The emission source column (process or flare) notes whether the emissions are likely to come from the normal processing of natural gas (process) or the result of upset or well field emissions (flare). The distinction was made on the basis of comments in the emission inventory and confirmed in conversations with the State. Current emissions are based on the average of several years data (2000, 1998, 1996) if available, and on one year's data if that was all that was available. In some cases, new plants were under construction and permit levels were used in lieu of actuals. Current reductions were based on data in the State inventories and confirmed via conversations with State agencies.

Floor emissions vary by the H_2S content of the gas, the amount of sulfur produced by the plant, the age of the plant (older plants are not subject to the NSPS), and State regulations. In Wyoming, although individual plants vary, the average H_2S content of natural gas is higher than in other States and the degree of control required under the NSPS is greater. In addition, newer plants tend to be larger and have undergone a BACT review. In New Mexico, the relatively low H_2S content means that less control may be required under the NSPS. This is due both to the H_2S content as well as the small amount of sulfur produced by the processing plants. However, a State rule (20.2.35 NMAC) requires a minimum of a 90 percent reduction for plants that release more than 5 tons per day of sulfur from existing plants regardless of the H_2S content of the gas.

The level of control assumed to be the floor will be the most stringent of all of the potential regulatory requirements. However, the application of the potential floor procedures can result in no SO_2 controls having to be applied on some sources. For example, the Duke Energy Artesia plant in New Mexico processes less than 2 long tons per day of sulfur (this is equivalent to about 1,600 tpy of SO_2 emissions) and therefore the NSPS does not apply. State regulations do not apply, since the sulfur throughput is below the regulatory threshold. The floor for this plant is based on the average emissions over the past three years.

2. Specific Example

The Burlington Northern Lost Cabin facility in Wyoming provided additional information needed to demonstrate how the floor calculations could be applied to a specific facility. The Lost Cabin facility consists of two existing gas processing lines with a capacity of 133 MMCF/day and has one new train with a capacity of 133 MMCF/day. Both lines process a gas with a methane concentration of 68 percent, a carbon dioxide concentration of 20 percent, and an H_2S content of 12 percent.

Each train is controlled by a three stage Claus unit followed by a SCOT tail gas unit. The unit is required to have a conversion efficiency of 99.8 percent. Plantwide emissions are limited to 642 lbs/hr and 1,367 tpy.

The plant underwent a BACT review under PSD and exceeds all requirements of the NSPS. Under the NSPS, a reduction of 97.5 percent would have been required since the H_2S content of the acid gas stream is 37 percent (which is defined as the gas stream leaving the amine regenerator and can be calculated as the ratio of the acid gases [H_2S and CO_2] in the input gas stream) and the sulfur production exceeds 300 long tons per day (see Table VII-1). Since the required reduction exceeds the floor level, the permitted levels represent the floor.

Since much of the plant is new, no data on upset emissions is available. Emissions from well-field activities are very variable. Wells are very large at this plant and one very large well can have up to 1,000 tons of emissions. The plant estimates that annual SO_2 emissions of about 500 tpy from well field activities can be expected.

D. COMPARISON WITH HISTORICAL EMISSIONS

Table VII-3 summarizes historical SO_2 emissions from natural gas processing plants located in the 9 WRAP States. California facilities are included in this table. This table provides a point of comparison with the floor allocations shown in Table VII-2. For Wyoming, the historic emissions are close to floor for most sources due to the high level of control. However, a direct comparison is difficult since the historical emissions may include well field and upset emissions. Two New Mexico sources will require additional control or additional emission allocations.

Table VII-2
Possible Floor - Natural Gas Processing Units

State	Plant	SCC	Emission Source (Process vs Flare)	Current % Reduction	Permit Emissions	Floor Emission Reduction	Possible SO_2 Floor (tpy)
NM	Conoco-Maljamar	31000028	Plant	0	3,574	87	222
NM	Western Gas Resources	31000208	Plant	90	3,127	90	3,127
NM	Agave Energy	31000205	Plant	0	2,983	86.3	365
NM	Duke Energy Eunice	31000208	Plant	90	2,756	90	2,250
NM	Duke Energy Artesia	31000208	Plant	0	1,459	0	1,192
NM	Dynergy Midstream Monument	31000208	Plant	90	1,431	90	675
NM	Dynergy Midstream Saunders	31000208	Plant	90	1,387	90	163
NM	Duke Energy Plant 5	31000205	Plant	96.4	1,300	96.4	1,181
NM	Sid Richardson	31000201	Plant	91.7	1,206	91.7	1,206
NM	JL Davis Gas Processing Denton Plant	31000205	Plant	0	1,158	0	840
NM	Marathon Oil	31000201	Plant	90	1,100	90	665
NM	Duke Energy Lee Gas	31000299	Plant	93	818	93	0[4]
NM	ARCO Permian Empire Abo Plant	31000208	Plant	96	565	96	431
NM	Duke Energy Burton Flats	31000205	Plant	0	246	0	164
NM	Duke Energy Dagger Draw Plant	31000208	Plant	98	243	98	218
NM	Duke Energy Huber Gas Plant	31000205	Unknown	0	231	0	163
UT	Tom Brown- Lisbon Plant		Plant	95	1,593[2]	95	1,593
WY	Howell Petroleum - Elk Basin	31000205	Plant	93.5	1,200	93.5	1,200
WY	Burlington Resources Lost Cabin		Plant	99.8	1,367[2]	99.8	1,367
WY	Burlington Resources Lost Cabin		Flare	0	500[1]	0	500
WY	KCS Mountain Ainsworth Flare	31000205	Flare	0	843	0	843
WY	KCS Mountain Rushmore Flare	31000205	Flare	0	118[1]	0	118
WY	Marathon Pitchfork Battery	31000205	Flare	0	61[1]	0	61
WY	Exxon Shute Creek	31000205	Plant	99.7	1,206	99.7	1,206
WY	Exxon Shute Creek	31000205	Flare	0	330[1]	0	330
WY	Amoco Whitney Canyon	31000205	Plant	99	5,379	99	5,379
WY	Amoco Whitney Canyon	31000205	Flare	0	223[1]	0	223
WY	Texaco Byron	31000205	Plant	0	200	0	200

Table VII-2 (continued)

State	Plant	SCC	Emission Source (Process vs Flare)	Current % Reduction	Permit Emissions	Floor Emission Reduction	Possible SO_2 Floor (tpy)
WY	Chevron Carter Creek	31000205	Plant	99+	0[3]		0
WY	Chevron Carter Creek	31000205	Flare	0	200	0	200
WY	Hallwood Petroleum Federal Packsaddle 1-24	31000205	Flare	0	133	0	133
WY	Hallwood Petroleum Federal Packsaddle 1	31000205	Flare	0	960[1]	0	960
WY	Oregon Basin Gas Plant	31000205	Plant	90	391	90	391
WY	KCS Gold Eagle Flare	31000205	Flare	0	790	0	790
WY	Interenergy Hiland Gas Plant	31000205	Flare	0	281[1]	0	281
WY	Marathon Oil Mill Iron	31000205	Flare	0	247	0	247
	Emission Totals				**39,606**		**28,884**

NOTES: 1. Only one year of data available; 2. Floor based on permit levels; 3. Plant does not incinerate tail gas - no SO_2 emitted; 4. Plant has no emissions listed for the past three years.
State SO_2 floor allocations based on the estimates in this table are NM (12,862 tpy), UT (1,593 tpy), and WY (14,429 tpy).

Table VII-3
Oil and Gas Production - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
CA	6	029	1141	13	1311	6	Oil/Gas	SANTA FE ENERGY	TEXACO CA INC	1,539	855	2,050	2,050
CA	6	029	1129	13	1311	6	Oil/Gas	TEXACO EXPLOR & PROD INC		1	89	112	63
CA	6	029	206	13	1311	6	Oil/Gas	BERRY PETROLEUM COMPANY		237	0	0	0
CA	6	019	71	12	1311	6	Oil/Gas	CHEVRON USA INC. - COALINGA		809	0	0	
CA	6	029	272	13	1311	6	Oil/Gas	M H WHITTIER	SENECA RESOURCES	347	0	0	
CA	6	053	19	12	1311	6	Oil/Gas	MOBIL OIL CORP - SAN ARDO	AERA ENERGY	304	0	1	6
CA	6	029	1135	13	1311	6	Oil/Gas	SHELL KERNRIDGE	AERA ENERGY LLC	294	<100	82	55
CA	6	019	64	12	1311	6	Oil/Gas	SHELL WESTERN E&P INC. - COALINGA		144	0	0	
CA	6	029	331	13	1311	6	Oil/Gas	SWEPI-WEST COAST DIVISION	AERA ENERGY LLC	775	<100	10	
CA	6	053	30	12	1311	6	Oil/Gas	TEXACO INC - SAN ARDO		100	<100	36	32
CA	6	029	299	13	1311	6	Oil/Gas	UNOCAL - BAKERSFIELD	UNOCAL OIL & GAS DIVISION	159	0	0	
CA	6	059	42775	14	1311	6	Oil/Gas	WEST NEWPORT OIL CO		297	<100	10	11
CO	8	045	24	51	1311	6	Oil/Gas	UNOCAL RETORT-PARACHUTE		679	0	0	0
CO	8	045	0025	51	1311	6	Oil/Gas	UNOCAL UPGRADE		177	0	0	0
NM	35	015	0024	65	1311	6	Oil/Gas	AGAVE ENERGY/YATES PLANT		962	962	962	2,983
NM	35	015	0002	65	1311	6	Oil/Gas	ARCO PERMIAN/EMPIRE ABO GAS PLNT		700	565	565	565
NM	35	015	0006	65	1311	6	Oil/Gas	GPM GAS/INDIAN HILLS AMINE PLNT		900	450	450	900
NM	35	025	0046	65	1311	6	Oil/Gas	GPM GAS/LEE GAS PLANT		818	0	818	818
NM	35	025	0007	65	1311	6	Oil/Gas	J.L. DAVIS GAS PROCESS/DENTON		385	890	891	1,158
NM	35	025	0052	65	1311	6	Oil/Gas	TEXACO/EUNICE NORTH GAS PLANT		673	1,076	1,346	673
NM	35	025	0051	65	1311	6	Oil/Gas	TEXACO/EUNICE SOUTH GAS PLANT		4,019	4,386	3,355	5,476
NM	35	015	0003	65	1311	6	Oil/Gas	TRANSWESTERN PIPE	DUKE ENERGY/HUBER GAS	221	231	231	231
NM	35	041	0001	63	1311	6	Oil/Gas	WARREN PETROLEUM/BLUITT GAS PLANT		270	3,348	582	270
NM	35	025	0061	65	1311	6	Oil/Gas	WARREN PETROLEUM/MONUMENT PLANT	MONUMENT PLANT	1,460	1,709	1,432	1,432
NM	35	045	0247	60	1311	6	Oil/Gas	WESTERN GAS PROCESSORS/SAN JUAN RVR		5,475	980	980	3,138
NM	35	025	0128	65	1311	6	Oil/Gas	CITATION/ANTELOPE RDG GAS PLANT		291	0	NA	
NM	35	025	0118	65	1311	6	Oil/Gas	CONOCO/BELL LAKE 2 WELL #6		129	0	NA	
NM	35	015	0125	65	1311	6	Oil/Gas	FEAGAN ENERGY/W DAGGER DRAW GAS PLT		240	0	NA	
NM	35	005	0050	65	1311	6	Oil/Gas	YATES PETROLEUM/PATHFINDER AMINE		227	57	57	

Table VII-3 (continued)

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
UT	49	037		35	1311	6	Oil/Gas	UNOCAL CORPORATION	TOM BROWN - LISBON PLANT	1,575	1,391	1,478	1,252
WY	56	029	0012	9	1311	6	Oil/Gas	AMOCO - ELK BASIN	HOWELL PETROLEUM - ELK BASIN	1,096	1,218	1,422	2,638
WY	56	041	0012	9	1311	6	Oil/Gas	AMOCO - WHITNEY CANYON		6,401	5,835	11,130	6,889
WY	56	041	0009	9	1311	6	Oil/Gas	CHEVRON - CARTER CREEK		1,537	1,165	3,330	2,096
WY	56	023	0013	8	1311	6	Oil/Gas	EXXON - SHUTE CREEK		1,078	1,999	2,015	1,383
WY	56				1311	6	Oil/Gas	EXXON BLACK CANYON DEHY & WELL FIELD					167
WY	56	017		9	1311	6	Oil/Gas	KCS MOUNTAIN RESOURCES - GOLDEN EAGLE			558	942	17
WY	56	003		9	1311	6	Oil/Gas	KCS MOUNTAIN RESOURCES - AINSWORTH			807	845	0
WY	56	029	0007	9	1311	6	Oil/Gas	MARATHON GAS PLANT - OREGON BASIN		406	456	388	358
WY	56	017		9	1311	6	Oil/Gas	MARATHON OIL - MILL IRON			234	260	0
WY	56	003	0012	9	1311	6	Oil/Gas	TEXAS-BYRON PLANT	BIG HORN GAS PROCESSING - BYRON	192	169	605	257
WY	56	037	0008	9	1311	6	Oil/Gas	UNION PAC - BRADY	RME PETROLEUM - BRADY	415	331	576	300
WY	56	013	008	9	1311	6	Oil/Gas	DEVON SFS OPERATING CO.	BEAVER CREEK				831
WY	56	037	0014	9	1311	6	Oil/Gas	COLORADO INTERSTATE GAS - TABLE ROCK		522	20	39	
WY	56	003	0013	9	1311	6	Oil/Gas	MARATHON OIL COMPANY - GARLAND		257	7	10	
WY	56	013		9	1311	6	Oil/Gas	LOUISIANA LAND & EXPLOR - LOST CABIN	BURLINGTON RESOURCES-LOST CABIN		4,547	1,336	1,700
										36,111	**34,735**	**38,346**	**37,749**

CHAPTER VIII
ELEMENTAL PHOSPHORUS PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

P4 Production has an elemental phosphorus facility near Soda Springs, Idaho. This is one of the two elemental phosphorus production facilities in the United States. Year 2000 SO_2 emissions from this facility are estimated to be 15,861 tpy. This reflects increased utilization compared with 1996 and 1998 operations. This facility has no SO_2 emissions limit in its operating permit. The Idaho Department of Environmental Quality is currently evaluating this facility's SO_2 emissions situation. For the purposes of this report, the floor allocation for P4 Production is set at its year 2000 SO_2 emissions level of 15,861 tons. It is expected that the State of Idaho will perform a more detailed evaluation of this facility during preparation of its regional haze State Implementation Plan (SIP).

B. FLOOR ALLOCATION ESTIMATION PROCEDURES

Recent historical emissions for P4 Production are listed below in Table VIII-1.

Table VIII-1
Elemental Phosphorus Production - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
ID	16	029	0001	7	2819	5	Chemicals/Plastics	MONSANTO/P4 PRODUCTION	P4 PRODUCTION	7,543	7,988	7,601	15,861

CHAPTER IX
GLASS MANUFACTURING

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

The air emissions from glass manufacturing are in three zones: (1) raw material blending and transport, (2) melting, and (3) forming and finishing. The majority of air emissions are in the melting furnace operation.

Melting for container and flat glass is generally conducted in a continuous reverbatory furnace fired by natural gas or oil. Electric boost furnaces have been introduced in some operations to minimize flue gas emissions.

The major source of SO_2 emissions in the glass industry is the glass melting operation. Forming and annealing operations are minor sources. Furnace emissions appear to be attributable to both the manufacturing process and the fuel burned. Fuel-derived SO_2 emissions are lower from natural gas-fired furnaces than from oil-fired furnaces, unless the oil has been desulfurized. Flue gases from furnaces burning natural gas have been reported to contain 2 parts per million (ppm) SO_2, or less. About 600 ppm SO_2 can be expected in flue gas from a furnace burning fuel oil containing one percent sulfur. Greater use of electric furnaces or electric boosting may decrease SO_2 emissions.

Process modifications that may reduce SO_2 emissions include altering the raw material charge to reduce the sulfur content or to increase the fraction of recycled glass, changing the furnace controls or equipment, and altering the pull rate. Process modifications that reduce the salt cake content in the raw batch can significantly reduce SO_2 emissions. For example, one California flat-glass plant reportedly reduced furnace emissions of SO_2 by 78 percent from 2.1 to 0.5 kilograms per megagram (kg/Mg) (5.0 to 1.1 lbs/ton) by reducing the salt cake in the raw batch 60 percent (from 12 to 5 kg/Mg, 30 to 12 lbs/ton of sand). Similarly, another California flat-glass plant has reportedly reduced its SO_2 emissions 75 percent (from 1.6 to less than 0.4 kg/Mg, 4 to less than 1 lbs/ton of batch constituents) by reducing the input of salt cake. Glass quality was not compromised in either case. The salt cake cannot be reduced below certain minimums without effecting glass quality. The minimum salt cake required varies depending upon furnace type, pull rate, glass type, and other variables.

Fuel changes have also been shown to reduce SO_2 emissions. These include switching to natural gas or low-sulfur fuel oil, switching to all-electric melting, and using electric boosting for melting. Electric melters significantly reduce SO_2, NO_x, and particulate emissions because they eliminate the combustion of fossil fuels. Electric melting also is reported to minimize SO_2 and other gaseous losses from the vaporization of raw materials because the surface of the melt is insulated by a semisolid crust. Gases discharged through the crust of the melt consist mainly of carbon dioxide and water. Today, borosilicate, opal, and green glass are produced with electric furnaces. The capacities of such furnaces are about 100 to 110 Mg/day (110 to 120 tons/day). Electric melters have not been demonstrated for larger operations, such as large container furnaces, the nominal capacities of which are about 220 Mg/day (240 tons/day), and flat-glass furnaces, which range from about 600 to 800 Mg/day (660 to 880 tons/day).

Several emission control systems that are available to the glass industry for particulate control are also capable of achieving various levels of secondary SO_2 control. For example, a venturi scrubber system can control SO_2 emissions from commercial glass plants. The system includes a packed tower where part of the sulfate particulates are removed from the hot furnace flue gases, a dual-throat venture scrubber, where SO_2 and

additional particulates are removed by alkaline washing, and a cyclone for final particulate collection. Currently, only the container glass segment of the glass industry is reported to use scrubber systems for emission control.

Injecting a sorbent such as alumina, limestone, or nepheline syenite into a fabric filter system can effectively remove SO_2 from furnace flue gases. The spent sorbent may be landfilled or possibly recycled.

One patented system of dry removal involves the combined use of hydrated lime and nepheline syenite for acid gas neutralization and fine particle agglomeration. In this system, hot furnace flue gas is first mixed with quench water, hydrated lime for primary SO_2 removal, and secondary air to cool the gas stream to a temperature range of 94° to 427°C (200° to 800°F). Next, nepheline syenite is added to the gas stream to capture residual SO_2 and submicrometer particulates. The gas stream enters the fabric filter where the solid product is removed for either recycling to the furnace or landfilling.

Dry sorbent systems at several commercial glass furnaces reduced SO_2 by 80 to 95 percent at a container glass furnace, 50 to 90 percent at a fiberglass furnace, and 88 to 98 percent at a flat-glass furnace.

Mist eliminators apparently have no effect on SO_x gases. One sampling test indicated no decrease in SO_2 and SO_3 concentrations through the control device (EPA, 1981).

B. FLOOR ALLOCATION ESTIMATION METHODS

It is expected that the floor allocation for glass manufacturing plants will be set according to recent historical SO_2 emissions from these facilities. These SO_2 emissions are listed in Table IX-1.

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 15 - Mineral Products Industry, 2000.

EPA, 1981: U.S. Environmental Protection Agency, "Control Techniques for Sulfur Oxide Emissions from Stationary Sources," Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

Table IX-1
Glass Manufacturing - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	Floor Allocation
CA	6	037	106797	14	3221	8	Glass	BALL-FOSTER GLASS CONTAINER CO	SAINT-GOBAIN CONTAINER	<100	<100	166	174	
CA	6	099	1662	11	3221	8	Glass	GALLO GLASS CO		61	271	269	440	
CA	6	039	801	12	3221	8	Glass	MADERA GLASS COMPANY		108	170	190	104	
CA	6	077	593	11	3221	8	Glass	OWENS ILLINOIS	OWENS-BROCKWAY GLASS CONTAINER	319	285	218	248	
CA	6	037	7427	14	3221	8	Glass	OWENS-BROCKWAY GLASS CONTAINER - VERNON		193	323	280	435	
CA	6	001	2086	11	3221	8	Glass	ANCHOR GLASS CONTAINER CORPORA		119	0	0		
CA	6	001	30	11	3221	8	Glass	OWENS-BROCKWAY GLASS CONTAINER - OAKLAND		122	128	64	57	
CO	8	059	0008	53	3221	8	Glass	COORS GLASS	ROCKY MOUNTAIN BOTTLE	159	221	234	255	237
OR	41	051	1876	5	3221	8	Glass	Owens-Brockway Glass Container, Inc.		103	169	116	108	131
										1,284	**1,667**	**1,537**	**1,821**	

CHAPTER X
COPPER SMELTERS

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Primary copper smelters in the WRAP States process copper sulfide ore concentrate to produce anode copper. There are six primary copper smelters in the WRAP region. Five of the primary copper smelters are near the copper mines in the southwest United States. These smelters use a batch copper converting process (either Pierce-Smith or Hoboken converter designs) to produce blister copper. Currently, only two of these smelters are producing copper (the ASARCO smelter in Hayden, Arizona and the Phelps Dodge smelter in Miami, Arizona). The other three smelters have suspended operations and are not producing copper at this time.

The sixth primary copper smelter in the WRAP States is the Kennecott Utah Copper Corporation near Garfield, Utah. The Kennecott smelter was built during the mid-1990s (replacing the existing smelter at the site) and uses a flash copper converting technology. This technology allows blister copper to be produced in a continuous process.

All primary copper smelters in the region control SO_2 emissions by routing the process off-gases from the smelting and converting processes to double contact sulfuric acid plants.

B. FLOOR ALLOCATION ESTIMATION METHODS

Because of the uniqueness of the existing copper smelters, retrofit technology analysis must be performed on a smelter-by-smelter basis. Currently, the Hidalgo smelter is the only BART-eligible source in this category. A double contact acid plant is considered the appropriate retrofit control equipment (all smelters in the western States are currently equipped with double contact acid plants). On August 21, 2000, New Mexico completed an engineering analysis that verified earlier determinations by the MTF that the fugitive SO_2 capture system at Hidalgo satisfies BART at 96 percent overall SO_2 capture.

The Annex to the Grand Canyon Visibility Transport Commission's (GCVTC) recommendations defines stepped reduction milestones through 2018 for SO_2 emissions from large industrial sources in the 9-State Commission Transport Region. The current year SO_2 allocation for the six copper smelters in the 9-State region is 86,000 tons. This allocation is reduced to 78,000 tons by 2013 and is the same in 2018. For the recent Emission Forecasts to 2018 analysis, the plant-level difference SO_2 emissions difference between 86,000 tons and 78,000 tons was simulated by subtracting 2,000 tons each from the four largest smelters, which are ASARCO-Hayden, BHP-San Manuel, Phelps-Dodge Chino Mines, and Phelps Dodge-Hidalgo. The resulting allocations of 2018 SO_2 emissions by facility are shown in Table X-1. Note that the 78,000 tons of SO_2 allocation for copper smelters is an aggregate value for the region, rather than a requirement for each smelter to reduce emissions to prescribed levels. Table X-1 illustrates one way that this regional allocation might be met. Many other examples are provided in the EPA regional haze rule.

Table X-1
Copper Smelter SO_2 Emission Projections (tpy)

State	Facility Name	2018
AZ	ASARCO Smelter-Hayden	21,000
AZ	BHP-San Manuel	14,000
AZ	Cyprus Miami Mine	8,000
NM	Phelps Dodge-Chino Mines	14,000
NM	Phelps Dodge-Hidalgo Smelter	20,000
UT	Kennecott Utah Copper Corp.	1,000
	Total Copper Smelter	78,000

C. COMPARISON WITH HISTORICAL EMISSIONS

Table X-1 SO_2 emission estimates can be compared with recent historical (1990 to 2000) emissions for those smelters shown in Table X-2.

Table X-2
Recent Historical Copper Smelter SO_2 Emissions

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
Smelter Sector													
AZ	4	007	0004	45	3331	2	Copper	ASARCO SMELTER - HAYDEN		29,814	33,124	22,077	16,753
AZ	4	021	0032	46	3331	2	Copper	BHP(Magma Metals)	BHP - San Manuel	15,900	16,678	10,409	0
AZ	4	007	0006	45	3331	2	Copper	CYPRUS MIAMI MINE		5,676	5,737	6,097	6,810
AZ	4	019	0040	46	1021	2	Copper	Cyprus Sierrita		800	548	<100	<100
NM	35	017	0001	64	3331	2	Copper	PHELPS DODGE/CHINO MINES		28,058	14,784	15,685	11,420
NM	35	023	0003	64	3331	2	Copper	PHELPS DODGE/HIDALGO SMELTER		41,433	32,121	29,188	0
UT	49	035	0030	32	3331	2	Copper	Kennecott Utah Copper Corp.		26,829	1,556	762	937
										148,510	**104,549**	**84,218**	**35,920**

CHAPTER XI
ALUMINUM PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Primary aluminum production plants in the United States produce aluminum metal by electrolytically reducing alumina that have been refined from bauxite ore. There are 23 primary aluminum plants in the United States. There are only 2 plants in the study region and both are located in Oregon.

Aluminum production is carried out in a semibatch manner in large electrolytic cells called pots with a direct current input of up to 280,000 amperes at about 5 volts. The pot, a rectangular steel shell ranging in size from 30-50 feet long, 9-12 feet wide, and 3-4 feet high, is lined with a refractory insulating shell on which carbon blocks are placed to form the cathode.

An aluminum pot will typically emit 20-35 kg per metric ton of gaseous and particulate fluoride and roughly an equal amount of particulate matter. The NSPS limits emissions to no more than 1 kg fluoride/Mg (2.0 lbs/ton) of aluminum produced for potroom groups at Soderberg plants, 0.95 kg/Mg (1.9 lbs/ton) of aluminum produced at pre-bake plants, and 0.05 kg/Mg (0.1 lbs/ton) of aluminum equivalent for anode bake plants.

The reduction cells in use for aluminum production in the United States are of two basic types – prebake and Soderberg. There are two types of Soderberg cells that are designated according to the manner of mounting the stud in the carbon anode: vertical stud Soderberg (VSS) or horizontal stud Soderberg (HSS).

Prebake cells are so named because the anodes are preformed and then baked in a separate facility often referred to as an anode bake plant. The anodes are then mounted in the cell and are consumed in the aluminum production. The anode butts, which remain after the anode is consumed, are recycled for use in the preparation of new anodes.

In the Soderberg process, continuously formed, consumable anodes are used. The anode paste is baked by the heat generated in the reduction cell.

The primary source of sulfur oxide emissions in aluminum production is the sulfur in the coke (normally petroleum coke) and the coal tar pitch binder used to produce the anodes. In the prebake process, the combustion fuel to bake the anodes may be a significant SO_2 emission source. Petroleum coke usually contains 2.5 to 5 percent sulfur, but may vary from 1.5 to 7 percent sulfur. Pitch normally contains about 0.5 percent sulfur. The sulfur content of the coke depends on the crude petroleum stock and the tendency of the sulfur to concentrate in the still bottoms at the refinery and thus in the coke.

As the coke is processed (during prebake) or consumed in the reduction cell, sulfur oxides are released. The emissions include those from the anode prebake operation (prebake), the “primary” emissions (which are captured by the pot hood exhaust system), and the “secondary” emissions (which escape the primary exhaust system and exit through the roof monitors). The great majority of SO_2 emissions are collected by the pot hood exhaust system.

One source reports uncontrolled SO_2 emissions from anode bake plants range from 5 to 47 ppm, which is 0.7 to 2 kg SO_2/Mg aluminum produced (1.4 to 4 lbs SO_2/ton aluminum

produced). Other data indicate that emissions are in the range of 0.09 to 1.7 kg SO_2/Mg aluminum produced (0.18 to 3.4 lbs SO_2/ton aluminum produced).

The total amount of SO_2 generated per unit of aluminum produced is essentially the same for the prebake, VSS, and HSS cases. The "primary" cell hooding configuration for collection of process fumes is affected by the characteristics of the different cell types. There are two types of prebake cells, center-worked prebake cells (CWPB) and side-worked prebake cells (SWPB), as well as the two Soderberg processes, VSS and HSS, which are in use by the domestic aluminum industry. Information from seven primary aluminum plants indicates the following:

Cell Type	Primary Hood Collection Efficiency, %	Primary Collector Exhaust Rate (10^6 square cubic feet per ton of aluminum)
CWPB	65 to 98	(4.11 to 5.05)
SWPB	85	(3.44)
VSS	81	(0.67)
HSS	80 to 95	(5.06 to 7.85)

This information indicates that the gas volume associated with the production of a fixed amount of aluminum is in the range of 5 to 12 times (average 8 times) greater for CWPB, SWPB, or HSS than for VSS. Consequently, the concentration of SO_2 in a volume of exhaust gas in the primary collector system can be expected to be about 8 times greater for a VSS unit than for other units.

Reported data on uncontrolled "primary" exhaust system SO_2 emissions are as follows:

Unit	Source	SO_2 Concentration, ppm	Total SO_2 emissions, kg SO_2/Mg Aluminum (lbs SO_2/ton aluminum)
Prebake Cell	A	5	Not reported
	B	Not reported	20.9 to 23.4 (41.7 to 46.8) [average of 22.4 (44.8)]
	C	Not reported	30 (60) [3% sulfur in the coke]
VSS Cell	A	80	Not reported
	B	200 to 300	17.5 to 25 (35 to 50)
	C	200 (average)	Not reported

The trend in construction of new aluminum plants is toward prebake systems. A major factor influencing this trend is the lower power requirement of the prebake cell compared with Soderberg cells. It is reported that 9 of the 11 aluminum plants opened since 1960 are of the prebake type, and 99 percent of the 324 Gigagrams (357,000 tons) capacity added since 1973 has been at prebake facilities. Of the 23 primary aluminum production plants in the United States, 18 use the prebake process and 5 use the Soderberg process.

B. FLOOR ALLOCATION ESTIMATION METHODS

There are two aluminum smelters located within the study region, and they are both located in Oregon. The data provided by the Oregon Department of Environmental Quality on the unit capacities and SO_2 emissions potential for these two smelters is provided in Table XI-1. This table shows that the SO_2 emissions potential for Reynolds Metal, if operated at its design capacity, is 4,700 tpy. This is the same as their permitted SO_2 emission limit. For NW Aluminum, the SO_2 emissions potential is 518 tpy.

The NSPS for primary aluminum plants limits fluoride emissions, but does not affect SO_2 emissions. Washington is the only State that has established an SO_2 emission limit specifically for primary aluminum plants. The rule limits the maximum allowable total SO_2 emissions from all sources within the plant to 60 lbs per ton of aluminum produced on a monthly basis. Based on the SO_2 emission rates by process for Reynolds Metal, which is 65.3 lbs SO_2 per ton of aluminum produced, applying the State of Washington rule would only provide an 8 percent reduction in SO_2 emissions.

Comparing the capacity-based SO_2 emission estimates in Table XI-1 with recent historical emissions (see Table XI-2) shows that recent historic SO_2 emissions from Reynolds Metals are considerably below their capacity/permitted emission limit, and that they vary considerably from year-to-year. NW Aluminum SO_2 emissions in the period 1996 to 2000 average about 80 percent of total capacity.

The floor control technology for aluminum smelters was determined by evaluating the emissions performance of Reynolds Metals and NW Aluminum. NW Aluminum uses a wet scrubber to achieve a 70 percent SO_2 emission reduction. Therefore, a wet scrubber with a 70 percent SO_2 reduction was selected as the floor technology for aluminum smelters. The effect of this floor technology application is shown in the rightmost column of Table XI-1.

REFERENCES

CFR, 2001: Code of Federal Regulations, "Subpart S - Standards of Performance for Primary Aluminum Plants (60.190-60.195)," July 1, 2001.

EPA, 1981: U.S. Environmental Protection Agency, "Control Techniques for Sulfur Oxide Emissions from Stationary Sources," Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

Table XI-1
Aluminum Plant Data Used to Estimate Floor Allocations

Company	Emissions Unit	Fuel Type	Actual Capacity	Capacity Units	Control Device	SO_2 Emission Factors (lbs/ton)	SO_2 Control Efficiency	SO_2 Emissions Actual Capacity (tons/yr)	Floor Allocation at 70% Control (tons/yr)
Reynolds Metals	Carbon bakes	Natural gas				0.18-.19		27	27
	Potroom fugitives	N/A			N/A	2.5	N/A	177	177
	Potroom emissions	N/A			N/A	62.5	N/A	4,488	1,346.4
	Backup fuel	#2 fuel oil				0.105		7.5	7.5
	Plant total							4,700	1,557.9
NW Aluminum	Cell line	N/A	97,500	TAP/yr	Wet scrubber		0.7	517	517
	Cell line	Propane	144,000	gallons/yr	No		N/A	<0.1	<0.1
	Casthouse furnace	Natural gas	80,000,000	cubic feet/yr	No		N/A	1	1
	Plant total							<518	518
Total								**5,218**	**2,076**

NOTES: Control Device: While there are no physical control devices, the most effective form of SO_2 control is limiting the amount of sulfur in fuel oil. For example, the sulfur content in distillate fuel oil sold in NW usually averages much less than 0.1, whereas the rule limit is 0.5. Actual Capacity Emission is limited by the SO_2 PSEL. SO_2 emission factors are in lbs per ton of aluminum produced.

Table XI-2
Aluminum Smelting - Historical Emissions - 1990 to 2000

State	State ID	County ID	Facility ID	IAS Region	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from 1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000
100 tpy or More SO_2													
OR	41	065	0001	5	3334	10	Metals/Mining/Minerals	Northwest Aluminum Company, Inc.		423	448	375	397
OR	41	051	1851	5	3334	10	Metals/Mining/Minerals	Reynolds Metals Company		3,340	0	503	1,510
										3,763	**448**	**878**	**1,907**

CHAPTER XII
SULFURIC ACID PLANTS

Sulfuric acid is the most widely used industrial chemical. The chief uses of sulfuric acid are in production of fertilizer, manufacture of chemicals, oil refining, pigment production, iron and steel processing, synthetic fiber production, and metallurgical operations. The predominant process used for the production of sulfuric acid is the contact process. The entire discussion in this chapter focuses on the contact process.

Sulfuric acid is produced by burning sulfur or sulfur-bearing materials to form SO_2. Sources of SO_2 include: (1) elemental sulfur; (2) spent acid; (3) smelter off-gas; (4) pyrites; and (5) waste gas from fossil-fuel-fired boilers.

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Contact sulfuric acid plants are classified as hot gas (sulfur burning) or cold gas (metallurgical and spent acid) systems. Plants operating on elemental sulfur receive hot SO_2 gas directly from the sulfur burner and waste heat recovery system. When SO_2 gas from a metallurgical operation or other byproduct source (such as spent acid or iron pyrites) is used, it is received cold from the wet scrubber-cooler and purification systems.

A basic variation of the contact process is the double absorption technique, also known as double catalysis. This design is largely based on the need to meet air pollution control regulations.

The only significant source of air emissions from a contact sulfuric acid plant is the tail gas leaving the final absorbing tower. This gas contains small amounts of SO_2 and even smaller amounts of SO_3, sulfuric vapor, and sulfuric acid mist.

SO_2 emissions are determined primarily by overall plant design (e.g., number of catalyst passes, amount of catalyst, dual or single absorption, etc.). New plants are usually designed to meet NSPS emission limits using the dual absorption process. In certain situations, plants can achieve better than NSPS limits using the dual absorption process. For example, in a metallurgical acid plant, lower SO_2 emissions can sometimes be achieved catalytically if the process gas from a smelter has a sufficiently high oxygen-to-SO_2 ratio. Proper catalyst volumes and interpass cooling can be incorporated into the initial design, however. Existing plants that are required to reduce their SO_2 emissions usually choose to convert to dual absorption or install a tail gas scrubber.

Dual absorption has been generally accepted as BACT. Conceptually, dual absorption is the addition of another converter and absorbing tower on the tail end of a single absorption plant (with appropriate heating and cooling of the gas stream) so there is no new technology involved. Only sulfuric acid is produced in the dual absorption equipment.

Various scrubbing, or tail gas, technologies are available for removing SO_2 from gas streams. Tail gas treatment is rarely used to achieve NSPS limits for new plants. A tail gas process at the end of a dual absorption plant may be the preferred technology where local regulations require substantially lower than NSPS emission rates.

Tail gas processes that produce a by-product that can be recycled to the acid plant (e.g., weak sulfuric acid) are of special interest because they eliminate the need for off-site by-product disposal. Two such processes are hydrogen peroxide scrubbing and SO_2 oxidation with activated carbon.

B. FLOOR ALLOCATION ESTIMATION METHODS

Based on the information available for sulfuric acid plants in the west, it was determined that it is appropriate to estimate the floor allocation by applying the NSPS requirements to each sulfuric acid plant.

Subpart H - Standards of Performance for Sulfuric Acid Plants

60.82 Standard for Sulfur Dioxide

On or after the date on which the performance test required to be conducted by Sec. 60.8 is completed, no owner or operator subject to the provisions of this subpart shall cause to be discharged into the atmosphere from any affected facility any gases which contain SO_2 in excess of 4 lbs per ton of acid produced. Achieving this standard requires a conversion efficiency of 99.7 percent in an uncontrolled plant, or the equivalent SO_2 collection mechanism in a controlled facility.

Table XII-1 lists the sulfuric acid plants, their characteristics, and the estimated annual SO_2 floor allocations. An initial SO_2 floor allocation was estimated by multiplying the daily throughput limit by the NSPS emission rate (4 lbs SO_2 per ton 100 percent acid produced), times 365 days per year, converted from lbs to tons by dividing by 2000. In equation form, this is:

$$Daily\ throughput\left(\frac{tons}{day}\right) * \frac{4\ lbs}{ton} * \frac{365\ days}{year} * \frac{1\ ton}{2000\ lbs}$$

This based on throughput initial floor allocation was found to exceed the annual SO_2 permit limits for each of these units. Therefore, the estimated floor allocations for these sulfuric acid plants was established using recent historic SO_2 emissions data. These historic emission values are all slightly below the annual SO_2 permit limits.

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 12 - Chemical Process Industry, 2000.

CFR, 2001: Code of Federal Regulations, Subpart H - Standards of Performance for Sulfuric Acid Plants (60.82), July 1, 2001.

