# ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

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Janice K. Brewer
Governor

Henry R. Darwin
Director


MAR 29 2013

Mr. Jared Blumenfeld
Regional Administrator
U.S. Environmental Protection Agency, Region IX
Mail Code: ORA-1
75 Hawthorne Street
San Francisco, CA 94105

RE: Proposed Revision to Arizona Regional Haze State Implementation Plan

Dear Mr. Blumenfeld,

Consistent with the provisions of Arizona Revised Statutes §§ 49-104, 49-106, 49-404, 49-425, 49-458, and 49-458.01, and the Code of Federal Regulations (CFR) Title 40, §§ 51.102 through 51.104, the Arizona Department of Environmental Quality (ADEQ) hereby submits to the U.S. Environmental Protection Agency (EPA) the "Arizona State Implementation Plan, Regional Haze Under Section 308 of the Federal Regional Haze Rule, March 2013" and "Arizona Regional Haze State Implementation Plan Revision, Technical Support Document, March 20, 2013" as a proposed revision to the Arizona State Implementation Plan (SIP).

On February 28, 2011, ADEQ adopted and submitted to the United States Environmental Protection Agency (EPA), Arizona's State Implementation Plan (SIP) for Regional Haze under Section 308 of the Federal Regional Haze Rule (RHR). On December 21, 2012, EPA proposed to approve in part and disapprove in part Arizona's Regional Haze SIP (77 FR 75704). The elements of Arizona's Regional Haze SIP that EPA is proposing to disapprove are included in the table below. To address these deficiencies, Arizona is proposing to revise elements in its Regional Haze SIP.

| EPA Proposed Disapproval | Relevant Section of CFR | Location in 2013 Regional Haze SIP Revision | Sections Being Replaced in 2011 Regional Haze SIP |
|---|---|---|---|
| SIP does not include the most recently available emission inventory (required by the RHR). | 40 CFR 51.308(d)(4)(v) | Sections 8.6 through 8.9 (*New Sections*) | None |
| Arizona's determination that Tucson Electric Power Sundt Generating Station Unit 4 is not BART eligible. | 40 CFR 51.301; 40 CFR Part 51, Appendix Y | No Change | No Change |

| EPA Proposed Disapproval | Relevant Section of CFR | Location in 2013 Regional Haze SIP Revision | Sections Being Replaced in 2011 Regional Haze SIP |
|---|---|---|---|
| Arizona's determination that Nelson Lime Plant is exempt from BART (EPA is seeking comment on whether this determination was reasonable and should be approved). | 40 CFR Part 51, Appendix Y | No Change | No Change |
| Arizona's conclusion that a BART determination is not required for $PM_{10}$ at the Hayden smelter and for $NO_X$ at the Miami smelter. | 40 CFR 51.301;<br>40 CFR 51.308(e)(1)(ii);<br>40 CFR 51.308(e)(1)(ii)(C) | Appendix D | Appendix D |
| Compliance schedules and requirements for equipment maintenance and operation related to BART controls at the Hayden smelter and the Miami smelter were not included in the State's submittal. | 40 CFR 51.308(e)(2) | No Change | No Change |
| Arizona's RPGs for 2018 on the 20% Best and 20% worst days at all of the class I areas. | 40 CFR 51.308(d)(1) | Sections 11.1 through 11.5, and adding 11.6, 11.7, 11.8, 11.9, 11.10 and 11.11 | Replacing Sections 11.1 through 11.5 |
| SIP does not include all measures needed to achieve State's apportionment of emission reduction obligations with respect to out-of-state class I areas. | 40 CFR 51.308(d)(3)(ii) | Section 11.8 (*New Section*) | None |
| Arizona did not adequately consider emissions limitations and schedules of compliance to achieve the RPGs or the enforceability of emissions limits and control measures. | 40 CFR 51.308(d)(3) | No Change | No Change |

The SIP revision consists of copies of the authorizing statutes cited above (Enclosure 1), a document demonstrating that the requirements of 40 C.F.R. Part 51 Appendix V are satisfied (Enclosure 2), the SIP revisions as described in the table above (Enclosure 3), and the revised Technical Support Document (Enclosure 4).

In order to expedite approval, ADEQ requests approval of the SIP revision by parallel processing pursuant to 40 C.F.R. Part 51 Appendix V, § 2.3.1. ADEQ scheduled a public hearing on the revision April 29, 2013, and expects to submit the final SIP revision to EPA by early May 2013.

Two paper copies and an electronic exact duplicate of the hard copy on CD are included with this letter. If you have any questions, please contact me at (602) 771-2288.

Sincerely,

Eric C. Massey, Director
Air Quality Division

cc. Colleen McKaughan, EPA
Tom Webb, EPA

Janice K. Brewer
Governor

# ARIZONA DEPARTMENT OF ENVIRONMENTAL QUALITY

1110 West Washington Street • Phoenix, Arizona 85007
(602) 771-2300 • www.azdeq.gov

Henry R. Darwin
Director

February 25, 2011

TO: Eric Massey
Division Director
Air Quality Division

Under A.R.S. §49-104(D)(2), I authorize you, Eric Massey, Division Director, Air Quality Division, Arizona Department of Environmental Quality, to perform any act, including execution of any pertinent documents, which I as Director of the Arizona Department of Environmental Quality am authorized or required to do by law with respect to A.R.S. Title 49, chapters 1 and 3 and any other acts relating to air quality including personnel actions. This authority shall remain in effect until it is revoked or you resign. You may further delegate this authority in the best interest of the agency, however, those delegations must be in writing and you must forward a copy of any further delegations to me.

This delegation is effective February 25, 2011. I ratify all acts performed by you as Air Quality Division Director concerning the duties and functions in this delegation letter.

Henry R. Darwin
Director

Northern Regional Office
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# ENCLOSURE 1

## Arizona Revised Statutes §§ 49-104, 49-106, 49-404, 49-425, 49-458, and 49-458.01

49-104. Powers and duties of the department and director

A. The department shall:

1. Formulate policies, plans and programs to implement this title to protect the environment.

2. Stimulate and encourage all local, state, regional and federal governmental agencies and all private persons and enterprises that have similar and related objectives and purposes, cooperate with those agencies, persons and enterprises and correlate department plans, programs and operations with those of the agencies, persons and enterprises.

3. Conduct research on its own initiative or at the request of the governor, the legislature or state or local agencies pertaining to any department objectives.

4. Provide information and advice on request of any local, state or federal agencies and private persons and business enterprises on matters within the scope of the department.

5. Consult with and make recommendations to the governor and the legislature on all matters concerning department objectives.

6. Promote and coordinate the management of air resources to assure their protection, enhancement and balanced utilization consistent with the environmental policy of this state.

7. Promote and coordinate the protection and enhancement of the quality of water resources consistent with the environmental policy of this state.

8. Encourage industrial, commercial, residential and community development that maximizes environmental benefits and minimizes the effects of less desirable environmental conditions.

9. Assure the preservation and enhancement of natural beauty and man-made scenic qualities.

10. Provide for the prevention and abatement of all water and air pollution including that related to particulates, gases, dust, vapors, noise, radiation, odor, nutrients and heated liquids in accordance with article 3 of this chapter and chapters 2 and 3 of this title.

11. Promote and recommend methods for the recovery, recycling and reuse or, if recycling is not possible, the disposal of solid wastes consistent with sound health, scenic and environmental quality policies. Beginning in 2014, the department shall report annually on its revenues and expenditures relating to the solid and hazardous waste programs overseen or administered by the department.

12. Prevent pollution through the regulation of the storage, handling and transportation of solids, liquids and gases that may cause or contribute to pollution.

13. Promote the restoration and reclamation of degraded or despoiled areas and natural resources.

14. Assist the department of health services in recruiting and training state, local and district health department personnel.

15. Participate in the state civil defense program and develop the necessary organization and facilities to meet wartime or other disasters.

16. Cooperate with the Arizona-Mexico commission in the governor's office and with researchers at universities in this state to collect data and conduct

projects in the United States and Mexico on issues that are within the scope of the department's duties and that relate to quality of life, trade and economic development in this state in a manner that will help the Arizona-Mexico commission to assess and enhance the economic competitiveness of this state and of the Arizona-Mexico region.
17. Unless specifically authorized by the legislature, ensure that state laws, rules, standards, permits, variances and orders are adopted and construed to be consistent with and no more stringent than the corresponding federal law that addresses the same subject matter. This provision shall not be construed to adversely affect standards adopted by an Indian tribe under federal law.
B. The department, through the director, shall:
1. Contract for the services of outside advisers, consultants and aides reasonably necessary or desirable to enable the department to adequately perform its duties.
2. Contract and incur obligations reasonably necessary or desirable within the general scope of department activities and operations to enable the department to adequately perform its duties.
3. Utilize any medium of communication, publication and exhibition when disseminating information, advertising and publicity in any field of its purposes, objectives or duties.
4. Adopt procedural rules that are necessary to implement the authority granted under this title, but that are not inconsistent with other provisions of this title.
5. Contract with other agencies, including laboratories, in furthering any department program.
6. Use monies, facilities or services to provide matching contributions under federal or other programs that further the objectives and programs of the department.
7. Accept gifts, grants, matching monies or direct payments from public or private agencies or private persons and enterprises for department services and publications and to conduct programs that are consistent with the general purposes and objectives of this chapter. Monies received pursuant to this paragraph shall be deposited in the department fund corresponding to the service, publication or program provided.
8. Provide for the examination of any premises if the director has reasonable cause to believe that a violation of any environmental law or rule exists or is being committed on the premises. The director shall give the owner or operator the opportunity for its representative to accompany the director on an examination of those premises. Within forty-five days after the date of the examination, the department shall provide to the owner or operator a copy of any report produced as a result of any examination of the premises.
9. Supervise sanitary engineering facilities and projects in this state, authority for which is vested in the department, and own or lease land on which sanitary engineering facilities are located, and operate the facilities, if the director determines that owning, leasing or operating is necessary for the public health, safety or welfare.

10. Adopt and enforce rules relating to approving design documents for constructing, improving and operating sanitary engineering and other facilities for disposing of solid, liquid or gaseous deleterious matter.
11. Define and prescribe reasonably necessary rules regarding the water supply, sewage disposal and garbage collection and disposal for subdivisions. The rules shall:
(a) Provide for minimum sanitary facilities to be installed in the subdivision and may require that water systems plan for future needs and be of adequate size and capacity to deliver specified minimum quantities of drinking water and to treat all sewage.
(b) Provide that the design documents showing or describing the water supply, sewage disposal and garbage collection facilities be submitted with a fee to the department for review and that no lots in any subdivision be offered for sale before compliance with the standards and rules has been demonstrated by approval of the design documents by the department.
12. Prescribe reasonably necessary measures to prevent pollution of water used in public or semipublic swimming pools and bathing places and to prevent deleterious conditions at such places. The rules shall prescribe minimum standards for the design of and for sanitary conditions at any public or semipublic swimming pool or bathing place and provide for abatement as public nuisances of premises and facilities that do not comply with the minimum standards. The rules shall be developed in cooperation with the director of the department of health services and shall be consistent with the rules adopted by the director of the department of health services pursuant to section 36-136, subsection H, paragraph 10.
13. Prescribe reasonable rules regarding sewage collection, treatment, disposal and reclamation systems to prevent the transmission of sewage borne or insect borne diseases. The rules shall:
(a) Prescribe minimum standards for the design of sewage collection systems and treatment, disposal and reclamation systems and for operating the systems.
(b) Provide for inspecting the premises, systems and installations and for abating as a public nuisance any collection system, process, treatment plant, disposal system or reclamation system that does not comply with the minimum standards.
(c) Require that design documents for all sewage collection systems, sewage collection system extensions, treatment plants, processes, devices, equipment, disposal systems, on-site wastewater treatment facilities and reclamation systems be submitted with a fee for review to the department and may require that the design documents anticipate and provide for future sewage treatment needs.
(d) Require that construction, reconstruction, installation or initiation of any sewage collection system, sewage collection system extension, treatment plant, process, device, equipment, disposal system, on-site wastewater treatment facility or reclamation system conform with applicable requirements.
14. Prescribe reasonably necessary rules regarding excreta storage, handling, treatment, transportation and disposal. The rules shall:

(a) Prescribe minimum standards for human excreta storage, handling, treatment, transportation and disposal and shall provide for inspection of premises, processes and vehicles and for abating as public nuisances any premises, processes or vehicles that do not comply with the minimum standards.
(b) Provide that vehicles transporting human excreta from privies, septic tanks, cesspools and other treatment processes shall be licensed by the department subject to compliance with the rules. The department may require payment of a fee as a condition of licensure. After the effective date of this amendment to this section, the department shall establish by rule a fee as a condition of licensure, including a maximum fee. As part of the rule making process, there must be public notice and comment and a review of the rule by the joint legislative budget committee. After September 30, 2013, the department shall not increase that fee by rule without specific statutory authority for the increase. The fees shall be deposited, pursuant to sections 35-146 and 35-147, in the solid waste fee fund established by section 49-881.
15. Perform the responsibilities of implementing and maintaining a data automation management system to support the reporting requirements of title III of the superfund amendments and reauthorization act of 1986 (P.L. 99-499) and title 26, chapter 2, article 3.
16. Approve remediation levels pursuant to article 4 of this chapter.
17. Establish or revise fees by rule pursuant to the authority granted under title 44, chapter 9, article 8 and chapters 4 and 5 of this title for the department to adequately perform its duties. All fees shall be fairly assessed and impose the least burden and cost to the parties subject to the fees. In establishing or revising fees, the department shall base the fees on:
(a) The direct and indirect costs of the department's relevant duties, including employees salaries and benefits, professional and outside services, equipment, in-state travel and other necessary operational expenses directly related to issuing licenses as defined in title 41, chapter 6 and enforcing the requirements of the applicable regulatory program.
(b) The availability of other funds for the duties performed.
(c) The impact of the fees on the parties subject to the fees.
(d) The fees charged for similar duties performed by the department, other agencies and the private sector.
C. The department may:
1. Charge fees to cover the costs of all permits and inspections it performs to ensure compliance with rules adopted under section 49-203, except that state agencies are exempt from paying the fees. Monies collected pursuant to this subsection shall be deposited, pursuant to sections 35-146 and 35-147, in the water quality fee fund established by section 49-210.
2. Contract with private consultants for the purposes of assisting the department in reviewing applications for licenses, permits or other authorizations to determine whether an applicant meets the criteria for issuance of the license, permit or other authorization. If the department contracts with a consultant under this paragraph, an applicant may request that the department expedite the application review by requesting that the

department use the services of the consultant and by agreeing to pay the department the costs of the consultant's services. Notwithstanding any other law, monies paid by applicants for expedited reviews pursuant to this paragraph are appropriated to the department for use in paying consultants for services.

D. The director may:

1. If the director has reasonable cause to believe that a violation of any environmental law or rule exists or is being committed, inspect any person or property in transit through this state and any vehicle in which the person or property is being transported and detain or disinfect the person, property or vehicle as reasonably necessary to protect the environment if a violation exists.

2. Authorize in writing any qualified officer or employee in the department to perform any act that the director is authorized or required to do by law.

49-106. Statewide application of rules

The rules adopted by the department apply and shall be observed throughout this state, or as provided by their terms, and the appropriate local officer, council or board shall enforce them. This section does not limit the authority of local governing bodies to adopt ordinances and rules within their respective jurisdictions if those ordinances and rules do not conflict with state law and are equal to or more restrictive than the rules of the department, but this section does not grant local governing bodies any authority not otherwise provided by separate state law.

49-404. State implementation plan

A. The director shall maintain a state implementation plan that provides for implementation, maintenance and enforcement of national ambient air quality standards and protection of visibility as required by the clean air act.

B. The director may adopt rules that describe procedures for adoption of revisions to the state implementation plan.

C. The state implementation plan and all revisions adopted before September 30, 1992 remain in effect according to their terms, except to the extent otherwise provided by the clean air act, inconsistent with any provision of the clean air act, or revised by the administrator. No control requirement in effect, or required to be adopted by an order, settlement agreement or plan in effect, before the enactment of the clean air act in any area which is a nonattainment or maintenance area for any air pollutant may be modified after enactment in any manner unless the modification insures equivalent or greater emission reductions of the air pollutant. The director shall evaluate and adopt revisions to the plan in conformity with federal regulations and guidelines promulgated by the administrator for those purposes until the rules required by subsection B are effective.

49-425. Rules; hearing

A. The director shall adopt such rules as he determines are necessary and feasible to reduce the release into the atmosphere of air contaminants originating within the territorial limits of the state or any portion thereof and shall adopt, modify, and amend reasonable standards for the quality of, and emissions into, the ambient air of the state for the prevention, control and abatement of air pollution. Additional standards shall be established for particulate matter emissions, sulfur dioxide emissions, and other air contaminant emissions determined to be necessary and feasible for the prevention, control and abatement of air pollution. In fixing such ambient air quality standards, emission standards or standards of performance, the director shall give consideration but shall not be limited to the relevant factors prescribed by the clean air act.

B. No rule may be enacted or amended except after the director first holds a public hearing after twenty days' notice of such hearing. The proposed rule, or any proposed amendment of a rule, shall be made available to the public at the time of notice of such hearing.

C. The department shall enforce the rules adopted by the director.

D. All rules enacted pursuant to this section shall be made available to the public at a reasonable charge upon request.

49-458. Regional haze program; authority

The department may participate in interstate regional haze programs that are established by the regional planning organization that is authorized for this region pursuant to 40 Code of Federal Regulations part 51, subpart P and the clean air act.

49-458.01. State implementation plan revision; regional haze; rules

A. The director shall submit to the administrator state implementation plan revisions to address regional haze visibility impairment in mandatory federal class I areas. The state implementation plan revisions submitted to the administrator shall address any of the following as necessary to submit an approvable plan:

1. The applicable time period.
2. A monitoring strategy for regional haze visibility impairment.
3. Calculations of baseline visibility conditions and natural visibility conditions.
4. Comprehensive emissions tracking strategies for clean air corridors.
5. Implementation of stationary source emissions reduction strategies.
6. Provisions addressing mobile source emissions.
7. Programs related to emissions from fire sources defined as wildland fire, including wildfire, prescribed natural fire, wildland fire use, prescribed fire and agricultural burning conducted and occurring on federal, state and private lands.
8. Provisions addressing the impact of dust emissions on visibility impairment.
9. Provisions relating to pollution prevention.
10. Best available retrofit technology requirements.
11. A report that assesses emissions control strategies for stationary source emissions of oxides of nitrogen and particulate matter and the degree of visibility improvement that would result from implemented strategies.
12. A long-term strategy that addresses regional haze visibility impairment.
13. Additional measures necessary to make reasonable progress toward remedying existing and preventing future regional haze in mandatory federal class I areas.
14. For the Arizona Grand Canyon visibility transport commission class I areas, a projection of the improvement in visibility conditions that are expected from the implementation of all measures set forth in the implementation plan.
15. For the eight other Arizona mandatory federal class I areas, provisions for the establishment of reasonable progress goals.
16. Periodic progress reports.

B. The department may establish intrastate market trading programs and participate in interstate market trading programs as necessary to submit an approvable plan under subsection A.

C. The director may adopt rules necessary for the revisions to the state implementation plan that address regional haze.

D. Except as provided in subsection E, the department may meet the requirements of subsection A by submitting plan revisions under 40 Code of Federal Regulations section 51.308 or section 51.309.

E. The department may submit a plan revision under 40 Code of Federal Regulations section 51.309 only if the revision contains a determination pursuant to 40 Code of Federal Regulations section 51.309 (d)(5)(ii) that mobile source emissions from areas within the state do not contribute

significantly to visibility impairment in any of the Grand Canyon visibility transport commission class I areas.

# ENCLOSURE 2

## State Implementation Plan Completeness Checklist

**STATE IMPLEMENTATION PLAN COMPLETENESS CHECKLIST**

**Submittal of**

**Proposed Arizona State Implementation Plan Revision**
**Regional Haze under Section 308 of the Federal Regional Haze Rule and Technical Support Document**

40 CFR Part 51, Appendix V, *Criteria for Determining the Completeness of Plan Submissions*, contains the "minimum criteria for determining whether a State Implementation Plan submitted for consideration by EPA is an official submission for purposes of review under §51.103," *Submission of plans, preliminary review of plans*. Appendix V requires the following to be included in plan submissions for review by EPA:

1. **"A formal letter of submittal from the Governor or his designee, requesting EPA approval of the plan or revision thereof (hereafter "the plan")."** [Appendix V, 2.1(a)]

The State requests approval of the State Implementation Plan (SIP) revision by parallel processing pursuant to 40 C.F.R. Part 51, Appendix V, § 2.3.1. See cover letter for SIP submission.

2. **"Evidence that the State has adopted the plan in the State code or body of regulations; or issued the permit, order, consent agreement (hereafter "document") in final form. That evidence shall include the date of adoption or final issuance as well as the effective date of the plan, if different from the adoption/issuance date."** [Appendix V, 2.1(b)]

ADEQ scheduled a public hearing on the proposed revision April 29, 2013, and expects to submit the final SIP revision to EPA by early May 2013.

3. **"Evidence that the State has the necessary legal authority under State law to adopt and implement the plan."** [Appendix V, 2.1(c)]

See Enclosure 1.

4. **"A copy of the actual regulation, or document submitted for approval and incorporation by reference into the plan, including indication of the changes made (such as, redline/strikethrough) to the existing approved plan, where applicable ..."** [Appendix V, 2.1(d)]

The proposed SIP revision and technical support document are included in Enclosures 3 and 4 of this submission.

5. **"Evidence that the State followed all of the procedural requirements of the State's laws and constitution in conducting and completing the adoption/issuance of the plan."** [Appendix V, 2.1(e)]

Not required for parallel processing version of SIP. See 40 C.F.R. Part 51, Appendix V, § 2.3.1(d).

6. **"Evidence that public notice was given of the proposed change consistent with procedures approved by EPA, including the date of publication of such notice."** [Appendix V, 2.1(f)]

Not required for parallel processing version of SIP. See 40 C.F.R. Part 51, Appendix V, § 2.3.1(d).

7. **"Certification that public hearing(s) were held in accordance with the information provided in the**

**public notice and the State's laws and constitution, if applicable and consistent with the public hearing requirements in 40 CFR 51.102."** [Appendix V, 2.1(g)]

Not required for parallel processing version of SIP. See 40 C.F.R. Part 51, Appendix V, § 2.3.1(d).

8. **"Compilation of public comments and the State's response thereto."** [Appendix V, 2.1(h)]

Not required for parallel processing version of SIP. See 40 C.F.R. Part 51, Appendix V, § 2.3.1(d).

9. **"Identification of all regulated pollutants affected by the plan."** [Appendix V, 2.2(a)]

Sulfur dioxide (SO2), Oxides of Nitrogen (NOx), Organic Carbon (OC), Elemental Carbon (EC), Fine Soil, Coarse Mass, and Sea Salt.

10. **"Identification of the locations of affected sources including the EPA attainment/nonattainment designation of the locations and the status of the attainment plan for the affected areas(s)."** [Appendix V, 2.2 (b)]

See Enclosures 3 and 4.

11. **"Quantification of the changes in plan allowable emissions from the affected sources; estimates of changes in current actual emissions from affected sources or, where appropriate, quantification of changes in actual emissions from affected sources through calculations of the differences between certain baseline levels and allowable emissions anticipated as a result of the revision."** [Appendix V, 2.2(c)]

See Enclosures 3 and 4.

12. **"The State's demonstration that the national ambient air quality standards, prevention of significant deterioration increments, reasonable further progress demonstration, and visibility, as applicable, are protected if the plan is approved and implemented. For all requests to redesignate an area to attainment for a national primary ambient air quality standard, under section 107 of the Act, a revision must be submitted to provide for the maintenance of the national primary ambient air quality standards for at least 10 years as required by section 175A of the Act."** [Appendix V, 2.2(d)]

See Enclosures 3 and 4.

13. **"Modeling information required to support the proposed revision, including input data, output data, models used, justification of model selections, ambient monitoring data used, meteorological data used, justification for use of offsite data (where used), modes of models used, assumptions, and other information relevant to the determination of adequacy of the modeling analysis."** [Appendix V, 2.2(e)]

See Enclosures 3 and 4.

14. **"Evidence, where necessary, that emission limitations are based on continuous emission reduction technology."** [Appendix V, 2.2(f)]

See Enclosures 3 and 4.

15. **"Evidence that the plan contains emission limitations, work practice standards and recordkeeping/reporting requirements, where necessary, to ensure emission levels."** [Appendix V, 2.2(g)]

Not applicable.

16. **"Compliance/enforcement strategies, including how compliance will be determined in practice."** [Appendix V, 2.2(h)]

Not applicable.

17. **"Special economic and technological justifications required by any applicable EPA policies, or an explanation of why such justifications are not necessary."** [Appendix V, 2.2(i)]

No known deviation from EPA policy.

# ENCLOSURE 3

*Proposed*
*Arizona State Implementation Plan*

*Regional Haze under Section 308 of the Federal Regional Haze Rule*

*March 2013*

ADEQ
Arizona Department
of Environmental Quality

*PROPOSED*

# *Arizona State Implementation Plan*

# *Regional Haze Under Section 308 Of the Federal Regional Haze Rule*

**Air Quality Division**
**March 2013**

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# CHAPTER 8

# SOURCES OF VISIBILITY IMPAIRMENT

***The following sections (8.6 to 8 9) will be added to Chapter 8 of Arizona's 2011 Regional Haze SIP.***

## 8.6 2002 & 2008 Emission Inventories

As noted in Section 8.4, CFR 40.51.308(d)(4)(v) requires a statewide emission inventory (EI) of pollutants that are reasonably anticipated to cause or contribute to visibility impairment in any mandatory Class I area. This Section of the RHR further requires that the statewide inventory include the most recent data available. The 2011 Arizona Regional Haze Submittal included the 2002 Emissions Inventory as developed by the state and the Western Regional Air Partnership (WRAP).

On December 21, 2012, the Environmental Protection Agency (EPA), proposed to approve and disapprove parts of Arizona's 2011 Regional Haze SIP as it pertained to sources of visibility impairment and emission inventories. Specifically, EPA proposed to disapprove Arizona's 2011 Regional Haze Submittal because it did not include the 2008 emissions inventory. To fulfill the requirement of the Regional Haze Rule and the proposed disapproval, ADEQ is submitting a 2008 EI calculated and compiled by the Western Regional Air Partnership (WRAP) and the Arizona Department of Environmental Quality (ADEQ).

### 8.6.1 2002 Arizona Emission Inventory

The 2002 Arizona EI and calculation methodology is presented in Chapter 8 of Arizona's 2011 Regional Haze SIP. The 2002 inventory served as the baseline inventory for the 2018 emission inventory estimation. The 2018 emissions were estimated from the 2002 inventory. The methodology for this estimation can also be found in Arizona's 2011 Regional Haze SIP.

### 8.6.2 2008 Arizona Emission Inventory

The 2008 EI was created by WRAP, Air Resource Specialists (ARS), and ADEQ. The 2008 inventory was created as part of the WRAP WestJump Project to create statewide inventories for all of the western U.S. states in order to satisfy 40 CFR §51.308(g)(4), which requires states to analyze and track the changes in emissions of visibility impairing pollutants every five years. It contains the most current data and calculations of pollutant emissions from all identified sources that were available by the completion of the enclosed Technical Support Document (TSD). The inventory was calculated using the 2008 EPA National Emissions Inventory (NEI) and other emission models and techniques.

These inventories were created as part of the WRAP WESTJUMP project, which created statewide inventories for all of the western U.S. States.

The 2002 EI was based on the most readily available and accurate source data and methods at the time of preparation; however, many of the calculated source category emissions methodologies and input data changed between the 2002 and 2008 EI preparations in order to enhance the accuracy of estimated statewide emissions. For this reason, many of the source category emission differences between the 2002 and 2008 inventories presented in this document should be viewed as a mixture of methodology, input data, and actual emissions changes. Furthermore, since the Arizona 2018 EI was estimated through the adjustment of the 2002 baseline Arizona EI, emissions from these two inventories are more readily comparable than emissions from the 2008 EI due to the aforementioned methodology and source data differences.

## 8.7 2002 and 2008 Emissions

A summary of the 2002 and 2008 Arizona EIs is presented below. Text highlighted in yellow in the tables below indicates significant methodology differences between the 2002 and 2008 EIs. An overview of the methodologies for the 2002 and 2008 inventory is included in the enclosed TSD.

### 8.7.1 $SO_2$ Emissions

**Table 8.9 – Arizona $SO_2$ Emission Inventory (2002 & 2008)**

| Source Category | Sulfur Dioxide Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 94,716 | 79,015 | -15,700 |
| Area | 2,677 | 3,678 | 1,001 |
| On-Road Mobile | 2,715 | 812 | -1,904 |
| Off-Road Mobile | 4,223 | 673 | -3,550 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Anthropogenic Fire* | NA | NA | NA |
| Wind Blown Dust | NA | 0 | NA |
| **Total Anthropogenic** | **104,330** | **84,177** | **-20,153 (-19%)** |
| **Natural Sources** | | | |
| Natural Fire* | 4,559 | 607 | -3,952 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **4,559** | **607** | **-3,952 (-87%)** |

| All Sources | | | |
|---|---|---|---|
| **Total Emissions** | **108,890** | **84,784** | **-24,105 (-22%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.2 $NO_X$ Emissions

**Table 8.10 – Arizona $NO_X$ Emission Inventory (2002 & 2008)**

| Source Category | Nitrogen Oxides Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 69,968 | 60,759 | -9,209 |
| Area | 9,049 | 39,403 | 30,354 |
| On-Road Mobile | 178,009 | 137,555 | -40,453 |
| Off-Road Mobile | 66,414 | 33,857 | -32,557 |
| Area Oil and Gas | 17 | 0 | -17 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Wind Blown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **323,458** | **271,575** | **-51,882 (-16%)** |
| **Natural Sources** | | | |
| Natural Fire* | 17,218 | 3,513 | -13,704 |
| Biogenic | 27,664 | 15,256 | -12,408 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **44,881** | **18,769** | **-26,112 (-58%)** |
| **All Sources** | | | |
| **Total Emissions** | **368,339** | **290,344** | **-77,995 (-21%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.3 Organic Carbon (Primary Organic Aerosol) Emissions

| Table 8.11 – Arizona Organic Carbon Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Primary Organic Aerosol Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| **Anthropogenic Sources** | | | |
| Point | 276 | 410 | 134 |
| Area | 4,728 | 6,445 | 1,718 |
| On-Road Mobile | 1,583 | 2,666 | 1,083 |
| Off-Road Mobile | 2,006 | 1,383 | -624 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 535 | 1,393 | 858 |
| Windblown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **9,128** | **12,298** | **3,169 (35%)** |
| **Natural Sources** | | | |
| Natural Fire* | 48,625 | 5,669 | -42,957 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **48,625** | **5,669** | **-42,957 (-88%)** |
| **All Sources** | | | |
| **Total Emissions** | **57,754** | **17,966** | **-39,787 (-69%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.4 Elemental Carbon Emissions

| Table 8.12 – Arizona Elemental Carbon Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Elemental Carbon Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| **Anthropogenic Sources** | | | |
| Point | 26 | 283 | 257 |
| Area | 449 | 1,337 | 889 |
| On-Road Mobile | 1,761 | 5,559 | 3,798 |
| Off-Road Mobile | 2,752 | 1,813 | -940 |
| Area Oil and Gas | 0 | 0 | 0 |

| Table 8.12 – Arizona Elemental Carbon Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Elemental Carbon Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| Fugitive and Road Dust | 39 | 47 | 8 |
| Windblown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **5,027** | **9,039** | **4,012 (80%)** |
| **Natural Sources** | | | |
| Natural Fire* | 9,719 | 412 | -9,307 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **9,719** | **412** | **-9,307 (-96%)** |
| **All Sources** | | | |
| **Total Emissions** | **14,745** | **9,450** | **-5,295 (-36%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.5 PM Fine Emissions

| Table 8.13 – Arizona PM Fine Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Fine Particulate Matter Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| **Anthropogenic Sources** | | | |
| Point | 632 | 4,434 | 3,801 |
| Area | 4,223 | 7,906 | 3,684 |
| On-Road Mobile | 1,080 | 511 | -569 |
| Off-Road Mobile | 0 | 97 | 97 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 10,072 | 24,592 | 14,520 |
| Windblown Dust | NA | 67 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **16,007** | **37,607** | **21,600 (>100%)** |
| **Natural Sources** | | | |
| Natural Fire* | 3,945 | 1,938 | -2,006 |
| Biogenic | 0 | 0 | 0 |

| | | | |
|---|---|---|---|
| Wind Blown Dust | 6,422 | 9,647 | 2,885 |
| **Total Natural** | **10,367** | **11,585** | **1,218 (12%)** |
| **All Sources** | | | |
| **Total Emissions** | **26,374** | **49,192** | **22,818 (87%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.6 Coarse Mass Emissions

| Table 8.14 – Arizona Coarse Mass Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Coarse Particulate Matter Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| **Anthropogenic Sources** | | | |
| Point | 8,473 | 5,260 | -3,214 |
| Area | 1,384 | 2,389 | 1,005 |
| On-Road Mobile | 1,004 | 5,597 | 4,593 |
| Off-Road Mobile | 0 | 162 | 162 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 79,316 | 141,117 | 61,801 |
| Windblown Dust | NA | 604 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **90,178** | **155,129** | **64,951 (72%)** |
| **Natural Sources** | | | |
| Natural Fire* | 10,125 | 1,692 | -8,433 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 57,796 | 86,827 | 29,031 |
| **Total Natural** | **67,921** | **88,519** | **20,598 (30%)** |
| **All Sources** | | | |
| **Total Emissions** | **158,099** | **243,648** | **85,549 (54%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.7 Ammonia Emissions

| Table 8.15 – Arizona Ammonia Emission Inventory (2002 & 2008) |
|---|

| Source Category | Ammonia Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 531 | 971 | 440 |
| Area | 32,713 | 34,878 | 2,165 |
| On-Road Mobile | 5,035 | 2,377 | -2,658 |
| Off-Road Mobile | 48 | 40 | -8 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Anthropogenic Fire* | NA | NA | NA |
| Windblown Dust | NA | 0 | NA |
| **Total Anthropogenic** | **38,326** | **38,265** | **-61 (0%)** |
| **Natural Sources** | | | |
| Natural Fire* | 3,878 | 0 | -3,878 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **3,878** | **0** | **-3,878 (-100%)** |
| **All Sources** | | | |
| **Total Emissions** | **42,203** | **38,265** | **-3,939 (-9%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.8 Volatile Organic Compounds (VOC) Emissions

**Table 8.16 – Arizona Volatile Organic Compound Emission Inventory (2002 & 2008)**

| Source Category | Volatile Organic Compound Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 5,464 | 3,489 | -1,975 |
| Area | 102,918 | 100,256 | -2,661 |
| On-Road Mobile | 110,424 | 54,589 | -55,834 |
| Off-Road Mobile | 56,901 | 42,297 | -14,604 |
| Area Oil and Gas | 46 | 12 | -34 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Windblown Dust | NA | 0 | NA |

| Table 8.16 – Arizona Volatile Organic Compound Emission Inventory (2002 & 2008) | | | |
|---|---|---|---|
| **Source Category** | **Volatile Organic Compound Emissions (tons/year)** | | |
| | **2002 (Plan02d)** | **2008 (WestJump2008)** | **Difference (Percent Change)** |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **275,753** | **200,644** | **-75,109 (-27%)** |
| **Natural Sources** | | | |
| Natural Fire* | 37,232 | 4,989 | -32,243 |
| Biogenic | 1,576,698 | 686,255 | -890,443 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **1,613,930** | **691,243** | **-922,686 (-57%)** |
| **All Sources** | | | |
| **Total Emissions** | **1,889,682** | **891,887** | **-997,795 (-53%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

### 8.7.9 Summary of 2008 Emissions Inventory

*Sulfur Dioxide ($SO_2$)*

In the 2008 EI, all source categories of pollutants, except area, showed a decrease in emissions when compared to the 2002 EI. The largest decrease occurred in point sources (Table 8.9)

*Nitrogen Dioxide ($NO_X$)*

All source categories for $NO_X$ showed lower emissions in the 2008 EI in comparison to the 2002 EI, except for area sources. The largest decrease occurred in mobile sources, showing 30% lower emissions for on- and off-road mobile emissions combined (Table 8.10).

It should be noted that Arizona is the second lowest contributor to emissions from annual U.S. oil production. In 2008, oil production from Arizona totaled 52,000 barrels or 0.003% of the national total[1]. Therefore, calculated and reported $NO_X$ emissions from Oil and Gas production are negligible in comparison to other source categories.

*Organic Carbon (Primary Organic Aerosol)*

Overall, organic carbon emissions decreased by 69% in the 2008 EI (Table 8.11). Emissions of organic carbon from fire were lower in 2008 when compared with 2002. It should be noted that current year inventories represent only snapshots of fire emissions for the year 2008.

*Elemental Carbon*

[1] U.S. Energy Information Administration. http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.

In the 2008 EI, total elemental carbon decreased by approximately 36% (Table 8.12). Most of the decrease occurred in fire emissions. It should be noted however, that on-road mobile emissions were higher in the 2008 EI than in the 2002 EI.

*PM Fine & Coarse Mass*

Emissions of both fine particulate matter (PM fine) and coarse mass were larger for windblown, fugitive dust, and road dust in the 2008 EI as compared to the 2002 EI (Tables 8.13 and 8.14). The increase in windblown dust is thought to be partly due to enhancements in dust inventory methodology. The 2008 EI was also slightly higher for area and point sources for PM fine as compared to the 2002 EI.

*Ammonia*

Total ammonia emissions were fairly consistent between the 2008 EI and 2002 EI (Table 8.15). Area sources show slightly higher emissions in the 2008 EI. However, on-road mobile sources show lower emission in the 2008 EI when compared to the 2002 EI.

*Volatile Organic Compound (VOC)*

The 2008 EI shows significantly lower emissions of VOCs in 2008 in comparison to the 2002 EI (Table 8.16). This is likely due to enhancements in biogenic inventory methodology. It should be noted that Arizona represents the second lowest contributing State to annual U.S. oil production. Oil production in Arizona in 2008 totaled 52,000 barrels or 0.003% of the national total[2]. Therefore, calculated and reported VOC emissions from Oil and Gas production are negligible in comparison to other source categories.

## 8.8 Summary of Input & Methodological Changes

### 8.8.1 Estimates of Population Changes

The Arizona Department of Administration (ADOA) provides estimates of State and County population data for each year dating to 1980[3]. For the years of 2002 and 2008, ADOA estimates Arizona state-wide populations to be 5,470,720 and 6,629,455 respectively, which is a 21.2% increase in state-wide population. An increase in population may lead to pollutant emission changes for a number of source categories; however, the degree to which certain pollutants change for given source categories indicate that population increases are likely not the sole cause for emission changes between the 2002 and 2008 EIs.

### 8.8.2 Methodological Changes

As noted in Section 8.7.9, there are several differences in the emissions between the 2002 EI and 2008 EI. There are many changes in methodology, input data, and model resolution that likely contribute to these differences in emissions. The list below summarizes the changes that have potentially affected the 2008 EI.

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[2] ibid

[3] Arizona Department of Administration (ADOA). http://www.workforce.az.gov/pubs/demography/Estimates1980_2009With2000CensusWithNotes.xls

1. ADEQ has reviewed emission estimates to understand the drastic changes in Area Source $SO_X$ and $NO_X$ emissions between the 2002 and 2008 EIs. This review indicated that these changes are due to a mixture of methodological changes and data completion issues. Therefore, ADEQ believes a more accurate indicator of $NO_X$ and $SO_X$ changes between the baseline and progress periods can be obtained through an analysis of the IMPROVE data. Some identified issues between 2002 and 2008 Area Source $NO_X$ and $SO_X$ estimated.
   - When extracting Area source emissions data from the 2008 NEI by SCC code for the State of Arizona, several reported emissions contained neither physical descriptors nor SCC codes. It is possible that these unidentified sources could represent sources which are being double counted in another portion of the inventory. All 2002 data was resolved by SCC code and physical descriptors, eliminating the possibility of double counting.
   - When extracting area source $NO_X$ emissions data from the 2008 NEI by SCC code, data can be sorted by the submitting agency or agencies. Submitting agencies include: AZDEQ, EPA, railroad companies, "AgFire", and "Multiple". The "Multiple" submitting agency label submitted 25 unidentifiable $NO_X$ area emission categories for the 15 Arizona counties. These $NO_X$ emissions totaled 23,371 tons. ADEQ is unable to assess the origin of these emissions.
   - $NO_X$ area source emissions reported to the NEI increased from 4736 tons in 2002 to 13,563 tons in 2008 for Maricopa County alone. Direct contact with Maricopa County revealed that the county was presenting a more accurate fuel burning emission inventory in 2008 and that the County's raised the emission limit of point source classification to more accurately reflect the CERR definition in 2008. In 2002 they reported 170+ point sources and in 2008 they only reported 18 point source facilities, with the remaining sources becoming Area Source emitters.
2. Biogenic emission differences for $NO_X$ and VOCs are primarily due to methodology, source data, and modeling resolution enhancements between 2002 and 2008.
3. Ammonia emission differences for On-road Mobile are primarily due to a switch from the MOBILE6 model to the MOVES model. The 2008 EPA NEI Technical Support Document (TSD)[4] reported a 54% decrease in highway vehicle $NH_3$ for 2008.
4. VOC emission differences for On-road Mobile are primarily due to a switch from the MOBILE6 model to the MOVES model.
5. On-road Elemental Carbon (EC) and Coarse Particulate Matter (CM) emission differences are primarily due to the switch between MOBILE6 and MOVES (which estimates higher PM emissions).
6. Reported Point Source Fines emissions exhibit a dramatic increase between 2002 and 2008, while CM decreases between 2002 and 2008. In theory, these two pollutants should track fairly closely to one another. ADEQ internal review revealed that many, if not most, sources within the State of Arizona were not reporting $PM_{2.5}$ prior to 2006 which likely explains the drastic change in Fines emissions between the 2002 and 2008 EIs.
7. Area source Fines emission differences are partially due to NEI changes. Calculation methodology changes resulted in an overall increase in Agricultural Tilling and Livestock emissions of 67% for the 2008 NEI.
8. Fugitive and Road Dust Fines and CM emission differences are primarily due to NEI changes. Calculation methodology changes resulted in an overall increase in Paved Road Dust emission of 128% for the 2008 NEI.
9. Windblown Dust Fines and CM emission differences are primarily due to the WRAP windblown dust (WBD) Model enhancing meteorological inputs and model resolution between the 2002 and 2008 emissions calculations. Appendix A gives a more complete overview of how Windblown

[4] EPA. 2012. 2008 National Emissions Inventory v. 2 Technical Support Document. http://www.epa.gov/ttn/chief/net/2008neiv2/2008_neiv2_tsd_draft.pdf

Dust emissions were partitioned into natural and anthropogenic sources. 2002 windblown emissions were not partitioned into natural and anthropogenic sources and are thus presented only as natural emissions above.

## 8.9 Regional Inventory Trends

As described in Section 8.8, most of the differences in emissions inventories can be attributed to changes in input data origination or calculation methodologies for emission estimations by sector. These inventories were created as part of the WRAP WESTJUMP project, which created statewide inventories for all of the western U.S. States. All of these inventories were created using similar methodologies, therefore it is reasonable to assert that the qualifying statements in Section 8.8 would hold true for all of the compiled emission inventories.