Idaho DEQ, 2002a: State of Idaho, Department of Environmental Quality, Air Quality Tier 1 Operating Permit, J.R. Simplot Co. - Don Siding Plant, 2002.

Idaho DEQ, 2002b: State of Idaho, Department of Environmental Quality, Air Quality Tier 1 Operating Permit, Nu-West Industries, Inc.; Agrium Conda Phosphate Operations, 2002.

Table XII-1
Sulfuric Acid Plants

State	Facility Name	Start Date	Sulfuric Acid Plant ID	Process	Control Technique	Annual SO_2 Permit Limit (tons)	Daily Throughput Limit (tons)	Based on Throughput SO_2 Floor Allocation (tpy)	Floor Allocation Using Historic Emissions Average (tpy)
Idaho	Nu-West Industries		East	NA	NA	945	1,550	1,131	612
Idaho	JR Simplot		300	Single contact	2 stage scrubber system	750	1,750	1,277	1,939
			400	Double contact	Double contact with mist eliminator	1,458	NA	1,458	
Wyoming	SF Phosphates, Inc.	1995	Source 9b	MEC		963.6	1,320	964	1,638
		1984	Source 9a	Lurgi		1,387	1,900	1,387	
Wyoming	Koch Sulfur Products		EU-1		NA	719	NA	719	1,197
			EU-5		NA	721	NA	721	

NA = not available.

CHAPTER XIII
METALLURGIC COKE PRODUCTION

A. SECTOR DESCRIPTION AND SIGNIFICANT SO_2 SOURCES

Metallurgical coke is derived from coal and used in iron and steel industry processes. Coke is manufactured by pyrolysis, the heating of coal in the absence of air. In this process, high grade, bituminous coal is heated in a enclosed chamber to approximately 1050°C (1925°F), which removes all volatile components of the coal. The resulting product is a solid material consisting of elemental carbon and any minerals that were not volatilized in the heating process.

1. By Product Coke Ovens

In a typical coking operation, 35 to 100 coke ovens are located in a row referred to as the oven battery. Each oven has three main parts: coking chambers, heating chambers, and regenerative chambers. The coking chamber has ports in the top for charging (loading) of the coal. A typical U.S. coke oven produces 7.5 tons to 39 tons of coke per cycle. Most coke plants are co-located with iron and steel production facilities.

All ovens currently operating in the United States are by-product recovery ovens. These ovens operate by reusing gases (volatiles) emitted by the hot coal. In by-product recovery ovens, the volatiles from the coal are collected and sent to a by-product recovery plant. The off gas is condensed and separated into a liquid fraction (coal tar) and a gaseous fraction (coal gas). The coal gas contains a number of contaminants including hydrogen sulfide. Some by-product recovery processes remove the sulfur from the gas prior to combustion. Approximately 33 percent to 40 percent of the clean coal gas is then returned to the oven battery to be used as fuel. The remaining coal gas can be used as fuel for other processes at the plant or sold to other facilities.

Emissions of SO_2 from coke ovens operations primarily result from combustion of the byproduct coal gas in the oven. A small portion of SO_2 emissions comes from uncontrolled "charging", the process of loading coal into the oven. Control of SO_2 from combustion of coal gas is primarily accomplished by; (a) removing the sulfur from the gas prior to combustion or (b) utilizing low sulfur coal in the coking process. There are a number of methods for removing sulfur from the coal gas, such as wet scrubbing.

2. Rotary Calciners

There is only one known rotary calciner used for coke production in the United States, P4 Production in Rock Springs, WY. It uses a Salem Brosius, 65 foot diameter, continuous feed rotary hearth calciner. Basically, the process involves feeding a mixture of coal and petroleum (pet) coke onto a rotating table located inside a furnace. The coal is heated to a high temperature as it rotates to produce coke. The coke exits the hearth and enters a cooling chamber. Like byproduct recovery ovens, the furnace operates by reusing the volatile gases emitted from the coal. However, in this process, the furnace is initially started with natural gas. Once started, the coal gas being emitted during the coking process is utilized as fuel directly. The waste gas is then ducted to an incinerator. Byproducts of the process include fine coke, ash, CO_2, SO_2, and rock.

Emissions of $SO_2$from a rotary hearth calciner are primarily due to the volatiles from the heated coal. The waste gas is ducted to an incinerator and baghouse prior to being

emitted to the atmosphere. There is no desulfurization of the waste gas. The amount of SO_2 emitted from the facility is a function of the properties of the feed coal.

B. FLOOR ALLOCATION ESTIMATION METHODS

The analysis was limited to facilities which emit greater than 100 tpy of SO_2 in total. There are three facilities which have been identified. Two are coking plants, Astaris Coking Plant in Wyoming and Geneva Steel in Utah. There is one rotary calciner in Wyoming, P4 Production, Rock Springs Coal Calcining Plant. The air pollution agencies for Wyoming and Utah provided information on the coking and calcining facilities for estimating floor allocations.

Astaris Coking Plant was shut down in April of 2001. Therefore, this facility does not receive an SO_2 allocation.

Geneva Steel has committed to ceasing all SO_2 emissions from the coke ovens and the sinter plant. These emissions have been banked for future use or trading as precursor pollutants within the current local Utah County PM_{10} SIP. The Utah Air Quality Board approved this change on June 5, 2002. Since the SO_2 emissions for coking and sintering at the plant are now essentially zero, the SO_2 floor allocation for coking is also zero.

The third facility is P4 Production, Rock Springs Coal Calcining Plant. The plant is designed to process 220,000 tpy of feed materials to produce 110,000 tpy of coke product. The plant operates for up to 8,000 hours per year. This works out to a design process rate of 27.5 tons per hour (tph) or 660 tons per day (tpd) of feed. According to the operating permit, the total facility potential to emit is 2,841.1 tpy of SO_2 based on 8,760 operating hours. There are no NSPS requirements the facility must comply with for SO_2. This rotary coker was built in 1972 and thus is "grandfathered" from the Wyoming Air Quality Division's permit requirements. The historical emissions for this facility are presented in Table XIII-1.

Table XIII-1
Historical SO_2 Emissions at P4 Production, Rock Springs, WY

Historical Emissions of SO_2 (tpy)					Average Annual SO_2 Emissions (tpy)
1990	1996	1997	1998	2000	1996 - 2000
933	663	586	642	633	631

As stated previously, the SO_2 emitted is a function of the feed coal. The plant uses a blend of coal and petroleum coke (pet coke). The 1994 annual inventory showed that the pet coke blend was 7.2 percent for the year, with SO_2 emissions of 420.0 tpy; up 15 percent from the 365.6 tpy emitted in 1993, when straight coal was used as 100 percent of the feedstock. The most recent year's data shows that the pet coke blend was 25 percent for 1998, the maximum allowable amount to maintain compliance with the SO_2 emissions limit.

The procedure for estimating the floor allocation for P4 Productions is difficult for several reasons. First, there are no identified control technologies available for the rotary calciner. Second, there are no NSPS requirements. Third, P4 Production has a potential to emit 2,841.1 tpy based on 8,760 hours of operation. This is much higher than the annual emissions reported by the plant. Lastly, the SO_2 emissions from the rotary calciner are a function of the sulfur content of the feed which varies over time. Since the coking process at P4 Production is unique and cannot be compared with emissions from other facilities, the SO_2 allocations for P4 Productions will be based on its average annual emissions. This is

consistent with the allocation approach developed for source categories with no technology available for reducing sulfur and variable sulfur content in the feed such as flaring.

The allocation for P4 Production will be based on emissions of SO_2 from years 1996, 1997, 1998 and 2000. Averaging historical emissions results in a floor allocation of 631 tpy of SO_2 for the P4 Production facility. As stated previously, the SO_2 floor allocations for Astaris and Geneva Steel are zero.

C. COMPARISON WITH HISTORICAL EMISSIONS

Table XIII-2 presents the historical SO_2 emissions and the SO_2 floor allocations for all three coking facilities. Note that Geneva Steel has an SO_2 allocation for its boilers, which is discussed in Section IV.

Table XIII-2
Coking Plant - Historical Emissions - 1990 to 2000

State	County ID	Facility ID	SIC	MTF Sector	Sector Description	Facility Name (1990)	Current Facility Name (if different from1990)	SO_2 tpy 1990	SO_2 tpy 1996	SO_2 tpy 1998	SO_2 tpy 2000	SO_2 Floor Allocation
WY	037	0003		10	Metals/Mining/ Minerals	Sweetwater Resources	P4 Production - Rock Springs	933	663	642	633	631
WY	023	001		10	Metals/Mining/ Minerals	FMC Coking Plant	Astaris Coking Plant	1,194	1,413	1,454	1,409	0
UT	049	0027	3312	10	Metals/Mining/ Minerals	Geneva Steel		8,473	2,020	881	979	0

REFERENCES

AWMA, 2000: Air and Waste Management Association, "Air Pollution Engineering Manual," 2nd edition, Chapter 14 - Metallurgical Industry, 2000.

EPA, 1981: U.S. Environmental Protection Agency, "Control Techniques for Sulfur Oxide Emissions from Stationary Sources," Second Edition, EPA-450/3-81-004, Office of Air Quality Planning and Standards, Research Triangle Park, NC, April 1981.

EPA, 1998: U.S. Environmental Protection Agency, "Compilation of Air Pollutant Emission Factors," AP-42, Fifth Edition, Volume I: Stationary Point and Area Source, Section 12.2 Coke Production" Office of Air Quality Planning and Standards, Research Triangle Park, NC, 1998.

CHAPTER XIV
FLOOR ALLOCATION SUMMARY

Table XIV-1 summarizes the SO_2 floor allocation estimates from all of the previous chapters by State and by sector. California estimates listed in Table XIV-1 are based on average SO_2 emissions in these sectors from 1996, 1998, and 2000. Table XIV-1 shows the estimated SO_2 floor allocation for non-utility sources in the 9-State Commission Transport Region to be about 195 thousand tons. If copper smelter SO_2 allocations in 2018 are subtracted from this amount, the floor allocation is 117 thousand tons. The non-smelter, non-California SO_2 emissions total is 89,000 tons.

Table XIV-2 provides a complete list of the facility-level SO_2 floor allocations, and includes year 2000 SO_2 emissions as a point of comparison.

Table XIV-1
State/Sector Summary of SO_2 Floor Allocations
(tons per year)

States	Sectors												Total
	Refineries	Lime Manufacturing*	Industrial Boilers	Pulp and Paper	Cement Manufacturing	Natural Gas Processing	Elemental Phosphorus**	Glass Manufacturing***	Copper Smelters	Aluminum Plants	Sulfuric Acid Plants	Coke Production	
Arizona		1,365	978		320				43,000				45,663
California													27,335
Colorado	1,614		387		4,936			237					7,174
Idaho			601	1,807	522		15,861				2,551		21,342
Nevada		435			448								883
New Mexico	2,244				1,103	12,862			34,000				50,209
Oregon			1,585	5,377				131		2,076			9,169
Utah	4,142	303	2,010		267	1,593			1,000				9,315
Wyoming	3,418		2,350		165	14,429					2,835	631	23,828
Total	**11,418**	**2,103**	**7,911**	**7,184**	**7,761**	**28,884**	**15,861**	**368**	**78,000**	**2,076**	**5,386**	**631**	**194,918**

NOTES: *Based on 1998 and 2000 historical SO_2 emission estimates.
**Based on year 2000 SO_2 emission estimates for P4 Production, which are substantially higher than 1996 or 1998 emissions.
***Based on 1996, 1998, and 2000 historical SO_2 emission estimates.

Table XIV-2
Facility-Level SO_2 Floor Allocations
Comparison with Year 2000 SO_2 Emissions (tons per year)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
AZ		Cement/Concrete	Arizona Portland Cement		X		320	0		0	
AZ	0011	Metals/Mining/Minerals	CHEMICAL LIME (CHEMSTAR)	CHEMICAL LIME - NELSON	X		702	632		632	
AZ	0003	Metals/Mining/Minerals	Chemical Lime (Douglas)		X		742	733		733	
AZ		Cement/Concrete	Phoenix Cement		X		539	320		320	
AZ	0007	Wood/Paper/Pulp	STONE CONTAINER	ABITIBI	X		1,893	0	978	978	
AZ	0001	Oil/Gas	Intermountain Refining		X	Closed	0	0		0	
AZ	0004	Copper	ASARCO SMELTER - HAYDEN		X		16,753	21,000		21,000	
AZ	0032	Copper	BHP(Magma Metals)	BHP - San Manuel	X		0	14,000		14,000	
AZ	0006	Copper	CYPRUS MIAMI MINE		X		6,810	8,000		8,000	
AZ	0040	Copper	Cyprus Sierrita		X		0	0		0	
											45,663
CO	0048	Metals/Mining/Minerals	CFI				267			0	
CO	0004	Oil/Gas	COLO REFINING		X	Refinery	545	562		562	
CO	0003	Oil/Gas	CONOCO DENVER		X	Refinery	1,972	1,052		1,052	
CO	0008	Glass	COORS GLASS	ROCKY MOUNTAIN BOTTLE	X		255	237		237	
CO	0002	Cement/Concrete	HOLNAM LAPORTE	HOLCIM LAPORTE	X		404	1,402		1,402	
CO	0001	Cement/Concrete	HOLNAM PORTLAND	HOLCIM PORTLAND	X		3,288	3,374		3,374	
CO	0097	Misc.	METRO WASTEWATER				56			0	
CO	0003	Cement/Concrete	SOUTHWEST PORTLAND	CEMEX-LYONS PLT.	X		50	160		160	
CO	9	Misc.	GENERAL SERVICES ADMINISTRATION				0			0	
CO	0001	Oil/Gas	LANDMARK PETROLEUM				0			0	
CO		CHP	TRIGEN-COLORADO ENERGY CORP.		X		2,583	0	387	387	
CO	24	Oil/Gas	UNOCAL RETORT-PARACHUTE		X		0			0	
CO	0025	Oil/Gas	UNOCAL UPGRADE		X		0			0	
CO	0001	Food	WESTERN SUGAR 1				19			0	
CO	0002	Food	WESTERN SUGAR 2				0			0	
											7,174
ID		Wood/Paper/Pulp/Cogeneration	Tamarack Energy				117			0	
ID	0004	Cement/Concrete	ASHGROVE CEMENT		X		1,327	522		522	
ID		Power	Avista				130			0	
ID		Food	Basic American Foods (Shelly)				149			0	
ID		Wood/Paper/Pulp	Boise Cascade - Emmett				252			0	
ID	0001	Misc.	DOE-INEEL				460			0	
ID	0005	Chemicals/Plastics	FMC	ASTARIS			0			0	
ID		Food	MAGIC VALLEY FOODS				0			0	
ID	0001	Chemicals/Plastics	MONSANTO/P4 PRODUCTION	P4 Production	X	Elemental Phosphorus	15,861	15,861		15,861	
ID	0003	Chemicals/Plastics	NU WEST INDUSTRIES			Sulfuric acid plants	86			612	
ID	0001	Wood/Paper/Pulp	POTLATCH		X	Paper Mill	1,694	1,807		1,807	
ID		Misc.	RICKS COLLEGE				0			0	
ID	0006	Chemicals/Plastics	SIMPLOT			Sulfuric acid plants	543			1,939	
ID	0010	Food	TASCO (NAMPA)	Amalgamated Sugar (Nampa)			1,697		242	242	
ID	0001	Food	TASCO (PAUL)	Amalgamated Sugar (Paul)			1,322		155	155	
ID	0001	Food	TASCO (TWIN)	Amalgamated Sugar (Twin)			1,053		203	203	
ID		Food	Idaho Supreme				0			0	
ID	0001	Misc.	MTN. HM. AFB				144			0	
											21,341
NV	0003	Metals/Mining/Minerals	CHEMSTAR APEX	CHEMICAL LIME CO-APEX PLANT	X	Lime plant	210	193		193	
NV	0387	Cement/Concrete	NEVADA CEMENT COMPANY	FERNLEY PLANT	X		172	305		305	
NV		Cement/Concrete	Royal Cement			Not in previous report		143		143	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
NV	0261	Metals/Mining/Minerals	GRAYMONT WESTERN US INC	PILOT PEAK	X	Lime plant	249	242		242	
NV	0451	Metals/Mining	SANTA FE PACIFIC GOLD CORP	TWIN CREEKS/NEWMONT MINING CORP			113			0	
NV	0433	Metals/Mining/Minerals	BASIC INC.(Now PREMIER CHEMICALS LLC)	PREMIER SERVICES (Gabbs Facility)						0	
NV	0863	Misc.	HAWTHORNE ARMY							0	
NV		Metals/Mining	Independence Big Springs	ANGLO GOLD						0	
NV	0019	Metals/Mining/Minerals	TITANIUM METALS							0	
											883
NM	0024	Oil/Gas	AGAVE ENERGY/YATES PLANT	Agave Plant	X		2,983	365		365	
NM	0002	Oil/Gas	ARCO PERMIAN/EMPIRE ABO GAS PLNT		X		565	431		431	
NM	0004	Oil/Gas	CONOCO/MALJAMAR GAS PLANT	MALJAMAR GAS PLANT	X		3,574	222		222	
NM	0023	Oil/Gas	GIANT INDUSTRIES/BLOOMFIELD REF		X	Refinery	920	414		414	
NM	0008	Oil/Gas	Giant Refining/Ciniza Refinery	(Gallup)	X	Refinery	1,779	603		603	
NM	0044	Oil/Gas	GPM GAS EUNICE GAS PLANT	VERSADO GAS PRODUCERS LLC	X		2,759			0	
NM	0011	Oil/Gas	GPM GAS/ARTESIA GAS PLANT	DUKE ENERGY/ARTESIA GAS PLANT	X		1,459	1,192		1,192	
NM	0006	Oil/Gas	GPM GAS/INDIAN HILLS AMINE PLNT				900			0	
NM	0046	Oil/Gas	GPM GAS/LEE GAS PLANT	Duke Energy Lee Plant	X		818	0		0	
NM	0035	Oil/Gas	GPM GAS/LINAM RANCH GAS PLANT	Duke Energy Plant 5			1,304	1,181		1,181	
NM	0007	Oil/Gas	J.L. DAVIS GAS PROCESS/DENTON		X		1,158	840		840	
NM	0008	Oil/Gas	MARATHON OIL/INDIAN BSN GAS PLT		X		1,100	665		665	
NM	0010	Oil/Gas	NAVAJO REFINING/ARTESIA REFINERY		X	Refinery	980	1,227		1,227	
NM	138	Oil/Gas	PAN ENERGY/BURTON FLATS GAS PLT	Duke Energy Burton Plant	X		246	164		164	
NM	0285	Oil/Gas	PAN ENERGY/DAGGER DRAW GAS PLT	DUKE ENERGY/DAGGER DRAW	X		247	218		218	
NM		Cement/Concrete	RIO GRANDE PORTLAND CEMENT		X		1,103	1,103		1,103	
NM	0008	Oil/Gas	SID RICHARDSON GASOLINE/JAL#3		X		0	1,206		1,206	
NM	55	Oil/Gas	TEXACO/BUCKEYE GASOLINE PLANT	DYNERGY			673			0	
NM	0052	Oil/Gas	TEXACO/EUNICE NORTH GAS PLANT		X		5,476			0	
NM	0051	Oil/Gas	TEXACO/EUNICE SOUTH GAS PLANT		X		231			0	
NM	0003	Oil/Gas	TRANSWESTERN PIPE	DUKE ENERGY/HUBER GAS	X		270	163		163	
NM	0001	Oil/Gas	WARREN PETROLEUM/BLUITT GAS PLANT		X		1,226			0	
NM	0060	Oil/Gas	WARREN PETROLEUM/EUNICE GAS PLANT	Duke Energy EUNICE GAS PLANT			2,756	2,250		2,250	
NM	0061	Oil/Gas	WARREN PETROLEUM/MONUMENT PLANT	Dynergy MONUMENT PLANT	X		1,387	675		675	
NM	0063	Oil/Gas	WARREN PETROLEUM/SAUNDERS PLANT	Dynergy SAUNDERS PLANT			0	163		163	
NM	0064	Oil/Gas	WARREN PETROLEUM/VADA GAS PLANT				3,138			0	
NM	0247	Oil/Gas	WESTERN GAS PROCESSORS/SAN JUAN RVR	Western Gas Resources	X			3,127		3,127	
NM	0128	Oil/Gas	CITATION/ANTELOPE RDG GAS PLANT		X					0	
NM	0118	Oil/Gas	CONOCO/BELL LAKE 2 WELL #6		X					0	
NM	0125	Oil/Gas	FEAGAN ENERGY/W DAGGER DRAW GAS PLT	Duke Energy Dagger Draw	X					0	
NM	0050	Oil/Gas	YATES PETROLEUM/PATHFINDER AMINE		X		0	0		0	
NM	0001	Copper	PHELPS DODGE/CHINO MINES		X		11,420	14,000		14,000	
NM	0003	Copper	PHELPS DODGE/HIDALGO SMELTER		X		0	20,000		20,000	
											50,209
OR	0002	Food	Amalgamated Sugar Company, The		X		987	0	74	74	
OR		Wood/Paper/Pulp			X	Not in previous report		0			
OR	1849	Wood/Paper/Pulp	Boise Cascade Company		X		1,834	1,532	411	1,943	
OR		Oil/Gas			X	Not in previous report					
OR	0005	Wood/Paper/Pulp	Georgia-Pacific West, Inc.		X		452	258	143	401	
OR	0007	Metals/Mining	Glenbrook Nickel Company				0			0	
OR	2125	Metals/Mining/Minerals	Globe Metallurgical Inc.				197			0	
OR	0036	Wood/Paper/Pulp			X		0	0			
OR	0004	Wood/Paper/Pulp	James River II, Inc.	Georgia- Pacific (Wauna Mill)	X		643	1,361	277	1,638	
OR	0001	Metals/Mining/Minerals	Northwest Aluminum Company, Inc.		X		397	518		518	
OR	1876	Glass	Owens-Brockway Glass Container, Inc.		X		108	131		131	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
OR	3501	Wood/Paper/Pulp	Pope & Talbot Pulp, Inc.		X		293	248	107	355	
OR	1851	Metals/Mining/Minerals	Reynolds Metals Company		X		1,510	1,558		1,558	
OR	6142	Wood/Paper/Pulp	Smurfit Newsprint Corporation 2		X	No longer pulping	519	0		0	
OR		Wood/Paper/Pulp	West Linn Paper Co.		X	Not in previous report		0	211	211	
OR	8866	Wood/Paper/Pulp	Weyerhaeuser Company	SierraPine, Ltd.	X		0	0	0	0	
OR	0471	Wood/Paper/Pulp	Willamette Industries, Inc.		X		327	310		310	
OR	8850	Wood/Paper/Pulp	Collins Products LLC	Weyerhaeuser Co.	X	Weyerhaeuser Springfield	1,721	1,668	362	2,030	
OR	5034	Misc.	Cascade Steel Rolling Mills, Inc.				0			0	
OR	2028	Oil/Gas		Kinder Morgan Energy Partners, L.P	X						
OR	0041	Chemicals/Plastics	Georgia-Pacific Resins, Inc.							0	
OR	0013	Wood/Paper/Pulp	J. Peterkort & Company	Collins Products LLC						0	
OR	5398	Wood/Paper/Pulp	Ogden Martin Systems of Marion, Inc.	Covanta Marion, Inc.	X					0	
OR	2050	Misc.	Oregon Health Sciences University	OHSU	X		0	0			
OR	0015	Wood/Paper/Pulp	Weyerhauser - Coos Bay			Hog waste-fired boiler	882			0	
											9,169
UT	10572	Copper	Kennecott Utah Copper Corp.		X	Smelter	2,534	1,000	700	1,700	
UT	10096	CHP	Sunnyside Cogeneration Associates		X		1,054		1,270	1,270	
UT	0004	Oil/Gas	Amoco Petroleum Products	Tesoro	X	Refining	1,368	1,388		1,388	
UT	0004	Misc.	Brigham Young University		X		125		1	1	
UT	0001	Metals/Mining/Minerals	Brush Wellman Inc.		X		179		23	23	
UT	0003	Oil/Gas	Chevron Products Company		X	Refining	1,242	1,240		1,240	
UT	-9902	Metals/Mining/Minerals	Continental Lime Inc.	Graymont	X	Lime	331	303		303	
UT	0008	Oil/Gas	Flying J Incorporated		X	Refining	300	674		674	
UT	0027	Metals/Mining/Minerals	Geneva Steel		X	Shutdown coke ovens and sinter plant	979		17	17	
UT	0001	Cement/Concrete	Holnam Incorporated	Holcim	X	Cement	288	267		267	
UT	0013	Oil/Gas	Phillips 66 Company		X	Refining	601	762		762	
UT		Oil/Gas	Silver Eagle Refining Inc.		X	Not in previous report (Refining)		77		77	
UT	-9901	Oil/Gas	Unocal Corporation	Tom Brown-Lisbon Plant	X	Natural gas processing	1,252	1,593		1,593	
UT		10676	Utelite Corporation				133	0		0	
											9,315
WY	0012	Oil/Gas	AMOCO - ELK BASIN	HOWELL PETROLEUM - ELK BASIN	X		2,638	1,200		1,200	
WY	0012	Oil/Gas	AMOCO - WHITNEY CANYON		X		6,889	5,602		5,602	
WY	0009	Oil/Gas	CHEVRON - CARTER CREEK		X		2,096	200		200	
WY		Cement/Concrete	Centex		X	Not in previous report		165		165	
WY	0013	Oil/Gas	EXXON - SHUTE CREEK		X		1,383	1,536		1,536	
WY		Oil/Gas	EXXON BLACK CANYON DEHY & WELLFIELD				167			0	
WY	0010	Metals/Mining/Minerals	FMC - GRANGER (TEXAS GULF)		X		212		305	305	
WY	48	Metals/Mining/Minerals	FMC - GREEN RIVER		X		4,901		956	956	
WY	0001	Metals/Mining/Minerals	FMC COKING PLANT	ASTARIS COKING PLANT	X	Shutdown April 2001	1,409			0	
WY	0001	Oil/Gas	FRONTIER OIL & REFINING - CHEYENNE		X	Refining	1,396	863		863	
WY	0002	Metals/Mining/Minerals	GENERAL CHEMICAL		X		5,000		750	750	
WY	0001	Food	HOLLY SUGAR - TORRINGTON		X		178		23	23	
WY		Oil/Gas	INTERENERGY - HILAND	WILDHORSE ENERGY - HILAND	X		269	281		281	
WY		Oil/Gas	KCS MOUNTAIN RESOURCES - GOLDEN EAGLE		X		17	790		790	
WY		Oil/Gas	KCS MOUNTAIN RESOURCES - AINSWORTH		X		0	843		843	
WY	1	Oil/Gas	KCS Mountain Resources Rushmore		X		118	118		118	
WY	0005	Chemicals/Plastics	KOCH SULFUR PRODUCTS COMPANY	PEAK SULFUR	X	Sulfuric acid plants	1,245	1,197		1,197	
WY		Oil/Gas	LOUISIANA LAND & EXPLOR - LOST CABIN [b]	BURLINGTON RESOURCES - LOST CABIN	X		213	1,867		1,867	
WY	0007	Oil/Gas	MARATHON GAS PLANT - OREGON BASIN	Oregon Basin Gas Plant	X		358	391		391	
WY		Oil/Gas	MARATHON OIL - MILL IRON		X		0	247		247	

Table XIV-2 (continued)

State	Facility ID	Sector Description	Facility Name (1990)	Current Facility Name	In Current Report	Comments	SO_2 Emissions Year 2000	SO_2 Non-Boiler Allocation	SO_2 Boiler Allocation	Total SO_2 Allocation	State Totals
WY	1	Oil/Gas	Marthon Oil Pitch Fork Battery		X		61	61		61	
WY	0003	Metals/Mining/Minerals	SWEETWATER RESOURCES	P4 PRODUCTION - ROCK SPRINGS	X	Rotary coker	633	631		631	
WY	0022	Chemicals/Plastics	SF PHOSPHATES, INC		X	Sulfuric acid plants	1,790	1,638		1,638	
WY	0001	Oil/Gas	LITTLE AMERICA REFINING COMPANY	SINCLAIR - CASPER	X	Refining	1,458	1,040		1,040	
WY	0011	Oil/Gas	SINCLAIR @ SINCLAIR		X	Refining	3,407	1,066		1,066	
WY		Oil/Gas	SNYDER OIL - RIVERTON DOME	DEVON SFS - RIVERTON DOME			492			0	
WY		Metals/Mining/Minerals	SOLVAY MINERALS		X		52		294	294	
WY	0012	Oil/Gas	TEXAS-BYRON PLANT	BIG HORN GAS PROCESSING - BYRON	X	Texaco	257	200		200	
WY	0008	Oil/Gas	UNION PAC - BRADY	RME PETROLEUM - BRADY	X		300			0	
WY	0005	Misc.	UW CENTRAL HEAT PLANT		X		193		22	22	
WY	0001	Oil/Gas	WYOMING REFINING CO	WYOMING REFINING - NEWCASTLE	X	Refining	876	449		449	
WY	008	Oil/Gas	DEVON SFS OPERATING CO.	BEAVER CREEK	X		831			0	
WY	0003	Metals/Mining/Minerals	AMERICAN COLLOID - WEST COLONY							0	
WY	0002	Oil/Gas	AMOCO REFINERY			Closed	0			0	
WY	0001	Metals/Mining/Minerals	BENTONITE CORPORATION	LOVELL			0			0	
WY	0014	Oil/Gas	COLORADO INTERSTATE GAS - TABLE ROCK				0			0	
WY	0013	Oil/Gas	MARATHON OIL COMPANY - GARLAND				0			0	
WY		Oil/Gas	Hallwood Petroleum-Federal Packsaddle 1-24		X	Not in previous report		133		133	
WY		Oil/Gas	Hallwood Petroleum-Federal Packsaddle 1		X	Not in previous report		960		960	
											23,828
TOTALS							**170,226**			**167,583**	**167,583**

[a]SO_2 Allocation based on historical emissions.
[b]Plant has just added capacity and allocation is based on current (July 2002 capacity).

Appendix A-8b. Western Emissions Backstop (WEB) Emissions & Allowance Tracking Systerm (EATS) Analysis

Western Backstop (WEB) Emissions and Allowance Tracking System (EATS) Analysis

Prepared by:
Perrin Quarles Associates, Inc.
675 Peter Jefferson Parkway, Suite 200
Charlottesville, VA 22911

July 18, 2003

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July 18, 2003

Western Backstop (WEB)
Emissions and Allowance Tracking System (EATS) Analysis

I. Introduction

This section of the State Implementation Plan/Tribal Implementation Plan (SIP/TIP) is an analysis of the information management needs of the Western Backstop Emissions and Allowance Tracking System (WEB EATS) which is a requirement for the program under 40 CFR 51.309. Section 309(d)(h)(4)(v) of the Regional Haze rule requires that "the Implementation Plan must provide for submitting data to a centralized system for the tracking of allowances and emissions." The purpose of this document is to describe the architectural and system requirements necessary to support a State/Regional emissions trading program information system. The document summarizes the overall needs and objectives of an emissions trading system to ensure successful implementation of the program. It is intended to serve as a roadmap to help WRAP implement the program once it has been triggered.

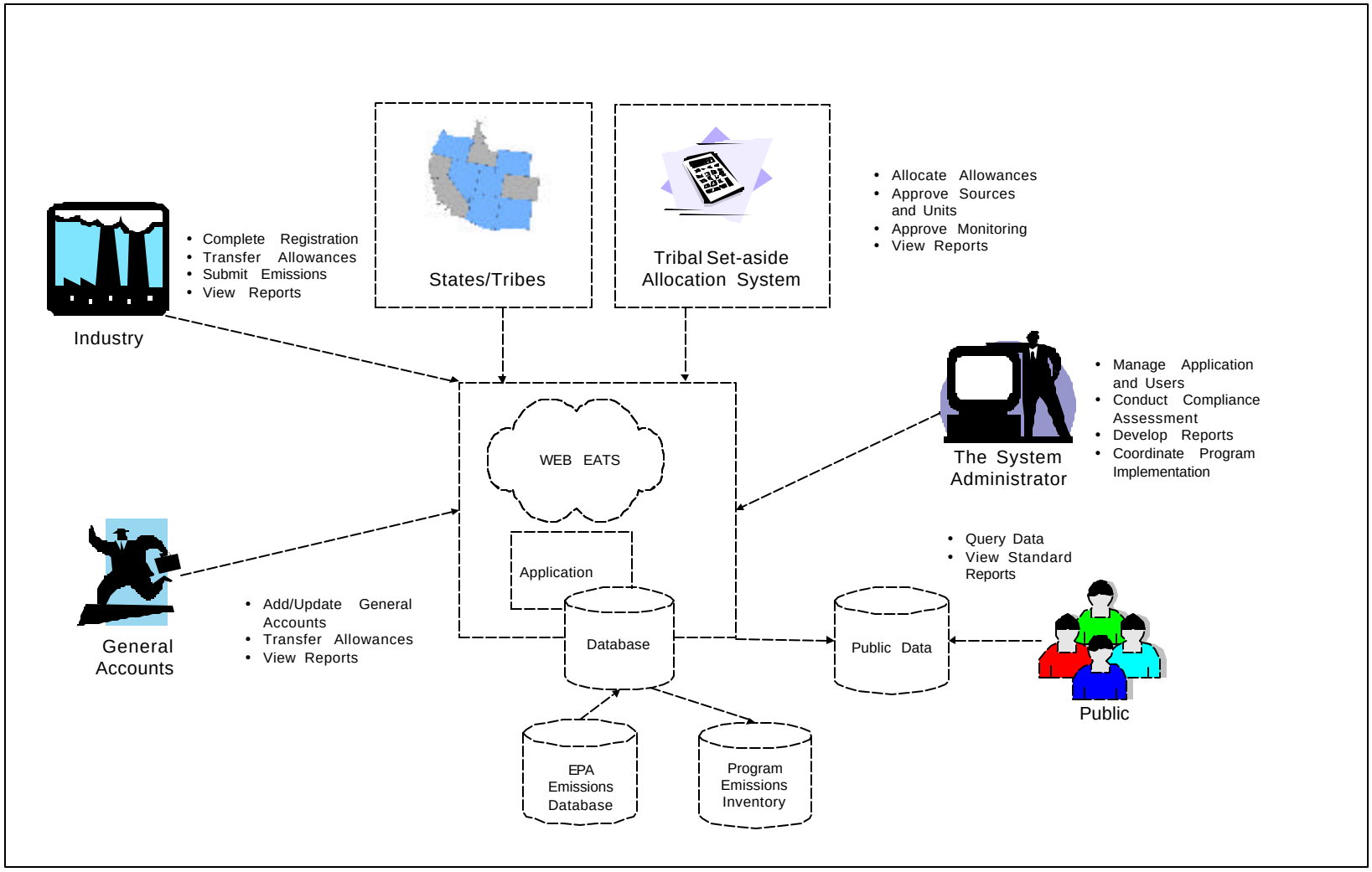
II. Overview of the System and Analysis

Figure 1 contains a graphical depiction of the overall information system, including the basic users, functionality needed for each of these user types, and a high level architecture. *Section III* describes each functional area of the application. *Section IV* describes the primary user groups and how they relate to the functional areas. *Section V* describes the considerations affecting the choice of technical architecture for the application. *Section VI* describes recommended design and development approaches, and *Section VII* addresses the overall responsibilities of the Tracking System Administrator (TSA).

The development and deployment of this application, if needed, would most likely occur after 2013, possibly later. It is assumed that currently available technology would not be used, nor is it possible to project what advancements in technology would be available. For this reason, this report does not address specific technologies, except as a reference point for better understanding or describing capability that would be needed. The focus is on general issues related to technology and the functional requirements for designing and implementing the program.

The scope of the application and information system needs which are described do not extend to several areas relating to the possible implementation of the Backstop Trading Program envisioned by Section 309. Excluded areas include the baseline emissions inventory for determining whether the program triggers, performing initial allowance allocations, and evaluating and tracking early reduction credits. Also, it has been assumed that it is not necessary to support a significant level of variation in requirements or needs from different States or tribes and that areas in which these requirements may vary, such as enforcement activities beyond the automatic provisions of the program, would be addressed in other systems.

Figure 1
Overall WEB EATS Model



III. Functional Areas

The system to support the WEB Trading Program must contain functionality to support implementation of the trading program in the following areas: source inventory, user management, account management, allowance allocations, allowance trading, emissions reporting and collection, compliance, and program assessment. At this time, the system functionality does not include consideration of allowance transfer price data. However, there may be a need to include this functional area in the final system design, and the overall system design needs to allow for this possible expansion of the functional areas. Because the core requirements for allowance transfer price tracking remain uncertain, this section does not discuss this functional area in further detail. Each of the other areas of functionality is described below. In addition, core requirements relating to the areas are defined.

A. Source Inventory

1. Description

a. Facilities and Units

The central focus of the system is the list or inventory of sources which are affected by the program. This inventory is initially derived from the baseline emissions inventory developed to support the development and approval of the WEB Trading Program as part of the SIP/TIP approval process. To this initial inventory, it is expected that States and Tribes may add sources, either during the period prior to triggering the program or after the Program Trigger Date. Throughout, it is expected that sources will permanently cease operation or "retire." To support the dynamic inventory, the information system must allow the addition of new sources and track the status, including the regulatory status, of all sources identified as potential program participants beginning with the baseline period.

To support changes in facility operation and ownership in both the pre-trigger and post-trigger period, it will be necessary to track basic changes in facility identity, including facilities which, due to these types of changes, change "identity" or divide into two facilities. This functionality would include tracking facility name changes.

It is assumed that States and Tribes would be responsible for identifying all "new" sources to the database and for making decisions and entering data about the applicability of the program to a new source. Once a source is identified as being subject to the program, the maintenance of these data would be the primary responsibility of the owners and operators of affected sources through the source representative. A single, secure portal for changing these data would be provided to authorized industry representatives.

b. Source Owners

The owners and operators of each source authorize individual(s) to represent them regarding allowance trading, emissions reporting and all other compliance activities. The identity of the owners and operators should be tracked to ensure that legal responsibility for compliance can be accurately determined at any point in time during which compliance is required. The WEB EATS should track changes in owners and operators for a source.

c. Source Representatives

The designated representatives appointed by the owners and operators of the source are also tracked so that appropriate communication about program activities involving the source and compliance is facilitated. Under the Duty to Register provisions, representatives of a source initially must register and use consistent source identifiers with the source program data first entered by the State or Tribe. The representative is responsible for the accuracy of submissions and certifying source compliance. Program rules should be structured to ensure that at no time during the operational phase of the program is an affected source unrepresented.

d. Source and Unit Detail

Additional information about the facility and units, including fuels, controls, and other operational information would be necessary for program implementation, particularly with respect to emissions monitoring, and for program assessment. During the design phase for WEB EATS development an assessment of these needs and the availability of information from other sources (for example, a shared air program database at EPA or in a State/Tribe) should be performed.