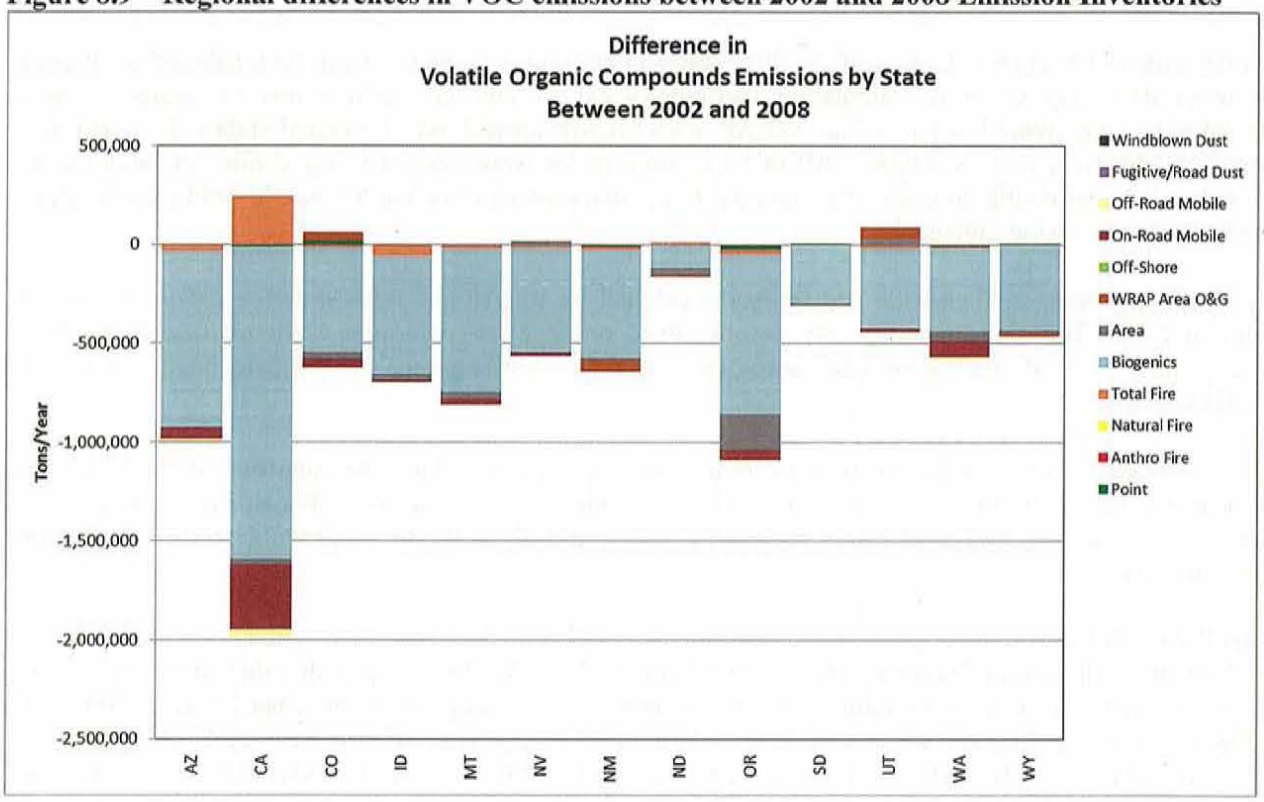
This section presents information and figures developed by WRAP and ARS showing differences in the 2002 and 2008 emission inventories by state for three pollutants to determine if the qualifiers hold true. The graphs split state emissions into source categories to identify trends for the calculated or reported sources.

Figure 8.9 shows VOC emissions by state in the Western U.S. and illustrates qualifiers #2 and #4 from Section 8.8.2. The trend of decreasing biogenic emissions for each state supports qualifier #2 and shows that differences in biogenic VOC emissions are primarily due to improvement in calculation methodology.

This figure also shows the large decreases in on-road mobile emissions for each state (Figure 8.9). While EPA reports a decrease of national VMT by 0.8% for 2005-2008[5], it is unlikely that this small decrease in VMT would be seen in every state. Arizona showed a 21.2% population increase between 2002 and 2008, which would likely result in a substantial VMT increase. Therefore, it is reasonable to believe that VOC decreases are likely due to a switch from the MOBILE6 model to the MOVES model (Section 8.8.2, #4).

[5] EPA. 2012. 2008 National Emissions Inventory v. 2 Technical Support Document. http://www.epa.gov/ttn/chief/net/2008neiv2/2008_neiv2_tsd_draft.pdf

**Figure 8.9 – Regional differences in VOC emissions between 2002 and 2008 Emission Inventories**



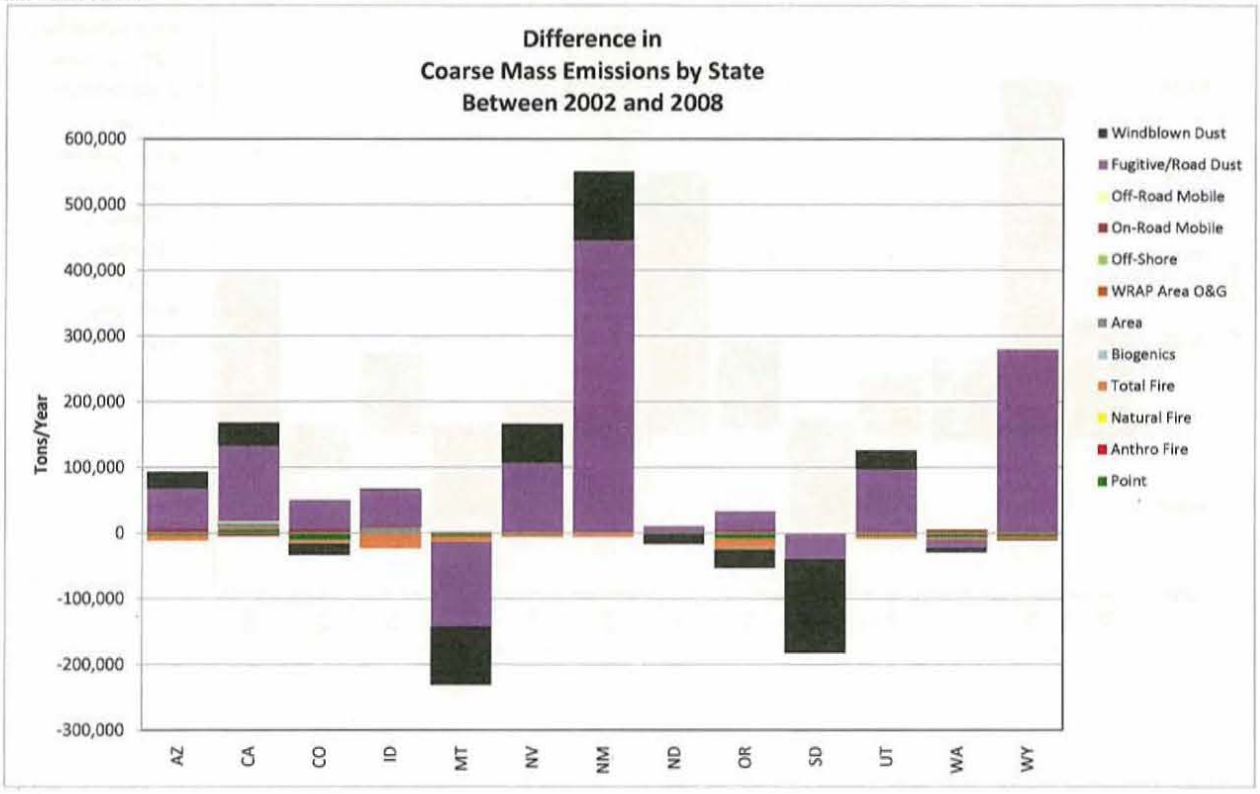

Coarse mass emissions for states in the western U.S. are shown in Figure 8.10 and illustrates trends on a regional basis. Emissions of coarse mass are due to physical disturbance of an area of land by anthropogenic activities (e.g. construction, driving on unpaved roadways, etc), natural activities (e.g. animal movement or burrowing), or a mixture of the natural and anthropogenic activities (e.g. wind suspension of dust from a cleared area). Activities that create the emissions may vary and change the magnitude of emissions created are primarily dependant on the local environment. Meteorology, soil characteristics, and vegetation coverage also play a large role in the magnitude of emissions produced from a certain area. Therefore, it is important to group the States which have a similar local environment. Arizona, South-eastern California, Nevada, New Mexico, and Utah comprise the southwestern U.S. which is characterized by its arid nature, in turn leading to sparse vegetation coverage. Figure 8.2 shows that local environmental factors play a large role in how windblown dust emissions differed between the 2002 and 2008 EIs.

Arizona, South-eastern California, Nevada, New Mexico, and Utah exhibit similar emission differences for windblown dust, fugitive dust, and road dust. Windblown dust emissions from the southwestern U.S. states are likely to be more affected by WRAP WBD model resolution increases and the decreased

precipitation, as reported in Table 1 of the enclosed TSD, than surrounding states due to higher local wind speeds increasing dust suspension into the atmosphere from dry, unvegetated soils.

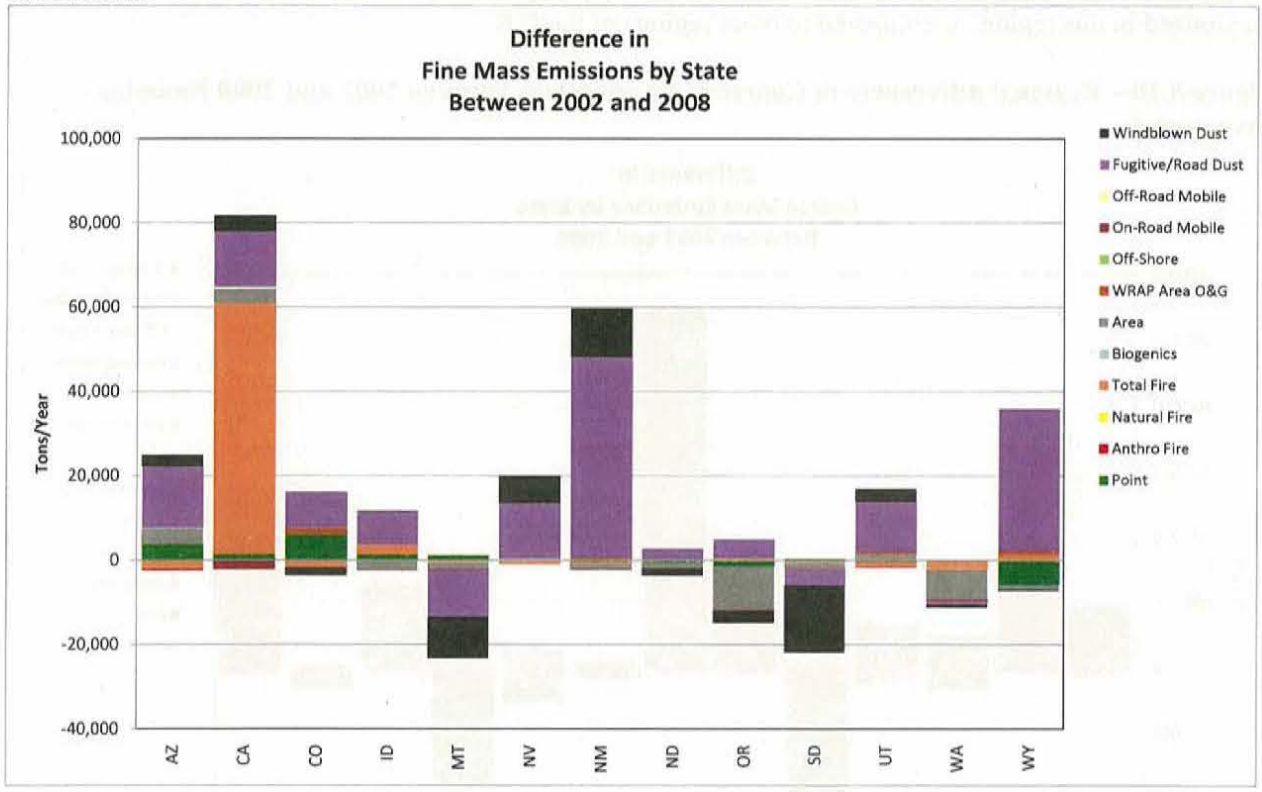
Emissions in road dust are likely responsible for the emission changes seen in the fugitive and road dust category. The 2008 NEI reports that road dust emissions increased by 128% over the 2005 NEI. Since the 2008 NEI version 1.5 was used for this source category, it is believed that this is the reason for the difference between 2002 and 2008 emissions for the combined categories of fugitive and road dust. Furthermore, the aridity of the southwestern U.S. likely result in road dust calculation disparities being maximized in this region, as compared to other regions of the U.S.

**Figure 8.10 – Regional differences in Coarse Mass emissions between 2002 and 2008 Emission Inventories**




Fines (Figure 8.11) show similar regional trends as coarse mass for windblown dust and fugitive/road dust for the arid southwestern U.S. This supports the theory that particulate matter emission differences are partially due to changes in calculation methodology. This does not prove qualifying statement #7 (Section 8.8.2); however, the lack of a regional trend helps support the assertion that PM fine does not originate from point sources.

**Figure 8.11 – Regional differences in Fine Mass emissions between 2002 and 2008 Emission Inventories**



# CHAPTER 11

# REASONABLE PROGRESS GOAL DEMONSTRATION

***The following sections (11.4, 11.5, 11.6, 11.7, 11.8, 11.9, 11.10, and 11.11) will replace sections 11.4 and 11.5 in Arizona's 2011 Regional Haze SIP be added to Chapter 8 of Arizona's Regional Haze SIP.***

*This is a replacement for Chapter 11 in its entirety*

## 11.1 Reasonable Progress Requirements

40 CFR 51.308(d)(1) requires that for each Class I area, the state must establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions in 2018 and to 2064. The reasonable progress goals (RPGs) must provide for improvement in visibility for the most-impaired (20% worst visibility) days over the period of the SIP and ensure no degradation in visibility for the least-impaired (20% best visibility) days over the same period.

In establishing RPGs, the state must estimate the 2018 URP at each Class I area. The state must consider the URP and the emission reductions needed to achieve it for the period covered by the plan. If the state ultimately establishes a RPG that provides for a slower rate of visibility improvement than would be required to meet natural conditions by 2064, the state must demonstrate how the URP is not reasonable at this time and that the state's goal is reasonable given current conditions, based on the four-factors. In addition, the state must provide to the public an assessment of the number of years it would take to achieve natural conditions if improvement continues at the rate selected by the state.

Four factors must be considered when establishing the RPGs: the costs of compliance; the time necessary for compliance; the energy and non-air quality environmental impacts of compliance; and the remaining useful life of any potentially affected sources. The state must also include a demonstration showing how factors were taken into consideration in selecting the goals.

## 11.2 The Process for Determining Reasonable Progress

The following steps were followed in setting the RPGs for each Arizona Class I area:

1. Compare Baseline to Natural Conditions

For each Class I area, identify baseline (2000-2004) visibility and natural conditions in 2064 for the 20% worst and best days. See Chapter 6.

2. Identify the Uniform Rate of Progress

For each Class I area, calculate the URP glide path from baseline to 2064, including the 2018 planning milestone for the 20% worst days. Show the URP glide path in both total deciview and by pollutant in deciview. Next, identify the improvement needed by 2018 and 2064, respectively. See Chapter 6.

3. Identify the Contributing Pollutants

For each Class I area, identify the pollutant species that are contributing to visibility impairment on the current (baseline) 20% worst and 20% best days. See Chapter 7.

4. Identify the Major Emission Sources within the State and Trends

Using the WRAP Emission Inventory for 2002 and 2018, describe statewide emissions by source category and pollutant, and identify projected emission trends from current (2002) to the 2018 planning milestone. See Chapter 8.

5. Analyze the Larger Sources Categories Contributing to Impairment

For each Class I area, determine the relative contribution of anthropogenic and nonanthropogenic sources in Arizona and neighboring states to the 20% worst and 20% best days using monitoring data, source apportionment and modeling results. Compare these results to baseline (2000-2004) to 2018 on-the-books emissions reductions expected. Review these results by pollutant. See Chapter 9.

6. Document the Emission Reductions from BART

Describe the results of the BART process and identify the emissions reductions that will be achieved from BART and other measures. See Chapter 10.

7. Identify the Projected Visibility Change in 2018 from "on-the-books" Controls and BART

For each Class I area, determine the visibility improvement expected in 2018 from on-the-books controls and BART using the WRAP CMAQ modeling results for the 20% worst and 20% best days. Identify the extent of visibility improvement related to the 2018 URP milestone in total deciview and in extinction by pollutant. See Chapter 9.

8. Identify Sources or Source Categories that are Major Contributors and Conduct the Four-Factor Analysis

As a result of the analysis under step 5, for each Class I area, determine key pollutant species and source categories that have the greatest affect on visibility in Arizona Class I areas. Analyze using the four-factor analysis. See Chapter 11.

9. Describe the Results of the Four-Factor Analysis

Section 11.3 describes the results of the four-factor analysis.

10. Set the Reasonable Progress Goals (RPG) Based on Steps 7, 8, and 9

Set the RPG for each Class I area in deciview, based on the improvement in 2018 for the 20% worst and best days, from on-the-books controls, BART, and the results of the four-factor analysis on major source categories. See Section 11.4.

11. Compare RPG to the 2018 URP Milestone. Provide an Affirmative Demonstration that Reasonable progress is being made based pollutant trends, Emission Reductions, and Improvements Expected under the Long-Term-Strategy.

For each Class I area, compare the RPG developed in Step 10 to the 2018 URP milestone. Provide an affirmative demonstration that reasonable progress is being made based on pollutant treads, emissions reductions from major anthropogenic source categories, and on-the-books controls. Describe the results of the four-factor analysis in step 9 above, and how future actions identified in the Long-Term Strategy are expected to improve visibility in the next 10 years to the 2018 milestone and beyond.

## 11.3 Summary of the Four-Factor Analysis

Section 308(d)(1)(i)(A) of the Regional Haze Rule requires that states consider the following factors and demonstrate how they were taken into consideration in selecting the reasonable progress goals:

- costs of compliance
- time necessary for compliance
- energy and non-air quality environmental impacts of compliance, and
- remaining useful life of any potentially affected sources.

In conducting this four-factor analysis, EPA guidance indicates that states have "considerable flexibility" in how these factors are taken into consideration, in terms of what sources or source categories should be included in the analysis, and what additional control measures are reasonable.

### 11.3.1 Rationale and Scope of the Four-Factor Analysis

The state considered certain source categories in applying the four factors. The following rationale was used for the four-factor analysis:

1. Focus on 20% worst visibility days.

Since the Regional Haze Rule primarily focuses on demonstrating reasonable progress for the 20% worst days, the four-factor analysis in this section addresses only the worst days. It is a reasonable assumption that emission reductions benefiting the worst days also benefits the best days. The CMAQ modeling projections in Chapter 9 and reasonable progress demonstration in this chapter both indicated that the 20% best days are maintained for most of the Class I areas in Arizona.

2. Focus on anthropogenic sources.

Since the purpose of this analysis is to evaluate certain sources or source categories for potential control, the four-factor analysis in the section addresses only anthropogenic sources, on the assumption that the focus should be on sources that are "controllable". Although nonanthropogenic sources such as wildfire and dust are major contributors to regional haze, ADEQ has determined this analysis is not applicable to these sources. In considering which anthropogenic sources or source categories to apply the statutory factors, ADEQ considered point, area, mobile, and fire (controlled burning).

For mobile sources, there are major emissions reductions projected by 2018 based on numerous "on-the-books" federal and state regulations, as described in detail in Section 11.4 and in Section 12.5 as part of on-going implementation under the LTS. There are also significant visibility improvements projected by 2018 due to these reductions, as Chapter 9 PSAT results indicate. Based on the above findings, ADEQ does not believe applying the four-factor analysis to mobile sources is necessary.

For fire sources, forestry and agricultural burning are large anthropogenic sources. as described in detail in Section 12, both of these activities are controlled under state-run smoke management programs that

meet all of the requirements for an Enhanced Smoke Management Program (ESMP), and as such represent an advanced level of smoke management. Both of these activities are also addressed under the Arizona Visibility Program. In Section 12, ADEQ has identified future efforts to evaluate new methods of protecting Class I areas from forestry burning. Based on current controls and future efforts, ADEQ did not believe applying the four-factor analysis to forestry and agricultural burning was needed.

As a result of the above consideration, ADEQ elected to focus the four-factor analysis on point and area sources only. Additional details are provided in the following sections.

3. Focus on $SO_2$ and $NO_X$ pollutants.

Although there are six visibility impairing pollutants, $SO_2$ and $NO_X$ (sulfate and nitrate) are typically associated with anthropogenic sources. As noted in Chapter 8, sulfates and nitrates are about three times more effective at impairing visibility than $PM_{2.5}$. Since a large component of particulate (both fine and course is associated with nonanthropogenic sources, such as wildfire and natural windblown dust, this pollutant was not included in the analysis.

### 11.3.2 Identification of Point and Area Sources for the Four-Factor Analysis

ADEQ maintains the focus on point and area sources of $SO_2$ and $NO_X$ for applying the four-factor analysis is consistent with EPA guidance, in terms of flexibility to consider which major source categories are "reasonable" to evaluate for the first planning period of the regional haze plan.

As described in Chapter 8 and 9, it is important to note that there are reductions projected in 2018 in $SO_2$ and $NO_X$ emissions and effects from point and area sources. This trend was a consideration in the four-factor analysis, in terms of what source categories ADEQ considered for this analysis. Large reductions in $SO_2$ and $NO_X$ were also used as supporting evidence in the demonstration that the reasonable progress goals selected were "reasonable".

The first step in the four-factor analysis is to identify the sulfate and nitrate contribution within Arizona. Table 11.1 shows the modeled sulfate and nitrate effects on the 20% worst days in 2018, based on PSAT modeling results, at each Class I area in Arizona. This table shows that the range of the Arizona portion on the worst days is from 6-24% for sulfate, and 7-54% for nitrate. The 2018 modeled concentration is used here to show projected contribution, in order to assess what further emission reductions would be beneficial in achieving reasonable progress.

**Table 11.1 – Arizona Share of Modeled Sulfate and Nitrate in 2018 on 20% Worst Days**

| Arizona Class I Area | Sulfate | | | Nitrate | | |
|---|---|---|---|---|---|---|
| | 2018 Total Sulfate ($ug/m^3$) | 2018 Arizona Sulfate ($ug/m^3$) | 2018 Arizona Sulfate Share (%) | 2018 Total Nitrate ($ug/m^3$) | 2018 Arizona Nitrate ($ug/m^3$) | 2018 Arizona Nitrate Share (%) |
| Chiricahua NM, Chiricahua W, Galiuro W | 0.92 | 0.06 | 6.52% | 0.14 | 0.01 | 7.14% |
| Grand Canyon NP | 0.62 | 0.06 | 9.68% | 0.17 | 0.06 | 35.29% |
| Mazatzal W, Pine Mountain W | 0.82 | 0.09 | 10.98% | 0.28 | 0.13 | 46.43% |

| Table 11.1 – Arizona Share of Modeled Sulfate and Nitrate in 2018 on 20% Worst Days | | | | | | |
|---|---|---|---|---|---|---|
| Arizona Class I Area | Sulfate | | | Nitrate | | |
| | 2018 Total Sulfate ($ug/m^3$) | 2018 Arizona Sulfate ($ug/m^3$) | 2018 Arizona Sulfate Share (%) | 2018 Total Nitrate ($ug/m^3$) | 2018 Arizona Nitrate ($ug/m^3$) | 2018 Arizona Nitrate Share (%) |
| Mount Baldy W | 0.77 | 0.14 | 18.18% | 0.13 | 0.05 | 38.46% |
| Petrified NP | 0.80 | 0.19 | 23.75% | 0.12 | 0.01 | 8.33% |
| Saguaro NP – West Unit | 1.0 | 0.13 | 13.00% | 0.45 | 0.22 | 48.89% |
| Saguaro NP – East Unit | 1.2 | 0.17 | 14.17% | 0.28 | 0.15 | 53.57% |
| Sierra Ancha W | 0.91 | 0.12 | 13.19% | 0.11 | 0.04 | 36.36% |
| Superstition W | 0.93 | 0.16 | 17.20% | 0.38 | 0.20 | 52.63% |
| Sycamore Canyon W | 0.58 | 0.05 | 8.62% | 0.26 | 0.11 | 42.31% |

The next step in the analysis is to identify the larger point and area source categories within the state. Table 11.2 shows the sulfate and nitrate point and area categories in Arizona, based on their projected emissions in 2018, as identified in Chapter 8 (the PRP18b emission inventory). These categories are external combustion boilers, industrial processes, internal combustion engines, stationary fuel combustion, and waste disposal. The table shows the tons per year of each pollutant, as the extent of the contribution. Excluded from these source categories are sources evaluated under BART.

| Table 11.2 – 2018 Projected Emissions from Arizona's Largest Source Categories | | | |
|---|---|---|---|
| Pollutant | Type | Source Category | Extent of Contribution (tons per year) |
| $SO_2$ | Point | External Combustion Boilers | 15,871 |
| | Point | Internal Combustion Engines | 185 |
| | Point | Industrial Processes | 41,118 |
| | Area | Stationary Source Fuel Combustion | 3,127 |
| | Area | Waste Disposal, Treatment, and Recovery | 272 |
| $NO_X$ | Point | External Combustion Boilers | 48,062 |
| | Point | Internal Combustion Engines | 11,068 |
| | Point | Industrial Processes | 9,510 |
| | Area | Stationary Source Fuel Combustion | 10,190 |
| | Area | Waste Disposal, Treatment, and Recovery | 2,357 |

### 11.3.3 Non-BART Sources

In its analysis of non-BART sources, ADEQ included all sources that had actual emissions over 40 tons per year of $NO_X$ and $SO_2$. In analyzing the inventory of sources, ADEQ determined that the evaluation could be meaningfully conducted by categorizing the inventory based on the significant emission units involved. The table below summarizes the categories that were considered:

| Table 11.3 - Non-BART Source Categories | |
|---|---|
| **Source Type** | **Number of Facilities** |
| Internal Combustion Engines and Turbines | 31 |
| Boilers | 7 |
| Asphalt Plants | 3 |
| Lime Plants | 2 |
| Portland Cement Plants | 2 |
| Primary Copper Smelters | 2 |
| Nitric Acid Plants | 1 |

It should be noted that the first two categories, internal combustion engines and turbines and boilers, cover a large number of equipment both in the subsequent categories and at facilities not listed above. For example, many asphalt plants use internal combustion engines as a power source.

Emission sources subject-to-BART were not included since source-specific determinations were made for those sources. However, non-BART emission units at facilities that were identified as subject to BART were included in the evaluation. In this section, significant source categories are evaluated. Visibility impacts from these source categories were not estimated.

1. Internal Combustion Engines/Combustion Turbines

This category includes commercial and institutional sources, electric generation, industrial engines, and engine testing. The primary sources are engines burning natural gas, which include natural gas-fired reciprocating internal combustion engines and natural gas-fired turbines, and engines burning diesel fuel. Generally speaking, low-emission combustion, steam injection, selective catalytic reduction, and selective non-catalytic reduction are considered potentially-viable $NO_X$ control strategies. It should be noted that most of these engines are fueled by fuel oil or natural gas. Emissions of $SO_2$ from the burning of natural gas are expected to be negligible. At this time, fuel oil combusted in these units is expected to have very low sulfur in it. In many cases, it amounts to 15 ppm of sulfur. Consequently, the $SO_2$ emissions resulting from these units are expected to be minimal.

In the Department's evaluation of this category, it was determined that a significant number of engines are portable in how they operate. Since these emission units are portable, it is difficult to perform a site-specific analysis addressing visibility impacts for these units. Portable equipment can stay at one site for as little as week before moving to another site. Additionally, many of the engines considered are not used as process-support engines but solely for backup purposes when commercial power supply is interrupted. In that regard, it can reasonably be presumed that the actual emissions from emergency backup engines will be minimal (typically emergency engines are run for one hour each week to check the operability of the engine).

There are multiple state and federal regulations that apply to this source category. These regulations are technology-based requirements that stipulate emission limitations and operational restrictions to ensure that emissions of $NO_X$ and $SO_2$ are minimized.

The following list identifies potentially applicable federal requirements:

- 40 CFR 60 Subpart IIII (Standards of Performance for Reciprocating Internal Combustion Engines)
- 40 CFR 60 Subpart JJJJ (Standards of Performance for Spark Ignition Engines)
- 40 CFR 60 Subpart GG (Standards of Performance for Stationary Gas Turbines)
- 40 CFR 60 Subpart KKKK (Standards of Performance for New Stationary Gas Turbines)
- 40 CFR 63 Subpart ZZZZ (National Emission Standards for Internal Combustion Engines)
- 40 CFR 63 Subpart YYYY (National Emission Standards for Combustion Turbines)

In addition, for older engines and turbines, Arizona Administrative Code R18-2-719 (Standards of Performance for Existing Stationary Rotating Machinery) applies.

As part of this assessment, the Department reviewed the information in the report titled "Supplementary Information for Four Factor Analyses by WRAP States" dated May 4, 2009. In review of the document, the Department was not able to ascertain the viability of the control options for a variable range of engine and turbine vintage and size. Additionally, the cost computations for the various technology options appeared to be derived from a generic costing tool called AIRControlNet. The Department has determined that the information presented in the report cannot be meaningfully adapted for the purposes of developing a four-factor analysis. In this regard, the Department has determined that it is not possible to complete a four-factor analysis without a major investment of resources, and an exhaustive facility-by facility review to evaluate each unit, which is beyond the scope and effort required in this first Regional Haze SIP therefore no further analysis was conducted.

2. External Combustion Boilers

This source category consists of electricity generating, industrial, and commercial boilers.

Generally speaking, low-$NO_X$ burners, over-fire air systems, flue gas recirculation, SCR and SNCR are considered viable $NO_X$ control strategies for this source category. Spray dry absorber flue gas desulfurization systems, and the use of low sulfur fuel are considered viable control strategies for sulfur dioxide emissions.

There are multiple state and federal regulations that apply to this source category. These regulations s are technology based standards that stipulate emission limitations and operational restrictions to ensure that emissions of $NO_X$ and $SO_2$ are minimized.

The following list identifies potentially applicable federal requirements:

- 40 CFR 60 Subpart D, Da, Db, Dc (Standards of Performance for Fossil Fuel-fired Steam Generators and Electric Utility Steam Generating Units)
- 40 CFR 63 Subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters at Major Sources proposed on June 4, 2010)
- 40 CFR 63 Subpart JJJJJJ (Area Source Boiler MACT proposed June 4, 2010)
- Additionally a comprehensive rule under 40 CFR 63 is expected for electric utilities by November 2011.

In addition, for older boilers, A.A.C. R18-2-703 and 724 (Standards of Performance for Fossil Fuel fired Steam Generators and General Fuel-burning Equipment) applies.

As part of this assessment, the Department reviewed the information in the report titled "Supplementary Information for Four Factor Analyses by WRAP States" dated May 4, 2009. In review of the document, the Department was not able to ascertain the viability of the control options for a variable range of boiler vintage and size. Additionally, the cost computations for the various technology options appeared to be derived from a generic costing tool called AIRControlNet. The Department has determined that the information presented in the report cannot be meaningfully adapted for the purposes of developing a four-factor analysis. In this regard, the Department has determined that it is not possible to complete a four-factor analysis without a major investment of resources, and an exhaustive facility-by facility review to evaluate each unit, which is beyond the scope and effort required in this first Regional Haze SIP therefore no further analysis was conducted. The Department will revisit this decision in the next planning period.

3. Asphalt Plants

This source category includes facilities that produce asphaltic concrete. The main sources of $NO_X$ and $SO_2$ emissions are the drum dryer and supporting internal combustion engines. The engines are addressed in Section 11.3.3.1. Many asphalt plants in Arizona are portable sources. These facilities typically only operate at a single location for a limited duration, depending on contractual obligations and product demand. Since many of these emission units are portable, it is difficult to perform a site-specific analysis addressing visibility impacts for these units.
Asphalt plants in Arizona are permitted as minor sources of emissions. Typically, each facility accepts an hourly, production, or emissions limit that reduces the emissions of $NO_X$ and $SO_2$ emitted into the atmosphere. Most modern drum dryers are equipped with low-$NO_X$ burners and other combustion technology that reduce $NO_X$ emissions.

Cost of Compliance

In review of literature for retrofitting existing drum dryers with low- $NO_X$ burner technology, the cost for such retrofits is estimated at about 3,000 dollars per ton of $NO_X$ reduced.

Time Necessary for Compliance

Considering the portable nature of this source category and the low- $NO_X$ burners typically available in most modern drum dryers, , no additional controls were identified for this source category.

Energy and Non-Air Quality Environmental Impacts of Compliance

Considering the portable nature of this source category, and the various controls already operated by modern drum dryers, no additional controls were identified for this source category and no energy or non-air quality impacts were identified.

Remaining Useful Life of Affected Sources

It is difficult to estimate the remaining life of any potentially affected source in this category. Remaining life is specific to the facility for which controls are considered.

4. Lime Plants

This source category includes facilities that produce lime. There are two lime plants that operate in Arizona: Chemical Lime Nelson and Chemical Lime Douglas.

The Nelson facility is located in Northern Arizona between Kingman and Flagstaff. Both kilns at this facility were identified as BART-eligible for $NO_X$ and $SO_2$. Based on a modeling analysis performed by Chemical Lime, it was determined that the facility does not cause or contribute to visibility impairment at any nearby Class I areas. Additional details on the modeling results can be found in Section VI.D of the BART Technical Support Document (TSD) in Appendix D of this plan. As a result of the dispersion modeling, no further analysis was conducted.

Due to economic conditions, the Douglas facility has been in care and maintenance mode since January 2009, and the Department has received no indication of when the facility will resume normal operations. Due to the lack of operation and economic conditions, no further analysis was conducted as part of this first Regional Haze SIP. The Department will revisit this decision in the next planning period.

5. Portland Cement Plants

There are two operating Portland cement plants in Arizona: California Portland Cement and Phoenix Cement.

The California Portland Cement plant is located 20 miles north of Tucson. The facility operates four cement kilns. Kiln 4 was identified as BART-eligible. Based on a modeling analysis performed by the company, it was determined that Kiln 4 does not cause or contribute to visibility impairment at any nearby Class I areas. Additional details on the modeling results can be found in Section VI.A of the BART TSD in Appendix D. Additionally the facility obtained a New Source Review/Prevention of Significant Deterioration (NSR/PSD) permit to construct and operate a modern, state-of-the-art kiln that would replace all 4 existing kilns. Due to economic conditions the facility was unable to commence construction on the new kiln within 18 months as required by law, but has resubmitted an application for re-approval. Due to the same economic conditions, Kilns 1-3 have been in care and maintenance mode since 2008 (as documented in a CPC letter dated March 19, 2013) and the Department has received no indication of when the facility will resume normal operations. Due to the lack of operation and economic conditions, no further analysis was conducted for Kilns 1-3 as part of this first Regional Haze SIP. The Department will revisit this decision in the next planning period.

The Phoenix Cement plant is located near Clarkdale. The facility operates a single kiln that commenced operation in the early 2000s. The operations are covered by a comprehensive air permit that includes facility-wide limits on $NO_X$ and $SO_2$. The permit also includes limits from the federal NSPS (Subpart F) and NESHAP (Subpart LLL). The modeling analysis conducted as part of the permit that authorized construction of the modern kiln included visibility modeling to ensure that the new kiln does not appreciably diminish or impair visibility.

The operating kilns at both the facilities employ preheater/pre-calciner technology to optimize fuel consumption patterns and consequently result in reduced nitrogen oxides emission levels relative to kilns that are not equipped with the technology. With the technology, more fuel is typically combusted at lower temperatures prior to the high-heat burning zone in the main kiln burner and consequently, the potential for thermal NOX generation is significantly reduced. Low NOX emission performance is enhanced by employing staged combustion. The purpose of staged combustion is to burn the fuel in 2 stages. Staged air combustion suppresses the formation of NOX by operating under fuel rich reducing conditions in the flame or primary zone where most of the NOX is potentially formed. This zone is followed by oxygen-rich conditions in a downstream secondary zone where CO is oxidized at a lower temperature with minimal NOX formation.

It should be noted very minimal SO2 emissions are expected from these two cement plant operations. The principal ingredient in the manufacturing process is limestone, which provides an inherent scrubbing opportunity and is maximized by the preheater/precalciner process. Due to this scrubbing, and to the fact that the sulfur content of the fuel and feed is very minimal, the resultant effect is low SO2 emissions at the stack.

In addition to the above, a 4-factor analysis was presented by Phoenix Cement to address the possibility of installation of Selective Non-Catalytic Reduction (SNCR) for the kiln. The Department agreed with the analysis provided.

**Cost of Compliance**

ADEQ has considered different estimates of the costs of installing and operating SNCR at PCC. Based in part on estimates provided by the EPA and PCC, which are incorporated in PCC's March 6, 2013 comments, and applicable cost-estimate guidance, ADEQ finds that the cost of installing SNCR at PCC would be in excess of $1,700,000 and the cost of operating SNCR at PCC would be in excess of $1,200,000 annually. Although incremental cost-effectiveness in $/Δdv or $/ton is not necessarily a required feature of a reasonable progress analysis for non-BART sources, such as PCC, ADEQ has considered the visibility modeling issues incorporated in PCC's March 6, 2013 comments and concludes that changes to visibility impairment in the Sycamore Canyon Wilderness Area that might be achieved by the installation and operation of SNCR at PCC are not warranted in light of these costs and given the revised reasonable progress demonstration for the Sycamore Canyon Wilderness Area. As demonstrated elsewhere in this SIP, reasonable progress will already be achieved for the Sycamore Canyon Wilderness Area significantly in excess of the corresponding URP.

**Time Necessary for Compliance**

Considering ADEQ's conclusions regarding the Cost of Compliance, above, no additional controls are identified for PCC. However, even if additional controls were identified, they would not need to be installed by 2018, because the 5-year requirement at CAA § 169A(g)(4), 42 U.S.C. § 7491(g)(4), applies only to sources subject to BART, which PCC is not, and because reasonable progress will already be achieved for the Sycamore Canyon Wilderness Area significantly in excess of the corresponding URP, as demonstrated elsewhere in this SIP.

**Energy and Non-Air Quality Environmental Impacts of Compliance**

The installation and operation of SNCR at PCC would require increased energy usage at PCC. Non-air quality environmental impacts associated with SNCR include the hazards of transporting and storing urea or ammonia, especially if anhydrous ammonia is used; and ammonia slip at potentially problematic levels, especially if urea is used.

**Remaining Useful Life**

ADEQ concludes that Kiln 4 has a remaining useful life for approximately the next 50 years. This is based on design information provided by PCC, the fact that Kiln 4 has been in operation for only 10 years, and lifetime projections of PCC's quarry and raw materials. However, the question of whether the installation and operation of SNCR at PCC is warranted as a function of the remaining useful life of the kiln implicates reasonably foreseeable changes at PCC that diminish or eliminate the need to impose the requirement of SNCR under this SIP. For these reasons as well, ADEQ finds that it is not reasonable to

require the installation and operation of SNCR at PCC as part of this SIP. The Department will revisit this decision in the next planning period.

6. Primary Copper Smelters

This source category includes two primary copper smelters that are operated in Arizona: Freeport McMoRan's Miami Smelter and ASARCO's Hayden Smelter.

Both smelters have equipment that was identified as subject-to-BART for $SO_2$ (see Section VI.C and E of the BART TSD). For each facility, the double contact sulfuric acid plant was determined as BART. The emissions from equipment not subject to BART (specifically some converters and the flash furnaces) are also routed to the acid plant and therefore will be subject to the same BART limits. No additional analysis was determined to be necessary for $SO_2$.

These operations also emit $NO_X$. Freeport Miami obtained a PSD permit for the installation of the Isasmelt furnace in the early 1990s and that permit contains BACT limits for $NO_X$ for affected emission units. Based on an emission analysis for FMMI, it has been concluded that the potential emissions from the BART-subject units is less than 40 tpy thus rendering the outcome that those units should not be subject to a BART analysis for NOX. Additionally, the WRAP modeling documented that the highest NOX impact from the FMMI operations at the Superstition Wilderness area with a threshold impact of 0.11 dv. When the threshold impact is indiscernible, it can be very reasonably construed that cost-effective visibility improvement strategies are not viable from a NOX emissions perspective. The Department will revisit this decision in the next planning period.

7. Nitric Acid Plants

This category includes one source (Apache Nitrogen Products in Benson, Arizona) that manufactures nitric acid for sale and for use in manufacturing of fertilizer products. The main sources of $NO_X$ emissions in this category are the nitric acid plants and internal combustion engines. The emissions from the engines are discussed in 11.3.3.1.

There are multiple state and federal regulations that will apply to nitric acid production. These standards are technology based standards that stipulate emission limitations and operational restrictions to ensure that emissions of $NO_X$ are minimized. Emissions of $SO_2$ from nitric acid plants are minimal.

The following list identifies applicable federal and state requirements:

- 40 CFR 60 Subpart G (Standards of Performance for Nitric Acid Plants)
- A.A.C. R18-2-706 (Standards of Performance for Existing Nitric Acid Plants)

The facility is covered by a permit that requires the operation of $NO_X$ controls including Selective Catalytic Reduction (SCR), absorption towers, and scrubbers to reduce $NO_X$ emissions.

<u>Cost of Compliance</u>

Considering that the applicable NSPS standard has a $NO_X$ limit, and the various controls already operated by the facility, no additional controls were identified for this source.

<u>Time Necessary for Compliance</u>

Considering that the applicable NSPS standard has a $NO_X$ limit, and the various controls already operated by the facility, no additional controls were identified for this source.

Energy and Non-Air Quality Environmental Impacts of Compliance

Considering that the applicable NSPS standard has a $NO_X$ limit, and the various controls already operated by the facility, no additional controls were identified for this source.

Remaining Useful Life of Affected Sources

The remaining useful life of the nitric acid plant was not available.

### 11.3.4 Conclusions from the Four-Factor Analysis

Based on the above analysis, ADEQ has concluded that it is not reasonable to require additional controls for these source categories at this time. ADEQ will be developing guidance for conducting a comprehensive review of individual non-BART stationary sources over the next five years, to identify any additional emission reductions that could improve Class I area visibility by end of this planning period covered by this submittal. This review will identify possible controls for non-BART sources and a schedule for implementation.

## 11.4 Determination of Reasonable Progress Goals

Under Section 308(d)(1) of the Regional Haze Rule states must "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions" for each Class I area. These reasonable progress goals (RPGs) are interim goals that must provide for incremental visibility improvement for the most impaired visibility days, and ensure no degradation for the least impaired visibility days.

### 11.4.1 Reasonable Progress Goals from Arizona's Regional Haze SIP Submitted in 2011

The RPGs for the first planning period are visibility goals for the year 2018. Based on the steps outlined in Section 11.2, ADEQ established RPGs for each Class I area in Arizona.