2. Core Data Entities and Attributes

- Facilities. Location, source category or type, permit IDs, size, Federal and State/Tribal cross identifiers with other data systems, program status, operational status (including retirement status), initial on-line date (for new sources).

- Units. Relationship to facilities, type, Federal and State/Tribal cross identifiers with other data systems, operational status (including retirement status), initial on-line date (for new units).

- People. Type and duration of relationship to facilities, type and duration of agent relationship to representatives, address, affiliation, security level, user ID, passwords (or equivalent), phone numbers, email or equivalent.

- Owners/operators. Address, relationship to facilities.

- Program applicability. Exemptions, opt-in or other program status information, including year affected (or non-affected), identification of Category 1 and 2 sources, etc. Could include permitted production capacity or other permit data.

3. Core Functional Requirements

- Populate initial facilities and units.
- Add and update facilities and units.
- Add and update owner/operator information.
- Change owner/operators for facilities.
- Add and update individual information for any person utilizing or identified in the application.
- Change representatives for facilities.
- For on-line changes, provide to users documentation of changes in owners and representatives to meet recordkeeping requirements. This could be email or other electronic format.
- Track changes in facility names and program identifiers and relationship to prior entities.
- Communicate/verify facility and unit inventory changes, particularly where change impacts regulatory status or responsibilities or triggers deadline.
- Add and update program applicability data.

B. User Management

1. Description

User security and authentication are key requirements for the WEB EATS. To support these requirements the application must contain functionality to store user identifying information and associate each user with the appropriate security level. A system administrator, or person designated by the system administrator, must use tools provided in the application to review and approve user accounts, and to access and monitor usage.

For any on-line access and submission by an industry user, the system should require appropriate compliance certifications and contain a record of certifications.

2. Core Data Entities and Attributes

- People. Relationship to facilities or to representatives and their agent, address, affiliation, type, security level, user ID, passwords (or equivalent), phone numbers, email or equivalent.

- User Access Requests. User identification (per People), information to facilitate approval, status of request (approval, denial).

- Certification Records. Content of certification, date, user identification.

3. Core Functional Requirements

- Receive requests for user registration.
- Approve/deny requests and establish security groups.
- Provide notification of request status and assigned user ID and passwords (or equivalent).
- Develop and apply user privileges for specific functional areas and categories of data.
- Delete or archive users.
- Revoke or modify user access privileges.
- Display appropriate certification statements for review and agreement.

C. Account Management

1. Description

In the model rule, an Allowance Tracking System account is defined as an account "established for purposes of recording the allocation, and for holding, transferring, or deducting allowances." The WEB EATS should contain at least four types of accounts: general, compliance, retirement and government accounts. It must include a range of functionality to support each type of account.

A *compliance account* holds allowances which are used for compliance purposes. There is one compliance account for each source subject to emissions trading requirements and the compliance account is assumed to have the identical owners and representatives as its associated source. A compliance account should be automatically created for each new source when a source has met the appropriate registration requirements. For specified periods, compliance accounts or the allowances in those accounts may be subject to restrictions on trading to facilitate annual compliance assessment.

A *general account* allows anyone to hold allowances separate from the compliance and true-up process. A representative for a facility must move allowances from a general account to a compliance account before the true-up deadline in order to use them for current year compliance. A general account is created upon request of any individual or entity, and like a facility's compliance account, must have a defined owner and an individual person named as an account representative. General accounts are populated through trading functions, described below. The system administrator should have the ability to archive or deactivate a general account if specified criteria are met (such as containing no allowances for a specified period of time). For analysis purposes, the type of general account holder should be identified.

A *retirement account* holds allowances which have been used for annual compliance to offset emissions or which have been voluntarily removed from the market by its owners. At least one retirement account will be identified initially; additional accounts may be necessary to meet specific needs, if a detailed analysis of requirements indicates that separating retired allowances would be useful for analysis or other purposes.

A *government account* holds allowances which are still under the control of a State or Tribe (or, as their agent, the Tracking System Administrator). These accounts will contain serialized allowances to be allocated in the future. The new source set-aside, for example, is a government account.

2. Core Data Entities and Attributes

- Accounts. Identification number, type, restrictions, relationship to source (if any), State/Tribe, or owner/representatives, owner type.

- People. Type and direction of relationship to accounts, address, affiliation, security level, user ID, passwords (or equivalent), phone numbers, email or equivalent.

- Owners/operators. Address, relationship to accounts.

3. Core Functional Requirements

- Add/create general accounts.
- Change owner/operators for general accounts.
- Change representatives for general accounts.
- Add/create retirement, government, and compliance accounts (system admin only).
- Implement freeze on account or specific allowances within account.
- Archive or delete accounts.
- Notification of changes to user and other responsible persons.

D. Allowance Allocations (Initial and Ongoing)

1. Description

The system should support both initial and ongoing allocations of allowances from government accounts into compliance accounts. The initial allocation for the first five year period would be provided by States or Tribes in a format to be defined by the TSA and system designers. It is recommended that the allocation process replicate the transfer of allowances from account to account, thus creating an audit trail of the allowance back to its original issuing State or Tribe. It is recommended that the system design include a standard file format for submission of initial allowance allocations by the State or Tribe.

All allowances would be serialized according to a numbering system to be determined as part of the system design when they are initially populated in the application. This serial number would be a permanent attribute of each allowance and could not be changed.

Ongoing allocations, which occur every five years for all allowances, would be supported through a process similar to the initial allocation, depending primarily on a standard file format, containing allocations determined by the State or Tribe for the period.

The application should generate a draft and final Regional Allocation Report for each five year allocation period.

The application should support periodic allocations of allowances to compliance accounts for new sources from the new source set-aside. Specialized tracking and reporting would be needed to record the date of all requests and the status of the set-aside account. When this account is depleted, the tracking information would be used to prioritize allocation of future allowances to these sources.

The application must support allocations of allowances for opt-in sources on an annual basis. It is assumed that the State or Tribe would provide data to support opt-in source allocation (including source identification) either on-line or in an electronic format.

The application must support notification of all allocations to registered sources and to the appropriate State or Tribe.

If a source representative elects a monitoring option for a unit under 1.(b) of Section I (Monitoring, Recordkeeping and Reporting) of the model rule, the source representative would submit a request to the State or Tribe about this election, and must provide information about the portion of the facility's allowance allocation attributable to these units. Upon approval of the request by the State or Tribe, the TSA (or the State or Tribe directly) would mark the appropriate number of allowances as "non-tradeable" in the allowance account for the source for all years already allocated. A record of the request and approval would be stored, so that future allocations would also be marked as non-tradeable. If the special monitoring status under Section I1.(b) is revoked or no longer applicable, the "non-tradeable" status of the allowances would be changed by the TSA.

2. Core Data Entities and Attributes

- **!** Accounts. Identification number, type, restrictions, relationship to source, State/Tribe, or owner/representatives, owner type.

- **!** Allowances. Serial number, type, origin, year (if not indicated by serial number), non-tradeable indicator.

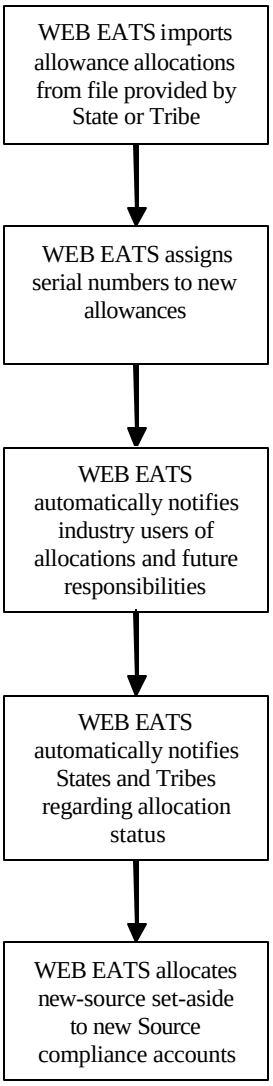
- Transactions. Transaction identifier, date, allowance range, transferor account, transferee account, type of transaction.

- Action Log. Type of submission or request, user, source, status, etc.

3. Core Functional Requirements

- Import of allowance allocations from file provide by State or Tribe.
- Assign serial numbers to new allowances.
- Notification system to automatically inform industry users of allocations and future responsibilities.
- Notification or report system to keep States and Tribes informed re allocation status.
- Tracking capability for new source set-aside requests.
- Allocations to compliance accounts from new-source set aside.

Figure 2
Flow Chart of Allowance Allocation Process



E. Allowance Trading

1. Description

The ability to trade allowances supports the underlying principle of an emissions trading program and the functionality to support allowance transfers is critical to the WEB EATS. Security of the data and transparency of the transfer record are critical to the overall program and should be carefully evaluated. The WEB EATS must provide the TSA the ability to maintain information on all current account holdings and an audit trail of all allowance

transactions, including both market transactions and regulatory transactions. The current standard for emissions trading programs established by EPA is to allow industry users to record allowance transfers on-line in real-time. These applications support both interactive, on-line transfers and batch transfers using specified file formats to transfer larger numbers of allowances. For batch transfers, industry has developed software to monitor allowance ownership and submit large volumes of allowance transfers with a minimum of user intervention. It is assumed that the technical capability for secure system-to-system interactions will continue to improve and that this approach will be more widely used in the future. Current allowance trading systems also support transfers performed by the TSA based on the receipt of paper forms. It is assumed that the reliance on paper forms will continue to diminish. Whether this functionality should be supported in the WEB EATS should be evaluated.

During the true-up period, activity in compliance accounts is frozen to allow the TSA to conduct the necessary compliance evaluation and allowance retirement. The WEB EATS would allow users to submit allowance transfers for allowances involved in an ongoing compliance process, but these transfers would be held and recorded following the completed process. All affected parties would be informed of the status of these transfers both when submitted and when finally recorded or denied.

For on-line transfers performed interactively by the transferor, the WEB EATS should provide access only to those accounts over which the transferor currently exercises control. Account access would be determined by the WEB EATS based on the user's relationships to specific general or compliance accounts. From these accounts, the user would select the accounts and specific allowances for the transfer. The user would then identify the account into which the allowances should be transferred. It is assumed that eligible recipients include general accounts, compliance accounts or a voluntary retirement account. The user would be asked to review and verify the transfer prior to its taking affect.

The process for electronic transfers of batch transfers will be more technology dependent. It would undoubtedly require definition of file transfer formats and security standards to ensure authentication of the submitter and completeness and quality of the data. It is not feasible to predict standards or available technology for this process at this time.

The paper-based process used by the TSA would be similar to the interactive process. Depending on the volume of paper transfers, redundancy of data entry or additional verification should be considered to ensure data quality and accuracy.

For all transfers (interactive, batch or paper), the WEB EATS must support a process of communication to both the transferor and transferee so that transfers recorded are fully disclosed to all parties and errors or other disputes between parties can be quickly identified and resolved.

The WEB EATS must support a process of either transaction reversal or transaction error correction, or both. This functionality would be restricted to the TSA.

Reports would be available to the TSA and designated State/Tribe users to review specific transactions or overall transaction activity at any time.

2. Core Data Entities and Attributes

- Accounts. Identification number, type, relationship to source, State/Tribe, or owner/representatives.

- Allowances. Serial number, type, origin, year (if not indicated by serial number).

- Transactions. Transaction identifier, date, allowance range, transferor account, transferee account, type of transaction, status.

3. Core Functional Requirements

- Interactive transfer.
- Batch transfer.
- Capability to freeze compliance accounts with regard to allowances involved in ongoing compliance assessment.
- Notification to transferor and transferee.
- Reports and summaries.
- Allowance transaction audit trail.

F. Annual Compliance Assessment

1. Description

Following each control period, the TSA must perform an assessment of annual compliance with the basic program requirement that each affected source hold a number of allowances equal to or exceeding the tons of SO_2 emissions for the period. The compliance module of the WEB EATS would support receipt of annual compliance notifications and certifications by the source representative. It is expected that most representatives would provide the certifications and designate allowances to be deducted using an on-line access similar to the allowance transfer capability. Following receipt of the annual compliance forms, the WEB EATS would then compare the allowances held in the compliance account and the level of emissions for the source (taking into account the year of allowances, flow control limitations and prior exceedances) and deduct the appropriate allowances from compliance accounts into retirement accounts. Emissions reported at the unit level would be "rolled" up to the facility level. The process would result in a compliance report or compliance assessment notification to source representatives, States and Tribes.

In addition, the WEB EATS would assess the need to apply flow control in subsequent years and determine the appropriate flow control factor.

Finally, the WEB EATS would identify any failure to meet allowance limitations. Based on the level of excess emissions the WEB EATS would compute the appropriate penalties, both monetary penalties and deduction of subsequent year allowances.

2. Core Data Entities and Attributes

- Annual compliance certifications. Facilities, submitter name/ID, year, compliance certification statements.

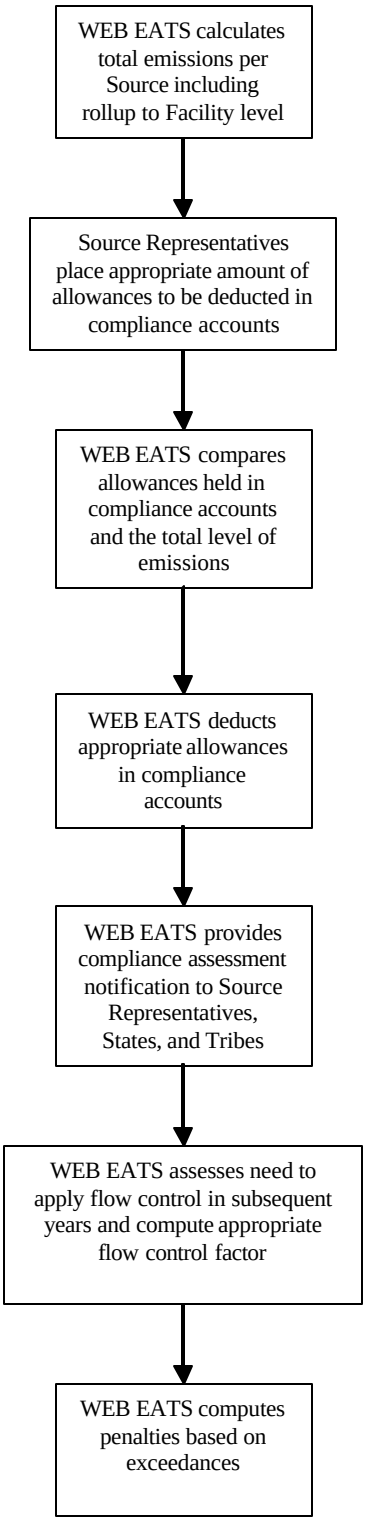
- Tracking. List of facilities for whom an annual compliance certification is required, received, etc.

- Compliance Results. Penalties, deductions, status, year.

3. Core Functional Requirements

- Receive and store annual compliance certifications.
- Perform compliance assessment.
- Calculate exceedances.
- Calculate flow control applicability and ratios.
- Communicate compliance results.

Figure 3
Flow Chart of Annual Compliance Assessment Process



G. Emissions Tracking and Emissions Reporting

1. Description

Emissions tracking and reporting for compliance purposes following the program trigger will require a wide range of functionality and data tables. There will be a need to evaluate carefully how and whether the functionality of the Emissions Tracking Database used for milestone tracking inventory purposes can be utilized to support the post-trigger emissions reporting. Also, it will be very useful to identify any potential overlap with existing emissions reporting systems used for other national or regional trading programs. For example, EPA plans to put into place the Emissions Collection System (ECS) and Monitoring Plan System (MPS) sometime after 2004. Although the software itself may not be adaptable for use as the emissions reporting module of WEB EATS, the system requirements and design should be consulted as an additional, more detailed, roadmap in the initial stage of system design.

The following general areas of functionality would be required:

Reporting Requirements and Tracking Information. To facilitate program implementation, the WEB EATS would identify monitoring and reporting obligations of each source participating in the program and track the receipt of required information. At least three types of reporters are envisioned:

- Part 75 reporters (submitting SO_2 emissions reports directly to EPA);
- Hourly non-Part 75 reporters; and
- Annual reporters (not participating in trading because of monitoring limitations).

For each of these type of reporting there are distinctly different reporting obligations and functionality to support submissions and reported information.

Monitoring and Emissions Information for Part 75 Units. For Part 75 affected sources who are reporting SO_2 monitoring and emissions data directly to EPA, the assumption is that redundant submission of these data would not be required. Instead, the WEB EATS would access or receive information from the EPA system about submissions and reported values under Part 75. Although EPA does not share these data directly with other data systems currently, it is anticipated that technological advances and the demand for shared data by other emissions trading programs would make this not only viable, but routine, by the time the program trigger occurs.

Monitoring Information for Non-Part 75 Units. For non-Part 75 units monitoring under Section I of the model rule, the submission requirements are not spelled out in the model rule. We recommend and assume that the program require and support the electronic

submission of monitoring plans that are needed to establish an identification base for monitoring methodologies, monitoring locations and monitoring systems. These data are needed to support periodic reporting of hourly emissions data and to ensure that the data from monitoring systems are certified and quality assured. Tracking capability would be needed to assist in identifying whether required submissions (electronic and hardcopy) have been received, reviews conducted and approvals issued. This capability would assist States and Tribes, the TSA, and source representatives in the implementation phase of the monitoring program.

Because monitoring plans contain important components which are either graphics or documentation and are not easily stored as data elements, system designers should consider including document management capability to complement the tracking of information and sharing of data between all parties. A robust document manager could provide a submission process and eliminate or greatly reduce submission of hard copy material. This is an area in which technical options and standard practices may improve significantly prior to the program trigger year.

Emissions Data for Non-Part 75 Units. For non-Part 75 sources required to monitor SO_2 emissions, the WEB EATS would support submission, processing and storage of hourly emissions data. By current standards, the volume of and processing capability for hourly data could be large. However, it is expected that processing power and data storage capability will continue to expand and costs will decline. It is also expected that the submission process would utilize the next generation of broadband access and communication, in whatever direction technology dictates. Standardization of data reporting protocols would probably facilitate design and implementation of data submission requirements. The shape of the WEB EATS would be dictated to a large degree by available technology, supporting basic functionality of receipt, tracking, checking, analysis, and communication between the regulated sources and program management.

Quality Assurance of Emissions Data. Underlying successful cap and trade programs is the assumption that the emissions recorded and traded are comparable from State to State, Tribe to Tribe and industry to industry. Clear monitoring protocols and quality emissions data are needed to maintain the viability of the program. The monitoring and emissions data collection process should include the appropriate level of checking, analysis to ensure accurate and complete monitoring and reporting. Part 75 is a useful model of standards and checking which has provided the appropriate level of market assurances about the quality of emissions. The designers and developers of the WEB EATS should provide comparable capability, including calculation checks, assessment of monitoring system quality assurance compliance, and the accuracy of missing data routines. Emissions data should be evaluated to check routinely and periodically for anomalies and inconsistencies.

Petition Tracking. To meet SIP approval requirements, petitions for alternative monitoring would require joint approval of the State/Tribe and the U.S. EPA. The WEB EATS should provide a mechanism to track petitions and their approval and disapproval in a centrally

accessible location for all State, Tribal and EPA program administrators. The WEB EATS should highlight and define electronically any aspect of the petition which results in allowable changes to reporting of monitoring or emissions data.

Annual Emission Statements for Reduced Monitoring Units. For units with reduced monitoring requirements under Model Rule Section I1.(b), the owner or operator would submit an annual emissions statement. The WEB EATS would track receipt of these submissions and record the emissions value reported. Annual production data or other information may also be required on a case-by-case basis as a condition of State or Tribe acceptance of the request under Paragraph b. These data should also be recorded in the data system.

2. Core Data Entities and Attributes

- Tracking. Including projected monitoring and reporting deadlines, submissions, and approvals or other status.
- Emissions Methodology/Reporter Type. Compliance period, Facility/Unit.
- Monitoring Locations. Units, stacks and pipes and attributes.
- Monitoring Systems Detail. Monitoring systems, formulas.
- Certification and Ongoing Quality Assurance Test Data. Test dates, overall results, test detail data.
- Cumulative Quarterly and Annual Emissions.
- Hourly Emissions Data.

3. Core Functional Requirements

- Track deadlines, requirements and submissions.
- Communicate with users about upcoming deadlines or deficiencies.
- Receive emissions report, quarterly and annual.
- Receive original and revised monitoring plans.
- Receive monitoring system certification and quality assurance data.
- Receive quality assurance test data and perform quality assurance checks.
- Address data quality problems.
- Provide final emissions data for annual compliance.

H. Program Assessment and Analysis

1. Description

Ongoing program assessment and evaluation is an explicit responsibility of the TSA and the system design and requirements should reflect the needs for various types of assessment including: environmental benefits, geographic impacts, market function, implementation successes and failures, co-benefits, and SO_2 control strategies. In each of these areas, the proposed database design should be evaluated to determine whether anticipated needs will be met. The analytical utility of the data in WEB EATS will be enhanced in some cases by ensuring that accurate and complete links to other databases are supported and maintained. Similarly, geographic analyses will be enhanced by having high quality and complete locational information. These data will facilitate the availability and use of deposition and other modeling data.

It is important to consider the needs of users who want access to basic and repeatable analyses and the needs of users who want access to the data to perform complex analysis or one-time analysis. The basic user may best be served by providing standard reports designed to provide a program overview, summary statistics or status reports on specific types of activity. Combined with basic filtering and sorting options, a well designed report will meet many of the ongoing needs. More flexibility in data analysis could be provided by developing a more robust query tool, perhaps with control over report formats and output file types. For the high end user with more complex analytical needs or requiring use of data volumes beyond the capability of the user interface platform, the ability to request and deliver data in standard formats should be considered. If it is determined that the basic user needs include access to large volumes of data in predictable summary formats or quick access to complex data, the design and development of a data warehouse to facilitate this access should be considered.

2. Core Data Entities and Attributes

- Data warehouse. To provide easier access to aggregated data for analysis purposes.

3. Core Functional Requirements

- Generate standard reports.
- Provide data query tool.
- Provide capability for data export and delivery.
- Provide links to other information systems.

I. Public Information Needs and Requirements

1. Description

To support market trading, information about market activity must be available to market participants and the general public. This includes, in particular, information about allowance trades and the identity of market participants, including representatives. The specific data content would be evaluated in detail at the time of design and development. It is expected that public access to some data, for example the tribal allocations for set-aside, would be limited.

It should be noted that the timeliness of the data is a critical aspect; but it may be appropriate to provide access to different types of information at different intervals. For example, a daily update cycle for allowance trading and representative changes has been adequate for the Federal trading programs; access to reported emissions data may be provided quarterly or even annually.

The ease of access for the public is also important. The current standard is to publish data though the Web, either in a readable format such as .pdf, in a standard spreadsheet format or through a query tool which retrieves and displays data in .html format through a browser. Although the technology available for public access to information in the next decade is not easily predicted, it would be expected that similar methods of providing access would be selected. The technical architecture and data formats should be selected based on security, speed or performance, overall accessibility to the technology, and flexibility offered in terms of both output and format.

2. Core Data Entities and Attributes

- Data warehouse. To provide easier access to aggregated data for analysis purposes.

3. Core Functional Requirements

- Timely public access to source inventory, account, allowance and representative information.
- Public access to periodic emissions data.
- Data downloading or extraction.

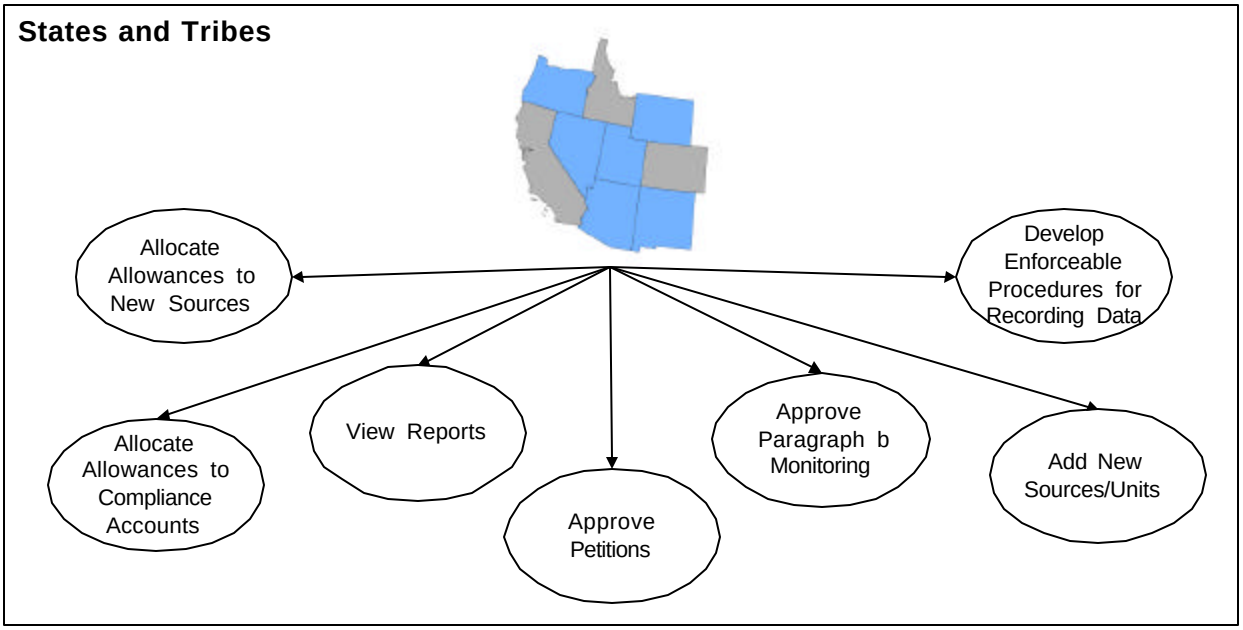
IV. Types of Users

As depicted in Figure 1, there are five basic categories of users for the application: State and Tribal users; industry users; general account holders; the Tracking System Administrator; and public users.

A. State and Tribal Users

Staff members of a State or Tribe participating in the Backstop Emissions Trading Program would be key stakeholders and users of the application. These users would have read-only access to almost all data in the application and a variety of reports. They would provide key data to the system using a combination of data upload or on-line capability. These would include facility and unit and program applicability data, general allowance allocations, allocations from new source set asides, and approvals of monitoring submissions. These users would have no day-to-day responsibilities for the operation, management or maintenance of the application or data.

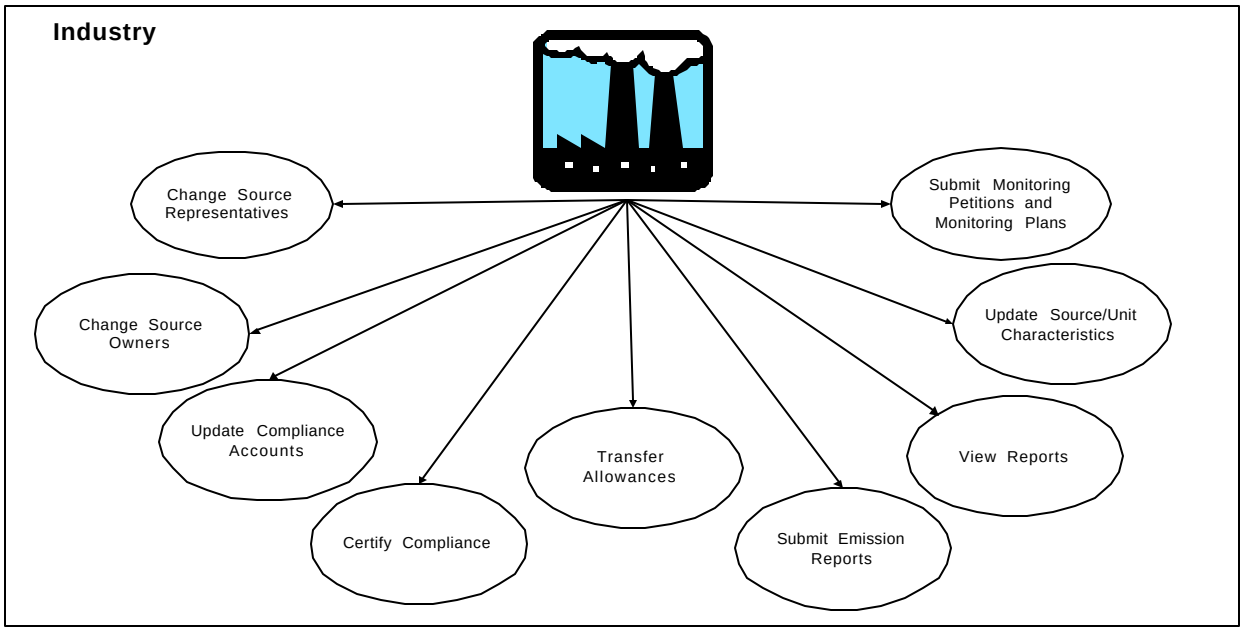
Figure 4
Use Case Diagram: State and Tribal Users



B. Industry Users

Representatives of the regulated community would also be key users of the application. These users would have access to data relating to sources under their control, as defined by their roles and responsibilities as source representatives. In this capacity, they would be able to maintain source and unit information, transfer allowances in compliance or general (that they set up) accounts to and from other accounts, and submit required emissions data and compliance certifications.

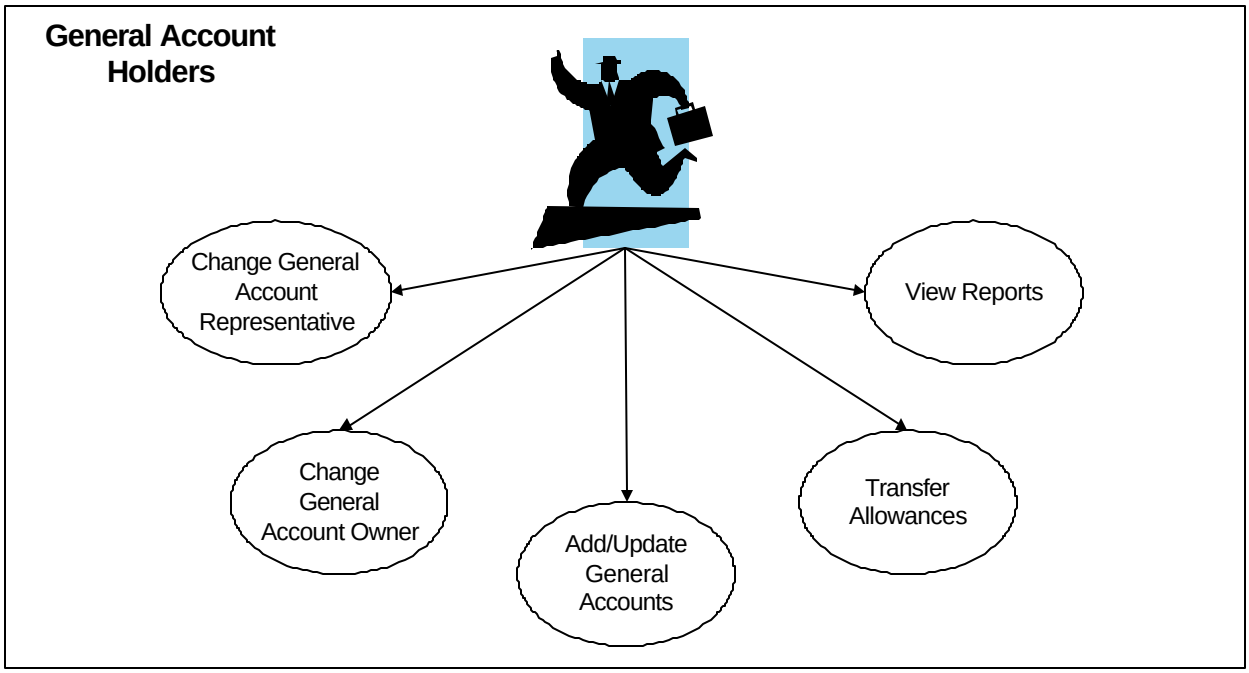
Figure 5
Use Case Diagram: Industry Users



C. General Account Holders

A representative for a general account would also have access to the application to update general account information, create new accounts, transfer allowances out of their general accounts to other accounts and to view reports. The general account holder would have limited (or no) access to source information, unless the holder is also a compliance account holder or until such information is determined to be public information.

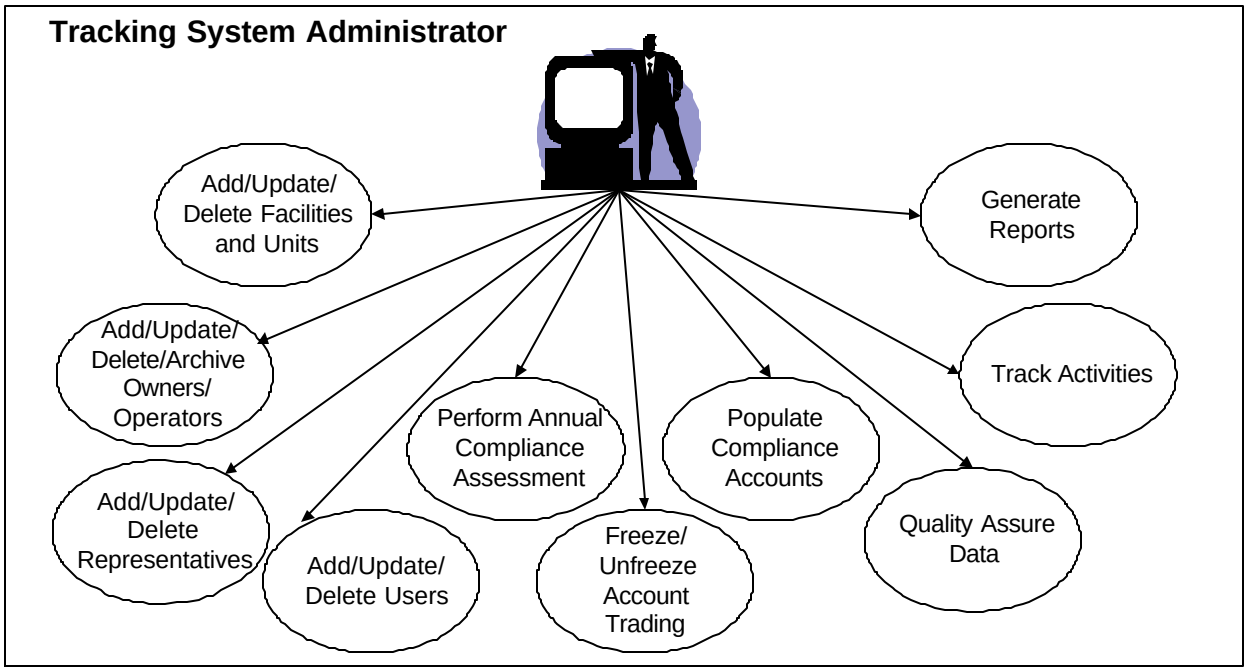
Figure 6
Use Case Diagram: General Account Holders



D. Tracking System Administrator

The Tracking System Administrator (TSA) would utilize virtually all functionality contained within the application. In appropriate circumstances the TSA would act on behalf of State/Tribal, industry and general account users. In addition, the TSA would perform all types of system management and maintenance activities to ensure effective operation of the application. The TSA would approve access for all users of the application.

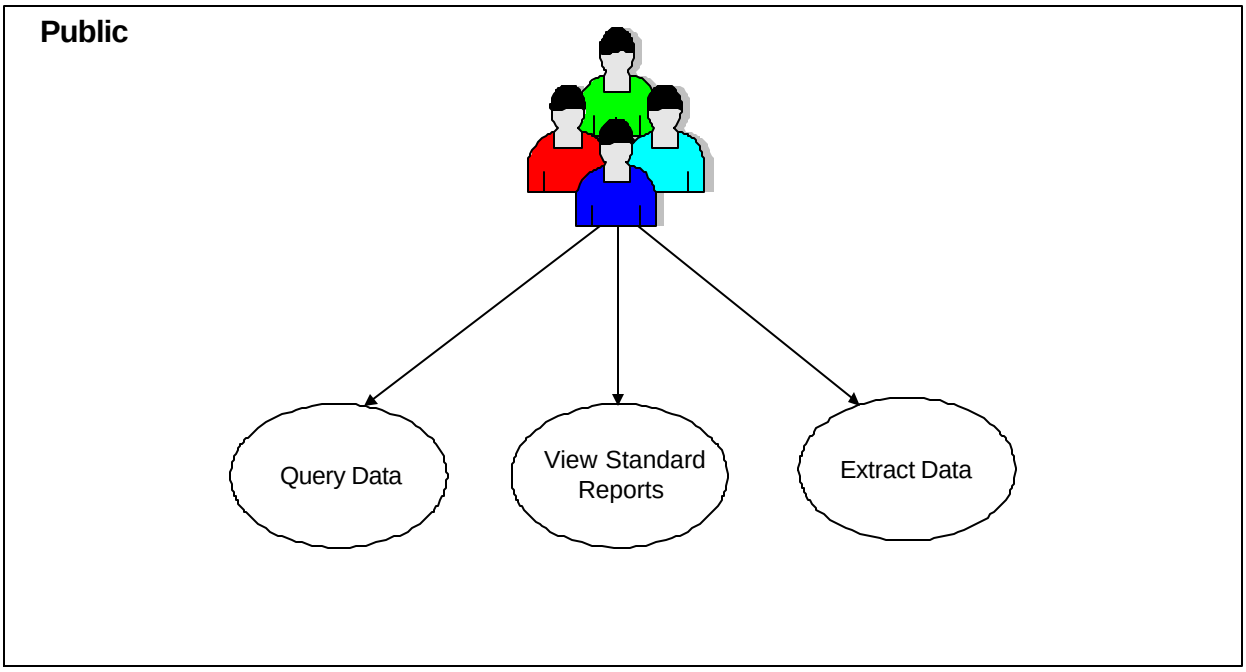
Figure 7
Use Case Diagram: Tracking System Administrator



E. Public Users

Public users have read-only access to selected data within the system. This access would be consistent with the security requirements of the application and data.

Figure 8
Use Case Diagram: Public Users



V. Technical Architecture

A key component of system design is the selection of a common architecture. One of the major components of system architecture is the number of levels or layers in a system. An application installed on a user's machine that does not communicate with any other applications or systems is a 1-tier system. A client-server system, where one application sits on a user's computer (client) and another, related application sits on the server is a 2-tier system. Most Web applications are 3-tier systems, where there is a browser and Web server (client), a business logic server and a database server. The system should be built with at least three layers to separate the display (client), business logic, and database, so that each layer could be modified without having to change other parts. The exact architecture would be determined at the time of system design.