The RPGs presented in Table 11.3 are those submitted in the 2011 Regional Haze SIP. These were based on ADEQ's evaluation and consideration of the following: the results of the Community Multiscale Air Quality (CMAQ) modeling described in Section 9.3, which includes "on-the-books" controls and other emission inputs (see Appendix C for list of CMAQ model emission inputs), the results of the four-factor analysis described in Section 11.3.3, and the BART review described in Chapter 10. The RPGs provide for visibility improvement at all Class I areas in Arizona on 20% worst days (Table 11.3); however, the goals do not meet the uniform rate of progress (URP). It is important to note that the URP represents the mathematical annual average deciview necessary each year to move from the baseline condition to the natural condition for any given Class I area. This annual average decrease does not take into account existing or real world conditions and are not achievable in every instance.

Table 11.3 shows that for all but two monitors, there is no degradation on 20% best days. For those areas with no degradation, there is an improvement in visibility conditions in 2018 on best days. ADEQ attributes this predicted improvement to a combination of factors: the numerous "on-the-books" controls

included in the CMAQ modeling and significant reductions in mobile sources emissions (as described in Section 11.4.3). The two monitors showing degradation on best days are CHIR1 and SAGU1, representing four Class I areas.

**Table 11.3 – Reasonable Progress Goals for 20% Worst and Best Days for Arizona Class I Areas**

| Arizona Class I Area | 20% Worst Days | | | 20% Best Days | |
|---|---|---|---|---|---|
| | Baseline (dv) | 2018 URP (dv) | 2018 Reasonable Progress (dv) | Baseline (dv) | 2018 Reasonable Progress (dv) |
| Chiricahua NM, Chiricahua W, Galiuro W | 13.43 | 11.98 | 13.35 | 4.91 | 4.94 |
| Grand Canyon NP | 11.66 | 10.58 | 11.14 | 2.16 | 2.12 |
| Mazatzal W, Pine Mountain W | 13.35 | 11.79 | 12.76 | 5.40 | 5.17 |
| Mount Baldy W | 11.85 | 10.54 | 11.52 | 2.98 | 2.86 |
| Petrified NP | 13.21 | 11.64 | 12.85 | 5.02 | 4.73 |
| Saguaro NP – West Unit | 16.22 | 13.90 | 15.99 | 8.58 | 8.34 |
| Saguaro NP – East Unit | 14.83 | 12.88 | 14.82 | 6.94 | 7.04 |
| Sierra Ancha W | 13.67 | 12.02 | 13.17 | 6.16 | 5.88 |
| Superstition W | 14.16 | 12.38 | 13.89 | 6.46 | 6.22 |
| Sycamore Canyon W | 15.25 | 13.25 | 15.00 | 5.58 | 5.49 |

On December 21, 2012, EPA proposed to partially approve and partially disapprove elements of Arizona's Regional Haze SIP, including the RPGs for all Arizona Class I areas (77 FR 75704). The following sections address those deficiencies.

### 11.4.2 Baseline and Progress Period Visibility

As discussed in Chapter 8, Section 8.8, comparisons between the 2002 and 2008 EIs are problematic, primarily due to methodology changes. As a result, ADEQ is using IMPROVE monitoring data as surrogates for assessing visibility at Arizona's Class I areas. ADEQ is also presenting a more robust 10-year trend analysis to illustrate how alternative methods of visibility trend analysis may affect the conclusions. The alternative method utilized the Theil Trend to calculate an annual trend for the 10-year period of interest and is an EPA accepted method for annual pollutant trend analysis[6]. For more details on the Theil Trend results, see Section III of the enclosed TSD. Additionally, modified versions of the baseline and progress period averages are presented to illustrate the effects of singular events (e.g. wildfires) and anomalous years that occurred in the middle of the 10 year period (e.g. 2005).

Table 11.4 shows the comparison of the baseline conditions (2000-2004) to the progress period (2005-2009). The progress period visibility was calculated in the same manner as the baseline conditions using data from the IMPROVE monitors for both 20% worst and best days and is shown in deciviews (dv). For the 20% worst days, all but two IMRPOVE monitors (GRCA2 and IKBA1) show improved visibility for the progress period compared with the baseline. There is no degradation on best days from baseline conditions to the progress period (Table 11.4). This analysis of monitored data indicates that visibility on

[6] EPA. Trends in Monitored Concentrations of Carbon Monoxide. National Air Quality and Emissions Trends Report, 2003.

best days for all sites is improving, while GRCA2 is showing no change. The Theil method showed similar results for both the 20% worst and 20% best days, though the method generally indicated that visibility degradation seen at some of the sites were not statistically significant, meaning that the differences seen in the baseline and progress periods do not represent an actual trend, but instead is a result of natural variation. For more details on the Theil Trend results, see Section III of the enclosed TSD.

**Table 11.4 – Comparison of Deciview for 20% Worst and Best Days for Arizona Class I Areas for the Baseline and Progress Period (2005-2009)**

| Arizona Class I Area | 20% Worst Days | | 20% Best Days | |
|---|---|---|---|---|
| | Baseline (dv) | 2005-2009 Progress Period (dv) | Baseline (dv) | 2005-2009 Progress Period (dv) |
| Chiricahua NM, Chiricahua W, Galiuro W | 13.4 | 12.2 | 4.9 | 4.4 |
| Grand Canyon NP | 11.7 | 12.0 | 2.2 | 2.2 |
| Mazatzal W, Pine Mountain W | 13.3 | 13.4 | 5.4 | 5.1 |
| Mount Baldy W | 11.8 | 11.8 | 3.0 | 2.9 |
| Petrified NP | 13.2 | 13.0 | 5.0 | 4.6 |
| Saguaro NP – West Unit | 16.2 | 14.9 | 8.6 | 8.0 |
| Saguaro NP – East Unit | 14.8 | 13.6 | 6.9 | 6.7 |
| Sierra Ancha W | 13.7 | 13.0 | 6.2 | 5.3 |
| Superstition W | 14.2 | 13.8 | 6.5 | 5.7 |
| Sycamore Canyon W | 15.3 | 15.2 | 5.6 | 5.1 |

As noted above, two monitors (GRCA2 and IKBA1) show decreasing visibility on worst days for the progress period (Table 11.4). These are the two monitors representing the Grand Canyon National Park (GRCA2), Mazatzal Wilderness (IKBA1), and Pine Mountain Wilderness (IKBA1). The deciview increase at both monitors can be explained by analyzing the contribution of individual pollutants. Table 11.5 shows the relative contribution of visibility impairing pollutants on 20% worst day at all Arizona Class I areas.

**Table 11.5 – Relative Contribution of Pollutants on 20% Worst Days for the Progress Period (2005-2009)**

| Site | Class I Area | Deciview (dv) | Percent Contribution (% of $Mm^{-1}$) and Rank | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| BALD1 | Mount Baldy W | 11.8 | 25% (2) | 4% (6) | 42% (1) | 8% (4) | 6% (5) | 16% (3) | 0% (7) |
| CHIR1 | Chiricahua NM, Chiricahua W, Galiuro W | 12.2 | 36% (1) | 5% (5) | 16% (3) | 5% (6) | 10% (4) | 27% (2) | 1% (7) |

| Table 11.5 – Relative Contribution of Pollutants on 20% Worst Days for the Progress Period (2005-2009) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Site | Class I Area | Deciview (dv) | Percent Contribution (% of $Mm^{-1}$) and Rank | | | | | | |
| | | | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| GRCA2 | Grand Canyon NP | 12.0 | 22% (2) | 7% (5) | **41% (1)** | 11% (4) | 6% (6) | 12% (3) | 0% (7) |
| IKBA1 | Mazatzal W, Pine Mountain W | 13.4 | 26% (2) | 8% (5) | **29% (1)** | 8% (6) | 8% (4) | 21% (3) | 1% (7) |
| PEFO1 | Petrified NP | 13.0 | 23% (2) | 5% (6) | 31% (1) | 11% (4) | 8% (5) | 21% (3) | 1% (7) |
| SAGU1 | Saguaro NP – East Unit | 13.6 | 25% (2) | 9% (5) | 18% (3) | 8% (6) | 11% (4) | 28% (1) | 1% (7) |
| SAWE1 | Saguaro NP – West Unit | 14.9 | 21% (2) | 11% (5) | 16% (3) | 8% (6) | 13% (4) | 31% (1) | 1% (7) |
| SIAN1 | Sierra Ancha W | 13.0 | 25% (2) | 6% (6) | 33% (1) | 9% (4) | 8% (5) | 19% (3) | 1% (7) |
| SYCA1 | Sycamore Canyon W | 15.2 | 15% (4) | 4% (6) | 29% (1) | 9% (5) | 15% (3) | 28% (2) | 0% (7) |
| TONT1 | Superstition W | 13.8 | 28% (1) | 8% (5) | 21% (3) | 7% (6) | 9% (4) | 26% (2) | 1% (7) |

For GRCA2 and IKBA1, the primary pollutant contributing to visibility impairment is organic carbon (particulate organic mass). In June 2009, three lightning sparked wildfires burned in close proximity to the GRCA2 monitor. The two visibility components associated with wildfire are organic carbon and elemental carbon. Observations regarding these two components are given below and results indicate that the visibility changes at GRCA2 were partially due to the 2009 wildfires:

- Elemental carbon showed a fairly large increase in visibility extinction using the RHR method; however, annual average elemental carbon measurements did not show increasing trends using the Theil method.
- Organic carbon showed an increase in extinction using the Regional Haze Rule method; however, annual average elemental carbon measurements did not show increasing trends using the Theil method.
- A separate analysis was performed that replaced the elemental and organic carbon extinction values for 2009 with longer term average extinction values to exclude the extreme effect of the wildfires from June 2009. The average baseline period (2000-2004) was compared to the average altered progress period (2005-2009) total extinction. The results of this analysis showed a decrease from 34.6 Mm-1 for the baseline period to 32.8 Mm-1 for the altered progress period. This provides evidence that the 2009 fires played an important role in the increased extinction when using the RHR method. A similar analysis was conducted replacing the elemental carbon and organic carbon values for 2003 with longer term averages, which acted to increase the total extinction change from 32.9 Mm-1 in the adjusted baseline period to 35.1 Mm-1 in the progress period. A summary of these results can be found in Table 11.5. These results illustrate how specific fire events can have a significant effect on the trends as determined by the RHR method.

The overall deciview increase at IKBA1 was affected by high measurements in 2005. The main components that contributed to this increase were organic carbon and ammonium sulfate. This increase is attributed to the following:

- Organic carbon showed a large increase in extinction using the Regional Haze Rule method, but did not show an increasing trend using the Theil method. The increase in organic carbon was strongly controlled by a large wildfire in July of 2005.
- Ammonium sulfate showed a large increase in extinction using the Regional Haze Rule method, but did not show an increasing trend using the Theil method. This large increase in ammonium sulfate using the Regional Haze Rule method was a regional trend. See Section III of the enclosed TSD for more information on ammonium sulfate trends.
- A separate analysis was performed that replaced the elemental and organic carbon extinction values for 2005 with longer term average extinction values to exclude the extreme effect of the wildfire from July 2005. The average baseline period (2000-2004) was compared to the average altered progress period (2005-2009) total extinction. The results of this analysis showed a decrease from 38.9 Mm-1 for the baseline period to 37.7 Mm-1 for the altered progress period (Table 11.6). This provides evidence that the 2005 fire played an important role increases in extinction when using the Regional Haze Rule method.

**Table 11.6 – Alternative RHR Analysis Results for 20% Worst Days at GRCA2 (2003 & 2009) and IKBA1 (2005)***

| Site | Year Adjusted | Total Extinction (Mm-1) | | | | | |
|---|---|---|---|---|---|---|---|
| | | Baseline | Adjusted Baseline | Progress | Adjusted Progress | Standard Change | Adjusted Change |
| GRCA2 | 2003 | 34.6 | 32.9 | 35.1 | -- | **0.5** | **2.2** |
| GRCA2 | 2009 | 34.6 | -- | 35.1 | 32.8 | **0.5** | **-1.8** |
| IKBA1 | 2005 | 38.9 | -- | 39.2 | 37.7 | **0.3** | **-1.2** |

* EC and POM visibility extinctions are replaced by ten-year average for 2003 and 2009 (GRCA2) and 2005 (IKBA1)

### 11.4.3 Visibility Trend Analysis: 2000 – 2009

The comparison between baseline conditions and the progress period show that overall visibility on worst and best days is either improving or unchanged at Arizona's Class I areas. This section presents visibility progress from 2000 to 2009 using two previously discussed methodologies: 1) the Regional Haze Rule method and 2) the Theil method.

Table 11.7 shows the deciview change and the change in extinction using the Regional Haze Rule method between the baseline period (2000 – 2004) and the progress period for each Class I area. This analysis shows changes in extinction for ammonium sulfate, organic carbon, elemental carbon, fine soil, coarse mass, and sea salt.

**Table 11.7: Difference in Aerosol Extinction by Component between the Baseline Period (2000-2004) and the Progress Period (2005-2009) on 20% Worst Days**

| Site | Deciview (dv) | Change in Extinction by Component ($Mm^{-1}$)* |
|---|---|---|

| | Baseline | Progress Period | Change in dv* | Amm. Sulfate | Amm. Nitrate | OC | EC | Soil | CM | Sea Salt |
|---|---|---|---|---|---|---|---|---|---|---|
| BALD1 | 11.8 | 11.8 | 0.0 | +0.3 | -0.1 | -2.1 | -0.7 | +0.4 | +1.3 | +0.1 |
| CHIR1 | 13.4 | 12.2 | -1.2 | +1.0 | -0.1 | -3.2 | -0.5 | -0.3 | -1.9 | +0.2 |
| GRCA2 | 11.7 | 12.0 | +0.3 | +0.5 | -0.4 | +0.1 | +0.5 | +0.1 | -0.3 | 0.0 |
| IKBA1 | 13.3 | 13.4 | +0.1 | +1.0 | -1.2 | +0.7 | 0.0 | -0.3 | 0.0 | +0.1 |
| PEFO1 | 13.2 | 13.0 | -0.2 | +0.5 | -0.3 | -1.4 | +0.5 | +0.6 | -1.0 | +0.1 |
| SAGU1 | 14.8 | 13.6 | -1.2 | -0.1 | -3.2 | -4.1 | -0.9 | -0.1 | +1.2 | +0.2 |
| SAWE1 | 16.2 | 14.9 | -1.3 | -0.7 | -2.3 | -1.9 | -0.5 | -1.4 | -2.2 | +0.2 |
| SIAN1 | 13.7 | 13.0 | -0.7 | +0.7 | -0.3 | -2.5 | +0.1 | +0.1 | -0.6 | +0.2 |
| SYCA1 | 15.3 | 15.2 | -0.1 | +0.7 | -0.7 | -0.5 | +0.4 | -1.0 | +1.4 | 0.0 |
| TONT1 | 14.2 | 13.8 | -0.4 | +1.3 | -0.5 | -3.5 | -0.6 | +0.4 | +0.5 | +0.2 |

For the 20% worst days, the Regional Haze Rule method exhibited an increase in deciview between the baseline and progress periods at GRCA2 and IKBA1 sites and decreases at all other Arizona IMPROVE monitors. Using the Theil method, there were no significant increases in deciview at any monitors from 2000 to 2009. Significant decreasing deciview metric trends occurred at all sites except BALD1, GRCA2, IKBA1, PEFO1, and SYCA1 (Table 11.9). Notable differences for individual component extinctions on the 20% worst are as follows:

- All sites except GRCA2 and IKBA1 measured decreases in organic carbon using the RHR method. No sites showed significant increasing trends using the Theil method and four sites showed significant decreasing trends.
- The Regional Haze Rule method analysis of ammonium sulfate showed increased extinction at all Arizona site except SAGU1 and SAWE1, with the largest increases in ammonium sulfate at the CHIR1, IKBA1 and TONT1. In contrast, no statistically significant ($p < 0.15$) increasing annual trends in ammonium sulfate were measured using the Theil method. Decreasing annual ammonium sulfate trends on the order of about 0.1 $Mm^{-1}$/year were measured at BALD1, CHIR1, SAGU1 and SAWE1 sites. Anomalously high ammonium sulfate occurred in 2005 at most Arizona sites, which influenced the increases noted using the RHR method.
- The Regional Haze Rule method analysis of ammonium nitrate extinction showed decreases at all Arizona sites for the 20% worst days. Analysis of all measured days showed no increasing trends, and decreasing trends on the order of 0.1 $Mm^{-1}$/year at the IKBA1, SAGU1, SAWE1, SIAN1 and TONT1.
- The Regional Haze Rule method analysis of coarse mass revealed increasing extinction values at BALD1, SAGU1, SYCA1, and TONT1. However, only BALD1 showed a statistically significant increasing trend for coarse mass for all measured days on the order of approximately 0.1 $Mm^{-1}$/year ($p < 0.15$).
- The Regional Haze Rule method showed decreases in PM fine (soil) at five IMPROVE sites from the baseline to the progress period while showing the highest increases at PEFO1, BALD1, and TONT1 for the 20% worst days. Theil method analysis showed increasing trends at only two Arizona sites for the 20% worst days (BALD1 and PEFO1) while SYCA1 showed a significantly decreasing trend.
- Increases in deciview at GRCA2 using the RHR method were due to increases in ammonium sulfate and elemental carbon and the lack of a decreasing particulate organic mass extinction that

occurred at most other Arizona Class 1 areas. Higher progress period measurements at GRCA2 were influenced by large events between June and August of 2009. These increases were partially offset by decreases in ammonium nitrate and coarse mass. GRCA2 did not show significantly increasing ammonium sulfate trends using the Theil method.

- Increases in deciview at IKBA1 were mostly due to increased ammonium sulfate and organic carbon. Higher measurements during the progress period at IKBA1 were influenced by large events in July 2005. These increases were partially offset by decreases in ammonium nitrate and soil. This site did not show significantly increasing ammonium sulfate trends using the Theil method.

For the 20% best days, the Regional Haze Rule method showed a decrease deciview at all sites except GRCA2, where the deciview remained the same (Table 11.9). Notable differences for individual component averages on the 20% best days were as follows:

- The greatest decreases in deciview are attributable to decreases in organic carbon, which decreased at all sites except IKBA1 (using the RHR method). Theil method analysis revealed significant decreasing trends at seven IMPROVE monitors (Table 11.9).
- Ammonium sulfate decreased at most sites, but increased slightly at GRCA2, SAGU1 and SYCA1 using the RHR method. Theil methodology revealed no statistically significant increasing site trends and three sites experienced statistically significant decreases in ammonium sulfate trends ($p < 0.15$) (Table 11.9).
- Ammonium nitrate decreased at all but GRCA2 using the RHR method and four of those decreases were statistically significant using the Theil method ($p < 0.15$) (Table 11.9).

**Table 11.8: Difference in Aerosol Extinction by Component between the Baseline Period (2000-2004) and the Progress Period (2005-2009) on the 20% Best Days**

| Site | Deciview (dv) | | | Change in Extinction by Component ($Mm^{-1}$)* | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Baseline Period | Progress Period | Change in dv* | Amm. Sulfate | Amm. Nitrate | OC | EC | Soil | CM | Sea Salt |
| BALD1 | 3.0 | 2.9 | -0.1 | -0.1 | -0.1 | -0.1 | 0.0 | 0.0 | +0.1 | 0.0 |
| CHIR1 | 4.9 | 4.4 | -0.5 | -0.2 | -0.1 | -0.5 | -0.1 | 0.0 | 0.0 | 0.0 |
| GRCA2 | 2.2 | 2.2 | 0.0 | +0.1 | 0.0 | -0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| IKBA1 | 5.4 | 5.1 | -0.3 | -0.3 | -0.2 | +0.1 | 0.0 | -0.1 | -0.1 | +0.1 |
| PEFO1 | 5.0 | 4.6 | -0.4 | -0.1 | -0.2 | -0.4 | 0.0 | +0.1 | 0.0 | 0.0 |
| SAGU1 | 6.9 | 6.7 | -0.2 | +0.1 | -0.2 | -0.2 | -0.1 | -0.3 | +0.3 | +0.1 |
| SAWE1 | 8.6 | 8.0 | -0.6 | -0.2 | -0.1 | -0.5 | -0.4 | -0.3 | +0.2 | +0.2 |
| SIAN1 | 6.2 | 5.3 | -0.9 | -0.3 | -0.4 | -0.7 | -0.1 | 0.0 | 0.0 | 0.0 |
| SYCA1 | 5.6 | 5.1 | -0.5 | +0.1 | -0.1 | -0.6 | -0.2 | -0.1 | +0.1 | 0.0 |
| TONT1 | 6.5 | 5.7 | -0.8 | -0.2 | -0.2 | -0.5 | -0.2 | -0.1 | -0.2 | +0.1 |

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction, values in blue indicate decreases.

Table 11.9 presents a ten-year trend analysis of extinction for individual visibility impairing pollutants using the Theil method. Only averages with p-value statistics less than 0.15 (85% confidence level) are

presented; increasing slopes are noted in red and decreasing slopes in blue. The Regional Haze Rule requires states to look at changes in extinction for the 20% worst and best days. As an alternative, ADEQ is presenting trend statistics for an average of all sampled days. Selection of the 20% worst and best days can vary seasonally from year to year, so the annual average of all sampled days may provide a better representation actual aerosol component trends.

**Table 11.9: Statistically Significant 2000-2009 Annual Average Trends for Aerosol Extinction by Component for Arizona Class I area IMPROVE Sites**

| Site | Group | Annual Trend* ($Mm^{-1}$/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Site Total (dv) | Amm. Sulfate | Amm. Nitrate | OC | EC | Soil | Coarse Mass | Sea Salt |
| BALD1 | 20% Best | -- | -- | 0.0 | -- | 0.0 | -- | 0.0 | 0.0 |
| | 20% Worst | -- | -0.2 | -- | -- | -- | **0.1** | **0.3** | 0.0 |
| | All Days | -- | -0.1 | 0.0 | -- | -- | -- | **0.1** | 0.0 |
| CHIR1 | 20% Best | **-0.1** | 0.0 | 0.0 | -0.1 | 0.0 | -- | 0.0 | 0.0 |
| | 20% Worst | **-0.3** | -- | -- | -0.7 | -0.1 | -- | -- | 0.0 |
| | All Days | **-0.2** | -0.1 | 0.0 | -0.2 | -0.1 | -- | -0.1 | 0.0 |
| GRCA2 | 20% Best | -- | -- | -- | -- | 0.0 | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -0.1 | -- | -- | -- | -- | -- |
| | All Days | -- | -- | 0.0 | -- | -- | -- | -- | -- |
| IKBA1 | 20% Best | **-0.2** | -0.1 | -0.1 | 0.0 | 0.0 | 0.0 | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | 0.0 | -- | -- | 0.0 |
| | All Days | -- | -- | -0.1 | -- | 0.0 | -- | -- | 0.0 |
| PEFO1 | 20% Best | **-0.1** | -- | 0.0 | -0.1 | -- | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | -- | **0.1** | -- | 0.0 |
| | All Days | **-0.1** | -- | 0.0 | -- | -- | 0.0 | **0.1** | 0.0 |
| SAGU1 | 20% Best | **-0.2** | -- | -0.1 | -0.1 | -- | -- | -- | -- |
| | 20% Worst | **-0.3** | -0.4 | -0.5 | -0.6 | -0.3 | -- | -- | **0.1** |
| | All Days | **-0.2** | -0.1 | -0.1 | -0.2 | -0.1 | -- | -- | 0.0 |
| SAWE1 | 20% Best | **-0.2** | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -- | 0.0 |
| | 20% Worst | **-0.3** | -0.3 | -0.6 | -0.5 | -- | -- | -- | 0.0 |

| Table 11.9: Statistically Significant 2000-2009 Annual Average Trends for Aerosol Extinction by Component for Arizona Class I area IMPROVE Sites | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Site | Group | Annual Trend* ($Mm^{-1}$/year) | | | | | | | |
| | | Site Total (dv) | Amm. Sulfate | Amm. Nitrate | OC | EC | Soil | Coarse Mass | Sea Salt |
| | All Days | -0.2 | -0.1 | -0.1 | -0.3 | -0.1 | -- | -- | 0.0 |
| SIAN1 | 20% Best | -0.2 | -0.1 | -0.1 | -0.1 | 0.0 | -- | -- | 0.0 |
| | 20% Worst | -0.2 | -- | -- | -- | -- | -- | -- | 0.0 |
| | All Days | -0.2 | -- | -0.1 | -0.4 | -0.1 | -- | -- | 0.0 |
| SYCA1 | 20% Best | -0.1 | -- | -- | -0.1 | -- | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | 0.1 | -0.3 | -- | -- |
| | All Days | -0.1 | -- | 0.0 | -- | -- | -0.1 | -- | -- |
| TONT1 | 20% Best | -0.2 | -0.1 | -0.1 | -0.1 | -0.1 | -- | -0.1 | 0.0 |
| | 20% Worst | -0.2 | -- | -0.1 | -0.8 | -0.2 | -- | -- | 0.1 |
| | All Days | -0.1 | -- | -0.1 | -0.2 | -0.1 | -- | -- | 0.0 |

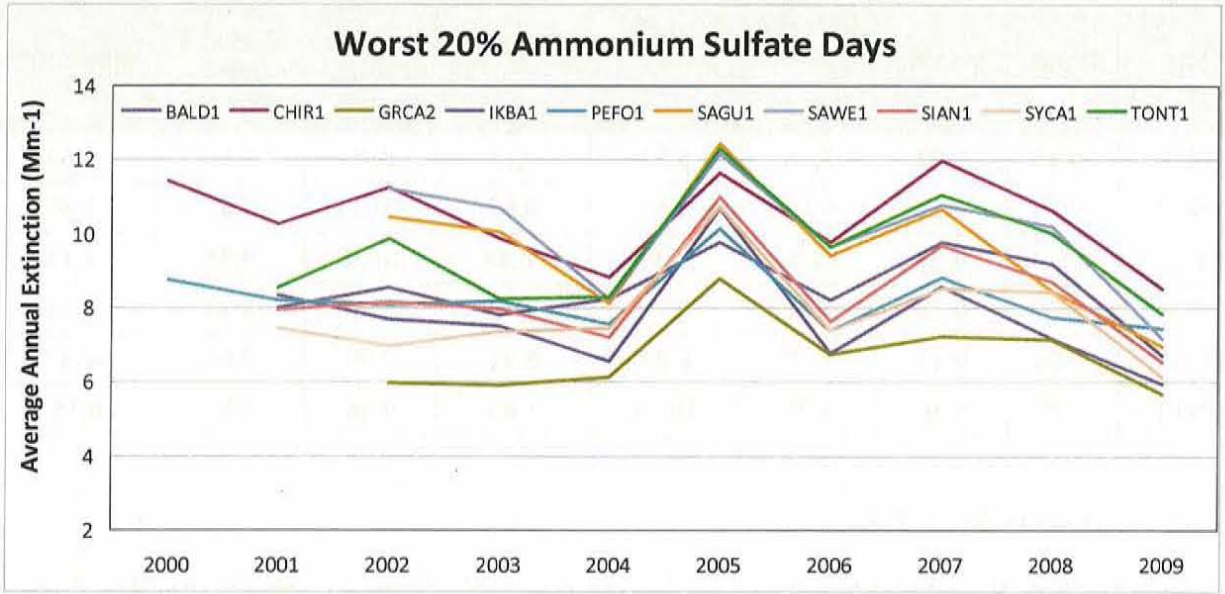
*Ammonium Sulfate*

Several of the tables in the preceding section have examined how ammonium sulfate extinction has changed within the 2000-2009 period at IMPROVE monitoring sites in Arizona. The comparison and analysis of baseline conditions and the progress period show increases in ammonium sulfate extinction at Arizona's IMPROVE monitors when using the Regional Haze Rule method, while showing no significant trends or decreasing Theil statistic trends for the 20% worst days, 20% best days, and all days.

To provide evidence of decreasing extinction at IMRPOVE monitors, ADEQ and Air Resource Specialists (ARS) performed an alternate analysis in which the 20% worst ammonium sulfate days were isolated, average annually, and averaged for the baseline and progress period. This analysis allows for a better understanding of how the visibility on 20% worst days for a specific pollutant can change between the baseline and progress period.

The analysis required by the Regional Haze Rule can cause seasonal shifts in the days chosen from the baseline and progress periods, which in turn can overlook seasonal highs for individual pollutants. A Theil statistics trend analysis was performed for each monitor on the annually averaged 20% worst days for 2000 - 2009. Using this analysis, extinction from ammonium sulfate decreases between 2000 – 2004 (Figure A). In 2005 and 2007, extinction from ammonium sulfate increased, which is followed by decreasing extinction from 2007 – 2009 (Figure A).

**Figure A: Average Annual Ammonium Sulfate Extinction (mM-1) for the 20% Worst Days**




When the baseline and progress period extinction averages are compared, all IMPROVE sites show increasing ammonium sulfate extinctions except SAWE1 (Table 11.10). However, when looking at the 20% worst days for ammonium sulfate from 2000 – 2009, no IMPROVE monitors show increasing trends. Statistically significant decreasing trends are found at BALD1, CHIR1, PEFO1, SAGU1, and SAWE1. The extreme differences are strongly influenced by ammonium sulfate concentrations measured in 2005. Since 2005 can be considered a mid-point, the data have a more neutral effect using the Theil method ($p < 0.15$). To illustrate the affect of 2005, ADEQ presents the results of an analysis in Table 11.10 where the Regional Haze Rule method is altered to include 2005 in the baseline period rather than the progress period. This altered Regional Haze Rule method resulted in reduced ammonium sulfate extinction values between the altered progress period (2006-2009) when compared to the altered baseline period (2000-2005) for all sites, except TONT1. This illustrates the strong affect that one outlier year can have in the Regional Haze Rule methodology.

**Table 11.10: 2000-2009 Ammonium Sulfate Extinction ($mM^{-1}$) Trends, Baseline (2000-2004) vs. Progress (2005-2009) Period Comparisons, and Altered Baseline (2000-2005) vs. Altered Progress (2005-2009) Period Comparisons the 20% Worst Ammonium Sulfate Days**

| Site | Slope | p-value | Baseline (2000-2004) | Period 1 (2005-2009) | Difference | Altered Baseline (2000-2005) | Altered Period 1 (2006-2009) | Difference |
|---|---|---|---|---|---|---|---|---|
| BALD1 | **-0.18** | **0.08** | 7.52 | 7.84 | **0.32** | 8.15 | 7.13 | **-1.02** |
| CHIR1 | **-0.15** | **0.14** | 10.33 | 10.51 | **0.18** | 10.55 | 10.22 | **-0.32** |
| GRCA2 | -0.05 | 0.24 | 6.39 | 7.12 | **0.73** | 6.87 | 6.70 | **-0.17** |
| IKBA1 | -0.09 | 0.36 | 8.16 | 8.73 | **0.57** | 8.48 | 8.47 | **-0.02** |

| Table 11.10: 2000-2009 Ammonium Sulfate Extinction ($mM^{-1}$) Trends, Baseline (2000-2004) vs. Progress (2005-2009) Period Comparisons, and Altered Baseline (2000-2005) vs. Altered Progress (2005-2009) Period Comparisons the 20% Worst Ammonium Sulfate Days | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Site** | **Slope** | **p-value** | **Baseline (2000-2004)** | **Period 1 (2005-2009)** | **Difference** | **Altered Baseline (2000-2005)** | **Altered Period 1 (2006-2009)** | **Difference** |
| PEFO1 | **-0.15** | **0.03** | 8.16 | 8.31 | **0.15** | 8.49 | 7.86 | **-0.64** |
| SAGU1 | **-0.29** | **0.13** | 9.54 | 9.58 | **0.05** | 10.26 | 8.87 | **-1.39** |
| SAWE1 | **-0.33** | **0.09** | 10.05 | 10.00 | **-0.05** | 10.58 | 9.45 | **-1.13** |
| SIAN1 | -0.07 | 0.30 | 7.81 | 8.71 | **0.90** | 8.45 | 8.14 | **-0.31** |
| SYCA1 | -0.04 | 0.43 | 7.30 | 8.24 | **0.94** | 7.99 | 7.62 | **-0.37** |
| TONT1 | 0.00 | 0.50 | 8.75 | 10.18 | **1.43** | 9.46 | 9.65 | **0.19** |

*Regional Ammonium Sulfate Trends*

Arizona's Regional Haze SIP addresses emissions and reasonable progress goals for the Class I areas within state boundaries. However, given that regional haze is an issue of the transport of pollutants, it is important to consider and analyze regional trends to understand the issues occurring within the state as well as those affecting and coming from neighboring states and beyond. This type of analysis allows for a better understanding of emission increases that are locally based and those that might be representative of a regional trend and thus the result of uncontrollable external factors (e.g. $NO_X$ emissions originating from a point source located within another state or country, PM emission increases that are regional trends and related to environmental factors, etc.). In this section, ADEQ presents an analysis of regional maps of IMPROVE monitor aerosol extinction changes between the baseline and progress periods in order to determine if previously identified ammonium sulfate trends within the State might be regional phenomena.

Figure B shows only those aerosol extinction components which have increased for the 20% most impaired days between the baseline (2000-2004) and progress (2005-2009) periods for all IMPROVE monitors in the western United States. Note that individual sites can show increases in specific aerosol components, but still show decreases in overall deciview values. There are fairly widespread increases in POM across much of the northwestern U.S. and substantial increases in ammonium sulfate across the State of Arizona, State of New Mexico, western Texas, and south-central Colorado. (Figure B). The ammonium sulfate increases are obviously regional in extent; however, it is difficult to determine an origination point. These increases could be due to a singular or combination of point or area sources within these states and/or Mexico.

**Figure B: Magnitude of Visibility Component Extinctions Increasing Between Baseline Average (2000-2004) and First Progress Period Average (2005-2009) for 20% Worst Days**

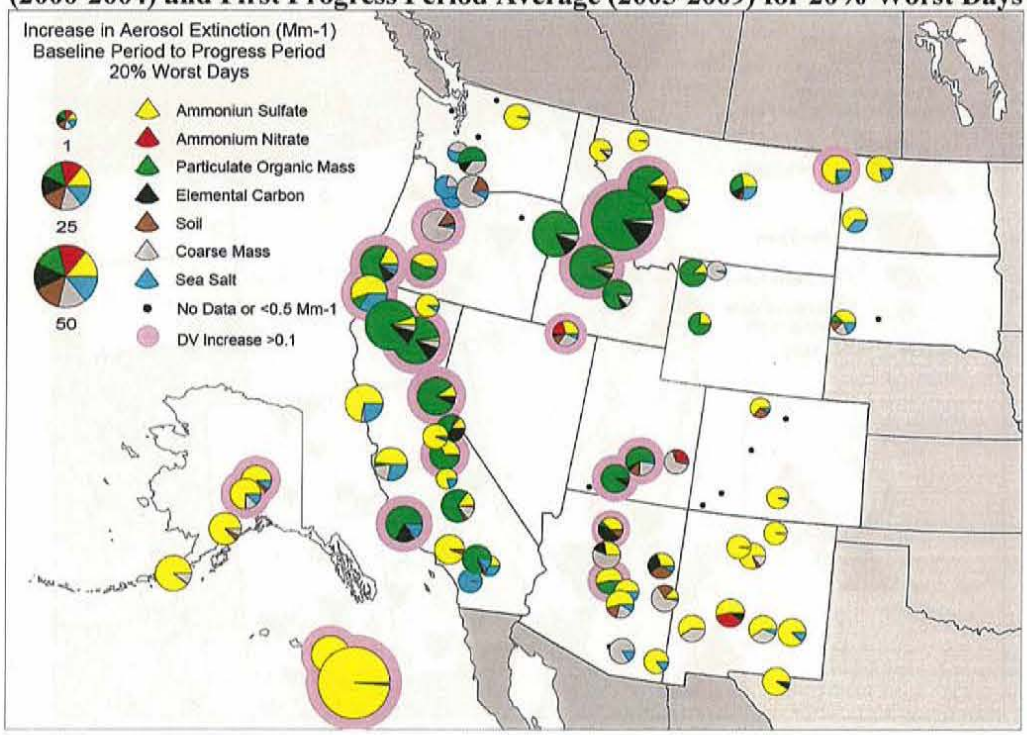



Figure B shows that extinction due to ammonium sulfate increased regionally between baseline and progress periods. The ammonium sulfate trends for the 20% worst days (Figure C) and all days (Figure D) were analyzed using Theil method statistics and found that there was either 1) no statistically significant trends at IMPROVE monitors within the four corners region (i.e. Arizona, Utah, Colorado, and New Mexico) or 2) the 10-year annual average ammonium sulfate extinction trends at these IMPROVE monitors exhibited statistically significant decreases ($p < 0.15$). Similar to what was previously reported for Arizona, regional Theil method trends disagree with the Regional Haze Rule method of a five year average comparison of the 20% worst days between the baseline and progress period (Table 11.9). Furthermore, this agreement between Arizona and south-western United States regional trends may indicate that 2005 and 2007 were outlier years for ammonium sulfate extinction within the entire four corners region and the Regional Haze Rule method does not reflect more recent visibility extinction improvements for ammonium sulfate.

**Figure C: 10-year annual average ammonium sulfate extinction trends for 20% worst days at CIA IMPROVE sites in the WRAP region.**

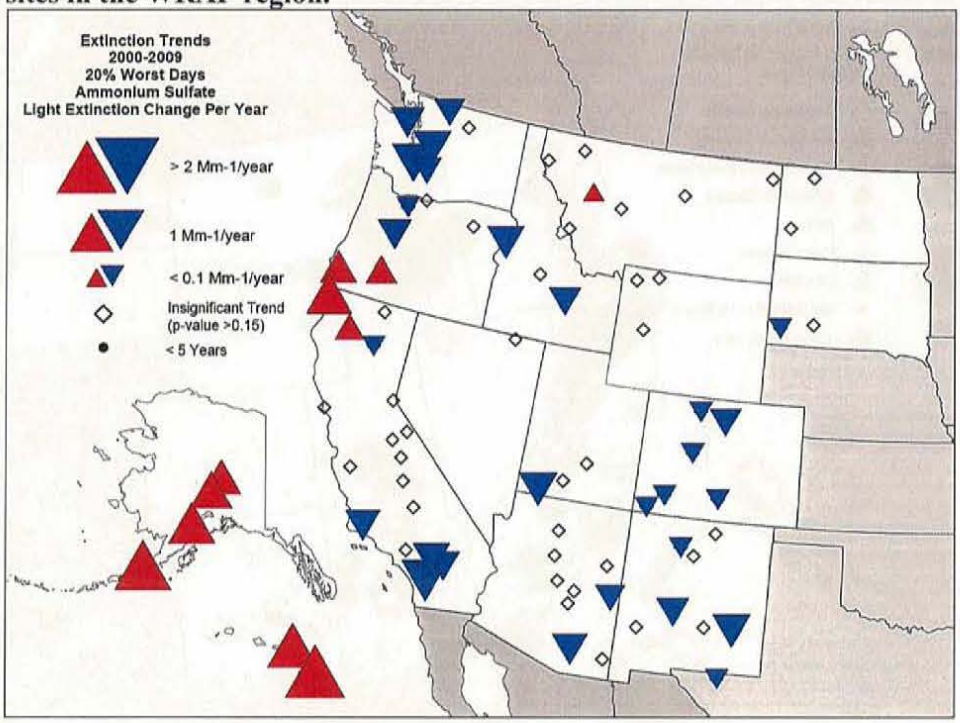
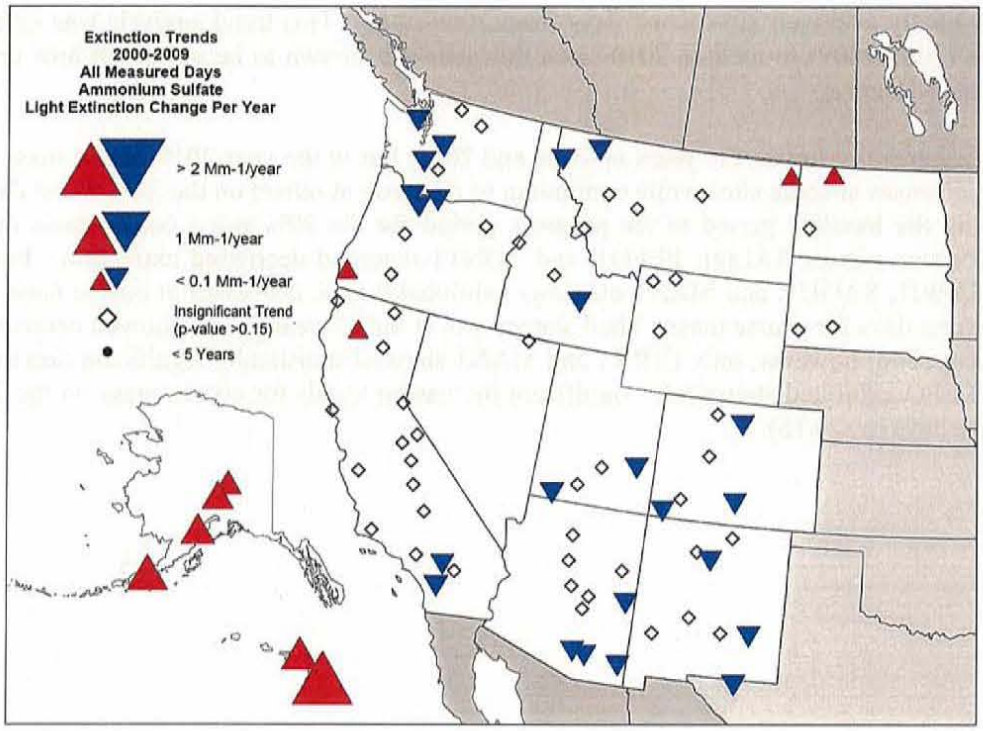



**Figure D: 10-year annual average ammonium sulfate extinction trends for all measured days at CIA IMPROVE sites in the WRAP region.**




### 11.4.4 Coarse Mass Analysis

Coarse particulate matter is generally recognized as having origination sources that are locally based. An analysis of coarse mass was conducted to gain a better understanding of trends between the baseline and progress period. ADEQ presents an alternate approach in selecting the 20% worst days, which is similar to the analysis performed for ammonium sulfate (Section 11.4.3). Furthermore, a qualitative analysis of the location of IMPROVE sites in relation to major $PM_{10}$ emitting point sources was performed to determine if an evident pattern exists between point source location and IMPROVE monitor location.

*20% Worst Coarse Mass Days*

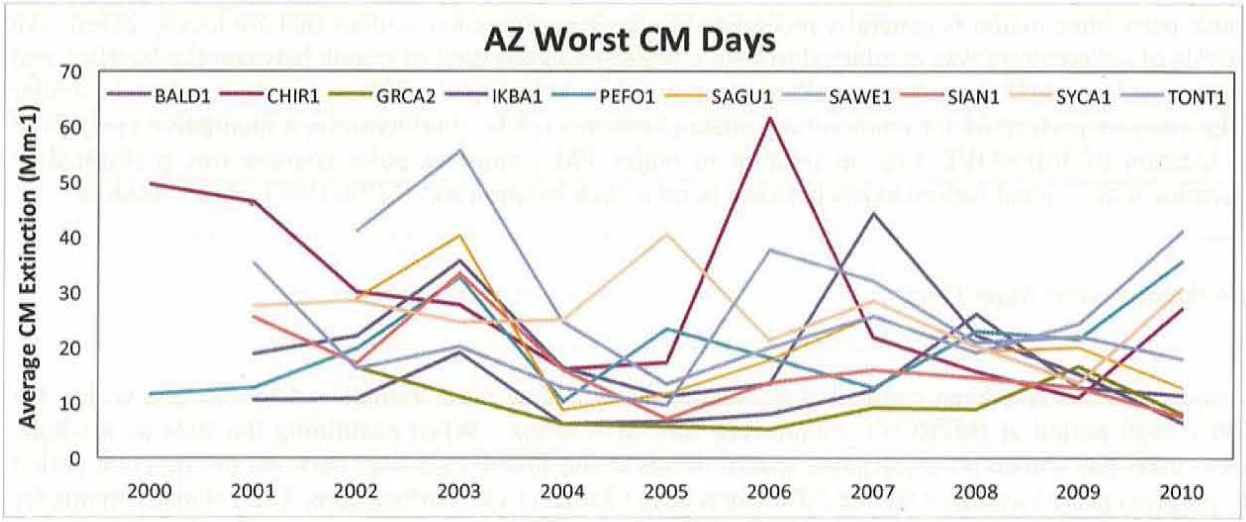
Several analyses have been conducted to examine how coarse mass extinction has changed within the 2000 - 2009 period at IMPROVE monitoring sites in Arizona. When examining the state as a whole, coarse mass has shown no discernable spatial trends at the IMPROVE sites between the baseline period and progress period averages for the 20% worst days (Table 11.6). Furthermore, Theil statistic trends for the 20% worst days only resulted in the BALD1 site exhibiting the only statistically significant trend between 2000-2009, where an increase has been noted (Table 11.9).

ADEQ and Air Resource Specialists (ARS) performed an alternate analysis where the 20% most impaired coarse mass days were isolated, averaged annually, and then averaged for the baseline and progress periods. This analysis was conducted to gain a better understanding of how the 20% worst days for a particular pollutant change between the baseline and progress periods rather than examining the 20% worst days for all pollutants combined. The combination analysis required by the Regional Haze Rule can cause seasonal shifts in the days chosen within the baseline and progress periods, which can miss seasonal highs for any given pollutant. A Theil statistics trend analysis was also performed for each

monitor on annually averaged 20% worst days from 2000-2010. This trend analysis was extended past prior analyses (2000-2009) to include 2010 since this year was shown to be unique in how coarse mass responded across Arizona.

Coarse mass is generally low in the years of 2008 and 2009, but in the year 2010 coarse mass extinction dramatically increases at some sites while continuing to decrease at others on the 20% worst days (Figure E). Comparing the baseline period to the progress period for the 20% worst coarse mass days (Table 11.11), all monitors except BALD1, PEFO1, and TONT1 recorded decreased extinction. Furthermore, the CHIR1, SAWI1, SAGU1, and SIAN1 monitors exhibited drastic decreases in coarse mass extinction for the 20% worst days for coarse mass. Theil statistics over the 11-year period showed decreasing trends at all sites except two; however, only CHIR1 and SIAN1 showed statistically significant decreases, while BALD1 and PEFO exhibited statistically significant increasing trends for coarse mass on the 20% worst days for coarse days ($p < 0.15$).

**Figure E: Average Annual Coarse Mass Extinction (mM-1) at each IMPROVE Site for the 20% Worst Coarse Mass Days.**




| Table 11.11: 2000-2010 Coarse Matter Visibility Extinction (mM-1) Trends and Baseline vs. Progress Period Comparisons for the 20% Worst Coarse Matter Days | | | | | |
|---|---|---|---|---|---|
| **Site** | **11-year trend (2000-2010)** | **p-value** | **Baseline (2000-2004)** | **Period 1 (2005-2009)** | **Period Difference** |
| BALD1 | **0.29** | **0.15** | 11.66 | 13.12 | **1.46** |
| CHIR1 | **-2.73** | **0.02** | 33.92 | 25.47 | **-8.45** |
| GRCA2 | -0.38 | 0.24 | 11.38 | 9.04 | **-2.34** |

| Table 11.11: 2000-2010 Coarse Matter Visibility Extinction (mM-1) Trends and Baseline vs. Progress Period Comparisons for the 20% Worst Coarse Matter Days | | | | | |
|---|---|---|---|---|---|
| **Site** | **11-year trend (2000-2010)** | **p-value** | **Baseline (2000-2004)** | **Period 1 (2005-2009)** | **Period Difference** |
| IKBA1 | -1.10 | 0.19 | 23.27 | 21.24 | **-2.03** |
| PEFO1 | **1.12** | **0.06** | 17.42 | 19.80 | **2.38** |
| SAGU1 | -1.26 | 0.38 | 25.88 | 18.83 | **-7.05** |
| SAWE1 | -0.56 | 0.31 | 40.47 | 20.49 | **-19.98** |
| SIAN1 | **-1.56** | **0.01** | 22.97 | 12.76 | **-10.21** |
| SYCA1 | -1.04 | 0.24 | 26.36 | 24.77 | **-1.59** |
| TONT1 | -0.32 | 0.50 | 21.08 | 24.47 | **3.38** |

### 11.4.5 Large Point Source Locations

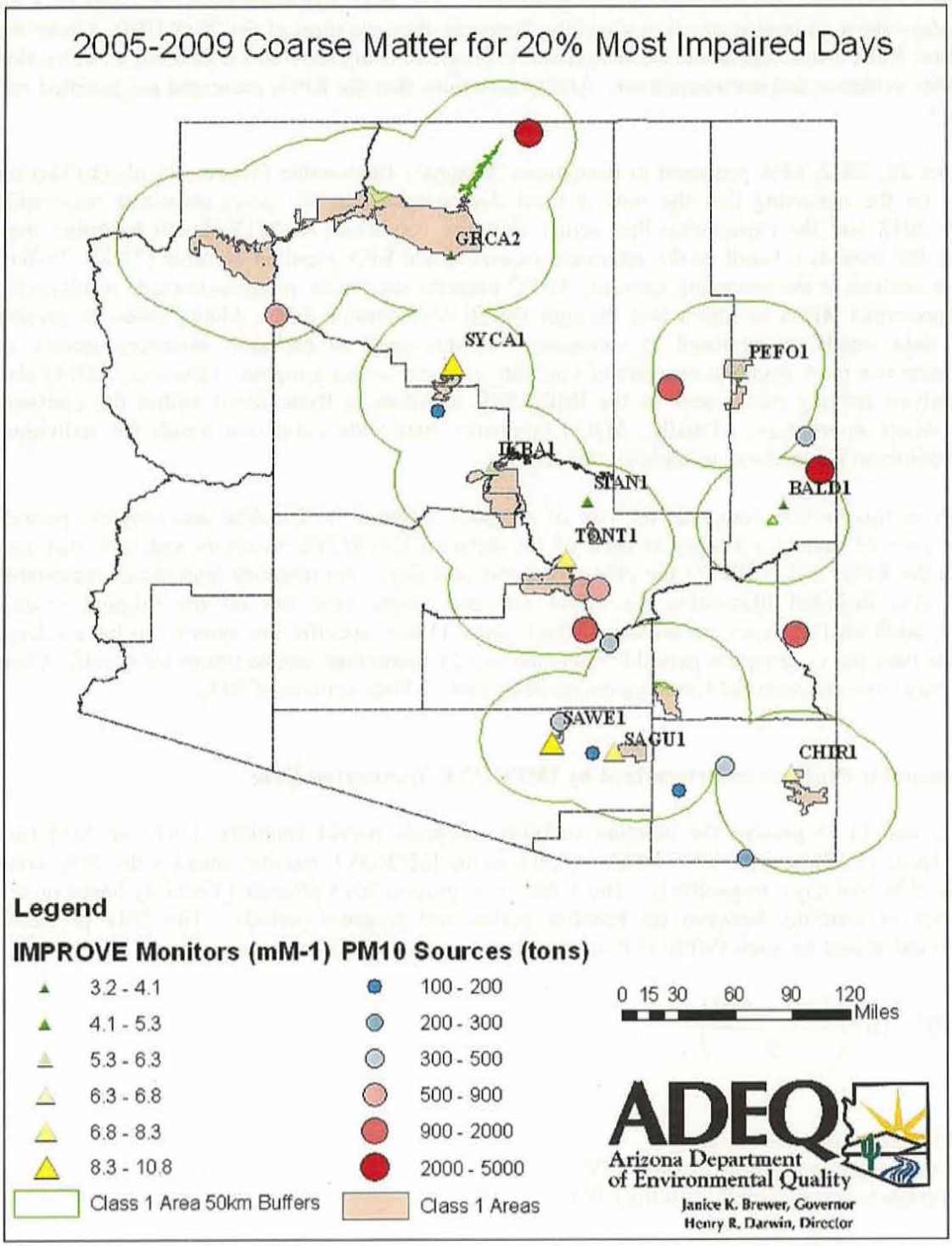
The analyses of coarse mass extinction between 2000 – 2009 and 2000 - 2010 show mixed results; however, there is evidence suggesting that coarse mass emissions originate from areas close to the individual IMPROVE monitors. Table 11.11 presents baseline vs. progress period differences that generally show decreasing trends across the state; however, it is difficult to discern regional trends from monitors within close proximity of one another.

There are three monitors (IKBA1, SIAN1, and TONT1) that are centrally located within the state and are, relatively speaking, in close proximity to one another. These three monitors show a small decrease, large decrease, and small increase in coarse mass extinction for the 20% worst coarse mass days. Similarly, SAWE1 and SAGU1 are the two monitors of closest proximity to each other within the state, but these two monitors show drastically different coarse mass extinction baseline averages. To investigate this issue, ADEQ qualitatively examined the location of all National Emissions Inventory reported major $PM_{10}$ emitting sources within the state against the location of individual IMPROVE monitors to determine if there are any trends. This analysis could provide evidence regarding whether locally driven point source emissions are related to disparities in regional coarse matter trends.

Figure F shows the location and the 2008 annual emissions for each point source in Arizona emitting over 100 tons per year. It also presents the progress period (2005-2009) average extinction ($mM^{-1}$) for coarse mass for the 20% worst days. This map shows that the 20% worst days at some monitors may be affected by local $PM_{10}$ sources, while other sites show little to no affect on extinction due to coarse mass from large $PM_{10}$ sources. The monitors that show relatively high extinction due to coarse mass (TON1, SAWE1, and SAGU1) are located relatively close to several large $PM_{10}$ emitting point sources. However, SYCA1 recorded high extinction values for the 20% worst days over the progress period and it is located near only one large source, which is a relatively small $PM_{10}$ emitter in comparison with other large sources on the map. Also, PEFO1 and BALD1 are located near very large $PM_{10}$ emitting sources yet have some of the lowest coarse mass extinction values for the 20% worst days recorded over the progress period. Overall, it is difficult to discern a visual relationship between large $PM_{10}$ point sources and CM extinctions for the 20% worst days. A finer scale emission inventory around each monitor may provide a better understanding of individual site trends for coarse mass extinction.

**Figure F: Arizona Class I areas, Class I area 50 km buffers, Class I area IMPROVE monitors, and Large Point Source Emitters of $PM_{10}$ (>100 tons/year). IMPROVE site values correspond to**

**Visibility Extinction (mM-1) of Coarse Mass averaged over the progress period (2005-2009)**




## 11.5 Demonstration of Reasonable Progress Goals for 20% Worst Days

EPA guidance indicates that "States may establish a RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath." The 2018 RPGs identified in Table 11.3 for 20% worst days show an improvement in visibility; however, they are short of the 2018 URP. Under the Regional Haze Rule, a state can demonstrate reasonable progress, using the four-factor analysis in Section 11.3 and other evidence and documentation. ADEQ maintains that the RPGs presented are justified and "reasonable".

On December 21, 2012, EPA proposed to disapprove Arizona's Reasonable Progress Goals (RPGs) for 2018 based on the reasoning that the state did not demonstrate that the goals constitute reasonable progress by 2018 and the expectation that actual visibility conditions in 2018 should be better than predicted by the state as a result of the economic recession and EPA required controls (77 FR 75704). Based on the analysis in the preceding sections, ADEQ presents reasonable progress towards reaching the previously presented RPGs as interpreted through IMPROVE monitor data. ADEQ chose to present IMPROVE data trends, as opposed to surrogate measures such as emission inventory trends, as monitoring data is a more accurate measure of visibility changes within a region. However, ADEQ also provides analysis relating trends seen at the IMPROVE monitors to those noted within the emission inventories where appropriate. Finally, ADEQ compares state-wide extinction trends for individual visibility impairment components to regional trends.

The analysis in this section compares the rate of progress between the baseline and progress periods towards the goal of natural visibility at each of the Arizona IMPROVE monitors and how that rate compares to the RPGs and URPs for the 20% worst and best days. An alternate analysis of reasonable progress is also included illustrating the effect that one single year has on the original results. Furthermore, additional analyses are provided which show 1) how specific fire events can have a large impact on the baseline vs. progress period comparison and 2) ammonium nitrate trends for specific Class I areas that may have the potential for being impacted by nearby large sources of $NO_X$.

### 11.5.1 Reasonable Progress as Determined by IMPROVE Monitoring Data

Tables 11.12 and 11.15 present the baseline visibility, progress period visibility, URP for 2018 (not included in Table 11.15), and the 2018 RPGs for each of the IMPROVE monitor sites for the 20% worst days and the 20% best days, respectively. The Tables also present 2018 projected visibility based on the rate of change in visibility between the baseline period and progress periods. The 2018 projected visibility was calculated for each IMPROVE monitoring site using the following equation:

$$PV = BP - 16 * \left( \frac{(BP - PP)}{5} \right)$$

where:

$PV$ = 2018 projected visibility (dV)
$BP$ = Average baseline period visibility (dV)
$PP$ = Average progress period visibility (dV)

This equation assumes a linear rate of progress between the baseline and progress period that can be extrapolated to 2018, that the average baseline period visibility is the visibility for the midpoint year of the baseline period (2002), and that the average progress period visibility is the visibility for the midpoint year of the progress period (2007). The 2018 projected visibility values can be utilized in two ways: 1) comparison with the RPGs as submitted in 2011, or 2) comparison with the URPs as submitted in 2011.

This is a rather simplistic method but ADEQ asserts that is more representative of actual progress compared to utilization of a highly uncertain emission inventory.

Table 11.12 presents the projected visibility for each IMPROVE site as compared to the RPGs and URPs for the 20% worst days. Six monitoring locations (shown in blue) are expected to surpass the RPGs for 2018 (as submitted in 2011). Furthermore, CHIR1, SAWE1, SAGU1, and SIAN1 are projected to surpass the URPs calculated for these sites for 2018. While BALD1 and SYCA1 are expected to experience visibility improvements by 2018, these improvements are not expected to meet the RPGs calculated by ADEQ. Two sites are projected to experience visibility degradation by 2018 when compared to 2002; these sites are GRCA2 and IKBA1 (shown in red).

**Table 11.12: Arizona Class I Area Reasonable Progress Goals Comparison to Progress Period Visibility for the 20% Worst Days. '2018 Projected Visibility' was extrapolated based on the rate of Visibility change between the Baseline and Progress Period Visibilities**

| Reasonable Progress Goals for 20% Worst Days for Arizona Class I Areas | | | | | | |
|---|---|---|---|---|---|---|
| **Arizona Class I Area** | **Site ID** | **Baseline (dv)** | **Progress (dV)** | **URP based 2018 visibility** | **2018 RPG (dV)** | **2018 Projected visibility** |
| Chiricahua NM, Chiricahua W, Galiuro W | CHIR1 | 13.4 | 12.2 | 12.0 | 13.4 | 9.6 |
| Grand Canyon NP | GRCA2 | 11.7 | 12.0 | 10.6 | 11.1 | 12.7 |
| Mazatzal W, Pine Mountain W | IKBA1 | 13.4 | 13.4 | 11.8 | 12.8 | 13.4 |
| Mount Baldy W | BALD1 | 11.9 | 11.8 | 10.5 | 11.5 | 11.6 |
| Petrified NP | PEFO1 | 13.2 | 13.0 | 11.6 | 12.9 | 12.6 |
| Saguaro NP - West Unit | SAWE1 | 16.2 | 14.9 | 13.9 | 16.0 | 12.0 |
| Saguaro NP - East Unit | SAGU1 | 14.8 | 13.6 | 12.9 | 14.8 | 11.0 |
| Sierra Ancha W | SIAN1 | 13.7 | 13.0 | 12.0 | 13.2 | 11.5 |
| Superstition W | TONT1 | 14.2 | 13.8 | 12.4 | 13.9 | 12.9 |
| Sycamore Canyon W | SYCA1 | 15.3 | 15.2 | 13.3 | 15.0 | 15.1 |

The visibility degradation at GRCA2 and IKBA1 are due to large, singular wildfire events that skew Regional Haze Rule method results for the 20% worst days. ADEQ has provided evidence that individual events can misrepresent visibility trends at IMRPOVE monitors when using the Regional Haze Rule method of analysis. The data shown in Table 11.13 illustrates this issue more clearly, presenting an analysis where two years' (2003 and 2009) visibility extinction data are adjusted for elemental carbon and organic carbon to 10-year averages in order to reduce the effects of wildfires located near an IMPROVE monitor near Grand Canyon NP. In the year of 2003, total extinction for the GRCA2 monitor was recalculated using the 10-year average extinction values for elemental carbon (2.7 $Mm^{-1}$) and organic carbon (10.7 $Mm^{-1}$). This was repeated for the year of 2009. During both years, 2003 and 2009, there were large wildfire events near the GRCA2 monitor and this substitution method was utilized to reduce the effects of these wildfire events on the overall trends of the Regional Haze Rule method. Without

substitution, total visibility extinction increases by 0.5 $mM^{-1}$ using the Regional Haze Rule method, while elemental carbon and organic carbon extinction normalization for the year of 2003 caused this degradation to increase to 2.2 $Mm^{-1}$, and 2009 extinction normalization caused the trend to reverse with total visibility improvement on the order of 1.8 $Mm^{-1}$ at GRCA2 (Table 11.13). A similar analysis was performed on data from the IKBA1 IMPROVE monitor where 2005 elemental carbon and organic carbon extinction values were replaced with 10-year average values, 2.3 $Mm^{-1}$ and 8.0 $Mm^{-1}$, respectively (Table 11.13). This exercise expresses the degree to which one large event can skew visibility trends for the 20% worst days.

**Table 11.13: Alternative method for the 20% Most Impaired Days at GRCA2 and IKBA1. EC and POM visibility extinctions are replaced by ten-year average for 2003 and 2009 (GRCA2) and 2005 (IKBA1)**

| | | Total Extinction (Mm-1) | | | | | |
|---|---|---|---|---|---|---|---|
| **Site** | **Year Adjusted** | **Baseline** | **Adjusted Baseline** | **Progress** | **Adjusted Progress** | **Standard Change** | **Adjusted Change** |
| GRCA2 | 2003 | 34.6 | 32.9 | 35.1 | -- | **0.5** | **2.2** |
| GRCA2 | 2009 | 34.6 | -- | 35.1 | 32.8 | **0.5** | **-1.8** |
| IKBA1 | 2005 | 38.9 | -- | 39.2 | 37.7 | **0.3** | **-1.2** |

This analysis shows that individual events can skew results and the same can be said for individual years. In previous sections, ADEQ has discussed the exceptionality of the year of 2005 when compared to other years' visibility. ADEQ has visibility data for 2010 to track trends at Class I areas; however, the Regional Haze Rule method requires the use of the immediate five year period following the baseline when analyzing visibility trends. The year of 2005 was an exceptionally high year for visibility extinction throughout the state. In Table 11.14, ADEQ performed an altered version of the Regional Haze Rule method where the baseline period was shifted to include the year 2005 (i.e. 2000-2005) and the progress period was shifted to include the most recently available IMPROVE monitoring data for the progress period (2006-2010). The information presented in Table 11.14 is in a format similar to Table 11.12 in order to see how these updated trends track to the year 2018 for comparison with RPGs and URPs. It is evident from the information that the events from 2005 have a strong affect on overall trends (Table 11.14). In this comparison, all IMPROVE monitor sites are meeting Arizona's previously set RPG values, but are also exceeding the URPs by 2018. Again, this analysis shows the limitations of the Regional Haze Rule methodology as one year near the mid-point has a strong influence on the overall trends.

**Table 11.14: Arizona Class I Area RPGs Adjusted Comparison to the Altered Progress Period Visibility (2006-2010) for the 20% Worst Days. '2018 Projected Visibility' was extrapolated based on the rate of visibility change between the Baseline and Progress Period Visibilities. In this case the Baseline period was altered to the years 2000-2005 and the Progress Period was adjusted to the years 2006-2010**

| Adjusted Reasonable Progress Goals for 20% Worst Days for Arizona Class I Areas | | | | | | |
|---|---|---|---|---|---|---|
| **Arizona Class I Area** | **Site ID** | **2000-2005 Baseline (dV)** | **2006-2010 Progress (dV)** | **URP based 2018 Visibility** | **2018 RPG (dV)** | **2018 Projected Visibility** |
| Chiricahua NM, Chiricahua W, | CHIR1 | 13.3 | 11.8 | 12.0 | 13.4 | 8.5 |

| Table 11.14: Arizona Class I Area RPGs Adjusted Comparison to the Altered Progress Period Visibility (2006-2010) for the 20% Worst Days. '2018 Projected Visibility' was extrapolated based on the rate of visibility change between the Baseline and Progress Period Visibilities. In this case the Baseline period was altered to the years 2000-2005 and the Progress Period was adjusted to the years 2006-2010 | | | | | | |
|---|---|---|---|---|---|---|
| Adjusted Reasonable Progress Goals for 20% Worst Days for Arizona Class I Areas | | | | | | |
| Arizona Class I Area | Site ID | 2000-2005 Baseline (dV) | 2006-2010 Progress (dV) | URP based 2018 Visibility | 2018 RPG (dV) | 2018 Projected Visibility |
| Galiuro W | | | | | | |
| Grand Canyon NP | GRCA2 | 11.8 | 11.4 | 10.6 | 11.1 | 10.5 |
| Mazatzal W, Pine Mountain W | IKBA1 | 13.6 | 12.6 | 11.8 | 12.8 | 10.4 |
| Mount Baldy W | BALD1 | 11.9 | 11.1 | 10.5 | 11.5 | 9.3 |
| Petrified NP | PEFO1 | 13.3 | 12.5 | 11.6 | 12.9 | 10.7 |
| Saguaro NP - West Unit* | SAWE1 | 16.0 | 14.8 | 13.9 | 16.0 | 12.2 |
| Saguaro NP - East Unit | SAGU1 | 14.7 | 13.3 | 12.9 | 14.8 | 10.2 |
| Sierra Ancha W | SIAN1 | 13.9 | 12.3 | 12.0 | 13.2 | 8.8 |
| Superstition W | TONT1 | 14.2 | 13.3 | 12.4 | 13.9 | 11.3 |
| Sycamore Canyon W | SYCA1 | 15.5 | 14.7 | 13.3 | 15.0 | 12.9 |

*2010 data was not included for this unit do to uncertainty of data's accuracy.

Table 11.15 presents the projected visibility for each IMPROVE site compared to ADEQ's RPGs for the 20% best days. No monitors are projected to experience visibility degradation on the 20% best days. Furthermore, all sites except GRCA2 are projected to surpass 2018 RPGs for the 20% least impaired days.

| Table 11.15: Arizona Class I Area Reasonable Progress Goals Comparison to Progress Period Visibility for the 20% Best Days. '2018 Projected Visibility' was extrapolated based on the rate of Visibility change between the Baseline and Progress Period Visibilities | | | | | |
|---|---|---|---|---|---|
| Reasonable Progress Goals for 20% Best Days for Arizona Class I Areas | | | | | |
| Arizona Class I Area | Site ID | Baseline (dV) | Progress (dV) | 2018 RPG (dV) | 2018 Projected visibility |
| Chiricahua NM, Chiricahua W, Galiuro W | CHIR1 | 4.9 | 4.4 | 4.9 | 3.3 |
| Grand Canyon NP | GRCA2 | 2.2 | 2.2 | 2.1 | 2.2 |
| Mazatzal W, Pine Mountain W | IKBA1 | 5.4 | 5.1 | 5.2 | 4.4 |

| Table 11.15: Arizona Class I Area Reasonable Progress Goals Comparison to Progress Period Visibility for the 20% Best Days. '2018 Projected Visibility' was extrapolated based on the rate of Visibility change between the Baseline and Progress Period Visibilities | | | | | |
|---|---|---|---|---|---|
| Reasonable Progress Goals for 20% Best Days for Arizona Class I Areas | | | | | |
| Arizona Class I Area | Site ID | Baseline (dV) | Progress (dV) | 2018 RPG (dV) | 2018 Projected visibility |
| Mount Baldy W | BALD1 | 3.0 | 2.9 | 2.9 | 2.7 |
| Petrified NP | PEFO1 | 5.0 | 4.6 | 4.7 | 3.7 |
| Saguaro NP - West Unit | SAWE1 | 8.6 | 8.0 | 8.3 | 6.7 |
| Saguaro NP - East Unit | SAGU1 | 6.9 | 6.7 | 7.0 | 6.3 |
| Sierra Ancha W | SIAN1 | 6.2 | 5.3 | 5.9 | 3.3 |
| Superstition W | TONT1 | 6.5 | 5.7 | 6.2 | 3.9 |
| Sycamore Canyon W | SYCA1 | 5.6 | 5.1 | 5.5 | 4.0 |

### 11.5.2 Ammonium Nitrate Q/D Analysis

EPA has performed an initial Q/D (emissions/distance) analysis to determine the point sources that need to be evaluated for further controls based on $NO_X$ emissions. In this section, ADEQ presents information showing that all of the Class I areas potentially impaired by these sources identified by EPA have exhibited decreased visibility impairment from ammonium nitrate between the baseline (2000-2004) and the progress period (2005-2009). Table 11.16 presents the initial results of EPA's Q/D analysis for those sources identified as impairing or possibly impairing Arizona Class I areas.

| Table 11.16: $NO_X$ emissions (Q) over distance (D) analysis for AZ facilities with Q/D values > 10. Also included is the nearest Class 1 Area to the facilities | | | | | |
|---|---|---|---|---|---|
| Source | Q (tpy) | D (km) | Q/D | Closest Class I Area | Class I Abbr. |
| Arizona Portland Cement Co | 5,635 | 6.99 | 806 | Saguaro Wilderness | SAGU |
| ASARCO Ray Ops Mine | 1,290 | 66.02 | 20 | Sierra Ancha Wilderness | SIAN |
| Cholla Plant | 34,066 | 31.75 | 1073 | Petrified Forest NP | PEFO |
| El Paso Nat Gas (Tucson Compr Station) | 336 | 14.72 | 23 | Saguaro Wilderness | SAGU |
| Flagstaff Comp Stn | 1,013 | 34.94 | 29 | Sycamore Canyon Wild. | SYCA |
| Irvington Gen Stn | 5,797 | 15.84 | 366 | Saguaro Wilderness | SAGU |
| Phoenix Cement | 3,224 | 12.65 | 255 | Sycamore Canyon Wild. | SYCA |
| Pima Co. Sewage Plant | 258 | 12.56 | 21 | Saguaro Wilderness | SAGU |
| TEP Springerville | 32,973 | 60.46 | 545 | Petrified Forest NP | PEFO |
| Williams Comp Stn | 1,388 | 19.12 | 73 | Sycamore Canyon Wild. | SYCA |

The Class I areas discussed in the Q/D analysis are: SAGU1, PEFO1, SYCA1, and SIAN1. The data from these monitors were analyzed according to the Regional Haze Rule method for changes in ammonium nitrate extinction for the 20% best and worst days (Table 11.16). All sites show improved visibility between 8% and 44% for the 20% best days for ammonium nitrate (Table 11.16). The 20% worst days show even greater visibility improvements for ammonium nitrate with extinctions decreasing between the baseline and progress period between 15% and 55% at the four Class I Areas identified (Table 11.17). Analysis of IMPROVE monitoring data by ADEQ at the SAGU1, PEFO1, SYCA1, and SIAN1 sites indicate that these sites are showing significantly improved visibility because of reductions in extinction due to ammonium nitrate.

**Table 11.17: IMPROVE monitoring ammonium nitrate trend results for Class I Areas located near facilities that exhibited high Q/D results**

| Change in Ammonium Nitrate Visibility Extinction | | | |
|---|---|---|---|
| **Class I Area** | **Abbreviation** | **20% Least Impaired [mM-1]** | **20% Most Impaired [mM-1]** |
| Saguaro Wilderness | SAGU1 | -0.2 (-19%) | -3.2 (-55%) |
| Petrified Forest NP | PEFO1 | -0.2 (-22%) | -0.3 (-17%) |
| Sycamore Canyon Wilderness | SYCA1 | -0.1 (-8%) | -0.7 (-33%) |
| Sierra Ancha Wilderness | SIAN1 | -0.4 (-44%) | -0.3 (-15%) |

## 11.6 Affirmative Demonstration of Reasonable Progress

The analyses presented in this Chapter satisfy the deficiencies identified by EPA regarding Arizona's reasonable progress goals. ADEQ presented a review of IMPROVE monitor data between the years of 2000 and 2009. This review presented standardized 20% best and worst visibility day comparisons between the baseline and progress periods as well as Theil statistical trend analysis as an alternative approach for understanding 10-year trends. Visibility aerosol extinction indicates that extinction due to ammonium nitrate, organic carbon, and elemental carbon are improving within almost all Arizona Class 1 areas. Fine Soil and Coarse Mass extinction values appear to be dependant on the local environment surrounding the Class 1 areas and show no discernable increasing or decreasing spatial trends across the state. Anomalously high years (2005 and 2007) for ammonium sulfate extinction revealed increasing ammonium sulfate visibility extinction between the baseline and progress periods; however, decreasing trends in ammonium sulfate in previous and recent years resulted in Theil statistics that either showed no statistically significant visibility extinction increases or statistically significant visibility decreases across the state ($p < 0.15$). Furthermore, similar trends for ammonium sulfate were noted for the four corners region.

Finally, ADEQ compared overall visibility trends at each of the IMPROVE monitor locations against previously submitted RPGs and URPs for 2018. These data indicated that if the current pace of visibility change continues, no Class I area will experience increased visibility impairment for the 20% worst days in 2018. Six monitoring locations are expected to surpass ADEQ's previously submitted RPGs for 2018 for the 20% worst days. Furthermore, four sites, CHIR1, SAWE1, SAGU1, and SIAN1 are projected to surpass the previously accepted URPs for the 20% worst days in 2018. Only GRCA2 and IKB1 are projected to experience visibility degradation for the 20% worst days in 2018 when compared to 2002. However, the visibility degradation noted at these sites is likely due to wildfires located close to these monitors during the progress period. ADEQ has shown that if elemental carbon and organic carbon values are standardized for years during which a fire has occurred close to the GRCA2 monitor that the

entire progress period trends are altered, exhibiting how skewed data can be when using the RHR method. ADEQ also showed that the exceptionally high extinction value year of 2005 was skewing data trends when using the RHR method. If this year was included in the baseline period and 2010 was added to the progress period during RHR method analysis, every site is projected to exceed URP visibility standards.

## 11.7 Major Reductions in Mobile Sources Emissions by 2018

As the largest anthropogenic source category, ADEQ believes that the trend in mobile source emission reductions from 2002 to 2018 is another factor in support of the demonstration of reasonable progress. As shown by the emission inventory information in Chapter 8, mobile sources annual emissions show a decrease from 2002 (plan02d) to 2018 (prp18b) and represent the largest emissions reductions of any single source category. This can be seen in the statewide emission inventory in Section 8.1 and the regional level emission in Section 8.2. The greatest reduction is in $NO_X$ emissions, followed by volatile organic compounds (VOCs), and to a lesser extent $SO_2$. Table 11.18 shows these reductions in ton per year (tpy) and percent reduction at the statewide level, from the baseline 2002 to the projections for 2018.

Table 11.18 also shows reductions from both on- and off-road mobile sources from 2002 to 2008. Most of the emission reductions of $SO_2$, $NO_X$, and VOCs from mobile sources are close to meeting the reductions that were projected for 2002 to 2018. Reductions in $NO_X$ from off-road mobile sources are surpassing what was projected for 2018.

| Table 11.18 – Mobile Source Emission Reductions in Arizona | | | |
|---|---|---|---|
| **Projected Reductions from 2002 to 2018 (% reduction)** | | | |
| **Source Category** | **$SO_2$** | **$NO_X$** | **VOC** |
| On-Road Mobile | -1,953 (72%) | -124,501 (70%) | -57,552 (52%) |
| Off-Road Mobile | -3,677 (87%) | -23,165 (35%) | -20,868 (37%) |
| **Actual Reductions from 2002 to 2008 (% reduction)** | | | |
| On-Road Mobile | -1,904 (70%) | -40,453 (22%) | -55,834 (50%) |
| Off-Road Mobile | -3,550 (84%) | -32,557 (49%) | -14,604 (26%) |

The mobile source emission inventory was based on the WRAP Mobile Source Emission Inventories Update. This report estimated all on-road and off-road mobile source emissions for the WRAP region for the 2002 base year and projections to 2008, 2013, and 2018. It also included emissions from aircraft, locomotives, marine shipping, and road dust. The contractor who conducted the project surveyed state and local air quality planning agencies to obtain the most up-to-date mobile source activity data and control program information. On-road mobile source emissions were estimated with EPA's MOBILE6.2 model. Emissions for most off-road mobile sources were estimated with EPA's Draft NONROAD2004 model. Locomotive emissions were estimated based on locomotive fuel consumption; aircraft emission were based on aircraft landing and takeoffs and FAA EDMS emission factors commercial marine emissions were estimated using a variety of activity data sources and EPA emission factors. For further information, see http://www.wrapair.org/forums/ef/UMSI/index.html.

The mobile source emission reductions are based on numerous "on-the-books" federal mobile source regulations that include the following:

For on-road mobile sources:

- Tier 1 light-duty vehicle standards
- National Low Emission Vehicle (NLEV) standards
- Tier 2 light-duty vehicle standards, with low sulfur gasoline
- Heavy-duty vehicle standards, with low sulfur diesel

For non-road mobile sources and equipment:

- Emission standards for new non-road spark-ignition engines below 25 horsepower
- Phase 2 emission standards for new spark ignition hand-held engines below 25 horsepower
- Phase 2 emission standards for new spark-ignition non-handheld engines below 25 horsepower
- Emission standards for new gasoline spark-ignition marine engines
- Tier 1 and 2 emission standards for new non-road compression-ignition engines below 50 horsepower including recreational marine engines
- Tier 2 and Tier 3 standards for new non-road compression-ignition engines of 50 horsepower and greater not including recreation marine engines greater than 50 horsepower
- Tier 4 emission standards for new non-road compression-ignition engines above 50 horsepower and reduced non-road diesel fuel sulfur levels

In 2004, EPA adopted the Tier 4 rule for Non-road Diesel Engines and Fuel, which took effect in 2008. These rules are expected to have major visibility benefits. Nationally, these rules are estimated to reduce emissions in 2030 from non-road engines, locomotive engines, and marine engines by 95% for $PM_{2.5}$, 90% for $NO_X$, and 99% for $SO_2$.
The visibility benefits that are projected for 2018 from these reductions can be found in Chapter 9, under the PSAT source apportionment results for sulfate and nitrate, on 20% worst days.

The extent of the mobile source emission reductions and the visibility improvements that are projected are significant factors in determining that the RPGs identified in this represent reasonable progress. It should be noted that the trend in emission reductions may likely be greater than expected. Increasing gasoline prices commonly reduce the annual vehicle miles traveled, which will lead to increased reductions in $NO_X$ emissions. Reductions to the primary National Ambient Air Quality Standards (NAAQS) for ozone and $SO_2$ will also have the secondary benefit of improving visibility as a result of emissions reductions.

## 11.8 Emission Reductions to with Respect to Out-of-State Class I Areas

The Clean Air Act Section 110(a)(2)(D)(i)(II) requires that each SIP contain provision to prevent sources or other types of emissions activity within a state from impairing visibility at Class I areas in neighboring states. On December 21, 2012, EPA proposed to disapprove Arizona's Regional Haze SIP on the basis that it does not contain the provisions or a demonstration that it includes measures sufficient to meet the interstate transport visibility requirement.

Based on the demonstration in the preceding chapters showing reasonable progress at Arizona's Class I areas, ADEQ asserts that the measures contained in the SIP are adequate to achieve reductions necessary to prevent visibility impairment at Class I areas in neighboring states.

## 11.9 Additional Emission Reductions Expected by 2018 due to the Long-Term

Under the Long-Term Strategy (LTS) described in Chapter 12, additional emission reductions that will result in visibility improvements are expected by 2018. Although these new strategies have yet to be implemented, it is reasonable to expect that these visibility improvements will occur and provide greater progress toward the 2018 URP than the RPGs estimated in this submittal. The key elements of the LTS include an evaluation and possible controls for non-BART sources, new smoke management improvements for prescribed burning, review and possible revision of state open burning regulations, and expected benefits associated with the revised $PM_{2.5}$ NAAQS.

## 11.10 Long-Term Strategy "Next Steps" in Analyzing Major Source Categories

As described in the LTS in Chapter 12, ADEQ will take the results of the four-factor analyses for source categories and will conduct further evaluation and analysis of these source categories to determine what additional control are appropriate to achieve further reasonable progress. It is expected this evaluation will be incorporated into the work described in Section 12.6.1 of the LTS that will develop criteria and guidance for evaluating all non-BART sources. Results from this evaluation will be reported in the required 2013 plan update.

## 11.11 Years to Reach Natural Conditions Based on Reasonable Progress Goals

The Regional Haze Rule allows states to set reasonable progress goals for a slower rate of progress than the URP. Section 308(d)(1)(B)(ii) also requires states to provide an assessment of the number of years it will take to reach natural conditions based on the reasonable progress goals set by a state. Table 11.19 provides this information for Arizona's Class I areas.

**Table 11.19 – Years to Meet Natural Conditions (NC) Based on Reasonable Progress Goals**

| Arizona Class I Area | Baseline (dv) | 2018 RPG (dv) | Annual Rate of Progress Based on RPG (dv) | Natural Conditions (dv) | Improvement Needed to Reach NC (dv) | Years to Meet NC |
|---|---|---|---|---|---|---|
| Chiricahua NM, Chiricahua W, Galiuro W | 13.43 | 13.35 | 0.006 | 7.2 | 6.23 | 1,038 |
| Grand Canyon NP | 11.66 | 11.14 | 0.037 | 7.04 | 4.62 | 125 |
| Mazatzal W, Pine Mountain W | 13.35 | 12.76 | 0.042 | 6.68 | 6.67 | 159 |
| Mount Baldy W | 11.85 | 11.52 | 0.024 | 6.24 | 5.61 | 234 |
| Petrified NP | 13.21 | 12.85 | 0.026 | 6.49 | 6.72 | 258 |
| Saguaro NP – West Unit | 16.22 | 15.99 | 0.016 | 6.24 | 9.98 | 624 |
| Saguaro NP – East | 14.83 | 14.82 | 0.001 | 6.46 | 8.37 | 8,370 |

| Table 11.19 – Years to Meet Natural Conditions (NC) Based on Reasonable Progress Goals | | | | | | |
|---|---|---|---|---|---|---|
| **Arizona Class I Area** | **Baseline (dv)** | **2018 RPG (dv)** | **Annual Rate of Progress Based on RPG (dv)** | **Natural Conditions (dv)** | **Improvement Needed to Reach NC (dv)** | **Years to Meet NC** |
| Unit | | | | | | |
| Sierra Ancha W | 13.67 | 13.17 | 0.036 | 6.59 | 7.08 | 197 |
| Superstition W | 14.16 | 13.89 | 0.019 | 6.54 | 7.62 | 401 |
| Sycamore Canyon W | 15.25 | 15.00 | 0.018 | 6.65 | 8.6 | 478 |

**(The following replaces Appendix D contained in the 2011 Regional Haze Submission)**

# APPENDIX D

# Arizona Best Available Retrofit Technology (BART) Analysis and Determination

## Arizona Department of Environmental Quality

## Technical Support Document

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# I. EXECUTIVE SUMMARY

Sections 169A and 169B of the Clean Air Act were promulgated by Congress in the 1990 Clean Air Act Amendments with the intent of preventing any future, and remedying any existing, impairment of visibility caused by manmade sources in 156 mandatory Class I areas. Through this requirement, Congress set the goal of achieving natural visibility conditions in the Class I areas by 2064. In the interim, States are required to make reasonable progress towards the achievement of this national goal.

Title 40 CFR §§ 51.300 through 309 (the "regional haze rules") implement §§ 169A and 169B of the Clean Air Act and require States to submit state implementation plans (SIPs) to address regional haze visibility impairment in the 156 Class I areas. These SIPs are intended to be the first in a series of actions that will become long term regional haze strategies to demonstrate reasonable further progress toward the goal that Congress set. One of the tools provided to the States to address reasonable further progress is called Best Available Retrofit Technology, or BART.

The regional haze rules use the term "BART-eligible source" to describe the sources that are potentially subject to this program. BART-eligible sources are those sources that have the potential to emit 250 tons or more of a visibility-impairing air pollutant; were constructed between August 7, 1962 and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories. Once a facility has been determined to be BART-eligible, air dispersion modeling tools are used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term "particulate matter" includes particles with an aerodynamic diameter that is less than 10 microns (μm), and particles with an aerodynamic diameter that is less than 2.5 μm.