The final decisions about system architecture should consider many factors, including security, performance, and maintainability.

A. Security

Due to the importance of data integrity and accuracy in the WEB EATS, security will be extremely important. The security measures should be based on current best practices and standards. The system's security can be divided into two areas: application and server level security.

1. Application Level Security

The system's application level security consists of the protective measures designed into the application's code. These include the logical measures to determine which users may access which areas of the system, the manner in which session management is handled and the protection of sensitive information, like passwords, at the application level.

- Password Encryption. The system must include a process to authenticate all authorized users to the system. Today's system utilizes encryption to protect the vulnerable data elements, such as user passwords. Implementation of an extremely robust encryption, routine or its equivalent should be incorporated into the system.

- Separate Logins. Each user should maintain a unique username and password, with the password encrypted and stored in a secure database. Each user should be assigned a unique ID.

- Separate User Types. The access rights and restrictions should be controlled at the user group level. Each user group would have a unique set of rights and restrictions within the WEB EATS. Upon user login to the system, the user's specific user group security should be verified and rights and restrictions set for the session. If the user belongs to multiple user groups, they should be assigned the highest rights for a given section or action among their user groups.

- Audit Trail. The system design should include specific requirements to maintain an audit trail of data adds, updates, and deletes for critical data elements. This audit trail should be designed to detect and resolve challenges to the data (for example, allowance ownerships), and as an additional means of restoring data should there be a breach of data integrity.

- Session Management. Strict session management control, in which session tokens are properly protected and validated, is essential. When two applications are run remotely from each other (like a browser and a server), they require session tokens to be able to communicate about the application state. To prevent attackers from hijacking active sessions and assuming the identity of a user, session tokens need to be regularly re-validated.

2. Server Security

The system's server level security consists of the protective measures designed to protect the server itself from inappropriate access. These include proper server maintenance and the modifying of default system passwords.

- Server-Side Data Validation and Business Logic. To the extent possible, all business logic and data validation should be checked and handled at the server level and not be coded at the client or browser level. Server-side validation improves performance and reduces the risk of a user bypassing business logic designed to prevent them from submitting invalid data. Server-side validation includes business logic as well as basic data type validation (i.e., length, range, data type, characters sets).

- Server Maintenance. The servers or host platform should be maintained according to security standards. For example, many of today's current servers are patched on a regular basis with the latest security releases as soon as they are available. Because flaws in server software are usually well known in the hacker community, it is important to protect the server from attackers.

- System Passwords. The system passwords to the servers or host platform should be modified from their defaults and changed on regular intervals. Because the default passwords for commercial servers are commonly known, they pose a security threat and should be changed. Also, standard security practices should be followed regarding the regular changing of passwords.

3. Physical Data Security

Physical data security should be provided by the measures to protect the data center, a specialized facility that hosts an application, from dangers. These dangers include theft, natural disasters, manmade catastrophes, and accidental damage (e.g., from electrical surges, extreme temperatures, spilled coffee, etc.). The data center that hosts the WEB EATS should maintain strong security practices and undergo periodic audits.

4. Backup and Recovery

The database should be backed up at least daily and the application files should be backed up regularly. It may be advisable to back-up the allowance transaction data at a more frequent interval, based on the frequency of use and level of recoverability deemed necessary. A copy of the backup files should be stored off-site from the data center to ensure minimum downtime should a catastrophe occur.

A Catastrophe Recovery Plan (CRP) should be created to enable the application to return to service as soon as possible following a catastrophe. Most CRPs contain the following:

- Threat analysis,
- Risk assessment,
- Mitigation steps,
- Response and recovery plans,
- Damage assessment process,
- Salvage procedures, and
- Rehabilitation plans.

B. System Performance

The system's performance can be greatly improved with the intelligent application of best practices and procedures for performance tuning and system design. These include the following:

1. Database Design and Query Optimization

The database should be designed with performance in mind. All database queries should be optimized to maximize performance. Use of views and indices or similar database functionality should be considered to maximize database performance. By limiting the results to only those that will be utilized immediately, the system will minimize the server and network resource load.

2. Session Variables

System design or programming technologies that overuse session variables can degrade the performance of the system. Therefore, only information that absolutely must be maintained to keep the session active should be stored in session variables. Following a user logout or the expiration of a short time limit, session variables should be explicitly purged from memory.

3. Archiving Data

Data should be archived regularly to conserve database space and enhance performance. A mechanism should be provided for retrieving the archived data for reporting purposes.

4. Data Volume

The data volume of the WEB EATS will be largely determined by the number of sources and the frequency of data collection. With a planned number of sources of less than a thousand, which may include the periodic submittal of hourly data collection, the database is

projected to grow approximately 4GB per year. To ensure maximum performance, the database should be regularly re-indexed and monitored for performance. It is recommended that the emissions data collection component sit on a separate server from the business logic server for performance gains.

5. Frequency of Use

The system design should take into account the number of users, the level of access, and the volume of data provided by users for specific processes. The WEB EATS usage is expected to be well within the normal expectation of capability for a small to moderate size application. For emissions data submission, the volume of data may be relatively high (by current standards) and require special design consideration.

C. Maintainability

To achieve a flexible system that evolves with program needs, the system should be developed for maximum maintainability. If the application is based on vendor software, it should be built upon well-known technology and platforms. If it is custom developed, it should be well documented and based upon best programming practices and standards and developed in a common development language. These measures will minimize time and cost to maintain the application following implementation.

In addition, the programming team should be required to adhere to programming standards, including code organization and documentation, to facilitate support and enhancements after deployment.

Post-deployment modifications should be developed by a set protocol including input from users.

D. System Outputs

The system should support various types of outputs, including data transfers, electronic communications, like email, and connections to external systems. During the system design, the needs of the proposed users and the archiving of data should determine exactly which system outputs should be available.

1. Data Transfers

The periodic transfer of emissions and related data should be communicated to the application via a standard information exchange protocol. The exact protocol and procedure will need to be determined based on best practices and volume of data at the time of implementation. Each data record should be error checked to verify its integrity during the submission process.

2. Electronic Communications

The application should contain functionality that notifies parties via electronic communication upon the execution of certain actions. These actions would include, for example, allowance transfers, freezing/unfreezing accounts, and system maintenance notices. The exact list of actions, subsequent message media, recipients, and structures should be determined as part of system design.

3. External System Connections

The application would be expected to provide data to external data systems such as the Emissions Inventory System that the WRAP will be using to perform the program trigger evaluations tracking. The system should also support connectivity with the National Environmental Information Exchange Network and Tribal Emissions Implementation Software Solution (TEISS). The exact methods used to connect other systems will be determined at the time of system design.

The application should also be able to communicate and transfer data files to and from other EPA data and allowance tracking systems, such as the system supporting the federal SO_2 emissions trading programs.

E. Application of Platform Selection Criteria

During the preliminary phases of the system design, a significant decision will be the selection of the technology platforms or architecture for the system. These platforms include the Web server, business logic server, database server, and client interface. For each of these platforms, consider these issues with the following questions in mind:

- Data volume. Will the volume of data which must be maintained, transferred and analyzed be supported by the database and/or the application? Be sure to calculate the data volumes over the estimated life cycle of the project keeping in mind any applicable program specific or overarching regulatory requirements relating to government recordkeeping.

- Performance. What are the minimum performance requirements for basic application tasks, such as accessing the system, updating source information, transferring allowances? What are the minimum performance requirements for infrequent tasks, such as annual compliance assessments, data quality analyses, or submitting hourly emissions data? What are the performance requirements for reports?

- Relative Costs. What are the overall cost constraints? What is the acceptable ratio of design costs to development costs and initial deployment costs versus maintenance costs? Research these issues for comparable systems and platforms.

- Maintainability. What specific standards and assumptions should be imposed for maintainability?

- Connectivity. Which connectivity standards should the system support?

- Efficiency. Are there specific design choices which will impact the efficiency of program implementation? Examine design options and platform options to maximize efficiency benefits of the information system for the overall operation of the program. To what extent should the efficiency benefits to regulated industry, general account holders and the public be taken into account?

- Availability. What level of system availability is acceptable for each type of user?

VI. Design and Development Approach

The second objective of this document is to serve as a roadmap to help the States and Tribes implement the program once it has been triggered. Outlined below is an implementation methodology that the States and Tribes can follow to design, develop and deploy the system. In addition, this section provides an analysis of cost and scheduling factors that should be considered.

A. Recommended Implementation Methodology

Upon the trigger of the WEB Trading Program, detailed system requirements will need to be assessed. The following section recommends, steps to design, develop and implement an information system for the program. It is recommended that a workgroup be created and assigned responsibility for this task. The workgroup should be comprised of user group representation, program analyst(s), and technical specialist(s).

1. Requirements Verification

The first step following the need to implement the program will be to verify the requirements of the information system. Since many of the procedural elements of the SIP/TIP will be decided in the future, the exact functionality may have changed since the creation of this document. Therefore, detailed requirements should be verified and incorporated into a system analysis document. It is expected that this stage of the process will require significant participation of all stakeholders, particularly the States and Tribes participating in the program.

2. Assessment of Current Standards and Technology

Following the verification of requirements, the workgroup should research and assess the current standards and technologies applicable to this type of information system. Since this application would probably not be designed until many years after this document, it was

determined that the current standards would have little value and these have not been evaluated or referenced.

3. Technical Architecture Option Evaluation

Just as the standards and technology should be evaluated, so should the possible technical architectures, as discussed above. Most systems at the time of the creation of this document are 3-tier, but that should certainly not limit the architecture of the WEB EATS. Also, the suggested measures for security and maintainability may no longer be applicable, and should thus be re-evaluated.

4. Closeness of Fit

Based upon the system analysis requirements, standards, and architecture assessments, the workgroup should perform a Closeness of Fit study to analyze the available products, technologies, and platforms available. By analyzing the field of products, technologies, and platforms available, the Closeness of Fit study should conclude with a recommended product or set of development technologies and standards.

5. Decision

Based upon the Closeness of Fit study, the workgroup should select a product from a vendor(s), develop a custom system, or a combination of the two.

6. Design/Customization/Development Strategy

Following the decision to either select a Commercial Off-the-Shelf (COS) product, develop a custom application, or customize an existing application, the workgroup should select a developer and/or TSA to design, develop and implement the system.

The development plan should include a careful review of the schedule of program implementation and requirements to ensure that the necessary elements of the application are in place at the appropriate time. A staged process, with design, development, and deployment of specific system modules, is recommended. For example, the initial phase of development would probably focus on the source registration capability and initial allowance allocations. Later development could include allowance transfers capability, annual compliance assessment or overall program assessments.

7. Development

Following agreement upon the system design, the developer or TSA should develop the system utilizing modern development best practices and procedures. It is recommended that the

developer and/or TSA work with the members of the requirements gathering workgroup to re-affirm and adjust requirements as needed.

8. Quality Assurance/Testing

Following the successful development of the system, the developer/TSA should submit the system for rigorous testing. A test environment should be set up and a test database should be populated with data that closely match the quantity and type of data that will be utilized during live transactions. All phases of the system should be rigorously tested by the developer/TSA, States and Tribes, and a select group of end-users.

9. Deployment

Following successful quality assurance of the system, the workgroup and the developer/TSA should agree that the system is ready to be deployed or implemented in a production environment. Prior to production, the database will need to be populated with the necessary baseline information including source inventory data, emissions data, users, etc. The developer/TSA should provide training/instructions to users of the system along with appropriate documentation. It is assumed that participating States and Tribes will work closely with the TSA to define and implement a communication strategy to ensure compliance with all program requirements and full use of the information management system developed to ensure its success.

B. Timing/Schedule

If there is no significant delay after program trigger in the initiation of the information system design and development process and if a staged approach to deployment is adopted, then an implementation schedule in which the necessary system elements are in place is achievable. This objective should be stated at the outset of the project.

It should be noted that the use of COS or the customization of an existing system might reduce the initial development time for the system. To fully design, develop and deploy a custom application by today's standards might extend one to two years. Additional time might be necessary if there were significant issues relating to functionality or process about which State and Tribal participants could not agree. Technology trends indicate that forthcoming design and development methodologies will likely reduce this estimate.

C. Cost Factors

Factors driving the cost of the information system include technical platform, design complexity, data volume, security level, and the level of and approach to integration with other data systems. The availability of and use of COS or another application as the basis for the application would also affect costs.

1. Technical Platform

The technical platform includes the server software and business logic systems that are required. There are a wide range of options for the level of solution required and cost. A middle-ground solution is most likely the most suitable for the WEB EATS, one that maximizes flexibility and maintainability.

2. Design Complexity

The level of complexity incorporated into the system design will be a large cost factor. Generally, the more complex systems are, the more they cost. Based on the current system analysis, the system design appears to be moderately complex. As with any application, the requirements phase of the project may result in relatively more or less complex requirements, directly affecting costs.

3. Data Volume

The amount or volume of data will be a key cost driver in selecting the database server. If only one database is utilized for both the allowance and emissions data in WEB EATS , the database will grow quickly and will require a high-end solution to maintain performance levels. It is expected that the relatively high data volume will require database optimization and regular tuning, which will add to the maintenance costs.

4. Security Level

The level of security built into the system will certainly affect the cost. The more robust the security model is, the more time consuming and costly to implement. The security level detailed in Section III(A)(I) dictates a moderate level of security.

VII. TSA Responsibilities and Performance Criteria

A. TSA Responsibilities

The Tracking System Administrator (TSA) will have responsibility for the deployment of the site, ongoing maintenance and the day-to-day program implementation tasks associated with the program. It seems likely that the TSA would also design and develop the information system, but it is not necessary that both development and support should be provided by the same organization. Regardless, the ongoing responsibilities of the TSA would include two types of support: information system and program implementation.

1. Information System

This category of support is to ensure that the information system is properly administered, supported and performs all required functionality.

- Data security. The TSA would assume responsibility for ensuring that the security of the site and the data is monitored and protected on an ongoing basis. This would include monitoring access to the site and attempted but failed access (particularly if occurring in significant volume).

- Data integrity. The TSA would assume responsibility for ensuring that the integrity of the data is monitored and protected on an ongoing basis. This would include ensuring that the referential integrity of the data is maintained, a data backup plan is implemented, and any opportunities for data corruption are identified and addressed.

- Data quality assessment and corrective maintenance. The TSA would develop within the application and be responsible for performing data checks to identify duplicative information, data omissions or other data of poor quality that are not easily prevented by error checks or data standards. The TSA would make corrections to the data, as necessary, and maintain documentation of changes.

- WEB EATS enhancements. The TSA would document and evaluate any proposed enhancements, modifications or additions to the application. Working with the State/Tribe participants in the trading program and within established budget constraints, the TSA would perform, test and deploy the modifications (in coordination with the assigned programming team).

- WEB EATS documentation. The TSA would have responsibility for maintaining all technical documentation for the WEB EATS (including enhancements and for maintaining records relating to its ongoing operation).

- User technical support. The TSA would provide technical support to all users of the application. This would include telephone support and responses to requests or inquiries through other means of communications. The TSA would maintain records of all technical support and the TSA response. Technical support needs could also be addressed through the use of other support tools, comparable to the FAQs or online support systems currently in use.

- Performance monitoring. The TSA would be responsible for monitoring the overall performance and availability of the application for all types of users. This would include identifying the causes of any disruption of service or availability and identifying any persistent problems experienced by the user community.

- Database administration. The TSA would monitor data performance and perform all maintenance and optimization tasks affecting the performance of the database. The TSA would maintain records of all database administration activities.

2. Program Implementation

The TSA is also expected to implement the program for the consortium of States and Tribes participating in the program. This is necessary to ensure that the program will be implemented consistently and cost effectively.

- User access administration. This support would include evaluating and responding to user access requests, password changes, and related usage issues.

- Coordination with States and Tribes. The TSA will coordinate, as necessary, with each State or Tribe participating in the program to ensure that the State or Tribe fulfills their responsibilities and is aware of the need for their participation in decisions or issues. This includes aiding the States and Tribes in developing enforceable procedures for recording the necessary data. For example, the TSA would obtain allocation lists, petitions, retirement approvals, information about new sources, and reduced emissions monitoring under Section I1.(6) of the model rule from the State or Tribe.

- Perform allowance allocations. Using the information provided by the State or Tribe, the TSA would perform allowance transfers from government accounts to compliance accounts. The TSA would provide a report (or electronic file) to the State or Tribe of these actions.

- Periodic status reports on system activity and program implementation issues. On a regular basis (monthly, quarterly and annually), the TSA would provide to the participating State and Tribes a summary of program activity. This report would include, for example, a summary of allowance transfer activities, a status report on emissions reports, or the level of public access to the database.

- Annual compliance assessment. The TSA would perform the annual compliance assessment or true-up and would coordinate with industry, States and Tribes regarding the results of this process. Following review or approval by the participating States and Tribes, the TSA would finalize the compliance assessment by retiring the appropriate number of allowances from compliance accounts. An end-of-year compliance report would be made available.

- Communication strategy development/implementation/support. Throughout the life of the program, the TSA would work with the participating States and Tribes to maintain and implement a communication strategy and plan. The purpose of the plan would be to ensure full participation of affected sources in the emissions trading program and to

maximize understanding of and knowledge about the program among all interested parties. The content of the plan would include a strategy for general guidance, day-to-day communications to sources about their actions (transfer confirmations, data receipts, etc.), State/Tribal reports, communications between States and Tribes about ongoing program issues such as monitoring approvals or petitions, participant or public meetings and publications containing program results or environmental assessments.

- Overall program assessment. The TSA would assist the States and Tribes in designing and conducting an assessment of the overall program operation, costs, and environmental benefits on a periodic basis.

- Error correction, followup and documentation. The TSA would be responsible for correcting any data entry errors reported by users that are not within the security limits for the user.

B. TSA Performance Criteria

To ensure adequate support for the program, it will be necessary to establish performance criteria for the TSA.

1. Technology Standards

For the WEB EATS and technology support, the key criteria should be based on technology standards prevalent at the time of deployment and they should be tailored to the technical architecture selected for the WEB EATS. The following criteria would fall into this category and should be defined at the appropriate time. The importance of each of these factors should also be considered during the WEB EATS system design phase and in the selection of a technical architecture.

- System performance (response time, number of concurrent users supported, frequency of WEB EATS or database errors, etc).

- System availability (average downtime).

- Timeliness of public access to data.

2. Contract Performance Standards

Other important criteria relating to TSA performance would be the traditional criteria relating to overall performance with respect to basic contract terms. These would include:

- Responsiveness to customer concerns,
- Timeliness and quality of status reports,
- Overall cost, and
- Budget accuracy.

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Appendix A-8c. Recommendations for Making Additional Determinations in the Context of Reasonably Attributable BART

Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART

Prepared by: The WESTAR Council

Prepared for: The Air Managers Committee, Western Regional Air Partnership

May 2003

Recommendations for Making Attribution Determinations in the Context of Reasonably Attributable BART

Prepared by:

The WESTAR Council RA BART Phase II Working Group: Alice Edwards, Alaska Department of Environmental Conservation; Mike Sundblom, Arizona Department of Environmental Quality; Deb Wolfe, Montana Department of Environmental Quality; Dana Mount, North Dakota Department of Health; Dave DuBois, New Mexico Environment Department; Colleen Delaney, Utah Department of Environment Quality; Alan Newman, Washington Department of Ecology; Lisa Reiner, Quinalt Indian Nation; Bruce Polkowsky and Kristi Gebhart, National Park Service; and Kristin Gaston and Bob Lebens, WESTAR.

Prepared for:

The Air Managers Committee of the Western Regional Air Partnership
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Authors of the Attribution Techniques (Section VI) are Mike Sundblom (Monitoring); Kristi Gebhart (Receptor Modeling); and Dave DuBois (Source Modeling), with assistance from Ajith Kaduwela, California Air Resources Board. Bruce Polkowsky and Colleen Delaney drafted the certification section and provided liaison between the Western Regional Air Partnership Market Trading Forum and the Working Group. Alan Newman, Washington Department of Ecology drafted the portion of the report outlining the example process to which Dana Mount also contributed. Kristin Gaston drafted the regulatory context section and along with Bob Lebens, edited the report.

EXECUTIVE SUMMARY

This report recommends a general procedure and applicable technical approaches that may be used by states and tribes to assess reasonable attribution in response to a Federal land manager (FLM) certification of visibility impairment in a Class I area (Certification).

WESTAR formed the Reasonably Attributable Best Available Retrofit Technology (RA BART) Phase II Working Group with Federal land management agency staff and members of state and tribal air quality agencies knowledgeable about RA BART and associated monitoring and modeling techniques. To provide the necessary framework, the report provides background information about both the certification process and the attribution determination process. However, the recommendations focus on the general principles of the attribution assessment process and the technical criteria used in the assessment.

The recommendations are summarized below:

General Principles:

The attribution assessment should be:

- A collaborative process that relies on existing data with minimal additional analyses.
- Technically and legally defensible.
- Accomplished at a reasonable cost and within a reasonable time frame.
- No more complex than necessary.
- Performed by state or tribal agency staff.
- Adequate to determine whether or not visibility impairment is attributable to an existing stationary source potentially subject to BART.

Technical Criteria:

- Emissions from BART-eligible sources must "cause or contribute to" visibility impairment. Visibility-impairing pollutants of concern must be identified.
- Factors to consider in assessing impairment include: duration, frequency, geographic extent, magnitude, and time of occurrence.
- Identify distance from source to Class I area to determine appropriate tools for characterization of the impairment.
- Quantitative results are preferable, although qualitative results such as photographs may be adequate.
- Use as many different indicators of impairment as practicable rather than relying on a single indicator.
- Consider level of uncertainty in the assessment.
- Use EPA guideline models whenever practicable.

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RA BART Rule (40 CFR 51.300-306)

I. BACKGROUND

A. Introduction and Purpose

Reasonably Attributable Best Available Retrofit Technology (RA BART) is the portion of EPA's visibility rule published in 1980 and codified in 40 CFR 51.302–51.306 that deals with visibility impacts from one source or a small groups of sources. RA BART refers to reasonably attributable visibility impairment and best available retrofit technology for eligible sources and emission limits, and emissions controls as defined by the statute and the rules. Some confusion exists regarding the application of RA BART, the process of assessing sources of visibility impairment, and the technical tools available for an RA BART attribution determination. RA BART is a statutory requirement, although certain of the requirements may no longer be applicable when a source complies with BART or installs BART-like controls or after a state implements a trading program under 51.308(e)(2) or any trading program under 51.309, and if no remaining visibility impacts continue from one source or a small group of sources.

This report, therefore, addresses the RA BART attribution process and builds upon case studies WESTAR developed in 2001 to examine and document how Reasonably Attributable Visibility Impairment (RAVI) had been addressed in previous assessments.[1]

The Federal land managers (FLMs) advocate maintaining RA BART as a tool because RA BART is effective when new monitoring indicates that a previously un-monitored area has visibility problems differing from the regional visibility impairment conditions at other areas. In addition, RA BART is effective when BART-eligible sources in the vicinity of the protected area are causing or contributing to identified visibility impairment.[2]

First, this report recommends attribution process principles and assessment techniques a state or tribe may consider in an attribution assessment to identify if, and to what degree, an existing source or small group of sources causes or contributes to visibility impairment. The report focuses on RAVI and does not specifically address impairment due to regional haze. Although this report includes references to regional haze, such references serve only to place the attribution process in the larger context of the broad regulatory framework that addresses visibility impairment, including the regional haze regulations.

Second, this report includes no recommendations with regard to establishing a threshold level at which reasonably attributable impairment exists. Instead, the working group outlined a recommended general process and recommended technical procedures that may be used as guidelines if an attribution assessment is necessary. Due to the circumstances unique to each attribution assessment and the requirement that the assessment be conducted on a case-by-case basis, recommending one specific analysis for every situation was not possible. A state or tribe should select from the techniques summarized in Section IV. Section IV(C) includes five examples of the attribution assessment process, each providing a range of techniques to be used

[1] WESTAR Council, *RA BART and RA BART-like Case Studies*, June 2001.

[2] This document specifically relates to RA BART and does not address broader issues relating to long-term visibility strategies. FLMs generally do not intend to issue Certifications citing specific sources except for situations involving BART sources.

based on available data. The examples also recommend more refined analyses that may require additional data.

Third, this report includes specific information about the current policy of FLM agencies regarding certifications of impairment (Certification), but makes no recommendations regarding the certification process. This report makes no recommendations regarding state process following an attribution determination nor examines options for performing the Best Available Retrofit Technology (BART) analysis or the incorporation of BART requirements into State Implementation Plans (SIPs).

Tribal Implementation

The recommendations in this document are intended to help states assess reasonable attribution following Certification by an FLM. Subject to the requirements of the Clean Air Act, 42 USC 7601(d) and the Tribal Authority Rule, 40 CFR 49.1– 49.11, a tribe may accept responsibility for making reasonably attributable determinations in response to a Certification by an FLM when a BART-eligible source identified by the FLM in the Certification is on the tribe's land. The regional haze rule also explicitly recognizes the authority of tribes to implement the provisions of that rule on tribal lands. Those provisions create the following framework:

1. Absent special circumstances, reservation lands are not subject to state jurisdiction.
2. Federally recognized tribes may apply for and receive delegation of federal authority to implement CAA programs (including visibility regulation), or "reasonably severable" elements of such programs. The mechanism for this delegation is a Tribal Implementation Plan (TIP). A reasonably severable element is one that is not integrally related to program elements that are not included in the plan submittal, and is consistent with applicable statutory and regulatory requirements.
3. Where a tribe does not seek delegation through a TIP, the Environmental Protection Agency (EPA), as necessary and appropriate, will promulgate a Federal Implementation Plan (FIP) within a reasonable timeframe to protect air quality on tribal lands.

Accordingly, these recommendations also may assist a federally recognized tribe that chooses to adopt a TIP to implement the RA BART provisions. In some cases, a tribe may be able to utilize the recommendations in much the same way as states. In many other cases, however, the recommendations may be modified to meet the unique situation of the tribe and the nature of its air program, including its manner of defining "reasonably severable elements" and its method of dividing responsibilities between the tribe and EPA. Because of these differences, the recommendations that follow do not refer to tribes every time states are referenced.

B. Regulatory Context

The national goal for visibility is set forth in the Clean Air Act (CAA) at 42 USC 7491: "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution." The requirements apply to 156 designated Class I areas.

As stated previously, Congress required that states provide a remedy for visibility impairment that was "reasonably attributable" to one source or a small group of sources. (42 USC 7491). Congress directed EPA to ensure that all SIPs contained measures necessary to make reasonable progress toward meeting the national goal, including requirements for identifying major sources of emissions causing or contributing to visibility impairment, and requirements for the application of BART on such sources. EPA promulgated rules pursuant to Congress's directive to provide guidelines to the states on appropriate techniques and methods for implementing the SIP requirements. (40 CFR 51.302(c)). (Note: when this report refers to a "source" within the meaning of this regulation, the phrase "or a small group of sources" is implied.)

The requirement to install Best Available Retrofit Technology controls on existing sources is a key element of the visibility protection provisions in the CAA demonstrating the need to focus on pollution emitted from a specific set of existing sources. Sources are potentially subject to BART controls if they meet the following criteria:

1. A major stationary source from 1 of 26 source categories identified in the CAA and regulations (see Appendix A);
2. Potential to Emit (PTE) 250 tons per year of any air pollutant; and,
3. Not in operation prior to August 7, 1962 and "in existence" on August 7, 1977.

In the 1980 visibility rule, EPA used the term "existing stationary facility" to define a facility that met the above criteria. However, to avoid any confusion about whether that term encompassed a larger group of sources, EPA now uses the term "BART-eligible source." The term "BART-eligible source" is used throughout this report for similar reasons, but the reader should be aware that some sections of the visibility rule still refer to "existing stationary facilities." For purposes of the attribution discussion in this paper, these terms are interchangeable.

In 1999, EPA added two new sections to the visibility rule to address regional haze (40 CFR 51.308 and 51.309). Pollutants causing regional haze may be transported hundreds of miles, and therefore, regional haze must be addressed as a broader regional issue. The 1980 visibility rule focused on direct visibility impacts of an individual source or small group of sources. The 1999 revisions are commonly referred to as the regional haze rule, although the 1999 rule incorporates the earlier requirements for BART as well as the new regional haze provisions.

To remedy RAVI, the regulations outline a process to identify and control emissions from sources that are directly impacting visibility at specific Class I areas (40 CFR 51.302). Three primary steps in this process are:

1. The Federal land manager certifies impairment;
2. The state identifies existing sources that cause or contribute to the visibility impairment; and

3. The state performs a BART analysis to determine what controls, if any, are required on any existing source that meets the BART criteria and has been identified as contributing to the impairment.

Attribution Process

The language of 40 CFR 51.302(c)(4)(i) provides the basic principle upon which the state will rely during the attribution process. That section states that the attribution must indicate each [BART-eligible source] "*which may reasonably be anticipated to cause or contribute to impairment of visibility*." Whether or not the impairment is "reasonably attributable" is determined by "visual observation or other technique the state deems appropriate." (40 CFR 51.301(s)). Because the state is responsible for identifying sources, this report provides recommendations for the state to consider when it undertakes an attribution determination.

Once visibility impairment is identified, RAVI is addressed on a case-by-case basis. Under the 1980 regulation, a state evaluates BART-eligible sources only after an FLM certifies the existence of visibility impairment. However, in the context of the current regional haze rule, states must also address BART requirements for regional haze (RH BART).[3] Several options exist for addressing RH BART. For example, rather than require a source-specific BART emission limit, a state may choose to develop a trading program, either regionally or within its own jurisdiction, that achieves greater reasonable progress than case-by-case RH BART.

If a state develops a trading program, the time period to achieve the emissions reductions may be extended. As a result, visibility conditions at a specific Class I area initially may remain static or even deteriorate during the early implementation period. During this time, FLMs have indicated that the RAVI process may be utilized to provide steady and continuing improvement in visibility. Within the context of the regional haze rule, this may be an example of a "geographic enhancement." As noted above, the recommendations in this report apply only to case-by-case applications of BART and are not intended to apply to the broader regional haze rule such as a market-based trading program implemented as part of the 1999 rule.

A state may find it difficult to determine a source/receptor link for RAVI difficult when there are other sources located in the area, including international sources. However, the regional haze rule provisions do not alter the requirement to undertake the attribution assessment.

State determines what controls, if any, are required

After the attribution determination, the state is required to perform a BART analysis to determine what types of controls, if any, should be placed on the source(s) found to be contributing to the impairment. The following factors affect the BART determination:

1. Available technology;
2. Costs of compliance;
3. Energy and non air quality environmental impacts of compliance;

[3] The RH BART provision was remanded to EPA by the U.S. Court of Appeals as a result of the ruling in *American Corn Growers Association v. EPA*, No. 9901348 (DC Cir. May 24, 2002)

4. Remaining useful life of the source; and,
5. Degree of improvement that can be anticipated to result from the use of the controls.

As noted above, this report does not provide guidance regarding state process following an attribution determination nor does it examine options for implementing the BART requirement.

II. FEDERAL LAND MANAGER CERTIFICATION OF IMPAIRMENT

The Federal land managers monitor visibility through a nationwide monitoring network, known as Interagency Monitoring of PROtected Visual Environments (IMPROVE). The IMPROVE network has recently been expanded and the FLMs anticipate reliable trend data for the new IMPROVE sites between the years 2006 and 2008. The FLMs plan to evaluate the current visibility conditions in Class I areas as well as trends occurring over time to identify areas where visibility is not improving.

The FLMs generally will use a screening process to identify Class I areas that may be affected by RAVI. This screening process will be influenced by the approach the state relies upon to address RH BART in its SIP. There are three approaches that may be used.

1. Case-by-Case Review of RH BART under 51.308

No distinction exists between emission reductions needed to address RH BART and reductions to address RAVI, therefore, the BART process will address both types of visibility impairment.

2. Trading Program under 51.308

The FLMs anticipate that the following screening criteria may be appropriate, but will not make a final decision until a 308 trading program has been developed. The screening criteria associated with this approach may be similar to the screening criteria associated with the trading program option under 51.309. However, the FLMs have indicated that the screening criteria ultimately selected for 51.308 will depend on how the trading program is structured, the selected emissions cap, and other aspects of the trading program.

Potential Screening Process Criteria:

(i) Sulfate, nitrate, organic carbon, other fine particulate, etc., levels in the Class I area are not decreasing.[4]
(ii) One or more BART-eligible sources of SO_2, NO_x, VOC, PM_{10}, etc., are located within 100 miles of the mandatory federal Class I area.
(iii) The BART-eligible sources identified in (ii) are not already well-controlled for pollutants that contribute to visibility impairment.

3. Milestones and Backstop Trading Program under 51.309

The FLMs plan to sign a Memorandum of Understanding (MOU) with the participating states to define the screening criteria the FLMs will use to certify impairment.

[4] The decrease of a pollutant (or secondary species of that pollutant) would be measured from the beginning of the market or emissions trading program, and such a trading program would take a long time (10 to 15 years) to reach the level of reduction that "meets" BART. The decrease would be tested over the first 5 to 10 years. A very quick time frame for reductions would negate the need for RA BART criteria.

Screening Process criteria:[5]

(i) Sulfate levels in the Class I area are not decreasing.
(ii) One or more BART-eligible sources of SO_2 are located within 100 miles of the mandatory federal Class I area.
(iii) The BART-eligible sources identified in (ii) are not already well-controlled for SO_2 (85% or better SO_2 control for coal-fired utility boilers).

Goal: For FLMs to complete the certification process between 2006 and 2008.[6]

These criteria were influenced by the design of the 309 trading program including emission reduction estimates, shape of the declining emission cap, inclusion of sources that were not BART-eligible, and inclusion of new source growth under the cap.

Although geographic enhancements do not need to be addressed under the first approach, they must be addressed in the two trading programs described above because emission reductions may occur more gradually in the context of a trading program. The FLMs do not anticipate certifying impairment under these circumstances but do intend to notify the state as part of the SIP development process if concerns arise regarding "hot spot" impacts from sources that may directly affect specific Class I areas.

Note: BART for regional haze has been addressed for SO_2 under this option. Regional haze BART for NO_x and PM will be addressed in SIP revisions that are due in 2008.

In all three cases discussed above, if the FLM determines that a certification of visibility impairment is necessary, the FLM will send an official Certification to the state. The Certification will generally include the following information:

1. Class I area(s) impacted;
2. Basis of certification (photographic documentation, monitoring, modeling, etc.);
3. Type of impairment certified: plume impact, or layered or uniform haze;
4. Pollutant(s) of interest; and,
5. Preliminary identification of source(s) believed responsible for impact.

FLM, State, and EPA roles in RA BART

FLMs are responsible for certifying impairment. The Certification demonstrates the FLM's determination that there is evidence of visibility impairment from one source or a small group of sources.

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[5] Within the context of established regional milestones for SO_2 and a backstop trading program, the FLMs have said it is appropriate to use the following screening process in making these recommendations as part of the Certification. Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Trading Program. An Annex to the Report of the Grand Canyon Visibility Transport Commission. Submitted by the Western Regional Air Partnership to the U.S. Environmental Protection Agency, p. 61, September 29, 2000.

[6] This goal will not in any way restrict the ability of the FLMs to certify impairment at a later date if it is necessary to fulfill their statutory obligations. *ibid*.

Following the Certification, states have the following regulatory obligations: (1) identify facilities that "emit an air pollutant which may be reasonably anticipated to cause or contribute to any visibility impairment" in that Class I area, and (2) for sources subject to BART, the state must identify the BART level of control technology. If the source does not have adequate control in place, the state must establish a BART limit in the SIP.

EPA has two major responsibilities for the RA BART requirement. First, in the states that do not have a SIP in place to address the RA BART requirements, but where the program is implemented through a FIP, EPA will conduct the BART analysis and establish any BART emission limits. Second, for the states with SIPs that include RA BART regulations, EPA will provide federal enforcement of state-established BART emission limits.

III. THE ATTRIBUTION DETERMINATION PROCESS

This section recommends a process for the state to follow in order to complete an attribution determination after receipt of a Certification from an FLM under 40 CFR 51.302(c)(1).

The Certification focuses on the existence of visibility impairment. While the FLM may identify sources or even sources areas that contribute to the Certification, the formal identification of sources is a state responsibility.

The state should make a detailed review of the data supporting the Certification to determine which sources or source areas require further evaluation. If the data are insufficient to identify specific sources or source areas, the state may request that the FLM perform more detailed analyses to further substantiate the impairment set forth in the Certification.

If the state determines sufficient information exists to proceed, the state should begin the process by: (1) evaluating which sources are BART-eligible, and (2) reviewing the impairment information provided by the FLM in support of the Certification.

1. Evaluate which sources are BART-eligible

Congress and EPA established criteria to determine which sources are subject to BART. The categories of sources subject to BART are listed in 40 CFR 51.301, the definition of "existing stationary facility," and also are included in Appendix A of this report.

The state must confirm that the potential source or group of sources is subject to the RA BART process by examining the potential source emissions and the dates of operation.

The criteria for determining if a source is BART-eligible may be complicated if a source has multiple units that were constructed at different times and a state may be unable to determine if a specific source would qualify as BART-eligible. EPA published guidelines in 1980 to aid states in implementing the 1980 rule.[7] In addition to the 1980 guidelines for determining BART-eligibility, EPA also has proposed guidelines that include criteria for determining if a source is BART-eligible.[8] These guidelines are expected to be re-proposed in 2004, promulgated in 2005 and codified at 40 CFR Part 51 as Appendix Y. The state should refer to both sets of guidelines to determine if a source is BART-eligible, although the proposed guidelines are not binding until final promulgation occurs.

When using the applicability criteria in Appendix Y, the state should look for information readily available from existing state data such as permitting history, emission inventory, or other similar databases.

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[7] U.S. Environmental Protection Agency, *Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power plans and Other Existing Stationary Facilities,* EPA-450/3-80-009(b), Office of Air Quality Planning and Standards, Research Triangle Park, N.D., November 1980 (1980 BART Guidelines).

[8] 66 FR 38108 *Proposed Guidelines for Best Available Retrofit Technology (BART)* (July 20, 2001). EPA will re-propose these guidelines as a result of the remand in *American Corn Growers v. EPA*.

1. If a database of Potential To Emit (PTE) is not available, state emission inventories can be a useful screening tool to determine whether a source meets the size criteria (for example, identify all sources with emissions greater than 100 tons/year of visibility impairing pollutants). Operating permit applications may also contain information about the PTE of a source, or individual units within a source.
2. State business records may be useful to determine when the facility was constructed or when it commenced operation. Newspaper article searches or a detailed historical review of each source may also provide useful information.
3. The state should require the source to provide information regarding the construction dates of individual emission units.
4. Institutional memory within the air agency can be invaluable if records of construction dates of major emission units are not available, although memories will not withstand legal challenges like hard documentary data.
5. New Source Review permitting records may be useful to identify new units that were constructed after 1977, determine the PTE of the source, or determine if reconstruction has occurred. (Note: the draft guidelines in Appendix Y state that modifications at a source do not affect applicability unless the change qualifies as reconstruction of the source).

If the source or group of sources identified in the Certification is not BART-eligible, the state should inform the FLM of its finding. The state should look in the vicinity of all the sources suspected of causing or contributing to the impairment identified in the Certification. If no BART-eligible sources exist, an attribution assessment is unnecessary.

2. Review Support Information in the FLM Certification

Initially, the state should acquire all the supporting information the FLM used in the Certification and independently evaluate the data. This initial review will help the state determine if the information is sufficient to support a reasonable attribution determination.

The state should consider the type of impairment in the Certification: (a) plume impact visibility impairment, (b) uniform haze visibility impairment, or (c) layered haze visibility impairment:

(a) Plume impact is the impairment addressed by the original visibility protection program under which the state must make a reasonable attribution determination before proceeding to the BART analysis (40 CFR 51.301-51.307).
(b) In some instances, uniform haze may be thought to be source-specific haze from a BART-eligible source. If a state can successfully demonstrate there is a source emitting any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility, the state should consider that portion of the uniform haze to be impact from the identified source(s) and, therefore, consider the source to be subject to BART.
(c) The visibility impairment may also be defined as layered haze, a condition that results when aerosols are “trapped” under stagnant air mass conditions.

Once the FLM has issued a Certification, the responsibility for the attribution assessment shifts to the state. If a state does attribute impairment to a source, the state must be able to defend its finding that one or more BART-eligible sources did cause or contribute to visibility impairment in the Class I area. However, the Ninth Circuit Court of Appeals established a low threshold for unacceptable visibility impairment.[9]

3. Evaluate Existing Data not included in the Certification

When analyzing supporting data, the state should determine if additional information exists that was not available to the FLM. Examples include special project camera studies or ambient monitoring data collected by the state or local air pollution control agency, the potential or actual PSD permit applicant,[10] or the university. In certain situations, another agency may have previously collected information that could be used in an attribution determination.[11] These data should be reviewed to determine whether they support the FLM Certification.

To conclude this portion of the attribution process, the state may wish to prepare a report that summarizes its initial evaluation of the Certification. The purpose of the report is to carefully document the state's findings and conclusions about its decisions. The report would address two questions:

First, the report would assess whether any BART-eligible source(s) exist that potentially contributed to visibility impairment as described in the Certification. The report would contain a preliminary determination of whether the sources are BART-eligible and, if possible, analyze each source's relative contribution to the impairment (based on available source/receptor information).

Second, the report would assess the impairment data. This assessment would include the state's evaluation of the supporting data in the Certification and an analysis of any additional data used in the attribution assessment. The data gaps found in this review would be identified along with any recommendations for strategies to obtain the missing information. The state may use these recommendations to determine the next steps in the attribution process.

If the state believes the Certification is supported by sufficient data, proceeds with an attribution assessment and makes a determination that the data does or does not indicate a source subject to BART, the attribution process is complete. However, if the state determines the data is insufficient to complete an attribution assessment, the evaluation process ends, and the state may proceed to the next step—identification of data gaps and the studies necessary to obtain this information.

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[9] See *Central Ariz. Water Conservation Dist v. EPA*, 990 F.2d 1531 (9th Cir. 1993); See also discussion in *RA BART and RA BART-like Case Studies*.

[10] For example, a PSD permit applicant may be required to obtain pre-application ambient air quality information, and that information may not have been available to or known to the FLM.

[11] In Washington state, the plume of a defunct copper smelter has been traced by its arsenic deposition. If this were an active facility, this ground tracing of the plume could be used to support a source/receptor connection in an attribution determination.

4. Identify data gaps and necessary studies to fill the gaps

As part of the data review, the state should note gaps or inconsistencies in the available data. Examples of data gaps and inconsistencies may include:

1. Missing photos in a sequence of photos,
2. Poor resolution of the plume or its source in the photos,
3. Back trajectory analyses done with a very large grid resolution or poor techniques,
4. IMPROVE monitor data missing at critical periods,
5. Lack of association between the source's emissions and monitored data at the receptor,
6. Special studies performed during a time when a source that potentially contributed to the impairment was not operating,
7. Contemporaneous studies with contradictory results that cannot be explained,
8. Ambient studies that use naturally occurring tracers and, when the suspected source(s) are tested, the tracers do not exist or exist at levels far below (or above) the level indicated by the ambient study results,
9. Tracer studies where the tracer was not found at the anticipated receptors,
10. No explicit exploration of whether wildfire or other natural events significantly caused or contributed to one or more of the impairment episodes,
11. Other differences or inconsistencies in the available data.

Once any data gaps have been identified, the state should decide which studies are necessary to obtain the missing information sufficient to complete an attribution assessment. The state should design potential studies and determine the resource needs of those studies. The amount of work necessary will depend on the availability of the information and how critical the information is to the attribution assessment. Section IV provides technical criteria and examples of the technical process the state may consider at this point in the process.

5. Consultation Process

The WESTAR review of previous RAVI assessments demonstrated the importance of including all stakeholders in the design of any data collection plans or modeling protocols. Competing studies can be very inefficient, expensive, and time-consuming, and ultimately may not help the state make a final decision.

If stakeholders are involved in the design of any data collection efforts or modeling protocols, disagreements may be resolved before the state or source continues with any additional studies. The state should consider involving the following stakeholders in the consultation process:

1. Affected sources
2. Neighboring states and tribes
3. Environmental Protection Agency
4. Federal land managers
5. Local environmental groups
6. Local permitting agencies

7. Local government representatives

6. Completion and Review of Additional Visibility Studies

When the additional visibility studies, if any, are complete, the state should evaluate the resulting data. The technical staff may wish to finalize the report and make recommendations based on the scientific aspects of the data.

7. Final Determination of Reasonably Attributable Visibility Impairment

The state may reach any one of the following conclusions:

1. The impairment certified by the FLM is reasonably attributable to the identified BART-eligible source(s) for specific pollutants;
2. The impairment certified by the FLM is reasonably attributable to the source(s) identified by the FLM and additional sources not identified by the FLM for specific pollutants;
3. There is inadequate data to support a determination that the impairment is due to the source(s) identified by the FLM;
4. The impairment is reasonably attributable to other adjacent BART-eligible sources for specific pollutants; or
5. The impairment certified by the FLM is not reasonably attributable to a BART-eligible source.

IV. GENERAL PRINCIPLES AND CRITERIA

This section provides general principles and technical criteria for the state to consider after receipt of an FLM Certification. After receipt of such a Certification, the state must determine whether BART-eligible sources "emit any air pollutant which may reasonably be anticipated to cause or contribute to any visibility impairment in any" Class I area. While these principles and technical criteria should generally be useful and applicable, each state must decide what is required to support its individual determination.

Part A contains general principles to guide the development of a conceptual framework for the attribution assessment process. Part B contains evaluation criteria to guide the decisions regarding a technical framework for the attribution assessment process.

Conceptually, the statutory framework for an attribution determination ("may reasonably be anticipated to cause or contribute to visibility impairment") should be the general principle guiding the attribution process. EPA maintains, and the Ninth Circuit agreed, that an affirmative attribution decision is possible even with considerable uncertainty and a low triggering threshold. However, each state should decide individually what is required to support its determination.

A. General Principles of the Attribution Process

Attribution process criteria address factors likely to influence the performance of the state attribution assessment. These criteria provide parameters to define and implement the attribution assessment process given resource constraints, legal considerations, administrative decisionmaking requirements, and other relevant factors. The general principles include the following:

1. Whenever possible, an attribution assessment should be a collaborative process that relies on existing data with a minimum of additional analysis (*see* section III). If supplemental data are needed, field studies should be designed in a collaborative process between affected states and tribes, identified sources, Federal land managers, EPA, and the general public. Past experience has shown that competing technical studies often result in an unnecessarily expensive and unduly complicated process.

2. Attribution assessments should be technically and legally defensible.

3. Attribution assessments should be accomplished at a reasonable cost and within a reasonable time frame.

4. Attribution assessments should be no more complex than necessary, recognizing that the circumstances surrounding a Certification may vary greatly. State or tribal agency staff should be capable of performing the attribution assessment and making the final determination, although contractors may be used for certain types of modeling or monitoring.

5. Reasonably attributable visibility impairment can only be identified if a source/receptor

links a potentially BART-eligible source or small group of sources to a Class I area.

B. Technical Criteria

The technical criteria address the appropriateness of available analytical techniques from a scientific perspective. The rule defines visibility impairment to mean "any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions."

The technical criteria include the following:

1. The BART source must emit an air pollutant that may reasonably be anticipated to cause or contribute to any of the impairment. The visibility-impairing pollutants of concern must be identified.

2. The attribution assessment should address the unique visibility impairment in the FLM Certification for the Class I area. Some factors to consider include:

    a. Duration: source's length of effect on visibility per episode;[12]

    b. Frequency: how often episodes of impairment occur;

    c. Geographic extent: how much of the Class I area is affected by the impairment;

    d. Magnitude: how much visibility impairment is due to the source's emissions; and

    e. Time of occurrence: including time of day and time of year.

    These factors need to be considered together, because they affect each other. An infrequent occurrence of a large magnitude episode may meet the criteria. A frequent occurrence of a small magnitude episode may also meet the criteria. The FLM may provide information about these criteria in the Certification, and the state should review this information as a starting point for its assessment. The state may consider other factors and data, as appropriate.

3. The attribution assessment should identify the distance from the source to the Class I area. This distance will affect the choice of tools appropriate for characterizing the specific source's impact on visibility impairment.

4. To the extent possible, the attribution assessment should be quantitative. Under certain circumstances, qualitative information, such as photographs or time-lapse video of distinct plumes or source-specific haze events, may be adequate.

5. The state should use as many approaches or indicators of impairment as practicable

[12] Based on previous cases, most impairment episodes are relatively short—lasting one to several hours—which may affect monitoring and other assessment techniques.

rather than relying on a single method. The assessment may rely on air monitoring and modeling techniques and other supporting scientific data. Consistency between source and observational techniques strengthens the analysis.[13]

6. The state should consider the level of uncertainty in the assessment.

7. EPA guideline models should be used whenever practicable. When other models are used, additional technical discussions with EPA may be necessary.

C. Examples of the Attribution Process

The state should consult this section after evaluation of the FLM Certification. At this point, the state will already have decided what gaps need to be filled to complete the attribution assessment.

The recommendations in this report recognize that each attribution determination will be unique. Because an attribution determination is a fact-specific and individual determination, it is not possible to recommended a single technical approach for a state to follow. A combination of monitoring and modeling techniques is usually appropriate, but instead of attempting to cover all possible combinations of techniques, this report provides five selected scenarios. The general principles and technical criteria identified in sections A and B are incorporated into these scenarios. The goal is to provide the state with references for use when it is creating its own individualized technical procedure.

In addition to the scenarios, this report provides detailed tables and narrative descriptions of techniques that may be considered and/or substituted for the techniques in the scenarios (see Section V).

<u>Scenario 1</u>: Limited data/one source

Data input: Small amount of existing data (i.e., one IMPROVE site with data for 2-3 years)
Evidence of "local" impact.
Limited meteorological data.

Where it is likely that one major source contributes to impairment, a combination of the following techniques is suggested:

1. Examine IMPROVE data, including quality assurance
2. Look at extinction budget to identify visibility-impairing pollutants
3. Perform some analysis of when the episodes are occurring
4. Perform a simple back trajectory analysis using a method such as HYSPLIT
5. Look at relationships between particulate species
6. Examine source emissions data for correlations with ambient monitoring
7. Perform dispersion model based on data and capabilities such as VISCREEN or CALPUFF Lite

[13] WESTAR Council, *RA BART and RA BART-like Case Studies*, June 2001.

8. Examine other data such as source owner data, deposition data, or photographic evidence

The results of this initial analysis may not always be conclusive. This level of review may be adequate if a source/receptor relationship can be identified. However, if the results are inconclusive, more data and/or more refined analyses may be necessary and may help the state reach an attribution determination. The state should consider how the available data and choice of techniques might affect its ability to assess the effectiveness of the controls in remedying the impairment.

It may be efficient to look ahead to the data and analytical needs of a potential BART analysis. For example, the state may wish to use a more refined model that would be useful for both attribution and remedy assessment.

Assuming there is a two-year time period[14] to collect data and analyze additional information, the following techniques also can be considered:

1. Better source characterization, including measurement of emissions of trace elements (source profiles) for use in CMB modeling
2. Met monitoring or modeling
3. Camera site, possibly with time-lapse video
4. Additional aerosol monitoring, episodic or saturation
5. In plume trajectory by aircraft, if available
6. Fine time-resolved optical monitoring, such as nephelometer, transmissometer, aethelometer combined with pollutant monitoring (e.g., SO_2, NOx, real time PM) for monitoring of episodes
7. More refined chemical visibility model, such as CALPUFF
8. Repeat initial techniques with new data

The technical criteria are listed below, followed by techniques that may be used to obtain results about the criteria.

1. The impairment must be related to emissions from specific sources. The visibility-impairing pollutants of concern should be identified.

   Techniques: Back trajectory, species relationships, relationship between source emissions and ambient monitoring, dispersion model refined by camera, aerosol, in plume, optical monitoring, and refined dispersion models.

2. The attribution assessment must address the unique visibility impairment certified by

[14] The 1999 regional haze rule revised the requirements for general plan requirements for visibility protection. As a result, plan revisions are required once every five years, rather than the Long Term Strategy review requirement of every three years. If an FLM certifies RAVI at least 6 months prior to a plan revision, section 51.302 requires that the State Plan revision address such Certifications. Given this 5-year cycle, we have presumed for this report that an attribution analysis should take about two years to complete in order to allow time for the BART engineering analysis, if needed.

the FLM for the Class I area. Some factors to consider include:

a. Duration: source's length of effect per episode
   Techniques: Monitoring, dispersion model, back trajectory, camera

b. Frequency: how often the impairment occurs
   Techniques: Monitoring, dispersion model, back trajectory, camera

c. Geographic extent: how much of the Class I area is impaired
   Techniques: Monitoring, dispersion model, additional data on deposition and other studies

d. Magnitude: how much impairment is due to the source
   Techniques: Dispersion model, receptor model

e. Time of occurrence
   Techniques: Monitoring, dispersion model, back trajectory, camera

3. Uncertainty of results: Each analytical method will have its own level of uncertainty. These individual uncertainties should be kept in mind as outputs are compared within the overall assessment. If the results of different techniques are the same or similar (within the uncertainties of the techniques), then the overall level of uncertainty is likely to decrease.

Scenario 2: Moderate data/multiple sources

Data input: Moderate amount of existing data (i.e., one IMPROVE site with data for six or more years)
Evidence of an increasing trend in sulfate
Meteorological data likely from several stations

Assuming the Certification identifies multiple BART sources of different types within a 100-mile radius, a combination of the following techniques is suggested:

1. Examine IMPROVE data, including quality assurance
2. Look at extinction budget to identify visibility-impairing pollutants
3. Perform some analysis of when the episodes are occurring
4. Perform multiple back trajectory analyses using a method such as HYSPLIT
5. Look at relationships between particulate species
6. Examine source emissions data for correlations with ambient monitoring
7. Perform dispersion model based on data and capabilities such as CALMET/CALPUFF
8. Examine other data such as source owner data, deposition data, or photographic evidence
9. Wind fields/Synoptic analyses
10. Comparison of different episodes
11. UNMIX, PMF and/or CMB

12. Analysis of any regional modeling already conducted, such as CMAQ
13. Long term visual monitoring, such as camera data or transmissometer data, compared to met data to identify quadrants of concern

The results of this initial analysis may not be conclusive. This level of review may be adequate if a source/receptor relationship can be identified.

However, if the results are inconclusive, more data and/or more refined analyses may be necessary and may help the state reach an attribution determination. The state should consider how the available data might affect the ability to assess the effectiveness of the controls in remedying the impairment. It may be efficient to look ahead to the data and analytical needs of a potential BART analysis. For example, the state may wish to use a more refined model that would be useful for both attribution and remedy assessment.

Assuming there is a two-year time period to collect data and analyze additional information, the following techniques also can be considered:

1. Emissions inventory
2. Analysis of a nested domain within the regional model
3. Source profiles (natural tracers)
4. Additional source measurements, such as stack testing
5. Met monitoring or modeling
6. Camera
7. Additional aerosol monitoring, episodic or saturation
8. Monitoring to measure additional parameters, such as precursors, ammonia and oxidants
9. In plume trajectory by aircraft, if available, to characterize plume chemistry
10. Fine time-resolved optical monitoring, such as nephelometer, transmissometer, aethelometer combined with pollutant monitoring (e.g., SO_2, NOx, real time PM) for monitoring episodes.
11. Repeat initial techniques with new data

The technical criteria are listed below, followed by techniques that may be used to obtain results about the criteria.

1. The impairment must be related to emissions from specific sources. The visibility-impairing pollutants of concern should be identified.

   Techniques: Back trajectory, species relationships, relationship between source emissions and ambient monitoring, dispersion model refined by camera, aerosol, in plume, optical monitoring, and refined dispersion models.

2. The attribution assessment must address the unique visibility impairment certified by the FLM for the Class I area. Some factors to consider include:

   a. Duration: each source's length of effect per episode

Techniques: Monitoring, dispersion model, back trajectory, camera

b. Frequency: how often the impairment occurs by source
Techniques: Monitoring, dispersion model, back trajectory, receptor model, camera

c. Geographic extent: how much of the Class I area is impaired
Techniques: Monitoring, dispersion model, additional data on deposition and other studies

d. Magnitude: how much impairment is due to each individual source
Techniques: Dispersion model, receptor model

e. Time of occurrence
Techniques: Monitoring, dispersion model, back trajectory, camera

Scenario 3: No IMPROVE data, Certification by modeling evidence

Data input: Detailed modeling of a source and specific visibility impairment using a CALPUFF run, or detailed (nested) run of regional model.
Detailed emissions data and meteorological data were input to the model.
No IMPROVE data available for this specific Class I area (monitoring may be at a "representative site")
Some optical data, photographic data, and limited aerosol data from other networks

Assuming the Certification points to a specific source, a combination of the following techniques is suggested:

1. Examine IMPROVE data for any nearby Class I areas (especially those included in the modeling domain) to better understand the regional conditions and compare with model outputs of the unique effect
2. Review the model's outputs on "high impact" days and compare with actual meteorological data of the area (to confirm transport, inversions, or other aspects of the model which may create the unique impact)
3. Review source emissions data used in the model
4. Review other monitoring data (optical measurements, deposition data, ozone data, etc.) to collaborate model predictions
5. Examine any photographic evidence

The results of this initial analysis may not always be conclusive. This level of review may be adequate if a source/receptor relationship can be identified. Because no visibility-specific particle monitoring is available in this case, the key to attribution is to determine that the source emissions are indeed reaching the Class I area on days when impairment exists. If the results are inconclusive, more data and/or more refined analyses may be necessary and may help the state reach an attribution determination. The state should consider if the available data and modeling information supplied with this Certification could be used to determine the effectiveness of the

controls in remedying the impairment. It may be efficient to look ahead to the data and analytical needs of a potential BART analysis if additional or different modeling will be necessary.

Additional data collection and analyses that might be considered:

1. Better source profiles or newer emissions information
2. Met monitoring or modeling
3. Camera
4. New aerosol monitoring (episodic or saturation)
5. In plume trajectory by aircraft, if available
6. Repeat initial analytical techniques with new data

The technical criteria are listed below, followed by techniques that may be used to obtain results about the criteria.

1. The impairment must be related to emissions from specific sources. The visibility-impairing pollutants of concern should be identified.

   Techniques: Confirm model inputs, compare with any new particle monitoring at Class I area. Examine performance of the model, and perform uncertainty analyses.

2. The attribution assessment must address the unique visibility impairment certified by the FLM for the Class I area. Some factors to consider include:

   a. Duration: source's length of effect per episode
      Techniques: Monitoring, dispersion model, back trajectory, camera

   b. Frequency: how often the impairment occurs
      Techniques: Monitoring, dispersion model, back trajectory, camera

   c. Geographic extent: how much of the Class I area is impaired
      Techniques: New monitoring and examination of dispersion model outputs, additional data on deposition and other studies

   d. Magnitude: how much impairment is due to the source
      Techniques: Dispersion model

   e. Time of occurrence
      Techniques: Monitoring, dispersion model, back trajectory, camera

Scenario 4: Direct Photographic Evidence

Data input: The FLM certified impairment in a wilderness area based on photographic evidence. Photographs taken over a period of two years showed a distinct haze in a valley located in the wilderness area when the wind is from the east. A series of photographs during two episodes showed a distinct plume that

originates at an existing stationary source constructed in 1965 and located ten miles east of the wilderness area. The photographic series showed that the plume traveled into the wilderness area.
Aerial photos during one episode also show a distinct plume that travels into the wilderness area. The wilderness area does not have an IMPROVE site. A Class I area located 50 miles to the north has an IMPROVE site that was representative for the area. This monitoring site does not show decreased visibility on the days when haze was photographed in the wilderness valley.

Assuming the Certification identifies one BART source, the following steps are suggested:

1. Review the photographic evidence and determine whether the photographs show a clear connection between the source and the haze documented in the wilderness area.

   In this example, the photographic evidence showed a clear connection between the source and the haze in the wilderness area. Qualitative information, such as photographic evidence that establishes a source/receptor link, is allowed under EPA regulations that define reasonable attribution as determined by "visual observation or other technique the State deems appropriate." (40 CFR 51.301(s)).

The results of this initial analysis may not always be conclusive. If the photographic evidence is not compelling, the state may reach a different conclusion. The state may determine that the impairment, as documented by the FLM, was not reasonably attributable to the source identified in the Certification. The FLM would then need to gather additional information to support a Certification. Alternatively, if the state determines that the source may be causing the haze but the qualitative evidence is not quite sufficient to determine attribution, the state could initiate a data collection effort to provide better information regarding visibility impairment at the Class I area. Such techniques may include:

1. Better source characterization, including measurement of emissions of trace elements (source profiles) for use in CMB modeling
2. Met monitoring or modeling
3. Additional aerosol monitoring (episodic or saturation)
4. In plume trajectory by aircraft, if available
5. Fine time-resolved optical monitoring, such as nephelometer, transmissometer, or aethelometer combined with pollutant monitoring (e.g., SO_2, NOx, real time PM) for monitoring of episodes.
6. More refined chemical visibility model, such as CALPUFF

The technical criteria are listed below, followed by techniques that may be used to obtain results about the criteria.

1. The impairment must be related to emissions from specific sources. The visibility-impairing pollutants of concern should be identified.
   Techniques: Back trajectory, species relationships, relationship between source emissions and ambient monitoring, dispersion model refined by camera, aerosol, in

plume, optical monitoring, and refined dispersion models.

2. The attribution assessment must address the unique visibility impairment certified by the FLM for the Class I area. Some factors to consider include:

   a. Duration: source's length of effect per episode
      Techniques: Monitoring, dispersion model, back trajectory, camera

   b. Frequency: how often the impairment occurs
      Techniques: Monitoring, dispersion model, back trajectory, camera

   c. Geographic extent: how much of the Class I area is impaired
      Techniques: Monitoring, dispersion model, additional data on deposition and other studies

   d. Magnitude: how much impairment is due to the source
      Techniques: Dispersion model, receptor model

   e. Time of occurrence
      Techniques: Monitoring, dispersion model, back trajectory, camera

3. Uncertainty of results: Each analytical method will have its own level of uncertainty. These individual uncertainties should be kept in mind as outputs are compared within the overall assessment. If the results of different techniques are the same or similar (within the uncertainties of the techniques), then the overall level of uncertainty is likely to decrease.

The final step in the attribution process scenario would be to verify that the source was operating on the days when the haze was observed in the area. The state should also determine if the source was experiencing unusual upset conditions during the times identified. In this example, the source was determined to have been operating normally. The state would then issue a determination that the visibility impairment at the Class I area was reasonably attributable to the existing stationary facility.

Scenario 5: Data Rich

Data input: A large special visibility study recently was conducted.
Four months of data spanning two seasons was collected including:

1. At one "receptor" site in a Class I area there were multiple meteorological, optical, and particulate samplers including extensive measurements of particle compositions, size distributions, scattering, absorption, light extinction, ions, oxidants, relative humidity, temperature, vertical wind profiles, SO_2, photographs, and concentrations of four unique tracers released from four different sources of interest. There were co-located samplers measuring several parameters in more than one way. There are at least some one, six, and twelve-hour particle measurements in addition to twenty-four hour samples.

2. This receptor site has been an IMPROVE site for several years and these data are also available.
3. At thirty-five other sites in the region, called "satellite" sites there was an IMPROVE Module-A sampler taking daily twenty-four hour samples which were analyzed for fine mass, S, soil elements, trace metals, and elemental H from which organics can be estimated. The unique tracers were also measured at many of these sites.
4. Aircraft sampling of plumes from source(s) of interest was conducted.
5. An extensive current emissions inventory was created.
6. Wind profilers were deployed at two to three sites in addition to the receptor site.
7. Measurements of the chemical composition of resuspended local dust, smoke from burning local fuels, and emissions from local point and area sources of interest were collected in order to create "source profiles" to be used in receptor modeling.

Assuming the certification identifies a BART source within 100 miles of the Class I area from which a unique tracer was released, a combination of the following techniques is suggested:

1. Examine fine particle data, including quality assurance. Use the collocated data to assess accuracy and precision. The one, six, and twelve-hour data should average up to match the twenty-four hour data and if reasonable, be used to examine the diurnal cycles in the fine particle concentrations.
2. Look at the extinction budget to identify visibility-impairing pollutants. Because size distributions were measured, the extinction budget can be estimated from Mie scattering calculations as well as by using simple techniques that assume bulk scattering and absorption efficiencies. Check to see if measured scattering plus absorption add up to the measured and reconstructed extinction.
3. Compare the special study data to historical IMPROVE and archived meteorological data to determine the representativeness of the study period.
4. Perform some analysis of when the episodes are occurring. EOF analysis can be helpful to summarize the massive data set. Use the photographs to create a time-lapse visualization of the scene at the receptor site.
5. Perform back trajectory analyses using HYSPLIT, CAPITA Monte Carlo or ATAD. Examine whether the trajectories change substantially when the study's wind-profiler data are included. Determine whether trajectories are consistent with tracer concentrations.
6. Look at relationships between particulate species (factor analysis) to see if they identify source types.
7. Look at the spatial and temporal patterns of trace elements and the major constituents of the fine mass. This may suggest dominant source areas and transport patterns for different source types. Use EOF analysis to determine the patterns that explain most of the covariance in the data. Check to see how well these are reconciled with the back trajectory modeling and the deterministic modeling. Check to see if the same dominant sources were indicated.
8. Examine source emissions data for correlations with ambient monitoring.
9. Perform dispersion model such as CALMET/CALPUFF.

10. Analyze wind fields, synoptic conditions, and satellite photos. Check to see if they were consistent with more sophisticated meteorological modeling. Look for unusual conditions such as wild fires, hurricanes, stagnation episodes, etc. Look to see if modeled and observed cloud patterns were comparable.
11. Compare the meteorological and chemical characteristics of different episodes
12. UNMIX, PMF and CMB can help determine major source types and when they were important.

If, at this point, similar source/receptor relationships have been identified using several different techniques, this level of review is adequate. If the results are inconclusive, and there are differing points of view about the frequency, duration, or significance of the attribution to the BART-eligible source, more analyses may be necessary. Often in a large study, measurements are made, but not immediately analyzed in the lab due to cost. If this is the case, more samples could be analyzed. It is unlikely that any additional field monitoring would be required.

The technical criteria are listed below, followed by techniques that may be used to obtain results about the criteria.

1. The impairment must be related to emissions from specific sources. The visibility-impairing pollutants of concern should be identified.

   Techniques: Reconstructed particle mass and light extinction including examination of the reconstructions in different size ranges and at different sites in the region, analysis of responses of light scattering to relative humidity, back trajectory analyses, examination of inter-species relationships compared to measured source profiles, dispersion modeling with sophisticated models such as REMSAD and CMAQ, analysis of wind fields and dispersion by comparison to measured tracer concentrations, computer animation of spatial patterns of species of interest, use of receptor models such as TMBR, DMB, and TAGIT that utilize unique tracer information, or other receptor models such as CMB, UNMIX, and PMF that do not require tracer information, but can use it. When so many different models can be used, model reconciliation is usually a part of a data-rich scenario.

2. The attribution assessment must address the unique visibility impairment certified by the FLM for the Class I area. Some factors to consider include:

   a. Duration: each source's length of effect per episode
      Techniques: Monitoring, dispersion model, back trajectory, camera

   b. Frequency: how often the impairment occurs by source
      Techniques: Monitoring, dispersion model, back trajectory, receptor model, camera

   c. Geographic extent: how much of the Class I area is impaired
      Techniques: Monitoring, dispersion model, analysis of spatial patterns using data from the satellite sites.

d. Magnitude: how much impairment is due to each individual source
   Techniques: Dispersion model, receptor model

e. Time of occurrence
   Techniques: Monitoring, dispersion model, back trajectory, camera

3. Uncertainty of results: In this case, the ability of a model to predict the observed tracer concentrations is an indicator of the model's uncertainty.

V. TECHNIQUES

A. Monitoring

Introduction

This section describes a variety of ambient air monitoring methods that, if appropriate, might be used to support an attribution analysis. The methods described include those most commonly used in pollution studies or ambient monitoring programs and should not be considered an exhaustive list of potential methods. Methods include, IMPROVE, filter based aerosol, continuous aerosol (includes optical methods such as the nephelometer), continuous gas and canister sampling, transmissometer, scene (includes film, video, digital), and tracer or aircraft methods.

Several of the methods described are currently in use as a part of national, state, local, tribal, or private ambient monitoring networks. These sites are generally located in urban areas, but those near the area of study could be used in the attribution analysis thereby reducing the cost of monitoring.

The IMPROVE network is designed to assess visibility in Class I areas and routinely measure visibility impairing pollutants. These sites offer value to the attribution analysis if they are located in the area of study.

The RA BART case studies show additional examples of the methods used during source attribution studies. The case studies also show that methods, other than ambient monitoring, may be used to support the analysis. Existing programs such as CASTNET (dry deposition network), surface water deposition studies, or snow deposition studies may provide additional data for the attribution analysis.

Although not specifically listed as a monitoring technique, meteorological monitoring is an important element the attribution analysis. Collection of meteorological data can range from simple wind, temperature, and relative humidity measurement to an array of acoustic wind profilers. The complexity of the meteorological monitoring program depends on data needs and the availability of existing data. As with ambient monitoring, meteorological data may be available at sites located near the study area and offers reduced monitoring cost.

1. IMPROVE

<u>Overview</u>: The Interagency Monitoring of PROtected Visual Environments (IMPROVE) program is a cooperative measurement effort governed by a steering committee composed of representatives from Federal and regional-state organizations. The IMPROVE monitoring program was established in 1985 to aid the creation of Federal and State implementation plans for the protection of visibility in Class I areas (156 national parks and wilderness areas) as stipulated in the 1977 amendments to the Clean Air Act. The objectives of IMPROVE are to: (1) establish current visibility and aerosol conditions in mandatory class I areas; (2) identify chemical species and emission sources responsible for existing man-made visibility impairment;

(3) document long-term trends for assessing progress towards the national visibility goal; and (4) with the enactment of the regional haze rule, provide regional haze monitoring representing all visibility-protected federal class I areas where practical.

Magnitude: Possible when used in conjunction with appropriate analytical techniques.

Frequency: Possible when used in conjunction with appropriate analytical techniques; Limited by twenty-four hour sample integration, and one-in-three day sampling frequency.

Duration: Possible when used in conjunction with appropriate analytical techniques; Limited by 24 hour sample integration, and one-in-three day sampling frequency.

Principle: Twenty-four hour integrated filter-based ambient monitor; Gravimetric analysis for $PM_{2.5}$ (Module D) and PM_{10}); S from Particle Induced X-ray Emission (PIXE); NO_3 from ion chromatography (denuded nylon filter from Module C); Organic and elemental carbon from Thermal Optical Reflectance (TOR); H from Proton Elastic Scattering (PESA).

Uncertainty: All elemental S if from sulfate; All sulfate is ammonium sulfate; NO_3 (Denuder efficiency is close to 100%. All nitrate is from ammonium nitrate);
Average organic molecule is 70% carbon; Carbon (organic and elemental) is defined by the analytical method; Fine soil based on elemental composition; Course mass ($PM_{10} – PM_{2.5}$) consists only of insoluble soil particles.

Strengths: Regulatory indicator for regional haze rule; Long term data record in or near many federal Class I areas; Extensive network currently in place.

Limitations: Integrated twenty-four hour sample; one-in-three day sampling interval; Nitrate losses due to volatilization from filter; Not capable of distinguishing between primary particulate and atmospherically transformed particulate.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance; Chemical analysis must be conducted by appropriate laboratory.

Regulatory Context: Regional Haze rule; Included in SIP Visibility Plan

2. FILTER-BASED AEROSOL

Overview: Filter-based aerosol monitoring is used to identify chemical species and obtain concentration measurements of atmospheric constituents that contribute to visibility impairment. Primary techniques include filter-based aerosol samplers that collect samples on various substrates in various size ranges such as $PM_{2.5}$ or PM_{10}. Aerosol monitoring can provide fine mass concentration, course mass concentration, optical absorption, major and trace elements, organic and elemental carbon, and sulfate, nitrate, and chloride ions. A variety of methods are available to conduct filter based aerosol monitoring. Many methods are approved as an EPA reference method, while some are not, but may offer variability that the reference method does not.

Magnitude: Possible when used in conjunction with appropriate analytical techniques.

Frequency: Possible when used in conjunction with appropriate analytical techniques; Limited by 24-hour sample integration and sampling frequency (daily sampling is possible depending on instrument selected).

Duration: Possible when used in conjunction with appropriate analytical techniques; Limited by 24-hour sample integration and sampling frequency (daily sampling is possible depending on instrument selected).

Principle: The methods used for analyses of these filter media include gravimetry (electro-microbalance) for mass; X-ray fluorescence (XRF) and particle induced X-ray emission (PIXE) for trace elements; Ion chromatography (IC) for anions and selected cations; Controlled-combustion for carbon; Gas chromatography/mass spectroscopy (GC/MS) for semi-volatile organic particles; Special measurement needs may include determining particle size and morphology through optical and/or electron microscopy.

Strengths: Large network of urban monitoring available; Filter based sampling allows for a variety of chemical/elemental analysis.

Limitations: Integrated twenty-four hour sample; Generally operated on one-in-three or one-in-six day sampling interval (daily sampling is possible depending on instrument selected); Not capable of distinguishing between primary particulate and atmospherically transformed particulate.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance; Chemical analysis must be conducted by appropriate laboratory.

Regulatory Context: Commonly used in NAAQS/SIP compliance monitoring networks.

3. CONTINUOUS AEROSOL

Overview: Aerosols can be measured continuously using several different methods. Optical measurement of aerosols can be measured using an instrument such as a nephelometer to measure light scattering (bscat) or a aethelometer to measure light absorption (babs) by aerosols (black carbon). Continuous instruments such as TEOM or BETA can provide PM_{10} or $PM_{2.5}$ aerosol concentration.

Magnitude: Possible when used in conjunction with appropriate analytical techniques.

Frequency: Possible when used in conjunction with appropriate analytical techniques; Limited by twenty-four hour sample integration and sampling frequency (daily sampling is possible depending on instrument selected).

Duration: Possible when used in conjunction with appropriate analytical techniques; Limited by twenty-four hour sample integration and sampling frequency (daily sampling is possible depending on instrument selected).

Strengths: Continuous measurement with at least hourly time resolution; Nephelometers and Aethelometers are commonly used to support Class I area monitoring programs and an existing data record may be available in some areas.

Limitations: Continuous aerosol measurement with methods such as TEOM and BETA are generally made in urban areas to support NAAQS compliance networks; Not capable of distinguishing between primary particulate and atmospherically transformed particulate.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance.

Regulatory Context: Commonly used in Class I area monitoring networks or urban NAAQS compliance networks.

4. CONTINUOUS GASEOUS

Overview: A variety of gaseous pollutants, such as Ozone (O_3), Carbon Monoxide (CO), Nitrogen Dioxide (NOx), nitric oxide (NO), ammonia (NH_3), hydrogen peroxide (H_2O_2), sulfur dioxide (SO_2), Organics, and HAPS/TOXICS, can be measured continuously. Gaseous monitoring is generally conducted with instruments that continuously draw sample air and periodically (as frequently as once per second) analyze the sample. Canister systems collect an ambient air sample over a specific period of time in clean evacuated canisters. The canisters are then subject to subsequent analysis at a laboratory using a method such as GC/FID. This method is able to provide time-integrated samples from several hours to twenty-four hours or more. Regular checks of the flow rate, stability, reproducibility, precision, and accuracy of these instruments must be conducted on a regular schedule in order to ensure data quality.

Magnitude: Possible when used in conjunction with appropriate analytical techniques.

Frequency: Possible when used in conjunction with appropriate analytical techniques.

Duration: Possible when used in conjunction with appropriate analytical techniques.

Strengths: Continuous measurement with hourly time resolution; Monitors available to identify variety of pollutants.

Weaknesses/Limitations: Generally require conditioned environment and frequent performance checks.

Practical Considerations: Data may be available from established urban area monitoring networks and some Class I area monitoring networks; Additional cost ($/year) for new sites.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance.

Regulatory Context: Commonly used in urban NAAQS compliance and HAPS/TOXICS networks.

5. TRANSMISSOMETER

Overview: Transmissometers measure the amount of light transmitted through the atmosphere over a known distance (generally between 0.5 km and 10.0 km) between a light source of known intensity and a receiver. The transmission measurements are electronically converted to hourly averaged light extinction (b_{ext}).

Magnitude: Possible when used in conjunction with appropriate analytical techniques.

Frequency: Possible when used in conjunction with appropriate analytical techniques.

Duration: Possible when used in conjunction with appropriate analytical techniques.

Uncertainties: A transmissometer must be installed in stable locations with a clear and unobstructed path to avoid interference with the signal.

Strengths: Continuous measurement of b_{ext} in many Class I areas and some urban areas.