On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the Western Regional Air Partnership's (WRAP's) Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In most cases where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, nine BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, eight sources that were potentially-subject-to-BART and another source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the

facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility. The one potentially-subject-to-BART facility that did not receive a letter from ADEQ (Tucson Electric Power Company's Irvington Generating Station) was also subject to additional scrutiny. Due to on-going conversations and information that Tucson Electric Power (TEP) had already submitted, ADEQ did not provide that facility a letter on July 13, 2007. The ten facilities and the options that were chosen are as follows:

Option 1: Demonstrate that the facility is not BART-eligible:
TEP - Irvington Generating Station

Option 2: Demonstrate that while the facility is BART-eligible, it is not subject-to-BART:
Arizona Portland Cement Company
APS West Phoenix
ASARCO Hayden Smelter
Chemical Lime Nelson Lime Plant
Freeport-McMoRan Miami Smelter (formerly Phelps Dodge Miami Smelter)

Option 3: Conduct a BART analysis:
Catalyst Paper (Snowflake) Inc. (formerly Abitibi Consolidated)
Arizona Electric Power Cooperative (AEPCO)
APS Cholla Power Plant
SRP Coronado Generating Station

ADEQ analysis of the information that was submitted by each of the companies listed above resulted in the following determinations:

Arizona Sources That Chose to Demonstrate "Not BART-Eligible":
TEP - Irvington Generating Station

Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":
Arizona Portland Cement Company
APS West Phoenix
Chemical Lime Nelson Lime Plant

Facilities That Required a BART Analysis:
Catalyst Paper
AEPCO
APS Cholla Power Plant
ASARCO Hayden Smelter
Freeport-McMoRan Miami Smelter
SRP Coronado Generating Station

With the exceptions of the ASARCO Hayden Smelter and the Freeport-McMoRan Miami Smelter, those facilities which were determined to be subject-to-BART agreed with ADEQ's June 13, 2007, letter, and submitted their own analyses of what BART should be for each facility. The Freeport-McMoRan Miami Smelter also provided information about BART applicability to its facility. While the company agreed that BART was applicable to specific emissions units, it provided arguments that the existing controls and emissions limitations at the facility comprised BART. ADEQ reviewed these arguments and, with some supplementary information, was able to conclude that the same arguments applied to the ASARCO

Hayden Smelter. After reviewing the analyses submitted, ADEQ determined that the following controls and emissions limitations constituted BART:

| Table 1.1 – $NO_X$ BART | | |
|---|---|---|
| **Facility** | **BART Control** | **BART Limit** |
| Catalyst Paper | **Power Boiler #2:** No additional controls | **Power Boiler #2:** 0.70 lb/MMBtu |
| AEPCO | **ST1:** LNB with Flu Gas Recirculation (FGR)<br>**ST2:** LNB with OFA<br>**ST3:** LNB with OFA | **ST1:** 0.056 lb/MMBtu<br>**ST2:** 0.31 lb/MMBtu<br>**ST3:** 0.31 lb/MMBtu |
| APS Cholla Power Plant | **Unit 2:** LNB with Separate Over Fire Air (SOFA)<br>**Unit 3:** LNB with SOFA<br>**Unit 4:** LNB with SOFA | **Unit 2:** 0.22 lb/MMBtu<br>**Unit 3:** 0.22 lb/MMBtu<br>**Unit 4:** 0.22 lb/MMBtu |
| ASARCO Hayden Smelter | Not Applicable | Not Applicable |
| Freeport-McMoRan Miami Smelter | Not Applicable | Not Applicable |
| SRP Coronado Generating Station | **Unit 1:** LNB with OFA<br>**Unit 2:** LNB with OFA | **Unit 1:** 0.32 lb/MMBtu<br>**Unit 2:** 0.32 lb/MMBtu |

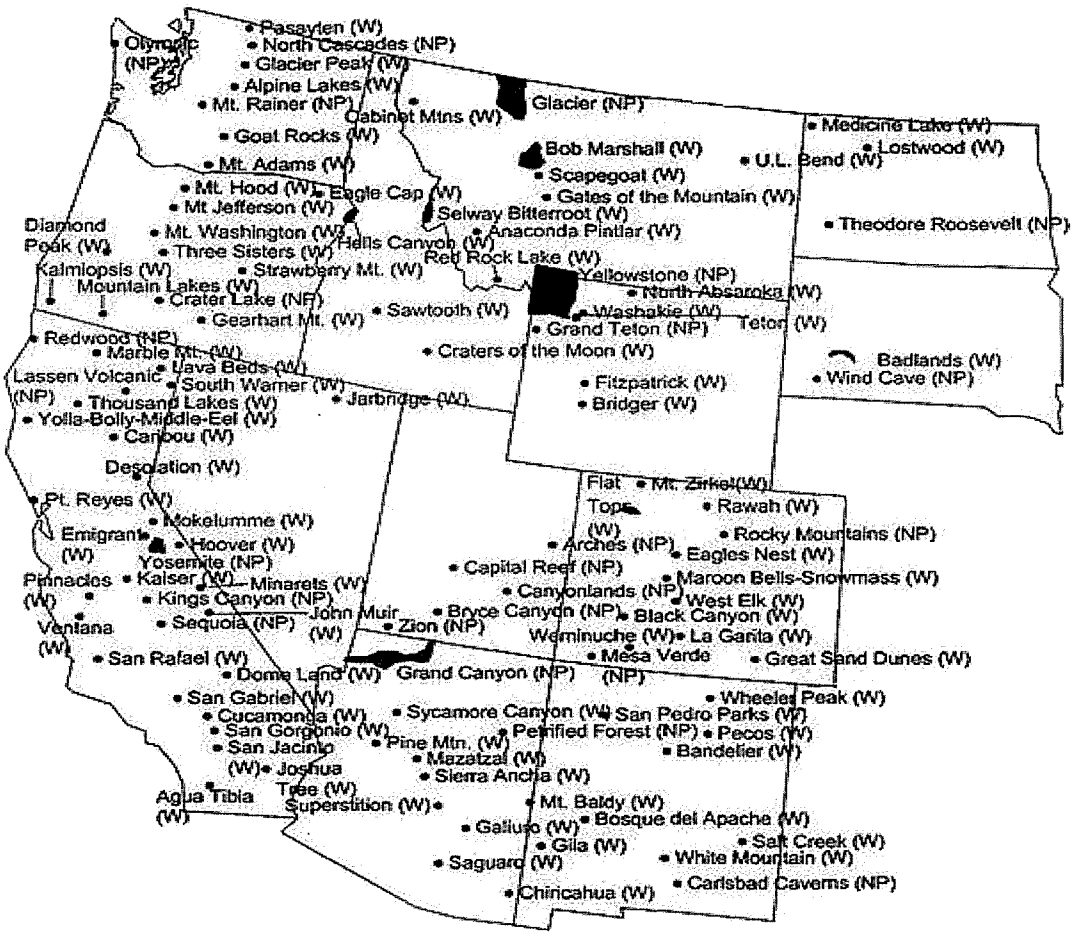
| Table 1.2 – $PM_{10}$ BART | | |
|---|---|---|
| **Facility** | **BART Control** | **BART Limit** |
| Catalyst Paper | Not applicable | Not Applicable |
| AEPCO | **ST1:** Combustion of Pipeline Natural Gas (PNG) and #2 Fuel Oil<br>**ST2:** Electro Static Precipitator (ESP) Upgrades<br>**ST3:** ESP Upgrades | **ST1:** 0.0075 lb/MMBtu for PNG / 0.0015 lb/MMBtu for #2 Fuel Oil<br>**ST2:** 0.03 lb/MMBtu<br>**ST3:** 0.03 lb/MMBtu |
| APS Cholla Power Plant | **Unit 2:** Fabric Filter<br>**Unit 3:** Existing Fabric Filter<br>**Unit 4:** Existing Fabric Filter | **Unit 2:** 0.015 lb/MMBtu<br>**Unit 3:** 0.015 lb/MMBtu<br>**Unit 4:** 0.015 lb/MMBtu |
| ASARCO Hayden Smelter | Not Applicable | Not Applicable |
| Freeport-McMoRan Miami Smelter | Existing Controls - Primary Copper Smelting NESHAP | Primary Copper Smelting NESHAP |
| SRP Coronado Generating Station | Existing Hot Side ESPs | 0.03 lb/MMBtu |

| Table 1.3 – SOx BART | | |
|---|---|---|
| **Facility** | **BART Control** | **BART Limit** |
| Catalyst Paper | **Power Boiler #2:** Upgraded scrubber/Baseline | **Power Boiler #2:** 0.80 lb/MMBtu |
| AEPCO | **ST1:** Use only PNG or #2 Fuel Oil<br><br>**ST2:** Existing Wet Limestone Scrubber<br>**ST3:** Existing Wet Limestone Scrubber | **ST1:** 0.00064 lb/MMBtu for PNG / 0.051 lb/MMBtu for #2 Fuel Oil<br>**ST2:** 0.15 lb/MMBtu<br><br>**ST3:** 0.15 lb/MMBtu |
| APS Cholla Power Plant | **Unit 2:** Wet Lime Scrubber<br>**Unit 3:** Wet Lime Scrubber<br>**Unit 4:** Wet Lime Scrubber | **Unit 2:** 0.15 lb/MMBtu<br>**Unit 3:** 0.15 lb/MMBtu<br>**Unit 4:** 0.15 lb/MMBtu |
| ASARCO Hayden Smelter | Existing Controls - Double Contact Acid Plant | Existing Controls |
| Freeport-McMoRan Miami Smelter | Existing Controls – Double Contact Acid Plant | Existing Controls |
| SRP Coronado Generating Station | **Unit 1:** Wet FGD<br>**Unit 2:** Wet FGD | **Unit 1:** 0.08 lb/MMBtu<br>**Unit 2:** 0.08 lb/MMBtu |

## II. Regional Haze Background

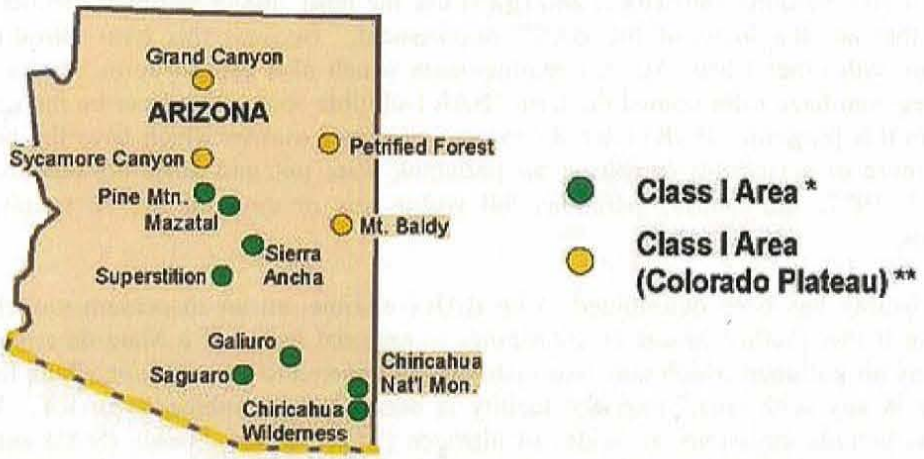
As noted in Section I, there are 156 mandatory, Federally-protected parks and wildernesses throughout the United States that make up Class I areas throughout the country. Of these Class I areas, more than 70 percent (110) are in the Western Continental United States (see Figure 2.1).

**Figure 2.1: Class I Areas in the Western Continental United States**




Arizona is home to 12 Class I Areas, including the Grand Canyon and Petrified Forest National Parks; the Mount Baldy, Sycamore Canyon, Pine Mountain, Mazatzal, Sierra Ancha, Superstition, Galiuro, Saguaro, and Chiricahua Wilderness Areas; and the Chiricahua National Monument (see Figure 2.2).

**Figure 2.2: Arizona Class I Areas**




In 1999, EPA adopted regional haze rules that address Congress' stated intent to remedy the existing visibility impairment, and to prevent future visibility impairment in the mandatory Class I areas. Congress also stated its goal that visibility in the Class I areas return to natural conditions by the year 2064. To achieve this, EPA's rules required the States to submit SIPs to address visibility impairment. Arizona's SIP must provide reasonable progress towards the national goal for the 12 Class I areas within the state, as well as address progress in those Class I areas outside Arizona that are impacted by emissions of visibility impairing pollutants originating within the State.

Title 40 CFR 51 §§ 308 and 309 both require States to address visibility impairing pollutant emissions from stationary sources. The principal tool for addressing such emissions is the requirement for specific stationary sources to install BART

## III. BACKGROUND FOR BART

Clean Air Act Sections 169A(b)(2) and (g)(7) use the term "major stationary source" to describe those sources that are the focus of the BART requirement. Because this term introduces some potential confusion with other Clean Air Act requirements which also use the term "major stationary source", EPA's regional haze rules coined the term "BART-eligible source" to describe the sources that might be subject to this program. BART-eligible sources are those sources which have the potential to emit 250 tons or more of a visibility-impairing air pollutant, were put into place between August 7, 1962, and August 7, 1977, and whose operations fall within one or more of the 26 specifically listed source categories.

Once a facility has been determined to be BART-eligible, an air dispersion modeling tool is used to determine if that facility causes or contributes to regional haze. If a State determines that the facility "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area," then the facility is deemed to be subject-to-BART. Visibility impairing pollutants include emissions of oxides of nitrogen (NOx), sulfur dioxide (SO2) and particulate matter (PM). The term particulate matter includes particles with an aerodynamic diameter that is less than 10 microns (μm), and particles with an aerodynamic diameter that is less than 2.5 μm.

The regional haze rules at 40 CFR 51.308(e)(1)(ii) require States to address any BART-eligible existing source that is determined by the State to emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area. In addressing BART, the Clean Air Act requires the State to consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology already in use 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.

Over the course of the regional haze rules, there have been a number of challenges to the provisions of the rules and the methodologies prescribed or accepted by EPA. In 1999, EPA explained in its preamble to the rules that the BART requirements demonstrated Congress' intent to focus attention directly on the problem of pollution from a specific set of sources which, as determined by a State, emit any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in a Class I area.

Specifically, EPA concluded that if a potentially-subject-to-BART source was located within an area upwind from a downwind Class I area, that source "may reasonably be anticipated to cause or contribute" to visibility impairment in the Class I area. The regional haze rules address visibility impairment resulting from emissions from a multitude of sources that are located across a wide geographic area. The problem of regional haze is caused in large part by the long-range transport of emissions from multiple sources. Therefore, EPA had also concluded that when weighing the factors set forth in the statute for determining BART, the States should consider the collective impact of BART sources on visibility. In particular, when considering the degree of visibility improvement that could reasonably be anticipated to result from the use air pollution control technology, EPA explained that the State should consider the degree of improvement in visibility that would result from the cumulative impact of applying controls to all sources subject-to-BART. EPA then proposed that the States should use this analysis to determine the appropriate BART emission limitations for specific sources.

In American Corn Growers v. EPA, in addition to other challenges to the rules, industry petitioners challenged EPA's interpretations that any source with any potential impacts in any Class I area should be subject-to-BART, and that BART should be applied after considering the collective impacts of BART sources on Class I areas. In 2002, the court concluded that the BART provisions in the 1999 regional haze rule were inconsistent with the provision in the Clean Air Act, as the Act gave the "states broad authority over BART determinations." 291 F.3d at 8.

With respect to the test for determining whether a source is subject-to-BART, the court held that the method that EPA had prescribed for determining which eligible sources are subject-to-BART illegally constrained the authority Congress had conferred to the States. Although the court did not decide whether EPA's proposed general collective contribution approach to determining BART was inconsistent with the Clean Air Act, the court did state that "[i]f the [regional haze rule] contained some kind of a mechanism by which a state could exempt a BART-eligible source on the basis of an individual contribution determination, then perhaps the plain meaning of the Act would not be violated. But the [regional haze rule] contains no such mechanism." Id, at 12.

With respect to EPA's interpretation that the Clean Air Act required the States to consider the degree of improvement in visibility that would result from the cumulative impact of applying controls in determining BART, the court also found that EPA was inconsistent with the language of the Act. 291 F.3d at 8. Based on its review of the statute, the court concluded that the five statutory factors in section 169A(g)(2) "were meant to be considered together by the states." Id. At 8.

On July 6, 2005, EPA took action to address the court's vacatur of the requirement in the regional haze rule requiring States to assess visibility impacts on a cumulative basis in determining which sources are subject-to-BART. Because this requirement was found only in the preamble to the 1999 regional haze rule, EPA concluded that no changes to the regulations were required. Instead, this issue was ultimately addressed by the BART guidelines, which provided States with different techniques and methods for determining which BART-eligible sources "may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area."

The July 6, 2005, amendments to the rules also required the States to consider the degree of visibility improvement resulting from a source's installation and operation of retrofit technology, along with the other statutory factors set out in Clean Air Act § 169A(g)(2), when making a BART determination. This was accomplished by listing the visibility improvement factor with the other statutory BART determination factors in 40 CFR 51.308(e)(91)(A), so that States are now required to consider all five factors, including visibility impacts, on an individual source basis when making each source's BART determination.

## IV. ARIZONA "POTENTIALLY-SUBJECT-TO-BART" DETERMINATION PROCESS

### A. Identification of Potentially-BART-Eligible Emissions Units

On April 4, 2005, the Stationary Sources Joint Forum (SSJF) of the WRAP published a draft report identifying BART-eligible sources in the WRAP region[7]. This report took a broad-brush approach to reviewing existing stationary sources of air pollution in order to determine whether or not emissions units at the facility could be considered to be BART-eligible. The report explains that the following series of steps were used to identify potentially BART-eligible facilities in the WRAP region:

Step 1: Identify the facilities that are categorical sources (i.e., one of the 26 source categories);

Step 2: Identify whether or not any of the emissions units at the facility are within the date range of BART;

Step 3: Determine whether or not the potential emissions of the entire facility (all emissions units) are greater than 250 tons per year of visibility-impairing pollutants.

### B. BART-Eligibility Determination

On June 15, 2005, EPA published final regulatory text and guidelines for implementing BART, including methodologies that are to be used to establish whether or not emissions units at a facility are truly BART-eligible. According to the language of the guidelines, there are three steps for determining which emissions units at a facility are considered to be BART-eligible. Those three steps are summarized as follows:

Step 1: Determine whether the plant contain emissions units in one or more of the 26 source categories:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 2.

Step 2: Identify the start-up dates of emissions units identified in Step 1. Determine whether the emissions units had begun operation after August 7, 1962 and were in existence on August 7, 1977:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, proceed to Step 3.

Step 3: Compare the potential emissions from all emissions units identified in Steps 1 and 2. Determine whether the combined potential emissions of visibility impairing pollutants from these emissions units are greater than 250 tons per year:
- a. If no, then emissions units are not BART-eligible.
- b. If yes, then emissions units are BART-eligible.

Appendix H of the April 4, 2005, draft SSJF report that identified potentially BART-eligible sources in the WRAP Region specifically recognized a list of sources under the jurisdiction of the Arizona Department of Environmental Quality (ADEQ), the Maricopa Air Quality Department (MCAQD), the

[7] See: http://www.wrapair.org/forums/ssjf/bartsources.html

Pima County Department of Environmental Quality (PDEQ) and the Pinal County Air Quality Control District (PCAQCD). Using this list as a basis, ADEQ concluded that 14 distinct sources comprised of 42 separate emissions units in Arizona were "potentially-BART-eligible".

## C. Potentially Subject-to-BART

### 1. Background

After determining BART-eligibility, the State must then determine whether the air pollution emission unit is "potentially-subject-to-BART". EPA finalized several options that allowed States flexibility when making the determination of whether a source "emits any pollutants which may reasonably be anticipated to cause or contribute to any visibility impairment."

Option 1: All BART-eligible sources are Subject-to-BART

EPA provided the States with the discretion to consider all BART-eligible sources within the State to be "reasonably anticipated to cause or contribute" to some degree of visibility impairment in a Class I area. EPA held that this option is consistent with the American Corn Growers court's decision, as it would be an impermissible constraint of State authority for the EPA to force States to conduct individualized analyses in order to determine that a BART eligible source "emits any air pollutant which may reasonably anticipated to cause or contribute to any impairment of visibility in any [Class I] area."

Option 2: All BART-Eligible Sources Do Not Cause or Contribute to Regional Haze

EPA also provided States with the option of performing an analysis to show that the full group of BART-eligible sources in a State may not, as a whole, be reasonably anticipated to cause or contribute to any visibility impairment in Class I areas. Although the option was provided, EPA did also state that it anticipated that in most, if not all, States BART-eligible-sources are likely to cause or contribute to some level of visibility impairment in at least one Class I area.

Option 3: Case-by-Case BART Analysis

The final option that was provided to the States was to consider the individual contributions of a BART-eligible source to determine whether the facility is subject-to-BART. Specifically, EPA allowed States to choose to undertake an analysis of each BART-eligible source in the State in considering whether each such source "emit[s] any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any [Class I] area." Alternatively, States may choose to presume that all BART-eligible sources within the State meet this applicability test, but provide sources with the ability to demonstrate on a case-by-case basis that this is not the case.

### 2. Arizona Process

When considering the options provided by EPA, ADEQ determined that the third option is the most consistent with the American Corn Growers case, as this option provides a rebuttable method for the evaluation of the visibility impact from a single source. If the air dispersion modeling analysis shows that a facility causes or contributes to Regional Haze, then it is required to address BART. A State is also provided with flexibility under this option, as it may exempt from BART any source that is not reasonably anticipated to cause or contribute to visibility degradation in a Class I area.

As noted in Section IV.B above, fourteen Arizona facilities were determined to be potentially-BART-eligible. On June 9, 2006, ADEQ provided potential emissions information along with stack parameters for each potentially-BART-eligible facility to the WRAP's Regional Modeling Center, which performed a CALPUFF modeling analysis to determine the predicted visibility impairment apportioned to each facility.

On June 7, 2007, the WRAP's Regional Modeling Center provided ADEQ with the results of the CALPUFF modeling analysis. Based upon the CALPUFF modeling results, ADEQ determined that if a "potentially-BART-eligible" source's twenty-second highest (98th percentile) visibility impact across the three years of modeling was greater than 0.5 deciviews (dv) in any Class I area less than 300 kilometers away, the facility would be considered to contribute to impairment of visibility in that Class I area. Similarly, if the "potentially-BART-eligible" source's impact was found to be greater than 1.0 dv in any Class I area less than 300 kilometers away, the facility would be considered to cause impairment of visibility in that Class I area. In every case where a "potentially-BART-eligible" source was found to have emissions that contributed to, or caused, impairment of visibility in a Class I area, ADEQ determined that the facility was "potentially-subject-to-BART." In some cases where a facility's contributions to impairment of visibility in a Class I area were within 20% of 0.5 dv, ADEQ requested that the source provide further information demonstrating that the facility was not "potentially-subject-to-BART." As a result, eight BART-eligible facilities were determined to be potentially-subject-to-BART, and one facility was recommended for further evaluation.

On July 13, 2007, the eight sources that were potentially-subject-to-BART and the source that was recommended for further evaluation were provided with a set of three options: (i) demonstrate that the facility is not BART-eligible; (ii) demonstrate that while the facility is BART-eligible, it is not potentially-subject-to-BART as the facility does not cause or contribute to regional haze; or (iii) agree that the facility is potentially-subject-to-BART and conduct a BART analysis for the facility.

## D. Subject-to-BART Determination

Once the "universe" of potentially-BART-eligible sources has been set, the State must make a determination about which of these sources are truly subject-to-BART. In order for a source to be subject-to-BART, a State must conclude that emissions of visibility impairing pollution from a BART-eligible source may reasonably be anticipated to cause or contribute to any visibility impairment in a mandatory Class I area.

As noted in Section V.C above, ADEQ's process only resulted in the determination that certain facilities are potentially-subject-to-BART. The cause for this intermediate step was that ADEQ was unable to access emissions and stack parameter information that is recommended by the EPA BART guidelines for analyzing a facility. Instead, ADEQ relied on information that was publicly available through the Title V permit applications for each of the facilities. Each of the facilities found to be potentially-subject-to-BART was provided with the opportunity to conduct a modeling analysis using emissions estimates that are reflective of steady-state operating conditions during periods of high capacity utilization. In other words, in accordance with the EPA July 6, 2005, BART guidelines, facilities were provided with the option of using of an emissions rate based on the maximum actual emissions over a 24-hour period for the most recent five year periods as an appropriate gauge of a source's potential impact. EPA explained that this would ensure that peak emission conditions are reflected, but would not overestimate a source's potential impact on any given day.

In its analysis of potentially BART-eligible sources, ADEQ identified one facility that appeared to be BART-eligible but deferred sending a letter to that facility, as representatives of the facility were already

engaged in dialogue regarding the facility's BART eligibility. Ultimately, the facility chose to demonstrate that it was never BART-eligible.

Arizona Sources That Chose to Demonstrate "Not BART-Eligible":

- TEP Irvington Generating Station

Of the nine facilities that received ADEQ's July 13, 2007, letter, five facilities provided documentation that argued that while the facility was BART-eligible, it was not potentially-subject-to-BART. Those five facilities are as follows:

Arizona Sources That Chose to Demonstrate Not "Potentially-Subject-to-BART":

- Arizona Portland Cement Company
- APS West Phoenix
- ASARCO Hayden Smelter
- Chemical Lime Nelson Lime Plant
- Freeport McMoRan Miami Smelter

Of the facilities that received ADEQ's July 13, 2007, letter, four responded that the facilities were indeed subject-to-BART and provided an BART-analysis for the BART-eligible equipment. Those four facilities are as follows:

Arizona Sources that Agreed To Be Subject-to-BART:

- Catalyst Paper
- AEPCO
- APS Cholla Power Plant
- SRP Coronado Generating Station

## V. ARIZONA SOURCES THAT CHOSE TO DEMONSTRATE "NOT BART-ELIGIBLE"

### A. TEP – Irvington Generating Station

On June 9, 2006, ADEQ sent a letter to the Western Regional Air Partnership's (WRAP's) Regional Modeling Center (RMC) requesting assistance in performing a CALPUFF modeling analysis for all BART-eligible sources. In the letter and supporting attachments, ADEQ identified Steam Unit I4 at Tucson Electric Power Company's (TEP's) Irvington Generating Station as potentially-BART-eligible emissions unit. The attachment to the letter went on to describe Unit I3 as also potentially-BART-eligible, as the emissions unit appeared to have been in existence in 1961, and the "in-service" date for the unit was not well documented in the files that ADEQ had reviewed.

On January 2, 2007, TEP submitted a letter to ADEQ providing information about the BART-eligibility of both Units I3 and I4. The letter explained that the issues to which it was specifically responding were:

- For Unit I3 – the date the unit began "operation"; and
- For Unit I4 – whether the coal conversion project effectively moved its "in existence" date to later than August 7, 1977.

Regarding Unit I3, TEP noted that in order for an emissions unit to be considered BART-eligible, the unit had to be "in existence" on August 7, 1977, but not "in operation" before August 7, 1962. According to the letter, Unit I3 commenced commercial operation on June 26, 1962. As documentation, TEP provided a work log from June 29, 1962, which indicates that "...Unit [I3] was placed in commercial operation on Tuesday, June 26, 1962." After reviewing this documentation, ADEQ agrees that Unit I3 was "in operation" prior to August 7, 1962, and is, therefore, not BART-eligible.

Regarding Unit I4, TEP stated that during the 1980s, Unit I4 was converted to burn coal in accordance with a prohibition order that was issued pursuant to Section 301(c) of the Power Plant and Industrial Fuel Use Act of 1978. The Final Prohibition Order became effective on September 21, 1981, as noted in Federal Register Vol. 46, p. 37960. In its January 2, 2007, letter, TEP stated that compliance with the Final Prohibition Order required TEP to reconstruct Unit I4. According to 40 CFR 51.301, Reconstruction is defined as follows:

> *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 § 60.15(f)(1) through (3) of this title.

TEP stated that because Unit I4 was reconstructed after August 7, 1977, the Unit was not "in existence" before August 7, 1977, and, therefore, must be considered "not BART-eligible".

In an electronic mail that was sent to a representative of TEP on May 15, 2007, ADEQ requested that TEP provide additional documentation that demonstrated that Unit I4 was reconstructed in the 1980s. On July 3, 2007, TEP submitted a supplemental letter to ADEQ, with the documentation that ADEQ had requested.

According to the July 3, 2007, the total cost for the Unit I4 coal conversion was reported in the 1987 FERC Form No. 1 to be approximately $125 million dollars, including the Unit I4 portion of the facilities that are shared by Units I3 and I4 (i.e., coal handling facility, water treatment, ash storage and disposal,

etc.). In January of 1988, Unit I4 was sold in a leaseback arrangement for $152 million, which TEP argues approximates the fair market value for the Unit. TEP stated that because Unit I4 was essentially in new condition following the coal conversion, it is reasonable to conclude that the construction of a comparable new unit would not be significantly greater than $152 million. Based upon this information, TEP stated that the coal conversion cost was significantly greater than 50% of the fixed capital cost of a comparable, entirely new unit. As a result, TEP concluded that Unit I4 was reconstructed in the 1980s, effectively changing the "in existence" date to after August 7, 1977. As a result, TEP concluded that Unit I4 was "not BART-eligible".

After reviewing the information that was provided by TEP, including the relevant portions of the December 31, 1987, FERC Form No. 1 Annual Report of Major Electric Utilities, Licensees and Others, TEP's 1987 Annual Report, and a work sheet entitled "Estimated Cost of Irvington Unit 4 Coal Conversion", ADEQ concurs that the cost of modifying TEP Irvington's Unit I4 is greater than 50 percent of the fixed capital cost of a comparable, entirely new source, and that Unit I4 was reconstructed in the 1980s.

In Federal Register, Vol. 70, No. 128, Wednesday, July 6, 2005, pages 39110-39112, EPA discusses Step 2 in determining whether a facility is BART-eligible. According to the background statement in the guidance:

> "Step 2 also addresses the treatment of 'reconstruction' and 'modifications.' Under the definition of BART-eligible facility, sources which were in operation before 1962 but reconstructed during the 1962 to 1977 time period are treated as new sources as of the time of reconstruction."
>
> The footnote attached to this statement goes on to state:
>
> "However, sources reconstructed after 1977, which reconstruction had gone through NSR/PSD permitting, are not BART-eligible."

At the time of TEP's 1987 reconstruction of Unit I4, reconstruction of most units at the Irvington Generating Station would have normally triggered the New Source Review (NSR) or Prevention of Significant Deterioration (PSD) permitting process. As TEP points out in its correspondence, however, TEP only commenced the reconstruction as a result of the an order that was issued pursuant to Section 301(c) of the Power Plant and Industrial Fuel Use Act of 1978. Arizona's PSD rule (Arizona Administrative Code, Title 9, Article 3, Rule 304 or A.A.C. R9-3-304) was approved into the State Implementation Plan in 1983. According to the PSD rule, all "major modifications" were required to obtain a PSD permit prior to construction and operation of the facility. The definitions that support this rule were found in A.A.C. R9-3-101. According to R9-3-101(91)[8] a major modification is defined as follows:

> "Major modification" means any physical change in or change in the method of operation of a major stationary source that would result in a significant net emissions increase of any pollutant subject to regulation under this Chapter.
>
> a. ...
>
> b. For the purposes of this definition the following shall not be considered a physical change or change in the method of operation:

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8 http://yosemite.epa.gov/R9/r9sips.nsf/AgencyProvision/ABAB0C337F5775248825698C0064E741/$file/az+deq+r9-3-101.pdf?OpenElement

i. ...
ii. Use of an alternative fuel or raw material by reason of an order under Sections 2 (a) and (b) of the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or by reason of a natural gas curtailment plan pursuant to the Federal Power Act;
iii. ...
iv. ...
v. ...
vi. ...
vii. ..."

Pursuant to A.A.C. R9-3-101(90)(b)(ii), TEP's reconstruction of Unit I4 did not constitute a major modification at the time that the reconstruction occurred, and therefore Arizona's PSD rule did not apply. TEP's January 2, 2007, letter states that "TEP believes that PSD is immaterial to BART eligibility, as Reconstruction under the RHR makes no mention of PSD or any of its provisions. In fact, no where in its rules[footnote omitted] governing BART eligibility, does it state that being subject to PSD is a condition of Reconstruction under the RHR."

ADEQ has reviewed 40 CFR Part 51 Appendix Y, Section II.A.2 and has determined that EPA has addressed this issue:

"What is a 'reconstructed source?'

1. Under a number of CAA programs, an existing source which is completely or substantially rebuilt is treated as a new source. **Such 'reconstructed' sources are treated as new sources as of the time of the reconstruction.** Consistent with this overall approach to reconstruction, the definition of BART-eligible facility (reflected in detail in the definition of 'existing stationary facility') includes consideration of sources that were in operation before August 7, 1962, but were reconstructed during the August 7, 1962 to August 7, 1977 time period.

2. ...

3. ...

4. The 'in-operation' and 'in existence' tests apply to reconstructed sources. If an emissions unit was reconstructed and began actual operation before August 7, 1962, it is not BART-eligible. Similarly, any emissions unit for which a reconstruction 'commenced' after August 7, 1977, is not BART-eligible." (emphasis added)

ADEQ has determined that EPA's guidance does not specifically address situations where a facility was reconstructed after August 7, 1977, but was exempted from PSD review at the time that reconstruction occurred. ADEQ concludes, however, that the plain reading of EPA's guidance is most appropriate, and has determined that it is appropriate to treat reconstructed sources as new sources as of the time of the reconstruction. As a result, ADEQ concurs that the reconstructed Unit I4 at TEP's Irvington Generating Station was not "in existence" prior to August 7, 1977. Therefore, ADEQ has determined that there are no BART-eligible emissions units at TEP's Irvington Generating Station.

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## VI. ARIZONA SOURCES THAT CHOSE TO DEMONSTRATE NOT "POTENTIALLY-SUBJECT-TO-BART"

### A. Arizona Portland Cement Company

On June 13, 2007, ADEQ sent a letter to Arizona Portland Cement Company (APCC) indicating that Kiln 4 was "potentially-subject-to-BART" for NOx and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the February 28, 2002, Amended Application for a Class I Permit, the 2005 Significant Revision Application, and observations from performance testing results which indicated that Kiln 4 had the following potential $NO_X$ and PM emissions (Table 6.1):

| Table 6.1 – Kiln 4 Emissions | | |
|---|---|---|
| **Emissions Unit** | **$NO_X$ Emissions (lb/hr)** | **PM Emissions (lb/hr)** |
| Kiln 4 | 540.10 | 11.39 |

According to the letter, the WRAP's Regional Modeling Center conducted an air dispersion modeling analysis using CALPUFF which demonstrated that the maximum 98th percentile three-year average total impact from the facility was 0.40 dv. These visibility impacts were expected to occur in both the Saguaro National Monument and the Galiuro Wilderness area.

On September 10, 2007, APCC submitted a letter to ADEQ stating that it agreed that Kiln 4 was the only emissions unit that was in operation at the facility that was BART-eligible. The letter went on to state that because the 98th percentile three-year average total impact from this emissions unit was 0.40 dv, concluded that Kiln 4 does not "cause" or "contribute to" visibility impairment in any Class I area.

When weighing APCC's response, ADEQ also gave consideration to additional extenuating circumstances regarding Kiln 4. In 1998, APCC obtained a significant permit revision from ADEQ, allowing the company to modify portions of Kiln 4 in an effort to increase the amount of clinker that the company could produce while taking limitations designed to ensure that there was not a significant net emissions increase as a result of the project. After completing Phase I of the changes to Kiln 4, APCC determined that it was not realizing the additional clinker production projected to occur as a result of the modification. In 2002 and 2003, APCC approached ADEQ with a new application for a permit revision, requesting the authority to construct a new Kiln 5 rather than finalizing the modifications to Kiln 4.

In 2003, during its review of a proposed Title V permit that would have provided APCC with the flexibility to choose between three operating scenarios, including the construction of Kiln 5, EPA identified an error in APCC's fugitive dust emissions calculations. According to EPA's calculations, the modifications that were completed in 1998 should have gone through New Source Review. As a result, EPA issued a Notice of Violation to APCC, alleging that the company avoided New Source Review when completing modifications to Kiln 4 in 1998. EPA also objected to the issuance of the proposed Title V permit, but later lifted its objection after ADEQ removed the alternative operating scenarios that would have allowed for further modification of the facility. A consent decree is being finalized between APCC and EPA to resolve the issue.

In 2008, ADEQ issued a new permit to APCC which would have allowed the facility to stop operations at all four existing kilns and construct and operate a new Kiln 6. The 18 month construction window ended in June 2010 and APCC has since reapplied for a permit for the Kiln 6 expansion.

Based upon the consideration of the history of this facility, and the maximum 98th percentile three-year average impact from all pollutants is less than 0.5 dv, ADEQ concurs that APCC is not subject-to-BART.

## B. APS West Phoenix

On June 13, 2007, ADEQ sent a letter to the Arizona Power Service Company's West Phoenix Generating Station indicating that three emissions units, Combined Cycle Units 1 through 3, were "potentially-subject-to-BART" for $NO_X$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the July 2000 Title V Operating Permit Application, and February 24, 2006 Significant Revision Application which showed that the facility had potential $NO_X$ emissions as follows:

**Table 6.2 – APS West Phoenix $NO_X$ Emissions**

| Emissions Unit | $NO_X$ Emissions (lb/hr) | $NO_X$ Emissions (tons/year) |
|---|---|---|
| Combined Cycle Unit 1 (NG)[a] | 255.80 | 1,120 |
| Combined Cycle Unit 2 (NG)[a] | 255.80 | 1,120 |
| Combined Cycle Unit 3 (SR app)[c] | 405.10 | 1,774 |
| Combined Cycle Unit 1 (oil)[b] | 763.00 | 3,342 |
| Combined Cycle Unit 2 (oil)[b] | 763.00 | 3,342 |
| Combined Cycle Unit 3 (SR app)[c] | 405.10 | 1,774 |

a. NG indicates potential emissions while burning natural gas
b. Oil indicates potential emissions while burning oil
c. SR app means that the potential emissions were to be limited as proposed in a significant permit revision application that was submitted on February 24, 2006.

On July 30, 2007, APS West Phoenix provided documentation to ADEQ demonstrating that the facility had accepted federally-enforceable conditions in Maricopa County Air Quality Permit Number V95-006 that placed limits on emissions of air pollutants from the facility. Specifically, the permit states in Table 1 that the "Allowable Combined Emissions for CC3, CC4, CC5, the CC4 and CC5 Cooling Towers, and the Clayton Boiler Emissions Units" for $NO_X$ was 405.1 tons per year. The same permit also limits the short term $NO_X$ emissions for Combined Cycle Unit 3 to no more than 34.3 pounds per hour.

On September 6, 2007, APS West Phoenix submitted a letter to ADEQ identifying errors in the underlying assumptions that were the basis of ADEQ's June 13, 2007, letter. Specifically, the facility identified the following issues:

- The data used as the pound per hour emission rate for Combined Cycle Unit 3 were actually tons per year emissions limitations for multiple emissions units, rather than a pound per hour emission rate for that same unit;
- Combined Cycle Unit 3 is equipped with a Selective Catalytic Reduction (SCR) unit;
- Combined Cycle Unit 3's stack height was assumed to be 54 feet, whereas the actual stack height for the unit is 82 feet;

- The air dispersion modeling analysis used West Phoenix emissions rates associated with fuel oil combustion. The Maricopa County Air Quality Department prohibits the combustion of fuel oil except during periods of natural gas curtailments, and should not have been considered the normal operating scenario.

APS West Phoenix stated that it would fix each of these assumptions, and resubmit an air dispersion modeling analysis that was performed by the WRAP's Regional Modeling Center with the adjusted values.

On October 7, 2007, APS West Phoenix submitted a second letter to ADEQ. In that letter, APS West Phoenix explained that it agreed with ADEQ's assessment that the Combined Cycle Units CC1, CC2 and CC3 were BART-eligible. APS West Phoenix stated, however, that after correcting the air dispersion modeling analysis using the assumptions identified above, the 98th percentile visibility impacts that ADEQ had predicted in the Superstition Wilderness and the Mazatzal Wilderness areas dropped from 0.69 dv and 0.64 dv, to 0.24 dv and 0.31dv respectively.

Based on the revised air dispersion modeling analysis that was submitted on October 7, 2007, APS West Phoenix stated that it did not cause or contribute to regional haze in a Class I area, and therefore was not subject-to-BART. Based upon its review of the information that has been submitted, and a review of the conditions in Maricopa County Air Quality Permit V95-006, ADEQ concurs that this facility is not subject-to-BART.

## C. ASARCO Hayden Smelter

On June 13, 2007, ADEQ sent a letter to the ASARCO Hayden Smelter indicating that Converters 1 through 5, and Anode Furnaces 1 through 3 were "potentially-subject-to-BART" for $SO_2$ and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the 1994 Application for a Class I Permit which showed that the facility had potential $SO_2$ and PM emissions as follows (Table 6.3):

**Table 6.3 – ADEQ Modeled Emissions for ASARCO Hayden**

| Emissions Unit | $SO_2$ emissions (lb/hr) | PM emissions (lb/hr) |
|---|---|---|
| Acid Plant Main Stack (Converters 1-5, Anode Furnace 1-3) | 114,000 | 115.83 |
| Annulus Main Stack (bypass for main stack) | 114,000 | 115.83 |
| Flash Furnaces and Converter Fugitives | 2,991 | 230.00 |

In Attachment 3 to the June 13, 2007, letter, ADEQ also identified the equipment that, according to Title V Permit 1000042, was potentially BART-eligible. That equipment included the following:

- Converters (5) – constructed in 1969
- Anode Furnaces 1-3 – constructed in 1971

Finally, ADEQ's analysis revealed that in 2004, the actual emissions of $PM_{10}$ from the facility was 157.3 tons per year. Because ADEQ was uncertain whether this number was representative of overall emissions of $PM_{10}$ from the ASARCO Hayden Smelter through the years, the potential emission rate information for

both $SO_x$ and PM was submitted to the WRAP's Regional Modeling Center. Based upon the information that ADEQ submitted, the WRAP's Regional Modeling Center provided ADEQ with the following modeled impacts:

| Table 6.4 – WRAP Modeled Impact from ASARCO Hayden | | |
|---|---|---|
| **Class I Area** | **98th % 3 Yr Avg. $PM_{10}$ Impact (dv)** | **98th % 3 Yr Avg. $SO_2$ Impact (dv)** |
| Galiuro Wilderness | 0.53 | 2.23 |
| Superstition Wilderness | 0.41 | 2.39 |
| Sierra Ancha Wilderness | 0.13 | 1.46 |
| Saguaro NM | 0.23 | 1.64 |
| Mazatzal Wilderness | 0.09 | 1.22 |
| Mount Baldy Wilderness | 0.04 | 0.76 |
| Pine Mountain Wilderness | 0.05 | 0.93 |
| Chiricahua NM | 0.13 | 1.39 |
| Gila Wilderness | 0.05 | 0.78 |
| Petrified Forest NP | 0.04 | 0.78 |
| Sycamore Canyon | 0.03 | 0.70 |

As a result, ADEQ determined that the facility was BART-eligible for $PM_{10}$ and $SO_2$ emissions.

On October 1, 2007, ASARCO LLC submitted a letter to ADEQ stating that the company has already installed BART-equivalent controls on the necessary emissions units, and that further control was not necessary.

In its review of ADEQ's analysis, ASARCO pointed out that errors were made in ADEQ's identification of the BART-eligible source. According to their own research, ASARCO determined that the BART-eligible emissions units at their facility were as follows:

- Converters (3)
  - Three converters were in operation prior to 1962;
  - One converter was enlarged from 13 x 32 feet to 13 x 35 feet in 1965
  - Converters #1 and #4 were added in 1968.
- Anode Furnaces #1 and #2 – Constructed in 1972
  - Anode Furnace #0 was constructed in 2001

As a result, ASARCO went on to state that it concluded that only two or three of the converters were considered to be BART-eligible. ASARCO stated that because the air dispersion modeling analysis was performed based upon the use of the potential to emit from the entire facility, the predicted impacts from the facility were overstated. Instead, ASARCO stated that the following emissions should have been modeled (Table 6.5):

| Table 6.5 – ASARCO Modeled Emissions for ASARCO Hayden | | | |
|---|---|---|---|
| Unit | $NO_x$ (tpy) | $PM_{10}$ (tpy) | $SO_2$ (tpy) |
| Total for BART-eligible Emission Units | 21.4[a]<br>23.3[b] | 61.1[a]<br>70.0[b] | 6,903[a]<br>10,337[b] |

a. 2 converters
b. 3 converters

ASARCO stated that "[i]f [PM] emissions from the BART-eligible units alone are modeled the visibility impact would be below the 0.5 dv threshold. Therefore, BART determination is necessary only for $SO_2$."

ADEQ has reviewed its documentation, and ASARCO's arguments regarding BART eligibility, and ADEQ agrees with ASARCO's assessment of its BART-eligible emissions unit, with the clarification that the converter that was modified in 1965 is considered BART-eligible.