Limitations: Not capable of identifying pollutants contributing to visibility impairment.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance; Data processing/quality assurance requires high level of expertise.

Regulatory Context: Commonly used in Class I area monitoring networks and in some urban areas.

6. SCENE

Overview: Scene monitoring refers to the use of still and/or time-lapse photography (including digital imagery) to provide a qualitative representation of visual air quality. Scene monitoring data quality objective recommendations are to document the appearance of scenes of interest under a variety of air quality and illumination conditions at different times of day and different seasons. Scene monitoring documents the visual condition observed at a monitoring site. The data collection schedule can be tailored to capture the periods when visibility impairment is most likely to occur at specific sites. Time-lapse movies (generally time-lapse video or super 8 mm film) can be used at monitoring sites and during special studies to document the visual dynamics of a scene or source.

Magnitude: Cannot provide a quantitative measurement of visibility impairment but can qualitatively illustrate various levels of visibility impairment.

Frequency: Possible depending on the method used. Time-lapse video may be able to demonstrate the frequency of the impairment. The use of still photography to document impairment frequency depends upon the number of images acquired over time.

Duration: Possible depending on the method used. Time-lapse video may be able to demonstrate the impairment frequency. The use of still photography to document impairment frequency depends upon the number of images acquired over time.

Uncertainties: n/a

Strengths: Provides image/video record

Limitations: Not capable of identifying pollutants contributing to visibility impairment.

Level of Expertise Required: Standard operating procedures available for routine operation and maintenance.

Regulatory Context: Commonly used in Class I area monitoring networks and in some urban areas.

7. TRACER METHODS, LIDAR SYSTEMS, AIRCRAFT BASED MEASUREMENTS

Overview: The methods described in this section are more specialized methods generally reserved for special studies as opposed to the previously described methods that are used more routinely. Tracer methods, lidar systems and aircraft based measurements will be described individually.

Tracer Methods:
A tracer element or compound is a substance with unique characteristics that allows positive identification at very low concentrations. The tracer compound of choice will vary by source type and composition of the plume being tracked. In general, the tracer must have very low natural background concentrations and ideally would have the same chemical form and properties as the compound being tracked. In ambient applications where use of the ideal tracer is not possible due to potential environmental risk, a near-substitute compound may be used. When used to determine potential source impacts, the chosen compound is released from a source stack and downwind monitors are used to detect the presence of the compound.

Lidar Methods:
A lidar transmits short pulses of laser light into the atmosphere. The laser beam loses light to scattering as it travels. At each range, some of the light is backscattered into a detector. Because the light takes longer to return from the more distant ranges, the time delay of the return pulses can be converted to the corresponding distance between the atmospheric scatterer and the lidar. The end result is a profile of atmospheric scattering versus distance. Analysis of this signal can yield information about the distribution of aerosols in the atmosphere. The amount of backscatter indicates the density of the scatters. This can be used to measure cloud base height or track

plumes of pollution. Other properties of the atmosphere can also be deduced from the lidar return signals. A frequency shift in the light because of the Doppler effect permits measurement of wind speeds. By detecting the amount of depolarization, one can discriminate between liquid droplets and nonspherical ice particles. Differential Absorption Lidar (DIAL) uses absorption, as evidenced by reduced backscatter from greater distances, to measure the concentration of atmospheric gases. A Raman lidar detects particular atmospheric components (such as water vapor) by measuring the wavelength-shifted return from selected molecules (NOAA).

Aircraft Based Measurements:
Aircraft based measurement systems utilize specially equipped aircraft to make pollutant and meteorological measurements at various elevations throughout the study domain. The aircraft can be equipped with a multitude of gaseous, aerosol, optical and meteorological equipment. This measurement method provides the advantage of vertical profiles of various parameters, the ability to track point source plumes, and the ability to establish boundary conditions for future analytical and modeling exercises.

References:

NOAA, Atmospheric Light Division, Environmental Technology Laboratory, http://www2.etl.noaa.gov/DIAL_lidar.html

U.S. Environmental Protection Agency, Visibility Monitoring Guidance (EPA-454/R-99-003), June 1999.

National Research Council, Protecting Visibility in National Parks and Wilderness Areas, National Academy Press, Washington D.C., 1993, pp. 315-357.

Table 1. Monitoring Techniques

Criteria	**Monitoring Method**						
	IMPROVE	Filter Based Aerosol	Continuous Aerosol	Gaseous; Continuous methods, canister sampling, etc.	Transmissometer	Scene 35mmfilm/8mm video, digital	Tracer Methods, Lidar systems, Aircraft based measurements
Pollutant							
PM_{10}	Yes	Yes	Yes	No	No	No	All Possible
$PM_{2.5}$	Yes	Yes	Yes	Yes	No	No	
NOx	(Site specific)	No	No	Yes	No	No	
SO_2	(Site specific)	No	No	Yes	No	No	
Sulfate	Yes	Yes	No	No	No	No	
Nitrate	Yes	Yes	No	No	No	No	
Carbon	Yes	Yes	No	No	No	No	
Organics	Yes	Yes	No	Yes	No	No	
Other	Reconstructed extinction		Nephelometer - Bscat Aethelometer - Babs	HAPS, TOXICS	Total Extinction	Visual Parameters	
Visibility/Concentration Changes							
Magnitude	Yes	Yes	All Possible	All Possible	All Possible	No	All Possible
Frequency	Yes	Yes	All Possible	All Possible	All Possible	Yes	All Possible
Duration	Yes	Yes				Yes	
Time of Day	No	No				Yes	
Likely Part of FLM Certification?	Possible						No

Monitoring Techniques (continued)

Principal							
Qualitative/ Quantitative	Quantitative					Qualitative	Qualitative/Quantitative
Strengths	Reconstructed extinction calculation, historical record	various chemical analysis, large network nationwide	Continuous measurement, nephelometer commonly located in or near Class I areas	Continuous measurement, variety of possible pollutants	Continuous measurement, provides light extinction value, historical record	Relatively inexpensive, uncomplicated operational requirements	Lidar and airplane based systems can provided temporal and spatial results, tracer methods can provide source-receptor data
Weaknesses/ Limitations	Fixed location in or near Class I areas, also located in several urban areas	Integrated 24 hour sample generally collected on one-in-three schedule, commonly in urban areas	TEOM, BETA, etc, commonly located in urban areas	Generally require conditioned environment for proper operation, commonly located in urban areas	Fixed location in or near Class I areas	Number of still images limited, video requires storage and routine review	Complex and relatively expensive to operate, requires specialized training and knowledge to operate and analyze results
Distinguish BART Sources?	Possible with other analysis	Possible with other analysis	No	Possible with other analysis	No	Possible with other analysis	Possible with other analysis
Practical Considerations							
Cost	Moderate; varies depending on the number of instruments					Low	High

B. Source Modeling

Introduction

Given the complex natural environment, the state must choose the configuration of modeling techniques that will provide the most information on the contributing source or sources of impairment within the limited resources of current technology, data, budgets, time and staff availability.

1. Physical Models

Physical models are those that simulate the meteorology and air quality over an area. Modeling relies on a numerical or analytical model to estimate particulate concentrations in space and time. Because of its nature and sources, particulate matter is difficult to model over all spatial scales. Many air quality models that are currently available were designed to be applied over the regional scale with grid sizes from four to forty kilometers. Modeling requires detailed meteorological fields and emissions inventory over the entire domain. The compilation of data required to run these models can require much effort and expertise. Efforts are underway by government agencies in the U.S. to generate and archive both emissions and estimated activity levels of many source types in geographical information systems.

Numerical source-oriented models are designed to simulate atmospheric diffusion or dispersion and estimate concentrations at defined receptors. Numerical source models can be grouped as kinematic, first-order closure, or second-order closure models (Bowne and Lundergan, 1983). Kinematic models are the simplest both mathematically and conceptually. These models simplify the non-linear equations of turbulent motion, thereby permitting a closed analytical approximation to describe pollutant concentration (Green *et al.*, 1980). First-order closure models are based on the assumption of an isotropic pollutant concentration field. Consequently, turbulent eddy fluxes are estimated as being proportional to the local spatial gradient of the transport quantities. The Eulerian grid models, Lagrangian particle models, and trajectory puff/plume models are included in this category. Second-order closure models involve a series of algorithm transformations of the equations of state, mass continuity, momentum, and energy by using the Boussinesque approximation and Reynold's decomposition theory (Holton, 1992; Stull, 1988).

2. Spatial Scales

The model's applicable spatial scales play a large role meeting the analysis' objectives and its ability to accurately assess spatial variability. PM_{10} and $PM_{2.5}$ concentrations modeled or measured at any receptor result from the complex interaction of meteorology, chemical transformations and emissions from nearby and distant sources. For example, a monitor located near an operating construction site will be impacted more by the daily construction activity than the surrounding area. That site may be classified as representing an area of a few tens of meters to no more than one kilometer depending on the size of the construction area and fugitive dust control measures.

The dimensions given below are nominal rather than exact and are presented as defined in 40 CFR part 58.

a. Micro-Scale (10 to 100 m): This scale does not apply to scenarios relevant to the attribution problem. Modeling at the microscale is usually done by simple Gaussian plume models such as ISCST3. Measurements in urban areas can show considerable variations at this scale while those in pristine areas would not. Variations often occur when monitors are located close to a low-level emissions source, such as a busy roadway, construction site, within a community that uses wood stoves, or a short industrial stack. Fortunately, compliance monitoring site exposure criteria avoids microscale influences even for source-oriented monitoring sites.

b. Middle Scale (100 to 500 m): Middle-scale monitors show significant differences between locations that are ~0.1 to 0.5 km apart. These differences may occur near large industrial areas with many different operations or near large construction sites. Monitors with middle-scale zones of representation are often source-oriented, used to determine the contributions from emitting activities with multiple, individual sources to nearby community exposure monitors.

c. Neighborhood Scale (500 m to 4 km): Neighborhood-scale monitors do not show significant differences in particulate concentrations with spacing of a few kilometers. This dimension is often the size of emissions and modeling grids used in large urban areas for PM source assessment, so this zone of representation of a monitor is the only one that should be used to evaluate such models. Sources affecting neighborhood-scale sites typically consist of small individual emitters, such as clean, paved, curbed roads, uncongested traffic flow without a significant fraction of heavy-duty vehicles, or neighborhood use of residential heating devices such as fireplaces and wood stoves.

d. Urban Scale (4 to 100 km): Urban-scale monitors show consistency among measurements with monitor separations of tens of kilometers. These monitors represent a mixture of particles from many sources within the urban complex, including those from the smaller scales. PM measurements at urban-scale locations are not dominated by any particular neighborhood, however. Urban-scale sites are often located at higher elevations and away from highly traveled roads, industries, and residential heating.

e. Regional-Scale Background (100 to 1,000 km): Regional-scale background monitors show consistency among measurements for monitor separations of a few hundred kilometers. Background concentrations are often more consistent for specific chemical compounds, such as sulfate or nitrate, than they are for PM mass concentrations. Regional-scale PM is a combination of naturally-occurring aerosol from windblown dust and marine aerosol as well as particles generated in urban and industrial areas that may be more than 1,000 km distant. Regional-scale sites are best located in rural areas away from local sources, and at higher elevations. National parks, national wilderness areas, and many state and county parks and reserves are appropriate areas for regional-scale sites. Many of the IMPROVE sites characterize PM regional scale background in different regions of the United States.

f. Continental-Scale Background (1,000 to 10,000 km): Continental-scale background monitors show little variation even when they are separated by more than 1,000 km. They are hundreds of kilometers from the nearest significant emitters. Though these sites measure a mixture of natural and diluted manmade source contributions, the manmade component is at its minimum expected concentration. The Jarbidge Wilderness IMPROVE site in northern Nevada is a good example of a continental-scale background site for particulate matter in North America.

e. Global-Scale Background (>10,000 km): Global-scale background monitors are intended to quantify concentrations transported between different continents as well as naturally-emitted particles and precursors from sea spray, volcanoes, and windblown dust. Yellow sand from China has been detected at the Mauna Loa, HI, laboratory (Darzi and Winchester, 1982; Braaten and Cahill, 1986), as well as on the North American continent. Red dust from Africa's Sahara desert has been detected at Mt. Yunque, Puerto Rico and over the southeastern United States. Other global-scale sites include McMurdo, Palmer, and Ahmundson-Scott stations in Antarctica (Lowenthal *et al.*, 1996), Pt. Barrow, Alaska, and Mace Head, Ireland.

3. Chemical Composition

This section illustrates how the chemical composition of aerosols is an important consideration in the choice of particulate matter models. The knowledge of how the aerosol's composition varies over an area will play a key role in the attribution study design.

The relative abundance of chemical components in the atmosphere closely reflect the characteristics of emission sources. Major chemical components of $PM_{2.5}$ and PM_{10} mass in urban and rural areas consist of nitrate, sulfate, ammonium, carbon, geological material, sodium chloride, and liquid water.

Chemical compositions can vary spatially in all scales of the atmosphere and depend on sources surrounding the monitoring site. For example, on the continental scale, the eastern U.S. fine particulate chemical compositions are different than those of the western states. In the eastern portion of the U.S., nonurban $PM_{2.5}$ is dominated by secondary sulfate, organics and elemental carbon (EPA, 1996). The data to support this conclusion are based on the IMPROVE and CASTNET networks. These networks provide a background fine-fraction aerosol database because the monitoring sites are primarily located in national parks and wilderness areas. Analysis of this network shows that the western U.S. nonurban $PM_{2.5}$ aerosol is predominantly carbon in nature. Nitrate also contributes significantly to the fine particle mass budget particularly in central and coastal California. Within these generalizations, obvious departures will be found especially near sources such as near the ocean and urban areas where the aerosol will be primarily influenced by sea salt and combustion particles, respectively.

The typical $PM_{2.5}$ chemical compositions vary by season (Chow et al., 1993a; 1996a, Watson et al., 1997), and consist of the following major components:

a. Organic Carbon: Organic carbon is composed of gases and particles containing combinations of carbon and hydrogen atoms. Organic compounds found in ambient air may also be associated with other elements and compounds, particularly oxygen, nitrogen, sulfur, halogens, and metals. Particulate organic carbon consists of hundreds, possibly thousands, of separate compounds (Rogge et al., 1993a). The mass concentration of organic carbon can be accurately measured, as can carbonate carbon (Chow et al., 1993b), but only about ten percent of the specific organic compounds that it contains have been measured. Vehicle exhaust (Rogge et al., 1993b), residential and agricultural burning (Rogge et al., 1998), meat cooking (Rogge et al., 1991), fuel combustion (Rogge et al., 1997), road dust (Rogge et al., 1993c), and particle formation from heavy hydrocarbon gases (Pandis et al., 1992), are the major sources of organic carbon in $PM_{2.5}$.

b. Elemental Carbon: Elemental carbon is black, often called "soot." Elemental carbon contains pure, graphitic carbon, but it also contains high molecular weight, dark-colored, nonvolatile organic materials such as tar, biological material (e.g., coffee), and coke. Elemental carbon usually accompanies organic carbon in combustion emissions, with diesel exhaust (Watson et al., 1994a, 1998) being the largest contributor.

c. Sulfate: Ammonium sulfate ((NH_4SO_4), ammonium bisulfate (NH_4HSO_4), and sulfuric acid (H_2SO_4), are the most common sulfate compounds in $PM_{2.5}$. These compounds are water-soluble and reside almost exclusively in the $PM_{2.5}$ size fraction. Sodium sulfate (Na_2SO_4) has been found in coastal areas where sulfuric acid has been neutralized by sodium chloride (NaCl) in sea salt. Although gypsum (Ca_2SO_4) and some other geological compounds contain sulfate, these are not easily dissolved in water for chemical analysis and are more abundant in the coarse fraction than in $PM_{2.5}$; they are usually classified in the geological fraction.

d. Nitrate: Ammonium nitrate (NH_4NO_3) is the most abundant nitrate compound, a large fraction of $PM_{2.5}$ occurs during winter, and a moderate fraction occurs during fall. Sodium nitrate ($NaNO_3$) is found in the $PM_{2.5}$ and coarse fractions near the oceans and salt playas. Small quantities of sodium nitrate have been found in summertime particulate matter inland owing to transport from the ocean (Chow et al., 1996b).

e. Ammonium: Ammonium sulfate (NH_4SO_4) and ammonium nitrate (NH_4NO_3) are the most common compounds containing ammonium from reactions between sulfuric acid, nitric acid, and ammonia gases. While most of the sulfur dioxide and oxides of nitrogen originate from fuel combustion in stationary and mobile sources, most of the ammonia derives from living things, especially animal husbandry practiced in dairies and feedlots.

f. Geological Material: Suspended dust consists mainly of oxides of aluminum, silicon, calcium, titanium, iron, and other metal oxides. In areas surrounded by substantial terrain (i.e., mountains), eons of runoff produce mineral compositions in soils that can be fairly homogeneous, with the exception of places where dry lake beds exist that have accumulated salt deposits. Industrial processes such as steel making, smelting, and mining have distinct geological compositions. For instance, cement production and distribution facilities may use alcareous, siliceous, argillaceous, and ferriferous minerals that may not be natural to the region, with limestone ($CaCO_3$) being the most abundant (Greer et al., 1992). Suspended geological material resides mostly in the coarse particle fraction (Houck et al, 1989,1990), and typically constitutes ~50% of PM_{10} while only contributing 5 to 15% of $PM_{2.5}$ (Watson et al., 1994b).

g. Sodium Chloride: Salt is found in suspended particles near oceans, open playas, and after de-icing materials are applied. Bulk sea water contains 57±7% chloride, 32±4% sodium, 8±1% sulfate, 1.1±0.1% soluble potassium, and 1.2±0.2% calcium (Pytkowicz and Kester, 1971). As noted above, sodium chloride is often neutralized by nitric or sulfuric acid in urban air where it is encountered as sodium nitrate or sodium sulfate.

h. Liquid Water: Soluble nitrates, sulfates, ammonium, sodium, other inorganic ions, and some organic material (Saxena and Hildemann, 1997) absorb water vapor from the atmosphere, especially when relative humidity exceeds 70% (Tang and Munkelwitz, 1993). Sulfuric acid absorbs some water or deliquesces at all humidities. Particles containing these compounds grow

into the droplet mode as they take on liquid water. Some of this water is retained when particles are sampled and weighed for mass concentration. The precise amount of water quantified in a $PM_{2.5}$ depends on its ionic composition and the equilibration relative humidity applied prior to laboratory weighing.

Ambient mass concentrations contain both primary and secondary particles. Primary particles are directly emitted by sources and usually undergo few changes between source and receptor. Atmospheric concentrations of primary particles are, on average, proportional to the quantities that are emitted.

Secondary particles are those that form in the atmosphere from gases that are directly emitted by sources. Sulfur dioxide, ammonia, and oxides of nitrogen are the precursors for sulfuric acid, ammonium bisulfate, ammonium sulfate, and ammonium nitrate particles. "Heavy" volatile organic compounds or HVOC (those containing more than eight carbon atoms) may also change into particles. The majority of these transformations result from intense photochemical reactions that also create high ozone levels. Secondary particles usually form over several hours or days and attain aerodynamic diameters in the accumulation mode between 0.1 and 1 μm. Several of these particles, notably those containing ammonium nitrate, are volatile and transfer mass between the gas and particle phase to maintain a chemical equilibrium. This volatility has implications for ambient concentration measurements as well as for gas and particle concentrations in the atmosphere.

Ambient concentrations of secondary aerosols are not necessarily proportional to quantities of emissions since the rate at which they form may be limited by factors other than the concentration of the precursor gases. Secondary particulate ammonium nitrate concentrations depend on gaseous ammonia and nitric acid concentrations as well as temperature and relative humidity. A nearby source of ammonia may cause a localized increase in $PM_{2.5}$ concentrations by shifting the equilibrium from the gas to the particulate ammonium nitrate phase (Watson et al., 1994c). Ammonium sulfate may form rapidly from sulfur dioxide and ammonia gases in the presence of clouds and fogs, or slowly in dry air. Because fine particle deposition velocities are slower than those of the gaseous precursors, $PM_{2.5}$ may travel much farther than the precursors, and secondary particles precursors are often found far from their emissions sources and may extend over scales exceeding 1,000 km.

4. Particle Formation

Ammonium nitrate and ammonium sulfate aerosols are the most prevalent secondary particles found at urban and non-urban sites throughout the U.S. during the winter. These particles can form when gas molecules are attracted to and adhere to existing particles.

Sulfur dioxide gas changes to particulate sulfate through gas- and aqueous-phase transformation pathways. In the gas-phase pathway, ultraviolet sunlight induces photochemical reactions creating oxidizing species that react with a wide variety of atmospheric constituents. The gas-phase transformation rate appears to be controlled more by the presence or absence of the hydroxyl radical and its competing reactions of other gases than by the sulfur dioxide concentrations.

In the presence of fogs or clouds, sulfur dioxide dissolves in droplets where it experiences aqueous reactions that are much faster than gas-phase reactions. When ozone and hydrogen peroxide are dissolved in the droplet, the sulfur dioxide is quickly oxidized to sulfuric acid. When ammonia is dissolved in the droplet, the sulfuric acid is neutralized to ammonium sulfate. If the fog or cloud evaporates and relative humidity decreases below 100 percent, the sulfate particle exists as a small droplet that includes a portion of liquid water. As the relative humidity further decreases below 70 percent, the droplet evaporates and a small, solid sulfate particle remains. The reactions within the fog droplet are very fast, and the rate is controlled by the solubility of the precursor gases. Aqueous transformation rates of sulfur dioxide to sulfate are 10 to 100 times as fast as gas-phase rates. These chemical reactions are critical to understanding PM concentrations in areas and downwind of areas that emits large amounts of SO_2. The location and SO_2 emissions output of large point sources such as coal and oil fired power plants need to be mapped and compared with transport patterns in order to determine the impact of ammonium sulfate particles on ambient surface concentrations.

Fogs serve as an environment for creating particles and as vehicles for particle removal. During heavy fogs, particles and precursor gases are scavenged as fog droplets grow to sizes that settle rapidly to the surface. The extent and intensity of these fogs is so poorly characterized, however, that it is not yet possible to determine where and when particle formation overtakes particle deposition, thereby adding to the $PM_{2.5}$ concentration loading.

Nitrogen oxide converts to nitrogen dioxide, primarily by reaction with ozone. Nitrogen dioxide can: 1) change back to nitrogen oxide in the presence of ultraviolet radiation; 2) change to short-lived species which take place in other chemical reactions; 3) form organic nitrates; or 4) oxidize to form nitric acid. The major pathway to nitric acid is a reaction with hydroxyl radicals that transforms nitrogen dioxide to nitric acid. Nitric acid deposits from the atmosphere fairly rapidly but, in the presence of ammonia, it is neutralized to particulate ammonium nitrate. This is an important process in secondary particle production because many agricultural areas surrounding populated urban areas contain large ammonia sources. Chow and Egami (1997) show that San Joaquin Valley ammonia concentrations are large during winter. Conversion rates for nitrogen dioxide to nitric acid, ranging from less than one percent per hour to ninety percent per hour. These rates are typically five to ten times the conversion rates for sulfate formation. Though they vary throughout a twenty-four hour period, these rates are significant during both daytime and nighttime hours, in contrast to the gas-phase sulfate chemistry that is most active during daylight hours. The important nitric acid-ammonia reaction has implications to network design by the need to locate and map possible sources of ammonia. Significant sources of ammonia are associated with animal husbandry and fertilizer applications. Locating and estimating ammonia emissions will be a difficult task because it is not traditionally tabulated in emission inventories and requires further research to refine the methodology to measure the emissions.

While ammonium sulfate is a fairly stable compound, ammonium nitrate is not. Its equilibrium with gaseous ammonia and nitric acid is strongly influenced by temperature and relative humidity. Atmospheric particle nitrate can occur in atmospheric aerosol particles as solid ammonium nitrate or as ionized ammonium nitrate in aerosol particles containing water. In both

the solid and ionized forms, ammonium nitrate is in equilibrium with gas-phase nitric acid and ammonia.

For fixed relative humidity, increasing temperature decreases the particle nitrate fraction. This is a consequence of the direct relation between the equilibrium constants and temperature. As temperature increases, the equilibrium constants increase, which means higher gas-phase pressures can be supported, thereby reducing the particle nitrate fraction. For fixed humidity, decreasing temperature increases the particle nitrate fraction. As temperatures approach 0°C, the curves approach limiting values. Particle fractions of one are used for ion ratios greater than or equal to one, and particle fractions are determined by the amount of available ammonia for ion ratios less than one. For the higher temperatures, increasing relative humidity increases the particle nitrate fraction. This is a consequence of liquid water present for the 60% and 80% relative humidity cases. When there is sufficient ammonia present with 30% relative humidity, more than 90% of the nitrate is in the particle phase for temperatures less than 20°C. More than half of the particle nitrate is gone at temperatures above 30°C, and all of it disappears at temperatures above 40°C.

Atmospheric water is another important component of suspended particulate matter. The sharp rise in liquid water content at relative humidities between 55% and 75% is known as deliquescence. A precise humidity at which soluble particles take on liquid water depends on the chemical mixture and temperature. Particles containing these compounds grow into the droplet mode as they take on liquid water, so the same concentration of sulfate or nitrate makes a much larger contribution to light extinction when humidities are high (>70 percent) than when they are low (<30 percent). Excess liquid water is also measured as part of the $PM_{2.5}$ mass when sampled by light scattering continuous monitors or when filters have not been equilibrated at relative humidities less than 30% prior to weighing.

Some of the organic carbon in suspended particles is also of secondary origin. Secondary organic compounds in particulate matter include aliphatic acids, alcohols, aromatic acids, nitro-aromatics, carbonyls, esters, phenols, and aliphatic nitrates (Grosjean and Seinfeld, 1989; Grosjean, 1992, Pandis et al., 1992, 1993; Seinfeld and Pandis, 1998). Normally, primary organic carbon particles are more prevalent than secondary organics with exceptions such as those found in Los Angeles where conditions of clear skies and high photochemical smog are frequent. Although secondary organic aerosol was thought to be minimal during winter in central California, recent analyses (Strader et al., 1998) demonstrate that it could be as much as 20% of twenty-four hour organic carbon in some samples. This occurs because low wintertime temperatures lower the saturation vapor pressure for semi-volatile organic compounds. This is probably minor during winter and fall when photochemical reactions are not dominant.

The exact precursors of secondary organics are not well understood, but they are believed to consist of heavy hydrocarbons with more than seven carbon atoms. Odum (1997) identifies aromatics as the major group of commonly measured reactive organic gases that affect both ozone and secondary aerosol formation.

5. Source Modeling Techniques

Before selecting a modeling technique, it is wise to establish a conceptual model. A conceptual model describes the relevant physical and chemical processes that affect emissions, transport, and transformation specific to the region of interest. It is the starting point for any source apportionment process. Conceptual models take advantage of the large body of scientific knowledge already acquired. They identify the sources that are likely to be present and eliminate those that are not. They examine meteorological conditions that affect concentrations and focus further modeling on the conditions conducive to the high concentrations.

Modeling techniques relevant to attribution are split into several categories depending complexity, physical attributes, purpose and cost to execute. The following tables on pages 55 to 62 provide a matrix of detailed information on specific models grouped in these categories.

a. Puff Modeling Techniques

These models are based on a Lagrangian framework where air parcels are tracked spatially and temporally. They can include chemical mechanisms as well as deposition effects. The most commonly used puff model is the CALMET/CALPUFF (Scire et al., 2000).

b. Grid Modeling Techniques

For estimating $PM_{2.5}$ levels, Eulerian models that include aerosol modules simulating the physical and chemical processes governing particulate concentrations in the atmosphere are more suitable than Lagrangian models such as plume trajectory models. Eulerian three-dimensional models may use either a simplified treatment of atmospheric chemistry (usually used to address long-term particulate concentrations at urban sites) or include a more detailed atmospheric chemistry treatment (usually used to simulate only a few days of episodes due to their compositional cost).

Commonly used long-term Eulerian models with simplified atmospheric processes include (Seigneur et al., 1997):

- Urban Airshed Model Version V (UAM-V).
- Urban Airshed Model with version V with Linear Chemistry (UAM-LC)
- Regulatory Modeling System for Aerosol and Deposition (REMSAD).

Short-term Eulerian models with complex atmospheric processes include:

- Urban Airshed Model Version V with Aerosols (UAM-AERO),
- Urban Airshed Model with Aerosol Inorganic Module (UAM-AIM).
- SARMAP Air Quality Model with Aerosols (SAQM-AERO).
- Community Multi-scale Air Quality Model (CMAQ)

- Comprehensive Air Quality Model with extensions (CAMx)

All of the above mentioned Eulerian models have been developed by various scientists from universities, federal and state agencies, and the private sector. These particulate air quality models provide a three-dimensional treatment to simulate the fate and transport of atmospheric contaminants. All of these Eulerian models include gas phase chemistry and aerosol dynamics and simulate atmospheric inorganics (such as sulfate, nitrate, and ammonium), but some of these models do not include the treatment of organics (i.e., REMSAD and UAM-LC).

c. Lagrangian Trajectory Model Techniques

The advantages of using Lagrangian models are the ease of use, the ability to perform many trajectories and perform back trajectories. Commonly used Lagrangian models include HYSPLIT (Draxler and Hess, 1997) and FLEXPART (Stohl and Siebert, 2001).

d. Meteorological Modeling Techniques

Meteorological models describe transport, dispersion, vertical mixing, and moisture in time and space. Meteorological models consist of straight line, interpolation (termed diagnostic), and first principle (termed prognostic) formulations, with increasing levels of complexity and requirements for computational and data resources.

The straight line model is applied to hourly wind directions from a single monitor, assuming an air mass travels a distance equal to the wind velocity in the measured direction, regardless of the distance from the monitoring site. This model is applicable for a few hours of transport in flat terrain, typically for evaluating a single emissions source.

Interpolation models integrate wind speed and directions from multiple measurement locations, including upper air measurements provide by remote sensors or balloon launches. The more advanced of these models allow barriers, such as mountains, to be placed between monitors. Wind fields, therefore, show different directions and velocities at different horizontal and vertical positions. Interpolation wind models are applicable to domains with a large number of well-placed monitors and for estimating the movement of air masses from many sources over transport times of more than half a day. The number and placement of monitors, especially upper air monitors, is especially important in mountainous terrain and in coastal areas where winds are unusual.

First principle models (Stauffer and Seaman, 1994; Seaman et al., 1995; Koracin and Enger, 1994) embody scientists' best knowledge of atmospheric physics and thermodynamics, employing basic equations for conservation and transfer of energy and momentum. Also known as "prognostic models," first principle models purport to need no data other than values from a sparse upper air network for interpolation. They are computationally intensive, often requiring supercomputers but have become more practical and cost-effective as workstation and desktop computers become more powerful. Modern versions use "four-dimensional data assimilation" or FDDA that compare model-calculated wind, humidity, and temperature fields with measurements and "nudge" model outputs toward observations.

A more complex meteorological model is not necessarily a better model for a specific application. One of the most widely used first principle model is the Fifth-Generation NCAR/Penn State Mesoscale Model or MM5 model (Grell et al., 1995). The MM5 meteorological model has been adopted as the platform for central California air quality studies (Seaman et. al., 1995). MM5 input data consist of wind speed, wind direction, temperature, atmospheric pressure, and relative humidity at ground level, within the boundary layer, and above the boundary layer. In many cases in valley situations ten-meter vertical resolution is needed within the surface layer, 30-50 m resolution is needed in the valley wide layer, and 100 m resolution is needed above the valleywide layer up to ~2000 m agl (Watson et al., 1998). Time resolution is at least hourly for these measurements. Measurements are needed where large differences are expected, although this is largely unknown for winter.

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Source Modeling and Back Trajectory Attribution Techniques

Table 2. Puff, Visibility and Trajectory Modeling Attribution Techniques

Evaluation Criteria	Air Quality Models					
		Visibility Models		Lagrangian Trajectory Models		
	CALPUFF	VISCREEN	PLUVUEII	HYSPLIT	RAPTAD	FLEXPART
Chemical Mechanisms						
Does the model simulate aqueous phase chemistry? (If it does what chemistry mechanism is used and does it include fog/cloud chemistry)	Yes; reactions for SO_4 and NO_3	NO	NO	NO	NO	NO
Does the model simulate gas phase chemistry? (if it does, what chemical mechanism is implemented)	Yes	NO	NO	NO	NO	NO
Simulate secondary organic aerosols	4 species model	NO	NO	NO	NO	NO
Inorganic PM (i.e. ions, SO_4, NO_3, etc)	SO_4, NO_3	NO	NO	NO	NO	NO
Size distributions (sectional or modal)	Coarse and fine modes	NO	NO	Only for deposition	NO	
Applicable spatial scales	Micro- to regional scale	Neighbor-hood to urban scale		Neighborhood to global scale	Neighborhood to global scale	Neighborhood to global scale
Applicable temporal scales (episodic or long term applications)	Episodic or Long term	N/A	N/A	Episodic or Long term	Episodic or Long term	Episodic or Long term
Does the model have the capability to distinguish BART sources?	YES	YES	YES	YES	YES	YES
Does the model have the capability to ingest field measurements (PM, HNO_3, H_2O_2, NH3, etc)	NO; only as background values	NO	NO	NO	NO	NO

Air Quality Models (continued)

Evaluation Criteria	CALPUFF	Visibility Models		Lagrangian Trajectory Models		
		VISCREEN	PLUVUEII	HYSPLIT	RAPTAD	FLEXPART
Visibility Modeling						
Does the model simulate background regional haze	NO	NO	NO	NO	NO	NO
Point source treatment (plume rise, plume in grid)	YES	YES	YES	YES	YES	YES
Does the model have the capability to calculate wet and dry deposition?	YES	NO	NO	YES	NO	YES
Visibility treatment: (extinction, deciview, visual range)	Extinction (total and for SO_4, NO_3, EC, OC, fine, coarse), Deciviews	*	*	NO	NO	NO
Input Requirements						
Meteorological data required (single site, gridded, number of levels, etc)	Gridded; able to run with single site	*	*	Gridded (FNL, EDAS, MM5)	Gridded (Use HOTMAC's prediction)	Gridded (ECMWF, MM5)
Emission data required (single stack, multiple point sources, gridded, etc)	Multiple point, area, volume	*	*	Multiple point sources, gridded inventory	Single stack or multiple point sources	*
Allow for initial and boundary conditions (is it required or not applicable)	YES	NO	NO	NO	NO	NO
Has the model been compared against field program data? Has the model been peer reviewed?	YES	YES	YES	YES	YES	NO
Does enough data exist now to run the model (Does data exist in a format ready for the model? Are current databases adequate for the model?)	Use CALMET with existing stations or MM data	YES	YES	Gridded met data available on NOAA ARL ftp site (FNL, EDAS); adaptable to read in MM5	Use HOTMAC to obtain wind and turbulence data	*

Air Quality Models (continued)

Evaluation Criteria		Visibility Models		Lagrangian Trajectory Models		
	CALPUFF	VISCREEN	PLUVUEII	HYSPLIT	RAPTAD	FLEXPART
Practical Considerations						
Costs to run (hardware platforms, file storage, operating system)	Inexpensive; PC, Windows, up to 20GB (with CALMET)	Inexpensive; PC, DOS, 1MB	Inexpensive; PC, DOS, 1MB	Inexpensive; PC, Windows, 20MB	Inexpensive: Linux PC, Redhat	Inexpensive; Linux PC, Redhat; can be compiled on PC
Have protocols or procedures been developed to run and interpret the model?	FLAG for Class I AQRVs	FLAG for Class I AQRVs	FLAG for Class I AQRVs	NO	NO	NO
Is the source code available?	YES	YES	YES	NO	YES	YES
Are beginning user training classes available?	YES; by EarthTech, BEE-Line	EPA; APTI	EPA; APTI	NO	YES	NO
Are user support groups available?	YES; one list-serve	YES; through EPA SCRAM	YES; through EPA SCRAM	NO	YES	NO
Level of expertise required to run and interpret results (Level of Linux, UNIX, PC skills required)	Moderate; able to run PC DOS programs; knowledge of atmospheric chemistry & physics	Simple; able to run on PC DOS and windows	Simple; able to run on PC DOS and Windows	Simple; able to run on PC running Windows	Simple to run: GUI allows the user to easily run the program Knowledge is needed to interpret results	Moderate; must compile source code for PC, Linux or UNIX; knowledge of met input formats
Output visualization required to interpret output numbers	YES	NO	NO	YES; has built in visualization	YES; has built in visualization	YES
Other strengths	*	*	*	*	Applicable from building scale to terrain scale.	*
Availability	EarthTech www.src.com	EPA	EPA	NOAA Air Resource Laboratory; www.arl.noaa.gov/ss/models/hysplit.html	Yamada Science & Art; http://www.ysasoft.com	http://www.forst.uni-muenchen.de/EXT/LST/METEO/stohl/flexpart.html

* No information available at this time

Source Modeling and Back Trajectory Attribution Techniques

Table 3. Eulerian Grid Based Modeling Attribution Techniques

Evaluation Criteria	Air Quality Models: Grid Models						
	CMAQ	REMSAD	CAMx	UAM-AERO	UAM-VPM	URM	CalGrid
Chemical Mechanisms							
Does the model simulate aqueous phase chemistry? (If it does, what chemistry mechanism is used and does it include fog/cloud chemistry)	35 equilibria and 99 reactions for SO_4 and NO_3	1 reaction for SO_4	1 reaction for SO_4	35 equilibria and 99 reactions for SO_4 and NO_3	*	2 reactions for sulfate	NO
Does the model simulate gas phase chemistry? (if it does, what chemical mechanism is implemented)	CBM-IV (93 reactions) or RADM2 (158 reactions)	CBM-IV (93 reactions) or RADM2 (158 reactions)	CB-IV with enhanced isoprene or SAPRC97	SAPRC97 (185 reactions)	CB	LCC (about 100 reactions)	YES (both CBM-IV and SAPRC)
Simulate secondary organic aerosols	Primary from emissions; secondary from organics	Primary from emissions	Primary from emissions; secondary from gas phase reactions of organic precursors using yields	Secondary from gas phase reactions of organic precursors using yields	Primary from emissions	Primary from emissions; secondary from gas phase reactions of organic precursors using production fractions	NO
Inorganic PM (i.e. ions, SO_4, NO_3, etc)	SO_4, NO_3 and other material	SO_4, NO_3, NH_4, and other material	SO_4, NO_3, NH_4, Cl, other ions and materials	SO_4, NO_3, NH_4, Cl, other ions and materials	SO_4, NO_3, NH_4, and other materials	SO_4, NO_3, NH_4, Cl, other ions and materials	NO
Size distributions (sectional or modal)	Lognormal; three modes: Aitken, Accumulation and coase	$PM_{2.5}$ fraction, coarse mode	Discrete bins, user specified up to 10	Discrete bins, user specified up to 10	Lognormal bins; user specified	Discrete bins; user specified	NO
Applicable spatial scales	Mesoscale	Mesoscale	Mesoscale	Urban scale	Urban scale	Mesoscale	Urban to Regional
Applicable temporal scales (episodic or long term applications)	Episodic	Long term	Episodic	Episodic	Episodic	Episodic	Episodic
Does the model have the capability to distinguish BART sources?	YES; using plume in grid	NO	YES	NO	NO	NO	NO

Air Quality Models (continued)

Evaluation Criteria	Grid Models						
	CMAQ	REMSAD	CAMx	UAM-AERO	UAM-VPM	URM	CalGrid
Chemical Mechanisms (continued)							
Does the model have the capability to ingest field measurements (PM, HNO_3, H_2O_2, NH_3, etc)	YES; as initial and boundary conditions	Uses default profiles	YES; as initial and boundary conditions	YES; as initial and boundary conditions	YES; as initial and boundary conditions	YES; as initial and boundary conditions	YES; as initial and boundary conditions
Visibility Modeling							
Does the model simulate background regional haze	YES	YES	YES	YES (with processing)	YES	YES	NO
Point source treatment (plume rise, plume in grid)	Plume in grid	NO	Plume in grid	NO	NO	NO	NO
Does the model have the capability to calculate wet and dry deposition?	YES	YES	YES	YES	YES	YES	YES
Visibility treatment: (extinction, deciview, visual range)	Extinction (total and for SO_4, NO_3, EC, OC, fine, coarse), Deciviews	Extinction (total and for SO_4, NO_3, EC, OC, fine, coarse), Deciviews	NO	YES (with processing)	*	*	NO
Input Requirements							
Meteorological data required (single site, gridded, number of levels, etc)	Gridded	Gridded	Gridded	Gridded	Gridded	Gridded	Gridded CALMET date
Emission data required (single stack, multiple point sources, gridded, etc)	Gridded	Gridded	Gridded	Gridded	Gridded	Gridded	Gridded
Allow for initial and boundary conditions (is it required or not applicable)	YES	YES	YES	YES	YES	YES	YES
Has the model been compared against field program data? Has the model been peer reviewed?	YES	YES	YES	YES	YES	YES	YES
Does enough data exist now to run the model (Does data exist in a format ready for the model? Are current databases adequate for the model?)	Extensive need for detailed emissions and meteorological fields	Extensive need for detailed emissions and meteorological fields	Extensive need for detailed emissions and meteorological fields	Extensive need for detailed emissions and meteorological fields	Extensive need for detailed emissions and meteorological fields	*	Extensive need for detailed emissions and meteorological fields

Air Quality Models (continued)

Evaluation Criteria	Grid Models						
	CMAQ	REMSAD	CAMx	UAM-AERO	UAM-VPM	URM	CalGrid
Practical Considerations							
Costs to run (hardware platforms, file storage, operating system)	Can be run inexpensively; Linux PC, up to 1 TB (annual runs)	Can be run inexpensive; Linux PC	Can be run inexpensively; Linux PC	Can be run inexpensively; Linux PC	Can be run inexpensively; Linux PC	Can be run inexpensively; Linux PC	Can be run inexpensively; Linux PC
Has a protocol or procedures been developed to run the model?	NO; but RPOs have regional haze protocols	NO; but RPOs have regional haze protocols	NO	NO	NO	NO	NO
Is the source code available?	YES	*	YES	YES	YES	YES	YES
Are beginning user training classes available?	YES; through EPA and RPOs	NO	YES; through SAI and RPOs	NO	NO	NO	NO
Are user support groups available?	YES; through EPA and RPOs	NO	NO	NO	NO	NO	NO
Level of expertise required to run and interpret results (Level of Linux, UNIX, PC skills required)	Considerable expertise in UNIX or Linux; knowledge of atmospheric chemistry & physics	*	Moderate to extensive	Moderate to extensive	*	*	Moderate
Output visualization required to interpret output numbers	YES; use PAVE	YES; use PAVE	YES	YES	YES	YES	YES
Availability	EPA; Sharon LeDuc 919-541-1335	SAI; Sharon Douglas 415-507-7108	ENVIRON; Ralph Morris 415-899-0700	SAI; Sharon Douglas 415-507-7108	SAI; Sharon Douglas 415-507-7108	Georgia Tech; Ted Russel, Talat Odman	California Air Resources Board

* No information available at this time

Table 4. Meteorological Modeling Attribution Techniques

Evaluation Criteria	Diagnostic Models		Mesoscale Prognostic Models				
	CALMET	Diagnostic Wind Model	RAMS	MM5	Eta *	ARPS	HOTMAC
Applicable spatial scales	Urban to regional scale	Urban to regional scale	Urban to global scale	Urban to global scale	Urban to global scale	Urban to global scale	Urban to mesoscale
Applicable temporal scales	Hourly to annual	Hourly to annual	Hourly to annual	Hourly to annual	Hourly to annual	Hourly to annual	Hourly to annual
Does enough data exist in organization now to run the model? Are the existing monitoring networks adequate within the domain?	Depends on area	Depends on area	Depends on area	Depends on area	Depends on area	Depends on area	Depends on area
For the prognostic models: Capable of FDDA?	N/A	N/A	Yes	Yes	Yes	Yes	Yes
For the prognostic models: Are files available (archived) from real-time?	N/A	N/A	NOAA is running the model for the east coast	Several federal agencies and regional consortiums are running MM5	NOAA is running the Eta model and fields available through NCEP ftp site	It can be initialized using NCEP analyses files as well as individual observations	No
Data storage/archival requirements for simulation of episodic and annual events	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation	Depends on modeling domain, grid size, number of species and length of simulation
Simulate clouds/precipitation fields? At what time intervals?	No	No	Yes – minutes to days	Yes – minutes to days	Yes – minutes to days	Yes – minutes to days	Yes – minutes to days
Has the model been compared against field program data? Has the model been peer reviewed?	Yes	Yes	Yes	Yes	Yes	Yes	Yes

Meteorological Modeling Attribution Techniques (continued)

Evaluation Criteria	Diagnostic Models		Mesoscale Prognostic Models				
	CALMET	Diagnostic Wind Model	RAMS	MM5	Eta *	ARPS	HOTMAC
Tools available to visualize output fields? What operating systems?	Yes – Unix, Linux, Windows	Yes – Unix, Linux, Windows	Yes – Unix, Linux	Yes – Unix, Linux	Yes – Unix, Linux	Yes – Unix, Linux	Yes – Built-in GUI; Unix, Linux, Windows
Are user groups, listservers available when problems arise?	Yes	Yes	Yes	Yes	No	Yes	Yes
Cost to run (hardware, software)	PC Windows, PC Linux; Free source code	PC Linux, UNIX; Free	PC Linux; licensed source code	PC Linux, UNIX; Free source code	PC Linux, UNIX; Free source code	PC Linux, UNIX; Free source code	PC Linux; licensed source code
Level of expertise required to run and interpret results (Level of Linux, UNIX, PC skills required)	Moderate	Moderate	High	High	High	High	High
Availability of user training	Yes	Yes	Yes	Yes	No	Yes	Yes
Is the source code available?	Yes	Yes	Yes	Yes	No	Yes	Yes
Has a protocol or procedures been developed to run the model?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Strengths	Relatively easy to use; little observed data needed	Relatively easy to use; little observed data needed	Detailed 3-D, complex flow in time	Detailed 3-D, complex flow in time	Detailed 3-D, complex flow in time	Detailed 3-D, complex flow in time	Detailed 3-D, complex flow in time
Weaknesses/ Limitations	Parameterization depended; may not capture various flows	Parameterization depended; may not capture various flows	Large computer time; time consuming to debug	Large computer time; time consuming to debug	Large computer time; time consuming to debug	Large computer time; time consuming to debug	No real time data initialization

* While the Eta is not considered a mesoscale model, it has been used to simulate meteorology down to 10 km grid scales. The workstation Eta is available from NOAA and used experimentally by some NWS offices.
* No information available at this time

C. Observational Modeling Techniques

Introduction

Observational or receptor modeling refers to a group of analysis techniques in which monitoring data collected at or in the region of a receptor are analyzed in various ways in order to infer information about the pollutants and the sources of the pollutants causing visibility impairment.

These types of models often are used as the first technique for source apportionment in order to get an initial understanding of the source-receptor relationships in a region. They are also used to verify or reconcile deterministic models, and to aid in planning intensive monitoring studies.

Results of observational models can either be quantitative or qualitative. Quantitative results are estimates of the fractions of a measured species that can be attributed to a single source or attributed among several sources or source areas. Qualitative results include such information as the wind directions and other meteorological conditions most associated with high concentrations, or inferences about probable source types based on the relationships between trace elements at a single site, or information about source areas based on the spatial and temporal patterns in the concentrations of a single species. Often several observational models are used together to form hypotheses about the important source areas and source types affecting the concentrations at a receptor.

Advantages of receptor models are that they are generally quick and inexpensive to run and require relatively little input data. Disadvantages include the necessity of employing simplifying assumptions such as linear relationships and often the results are limited to averages over long periods of time or large spatial areas. Subjective user judgment is required to choose appropriate input data and/or interpret the results of many receptor models. As an example, suppose the UNMIX model data located a source associated with high concentrations of Br, K, elemental carbon, and organic carbon, and another source associated with high Se and S. It is the judgment of the modeler regarding the relationship of the individual species to a specific source that determines that first source is “smoke” and the second is “coal-fired power plants.”

Receptor models could potentially be grouped in several different ways, based on their different attributes. Here they are somewhat arbitrarily put into four categories, with each category requiring incrementally more particulate data at the receptor: 1) back-trajectory analyses; 2) analyses of interspecies relationships; 3) analyses of spatial and temporal patterns; and 4) analyses that require a unique tracer. Some models that fall into each category are listed below:

Category 1. Back-Trajectory Analyses

a. Residence Time Analyses including residence time, source contribution function, conditional probability, and so forth. These give qualitative information about source areas and transport patterns.

b. Trajectory Mass Balance – Regression of residence time of back trajectories in selected source areas against concentrations yielding quantitative source attributions.

Category 2. Analyses of Interspecies Relationships

a. Chemical Mass Balance (CMB) - Quantitative source attributions are obtained by a weighted regression of known source profiles against measured concentrations of several species.
b. UNMIX – By looking for "edges" in the relationships between species, UNMIX estimates both the source profiles and the quantitative source contributions from each source.
c. Positive Matrix Factorization (PMF) – PMF, like UNMIX, uses the relationships between species to estimate the number and composition of the sources and the quantitative source contributions.
d. Enrichment Factors (EF) – The "enrichment" of certain ratios of trace elements is used to qualitatively infer source types impacting a receptor.

Category 3. Analyses of Spatial and Temporal Patterns

a. Empirical Orthogonal Function Analysis (EOF) – Analysis of spatial and temporal patterns leading to qualitative information about locations of dominant source areas, frequency and timing of source impacts and meteorological conditions associated with them.
b. Receptor Model Applied to Patterns in Space (RMAPS) – With additional assumptions applied to EOFs, quantitative source attributions are estimated.

Category 4. Tracer Analyses

a. Tracer Mass Balance Regression (TMBR) – Tracer concentrations, possibly weighted by other factors, are regressed against concentrations of the species of interest to give a quantitative estimate of the contribution from the source that emitted the tracer.
b. Differential Mass Balance (DMB) - The differential ratios of tracer to pollutant between source and receptor are adjusted based on simple chemistry and meteorology to give an estimate of the contribution of the tracer source to the receptor.
c. Tracer-Aerosol Gradient Interpretive Technique (TAGIT) – By comparing the ratios of tracer to concentration of interest at "background" sites to the ratios at tracer-affected sites, a quantitative attribution of the tracer source to the receptor is estimated.

Following are brief descriptions of each of these models and a few references giving further details and examples of their use.

1a. Qualitative Back Trajectory Residence Time Analyses

There are several methods of statistically analyzing the relationships between where air masses arrived from and the concentrations measured at a receptor. These include, but are not limited to: 1) where was air most likely to arrive from when concentrations are high; 2) if air arrived from a given area, what is the probability that the concentration at the receptor was high when the air mass arrived there; 3) what is the mean (or median or maximum or distribution) of

concentrations at the receptor when air masses arrived from a given area. Selected References: Ashbaugh et al. (1985), Gebhart et al. (2001), Poirot and Wishinski (1986).

Data Needed: A time series of concentrations of the species of interest. One or more back trajectories of three to five days duration corresponding to each concentration. Back trajectories can be calculated by any of several methods including ATAD, Hysplit, the CAPITA Monte Carlo Model, as well as others. Standard National Weather Service upper air data can be used as input, though more detailed meteorological data can be input if available. Dispersion can be included in some of these models.

Model Assumptions: Errors in trajectory placement are random and uncorrelated. Variations in deposition, chemistry, emissions, and so forth, have less influence on measured concentrations on average than variations in transport directions.

Biggest Potential Problems: Results of these types of analyses are qualitative rather than quantitative. Results are more statistically robust when averaged over long time periods, usually a minimum of one season and preferably several years. Nearby sources cannot be resolved. User judgment is required to choose trajectories of an appropriate type, height, and length and also to choose appropriate definitions of "high" concentrations. Some concentrations that vary seasonally may have all "high" concentrations in a single season, necessitating some compensation in the analysis. Model results are probably more appropriate for species such as particulate sulfate that are relatively uniform over large spatial scales, rather than, for example, particulate nitrate, which is more volatile and seems to be more related to local sources than long-range transport.

1b. TrMB (Trajectory Mass Balance)

This is a multiple linear regression of the frequency of occurrence of trajectory endpoints in each of several source areas against the corresponding concentrations at the receptor. The result is the average attribution of a single species among up to about 25 source areas over a long time, for example, one season or year, or several years. Selected references: Gebhart and Malm (1989), Stohl (1998).

Data Needed: Time series of concentrations of the pollutant of interest at a single site. One or more back trajectories associated with each concentration. Input data for these are upper air winds, temperatures, and moisture over a large area. Often data are obtained from the standard National Weather Service observations, but other data such as higher resolution wind fields, wind profiler data specific to a given study, can also be used if available. Emission data can be used if available, but must vary in time to be useful. Simple chemistry and/or deposition can be used if data are available. The user defines the size and locations of the source areas to be considered.

Model Assumptions: Average contributions of each source area can be written as a linear combination of the contributions from several source areas. Average chemistry and deposition are adequate to explain average source contributions. Errors in back trajectories are random and normally distributed.

Biggest Potential Problems: No attribution to single sources—only to source areas. Attributions must be averaged over long time periods. Nearby sources cannot be modeled accurately. Subjectivity in choosing source areas. Violation of assumptions of linear chemistry.

2a. Chemical Mass Balance (CMB)

CMB is a multiple linear regression of measured concentrations against known source profiles. It is used for the attribution of all measured chemical species among several sources for each concentration measurement period for a single monitoring site. Regressions are weighted by the uncertainties in both the source profiles and the concentrations. Selected References: Watson et al. (1984 and 2001).

Data Needed: Concentrations and measurement uncertainties of both the chemical species of interest and of as many trace elements as possible are necessary for each time period and location for which attributions are desired. IMPROVE data can be used. A source profile is needed for each source. These are the relative amounts of each emitted chemical species and the uncertainties in these values.

Model Assumptions: Compositions of source emissions are constant over the period of ambient and source sampling. Chemical species do not react with each other, for example, they add linearly. All sources with a potential for significantly contributing to the receptor have been identified and have had their emissions characterized. The sources' compositions are linearly independent of each other. The number of sources or source categories is less than or equal to the number of chemical species. Measurement uncertainties are random, uncorrelated and normally distributed.

Biggest Potential Problems: The model cannot directly apportion secondary species such as sulfates, nitrates, and secondary organics. There are some workarounds for this. The usual tactic is to apportion these species between the known primary sources and a source designated as "secondary particles." It is also possible to use "fractionated" or "aged" source profiles where an attempt is made to pre-determine the chemical processes that occurred between source and receptor and then adjust the source profile accordingly. Obtaining all necessary source profiles can be difficult. In some studies, other receptor models have estimated source profiles.

2b. UNMIX

For a selection of measured species, UNMIX uses singular value decomposition with additional non-negativity constraints to estimate the number of sources, the source compositions, and the source contributions to each sample at a single monitoring site. UNMIX attempts to find the "edges" in the relationships between species and relates these to sources. Selected References: Henry (1997a, 1999), Lewis et al. (1998).

Data Needed: A time series of concentrations of several species measured at a single site. IMPROVE data can be used.

Model Assumptions: Concentrations are linear combinations of an unknown number of sources of unknown composition. Contributions from sources are positive. Source compositions are approximately constant in time. For each source there are some samples that contain little or no contribution from that source.

Biggest Potential Problems: A maximum of seven sources can be identified. There is some subjectivity in choosing fitting species, number of sources, how to deal with missing or below detection limit values, and which time periods and species should be analyzed together. Sources of secondary species will probably violate the assumption of constant source composition. This can cause multiple sources to be identified for a single physical source that impacts the receptor under differing conditions. Supplemental analysis may be required to deconvolute these.

2c. Positive Matrix Factorization (PMF)

PMF uses an iterative weighted least squares method to decompose a time-by-species matrix to estimate the number and composition of the sources and the contributions of each source to each measured species. It will also calculate error estimates for these values. Selected References: Paatero and Tapper (1994), Paatero (1997); Xie *et al.* (1999).

Data Needed: A time series of concentrations and their uncertainties for several species at a single monitoring location. IMPROVE data can be used.

Model Assumptions: Concentrations are linear combinations of an unknown number of sources of unknown composition. Contributions from sources are positive. Source compositions are approximately constant in time.

Biggest Potential Problems: Correlations in detection limits or uncertainties as well as in concentrations can influence the results. For example, PMF may detect positive correlations between species either due to source activity (desirable) or measurement protocol changes (undesirable).

2d. Enrichment Factors (EF)

The differences in ratios of elemental concentrations between a reference sample and a measured sample are used to determine how sources may have "enriched" the concentrations of certain species. Some examples include: high Al/Ca has been linked to Saharan dust, high Br/Pb may indicate lead is linked to autos rather than industry, high Se is linked to coal burning, heavy metals are linked to smelting, V and Ni are linked to residual oil combustion. Selected References: Lawson and Winchester (1979), Parekh et al. (1989), Perru (1997), Roshid and Griffiths (1993).

Data Needed: Time series of concentrations of trace elements and the species of interest. Some historical information about the "standard" crustal, sea salt, or other ratios for a region.

Model Assumptions: Elemental ratios depend mostly on enrichment of trace elements by a source and have less dependence on meteorology. The reference ratios are constant.

Biggest Potential Problems: Attributions are generally to source areas, not to single sources.

3a. Empirical Orthogonal Function Analysis (EOF)

A few (typically two to six) spatial patterns that explain most of the covariance in the spatial and temporal patterns of a measured species are obtained by singular value decomposition. Associations between the spatial patterns and source areas and/or transport of air pollutants into the study area can often be inferred, but are qualitative. The original data matrix can be approximately reconstructed by linearly recombining these few patterns. Selected References: Gebhart and Malm (1997), Henry et al. (1991), Malm et al. (1990), Malm and Gebhart (1997).

Data Needed: Measurements of a single air pollutant of interest at several sites for several time periods. Typically used are concentrations measured at fifteen to forty sites for thirty or more time periods. There must be more time periods than sites. Data from special studies are often analyzed in this way.

Model Assumptions: Only a few spatial patterns are required to explain a large majority of the covariance in the spatial and temporal patterns. These patterns have a physical meaning that can be inferred, such as transport of emissions from a source into the study area or local stagnation.

Biggest Potential Problems: Source attributions are qualitative, not quantitative and interpretation of the spatial patterns is subjective. The model requires a site by time matrix with no missing values, so some method of eliminating or filling in both missing and below detection limit values is necessary.

3b. Receptor Model Applied to Patterns in Space (RMAPS)

Determines the average attribution of a single species among a few source areas by decomposing the time by site matrix of concentrations into a source matrix and a time weighting matrix. Similar to UNMIX, the edges in the scatterplots between sources and non-negativity requirements are used to constrain the identification of sources. Selected References: Henry (1997 b, c, d), White (1999).

Data Needed: Time series of concentrations of the pollutant of interest at several sites within a region. The model previously has been used in special studies such as Project MOHAVE and PREVENT where there are fifteen to forty sites within a one or two state region collecting data daily for several weeks or months.

Model Assumptions: Average contributions of each source area can be written as a non-negative linear combination of the major principal components of the data. The spatial scale of the pollutant is large compared to the spacing of the sampling sites.

Biggest Potential Problems: If the second major assumption is violated, the concentrations of the pollutant at each site will have little correlation with the other sites; therefore the model would not apply because it relies on the common variations among sites.

4a. Tracer Mass Balance Regression (TMBR) also called Multiple Linear Regression (MLR) on Marker Species

Estimates the attribution of the aerosol species of interest by a source or source type, which emitted or emits a unique tracer. Uncertainty estimates are also generated if included in the regression. The model is a regression of the tracer, possibly weighted by other factors against the species of interest. Selected References: Malm et al. (1989 a, b, c).

Data Needed: Time series of ambient concentrations and their uncertainties for the aerosol species being apportioned and also the tracer species.

Model Assumptions: The tracer(s) are uniquely emitted by non-overlapping groups of sources. Source emissions are constant over the period of ambient sampling. Deposition and conversion are constant for all sampling periods and can be estimated by first-order approximations. In the WHITEX application, sulfate oxidation rates were assumed to be related to RH, where RH was a surrogate for time the air mass spent in clouds. Measurement errors are random, uncorrelated, and normally distributed.

Biggest Potential Problems: Tracer concentrations are not often available. Source profiles, deposition, and conversion all vary in time and space.

4b. Differential Mass Balance (DMB)

DMB estimates the fraction of a species of interest attributable to a single source that can be tagged with a unique tracer. The ratio of measured tracer to measured sulfate or nitrate is assumed to be related to the fractional contribution of the traced source. The ratio is adjusted based on the estimated difference between the ratio at the source to the ratio at the receptor. Travel times between the source and receptor are estimated based on winds, and then by using simple estimates of dispersion, deposition and oxidation, the tracer to secondary species ratio is adjusted. Selected References: Malm (1989b, c).

Data Needed: Time series of tracer concentrations and concentrations and emission rates of the species of interest and its precursors, for example, sulfur dioxide and sulfate. Estimates of wind speed and direction, mixing heights, deposition and oxidation rates.

Model Assumptions: Wind direction does not change during transport time. The rates for deposition and conversion are first-order and invariant in space and time along the transport path between the source and the receptor. The ratio of the emission rates for the species of interest or its parent species and the tracer is known.

Biggest Potential Problems: Simple chemistry and meteorology may not be adequate, especially for long transport times, complex terrain, and/or changing chemical regimes. Tracer concentrations unique to a single source are often not available. The fraction of attributable concentration may only be calculable to within a range based on the reasonable ranges of rate coefficients.

4c. Tracer-Aerosol Gradient Interpretive Technique (TAGIT)

Results are the attribution of primary or secondary species associated with the source "tagged" by a tracer release. TAGIT computes attributions on a sample period-by-sample period basis. For each sample period, background concentration of the species of interest is determined by averaging the concentrations of the species at nearby sites that do not have tracer concentrations and are significantly above background. These sites are presumed to be unaffected by the tracer-tagged source and thus represent the average background. This background for each sample period is then subtracted from the concentration of the species of interest at impacted receptor sites for corresponding sample periods. The difference is the concentration attributable to the tagged source. Green (2001), Kuhns et al. (1999), Pitchford et al. (2000).

Data Needed: Concentrations of a unique tracer from a source of interest and simultaneous concentrations of a pollutant of interest at several sites in a region.

Model Assumptions: There is no impact from the tagged source if the tracer concentration is less than the level considered to be "significantly" above its' background. Background concentrations of the species of interest do not vary systematically in space.

Biggest Potential Problems: Assuming no impact from the tagged source when tracer is not statistically above background can lead to an underestimation of attribution. Measured tracer concentrations often have large uncertainties. Some sampling periods will have a negative concentration attributed to the tagged source.

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Table 5. Observational Modeling Techniques

	Analyses of Back Trajectories					
Criteria	**Residence Time & Source Contribution Function**	**Conditional Probability**	**Concentration Statistics by Air Mass History (Mean, Max, Median)**	**Cluster Analysis**	**Hit – No Hit**	**Trajectory Mass Balance**
Quantitative Source Attribution?	No	No	No	No	No	Yes
Number of sources that can be distinguished?	Typically only about 10 or fewer transport patterns are distinguishable	Maximum of 10-15	1/grid cell, typically 50x50 (2500), though usually only about 5-20 transport patterns are distinguishable	2-15	1	20-30 max
Averaging Time of Result?	Weeks to years	Weeks to years	Weeks to years	Weeks to years	Daily, possibly hourly	Months to years
Previous use at Class I Areas? (See Text for References)	Yes	Yes	Yes	Yes	Yes	Yes
Magnitude of impacts?	No	No	Yes	No	No	Yes
Frequency of impacts?	Yes	No	No	Yes	Yes	Yes
Duration of impacts?	Yes	No	No	Yes	Yes	Yes
Time of Day of impacts?	Depends on particle data	Depends on particle data	Depends on particle data	Depends on particle data	Yes	Depends on particle data
Time of Year of impacts?	Yes	Yes	Yes	Yes	Yes	Yes
Appropriate for what source-receptor distances?	Regional Scale	Regional Scale	Regional Scale	Regional Scale	Regional Scale	Regional Scale
Attribution of Secondary Species?	Yes	Yes	Yes	Yes	Yes	Yes
Cost to run?	Minimal	Minimal	Minimal	Minimal	Minimal	Minimal
Code Available?	No	No	No	No	No	No
Equations and/or algorithms available?	Yes	Yes	Yes	Yes	None needed	Yes
Computer Hardware Needed	PC	PC	PC	PC	PC	PC
Additional software necessary?	Any programming language or statistical package and graphics and/or mapping software that allows overlay of data on a map	Any programming language or statistical package and graphics and/or mapping software that allows overlay of data on a map	Any programming language or statistical package and graphics and/or mapping software that allows overlay of data on a map	Any programming language or statistical package and graphics and/or mapping software that allows overlay of data on a map	Graphing or mapping software that allows overlay of data on a map	Any programming language or statistical package and graphics and/or mapping software that allows overlay of data on a map
EPA Approved Model?	No	No	No	No	No	No

Observational Modeling Techniques(continued)

	Analyses of inter-species relationships				Analyses of Spatial and Temporal Patterns	
Criteria	**CMB**	**PMF**	**UNMIX**	**Factor Analysis**	**EOF**	**RMAPS**
Quantitative Source Attribution?	Yes	Yes	Yes	No	No	Yes
Number of sources that can be distinguished?	Usually < 10	Usually < 10	7	< Number of species analyzed	Usually 4-8 transport patterns	Usually 4-8 transport patterns
Averaging Time of Result?	Same as monitoring data	Same as monitoring data	Same as monitoring data		Same as monitoring data	Same as monitoring data
Previous use at Class I Areas? (See Text for References)	Yes	No?	No?	Yes	Yes	Yes
Magnitude of impacts?	Yes	Yes	Yes	No	No	Yes
Frequency of impacts?	Yes	Yes	Yes	Yes	Yes	Yes
Duration of impacts?	Yes	Yes	Yes	No	Yes	Yes
Time of Day of impacts?	Depends on input data	Depends on input data	Depends on input data	Depends on input data	Depends on input data	Depends on input data
Time of Year of impacts?	Yes	Yes	Yes	Yes	Yes	Yes
Appropriate for what source-receptor distances?	Urban to regional scales	Urban to regional scales	Urban to regional scales	Urban to regional scales	Regional Scale	Regional Scale
Attribution of Secondary Species?	With additional information	With additional information	With additional information	Yes	Yes	Yes
Cost to run?	Free to purchase, minimal to run	$700 to purchase, minimal to run	Currently free to purchase, minimal to run, $100 (student)-1500 (full) for MATLAB	Minimal	Minimal	Minimal
Code Available?	Yes	Yes	Yes	No	No	No
Equations and/or algorithms available?	Yes	Yes	Yes	Yes	Yes	Yes
Computer Hardware Needed	PC	PC	PC	PC	PC	PC
Additional software necessary?	No	No	MATLAB with optimization toolbox	Any statistics package	Any statistics package with ability to do singular value decompositions	Any statistics package with ability to do singular value decompositions
EPA Model?	Yes	No?	Yes?	No	No	No

Observational Modeling Techniques (continued)

	Analyses of Unique Tracer Data		
Criteria	**TMBR**	**DMB**	**TAGIT**
Quantitative Source Attribution?	Yes	Yes	Yes
Number of sources that can be distinguished?	1-3	1-3	1/tracer
Averaging Time of Result?		Same as particulate data	Same as particulate data
Previous use at Class I Areas? (See Text for References)	Yes	Yes	Yes
Magnitude of impacts?	Yes	Yes	Yes
Frequency of impacts?	Yes	Yes	Yes
Duration of impacts?	Yes	Yes	Yes
Time of Day of impacts?	Depends on particulate data	Depends on particulate data	Depends on particulate data
Time of Year of impacts?	Yes	Yes	Yes
Appropriate for what source-receptor distances?	Urban to Regional Scale	Urban to Regional Scale	Regional Scale
Attribution of Secondary Species?	Yes	Yes	Yes
Cost to run?	Minimal	Minimal	Minimal
Code Available?	No	No	No
Equations and/or algorithms available?	Yes	Yes	Yes
Computer Hardware Needed	PC	PC	PC
Additional software necessary?	Any programming language, spreadsheet, or statistical package	Any programming language, spreadsheet, or statistical package	Any programming language, spreadsheet, or statistical package
EPA Model?	No	No	No

Appendix A: **RA BART Rule** (40 CFR 51.300-306)

Sec. 51.300 Purpose and applicability.

Authority: Secs. 110, 114, 121, 160-169, 169A, and 301 of the Clean Air Act, (42 U.S.C. 7410, 7414, 7421, 7470-7479, and 7601).

Source: 45 FR 80089, Dec. 2, 1980, unless otherwise noted.

(a) Purpose. The primary purposes of this subpart are to require States to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution; and to establish necessary additional procedures for new source permit applicants, States and Federal Land Managers to use in conducting the visibility impact analysis required for new sources under Sec. 51.166. This subpart sets forth requirements addressing visibility impairment in its two principal forms: ``reasonably attributable" impairment (i.e., impairment attributable to a single source/small group of sources) and regional haze (i.e., widespread haze from a multitude of sources which impairs visibility in every direction over a large area).

(b) Applicability. (1) General Applicability. The provisions of this subpart pertaining to implementation plan requirements for assuring reasonable progress in preventing any future and remedying any existing visibility impairment are applicable to:

(i) Each State which has a mandatory Class I Federal area identified in part 81, subpart D, of this title, and Each State in which there is any source the emissions from which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area.

(ii)The provisions of this subpart pertaining to implementation plans to address reasonably attributable visibility impairment are applicable to the following States: Alabama, Alaska, Arizona, Arkansas, California, Colorado, Florida, Georgia, Hawaii, Idaho, Kentucky, Louisiana, Maine, Michigan, Minnesota, Missouri, Montana, Nevada, New Hampshire, New Jersey, New Mexico, North Carolina, North Dakota, Oklahoma, Oregon, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Virgin Islands, Washington, West Virginia, Wyoming.

(3) The provisions of this subpart pertaining to implementation plans to address regional haze visibility impairment are applicable to all States as defined in section 302(d) of the Clean Air Act (CAA) except Guam, Puerto Rico, American Samoa, and the Northern Mariana Islands.

[45 FR 80089, Dec. 2, 1980, as amended at 64 FR 35763, July 1, 1999]

Sec. 51.301 Definitions.

For purposes of this subpart:

Adverse impact on visibility means, for purposes of section 307, visibility impairment which interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the Federal Class I area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of visibility impairments, and how these factors correlate with (1) times of visitor use of the Federal Class I

area, and (2) the frequency and timing of natural conditions that reduce visibility. This term does not include effects on integral vistas.

Agency means the U.S. Environmental Protection Agency.

BART-eligible source means an existing stationary facility as defined in this section. Best Available Retrofit Technology (BART) means an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by an existing stationary facility. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and nonair quality environmental impacts of compliance, any pollution control equipment in use or in existence at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Building, structure, or facility means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities must be considered as part of the same industrial grouping if they belong to the same Major Group (i.e., which have the same two-digit code) as described in the Standard Industrial Classification Manual, 1972 as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0 respectively).

Deciview means a measurement of visibility impairment. A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. The deciview haze index is calculated based on the following equation (for the purposes of calculating deciview, the atmospheric light extinction coefficient must be calculated from aerosol measurements):

Deciview haze index = $10 \ln_e (b_{ext}/10Mm^{-1})$ Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

Existing stationary facility means any of the following stationary sources of air pollutants, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

Fossil-fuel fired steam electric plants of more than 250 million British thermal units per hour heat input,

Coal cleaning plants (thermal dryers),

Kraft pulp mills,

Portland cement plants,

Primary zinc smelters,

Iron and steel mill plants,

Primary aluminum ore reduction plants,

Primary copper smelters,

Municipal incinerators capable of charging more than 250 tons of refuse per day,

Hydrofluoric, sulfuric, and nitric acid plants,

Petroleum refineries,

Lime plants,

Phosphate rock processing plants,

Coke oven batteries,
Sulfur recovery plants,
Carbon black plants (furnace process),
Primary lead smelters,
Fuel conversion plants,
Sintering plants,
Secondary metal production facilities,
Chemical process plants,
Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
Taconite ore processing facilities,
Glass fiber processing plants, and
Charcoal production facilities.

Federal Class I area means any Federal land that is classified or reclassified Class I.

Federal Land Manager means the Secretary of the department with authority over the Federal Class I area (or the Secretary's designee) or, with respect to Roosevelt-Campobello International Park, the Chairman of the Roosevelt-Campobello International Park Commission.

Federally enforceable means all limitations and conditions which are enforceable by the Administrator under the Clean Air Act including those requirements developed pursuant to parts 60 and 61 of this title, requirements within any applicable State Implementation Plan, and any permit requirements established pursuant to Sec. 52.21 of this chapter or under regulations approved pursuant to part 51, 52, or 60 of this title.

Fixed capital cost means the capital needed to provide all of the depreciable components.

Fugitive Emissions means those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening.

Geographic enhancement for the purpose of Sec. 51.308 means a method, procedure, or process to allow a broad regional strategy, such as an emissions trading program designed to achieve greater reasonable progress than BART for regional haze, to accommodate BART for reasonably attributable impairment.

Implementation plan means, for the purposes of this part, any State Implementation Plan, Federal Implementation Plan, or Tribal Implementation Plan.

Indian tribe or *tribe* means any Indian tribe, band, nation, or other organized group or community, including any Alaska Native village, which is federally recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians.

In existence means that the owner or operator has obtained all necessary preconstruction approvals or permits required by Federal, State, or local air pollution emissions and air quality laws or regulations and either has (1) begun, or caused to begin, a continuous program of physical on-site construction of the facility or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of construction of the facility to be completed in a reasonable time.

In operation means engaged in activity related to the primary design function of the source.

Installation means an identifiable piece of process equipment.

Integral vista means a view perceived from within the mandatory Class I Federal area of a specific landmark or panorama located outside the boundary of the mandatory Class I Federal area.

Least impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the lowest amount of visibility impairment.

Major stationary source and major modification mean major stationary source and major modification, respectively, as defined in Sec. 51.166.

Mandatory Class I Federal Area means any area identified in part 81, subpart D of this title.

Most impaired days means the average visibility impairment (measured in deciviews) for the twenty percent of monitored days in a calendar year with the highest amount of visibility impairment.

Natural conditions includes naturally occurring phenomena that reduce visibility as measured in terms of light extinction, visual range, contrast, or coloration.

Potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable.

Secondary emissions do not count in determining the potential to emit of a stationary source.

Reasonably attributable means attributable by visual observation or any other technique the State deems appropriate. Reasonably attributable visibility impairment means visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources.

Reconstruction will be presumed to have taken place where the fixed capital cost of the new component exceeds 50 percent of the fixed capital cost of a comparable entirely new source. Any final decision as to whether reconstruction has occurred must be made in accordance with the provisions of Sec. 60.15 (f) (1) through (3) of this title.

Regional haze means visibility impairment that is caused by the emission of air pollutants from numerous sources located over a wide geographic area. Such sources include, but are not limited to, major and minor stationary sources, mobile sources, and area sources.

Secondary emissions means emissions which occur as a result of the construction or operation of an existing stationary facility but do not come from the existing stationary facility. Secondary emissions may include, but are not limited to, emissions from ships or trains coming to or from the existing stationary facility.

Significant impairment means, for purposes of Sec. 51.303, visibility impairment which, in the judgment of the Administrator, interferes with the management, protection, preservation, or enjoyment of the visitor's visual experience of the mandatory Class I Federal area. This determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency and time of the visibility impairment, and how these factors correlate with (1) times of visitor use of the mandatory Class I Federal area, and (2) the frequency and timing of natural conditions that reduce visibility.

State means ``State'' as defined in section 302(d) of the CAA.

Stationary Source means any building, structure, facility, or installation which emits or may emit any air pollutant.

Visibility impairment means any humanly perceptible change in visibility (light extinction, visual range, contrast, coloration) from that which would have existed under natural conditions.

Visibility in any mandatory Class I Federal area includes any integral vista associated with that area.

[45 FR 80089, Dec. 2, 1980, as amended at 64 FR 35763, 35774, July 1, 1999]

Sec. 51.302 Implementation control strategies for reasonably attributable visibility impairment.

(a) Plan Revision Procedures. (1) Each State identified in Sec. 51.300(b)(2) must have submitted, not later than September 2, 1981, an implementation plan meeting the requirements of this subpart pertaining to reasonably attributable visibility impairment.

(2)(i) The State, prior to adoption of any implementation plan to address reasonably attributable visibility impairment required by this subpart, must conduct one or more public hearings on such plan in accordance with Sec. 51.102.

(ii) In addition to the requirements in Sec. 51.102, the State must provide written notification of such hearings to each affected Federal Land Manager, and other affected States, and must state where the public can inspect a summary prepared by the Federal Land Managers of their conclusions and recommendations, if any, on the proposed plan revision.

(3) Submission of plans as required by this subpart must be conducted in accordance with the procedures in Sec. 51.103.