At the time that ADEQ was assessing BART eligibility, ADEQ based its analysis on the potential emissions from the entire facility, as it was not possible for ADEQ staff to apportion emissions to the specific emissions units based upon the information that had been submitted by ASARCO. As a result, ADEQ provided all of the potential PM and $SO_2$ emissions to the Regional Modeling Center, understanding that ASARCO would have the expertise necessary to apportion emissions to each emissions unit that was BART-eligible.

With respect to PM10, the Department has determined that the PM10 potential to emit from the BART-eligible units exceeds 15 tons per year. As documented in ADEQ's comments dated March 6, 2013 on EPA's proposed rulemaking, each emission unit has to be evaluated individually against the 15 tpy threshold to assess BART applicability. Since the average PTE for each of the BART-eligible units is below 15 tpy, the units should not be subject to a BART analysis. However, Asarco has gone ahead and completed a BART analysis. ADEQ has analyzed the proposal and is incorporating it as part of this SIP.

With respect to SO2 emissions, ASARCO stated the following:

> "During the deliberations of the Market Trading forum [sic] of the Western Regional Air Partnership (WRAP), all parties involved including ADEQ and the U. S. Environmental Protection Agency (EPA), agreed that the controls and emissions limitation for primary copper smelters already met BART for $SO_2$."

ADEQ understands that there may have been, at one time, a general principle to which U.S. EPA, ADEQ, and perhaps other parties agreed regarding the controls and emissions limitation for primary copper smelters. According to ADEQ's interpretation of the Regional Haze Rules, and its application of EPA's BART guidelines, however, general principles are not enough to exempt a facility from a BART analysis. Instead, ADEQ has determined that it is necessary to evaluate ASARCO's facility for the potential applicability of BART.

### D. Chemical Lime Company – Nelson Lime Plant

On June 13, 2007, ADEQ sent a letter to Chemical Lime Company's (CLC's) Nelson lime plant indicating that Kilns 1 and 2 were "potentially-subject-to-BART" for $NO_X$ and $SO_2$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the November 30, 2001, Amended Application for a Class I

permit, as well as air quality control permit number 36425 which showed that the facility had potential $NO_X$ and $SO_2$ emissions as follows (Table 6.6):

| Table 6.6 – ADEQ Modeled Emissions for CLC Nelson | | |
|---|---|---|
| **Emissions Unit** | **$SO_2$ Emissions (lb/hr)** | **$NO_X$ Emissions (lb/hr)** |
| Kiln 1 | 215.59 | 122.14 |
| Kiln 2 | 484.27 | 182.78 |

Using these emissions rates, and modeling information about the facility from the sources identified above, the WRAP's Regional Modeling Center provided ADEQ with the following modeled impacts (Table 6.7):

| Table 6.7 – WRAP Modeled Impact from CLC Nelson | | | |
|---|---|---|---|
| **Class I Area** | **98th % 3 Yr Avg. $NO_X$ Impact (dv)** | **98th % 3 Yr Avg. $SO_2$ Impact (dv)** | **98th % 3 Yr Avg. Total Impact (dv)** |
| Grand Canyon NP | 0.38 | 0.32 | 0.74 |
| Sycamore Canyon WA | 0.06 | 0.13 | 0.18 |
| Zion NP | 0.10 | 0.11 | 0.20 |
| Pine Mountain Wilderness | 0.03 | 0.08 | 0.10 |
| Mazatzal Wilderness | 0.03 | 0.08 | 0.11 |
| Bryce Canyon NP | 0.05 | 0.07 | 0.11 |
| Joshua Tree NM | 0.03 | 0.12 | 0.14 |
| Sierra Ancha Wilderness | 0.02 | 0.06 | 0.07 |
| Superstition Wilderness | 0.02 | 0.07 | 0.08 |

On September 21, 2007, CLC submitted a letter to ADEQ along with a new modeling analysis indicating that "...the 3-year average of the 8th highest visibility change is less than 0.5 dv in all Class I areas." Based upon its review of the new modeling analysis, Chemical Lime concluded that the Nelson facility did not cause or contribute to visibility impairment in any Class I area, and that the emissions units were, therefore, not subject-to-BART.

According to the documentation submitted in support of the new modeling analysis, Chemical Lime estimated its emission rates of NOx, $SO_2$ and PM for the BART applicability modeling analysis using the maximum production rates achieved by each kiln during the meteorological period that was modeled (a method which can result in the over prediction of actual impacts on an annual basis), and from using representative emissions factors that were derived from source testing performed at the Nelson facility. The emission rates that CLC modeled are as follows (Table 6.8):

| Table 6.8 – CLC Modeled Emissions for CLC Nelson | | |
|---|---|---|
| **Emissions Unit** | **$SO_2$ Emissions (lb/hr)** | **$NO_X$ Emissions (lb/hr)** |
| Kiln 1 | 117.8 | 95.23 |

| | | |
|---|---|---|
| Kiln 2 | 375.5 | 99.20 |

According to ADEQ's review of the modeling analysis, none of the other fixed parameters (i.e., elevation, stack height, stack diameter, exhaust gas velocity, and exit temperature) were significantly modified in CLC's analysis. The only difference noted was that the elevation of the facility used by ADEQ was 1,570.7 meters above sea level, whereas the company reported the elevation to be 1,570.3 meters above sea level. Because the difference between the two parameters was less than half of a meter (approximately 1.5 feet) ADEQ determined that the change was not significant.

The resulting modeling impacts from the screening assessment performed by CLC, as documented in the September 21, 2007, submission and a May 28, 2009, electronic mail to ADEQ, were as follows (Table 6.9):

**Table 6.9 – Modeled Impact from CLC Nelson**

| Class I Area | 98th % 3 Yr Avg. $NO_X$ Impact (dv) | 98th % 3 YR Avg. $SO_2$ Impact (dv) | 98th % 3 Yr Avg. Total Impact (dv) |
|---|---|---|---|
| Grand Canyon NP | 0.291 | 0.205 | 0.498 |
| Sycamore Canyon WA | 0.015 | 0.107 | 0.123 |
| Zion NP | 0.054 | 0.081 | 0.136 |
| Pine Mountain Wilderness | 0.003 | 0.069 | 0.072 |
| Mazatzal Wilderness | 0.017 | 0.056 | 0.073 |
| Bryce Canyon NP | 0.026 | 0.048 | 0.074 |
| Joshua Tree NM | 0.014 | 0.093 | 0.108 |
| Sierra Ancha Wilderness | 0.010 | 0.039 | 0.049 |
| Superstition Wilderness | 0.009 | 0.045 | 0.054 |

As can be seen from the table above, the company's modeling analysis showed that the 98th percentile, three-year average total impact from the plant was predicted to be less than 0.5 dv for every Class I area within 300 kilometers of the facility. The company also recognized, however, that the predicted impacts within the Grand Canyon were marginally below 0.5 dv. As a result, the company stated that "[a]lthough the maximum visibility change obtained in the screening modeling analysis is not equal to or greater than the 0.5 dv contribution threshold, a refined analysis was performed in which light extinction in the Grand Canyon National Park was calculated using the CALPOST-IMPROVE implementation of the revised light extinction algorithm…" Based upon the refined analysis, the 98th percentile (8th highest) Visibility Change in the Grand Canyon was calculated to be as follows (Table 6.10):

**Table 6.10 – Modeled Impact from CLC Nelson at the Grand Canyon NP**

| Class I Area | 98th Percentile (8th highest) Visibility Change (dv) | | | |
|---|---|---|---|---|
| | 2001 | 2002 | 2003 | Average |
| Grand Canyon NP | 0.417 | 0.379 | 0.585 | 0.460 |

Based upon its refined visibility change analysis, CLC determined that the visibility change attributable to the Nelson facility is below 0.5 dv, and it concluded that the facility does not significantly contribute to visibility impairment within the Grand Canyon National Park. As a result, CLC determined that the results of the analysis indicated that the 3-year average of the 8th highest visibility change was less than 0.5 dv in all Class I areas within 300 km of the facility, and concluded that its Nelson facility was not-subject-to-BART.

Based upon the consideration of the analysis performed for this facility, CLC's conservative approach for estimating emissions impacts during the meteorological period, and the maximum 98th percentile three-year average impact from all pollutants is less than 0.5 dv, ADEQ concurs that the Chemical Lime Company's Nelson Lime Plant is not subject-to-BART.

### E. Freeport McMoRan Miami Smelter

On June 13, 2007, ADEQ sent a letter to Freeport McMoRan Miami Inc (FMMI) indicating that the Miami Smelter Converters 1 through 5; the Remelt Vessel and the Acid Plant were "potentially-subject-to-BART" for $SO_2$ and PM emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the Air Quality Permit Number 1000046, and the application for Air Quality Permit Number 1000046 which showed that the facility had potential $SO_2$ and PM emissions as follows (Table 6.11):

**6.11 – ADEQ Modeled Emissions from FMMI**

| Emissions Unit | $SO_2$ Emissions (lb/hr) | PM Emissions (lb/hr) |
|---|---|---|
| Acid Plant Tailgas Stack (Converters 1-5) | 820.0 | 20.40 |
| Vent Fume Stack (Electric Furnace Stack) | 312.0 | 56.30 |
| Shaft Furnace Stack | 0.030 | 4.110 |
| Smelter Fugitives | 1288 | 48.55 |
| Rod Plant Fugitives | 0.000 | 0.100 |

On July 17, 2007, FMMI responded stating that "although, we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area, we would like to point out some corrections in the emissions points and emissions used in the modeling." According to the letter, FMMI disputed the stack height, diameter and velocity values that were used for the Vent Fume Stack and the emissions release point and temperature for fugitive emissions from the smelter that ADEQ provided to the WRAP's RMC in its June 9, 2006, letter. FMMI also reported that the Rod Plant shaft furnace should not have been included as part of the smelter, and the acid plant preheater was installed in 1991 as part of the company's ISA modification.

On August 3, 2007, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/mold pouring Vessel (installed in approx. 1974)

FMMI then provided ADEQ with information regarding the five steps that EPA proposed in its BART guidance, but indicated that EPA provided the option for streamlining the review. According to FMMI's letter, EPA's guidance at 40 CFR Part 51, Appendix Y, § IV(C) states:

> "For VOC and PM sources subject to MACT standards, States may streamline the analysis by including a discussion of the MACT controls and whether any major new technologies have been developed subsequent to the MACT standards."

FMMI's letter goes on to provide a "streamlined review" of emissions from relevant emissions units at the FMMI smelter, and justification for the Rod Plant Shaft Furnace being separated from the BART-eligible source, as this furnace is not part of a listed source category.

After verbal discussions with ADEQ staff regarding the August 3, 2007, letter, FMMI submitted a final letter regarding the matter to ADEQ on November 29, 2007. In this letter, FMMI provided additional information to supplement the August 3, 2007, letter. In the letter, FMMI provides additional citations for the streamlined BART reviews for $SO_2$ and PM emissions at the Miami Smelter.

FMMI has also provided information (through its March 6, 2013 letter to EPA on the proposed rulemaking) that the remelt furnace was actually installed prior to 1962 and should not be considered a BART-eligible unit. Additionally, FMMI has provided emission estimates for NOX from the BART-eligible units documenting that the total is below 40 tons per year.

After reviewing the information that was submitted by FMMI, ADEQ agrees it is necessary to evaluate FMMI's facility for the potential applicability of BART through its process for conducting a BART analysis.

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## VII. ARIZONA SOURCES THAT REQUIRED A BART ANALYSIS

Pursuant to the discussion in the previous Section, the following six facilities were identified as having to conduct a BART analyses. Due to the case-by-case nature of the BART analyses, ADEQ has included specific sections in this technical support documents for each of these facilities. A brief summary of the circumstances leading to ADEQ's subject-to-BART determinations are as follows:

### A. Catalyst Paper (Snowflake) Inc. (CPSI) formerly Abitibi Consolidated

On June 13, 2007, ADEQ sent a letter to Abitibi Consolidated indicating that Power Boiler 2, a coal-fired boiler at the paper and pulp mill was "potentially-subject-to-BART" for $SO_2$ and $NO_X$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the Title V Permit Application –Amended Version submitted in March 2000 which showed that the facility had potential $NO_X$ and $SO_2$ emissions as follows (Table 7.1):

| Table 7.1 – ADEQ Modeled Emissions for CPSI | | |
|---|---|---|
| **Emissions Unit** | **$NO_X$ Emissions (lb/hr)** | **$SO_2$ Emissions (lb/hr)** |
| Power Boiler 2 | 555.00 | 915.00 |

On October 23, 2007, Abitibi Consolidated provided a BART analyses to ADEQ. ADEQ's analysis and BART determination for CPSI can be found in Section IX of this document.

### B. Arizona Electric Power Cooperative, Inc. - Apache Generating Station

On June 13, 2007, ADEQ sent a letter to Arizona Electric Power Cooperative Inc.'s (AEPCO's) Apache Generating Station indicating that Steam Units 1 through 3 were "potentially-subject-to-BART" for $NO_X$ and $SO_2$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association; and its review of the Air Quality Permit Number 35043, and the January 6, 2005, application for Class I Permit Renewal, which showed that the facility had potential $NO_X$ and $SO_2$ emissions as follows (Table 7.2):

| Table 7.2 – ADEQ Modeled Emissions from AEPCO | | |
|---|---|---|
| **Emissions Unit** | **$NO_X$ Emissions (lb/hr)** | **$SO_2$ Emissions (lb/hr)** |
| Steam Unit #1 | 264.90 | 0.57 |
| Steam Unit #2 | 576.47 | 1.24 |
| Steam Unit #3 | 576.47 | 1.24 |

In July of 2007, AEPCO scheduled a meeting with ADEQ to discuss its concurrence that the facility was subject-to-BART. In the meeting, AEPCO indicated that the information that was provided to the WRAP's RMC was based upon Steam Units #2 and #3 burning natural gas, rather than coal. AEPCO discussed a proposed modeling protocol with ADEQ, and explained that when modeling its baseline conditions, AEPCO would use the emission rates associated with burning coal at the facility.

On January 2, 2008, AEPCO provided its BART analysis to ADEQ. ADEQ's analysis and BART determination for AEPCO's can be found in Section XI of this document.

### C. APS Cholla Power Plant

On June 13, 2007, ADEQ sent a letter to Arizona Public Service's (APS's) Cholla Generating Station indicating that Steam Units 1 through 4 were "potentially-subject-to-BART" for $NO_X$, PM, and $SO_2$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the application for Air Quality Permit Number 46353 (Table 7.3):

**Table 7.3 – ADEQ Modeled Emissions from APS Cholla**

| Emissions Unit | $NO_X$ Emissions (lb/hr) | PM Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) |
|---|---|---|---|
| Unit #1 | 279.40 | 38.10 | 304.8 |
| Unit #2 | 646.40 | 293.80 | 705.10 |
| Unit #3 | 644.40 | 87.90 | 351.50 |
| Unit #4 | 1,086.80 | 384.10 | 3,414.40 |

In August of 2007, representatives of APS's Cholla Generating Station met with representatives of ADEQ to discuss some outstanding questions that the company had regarding ADEQ's analysis. During the course of that meeting, APS provided a copy of Arizona Public Service Company Correspondence that was sent to Gus Hansen, Supt. at Cholla S.E.S. entitled "Operating Notes for May 1962". According to information provided by this document, "[o]n Tuesday, May 1, 1962, unit [#1] placed into commercial operation." As a result, APS argued that Unit #1 was "in operation" prior to August 7, 1962, and therefore was not BART-eligible. After reviewing this documentation, ADEQ concurs that Unit #1 was never BART-eligible.

On September 13, 2007, APS provided a letter to ADEQ providing a schedule for the submission of a modeling protocol and conducting a BART analysis with the goal of providing the final BART analysis on December 14, 2007. In December of 2007, ADEQ received the BART analysis. ADEQ's analysis and BART determination for the APS Cholla Power Plant can be found in Section XI of this document.

### D. ASARCO Hayden Smelter

As discussed in Section VI.C of this document, ADEQ has determined that a BART analysis regarding $SO_2$ emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that ASARCO had provided can be found in Section XII of this document.

### E. Freeport-McMoRan Miami Smelter

As discussed in Section VI.E of this document, ADEQ has determined that a BART analysis regarding PM and $SO_2$ emissions from this facility must be completed. ADEQ's review and determination based upon its own analysis of the facts and the information that Freeport-McMoRan Miami Inc. had provided can be found in Section XIII of this document.

## F. SRP Coronado Generating Station

On June 13, 2007, ADEQ sent a letter to Salt River Project's (SRP's) Coronado Generating Station indicating that Units 1 and 2 were "potentially-subject-to-BART" for PM, $SO_2$ and $NO_X$ emissions. ADEQ based the letter on its analysis of the facility as described in a June 9, 2006, letter to the Western Governor's Association, and its review of the August 21, 2003 Application for Class I Permit Renewal which showed that the facility had potential $NO_X$, PM, and $SO_2$ emissions as follows (Table 7.4):

**Table 7.4 – ADEQ Modeled Emissions for SRP Coronado**

| Emissions Unit | $NO_X$ Emissions (lb/hr) | PM Emissions (lb/hr) | $SO_2$ Emissions (lb/hr) |
|---|---|---|---|
| Unit #1 | 3,303 | 472 | 3,775 |
| Unit #2 | 3,303 | 472 | 3,775 |

On August 22, 2007, representatives of SRP's Coronado Generating Station met with ADEQ to discuss issues that were unique to the Coronado Generating Station, including a potential settlement with EPA regarding alleged New Source Review violations that would address $NO_X$ and $SO_2$ emissions. In addition, the company provided a proposed response to ADEQ's request for a BART analysis.

In February 2008, SRP provided its BART analysis to ADEQ. On August 12, 2008, EPA announced a "...major Clean Air Act (CAA) New Source Review (NSR) settlement agreement with [SRP]..." EPA explained that "[u]nder the settlement, SRP will spend over $400 million between now and June 2014, to install state-of-the-art pollution control technology for the reduction of sulfur dioxide ($SO_2$) and nitrogen oxides ($NO_x$)."

ADEQ's analysis and BART determination for the SRP Coronado Generating Station can be found in Section XIV of this document.

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## VIII. ARIZONA BART DETERMINATION PROCESS

Clean Air Act § 169A(g)(7) directs States to consider five factors in making BART determinations. The regional haze rule codified these factors in 40 CFR § 51.308(e)(1)(ii)(B), which directs States to identify the "best system of continuous emissions control technology" taking into account "the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source."

The visibility BART regulations define BART as meaning "...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 ... [a BART-eligible source]. 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 requirement 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."

In its guidance, EPA was clear that each State must determine the appropriate level of BART control for each source that is determined to be subject-to-BART. In making a BART determination, a State must consider the following factors:

- The costs of compliance;
- The energy and non-air quality environmental impacts of compliance;
- Any existing pollution control technology in use 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.

It appears to ADEQ that BART is a close kin to Best Available Control Technology (BACT). Both control technology requirements are based upon similar concepts, including the fact that both are conducted on a case-by-case basis, and both may constitute the application of production processes or available methods, systems and techniques to reduce air pollution emissions. The most significant difference between the two appears to be that BART must accommodate issues associated with retrofitting existing equipment with new air pollution controls that were not included in the initial design of the facility. Since the concepts between the two technology requirements are reasonably similar, ADEQ has determined that it is reasonable method for conducting a BART analysis is following the BACT methodology, taking specific care to address all five of the BART factors.

The Department's framework for performing a BART analysis comprises the following seven key steps:

1. Identify the existing control technologies in use at the source (BART factor 3);
2. Identify all available retrofit control technologies with practical potential for application to the specific emission unit for the regulated pollutant under evaluation;
3. Eliminate all technically infeasible control technologies;
4. Evaluate control effectiveness of remaining technologies;
5. Evaluate energy and non-air quality environmental impacts and document results (BART factors 1, 2 and 4); and
6. Evaluate visibility impacts (BART factor 5).
7. Select BART

Materials considered by the applicant and by the Department in identifying and evaluating available control options include the following:

- Entries in the RACT/BACT/LAER Clearinghouse (RBLC) maintained by the U.S. EPA, is the most comprehensive and up-to-date listing of control technology determinations available;
- Information provided by pollution control equipment vendors;
- Information provided by industry representatives; and
- Information provided by other Regional Planning Organizations and State permitting authorities.

Step 1: Identify the Existing Control Technologies in Use at the Source

This step is in addition to the five steps that are recommended in Section IV.D of 40 CFR Part 51, Appendix Y ("EPA's BART guidelines"). Of the four facilities that have agreed that they are "potentially-subject-to-BART", two are already in a process of designing or installing new air pollution control devices on emissions units that are "potentially-subject-to-BART". Since the installation of these controls was not required by BART, ADEQ determined that it was appropriate to include a step that described the existing control technologies that provide the baseline against which BART will be judged.

Step 2: Identify All Available Retrofit Control Options

This step is functionally equivalent to Step 1 in EPA's BART guidelines.

At the outset of any BART analysis, EPA's guidelines suggest that States should consider all control options that have potential application to the emissions unit, regardless of technical feasibility. This includes having an understanding of other required controls, including those technologies that are required under BACT or Lowest Achievable Emissions Rate (LAER) determinations, pollution prevention practices, the use of other add-on controls, and upgrades to existing air pollution controls that are already in place. As with BACT and LAER determinations, control alternatives can also take into account technology transfer of controls that have been applied to similar source categories. Unlike some permitting authorities' BACT and LAER procedures, however, BART does not contain a requirement to redesign the source when considering available control alternatives. For example, an existing pulverized-coal-fired electricity generating facility should not be required to consider integrated gasification coal combustion during the BART process, as BART focuses on technologies that can be retrofitted to the existing equipment.

In BACT and LAER determinations, any New Source Performance Standard (NSPS) or National Emissions Standard for Hazardous Air Pollutants (NESHAP) that exists for a source category is considered to the "floor" level of control, meaning that any proposed emission rate or control technology that is less stringent than the NSPS or NESHAP is not acceptable. Because BART involves retrofitting technology to existing emissions units that are not undergoing a major modification, it is possible, albeit unlikely, that an NSPS or NESHAP for a source category might not be the "floor" control for BART. Regardless, where a NSPS or NESHAP exists for a source category, EPA has directed States to include a level of control equivalent to the NSPS or NESHAP as one of the control options to be considered.

For some emissions units that are subject-to-BART controls, the actual control measures or devices that comprise BART may already be in place. In such instances, the BART analysis should consider

improvements to the existing controls or emissions limitations for those emissions units, and should not be limited to consideration of only the control devices themselves.

Finally, in some cases, if a State determines that a BART source already has controls in place which are the most stringent controls available, then it may not be necessary to comprehensively complete each following step of the BART analysis. EPA's guidance states that as long as the most stringent controls are made federally enforceable for the purposes of implementing BART for that source, a State may skip the remaining analyses, including the visibility analyses. Likewise, if a source commits to the most stringent level of BART control at the outset, then EPA's guidance suggests that there is no need to complete the remaining steps of the BART process.

Step 3: Eliminate All Technically Infeasible Control Options

This step is functionally equivalent to Step 2 in EPA's BART guidelines.

In this step, States are to evaluate the technical feasibility of the control options that were identified in Step 1. EPA's guidance generally considers a control option to be technically feasible if the controls have either: (1) been installed and operated successfully under similar conditions for the type of source under review, or (2) are available and could be applicable to the source under review. EPA's guidance states that a technology should be considered to be available if the source owner may obtain the control device through commercial channels, or the control is otherwise available within the common sense meaning of the term. Similarly, EPA considers an available control technology to be "applicable" if the control can be reasonably installed and operated on the source type that is under review. If a technology is considered to be both available and applicable, a State should consider the technology to be technically feasible.

If a technology is determined to be technically infeasible, then the State should provide documentation that demonstrates that the control is technically infeasible. EPA's guidance suggests that documentation that would be considered acceptable includes an explanation, based on physical, chemical, or engineering principles, as to why the control is technically infeasible and a discussion regarding why technical difficulties would preclude the successful use of the control option on the emissions unit under review.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

This step is functionally equivalent to Step 3 in EPA's BART guidelines. EPA's guidelines state that there are two key issues that must be addressed in this step:

(1) States should ensure that the degree of control is expressed using a metric that ensures an "apples to apples" comparison of emissions performance levels among the options; and

(2) States should give appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels.

When choosing an appropriate metric, EPA recommends selecting a metric that properly allows for the comparison of an inherently lower polluting process with a process that can only be addressed through the application of additional pollution controls. As a result, EPA has suggested that it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed (i.e., pounds per million BTU, or pounds per ton of cement produced).

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step is functionally equivalent to Step 4 in EPA's BART guidelines. After identifying the available and technically feasible control technology options, States are expected to analyze the following when making a BART determination:

- Costs of Compliance
- Energy Impacts
- Non-air Quality Environmental Impacts
- Remaining Useful Life.

Each State is responsible for presenting an evaluation of each impact along with appropriate supporting information. States should discuss and, where possible, quantify both beneficial and adverse impacts. In general, the analysis should focus on the direct impact of the control alternatives.

*Costs of Compliance*

In the regional haze rules and its BART guidance document, EPA has stated that States have flexibility in how costs are calculated. EPA has expressed its position that the Control Cost Manual provides a good reference tool for cost calculations, but also provided some flexibility in this matter. If there are elements or sources that are not addressed by the Control Cost Manual, or if there are additional cost methods that were not considered in the BART guidance document, EPA determined that these methods could serve as useful supplemental information.

EPA's guidance also explains that States should consider both the average and incremental annualized costs of a control, as both provide information that is helpful when making a control determination. EPA took great care to explain, however, that these kinds of calculations can be misused, and that both numbers should be reviewed carefully.

In its guidance, EPA provided an example where a State may be faced with choosing between two available control options. The first control option (Option A) achieves a good level of control for a reasonable cost. The second control (Option B) achieves a slightly greater emissions reduction at a significantly increased cost. In this scenario, EPA explained that if only the average costs for Options A and B were considered, the overall costs associated with Options and B would be considered reasonable. EPA stated that while this may seem sufficient, a State should continue to look at the cost associated with a small increase in pollution control for a significantly greater price. EPA called this cost the "incremental cost" and explained that it can be determined through the following equation:

$$\frac{[CostOptionA - CostOptionB]}{[TotalAnnualEmissionsOptionA - TotalAnnualEmissionsOptionB]}$$

EPA explained that by considering this incremental cost, a State may determine that the incremental cost per unit of pollution removed that is associated with Option B may be greater than the benefit of requiring the control. As a result, even though the average cost associated with both controls might be reasonable, the incremental cost may make one option more desirable than the other.

As stated in the introduction to this Section, ADEQ sees the BART determination process as being substantially similar to the BACT processes. While BACT has components that address visibility, the principal cost decisions are generally charged only to the pollutant that is being reduced. Visibility

impacts, on the other hand, are quantified and considered as an environmental impact, rather than an economic impact. As a result, the most useful cost metric for comparing control technologies under BACT and LAER ends up being dollars-per-ton-of-pollutant-removed (dollars per ton).

Although the BART determination process is substantially similar to methodologies that are used to establish BACT and LAER, the entire purpose behind BART is to support Congress' goal of reducing visibility impairment in Class I areas. In addition, BART differs from BACT and LAER in that the environmental impacts of the selected control can only address issues that are not related to air quality. As a result, ADEQ has determined that in addition to a dollar per ton metric, the BART determination process should also provide lesser consideration to a dollar-per-deciview-improvement metric.

*Energy Impacts*

In its guidance, EPA suggests that States should also examine the energy requirements of the control technology to determine whether the use of that technology will result in energy penalties or benefits. For instance, if a control technology is required to remediate an emissions stream that is rich in volatile organic compounds, a facility might benefit by using this combustion process to reduce energy costs. Conversely, a facility that installs a wet scrubber may suffer an energy penalty due to the increased power necessary to overcome the increased air flow resistance through the scrubber.

It should be noted that unless there is ample justification, only direct energy benefits or penalties should be considered in this analysis. Indirect energy costs should not be considered unless there is something unusual or significant enough to warrant further consideration. It is appropriate for energy impact analyses to consider the local availability (or scarcity) of specific fuels, as well as the potential differences between locally or regionally available coals.

It is also important to note that adverse energy impacts are not enough, in and of themselves, to disqualify a technology from consideration. If such penalties or benefits exist, however, it is appropriate to document these and include them in this section so that the results of all of the analyses required in this Step can be considered as a whole.

*Non-Air Quality Environmental Impacts*

This portion of the analysis is to focus on impacts to environmental media other than air quality. Examples of common environmental impacts include hazardous waste generation, hazardous waste discharges, and discharges of polluted water from a control device.

All non-air quality environmental impacts should be reviewed using site-specific circumstances when possible. Should a State propose to adopt the most stringent BART option then it is not necessary to perform this analysis of environmental impacts for the entire list of technologies that were ranked in the previous Step. In general, the analysis only needs to address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection of a control alternative, or to eliminate a more stringent control technology.

In general, States should identify and document any direct or indirect, significant or unusual environmental impacts that are associated with a specific control alternative. For example, a wet scrubber will release effluent that has the potential to affect water or land use. Other examples might include disposal of spent catalyst, or contaminated carbon from a filtration device. Such types of environmental impacts could become even more important with the potential for sensitive site-specific receptors, or

when comparing control technologies that have similar or marginal air quality improvements but result in substantial environmental impacts.

*Remaining Useful Life*

The remaining useful life of a source should be considered in the evaluation of the different controls, as it has the potential to impact the overall cost analysis. If the remaining useful life represents a relatively short period of time, then the annualized costs associated with the application of a control technology will increase significantly. EPA explained in its guidelines that the remaining useful life is the difference between the date that controls will be put into place and the date that the facility permanently stops operations.

If the remaining useful life of the facility affects the BART determination, then this date should be placed into a federally or State-enforceable restriction that prevent further operation of that facility after that date. If a source wants to have the flexibility to continue operating after the date upon which operations are expected to cease, then the BART analysis may account for the option, but it must maintain consistency with the statutory requirement to install BART within 5 years. In addition, if the remaining useful life changes the BART decision as a result of adverse cost impacts, then the BART determination should identify the more stringent level of control that would be required as BART if there was no assumption that reduced the remaining useful life of the facility.

Step 6: Evaluate Visibility Impacts

This step is functionally equivalent to Step 5 in EPA's BART guidelines.

Once a State has determined that its source or sources are subject-to-BART, a visibility improvement determination for the source(s) must be conducted as part of the BART determination. States have the flexibility in setting absolute thresholds, target levels of improvement, or de minimis levels for visibility improvement since the deciview improvement must be weighed among the five factors. States are also free to determine the weight and significance to be assigned to each factor. For example, a 0.3 dv improvement may merit a stronger weighting in one case versus another. As a result, EPA does not recommend a "bright line" analysis to be used across all facilities that are subject-to-BART.

EPA's guidelines recommend the use of CALPUFF or another appropriate dispersion model to determine the visibility improvement expected at a Class I area from the potential BART control technology applied to the source. Modeling should be conducted for $NO_X$ emissions, direct PM emissions ($PM_{2.5}$ or $PM_{10}$), and $SO_2$ emissions. If the source is making the visibility determination, States should review and approve or disapprove the source's analysis before making the expected improvement determination.

Arizona instituted a portion of this process by asking sources for a modeling protocol for each of the BART analyses that were submitted. Each source was then asked to run its model at pre-control and post-control emission rates using the accepted methodology in the protocol. Sources used the 24-hour average actual emissions rate from the highest emitting day of the meteorological period modeled, and calculated the model results for each receptor as the change in deciviews compared against natural visibility conditions. Post-control emissions rates were then calculated as a percentage of pre-control emissions rates.

Step 7: Select BART

This step is in addition to the five steps that are recommended in EPA's BART guidelines.

States have discretion to determine the order in which they should evaluate control options for BART. EPA's guidance states that whatever the order, States should always address the five factors. In addition, States should provide a justification for whatever control option is selected. ADEQ has determined that the contents of the TSD will provide the necessary explanations.

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# IX. CATALYST PAPER (SNOWFLAKE) INC. (CPSI) FORMERLY ABITIBI CONSOLIDATED) BART ANALYSIS AND DETERMINATION

## A. Process Description

Abitibi Consolidated was purchased by CPSI in April of 2008. CPSI operates a recycled paper mill near Snowflake, Arizona, which produces newsprint and newsprint-like grades at a capacity of approximately 1,460 tons per day. A Powerhouse consisting of 3 boilers provides steam and electricity for use at the mill. Power Boiler #2 is rated at 1,132 million British thermal units (MMBtu) per hour and is the primary boiler. Power Boilers #1 and #3 are standby units and are rated at 523 MMBtu per hour and 337 MMBtu per hour respectively.

## B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Power Boiler #2 is a coal-fired boiler installed in 1975. It emits more than 250 tons per year (tpy) of nitrogen oxides ($NO_X$) and sulfur dioxide ($SO_2$). CALPUFF modeling performed by CPSI demonstrated that the boiler has a visibility extinction of 0.739 deciviews on the Sierra Ancha Wilderness Area and 0.523 deciviews on the Superstition Wilderness Area. Therefore, the unit contributes to the impairment of visibility at a Class I area and is subject-to-BART for $NO_X$ and $SO_2$.

## C. $NO_X$ BART Analysis and Determination

Step 1: Identify the Existing Control Technologies in Use at the Source

CPSI currently does not operate any $NO_x$ control technology on Power Boiler #2 although there is a permit limit of 0.7 lb/MMBtu. There is an existing over fire air system (OFA) that has never been operated.

Step 2: Identify All Available Retrofit Control Options

CPSI has identified seven control options:

- Operate the existing OFA
- Install Low $NO_X$ Burners (LNB)
- Install LNB with new OFA
- Install LNB, new OFA, and a selective non-catalytic reduction system (SNCR)
- Install a Rotating Over Fire Air (ROFA) system
- Install a ROFA with SNCR
- Install LNB, new OFA, and a selective catalytic reduction system (SCR)

**Operate the existing OFA.** The existing OFA consists of a 300 horsepower fan which reduces $NO_x$ emissions by diverting a portion of the combustion air to the lower furnace.

**Install LNB.** LNB stage the combustion process to provide a fuel-rich condition initially so that less oxygen is available to combine with nitrogen and form $NO_X$.

**Install LNB with new OFA.**

**Install LNB, new OFA, and SNCR.** SNCR works by injecting ammonia or urea into the furnace to reduce $NO_X$ to nitrogen and water. SNCR is more effective when combined with LNB and OFA.

**Install a Rotating Opposed Fire Air system (ROFA).** ROFA works by creating a turbulent flow of air throughout the volume of the furnace which lowers combustion temperature and reduces the formation of $NO_X$.

**Install a ROFA with SNCR.**

**Install LNB, new OFA, and SCR.** SCR operates much like SNCR but with the addition of a catalyst. The catalyst provides a surface on which the reduction reaction takes place.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

According to the analysis performed by Catalyst Paper, the technically feasible control options were identified as being able to achieve the following emissions rates (Table 9.1):

**Table 9.1 – Control Effectiveness of Control Options**

| Control Option | Achievable Emissions Rate (lb/MMBtu) |
|---|---|
| OFA | 0.525 |
| LNB | 0.370 |
| ROFA | 0.348 |
| ROFA with SNCR | 0.291 |
| LNB with new OFA | 0.265 |
| LNB, OFA, and SNCR | 0.194 |
| LNB,OFA, and SCR | 0.070 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Cost of Compliance*

During the course of Catalyst Paper's review of the technically feasible control options, the company identified the expected amount of emissions reduced by the application of each control option, as well as the annualized cost, and the average cost effectiveness of the controls. That information is summarized in Table 9.2 below.

| Table 9.2 – Cost of Compliance of Control Options | | | |
|---|---|---|---|
| **Control Option** | **Expected Emissions Reduction (tpy)** | **Annualized Cost** | **Average Cost Effectiveness ($/ton $NO_x$)** |
| OFA | 868 | $3,221,359[2] | $3,711 |
| LNB | 1,636 | $3,400,185 | $2,078 |
| ROFA | 1,745 | $4,262,553 | $2,443 |
| ROFA with SNCR | 2,028 | $4,903,534 | $2,418 |
| LNB with new OFA | 2,157 | $3,509,992 | $1,627 |
| LNB, OFA, and SNCR | 2,509 | $3,968,779 | $1,582 |
| LNB,OFA, and SCR | 3,124 | $7,181,536 | $2,299 |

1. This analysis assumes the facility is current emitting $NO_x$ at the permit limit of 0.7 lb/MMBtu. That is the rate at which CPSI modeled visibility impacts and therefore must be held constant for any analysis based on emission rates.
2. There is a large annualized cost to this existing equipment because it has been assumed that its operation would make the fly ash from the boiler unsellable.

From Table 9.2, it can be seen that ROFA and ROFA with SNCR are inferior options because there is an option (LNB with new OFA) that provides greater annual reduction at a lower annualized cost. ADEQ has eliminated those control options from consideration and the incremental cost effectiveness associated with the remaining control options is as follows (Table 9.3):

| Table 9.3 – Incremental Cost Effectiveness of Remaining Control Options | | |
|---|---|---|
| **Control Option** | **Cost Effectiveness ($/ton $NO_X$)** | **Incremental Cost Effectiveness ($/ additional ton $NO_X$)** |
| OFA | $3,711 | -- |
| LNB | $2,078 | $233 |
| LNB with new OFA | $1,627 | $211 |
| LNB, OFA, and SNCR | $1,582 | $1,303 |
| LNB,OFA, and SCR | $2,299 | $5,224 |

*Energy Impacts*

According to the analysis provided by CPSI, there are adverse energy impacts that require consideration for several of the technically feasible control options. Specifically, CPSI reported that the OFA would require 224 kW of power, the SNCR would require 10 kW, and the SCR would require 377 kW. ADEQ notes that the LNB would require no additional power.

*Non Air-Quality Environmental Impacts*

According to CPSI's analysis, non-air quality impacts may result due to the application of several technically feasible control technologies. Specifically, CPSI stated that due to the potential increase in

the amount of unburnt carbon, the installation of LNB and OFA may have the potential of rendering the fly ash unsellable. If the fly ash were rendered unsellable, the fly ash would increase the amount of solid waste generated at the facility, ultimately increasing the amount sent to the landfill.

In addition to the LNB and OFA technologies, SCR and SNCR have the potential to impact the salability of the fly ash. As noted above, both technologies rely on the injection of ammonia to reduce the formation of $NO_X$. Most SCR and SNCR vendors recommend that the operator inject more than the stoichiometric amount of ammonia to drive $NO_X$ formation to a minimum. This practice results in emissions of ammonia (called ammonia slip). Since the ammonia has an affinity for the fly ash, its presence in the exhaust stream could result the spoiling of the fly ash, leading to increased solid waste from the facility.

*Remaining Useful Life*

None of the documentation submitted by CPSI has indicated that the facility will be shut down in the near future. For the purposes of its analyses, CPSI assumed a typical equipment life of 15 years for calculating the annualized cost of control options. As a result, ADEQ has determined that the remaining useful life of the mill has no effect on this BART analysis.

Step 6: Evaluate Visibility Impacts

As part of its analysis of potential BART options, CPSI estimated the total visibility improvement that is projected to occur should one of the technically-feasible and cost-effective control options be applied. Based upon that information, ADEQ was also able to calculate the average cost effectiveness in terms of dollars per deciview of visibility improvement. CPSI's results are summarized in Table 9.4 below.

**Table 9.4 – Visibility Impacts of Remaining Control Options**

| Control Option | Deciview Improvement* | Cost Effectiveness* ($/Deciview) |
|---|---|---|
| OFA | 0.076 | $42.4 million |
| LNB | 0.164 | $20.7 million |
| LNB with new OFA | 0.207 | $17.0 million |
| LNB, OFA, and SNCR | 0.252 | $15.7 million |
| LNB,OFA, and SCR | 0.309 | $23.2 million |

*Based on visibility effects at most impacted Class I area – Sierra Ancha WA

Step 7: Select BART

Based upon its review of CPSI's analysis, and in particular the marginal visibility impact from the current facility operations and the magnitude of the dollar per deciview costs in Table 9.4 , ADEQ has determined that BART for control of $NO_X$ from Power Boiler #2 is the current emission limit of 0.7 lb/MMBtu.

## D. $SO_X$ BART Analysis and Determination

Step 1: Identify the Existing Control Technologies in Use at the Source

Power Boiler #2 has a $SO_2$ permit limit of 0.8 lb/MMBtu and is controlled with a wet sodium flue gas desulfurization system tray tower scrubber. The scrubber captures 68% of the flue gas and has a control efficiency of 94%. The overall control efficiency of the system is 63.9%.

Step 2: Identify All Available Retrofit Control Options

CPSI has identified two control options as potentially being BART:

- Upgrade the existing scrubber
- Add a second scrubber

**Upgrade the existing scrubber**. When CPSI conducted this analysis, the scrubber on Power Boiler #2 has a control efficiency of 94%. The scrubber control efficiency could be increased to 98% by performing the following upgrades:

- Wash the integral mist eliminators with demineralized water.
- Improve bypass damper control.
- Improve scrubber solution pH control
- Blowdown spent scrubber liquor based on density control rather than the current manual blowdown procedure.
- Add sidewall casing baffles below the recycle spray nozzles and mist eliminators to prevent gas leakage.
- Replace worn and plugged spray nozzles.
- Clean scrubber equipment and piping to remove plugging and buildup.

Increasing the scrubber's control efficiency from 94 to 98% would result in increasing the scrubber's overall control efficiency from 63.9% to 66.6%.

These efficiencies were calculated in 2007 and were based on the historical combustion of McKinley Mine coal with an average sulfur content of 1.1 lb/MMBtu. In 2008, CPSI was forced to switch to Lee Ranch Mine coal due to the closure of the McKinley Mine. The coal now available to CPSI has an average sulfur content of 2.3 lb/MMBtu and the facility has been forced to complete much of the upgraded scrubber project in order to maintain compliance with the 0.8 lb/MMBtu emission limit in its operating permit. As it now represents baseline control, it is no longer appropriate to consider upgrading the scrubber to be an additional control option.

Add a second scrubber. A second scrubber could be added in order to capture 100% of the flue gas at an efficiency of 98%. This would increase the overall control efficiency from 63.9% to 98% control.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that both control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies.

According to the analysis performed by CPSI, the technologically feasible controls are capable of achieving the following emissions rates (Table 9.5):

| Table 9.5 – Control Effectiveness of Control Options | |
|---|---|
| **Control Option** | **Achievable Emissions Rate (lb/MMBtu)** |
| Upgrade Current Scrubber / Baseline Control | 0.80 |
| Add Second Scrubber | 0.044 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Cost of Compliance*

During the course of CPSI's review of the technically feasible control options, the company identified the expected amount of emissions reduced by the application of each control option, as well as the annualized cost and the average cost effectiveness. That information is summarized in Table 9.6 below.

| Table 9.6 – Cost of Compliance of Control Options | | | |
|---|---|---|---|
| **Control Option** | **Expected Emissions Reduction (tpy)** | **Annualized Cost** | **Average Cost Effectiveness ($/ton $SO_2$)** |
| Upgrade Current Scrubber / Baseline Control | 0 | 0 | N/A |
| Add second scrubber | 3,743 | $4,769,365 | $1,274 |

1. This analysis assumes the facility is current emitting $SO_2$ at the permit limit of 0.8 lb/MMBtu. That is the rate at which CPSI modeled visibility impacts and therefore must be held constant for any analysis based on emission rates.

*Energy Impacts*

It is expected that the addition of a second scrubber would increase the amount of energy necessary to overcome the increased pressure drop that would result from the gas moving through the scrubber. CPSI, however, has stated that these energy impacts are expected to be minimal.

*Non Air-Quality Environmental Impacts*

CPSI has stated that the addition of a second scrubber will result in the generation of an additional 8,000 tpy of solid scrubber waste and the additional use of 38 million gallons of water per year.

*Remaining Useful Life*

None of the documentation submitted by CPSI has indicated that the facility will be shut down in the near future. For the purposes of its analyses, CPSI assumed a typical equipment life of 15 years for calculating the annualized cost of control options. As a result, ADEQ has determined that the remaining useful life of the mill has no effect on this BART analysis.

Step 6: Evaluate Visibility Impacts

As part of its analysis of potential BART option, CPSI estimated the total visibility improvement that is projected to occur should one of the technically-feasible and cost-effective control options be applied. Based upon that information, ADEQ was also able to calculate the average cost effectiveness in terms of dollars per deciview of visibility improvement. CPSI's results are summarized in Table 9.7 below.

**Table 9.7 – Visibility Impacts of Control Options**

| Control Option | Deciview Improvement* | Cost Effectiveness* ($/Deciview) |
|---|---|---|
| Add 2nd Scrubber | 0.20 | $23.8 million |

1. Based on visibility effects at most impacted Class I area – Sierra Ancha WA

Step 7: Select BART

Based upon its review of CPSI's analysis, and the all of the considerations listed above, ADEQ has determined that BART for control of $SO_2$ from Power Boiler #2 is the current upgraded scrubber, as defined in Step #2, with an emission limit of 0.80 lb/MMBtu.

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# X. ARIZONA ELECTRIC POWER COOPERATIVE – APACHE GENERATING STATION BART ANALYSIS AND DETERMINATION

## A. Process Description

The Apache Generating Station consists of seven electric generating units (two coal/natural gas-fired steam electric units, a natural gas/fuel oil-fired steam electric, combined cycle unit, and four natural gas/fuel oil-fired turbines) with a total generating capacity of 560 megawatts (MW). The power plant is located approximately 3 miles southeast of the town of Cochise in the Wilcox Basin in Cochise County, Arizona. Apache Steam Unit 1 is a wall-fired steam electric generating unit that can burn natural gas and numbers 2 through 6 fuel oils. The unit is permitted to produce up to a maximum capacity of 85 MW of electricity. Steam Units 2 and 3 are 195 MW natural gas and coal-fired steam electric generating units equipped with dry-bottom turbo-fired coal boilers manufactured by Riley Stoker.

The remaining four units at the Apache Generating Station are simple cycle gas turbines. Steam Unit 1 and Gas Turbine 1 can be operated separately or in a combined cycle configuration.

## B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Apache Generating Station Units 1, 2, 3 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Emissions of visibility impairing pollutants from all BART-eligible emissions units - nitrogen oxides ($NO_X$), sulfur dioxide ($SO_2$), and particulate matter (PM) – are greater than 250 tons per year for each pollutant.

The simple cycle gas turbines at the Apache Generating Station are not BART-eligible, and therefore were not considered as part of this analysis.

## C. Impact on Visibility

CALPUFF modeling was performed at nine Class I areas that are located within 300 kilometers of the Apache Generating Station. Table 10.1 provides the baseline maximum impact on visibility in deciview (98th percentile, 3-year average).

**Table 10.1 – Modeled Baseline Impact on Visibility**

| Affected Class I Area | Unit 1 (dv) | Unit 2 (dv) | Unit 3 (dv) |
|---|---|---|---|
| Chiricahua NM | 2.75 | 2.47 | 2.37 |
| Galiuro Wilderness | 1.58 | 1.92 | 1.75 |
| Saguaro NP | 1.98 | 1.69 | 1.55 |
| Gila Wilderness | 0.45 | 0.76 | 0.69 |
| Superstition | 0.98 | 1.49 | 1.35 |

| Table 10.1 – Modeled Baseline Impact on Visibility | | | |
|---|---|---|---|
| **Affected Class I Area** | **Unit 1 (dv)** | **Unit 2 (dv)** | **Unit 3 (dv)** |
| Wilderness | | | |
| Mt. Baldy Wilderness | 0.32 | 0.45 | 0.41 |
| Sierra Ancha Wilderness | 0.62 | 0.89 | 0.80 |
| Mazatzal Wilderness | 0.81 | 0.85 | 0.76 |
| Pine Mountain Wilderness | 0.68 | 0.68 | 0.61 |

The impact of Units 1, 2, and 3 on the visibility in at least one Class I area is more than 0.5 Deciviews. Therefore, per 40 CFR Part 51, Appendix Y, these units cause or contribute to visibility impairment and are subject-to-BART.

## D. Steam Unit 1 (ST1)

### D.1 $NO_X$ BART Analysis

$NO_X$ formation in fossil fuel-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and fuel characteristics. A $NO_X$ BART analysis was completed for the cases when ST1 burns 100 percent pipeline natural Gas (PNG), 100 percent No. 6 fuel oil (this was done as a test case, as AEPCO has never combusted No. 6 fuel oil in the unit), and 100 percent No. 2 fuel oil.

*Formation of $NO_X$*

During combustion, $NO_X$ forms in three different ways: thermal $NO_X$, fuel $NO_X$, and prompt $NO_X$. When combusting PNG, the most dominant source of $NO_X$ is from thermal $NO_X$, which results from high-temperature fixation of atmospheric nitrogen in the combustion air. Because PNG generally contains small quantities of nitrogen, the overall contribution from fuel $NO_X$ is small, whereas a significant amount of fuel $NO_X$ can be generated from fuel oil combustion. A very small amount of $NO_X$ is called "prompt" $NO_X$. Prompt $NO_X$ results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no $NO_X$ emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate $NO_X$ control technologies with practical potential for application to ST1, including those control technologies identified as BACT or LAER by permitting

agencies across the United States. ST1 $NO_X$ emissions are currently controlled through the use of good combustion practices.

The following potential $NO_X$ control technology options were considered:

- New LNBs with OFA
- Flue Gas Recirculation (FGR)
- Rotating Opposed Fire Air (ROFA)
- LNBs with selective non-catalytic reduction system (SNCR and Rotamix)
- LNBs with selective catalytic reduction system (SCR)
- Neural Net Controls

**New LNBs with OFA System**. The mechanism used to lower $NO_X$ with LNBs is to stage the combustion process and provide a fuel-rich condition in the initial stages of combustion; this is so oxygen needed for combustion is not diverted to combine with nitrogen resulting in the formation of $NO_X$. Fuel-rich conditions favor the conversion of fuel nitrogen to nitrogen dioxide (N2) instead of $NO_X$. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char, or remaining uncombusted fuel. Both LNBs and OFA are considered to be a capital cost, combustion technology retrofit that may require water wall tube replacement.

**FGR**. FGR generally extracts flue gas from downstream of the economizer or air heater and is mixed into the combustion air duct. This recirculation can be achieved with a new FGR fan or by using the existing forced-draft fan to inject the flue gas into the combustion air (induced flue gas recirculation [IFGR]). Flue gas recirculation adds oxygen-lean, heat-absorbing mass to the combustion air, thus lowering the combustion temperature and reducing thermal NOx emissions.

**ROFA**. Mobotec markets ROFA as an improved, second-generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively."

A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes. Mobotec would propose one 700 horsepower fan for ST1. Mobotec's budgetary proposals included expected NOx emission rates for PNG and No. 2 and No. 6 fuel oils, and are presented in Table 2. While a typical installation does not require modifying an installed LNB system, and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. Although not specifically identified, Mobotec generally includes bent tube assemblies for OFA port installation if required. Mobotec does not provide installation services, because they believe that the owner can more cost-effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

**SNCR**. SNCR is generally used to achieve modest NOx reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces $NO_X$ to nitrogen and water. $NO_X$ reductions of up to 60 percent have been achieved, although 20 to 40 percent is a more realistic expectation for most applications. Reagent utilization, which is a measure of the efficiency with which the reagent reduces $NO_X$, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low-reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create

problems downstream. Typical problems include rendering the fly ash unsellable, reacting with sulfur to foul heat exchange surfaces, or creating a visible stack plume. Reagent utilization can have a significant impact on economics in that each incrementally higher level of $NO_X$ reduction generally results in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet $NO_X$) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. Budgetary proposals were received from Mobotec for their Rotamix system, and previous Fuel Tech proposal information for other projects was used.

**SCR**. SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia is injected into the flue-gas stream, where it reduces $NO_X$ to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580°F and 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower $NO_X$ emissions.

**Neural Net Controls**. Information regarding neural net controls was received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NOx reduction. NeuCo stated that these products can be used on most control systems and can be effective even in conjunction with other $NO_X$ reduction technologies. NeuCo predicts that CombustionOpt can reduce $NO_X$ by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Because NeuCo does not guarantee $NO_X$ reduction, ADEQ has determined that the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a supplementary or "polishing" technology, but not on a "stand-alone" basis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.2 lists the various control technologies and estimated emissions rates.

**Table 10.2 – $NO_X$ Control Technology Emission Rate Ranking**

| Technology | Source of Estimated Emissions | Estimated Emission Rate[4] (PNG) | Estimated Emission Rate (No. 6 Fuel Oil)[d] | Estimated Emission Rate (No. 2 Fuel Oil)[d] |
|---|---|---|---|---|
| LNB with FGR[e] | Coen | 0.056 | 0.15 | 0.06 |
| ROFA[b] | Mobotec | 0.08 | 0.16 | 0.08 |
| ROFA with Rotamix[b] | Mobotec | 0.06 | 0.11 | 0.06 |
| LNB with FGR, SNCR | Coen & Fuel Tech | 0.06[c] | 0.11[c] | 0.05[c] |
| SCR[a] | CH2M Hill | 0.07 | 0.07 | 0.07 |

[a] SCR estimated $NO_X$ emissions rate is the same for all scenarios. Operating cost would be affected by inlet $NO_X$ levels.
[b] Calculated from Mobotec proposal information fuel baselines (47 percent reduction for ROFA and additional 30 percent for Rotamix)
[c] From Previous Fuel Tech Proposal at 25 percent reduction
[d] Results are in lb/MMBtu
[e] From Coen Proposal

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

*Energy Impacts*

Installation of LNBs is not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies will not have energy impacts. The Mobotec ROFA system requires installation and operation of one 700 horsepower ROFA fan (522 kilowatts [kW] total). An estimated auxiliary power requirement for an SNCR system for an 85-MW (with the 10-MW combustion turbine included) unit is estimated at 85 kW. The same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

*Environmental Impacts*

Environmental impacts associated with SCR and SNCR involve the hazards associated with the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

*Economic Impacts*

Costs and emissions estimates for the LNBs, SNCR, and SCR were obtained from equipment vendors. Costs for the ROFA and Rotamix systems were obtained from Mobotec. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of $NO_X$ removed is summarized in Table 10.3. The capital costs shown in Table 3 are applicable for all of the fuels under consideration, and No. 6 fuel oil was used as the basis to determine worst-case emission levels. For example, if LNBs are installed for PNG, the burner costs include the capability to burn both PNG and No. 2 and 6 fuel oils (with only minor equipment modification, atomization changes, and burner control revisions). Similarly, the cost information for any of the $NO_X$ reduction technologies listed in Table 3 will apply for the fuel alternatives under consideration. Costs for LNBs are presented with FGR because this scenario is representative of current operation of ST1 when it is operated in combined cycle with Gas Turbine #1. Costs for LNBs without FGR would be lower. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

| Table 10.3: $NO_x$ Control Cost Comparison | | | | | |
|---|---|---|---|---|---|
| **Factor** | **ROFA[c]** | **LNB with FGR** | **LNB with FGR & SNCR[b]** | **ROFA with Rotamix** | **LNB with SCR[a]** |
| Total installed capital cost (Million $) | $2.700 | $1.184 | $4.584 | $4.457 | $25.50 |
| Total installed capital cost + additional owner costs (Million $) | $4.725 | $2.072 | $5.730 | $7.800 | $31.88 |
| Total first year fixed and variable O&M costs (Million $) | $0.145 | $0.204 | $0.116 | $0.195 | $0.346 |
| Total first year annualized cost | $0.939 | $0.552 | $1.079 | $1.506 | $5.705 |
| Power consumption (MW) | 0.52 | 0.85 | 0.09 | 0.52 | 0.43 |
| Annual power usage (Million kW-hr/yr) | 1.9 | 3.1 | 0.3 | 1.9 | 1.5 |
| NOx design control efficiency | 46.8% | 50.2% | 63.5% | 63.5% | 76.7% |
| Tons NOx removed per year | 278 | 297 | 376 | 376 | 455 |
| First year average control cost ($/ton removed) | $3,382 | $1,856 | $2,870 | $4,004 | $12,542 |
| Incremental control cost ($/ton removed) | -$19,659 | $1,856 | $1,425 | ---[d] | $53,311 |

[a] Based on $300 per kW SCR factored estimate for 85 megawatts
[b] Based on $40 per kW SNCR factored estimate for 85 megawatts
[c] ROFA has a negative incremental control cost because when compared with LNB with FGR the technology costs more and removes less tons of $NO_x$
[d] The incremental control cost for ROFA with Rotamix when compared with LNB with FGR and SNCR results in a non number as the two technologies have the same $NO_x$ removal in tons per year

Step 6: Evaluate Visibility Impacts

Table 10.4 below shows the total deciview reduction for the most impacted Class I area. For ST1, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

| Table 10.4 – Control Technologies and Respective Deciview Reduction | | | |
|---|---|---|---|
| **Control** | **Deciview Reduction** | **Total Annualized Cost (Million $)** | **Cost per deciview reduced (Million $/deciview reduced)** |
| LNB with FGR | 0.194 | 0.552 | 2.845 |
| ROFA | 0.256 | 0.939 | 3.668 |
| ROFA with Rotamix | 0.240 | 1.506 | 6.274 |

| Table 10.4 – Control Technologies and Respective Deciview Reduction | | | |
|---|---|---|---|
| **Control** | **Deciview Reduction** | **Total Annualized Cost (Million $)** | **Cost per deciview reduced (Million $/deciview reduced)** |
| LNB with FGR and SNCR | 0.240 | 1.079 | 4.497 |
| SCR | 0.409 | 5.705 | 13.948 |

Step 7: BART Determination

After review reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for $NO_X$ is the installation of LNB with FGR (which will also burn No. 2 fuel oil with minor equipment change out) with a $NO_X$ emissions limit of 0.056 lb/MMBtu when burning PNG, and 0.06 lb/MMBtu when burning No. 2 fuel oil. It should be noted that the proposed BART limit for ST1 will apply when ST1 operates alone or if ST1 and GT1 are operated as a combined cycle operation. The proposed BART limit does not apply to (a) GT1 in stand-alone simple cycle operation or (b) ST1/GT1 when ST1 burners are shut off and ST1 is not producing electricity.

## D.2 $PM_{10}$ BART Analysis

The $PM_{10}$ BART analysis is only completed for the case when ST1 burns 100 percent No. 6 fuel oil. This was done for comparison only, as AEPCO has never combusted No. 6 fuel oil in the unit).

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

The following retrofit control technologies have been identified for $PM_{10}$ control on ST1:

- Use of low-sulfur fuel oil (No. 2 fuel oil)
- Switch to PNG
- New LNBs/particulate matter burner
- Dry electrostatic precipitator (ESP)
- Wet ESP
- Fabric filter

**Low Sulfur Distillate Oil**. Particulate matter emissions would be reduced with the switching of fuel oil grades from No. 6 to No. 2. $PM_{10}$ emissions while burning No. 2 fuel oil are estimated at 0.0143 lb/MMBtu.

**Switch to PNG.** Expected $PM_{10}$ emissions when burning PNG are estimated at 0.0075 lb/MMBtu.

**New LNBs/Particulate Matter Burner.** With the Coen LNB, particulate matter emissions are also reduced. From the budgetary information received from Coen, particulate matter emissions are estimated at less than 0.03 lb/MMBtu and 0.0015 lb/MMBtu while burning No. 6 fuel oil (with LNB and IFGR), and No. 2 fuel oil (LNB), respectively.

**Dry ESP**. A dry ESP operates by first placing a charge on the particulates though a series of electrodes, and then capturing the charged particulates on collection plates. While an ESP can be designed for high-particulate removal, operation is susceptible to particle resistivity, which denotes a collected particle's ability to ultimately discharge to the collection plate. Low-resistivity particles can be easily charged but may quickly lose their charge at the collection plate and tend to be re-entrained into the flue gas stream. Higher resistivity particles may form a "back corona," which is caused by a layer of non-conductive particles being formed on the collection plate. Back corona may prevent other charged gas stream particles from migrating to the collection plate. Particle resistivity is also influenced by flue gas temperature. ESP sizing is in large part determined by particulate size, with larger ESP size required when smaller particulates are expected. In addition, the particulates from an oil-fired unit tend to be small and sticky, and if a Spray Dryer Absorber is used for $SO_2$ reduction, there will be a greatly increased inlet particulate loading to the ESP. Because of the uncertainty in chemical and physical characteristics of the oil-fired particulate, ADEQ determined that a dry ESP is not a good technological match for ST1.

**Wet ESP.** While wet ESP operation is similar to the dry ESP through the charging and collection of flue gas particulates, the wet technology has significant advantages. The wet ESP is not sensitive to particulate resistivity and can accommodate changes in particulate loading more easily than a dry ESP. Collection plates can be created from metal or fabric, and the collected particulate is washed off the plates with water.

Wet ESPs have successfully been demonstrated on similar oil particulate or chemical mist applications. However, flue gas leaving the wet ESP will be saturated and may result in a visual steam plume exiting the stack. The wet ESP will use water to collect and remove the particulates, and will produce a wastewater byproduct. While the wet ESP $PM_{10}$ emission level is estimated to be similar to a fabric filter without SDA operation, increased particulate loading from an SDA may not allow a wet ESP to meet required collection efficiency. Therefore, ADEQ has determined that a wet ESP is not a technically acceptable alternative when matched with an SDA.

**Fabric Filter.** Fabric filter technology achieves particulate reduction through the filtration of the flue gas through filter bags. The collected particles are periodically removed from the bag through a pulse jet or reverse flow mechanism. A pulse jet filtration system would likely be selected for installation on ST1, because this fabric filter technology results in lower capital cost and a smaller required footprint.

Because of the somewhat sticky particles produced during oil firing, using an appropriate fabric or coating bags with a suitable pre-coat material is imperative. If fabric bags become "blinded" by allowing hard-to-remove particulates to become embedded in the fabric structure, total bag replacement may be necessary. Blinded bags will continue to provide excellent filtration efficiencies; however, the pressure drop across the fabric may exceed system draft capability.

ADEQ has determined that while a fabric filter is not an acceptable alternative for particulate matter/$PM_{10}$ emissions control for an oil-fired unit without using a coating material for the bags, it is anticipated to function satisfactorily with a pre-coat and the increased particulate loading from the SDA operation.

<u>Step 3: Eliminate All Technically Infeasible Control Options</u>

ADEQ has determined that all of the identified control technologies are technically feasible, with the exception of wet and dry ESPs, for the reasons discussed in Step 1 above.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

ST1 particulate matter emissions are currently estimated at 0.0737 lb/MMBtu while burning No. 6 fuel oil. The BART $PM_{10}$ analysis will be completed only for the case of firing 100 percent No. 6 fuel oil. The $PM_{10}$ control technology emission rates are summarized in Table 10.5. No capital costs are associated with switching to PNG.

**Table 10.5 – $PM_{10}$ Control Technology Emission Rates**

| Control Technology | Expected $PM_{10}$ Emission Rate (lb/MMBtu) |
|---|---|
| Current Baseline | 0.0737 |
| Fabric Filter | 0.015 |
| New LNB[a] | 0.0015 |
| Switch to PNG | 0.0075 |

[a] When burning No. 2 fuel oil

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

*Energy Impacts*

No additional energy impact is expected from $PM_{10}$ reduction as a result of a new LNBs/particulate matter burner retrofit or burning of low-sulfur fuel oil. A fabric filter and ductwork will add an estimated 6 to 8 inches of water pressure drop to the system and additional electrical load requirements.

*Environmental Impacts*

There are no negative environmental impacts from the usage of new LNBs/particulate matter burners, switching to low-sulfur diesel fuel, or using a fabric filter.

*Economic Impacts*

A summary of the costs and particulate matter removed for the alternatives is recorded in Table 6.

**Table 10.6 – Particulate Matter Control Cost Comparison***

| Factor | Fabric Filter | Switch to PNG | Switch to Low-Sulfur Fuel |
|---|---|---|---|
| Total installed capital costs | $20,000,000[a] | $0 | $1,000,000[b] |

| Table 10.6 – Particulate Matter Control Cost Comparison* | | | |
|---|---|---|---|
| **Factor** | **Fabric Filter** | **Switch to PNG** | **Switch to Low-Sulfur Fuel** |
| Total first year fixed and variable O&M costs | $253,592 | -- | -- |
| Total first year annualized cost | $3,615,938 | -- | -- |
| Power consumption (MW) | 0.40 | -- | -- |
| Annual power usage (Million kW-hr/year) | 1.4 | -- | -- |
| Particulate matter design control efficiency | 79.6% | -- | -- |
| Tons particulate matter removed per year | 116 | -- | -- |
| First year average control cost ($/ton particulate matter removed) | $24,916 | -- | -- |
| Incremental control cost ($/ton particulate matter removed) | $31,284 | -- | -- |

* LNB costs included in NOx BART analysis
[a] Based on vendor cost information
[b] From CH2M HILL database

Step 6: Evaluate Visibility Impacts

Improvements in visibility due to $PM_{10}$ controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without $PM_{10}$ controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis, and based upon the information above ADEQ has determined that, for Unit 1, BART for $PM_{10}$ is the use of PNG or No. 2 fuel oil with a $PM_{10}$ emissions limit of 0.0075 lb/MMBtu when burning PNG, and 0.0015 lb/MMBtu when burning No. 2 fuel oil. This BART determination represents no change from the current operating scenario. It should be noted that the proposed BART limit for ST1 will apply when ST1 operates alone or if ST1 and GT1 are operated as a combined cycle operation. The proposed BART limit does not apply to (a) GT1 in stand-alone simple cycle operation or (b) ST1/GT1 when ST1 burners are shut off and ST1 is not producing electricity.

### D.3 $SO_2$ BART Analysis

$SO_2$ forms in the boiler during the combustion process and is primarily dependent on natural gas and fuel oil sulfur content. Emissions indicate that BART analysis is not required when ST1 burns PNG or fuel oil No. 2. Thus, the analysis in this section is limited to the case when ST1 is burning No. 6 fuel oil.

The EPA BART guidelines require that oil-fired units consider limiting the sulfur content of the fuel oil burned. Because current requirements for low-sulfur diesel fuel limit sulfur content to 0.05 percent, fuel switching will be analyzed as an $SO_2$ option for this study. Also, a dry FGD system with $SO_2$ reduction capability similar to the fuel switch option will be considered.

Step 1: Identify the Existing Control Technologies in Use at the Source

There is no $SO_2$ emissions control equipment installed on ST1.

Step 2: Identify All Available Retrofit Control Options

A broad range of information sources was reviewed in an effort to identify potentially applicable emission control technologies for $SO_2$ at ST1, including control technologies identified as BACT or LAER by permitting agencies across the United States.

Following elimination of the PNG and fuel oil No. 2 BART engineering analysis after RLBC database review, the following potential $SO_2$ control technology options were considered for application when ST1 burns fuel oil No. 6:

- Use of low-sulfur distillate oil (No. 2 fuel oil)
- Switch to PNG
- SDA

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.7 lists the various control technologies and estimated emissions rates.

**Table 10.7 – Control Technology Options Evaluated**

| Technology | Expected Emission Rate (lb/MMBtu) | Estimated Cost (Millions $) |
|---|---|---|
| Current Baseline with No. 6 Fuel Oil | 0.906 | -- |
| Low-Sulfur Fuel Oil | 0.051 | 0 |
| SDA | 0.10 | 20 |
| PNG | 0.00064 | 0 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

*Energy Impacts*

There is no energy impact associated with switching to low-sulfur diesel fuel; however, additional system pressure drop equivalent to 0.4 MW at a first-year cost of $71,832 will result from the installation of an SDA.

*Environmental Impacts*

There is no environmental impact associated with switching to low-sulfur diesel fuel. An SDA system generates solid waste requiring disposal.

*Economic Impacts*

A summary of the costs and amount of $SO_2$ removed for fuel switching is provided in Table 10.8. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

**Table 10.8 – $SO_2$ Control Costs**

| Factor | SDA | Switch to PNG | Switch to Low-Sulfur Fuel |
|---|---|---|---|
| Total installed capital costs | $20,000,000[a] | $0 | $0 |
| Total first year fixed and variable O&M costs | $519,359 | -- | -- |
| Total first year annualized cost | $3,811,706 | -- | -- |
| Power consumption (MW) | 0.40 | -- | -- |
| Annual power usage (Million kW-hr/year) | 1.4 | -- | -- |
| $SO_2$ design control efficiency | 89.0% | 99.9% | 91% |
| Tons $SO_2$ removed per year | 1,587 | -- | -- |
| First year average control cost ($/ton $SO_2$ removed) | 2,446 | -- | -- |
| Incremental control cost ($/ton $SO_2$ removed) | 2,446 | -- | -- |

[a] Based on vendor cost information

Step 6: Evaluate Visibility Impacts

Improvements to deciview impacts from $SO_2$ controls are minimal relative to uncontrolled emissions while combusting No. 6 fuel oil. In addition, the incremental costs related to adding a fabric filter and SDA are high. Impacts from the combustion of No. 2 fuel oil or natural gas without $SO_2$ controls are expected to be less than those from the combustion of No. 6 fuel oil with emission controls.

Step 7: BART Determination

After reviewing the company's BART analysis and based upon the information above, ADEQ has determined that, for Unit 1, BART for $SO_2$ is the use of PNG or No. 2 fuel oil with an $SO_2$ emissions limit of 0.00064 lb/MMBtu when burning PNG, and 0.051 lb/MMBtu when burning No. 2 fuel oil. It should be

noted that the proposed BART limit for ST1 will apply when ST1 operates alone or if ST1 and GT1 are operated as a combined cycle operation. The proposed BART limit does not apply to (a) GT1 in stand-alone simple cycle operation or (b) ST1/GT1 when ST1 burners are shut off and ST1 is not producing electricity.

## E. Steam Units 2 and 3

Steam Units 2 and 3 are substantially similar in design, construction and electrical output. While there are physical differences between the two units that will result in different costs for the same control technology, the overall differences were determined to be minimal. As a result, ADEQ has determined that it is appropriate to consider BART for both Units in a single section.

### E.1 $NO_X$ BART Analysis

During coal combustion, $NO_X$ forms in three ways. The dominant source of $NO_X$ formation is the oxidation of fuel-bound nitrogen (fuel $NO_X$). During combustion, part of the fuel $NO_X$ is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and $NO_2$) and partially reduced to molecular nitrogen ($N_2$). A smaller part of $NO_X$ formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal $NO_X$). A very small amount of $NO_X$ is called "prompt" $NO_X$. Prompt $NO_X$ results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 currently use over-fired air (OFA) and under-fired air systems to control $NO_X$ emissions.

Step 2: Identify All Available Retrofit Control Options

The second step of the BART process is to evaluate $NO_X$ control technologies with practical potential for application to Units 2 and 3, including those control technologies identified as Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) by permitting agencies across the United States. Both Steam Unit 2 and 3 $NO_X$ emissions are currently controlled through the use of OFA and UFA systems added to the burners. The Units are dry turbo-fired boilers, with 12 Riley directional flame burners. The following potential $NO_X$ control technology options were considered:

- New/modified state-of-the-art LNBs with advanced OFA
- Rotating opposed fire air (ROFA)
- Selective non-catalytic reduction system (Rotamix and SNCR)
- Selective catalytic reduction (SCR) system
- Neural Network Controls/Boiler Combustion Controls (Neural Net)

**New LNBs with OFA System.** The mechanism used to lower $NO_X$ with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form $NO_X$. Fuel-rich conditions favor the conversion of fuel bound nitrogen to $N_2$ instead of $NO_X$. Additional air (OFA or UFA) is then introduced upstream or downstream in a lower temperature zone to burn out the char.

**ROFA.** Mobotec markets ROFA as an improved second generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles." Rotation is reported to prevent laminar flow and improve gas mixing, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. Mobotec expects that enhanced mixing will also result in reduction in hot and cold furnace zones, improved heat absorption and boiler efficiency, and lower carbon monoxide (CO) and $NO_X$ emissions. A typical ROFA installation will have a booster fan(s) to supply the high-velocity air to the ROFA boxes. Mobotec proposed one 2,100 horsepower fan for each unit, which would provide hot air at all boiler loads.

**SNCR.** With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100 °F, where it reduces $NO_X$ to nitrogen and water. $NO_X$ reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is a more realistic expectation for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces $NO_X$, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. Problems include rendering fly ash unsellable, and also reacting with sulfur to form ammonium bisulphate, which can foul heat exchanger surfaces or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of $NO_X$ reduction generally resulting in higher reagent utilization and higher operating cost. Reductions from higher baseline inlet $NO_X$ concentrations are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption.

**SCR.** SCR works on the same chemical principle as SNCR but instead uses a catalyst to promote the chemical reaction. Ammonia or urea is injected into the flue-gas stream, where it reduces $NO_X$ to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F to 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower $NO_X$ emissions. One type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. However, for Units 2 and 3 the SCR could be installed after the hot-side ESP and before the air heater. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher $NO_X$ removal rate, a full-scale SCR was used as the basis for analysis at Units 2 and 3.

**Neural Net Controls/Boiler Combustion Control.** Review of neural net and improved boiler combustion control are combined for purposes of this analysis under the potential implementation of neural net boiler control system. Information regarding neural net controls was provided by NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for $NO_X$ reduction. NeuCo stated these products can be used on most control systems, and can be effective even in conjunction with other $NO_X$ reduction technologies. NeuCo predicts that CombustionOpt can reduce $NO_X$ by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.9 lists the various control technologies and estimated emissions rates.

| Table 10.9 – Control Technology and Respective Emission Rates | |
|---|---|
| **Control Technology** | **Expected $NO_X$ Emission Rate** |
| Neural Net/Boiler Combustion Control | 15% reduction |
| New LNBs with OFA System | 0.31 lb/MMBtu |
| ROFA | 0.26 lb/MMBtu |
| SNCR | 0.18 lb/MMBtu |
| SCR | 0.07 lb/MMBtu |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

*Energy Impacts*

Installation of LNBs and modification to the existing OFA and UFA systems are not expected to significantly impact the boiler efficiency or forced-draft fan power usage. Therefore, these technologies are not expected to have significant energy impacts.

The Mobotec ROFA system requires installation and operation of one 2,100 horsepower ROFA fan (1,566 kilowatts [kW] total) for each unit. Fuel Tech provided an estimate of 130 kW of additional auxiliary power, and the same estimate was used for Rotamix. SCR retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase.

*Non-Air Quality Environmental Impacts*

Mobotec generally predicts that CO emissions, and unburned carbon in the ash, commonly referred to as loss on ignition (LOI), would be the same or lower than prior levels for the ROFA system.

SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels. Other environmental impacts involve the potential public and employee safety hazard associated with the storage of ammonia, especially anhydrous ammonia, and the transportation of the ammonia to the power plant site.

*Economic Impacts*

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of $NO_X$ removed is summarized in Table 10.10 for Unit 2 and Table 10.11 for Unit 3. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

**Table 10.10 – Control Technology Efficiency and Costs for Unit 2**

| Factor | LNB with OFA | ROFA | ROFA with Rotamix | LNB with OFA and SNCR | LNB with OFA and SCR |
|---|---|---|---|---|---|
| Major Materials Design Costs (Million $) | $2.000 | $3.627 | $5.441 | $6.830 | $29.30 |
| Total Installed Capital Costs (Million $) | $4.760 | $9.616 | $12.63 | $12.54 | $48.74 |
| Total First Year Fixed and Variable Costs (Million $) | $0.080 | $0.750 | $1.024 | $0.545 | $1.466 |
| Total First Year Annualized Cost (Million $) | $0.533 | $1.664 | $2.225 | $1.738 | $6.102 |
| Power Consumption (MW) | - | 1.57 | 2.07 | 0.50 | 1.00 |
| Annual Power Usage (Kilowatt-Hr/Year) | - | 12.6 | 16.6 | 4.0 | 8.0 |
| $NO_X$ Design Control Efficiency | 34.2% | 44.8% | 61.8% | 51.2% | 85.1% |
| Tons of $NO_X$ Removed | 1,305 | 1,710 | 2,358 | 1,953 | 3,250 |
| Average Cost ($/ton) | $408 | $973 | $944 | $890 | $1,878 |
| Incremental Cost ($/ton) | $408 | $2,793 | $1,203 | $301 | $4,350 |

| Table 10.11: Control Technology Efficiency and Costs for Unit 3 | | | | | |
|---|---|---|---|---|---|
| **Factor** | **LNB with OFA** | **ROFA** | **ROFA with Rotamix** | **LNB with OFA and SNCR** | **LNB with OFA and SCR** |
| Major Materials Design Costs (Million $) | $2.000 | $3.627 | $5.441 | $6.830 | $29.30 |
| Total Installed Capital Costs (Million $) | $4.760 | $9.616 | $12.62 | $12.54 | $48.74 |
| Total First Year Fixed and Variable Costs (Million $) | $0.080 | $0.719 | $0.981 | $0.525 | $1.426 |
| Total First Year Annualized Cost (Million $) | $0.533 | $1.634 | $2.182 | $1.718 | $6.062 |
| Power Consumption (MW) | - | 1.57 | 2.07 | 0.50 | 1.00 |
| Annual Power Usage (Kilowatt-Hr/Year) | - | 12.0 | 15.8 | 3.8 | 7.7 |
| $NO_X$ Design Control Efficiency | 27.9% | 39.5% | 58.1% | 46.5% | 83.7% |
| Tons of $NO_X$ Removed | 926 | 1,312 | 1,929 | 1,543 | 2,778 |
| Average Cost ($/ton) | $575 | $1,246 | $1,131 | $1,113 | $2,183 |
| Incremental Cost ($/ton) | $575 | $2,855 | $1,203 | $360 | $4,572 |

Step 6: Evaluate Visibility Impacts

Tables 10.12 and 10.13 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

| Table 10.12 – Control Technology and Visibility Impact Reduction for Unit 2 | | | | |
|---|---|---|---|---|
| **Control** | **Deciview Reduction** | **Total Annualized Cost (Million $)** | **Cost per deciview reduced (Million $/dv)** | **Average Cost ($/ton)** |
| Neural Net/Boiler Combustion Control | Unknown | Unknown | Unknown | Unknown |
| New LNB with OFA System | 0.267 | $0.533 | $1.996 | $408 |
| ROFA | 0.359 | $1.664 | $4.636 | $973 |
| ROFA with Rotamix | 0.491 | $2.225 | $4.532 | $944 |
| LNB with OFA and SNCR | 0.416 | $1.738 | $4.177 | $890 |
| LNB with OFA and SCR | 0.676 | $6.103 | $9.028 | $1,878 |

| Table 10.13 – Control Technology and Visibility Impact Reduction for Unit 3 | | | | |
|---|---|---|---|---|
| **Control** | **Deciview Reduction** | **Total Annualized Cost (Million $)** | **Cost per Deciview Reduced (Million** | **Average Cost ($/ton)** |

| | | | $/dv) | |
|---|---|---|---|---|
| Neural Net/Boiler Combustion Control | Unknown | Unknown | Unknown | Unknown |
| New LNB with OFA System | 0.206 | $0.533 | $2.586 | $575 |
| ROFA | 0.298 | $1.634 | $5.484 | $1,246 |
| ROFA with Rotamix | 0.436 | $2.182 | $5.004 | $1,131 |
| LNB with OFA and SNCR | 0.356 | $1.718 | $4.825 | $1,113 |
| LNB with OFA and SCR | 0.633 | $6.062 | $9.577 | $2,183 |

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that, for Units 2 and 3 BART for $NO_X$ is new LNBs with OFA system with a $NO_X$ emissions limit of 0.31 lb/MMBtu for both Units 2 and 3.

## E.2 $PM_{10}$ BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

Both Steam Units 2 and 3 are currently equipped with hot-side Electrostatic Precipitators (ESPs).

Step 2: Identify All Available Retrofit Control Options

Steam Units 2 and 3 are currently equipped with hot-side ESPs. Historically, outlet ESP particulate emissions on Units 2 and 3 have ranged from approximately 0.007 to 0.045 lb/MMBtu. This wide range in outlet emissions can in part be attributed to the hot-side operation, as well as the wide variety of coals being burned in the boilers. Hot-side ESP effectiveness may also be impacted by sodium content in the ash.

Three retrofit control technologies have been identified for additional particulate matter control:

- Performance upgrades to existing hot-side ESP
- Replace current ESP with a fabric filter unit
- Install a polishing fabric filter after ESP

**Performance Upgrades.** Modifications to the hot-side ESPs, such as improving the rapping system, controller upgrades, conversion to cold-side operation, flue gas conditioning, wide plate spacing, addition of particle pre-charging system, etc., could be implemented to improve ESP particulate collection efficiency.

**Replace Current ESP with a Fabric Filter Unit.** Full-size pulse jet fabric filters could be installed as a replacement for the existing ESPs on Units 2 and 3. These fabric filters would be sized for approximately 3.5 or 4:1 Air to Cloth (A/C) ratio (actual cubic feet per minute of flue gas per square foot of fabric). An A/C ratio of 4:1 was used for this analysis. Fabric filters have been proven to provide highly effective

and consistent particulate emissions reduction, with outlet emissions of approximately 0.015 lb/MMBtu. The ESPs would be removed from service with these replacement fabric filters.

**Install a Polishing Fabric Filter.** A polishing fabric filter could be added downstream of the existing ESPs on Units 2 and 3. One such technology is licensed by the Electric Power Research Institute, and referred to as a COHPAC (Compact Hybrid Particulate Collector). The COHPAC collects the ash that is not collected by the ESP, thus acting as a polishing device. The ESPs would be kept in service for the COHPAC fabric filter to operate effectively.

The COHPAC fabric filter is about one-half to two-thirds the size of a full-size fabric filter. Because the COHPAC has a higher A/C ratio (as high as 6 to 8:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1), an A/C ratio of 6:1 was used for this analysis.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

Table 10.14 lists the various control technologies and estimated emissions rates.

**Table 10.14 – Control Technology and Respective Emission Rates**

| Control Technology | Expected $PM_{10}$ Emission Rate |
|---|---|
| ESP Upgrades | 0.03 lb/MMBtu |
| Full size fabric filter | 0.015 lb/MMBtu |
| Polishing Fabric Filter | 0.015 lb/MMBtu |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

This step involves the consideration of energy, non-air quality environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

*Energy Impacts*

Energy is required to overcome the additional pressure drop from both the fabric filter replacement and COHPAC fabric filter, and associated ductwork. Therefore, fan upgrades may be required for both alternatives to overcome the additional pressure drop. An estimated 6 to 8 inches of water pressure drop for the replacement fabric filter may be experienced, with 8 to 10 inches of water pressure drop likely for

the COHPAC unit. The polishing fabric filter will also result in maintaining the existing ESP in service, which will result in power consumption in addition to what is required by the fabric filter replacement option.

COHPAC fabric filters on Units 2 and 3 would require approximately 1.3 MW of power each.

Energy impacts from ESP upgrades are unknown and would vary depending on the precipitator upgrade applied.

*Non-Air Quality Environmental Impacts*

There are no negative environmental impacts from precipitator upgrades, the addition of a replacement or COHPAC polishing fabric filter.

*Economic Impacts*

A comparison of the costs and $PM_{10}$ removed for a replacement fabric filter or COHPAC polishing fabric filter are shown in Table 10.15 and 10.16 for Units 2 and 3 respectively. Specific costs for the precipitator upgrades were not evaluated as AEPCO has yet to evaluate the upgrades that may be applicable to Units 2 and 3. Capital cost information was provided by Alstom for both the polishing and replacement fabric filters. The complete Economic Analysis is contained in Appendix A of the AEPCO BART submittal.

**Table 10.15 – Control Technology Efficiency and Costs for Unit 2**

| Factor | ESP Upgrades | Polishing Fabric Filter | Full Size Fabric Filter |
|---|---|---|---|
| Major Materials Design Costs | Unknown | $6,666,667 | $10,000,000 |
| Total Installed Capital Costs | Unknown | $15,866,667 | $23,800,000 |
| Total First Year Fixed and Variable Costs | Unknown | $708,050 | $623,824 |
| Total First Year Annualized Cost | Unknown | $2,217,411 | $2,887,867 |
| Power Consumption (MW) | Unknown | 1.30 | 1.00 |
| Annual Power Usage (Kilowatt-Hr/Year) | Unknown | 10.5 | 8.0 |
| $PM_{10}$ Design Control Efficiency | Unknown | 66.67% | 66.67% |
| Tons of $PM_{10}$ Removed | Unknown | 243 | 243 |
| Average Cost ($/ton) | Unknown | $9,121 | $11,878 |
| Incremental Cost ($/ton) | Unknown | $9,121 | $11,878 |

**Table 10.16 – Control Technology Efficiency and Costs for Unit 3**

| Factor | ESP Upgrades | Polishing Fabric Filter | Full Size Fabric Filter |
|---|---|---|---|

| | | | |
|---|---|---|---|
| Major Materials Design Costs | Unknown | $6,666,667 | $10,000,000 |
| Total Installed Capital Costs | Unknown | $15,866,667 | $23,800,000 |
| Total First Year Fixed and Variable Costs | Unknown | $682,996 | $604,552 |
| Total First Year Annualized Cost | Unknown | $2,192,357 | $2,868,595 |
| Power Consumption (MW) | Unknown | 1.30 | 1.00 |
| Annual Power Usage (Kilowatt-Hr/Year) | Unknown | 10.0 | 7.7 |
| $PM_{10}$ Design Control Efficiency | Unknown | 66.67% | 66.67% |
| Tons of $PM_{10}$ Removed | Unknown | 231 | 231 |
| Average Cost ($/ton) | Unknown | $9,471 | $12,393 |
| Incremental Cost ($/ton) | Unknown | $9,471 | $12,393 |

Step 6: Evaluate Visibility Impacts

Tables 10.17 and 10.18 below show the total deciview reduction for the most impacted Class I area for Units 2 and 3 respectively. For Units 2 and 3, the most impacted Class I area is the Chiricahua Wilderness Area and National Monument.