(b) State and Federal Land Manager Coordination. (1) The State must identify to the Federal Land Managers, in writing and within 30 days of the date of promulgation of these regulations, the title of the official to which the Federal Land Manager of any mandatory Class I Federal area can submit a recommendation on the implementation of this subpart including, but not limited to:

(i) A list of integral vistas that are to be listed by the State for the purpose of implementing section 304,

(ii) Identification of impairment of visibility in any mandatory Class I Federal area(s), and

(iii) Identification of elements for inclusion in the visibility monitoring strategy required by section 305.

(2) The State must provide opportunity for consultation, in person and at least 60 days prior to holding any public hearing on the plan, with the Federal Land Manager on the proposed SIP revision required by this subpart. This consultation must include the opportunity for the affected Federal Land Managers to discuss their:

(i) Assessment of impairment of visibility in any mandatory Class I Federal area, and

(ii) Recommendations on the development of the long-term strategy.

(3) The plan must provide procedures for continuing consultation between the State and Federal Land Manager on the implementation of the visibility protection program required by this subpart.

(c) General plan requirements for reasonably attributable visibility impairment. (1) The affected Federal Land Manager may certify to the State, at any time, that there exists reasonably attributable impairment of visibility in any mandatory Class I Federal area.

(2) The plan must contain the following to address reasonably attributable impairment:

(i) A long-term (10-15 years) strategy, as specified in Sec. 51.305 and Sec. 51.306, including such emission limitations, schedules of compliance, and such other measures including schedules

for the implementation of the elements of the long-term strategy as may be necessary to make reasonable progress toward the national goal specified in Sec. 51.300(a).

(ii) An assessment of visibility impairment and a discussion of how each element of the plan relates to the preventing of future or remedying of existing impairment of visibility in any mandatory Class I Federal area within the State.

(iii) Emission limitations representing BART and schedules for compliance with BART for each existing stationary facility identified according to paragraph (c)(4) of this section.

(3) The plan must require each source to maintain control equipment required by this subpart and establish procedures to ensure such control equipment is properly operated and maintained.

(4) For any existing reasonably attributable visibility impairment the Federal Land Manager certifies to the State under paragraph (c)(1) of this section, at least 6 months prior to plan submission or revision:

(i) The State must identify and analyze for BART each existing stationary facility which may reasonably be anticipated to cause or contribute to impairment of visibility in any mandatory Class I Federal area where the impairment in the mandatory Class I Federal area is reasonably attributable to that existing stationary facility. The State need not consider any integral vista the Federal Land Manager did not identify pursuant to Sec. 51.304(b) at least 6 months before plan submission.

(ii) If the State determines that technologicial or economic limitations on the applicability of measurement methodology to a particular existing stationary facility would make the imposition of an emission standard infeasible it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results.

(iii) BART must be determined for fossil-fuel fired generating plants having a total generating capacity in excess of 750 megawatts pursuant to ``Guidelines for Determining Best Available Retrofit Technology for Coal-fired Power Plants and Other Existing Stationary Facilities" (1980), which is incorporated by reference, exclusive of appendix E, which was published in the Federal Register on February 6, 1980 (45 FR 8210). It is EPA publication No. 450/3-80-009b and is for sale from the U.S. Department of Commerce, National Technical Information Service, 5285 Port Royal Road, Springfield, Virginia 22161. It is also available for inspection at the Office of the Federal Register Information Center, 800 North Capitol NW., suite 700, Washington, DC.

(iv) The plan must require that each existing stationary facility required to install and operate BART do so as expeditiously as practicable but in no case later than five years after plan approval.

(v) The plan must provide for a BART analysis of any existing stationary facility that might cause or contribute to impairment of visibility in any mandatory Class I Federal area identified under this paragraph (c)(4) at such times, as determined by the Administrator, as new technology for control of the pollutant becomes reasonably available if:

(A) The pollutant is emitted by that existing stationary facility,

(B) Controls representing BART for the pollutant have not previously been required under this subpart, and

(C) The impairment of visibility in any mandatory Class I Federal area is reasonably attributable to the emissions of that pollutant.

[45 FR 80089, Dec. 2, 1980, as amended at 57 FR 40042, Sept. 1, 1992; 64 FR 35764, 35774, July 1, 1999]

Sec. 51.303 Exemptions from control.

(a)(1) Any existing stationary facility subject to the requirement under Sec. 51.302 to install, operate, and maintain BART may apply to the Administrator for an exemption from that requirement.

(2) An application under this section must include all available documentation relevant to the impact of the source's emissions on visibility in any mandatory Class I Federal area and a demonstration by the existing stationary facility that it does not or will not, by itself or in combination with other sources, emit any air pollutant which may be reasonably anticipated to cause or contribute to a significant impairment of visibility in any mandatory Class I Federal area.

(b) Any fossil-fuel fired power plant with a total generating capacity of 750 megawatts or more may receive an exemption from BART only if the owner or operator of such power plant demonstrates to the satisfaction of the Administrator that such power plant is located at such a distance from all mandatory Class I Federal areas that such power plant does not or will not, by itself or in combination with other sources, emit any air pollutant which may reasonably be anticipated to cause or contribute to significant impairment of visibility in any such mandatory Class I Federal area.

(c) Application under this Sec. 51.303 must be accompanied by a written concurrence from the State with regulatory authority over the source.

(d) The existing stationary facility must give prior written notice to all affected Federal Land Managers of any application for exemption under this Sec. 51.303.

(e) The Federal Land Manager may provide an initial recommendation or comment on the disposition of such application. Such recommendation, where provided, must be part of the exemption application. This recommendation is not to be construed as the concurrence required under paragraph (h) of this section.

(f) The Administrator, within 90 days of receipt of an application for exemption from control, will provide notice of receipt of an exemption application and notice of opportunity for public hearing on the application.

(g) After notice and opportunity for public hearing, the Administrator may grant or deny the exemption. For purposes of judicial review, final EPA action on an application for an exemption under this Sec. 51.303 will not occur until EPA approves or disapproves the State Implementation Plan revision.

(h) An exemption granted by the Administrator under this Sec. 51.303 will be effective only upon concurrence by all affected Federal Land Managers with the Administrator's determination.

[45 FR 80089, Dec. 2, 1980, as amended by 64 FR 35774, July 1, 1999]

Sec. 51.304 Identification of integral vistas.

(a) On or before December 31, 1985 the Federal Land Manager may identify any integral vista. The integral vista must be identified according to criteria the Federal Land Manager

develops. These criteria must include, but are not limited to, whether the integral vista is important to the visitor's visual experience of the mandatory Class I Federal area. Adoption of criteria must be preceded by reasonable notice and opportunity for public comment on the proposed criteria.

(b) The Federal Land Manager must notify the State of any integral vistas identified under paragraph (a) of this section, and the reasons therefor.

(c) The State must list in its implementation plan any integral vista the Federal Land Manager identifies at least six months prior to plan submission, and must list in its implementation plan at its earliest opportunity, and in no case later than at the time of the periodic review of the SIP required by Sec. 51.306(c), any integral vista the Federal Land Manager identifies after that time.

(d) The State need not in its implementation plan list any integral vista the identification of which was not made in accordance with the criteria in paragraph (a) of this section. In making this finding, the State must carefully consider the expertise of the Federal Land Manager in making the judgments called for by the criteria for identification. Where the State and the Federal Land Manager disagree on the identification of any integral vista, the State must give the Federal Land Manager an opportunity to consult with the Governor of the State.

[45 FR 80089, Dec. 2, 1980, as amended by 64 FR 35774, July 1, 1999]

Sec. 51.305 Monitoring for reasonably attributable visibility impairment.

(a) For the purposes of addressing reasonably attributable visibility impairment, each State containing a mandatory Class I Federal area must include in the plan a strategy for evaluating reasonably attributable visibility impairment in any mandatory Class I Federal area by visual observation or other appropriate monitoring techniques. Such strategy must take into account current and anticipated visibility monitoring research, the availability of appropriate monitoring techniques, and such guidance as is provided by the Agency.

(b) The plan must provide for the consideration of available visibility data and must provide a mechanism for its use in decisions required by this subpart.

[45 FR 80089, Dec. 2, 1980, as amended at 64 FR 35764, July 1, 1999]

Sec. 51.306 Long-term strategy requirements for reasonably attributable visibility impairment.

(a)(1) For the purposes of addressing reasonably attributable visibility impairment, each plan must include a long-term (10-15 years) strategy for making reasonable progress toward the national goal specified in Sec. 51.300(a). This strategy must cover any existing impairment the Federal Land Manager certifies to the State at least 6 months prior to plan submission, and any integral vista of which the Federal Land Manager notifies the State at least 6 months prior to plan submission.

(2) A long-term strategy must be developed for each mandatory Class I Federal area located within the State and each mandatory Class I Federal area located outside the State which may be affected by sources within the State. This does not preclude the development of a single comprehensive plan for all such areas.

(3) The plan must set forth with reasonable specificity why the long-term strategy is adequate for making reasonable progress toward the national visibility goal, including remedying existing and preventing future impairment.

(b) The State must coordinate its long-term strategy for an area with existing plans and goals, including those provided by the affected Federal Land Managers, that may affect impairment of visibility in any mandatory Class I Federal area.

(c) The plan must provide for periodic review and revision, as appropriate, of the long-term strategy for addressing reasonably attributable visibility impairment. The plan must provide for such periodic review and revision not less frequently than every 3 years until the date of submission of the State's first plan addressing regional haze visibility impairment in accordance with Sec. 51.308(b) and (c). On or before this date, the State must revise its plan to provide for review and revision of a coordinated long-term strategy for addressing reasonably attributable and regional haze visibility impairment, and the State must submit the first such coordinated long-term strategy. Future coordinated long-term strategies must be submitted consistent with the schedule for periodic progress reports set forth in Sec. 51.308(g). Until the State revises its plan to meet this requirement, the State must continue to comply with existing requirements for plan review and revision, and with all emission management requirements in the plan to address reasonably attributable impairment. This requirement does not affect any preexisting deadlines for State submittal of a long-term strategy review (or element thereof) between August 30, 1999, and the date required for submission of the State's first regional haze plan. In addition, the plan must provide for review of the long-term strategy as it applies to reasonably attributable impairment, and revision as appropriate, within 3 years of State receipt of any certification of reasonably attributable impairment from a Federal Land Manager. The review process must include consultation with the appropriate Federal Land Managers, and the State must provide a report to the public and the Administrator on progress toward the national goal. This report must include an assessment of:

(1) The progress achieved in remedying existing impairment of visibility in any mandatory Class I Federal area;

(2) The ability of the long-term strategy to prevent future impairment of visibility in any mandatory Class I Federal area;

(3) Any change in visibility since the last such report, or, in the case of the first report, since plan approval;

(4) Additional measures, including the need for SIP revisions, that may be necessary to assure reasonable progress toward the national visibility goal;

(5) The progress achieved in implementing BART and meeting other schedules set forth in the long-term strategy;

(6) The impact of any exemption granted under Sec. 51.303;

(7) The need for BART to remedy existing visibility impairment of any integral vista listed in the plan since the last such report, or, in the case of the first report, since plan approval.

(d) The long-term strategy must provide for review of the impacts from any new major stationary source or major modifications on visibility in any mandatory Class I Federal area. This review of major stationary sources or major modifications must be in accordance with Sec. 51.307, Sec. 51.166, Sec. 51.160, and any other binding guidance provided by the Agency insofar as these provisions pertain to protection of visibility in any mandatory Class I Federal areas.

(e) The State must consider, at a minimum, the following factors during the development of its long-term strategy:

(1) Emission reductions due to ongoing air pollution control programs,

(2) Additional emission limitations and schedules for compliance,

(3) Measures to mitigate the impacts of construction activities,

(4) Source retirement and replacement schedules,

(5) Smoke management techniques for agricultural and forestry management purposes including such plans as currently exist within the State for these purposes, and

(6) Enforceability of emission limitations and control measures.

(f) The plan must discuss the reasons why the above and other reasonable measures considered in the development of the long-term strategy were or were not adopted as part of the long-term strategy.

(g) The State, in developing the long-term strategy, must take into account the effect of new sources, and the costs of compliance, the time necessary for compliance, the energy and nonair quality environmental impacts of compliance, and the remaining useful life of any affected existing source and equipment therein.

[45 FR 80089, Dec. 2, 1980, as amended at 64 FR 35764, 35774, July 1, 1999]

APPENDIX A-9. MOBILE SOURCES

This appendix contains work products and references relied upon by Arizona in the development of Chapter 9 of the Regional Haze SIP.

Appendix A-9a. Arizona Mobile Source Work Group Findings and Recommendations Related to Mobile Source Emissions

Arizona Regional Haze Mobile Source Working Group
Mobile Source Significance Determination

INTRODUCTION

Statement of Purpose

This report presents the findings of the Mobile Source Working Group (MSWG) regarding the significance of Arizona mobile source emissions on the visibility impairment for the 16 Class I areas on the Colorado Plateau. The other Class I areas within the State will not be addressed here but will be addressed under Section 309(g) of the Regional Haze Rule (RHR) later. The MSWG's analysis was based on the regulatory requirements in 40 CFR 51.309(d)(5)(i-iii), the Grand Canyon Visibility Transport Commission (GCVTC) report that formed the basis for those regulations, and information from the Western Regional Air Partnership (WRAP).

The MSWG provides this report to the Arizona Department of Environmental Quality (ADEQ) for their consideration in preparing the Arizona Regional Haze State Implementation Plan (SIP).

Summary of Findings

Based on the analysis of available data, the MSWG finds that mobile source emissions in Arizona do not significantly contribute to visibility impairment in any of the 16 GCVTC Class I areas on the Colorado Plateau.

In reaching that conclusion, the MSWG analyzed mobile source pollutant emissions data of volatile organic compounds (VOC), oxides of nitrogen (NO_X), sulfur dioxide (SO_2), elemental carbon (EC), organic carbon (OC), and fine particulates ($PM_{2.5}$) for the years 2003 to 2018; air quality modeling and other technical information available from the WRAP; their approach in making the significance determination for the region, and the Environmental Protection Agency (EPA) current and future programs and their potential benefits. This conclusion is based upon the findings listed below, and explained in this report.

1) Mobile source emissions of VOC, NOx, $PM_{2.5,}$ SO_2, EC, and OC will decline from 2003 to 2018.

2) Year to year mobile source emissions of VOC, NOx $PM_{2.5}$, EC, and OC are expected to decline from 2003 to 2018.

3) Annual mobile source emissions of SO_2 are expected to decline from 2003 to 2013 with a slight increase from 2013 to 2018 with proposed federal standards for non-road equipment and diesel fuel. The minor increase is uncertain and cannot be accurately quantified and will be further addressed in the Technical

Support Document (TSD). In the event that the EPA proposed non-road standards are not adopted, Arizona will be required to submit a SIP revision as proposed by the WRAP, in their letter dated May 6, 2003 to ensure reasonable progress prior to December 31, 2008.

4) Annual mobile source emissions of VOC, NOx $PM_{2.5}$, EC, and OC are expected to have a minimal impact on visibility.

5) Reasonable progress will be achieved over the planning period with the projected emission reductions.

6) The relative contribution of mobile source SO_2 emissions is insignificant compared to that of the emissions from stationary sources.

7) There is considerable uncertainty in regulations and projections of emissions. The projected increase in SO_2 for the later part of the planning period is not certain. By 2008, the emissions for 2013 can be better assessed with some certainty.

REGULATORY REQUIREMENT

Regional Haze Rule

The federal RHR relies upon the GCVTC report as the basis for states to submit a SIP under 40 CFR 51.309(d)(5).

Section 309 of the RHR requires states to evaluate mobile source emissions, and if they are determined to significantly contribute to regional haze in the 16 Class I areas, then additional provisions apply.

SIPs developed under Section 309 must include the following elements:

- A statewide inventory of current mobile source emissions and projected future emissions of VOC, NO_X, SO_2, $PM_{2.5,}$ EC, and OC, for the years 2003 to 2018. The emissions inventory must also include projections for 2005, or an alternative year when the mobile source emissions are found to be at their lowest levels (40 CFR 51.309(d)(5)(i)).

- A determination of whether mobile source emissions from any areas in the state "contribute significantly" to visibility impairment at any of the 16 Class I areas (40 CFR 51.309(d)(5)(ii)).

- If any area of the state is found to contribute significantly to visibility impairment at any of those 16 Class I areas, the SIP must also include:

- An emission budget (cap) and measures to ensure that emissions do not increase beyond their lowest projected levels for the planning period (40 CFR 51.309(d)(5)(iii)(A)).
- An emission tracking system to ensure that mobile source emissions do not increase thereafter (40 CFR 51.309(d)(5)(iii)(B)).

- Progress reports to EPA on the implementation of mobile source recommendations of the GCVTC (40 CFR 51.309(d)(5)(iv).

In the event that EPA finalizes the rule change as proposed, 51.309(d)(5)(ii) and (iii) above will then be removed (see below).

WRAP APPROACH TO SIGNIFICANCE DETERMINATION

Recently, the WRAP concluded that the attempt to measure mobile source significance is no longer necessary because new federal programs will achieve continual emission reductions as required for significant areas in Section 309(d)(5)(iii). On May 6, 2003, the WRAP submitted a letter to EPA proposing amendments to the RHR to eliminate the requirement to conduct the mobile source significance determination, and to address non-road mobile sources of SO_2. The WRAP letter is provided in Attachment A. The EPA has published these changes to the rule (Federal Register Vol.68, No. 128, July 3, 2003), along with a 30-day comment period. EPA has proposed a direct final for the rule. Even if the rule is challenged it still could be finalized by the end of the year.

Proposed WRAP Amendments: Significance Requirements

The GCVTC and the final RHR assumed that mobile sources were expected to decline from 2003-2005 and increase annually through 2018. As noted above, the rule required emission budgets in “significant” areas to prevent the increase in emissions. That goal is being achieved without emission caps because of new federal programs: Tier 1 gasoline sulfur controls in January 2001, and Tier 2 motor vehicle controls in February 2000, and heavy-duty engine and vehicle standards and highway diesel sulfur controls in October 2000 and January 2001. New and updated emissions models predict dramatic emission reductions from these programs. Therefore, the WRAP recommended that EPA remove the requirements for the significance determination in Sections 40 CFR 51.309(d)(5)(ii) and (iii) and amend the rule to require states to demonstrate and monitor a continuous reduction of mobile source emissions of each of the pollutants.

Proposed WRAP Amendments: SO_2 Emission Reductions

The WRAP recommendation also specifically addresses the issue of the projected increase in SO_2 emissions from non-road mobile sources in the late years of the planning period (2013-2018). Earlier this year, EPA proposed new standards for non-road equipment and non-road diesel fuels that will dramatically reduce SO_2 emission

and ensure continued emission reductions for this pollutant (Federal Register Vol.68, No. 100, May 23, 2003). Those rules will not be finalized before December 31, 2003, the deadline for states to submit their Regional Haze SIPs. Therefore, the WRAP proposed amendment would require states to submit SIP revisions by 2008 to assess whether reasonable progress is being made and if necessary take action to reduce non-road SO_2 emissions if the EPA does not adopt the proposed federal standard to ensure reasonable progress.

SIGNIFICANCE DETERMINATION AND FINDINGS

The MSWG has determined that mobile sources emissions within areas in Arizona do not contribute significantly to visibility degradation at the 16 Class I areas. This conclusion also supports the WRAP recommendation that determination of mobile source emissions impact should be removed from the RHR and replaced with a requirement for states to demonstrate continual mobile source emission reductions over the planning period, considering economic and technological reasonableness and applicable state authority of the strategy.

In making the significance determination, the MSWG analyzed the Arizona mobile source emissions and the impact of the new federal programs to determine if continuous reductions were achieved for each of the pollutants throughout the planning period. The MSWG evaluated the technical data and recent modeling results prepared by ENVIRON for the WRAP. The findings provided below are based upon that review.

Current and Projected Emissions from Mobile Sources

Inventory

The WRAP developed comprehensive emission inventories for mobile sources for the State of Arizona and other western states in 5-year increments. It is assumed that interim years follow the 5-year trends. This inventory included the two major urban areas in the state (Phoenix region represented as Maricopa County, and Tucson region represented as Pima County). The emissions from these two counties follow that of the State totals, with their emissions continuing to decline over the planning period. The current and projected statewide inventories of emissions from mobile sources are shown in Table 1.

Table 1: Arizona Projected Emissions for Mobile Sources 2003 through 2018 TPD

	AZ. Total
2003	989.1
2008	733.1
2013	582.2
2018	495.9
% Change	**-50%**

Finding 1. Mobile source emissions of all pollutants (VOC, NOx, $PM_{2.5}$, EC, OC, and SO_2) decline from 2003 to 2018.

The analysis of the Arizona data parallels that of the regional analysis conducted by the WRAP. The success of new mobile source control programs is demonstrated most clearly in the dramatic reductions of emissions from 2003 to 2018. During this period of continued growth in population and vehicle miles traveled (VMT), all mobile source emissions are reduced. The total of all mobile source emissions decline 50% for the planning period. An analysis of the data for each pollutant during that same period shows that emissions of VOC and NOx steadily decline (by 51% and 52% respectively), while $PM_{2.5}$ shows a decrease of 22%. Additionally, because both EC and OC are represented as a percentage of the $PM_{2.5}$ we can assume that both EC and OC will follow the reduction observed in $PM_{2.5}$; SO_2 also declines by 11% (Attachment B).

Finding 2. Year to year mobile source emissions of VOC, NOx, $PM_{2.5}$, EC, and OC are expected to decline from 2003 to 2018.

The GCVTC recommended that emissions show reasonable progress. The GCVTC defined reasonable progress as steady and continuing emission reductions that, in the long-term, lead to improvements in visibility. This is used as the measure of reasonable progress under Section 309. The WRAP and EPA interpretation of the rule requires that each pollutant must be measured separately in the demonstration of continual reductions.

Attachment B provides a demonstration that VOC, NOx, and $PM_{2.5}$, and hence EC and OC, each show annual reductions in the planning period and thus meet the reasonable progress goal in the RHR.

Finding 3. Annual mobile source emissions of SO_2 are expected to continually decline from 2003 to 2013 with a minor increase from 2013 to 2018 with proposed federal sulfur standards for non-road diesel.

Annual mobile source emissions of SO_2 show an overall decline of 11% over the planning period with existing federal programs (Attachment B). The proposed non-road federal standards are expected to ensure annual emission reductions (Attachment C).

As noted in the WRAP letter of May 6, 2003, the proposed federal non-road standards are critical to this progress. As long as EPA adopts the proposed federal non-road standards, reasonable progress is achieved. Without these standards, the annual emission reductions for mobile sources are achieved only until 2013 when SO_2 emissions increase from 9.5 tons/day to 18.6 tons/day (Attachment B). If the non-road standards are adopted, the overall SO_2 emissions will decline by 27% from 2003 to 2018. The slight increase from 2013 to 2018 is uncertain and cannot be accurately quantified and will be further addressed in the TSD. If EPA fails to adopt the proposed

standards by 2008, Arizona will have adequate time to reassess the progress and adopt state standards if necessary to account for any emissions increases in mobile source emissions. Even though some uncertainty exists in these projections, the new standards would ensure that annual emissions would decline for SO_2 emissions and therefore all mobile sources emissions in the state.

The RHR clearly does not require a separate analysis of on-road and non-road emissions in making the significance determination. However, the evaluation of the SO_2 emissions data demonstrates the importance of the federal non-road rule (see Attachments B and C). A comparison of emissions in the years 2003 and 2018 from Attachment B shows that on-road SO_2 emissions decrease by 78%, while non-road SO_2 emissions decrease until 2013 and then increase late in the planning period, resulting in a 46% increase overall. That increase is without the proposed federal non-road standards. Assuming the proposed federal standards are adopted (see Attachment C), the non-road SO_2 emissions decline by 27%.

The point is made even more dramatically in a comparison of 2018 non-road SO_2 emissions in Attachments B and C, showing that 2018 SO_2 emissions will be 16.5 tons/day without controls and 8.2 tons/day if the proposed federal standards are adopted. This will result in a 50% reduction in non-road SO_2 emissions.

Finding 4. Annual mobile source emissions of VOC, NOx, $PM_{2.5}$, EC, and OC are expected to have a minimal impact on visibility.

The WRAP performed a modeling analysis to estimate the impact of mobile source emissions from Phoenix Metropolitan area at the GCVTC Class I in 2018. The forecast year 2018 was chosen since it represents the year with the lowest emissions, and is at the end of the planning period. Table 2 summarizes the relative impact of emissions from the Phoenix Metropolitan area at the 16 GCVTC Class I areas, expressed as a percentage of the projected WRAP 2018 Base Case light extinction. Based on WRAP modeling, by 2018 the impact of mobile sources from Arizona urban areas on the GCVTC class I areas will be between 0% and 4% of the projected light extinction.

Table 2. Contribution to Light Extinction from Phoenix Mobile Source Emissions (Expressed as a % of WRAP 2018 Base Case Light Extinction)

Class I Area on the Colorado Plateau	Phoenix
Arches NP	0%
Black Canyon NP	0%
Bryce Canyon NP	0%
Canyonlands NP	0%
Capitol Reef NP	0%
Flat Tops Wilderness	0%
Grand Canyon NP	1%
Maroon Bells Wilderness	0%
Mesa Verde NP	1%
Mount Baldy Wilderness	2%

Petrified Forest NP	4%
San Pedro Parks WA	1%
Sycamore Canyon WA	2%
West Elk Wilderness	0%
Weminuche Wilderness	0%
Zion NP	0%

Source: Table 3. Percent change in light extinction over 2018 WRAP Base Case Conditions at the 16 Class I areas on the Colorado Plateau due to Mobile Source Emissions from the 9 GCVTC States, California, Phoenix, and Las Vegas, *"WRAP Technical memorandum from the Air Quality Modeling Forum to the Mobile Source Forum", November 4, 2002.*

Finding 5. Reasonable progress will be achieved over the planning period with the projected emission reductions for all mobile source pollutants.

The GCVTC definition of reasonable progress is thus met in findings 2 and 3 above, assuming the adoption of the proposed federal non-road rules.

Finding 6. The relative contribution of mobile source SO_2 is insignificant compared to that of stationary sources.

Based upon data from the WRAP Annex, the category of stationary sources is the primary source of SO_2 contributing to regional haze in the GCVTC 16 class I areas. In Arizona, the mobile source contribution to the total concentration of SO_2 is relatively small. In 2003, it represents about 5.3% of the total; while in 2018, with EPA's proposed rule, it is about 3.9% of total emissions. These data also show that the potential relative contribution of mobile sources emissions to the total SO_2 would be decreasing at a greater rate than that of stationary sources with EPA's new proposed non-road rule. This continued improvement in mobile source emissions is the result of stringent federal programs created after the 1995 GCVTC report. Therefore, the WRAP concluded that the Commission's concern about the potential impact from mobile sources has been addressed. Additional federal control programs for mobile sources will provide an even greater improvement in emissions in upcoming years.

Finding 7. The uncertainty in regulations and projections in emissions adds to the determination.

It is important to note that uncertainty exists in several areas: 1) the adoption of the proposed federal non-road standards as proposed on May 23, 2003; 2) the projected benefits that might be achieved, and 3) the projections of emissions from the model for the later years. When looking at the data, the projections for the early years are likely to be more valid than those estimated for 2018. This uncertainty can be addressed through periodic reporting on the progress of the reduction in mobile source emissions and then making adjustments in the SIP.

MSWG RECOMMENDATION TO ADEQ FOR SIGNIFICANCE DETERMINATION:

Based on this analysis, the MSWG concludes that mobile source emissions do not significantly contribute to regional haze at any of the 16 GCVTC Class I areas. This finding does not attempt to address the other Class I areas in the State that will be addressed in the future under Section 309(g) of the RHR.

In evaluating the impact of mobile source emissions in the 16 Class I areas, the MSWG considered a wide range of information from the WRAP analysis as well as Arizona-specific data on total emissions as well as specific pollutants. The Working Group concludes that reductions in mobile source emissions will meet the GCVTC goal of continued reduction throughout the planning period based upon new and proposed federal programs with the EPA adoption of the proposed non-road rules. In the event that EPA's proposed non-road standards are not realized, the WRAP recommends that states be required to file a SIP revision to ensure reasonable progress prior to December 31, 2008.

Based upon the findings above, the MSWG recommends that ADEQ consider this report in preparing the significance determination for the Arizona Regional Haze SIP.

Should the proposed revisions to the RHR become effective prior to the submission of the Arizona SIP under Section 309, references to 40 CFR 51.309(d)(5)(ii-iii) will be eliminated.

List of Attachments:

Attachment A "WRAP Letter to EPA (Dated May 6, 2003)"

Attachment B "Total Arizona Mobile Source Emissions by Pollutant Projected for 2003 through 2018 Assuming No New Regulations"

Attachment C "Total Arizona Mobile Source Emissions by Pollutant Projected for 2003 through 2018, Assuming a 15 ppm Sulfur Non-road Diesel Standard"

Western Regional Air Partnership

May 6, 2003

The Honorable Christie Todd Whitman
Administrator
U.S. Environmental Protection Agency (1101A)
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Dear Administrator Whitman:

The Western Regional Air Partnership (WRAP) requests that EPA update Section 309 of the Regional Haze Regulations to reflect the current situation relative to mobile source emissions in the West. The approach to mobile sources currently included in Section 309 is based on recommendations of the Grand Canyon Visibility Transport Commission (GCVTC) that are now outdated because of new mobile source emissions models and new federal engine and fuel standards adopted by EPA since the Commission made its recommendations in 1996.

The WRAP's suggested revisions update section 309 requirements to conform with expected trends in mobile source emissions. They also eliminate certain mobile source requirements which are now unnecessary, and add a substitute requirement for sulfur dioxide emissions from non-road mobile sources that would take effect if EPA's recently proposed standards for sulfur in non-road diesel fuel are not adopted.

Specifically, the requested revision would eliminate §51.309(d)(5)(ii) and (iii) and modify the provisions of §51.309(d)(5)(i) to require a showing of continuous emission reduction of total mobile source emissions of VOC, NOx, PM2.5, organic carbon and elemental carbon (evaluated separately) over the period 2003-2018. For SO2, the requested correction would require an implementation plan revision by no later than December 31, 2008 containing any necessary long-term strategies to reduce emissions of SO2 from non-road sources in the event that EPA does not adopt a federal standard as recently proposed. Specific regulatory language to implement these suggested changes is included in Attachment 1.

Staffed by:
Western Governors' Association
1515 Cleveland Place, Suite 200
Denver, CO 80202
(303) 623-9378
Fax (303) 534-7309

www.wrapair.org

Staffed by:
National Tribal Environmental Council
2221 Rio Grande NW
Albuquerque, NM 87104
(505) 242-2175
Fax (505) 242-2654

EPA's Regional Haze Rule currently requires states that choose to submit plans under Section 309 to provide for: "A determination whether mobile source emissions in any areas of the state contribute significantly to visibility impairment in any of the 16 Class I Areas, based on the statewide inventory of current and projected mobile source emissions" (51.309(d)(5)(ii)).

If mobile source emissions in any area of the state are found to contribute significantly to visibility impairment in any of the 16 Class I areas, the rule requires: "The establishment and documentation of a mobile source emissions budget for any such area, including provisions requiring the state to restrict the annual VOC, NOx, SO2, elemental and organic carbon, and/or fine particle mobile source emissions to their projected lowest level, to implement measures to achieve the budget or cap, and to demonstrate compliance with the budget." (51.309(d)(5)(iii)(A)).

These provisions are based on the GCVTC's recommendations for mobile sources. The GCVTC was concerned because their modeling of mobile source emissions showed emissions reaching a low point in 2005 and then increasing.

Due to new mobile source emissions models and, more importantly, new federal engine and fuel standards adopted by EPA since the Commission made its recommendations in 1996, the WRAP's current emissions projections indicate a significant decline in mobile source emissions throughout the West during the 2003-2018 time period covered by the Section 309 plans. This trend is especially dramatic for on-road mobile source emissions.

While we also project emission reductions from non-road mobile sources (except SO2), the reductions are not as great. By 2018, in the absence of new standards for non-road diesel engines and fuel, such as those recently proposed by EPA, the contribution to visibility impairment in the West from non-road sources will be much greater than that from on-road sources. For this reason, the WRAP supports expeditious implementation of rigorous new engine and fuel standards for non-road diesel sources that are similar in stringency to those for on-road sources.

Regarding SO2, the WRAP has found that current federal regulations for on-road gasoline and diesel fuel provide the most effective level of control possible at this time. On the other hand, the WRAP has found that SO2 emissions from non-road mobile sources will continue to be of concern in the absence of a federal standard for non-road diesel fuel. Since EPA has proposed new federal standards to address this problem, the WRAP's suggested update to Section 309 postpones action as part of the plans due this year, but requires states to submit an implementation plan revision by no later than December 31, 2008 containing any necessary long-term strategies to reduce emissions of SO2 from non-road sources, consistent with the goal of reasonable progress. This requirement is intended to

ensure that states work to reduce current levels of SO2 from non-road sources as part of their regional haze plans if EPA does not adopt a federal standard as recently proposed.
In the event that EPA does pass a federal sulfur standard for non-road diesel fuel, the WRAP does not believe that the resulting emission reductions should be allowed to be used to offset emissions from other sources that are contributing to haze in the West.

Given that Section 309 plans are due at the end of this year, we are hopeful that EPA will be able to work with the Office of Management and Budget to make this revision to the rule on an expedited basis. We appreciate your assistance with this request and will certainly provide any additional information EPA may need.

Sincerely,

Michael O. Leavitt
Governor of Utah
WRAP Co-Chair

Fred S. Vallo, Sr.
Governor of Pueblo of Acoma
WRAP Co- Chair

cc: Mr. Jeffrey Holmstead, EPA
Ms. Lydia Wegman, EPA

Attachment 1:
Proposed Revised Rule Language

CFR 51.309(d)(5) Mobile sources. The plan submission must provide for:

(i) Statewide inventories of on-road and non-road mobile source emissions of VOC, NOx, SO2, fine particles (PM-2.5), elemental carbon, and organic carbon for the years 2003, 2008, 2013, and 2018.

The inventories must demonstrate a continuous decline in total mobile source emissions (on-road plus non-road; tailpipe and evaporative) of VOC, NOx, fine particles (PM-2.5), elemental carbon, and organic carbon, evaluated separately. If the inventories show that mobile source emissions of each of these pollutants will continuously decline over the period, no further action is required as part of this plan to address mobile source emissions of these pollutants. If the inventories show that mobile source emissions of one or more of these pollutants will not continuously decline over the period 2003-2018, the plan submission must provide for an implementation plan revision by no later than December 31, 2008 containing any necessary long-term strategies to achieve a continuous decline in mobile source emissions of the pollutant(s), to the extent practicable, considering economic and technological reasonableness and applicable state authority.

The plan submission must also provide for an implementation plan revision by no later than December 31, 2008 containing any long-term strategies necessary to reduce emissions of SO2 from non-road mobile sources, consistent with the goal of reasonable progress. In assessing the need for such long term strategies, the state may consider emissions reductions achieved or anticipated from any new federal standards for sulfur in non-road diesel fuel.

Delete 309(d)(5)(ii) and (iii) and the definition of mobile source emissions budget found at 309(b)(6).

Definition of continuous decline: The emission inventories submitted as part of this plan must show that statewide mobile source emission levels (on-road plus non-road) of each listed pollutant in 2008, 2013, and 2018 are less than the estimated level of that pollutant for the previous period (i.e., 2008 less than 2003; 2013 less than 2008; and 2018 less than 2013).

Attachment B
Total Arizona Emission by Pollutant
Projections for 2003 through 2018
Assume No New Regulations
(TPD)

	State Total				
	VOC	NOx	PM2.5	SO2	Total
2003	448.7	496.5	23.0	20.9	**989.1**
2008	319.9	381.2	22.0	14.6	**737.7**
2013	256.9	296.7	19.1	16.6	**589.3**
2018	222.0	237.3	18.0	18.6	**495.9**
% Change	**-51%**	**-52%**	**-22%**	**-11%**	**-50%**

	Non-road				
	VOC	NOx	PM2.5	SO2*	Total
2003	112.1	150.2	14.2	11.3	**287.8**
2008	77.7	124.4	13.8	13.0	**228.9**
2013	70.3	111.1	13.3	14.8	**209.5**
2018	69.7	107.8	13.4	16.5	**207.4**
% Change	**-38%**	**-28%**	**-6%**	**46%**	**-28%**

*2003 and 2018 are actual model outputs;
2008 and 2013 are extrapolated and assumed to be linear.

	On-road				
	VOC	NOx	PM2.5	SO2	Total
2003	336.6	346.3	8.8	9.6	**701.3**
2008	242.2	256.8	8.2	1.6	**508.8**
2013	186.6	185.6	5.8	1.8	**379.8**
2018	152.3	129.5	4.6	2.1	**288.5**
% Change	**-55%**	**-63%**	**-48%**	**-78%**	**-59%**

Note: Both EC and OC are represented as a percentage of the $PM_{2.5}$ and we can assume that both EC and OC will follow the changes observed in $PM_{2.5}$

Attachment C
Total Arizona Emission by Pollutant
Projections for 2003 through 2018
Assume a 15 ppm Sulfur Non-road Diesel Standard
(TPD)

	State Total				
	VOC	NOx	PM2.5	SO2	Total
2003	448.7	496.5	23.0	20.9	**989.1**
2008	319.9	381.2	22.0	10.0	**733.1**
2013	256.9	296.7	19.1	9.5	**582.2**
2018	222.0	237.3	18.0	10.3	**487.6**
% Change	**-51%**	**-52%**	**-22%**	**-51%**	**-51%**

Note: Assumes all the reductions associated with 15 ppm Standard come between 2013 and 2018

	Non-road				
	VOC	NOx	PM2.5	SO2	Total
2003	112.1	150.2	14.2	11.3	**287.8**
2008	77.7	124.4	13.8	8.4	**224.3**
2013	70.3	111.1	13.3	7.7	**202.4**
2018	69.7	107.8	13.4	8.2	**199.1**
% Change	**-38%**	**-28%**	**-6%**	**-27%**	**-31%**

	On-road				
	VOC	NOx	PM2.5	SO2	Total
2003	336.6	346.3	8.8	9.6	**701.3**
2008	242.2	256.8	8.2	1.6	**508.8**
2013	186.6	185.6	5.8	1.8	**379.8**
2018	152.3	129.5	4.6	2.1	**288.5**
% Change	**-55%**	**-63%**	**-48%**	**-78%**	**-59%**

Note: Both EC and OC are represented as a percentage of the $PM_{2.5}$ and we can assume that both EC and OC will follow the changes observed in $PM_{2.5}$