**Table 10.17 – Control Technology and Visibility Impact Reduction for Unit 2**

| Control | Deciview Reduction | Total Annualized Cost (Million $) | Cost per Deciview Reduced (Million $/dv) | Average Cost ($/ton) |
|---|---|---|---|---|
| ESP Upgrades | Unknown | Unknown | Unknown | Unknown |
| Polishing Fabric Filter | 0.085 | $2.217 | $26.09 | $9,121 |
| Full Size Fabric Filter | 0.085 | $2.888 | $33.98 | $11,880 |

**Table 10.18 – Control Technology and Visibility Impact Reduction for Unit 3**

| Control | Deciview Reduction | Total Annualized Cost (Million $) | Cost per Deciview Reduced (Million $/dv) | Average Cost ($/ton) |
|---|---|---|---|---|
| ESP Upgrades | Unknown | Unknown | Unknown | Unknown |
| Polishing Fabric Filter | 0.094 | $2.192 | $23.32 | $9,471 |
| Full Size Fabric Filter | 0.094 | $2.869 | $30.52 | $12,390 |

Step 7: BART Selection

Based upon its review of the analysis provided by AEPCO, and the information provided above, ADEQ has determined that BART for $PM_{10}$ emissions is upgrades to the existing ESP and a $PM_{10}$ emissions limit of 0.03 lb/MMBtu for both Units 2 and 3. The upgrades to the existing ESP will involve a possible installation of a flue gas conditioning system, improvements to the scrubber bypass damper system, and implementing programming optimization measures for ESP automatic voltage controls.

### D.3 $SO_2$ BART Analysis

$SO_2$ forms in the boiler during the combustion process from the oxidation of the sulfur present in the coal, and is primarily dependent on coal sulfur content. The BART analysis for $SO_2$ emissions on Units 2 and 3 is described below.

Step 1: Identify the Existing Control Technologies in Use at the Source

Steam Units 2 and 3 currently have wet limestone scrubbers installed for $SO_2$ removal.

Step 2
: Identify All Available Retrofit Control Options

The following potential $SO_2$ control technology option was considered:

- Enhancement of current wet limestone scrubber or SDAS

Units 2 and 3 currently operate wet limestone scrubbers for $SO_2$ removal, with current emissions of 0.184 lb/MMBtu and 0.151 lb/MMBtu respectively. The EPA BART guidelines state that for existing units with $SO_2$ controls achieving at least 50 percent $SO_2$ removal, cost-effective scrubber upgrades should be considered. EPA has recommended consideration of the following potential upgrades:

- Elimination of bypass reheat
- Installation of liquid distribution rings
- Installation of perforated trays
- Use of organic acid additives
- Improve or upgrade scrubber auxiliary system equipment
- Redesign spray header or nozzle

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the identified control technology upgrades are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

When evaluating the control effectiveness of $SO_2$ reduction technologies, each option can be compared against benchmarks of performance. In its BART analysis, AEPCO chose to compare its proposed technology upgrades to EPA's presumptive BART emission limitations. According to EPA's BART guidance documents, the presumptive limit for $SO_2$ on a BART-eligible coal-burning unit, used here as a point of reference, is 95 percent removal, or 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

Over the past several years AEPCO has completed several scrubber upgrades to improve performance, including the following:

- Elimination of flue gas bypass
- Splitting the limestone feed to both the absorber feed tank and tower sump
- Upgrade of the mist eliminator system
- Installation of suction screens at pump intakes
- Automation of pump drain valves
- Replacement of scrubber packing with perforated stainless steel trays

Dibasic acid additive was tested; however results did not show significantly higher $SO_2$ removal.

*Energy Impacts*

Upgraded operation of the existing wet limestone scrubber or SDAS system is not expected to result in any additional power consumption.

*Environmental Impacts*

There will be incremental additions to scrubber waste disposal and makeup water requirements and a reduction of the stack gas temperature if there is elimination of flue gas bypass.

*Economic Impacts*

There are no anticipated cost impacts attributable to upgraded scrubber operation.
Step 6: Evaluate Visibility Impacts

A Visibility Impact Analysis was not performed for $SO_2$ since the existing scrubbers are proposed as BART.

Step 7: BART Selection

After reviewing the company's BART analysis, and based upon the information above, ADEQ has determined that BART for $SO_2$ emissions is no new controls and an emission limit of 0.15 lb/MMBtu.

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## XI. APS CHOLLA GENERATING STATION BART ANALYSIS AND DETERMINATION

### A. Process Description

The APS Cholla Power Plant ("APS Cholla") consists of the following four electric generating units with a total generating capacity of 1,150 megawatts (MW).

- Unit 1: 125 MW
- Unit 2: 300 MW
- Unit 3: 300 MW
- Unit 4: 425 MW

Each unit is a coal-fired steam generating unit equipped with a tangentially-fired, dry-bottom boiler. Each of these Units burns bituminous or sub-bituminous coal to generate super-heated steam. This steam is then used to drive turbines/generators for producing electricity. Cholla purchases coal from the Lee Ranch and El Segundo mines.

### B. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

Units 2, 3 and 4 are potentially subject-to-BART because:

1. These units belong to one of the 26 categorical sources;
2. These units were in existence on August 7, 1977;
3. Combined emissions of visibility impairing pollutants from all three of these Units - nitrogen oxides ($NO_X$), particulate matter less than 10 microns ($PM_{10}$), and sulfur dioxide ($SO_2$) - are greater than 250 tons per year for each pollutant.

### C. Impact on Visibility

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant. The following table provides the baseline maximum impact on visibility in deciview.

**Table 11.1 – Modeled Baseline Impact on Visibility**

| Affected Class I Area | Unit 2 | Unit 3 | Unit 4 |
|---|---|---|---|
| Capital Reef NP | 1.25 | 2.70 | 2.40 |
| Grand Canyon NP | 1.45 | 2.45 | 2.65 |
| Petrified Forest NP | 1.40 | 3.00 | 3.40 |
| Sycamore Canyon WA | 1.62 | 2.50 | 2.70 |
| Gila WA | 0.68 | 2.10 | 2.20 |
| Mount Baldy WA | 1.12 | 2.25 | 2.25 |
| Sierra Ancha WA | 0.91 | 1.90 | 2.15 |
| Mazatzal WA | 1.02 | 1.72 | 1.85 |

| Table 11.1 – Modeled Baseline Impact on Visibility | | | |
|---|---|---|---|
| **Affected Class I Area** | **Unit 2** | **Unit 3** | **Unit 4** |
| Pine Mountain WA | 1.20 | 1.75 | 1.88 |
| Superstition WA | 0.95 | 1.95 | 2.15 |
| Galiuro WA | 0.57 | 1.18 | 1.28 |
| Mesa Verde NP | 0.81 | 1.45 | 1.40 |
| Saguaro NP | 0.43 | 0.95 | 1.15 |

## D. Nitrogen Oxides ($NO_x$) BART Analysis and Determination for Units 2, 3 and 4

Step 1: Identify the Existing Control Technologies in Use at the Source

The Cholla BART Analysis was completed in late 2007. At that time, the Units were equipped with Close-coupled Overfire Air (COFA). Overfire air is used to reduce $NO_X$ by reducing excess air in the combustion zone. In a COFA system, air nozzles are immediately above the burners.

Low $NO_X$ Burner (LNBs) and Seperated Overfire Air (SOFA) were installed on Units 2, 3 and 4 in March 2008, May 2009 and May 2008 respectively. LNBs and SOFAs are utilized for increased $NO_X$ reduction.

Step 2: Identify All Available Retrofit Control Options

APS Cholla has identified the following available retrofit control technologies for $NO_X$ control in Units 2, 3 and 4.

- LNB with Separate Overfire Air (SOFA) System
- LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System
- Rotating Opposed Flow Air system (ROFAs)
- ROFA with Rotary Mixing of Additives (Rotamix)
- LNB with SOFA and Selective Catalytic Reduction (SCR)

**LNB with Separate Overfire Air (SOFA) System.** Initial combustion takes place in fuel-rich condition so that the oxygen needed for combustion is not diverted to form $NO_X$. Additional air (separate overfire air) is then introduced in a lower temperature zone to burn out the char.

**LNB with SOFA and Selective Non-Catalytic Reduction (SNCR) System**. SNCR systems reduce $NO_x$ by injecting reagent (ammonia or urea) into the furnace within a temperature range of 1600° to 2100° F. $NO_X$ reduction of 40% to 60% can be achieved. Reagent utilization is a measure of efficiency with which the reagent reduces $NO_X$. Ammonia slip may occur due to lower temperatures, or inadequate mixing causing problems downstream. Potential problems include: rendering fly ash unsalable and reacting with sulfur to form ammonium bisulphate which can foul exchangers. The combination of LNB and SOFA with SNCR may achieve lower emission reductions than can be achieved by the individual technologies alone.

**Rotating Opposed Flow Air System (ROFA)**. ROFA is an improved overfire air system. In this technology, the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. This rotation prevents laminar flow and improves gas mixing. As a result, the entire volume of the furnace is used more effectively for combustion process. A typical ROFA system requires a booster fan to supply high velocity air to the ROFA boxes.

**ROFA with Rotary Mixing of Additives (Rotamix).** ROFA along with Rotamix system provides enhanced mixing in the combustion chamber for optimal conditions to achieve multi-pollutant reduction. The turbulent mixing created by ROFA and Rotamix improves the efficiency of pollutant capture and reduces the stoichiometric amount of sorbent needed to reduce pollutants emissions.

**LNB with SOFA and Selective Catalytic Reduction (CR)**. In SCR systems, vaporized ammonia ($NH_3$) injected into the flue gas stream acts as a reducing agent, achieving $NO_X$ emission reductions when the gas stream is passed over a vanadium/titanium-based catalyst. The $NO_X$ and ammonia react to form nitrogen and water vapor. The SCR ammonia-catalytic reaction requires a temperature range of 580-750° F.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The following table provides the $NO_X$ emission rates that will be achieved with different feasible $NO_X$ control technologies for Units 2, 3 and 4.

**Table 11.2 – Achievable $NO_X$ Emissions Rates By Technology**

| Control Technology | $NO_X$ Emissions | | |
|---|---|---|---|
| | Unit 2 | Unit 3 | Unit 4 |
| | Pounds per MMBtu | Pounds per MMBtu | Pounds per MMBtu |
| LNB with COFA (Baseline) | 0.50 | 0.410 | 0.415 |
| LNB with SOFA | 0.22 | 0.22 | 0.22 |
| LNB with SOFA and SNCR | 0.17 | 0.17 | 0.17 |
| ROFA | 0.16 | 0.16 | 0.16 |
| ROFA with Rotamix | 0.12 | 0.12 | 0.12 |
| LNB with SOFA and SCR | 0.07 | 0.07 | 0.07 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Economic Impacts*

The following Tables 3, 4 and 5 present the cost of compliance for the feasible technologies for Units 2, 3 and 4. The tables also report the predicted impact of these technologies on visibility [98th percentile deciview (dv)] reduction.

Energy Impacts

ROFA system will require a 3,300 HP fan for the supply of high-velocity air. Thus, there will be an additional power requirement of 130 KW.

SCR retrofit will cause additional pressure drop (6-8 inches water gauge) in the flue gas system due to catalyst.

LNBs and SOFA systems do not significantly impact boiler efficiency or power usage.

Non-Air Quality Environmental Impacts

SNCR and SCR installations could impact the salability and disposal of fly ash due to ammonia levels. At this time, APS Cholla sells its fly ash, and if sellability of the fly ash is impacted, costs associated with the proposed controls will increase. SCR and SNCR may also involve potential safety hazard associated with handling of anhydrous ammonia, and transportation of ammonia to the plant site.

Remaining Useful Life

Units 2, 3 and 4 have projected remaining lives of 40 years at each unit.

Step 6: Evaluate Visibility Impacts

CALPUFF modeling was performed at 13 Class I areas that are located within 300 kilometers of Cholla Power Plant the degree of that may be reasonably expected from the use of BART. The impacts are modeled for different $NO_X$ control scenarios, combined with $SO_2$ and $PM_{10}$ technologies. Since, as shown in Table 11.1, the Petrified Forest National Park is the most impacted area out of all the 13 Class I areas, Tables 11.3, 11.4 and 11.55 present the improvement in visibility (in deciview) in that area.

| Table 11.3: Unit 2 Cost and Visibility Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|
| $NO_X$ Control Technologies | Emission Rate | $NO_X$ Removal | Annualized Cost | 1st yr Avg. Cost | Incremental Control Cost | Dv Impact for Max. Impacted Area (Petrified Forest NP) | |
| | lb/MMBtu | Tons/year | Million $ | $/ton | $/ton | 98th percentile dv reduction | million $/dv reduced |
| LNB with COFA (Baseline) | 0.503 | - | - | - | - | - | - |
| LNB with SOFA | 0.22 | 3,314 | $0.635 | $192 | $192 | 0.187 | $3.40 |
| LNB with SOFA and SNCR | 0.17 | 3,900 | $2.175 | $558 | $2,628 | 0.218 | $9.98 |
| ROFA | 0.16 | 4,017 | $2.297 | $572 | $1,043 | 0.232 | $9.90 |
| ROFA with Rotamix | 0.12 | 4,485 | $3.384 | $755 | $2,323 | 0.261 | $12.97 |
| LNB with SOFA and SCR | 0.07 | 5,071 | $9.625 | $1,898 | $10,650 | 0.287 | $33.54 |

| Table 11.4 – Unit 3 Cost and Visibility Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|
| $NO_X$ Control Technologies | Emission Rate | $NO_X$ Removal | Annualized Cost | 1st yr Avg. Cost | Incremental Control Cost | Dv Impact for Max. Impacted Area (Petrified Forest NP) | |
| | lb/MMBtu | Tons/year | Million $ | $/ton | $/ton | 98th percentile dv reduction | million $/dv reduced |
| LNB with COFA (Baseline) | 0.41 | - | - | - | - | - | - |
| LNB with SOFA | 0.22 | 2,096 | $0.635 | $303 | $303 | 0.126 | $5.04 |
| LNB with SOFA and SNCR | 0.17 | 2,648 | $2.157 | $814 | $2,756 | 0.164 | $13.15 |
| ROFA | 0.16 | 2,758 | $2.243 | $813 | $786 | 0.169 | $13.27 |
| ROFA with Rotamix | 0.12 | 3,200 | $3.308 | $1,034 | $2,409 | 0.198 | $16.71 |
| LNB with SOFA and SCR | 0.07 | 3,751 | $9.569 | $2,551 | $11,363 | 0.230 | $41.61 |

| Table 11.5 – Unit 4 Cost and Visibility Analysis | | | | | | | |
|---|---|---|---|---|---|---|---|
| $NO_X$ Control Technologies | Emission Rate | $NO_X$ Removal | Annualized Cost | 1st yr Avg. Cost | Incremental Control Cost | Dv Impact for Max. Impacted Area (Petrified Forest NP) | |
| | lb/MMBtu | tons/year | Million $ | $/ton | $/ton | 98th percentile dv reduction | million $/dv reduced |
| LNB with COFA (Baseline) | 0.42 | - | - | - | - | - | - |
| LNB with SOFA | 0.22 | 3,390 | $0.820 | $242 | $242 | 0.207 | $3.96 |
| LNB with SOFA and SNCR | 0.17 | 4,259 | $2.852 | $670 | $2,338 | 0.265 | $10.76 |
| ROFA | 0.16 | 4,433 | $3.179 | $717 | $1,877 | 0.281 | $11.31 |
| ROFA with Rotamix | 0.12 | 5,129 | $4.537 | $885 | $1,951 | 0.336 | $13.50 |
| LNB with SOFA and SCR | 0.07 | 5,998 | $13.23 | $2,206 | $10,007 | 0.408 | $32.43 |

Step 7: BART Selection

According to the Regional Haze Rule, only dV changes in excess of 1.0 dV are perceptible.

A review of the data presented in Tables 11.3, 11.4, and 11.5 indicates that CALPUFF model-predicted visibility improvements (delta dV) for all five $NO_x$ control scenarios are less than 0.5 dV. For example, in the case of Unit 3, the dV changes range from 0.126 dV for the LNB with SOFA (Scenario 1) to 0.230 dV for LNB with SOFA and SCR (Scenario 5). The change in dV between the least expensive and most expensive $NO_x$ control technologies (the two noted above) is only 0.104 dV. The corresponding capital costs are $5.4 million for LNB/SOFA and $82.8 million for LNB/SOFA with SCR.

Based on these facts and the five-factor analysis discussed above, ADEQ has concluded that LNB with SOFA constitute BART for $NO_x$ emissions for Cholla Units 2, 3, and 4.

## E. $PM_{10}$ BART

Step 1: Identify the Existing Control Technologies in Use at the Source

Unit 2 currently has a mechanical dust collector for control of $PM_{10}$ emissions. Additional particulate matter control is provided by a venturi scrubber. Cholla 2 is currently able to achieve emission rate of 0.020 lb/MMBtu.

Unit 3 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.015 lb/MMBtu of $PM_{10}$. The facility completed installation of a fabric filter in May 2009. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for $PM_{10}$.

Unit 4 was previously equipped with a hot-side ESP and was able to achieve an emission rate of 0.024 lb/MMBtu of $PM_{10}$. The facility completed installation of a fabric filter in May 2008. With the installation of the fabric filter, the facility expects to consistently achieve an emission rate of 0.015 lb/MMBtu for $PM_{10}$.

Step 2: Identify All Available Retrofit Control Options

Since Units 3 and 4 will be equipped with fabric filters, and fabric filters are considered the top control technology for reducing PM emissions. As a result, no other technology is considered for these two Units. The following retrofit technologies are considered for Unit 2:

- Electrostatic Precipitators
- Fabric Filters

**Electrostatic Precipitator**. An ESP operates by placing a charge on the particles through electrodes, and then capturing the charged particles on collection plates.

**Fabric Filter**. The flue gas passes through the bags to remove particulate matter. The bags are cleaned by initiating a pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag and releases the dust cake from the bag surface into a hopper.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that both fabric filters and electrostatic precipitators are technically feasible options.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

**Electrostatic Precipitator.** ESPs are capable of achieving an emission rate of 0.015 lb/MMBtu. However, ESP operation is susceptible to particle resistivity. Particle resistivity is influenced by flue gas temperature. Thus, operational variations may not result in consistent compliance with the emission limit.

**Fabric Filter.** Fabric filters are proven to be highly effective and provide a consistent particulate matter reduction. The emissions at the outlet of fabric filter are expected to be less than 0.015 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Economic Impact*

Since Units 3 and 4 are already equipped with bag filters, no economic impact analysis is required. For Unit 2, since the facility has already decided to install a new bag filter in 2015, this is the only option considered for the economic analysis.

**Table 11.6 – Economic Impacts for Unit 2**

| Control | Emission Rate (lb/ MMbtu) | Total Emission (Tons/ Yr) | Total Emission Reduction (Tons) | Annualized Cost ($MM) | Cost/ Ton ($) | Incremental Cost/ton ($/ton) |
|---|---|---|---|---|---|---|
| Baseline (no control) | 0.020 | 234 | - | - | - | - |
| Fabric Filter | 0.015 | 176 | 58 | 9.40 | 160,747 | 160,747 |

*Energy Impacts*

Since Units 3 and 4 are already equipped with bag filters, no energy impact analysis is required. For Unit 2, the installation of new fabric filter will result in additional pressure drop across the filter and associated duct work. Thus, additional power will be required. This is likely to be offset by the removal of mechanical dust collector and venturi scrubber.

*Non-Air Quality Environmental Impacts*

There are no negative environmental impacts from the installation of new fabric filter.

Step 6: Evaluate Visibility Impacts

The installation of a fabric filter is the only option considered for BART for all the 3 units.

Step 7: BART Selection

Based upon its review of the company's BART analysis and the information provided above, the Department has determined that, fabric filter with an associated emission limit of 0.015 lb/MMBtu is the BART for control of $PM_{10}$ for Units 2, 3 and 4.

## F. Sulfur Dioxide ($SO_2$) BART

Step 1: Identify the Existing Control Technologies in Use at the Source

**Unit 2**. This unit is equipped with four venturi flooded disc scrubbers/absorber with lime reagent for $SO_2$ control. Currently, APS Cholla is able to achieve 0.14 lb/MMBtu to 0.25 lb/MMBtu of $SO_2$ on Unit 2.

**Unit 3.** This unit did not have any $SO_2$ control technology when the BART analysis was completed in late 2007. The facility installed a new wet lime scrubber in May 2009 to capture and treat all flue gases. This will result in Unit 3 consistently meeting an emission limit of 0.15 lb/MMBtu.

**Unit 4**. This Unit was previously operating with 36% flue gas scrubbing with emission rate of 0.734 lb/MMBtu. The facility installed a new wet lime scrubber in May 2008 to capture and treat all flue gases. This will result in Unit 4 consistently meeting an emission limit of 0.15 lb/MMBtu.

Step 2: Identify All Available Retrofit Control Options

**Unit 2**. The facility plans to remove the venturi section of the scrubber and considered a wet lime scrubber section for possible operational upgrades. Installation of bag filter as a part of BART will improve the performance of scrubber due to decreased plugging of scrubber. The facility expects to achieve 0.15 lb/MMBtu consistently with these operational upgrades.

**Unit 3**. In late 2007, APS Cholla identified the following available retrofit control technologies for $SO_2$ control in Unit 3:

- Dry Flue Gas Desulfurization (FGD) System
- Dry Sodium Sorbent Injection
- Wet Lime Scrubber

**Dry Flue Gas Desulfurization (FGD) System**. Dry FGD is based on the spray drying of lime slurry into flue gas. The $SO_2$ is absorbed into the fine spray droplets and reacts with the calcium to form dry calcium sulfite or sulfate. This is collected by the particulate control device along with fly ash.

**Dry Sodium Sorbent Injection**. Dry duct injection of sodium carbonate or sodium bicarbonate into the flue gas is utilized to remove $SO_2$. Unreacted/reacted sorbent is collected by the particulate control device along with fly ash.

**Wet Lime Scrubber**. $SO_2$ laden flue gas enters a scrubber where it is sprayed with lime slurry. The $SO_2$ reacts with the calcium to form calcium sulfite or sulfate which is removed and disposed off as scrubber waste, or reclaimed as gypsum.

Subsequently, Cholla intalled a new Wet Lime Scrubber on Unit 3 in May 2009. Therefore, the new wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

**Unit 4**. The wet lime scrubber, as described above, is the only retrofit control technology considered for this unit.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the control options identified above are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

**Dry FGD System.** This technology is estimated to achieve 90% control efficiency. Thus the achievable emission rate with this technology is 0.25 lb/MMBtu.

**Dry Sodium Sorbent Injection**. Maximum $SO_2$ removal efficiency for this technology is 75%. Thus, for an initially uncontrolled emission rate of 2.5 pounds/MMBtu, the achievable emission rate with this technology is 0.625 lb/MMBtu.

**Wet Lime Scrubber**. Wet lime scrubbers are capable of very high $SO_2$ removal efficiency. Based on a 95% control efficiency, the wet lime scrubber can achieve the emission rate of 0.15 lb/MMBtu.

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Economic Impact*

**Unit 2**. Only operational upgrades will be done on the existing wet lime scrubber. Hence there is no economic impact.

**Unit 3**. The installation of a new wet lime scrubber was completed in May 2009. This technology provides the maximum reduction in $SO_2$ emissions. The wet lime scrubber is the only option considered for economic analysis.

**Table 11.7 – Economic Impacts for Unit 3**

| Control | Emission Rate (lb/ MMbtu) | Total Emission (Tons/ Yr) | Total Emission Reduction (Tons) | Annualized Cost (Million$) | Cost/ Ton ($) | Incremental Cost/ton ($/ton) |
|---|---|---|---|---|---|---|
| Baseline (no control) | 1.00 | 11,033 | - | - | - | - |
| Wet Lime scrubber | 0.15 | 1,655 | 9,378 | $8.80 | 936 | $936 |

**Unit 4.** The facility has completed the installation of a new wet lime scrubber in May 2008. Thus, there is no economic impact that needs to be assessed.

*Energy Impacts*

There will be no energy impact for Units 2, 3, and 4 as these scrubbers are already in place.

*Non-Air Quality Environmental Impacts*

There will be no non-air quality environmental impact for Units 2, 3, and 4 as these scrubbers are already in place.

Step 6: Evaluate Visibility Impacts

Wet lime scrubber is the only option considered for BART for Units 2, 3 and 4.

Step 7: BART Selection

Based upon its review of the BART analysis provided by the company, and the information provided above, the Department has determined that wet lime scrubbers with an associated emission limit of 0.15 lb/MMBtu is the BART for control of $SO_2$ for Units 2, 3 and 4.

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# XII. ASARCO HAYDEN SMELTER BART ANALYSIS AND DETERMINATION

## A. Process Description

According to EPA's Air Pollution Manual (AP-42) Section 12.3.1, copper mining produces ores that contain less than 1 percent copper. In order to produce copper, the mined ore must be concentrated through crushing, grinding and flotation purification, which results in an enriched ore that contains approximately 15 to 35 percent copper. This is often times referred to as "concentrate".

A typical pyrometallurgical copper smelting process includes 4 steps: roasting, smelting, concentrating and fire refining. Ore concentrate is first roasted to reduce the number of impurities in the concentrate, including sulfur and some heavy metals. The Hayden Smelter introduces a dried concentrate feed, along with combustion oxygen, into an INCO oxygen flash furnace. In this process, the charge of concentrate is mixed with a siliceous flux (often times a low-grade copper ore) and then heated in air to approximately 650 °C (1200 °F). This process eliminates 20 to 50 percent of the sulfur in the concentrate by converting the sulfur into sulfur dioxide ($SO_2$). The remaining material that leaves the INCO oxygen flash furnace is typically called matte, which is tapped from the furnace, flowing down ventilated launders into ladles that are staged below the furnace's floor. Matte typically contains 35 to 65 percent copper. Once the ladles are filled, they are moved to the converter aisle for transferring the molten matte into the converters. The slag produced by this process is skimmed and removed to a slag pot for delivery to the slag cooling area.

In its converter aisle, the Hayden smelter utilize five Pierce-Smith batch converters in order to produce blister copper by eliminating the remaining iron and sulfur that is present in the material. The ladles filled with matte from the furnace process are carried by crane into the converter aisle, and are then used to dump the molten material into the converters. Once filled, air is blown through the molten matte. Flux (silica) and other materials are added at various times during the process in order to regulate the temperature, and to facilitate the chemical reactions that allow the formation of an iron/silica slag.

The molten bath is allowed to "blow" until sufficient slag has formed on the surface. Operators will then roll the converter out in order to skim the slag off of the top. Additional matte, siliceous flux and scrap metal will again be added to the bath, and then the converter will be rolled back in to continue blowing. After several skimming processes, the converter will be filled with an adequate amount of relatively pure white metal. A final air blast will then be used to oxidize the copper sulfide to produce $SO_2$ and blister copper which is generally 98 to 99 percent pure copper. Impurities in blister copper often includes gold, silver, antimony, arsenic, bismuth, iron, lead, nickel, selenium, sulfur, tellurium, and zinc.

Each converter at the Hayden smelter is equipped with primary and secondary hooding systems. The primary hooding systems are designed to capture the $SO_2$ emissions that are emitted while the converters are "rolled-in". These $SO_2$ gases are then routed through a dust removal system, and then sent to the acid plant for treatment and conversion into sulfuric acid. The secondary hooding systems are designed to capture fugitive gases that escape the primary hood, or are emitted when the converter is "rolled-out" for skimming and charging. Gases that are collected by the secondary hooding are directed to a baghouse for dust removal, and are then exhausted to the atmosphere via the facility's 1,000 foot stack.

Once the blister copper has been produced, the Hayden smelter transfers the blister copper to the anode furnaces via ladle and overhead crane. The anode casting furnace accepts two to three charges from the converter aisle. Once filled, air is introduced into the flash furnace in order to further refine the copper. Impurities within the copper bath form an oxide slag which is removed from the furnace and returned to the converters. After the slag is removed and is no longer forming, natural gas is bubbled through the molten bath to remove any excess oxygen. The resultant purified copper (approximately 99% pure) is

then cast into specifically designed shapes and shipped by rail cars and trucks to off-site refineries for final processing.

## B. Description of Emissions Units Subject-to-Best Available Retrofit Technology (BART)

On July 13, 2007, the Arizona Department of Environmental Quality sent a letter to ASARCO, Inc. identifying the following emissions as potentially subject-to-BART:

**Table 12.1 – ADEQ Identified Potentially Subject-to-BART Pollutants and Emissions Units**

| Emissions Unit(s) | Pollutants Potentially Subject-to-BART |
|---|---|
| Converters 1-5 | $SO_2$, $PM_{10}$ |
| Anode Furnaces 1-3 | $SO_2$, $PM_{10}$ |

On October 1, 2007, ASARCO responded stating that several of the emissions units were inappropriately identified as potentially Subject-to-BART. According to ASARCO's records, the company had operated three of the converters prior to the 1962 BART window. ASARCO went on to state that one of the three converters was enlarged from 13 x 32 feet to 13 x 35 feet in 1965, and that converters #1 and #4 were added in 1968, making the determination that "two or three of five are date eligible." ASARCO also stated that Anode Furnaces #1 and #2 were constructed in 1972, in the BART window, but asserted that Anode Furnace #0 was constructed in 2001, and was therefore not eligible for BART consideration.

ASARCO did not provide records in the October 1, 2007, letter demonstrating that its statements were indeed true. ADEQ's research of historical smelter logs, however, revealed that ASARCO did indeed operate three converters before 1962. ADEQ was also able to confirm that the date of construction for Anode Furnace #0 was 2001. As a result, ADEQ concurs with ASARCO's assessment of the BART-eligible emissions units, with the clarification that the converter that was enlarged in 1965 is considered BART-eligible. As a result, three converters and two Anode furnaces are considered BART-eligible.

As noted Section VI.C ADEQ determined that the potential emissions of $PM_{10}$ were not sufficient to determine that the ASARCO Hayden smelter was subject-to-BART for that pollutant. Emissions of $SO_2$ from the facility, on the other hand, were determined to be subject-to-BART.

## C. STREAMLINED $SO_x$ BART ANALYSIS

Step 1: Identify the Existing Control Technologies in Use at the Source

According to Air Quality Permit 1000042, issued by ADEQ on October 9, 2001, the ASARCO Hayden smelter has installed and operates the following control technologies on the equipment subject-to-BART (Table 12.2):

**Table 12.2 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the Hayden Smelter**

| Emissions Units Subject-to-BART | Current Control | $SO_x$ Emission Limit |
|---|---|---|
| Converters (three) | 1. Primary hooding | 1. Multi Point Roll Back Rule |

| Table 12.2 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the Hayden Smelter | | |
|---|---|---|
| **Emissions Units Subject-to-BART** | **Current Control** | **$SO_x$ Emission Limit** |
| | 2. Secondary hooding<br>3. Double contact acid plant | [A.A.C. R18-2-715(F)(2)(b)] |
| Anode Furnaces #1 and #4 | No controls | 1. Multi Point Roll Back Rule [A.A.C. R18-2-715(F)(2)(b)] |

In addition to identifying the above controls for the BART-eligible equipment at the Hayden primary copper smelter, ADEQ also determined that it is important to note the process changes and control equipment that have been installed over time at the facility.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, prior to 1971, all smelting operations process gasses from the facility were emitted into the atmosphere after electrostatic precipitators removed the particulate matter from the gases. In 1971, however, the company installed an acid plant as an $SO_2$ control for primary converter gases. According to sulfur balance information from the time period, $SO_2$ emissions from the facility were well in excess of 100,000 tons per year.

In 1983, the company undertook a series of additional improvements, including the replacement of twelve multiple-hearth roasters and two reverberatory furnaces, replacing them with an INCO Flash smelting furnace. At the same time, ASARCO installed a 650 ton per day oxygen plant that would enrich the smelting process gasses. Based upon this addition, the company was able to replace the existing single contact acid plant with a new double-contact acid plant. The emissions reductions resulting from these projects were estimated to be 63,584 tons per year of $SO_2$. According to ASARCO's calculations, the double-absorption acid plant recovers 99.81 percent of the $SO_2$ emissions that are vented to it.

In 1992, ASARCO made a modification to the smelter's existing gas handling system, and installed an $18.4 million wet gas handling system. This modification allowed the flash furnace off gas to be treated at temperatures that are less than 200° F, approximately 400° F less than the previous system. Due to the lower temperatures, the volume of gas being vented from the flash furnace was reduced, enabling the acid plant to provide additional ventilation to the converters. This additional ventilation allowed the secondary hoods to draw capture more $SO_2$ emissions from the converter building.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the complete list of $SO_2$ Process and Control Technologies employed by the Hayden primary copper smelter throughout the years is as follows (Table 12.3):

| Table 12.3 – Implementation of $SO_2$ Process and Control Technology | |
|---|---|
| **Year** | **Equipment** |
| 1971 | Installation of No. 1 Acid Plant. |
| 1972 | Acid Plant Mist Precipitator Modification.<br>Installation of Reverberatory Vent Fans to improve ventilation. |
| 1973 | Installation of Acid Coolers (Crane) for improved acid plant performance and Matte Fume Vent to improve the capture of fugitive emissions. |

| Table 12.3 – Implementation of $SO_2$ Process and Control Technology | |
|---|---|
| **Year** | **Equipment** |
| 1974 | Installation of Converter Spray Chamber for particulate removal and Plate Heat Exchanger. |
| 1975 | Matte Fume Enclosing to improve the capture of fugitive emissions. |
| 1976 | Installation of Separator - Demister to improve acid plant performance. |
| 1978 | Installation of Flue Gas Sampling Station. |
| 1980 | Installation of secondary hooding on the converters to minimize release of fugitive emissions directly to atmosphere. |
| 1983 | Replacement of multiple-hearth roasters and reverberatory furnaces with an Inco flash smelting furnace and gas handling equipment including slag skimming hoods, matte tapping hoods, and slag return hoods at the flash furnace for improved sulfur recovery.<br><br>Installation of gas cleaning mist precipitators. |
| 1983/1984 | Installation of Monsanto acid plant No. 2 for treatment of all primary process gases. |
| 1988 | Installation of acid plant APV Heat Exchanger to improve gas cleaning performance. |
| 1989 | Electric slag cleaning vessel with an $SO_2$ control device; a caustic scrubber that controls a portion of the overall $SO_2$. |
| 1991 | Shutdown of acid plant No.1.<br><br>Repair of a gas-to-gas heat exchanger leak at the acid plant.<br><br>Repaired converter flues; replaced primary converter hoods and jackets; rebuilt all units in the Cottrell electrostatic precipitator; installed concrete sumps and improved sprays in the gas spray chamber of the acid plant to reduce fugitive $SO_2$ emissions. |
| 1993 | Upgrade of acid plant mist precipitator and acid plant intermediate fan. |
| 1993 | Modification of flash furnace uptake and replacement of cooling fins on the settling chamber to prevent the generation of fugitive emissions caused by inadequate cooling. |
| 1995 | Replacement of acid plant heat exchanger and retube of cold heat exchanger. |
| 1997 | Retube of Tail Gas Reheater Heat Exchanger. |
| 1998 | Installation of wet gas handling system for improved treatment of furnace emissions.<br><br>Installation of new Hot IP Heat Exchanger; Cold IP Heat Exchanger; SX Distribution in IP Absorbing Tower; Foxboro IA distributive process control |
| 1999/2000 | Redesign of converter primary hood doors. The gaps in the primary hoods at the converter mouths were redesigned and a flexible seal installed to minimize the escape of fugitive emissions to the secondary hooding system. |
| 2000 | CEM Upgrade (Stack Monitors) |

Step 2 - 6: Streamlined Analysis

On October 1, 2007, ASARCO submitted a letter stating:

"During the deliberations of the Market Trading forum of the Western Regioanl Air Partnership (WRAP), all parties involved including ADEQ and the U.S. Environmental Protection Agency (EPA), agreed that the controls and emissions limitation for primary copper smelters already met BART for $SO_2$. This was reflected in the milestones included in the State Implementation Plan (SIP) that ADEQ submitted to EPA under 40 CFR 51.309 (Section 309 SIP). The milestones being proposed for inclusion in the model 308 SIP currently being developed by the WRAP include an allowance of 26,000 tons of $SO_2$ for the Hayden smelter and are based on the fact that the smelter is at or beyond the BART requirements."

On November 27, 2007, the only other batch primary copper smelting operation in the Western United States, Phelps Dodge Miami Incorporated, submitted a letter to ADEQ indicating that in December 2003, the Western Regional Air Partnership (WRAP) had made a finding that "[a] double-contact acid plant will be considered the appropriate retrofit control equipment..." for $SO_2$ emissions. In support, PDMI referred ADEQ to a December 2002 report from E.H. Pechan & Associates, Inc. entitled *WRAP Market Trading Forum Non-Utility Sector Allocations Final Report from the Allocations Working Group.*

ADEQ reviewed the December 2002 report, and found that, at the time the report was published, the WRAP did state that "[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.)" In addition, the report noted that there were six primary copper smelters in the WRAP region. Of the six, five were near copper mines in the southwest United States and use a batch process to produce copper. Of these five, only two of the smelters were producing copper, "...(the ASARCO smelter in Hayden, Arizona and the Phelps Dodge smelter in Miami, Arizona.)"

The WRAP's report also stated that the sixth smelter, Kennecott Utah Copper Corporation's operation near Garfield, Utah, was constructed in the mid 1990's and that it uses a flash copper converting technology. This flash copper converting technology allows copper to be produced in a continuous process.

ADEQ's analysis of the copper smelting industry in 2009 in the United States has revealed that there are currently three operating copper smelters. Those smelters are the ASARCO smelter in Hayden, Arizona, the Freeport McMoRan (formerly Phelps Dodge) smelter in Miami, Arizona, and the Kennecot Utah Copper Corporation's facility near Garfield, Utah. No other copper smelters have operated since the time that the WRAP's report has been published, and ADEQ is unaware of any plans to restart any of those smelters in the near future.

As previously noted, ADEQ's review of the Kennecott Utah Copper Corporation's operation has led to the determination that the continuous production of blister copper is a fundamentally different process than the process employed by ASARCO's Hayden Smelter. ADEQ has also determined that BART does not contain a requirement that the source be redesigned when the Agency considers the available control alternatives. As a result, ADEQ has concluded that it is not necessary to consider the use of Kennecott Utah Copper Corporation's process as a potential BART alternative.

Emissions from the Hayden smelter have varied over the years due to a number of factors, including the price of, and demand for, copper. According to the *2018 $SO_2$ Emissions Evaluation For Non-Utility Sources Final Report* provided by Pechan to the WRAP's Stationary Sources Joint Forum, historical $SO_2$ emissions from the ASARCO Hayden smelter are as follows:

| Table 12.4 – Annual $SO_2$ Emissions from the ASARCO Hayden Smelter. | |
|---|---|
| **Year** | **$SO_2$ Emissions (Tons Per Year)** |
| 1990 | 29,814 |
| 1996 | 33,124 |
| 1998 | 22,077 |
| 2000 | 16,753 |
| 2003 | 18,977 |
| 2004 | 19,395 |

As noted in Table 12.4, $SO_2$ emissions from the Hayden smelter have varied since 1990. The ASARCO Hayden smelter is considered a custom smelter, and while it obtains some feed of concentrates from its own mines, it also processes materials from other copper mines within the region. The variability of the $SO_2$ emissions appears to be correlated with the price of copper, which was low in the late 1990s and early 2000s. By 2003, however, copper prices had recovered, accounting for the increasing emissions noted in 2003 and 2004.

According to ADEQ's *Final Hayden Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the process changes and installation of air pollution controls through the years has resulted in an increased overall $SO_2$ control efficiency at the Hayden primary copper smelter. Since the 1970s, the $SO_2$ control rate has risen from approximately 32% to approximately 42% with the installation of the double contact acid plant in the mid-1970s, to approximately 92% as a result of the activities identified in Table 5. Conversely, estimated $SO_2$ emissions from the facility fell from approximately 200,000 tons per year in the early 1970s, to less than 25,000 tons per year at the current time.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that there are no emission limitations or air pollution control devices that have been approved for anode furnace operations. Additionally, there are no emission limitations or air pollution control devices that have been approved for copper converters since the installation of the Double Contact Acid Plant in 1974. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the installation of the Double Contact Acid Plant there have been no changes at either the ASARCO Hayden smelter or the Freeport McMoRan Miami smelter that have triggered Prevention of Significant Deterioration review for sulfur oxides ($SO_x$). As a result, ADEQ has determined that the most stringent control available to control $SO_x$ emissions from primary copper smelting operations is the Double Contact Acid Plant.

It should also be noted that EPA non-attainment designations for the new 1-hour SO2 standard are required to be completed in June 2013. EPA has proposed to accept the Governor's recommendation to designate the Hayden area as non-attainment for the new standard. This designation will result in an obligation for the State of Arizona to work on a State Implementation Plan to prescribe control strategies to bring the area to compliance with the 1-hour SO2 standard within 5 years of designation. That timeline will ensure that additional SO2 emission reductions that are necessary to protect human health will be in place prior to the end of the BART period, which will be no sooner than July 15, 2018. It clearly creates certainty with both regulatory processes where the establishment of any new controls to achieve compliance with the NAAQS will essentially translate into significant improvement from a visibility perspective. It should be noted that the control technology evaluation from a NAAQS compliance standpoint does not have built-in cost considerations. From that standpoint, that process will result in

emission reductions that may otherwise be considered cost-prohibitive in a conventional BART analysis. Asarco has currently submitted a permit revision application for the installation of new converters and capture systems with a projected cost of more than 100 million dollars.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with ASARCO's conclusion that the installation and operation of the double contact acid plant with the New Source Performance Standard of 650 ppm constitutes BART for $SO_2$.

**PARTICULATE BART ANALYSIS**

**Step 1: Identify the Existing Control Technologies in Use at the Source**

Asarco-Hayden Smelter has installed and operates the following control technologies on the equipment subject-to-BART:

- Converters #1, #3, #4 and #5: Primary hoods routed to cyclones, wet scrubbers, wet gas cleaning section, and acid plant
- Secondary hoods routed to secondary hood baghouse
- Anode furnaces #1 and #2: No controls (during baseline period)

Asarco has made the following modifications for particulate matter emissions control since 1977.

- In 1998, Asarco made a modification to the existing gas handling system, and installed an $18.4 million wet gas handling system. This modification allowed the flash furnace off gas to be treated at temperatures that are less than 200° F, approximately 400° F less than the previous system. Due to the lower temperatures, the volume of gas being vented from the flash furnace has reduced, enabling the acid plant to provide additional ventilation to the converters, allowing the secondary hoods to capture more particulate matter emissions from the converter building.

- Asarco installed the anode furnace baghouse in late 2011 to reduce lead emissions as the Hayden Smelter is located in an area that was being considered for lead Non-attainment designation. Asarco intends to rely on emissions reductions from the anode furnace baghouse project to facilitate the converter aisle retrofit, a beyond-BART project aimed at achieving attainment of the 1-hour $SO_2$ NAAQS.

**Steps 2: Identify all available retrofit control technologies with practical potential for application to the specific emission unit for the regulated pollutant under consideration**

The following technologies are potentially available for particulate matter control from the converters and anode furnaces:

- Double contact acid plant (existing on converter primary)
- Baghouse (existing on converter secondary)
- Wet scrubbing
- Hot electrostatic precipitator (ESP)
- Cyclone/multiclone

**Step 3: Eliminate all technically infeasible control technologies.**

The converter primary off-gas stream is controlled by cyclones, wet scrubbers, and the acid plant. Further controls are not deemed feasible due to the highly corrosive nature of the off-gas and the fineness of the particulate that may be escaping.

The converter secondary off-gas stream is controlled by the secondary hood baghouse, which represents the most effective of available technologies, and addition of a less effective control thereafter is judged technically infeasible and unnecessary.

Acid plants are not technically feasible for the converter secondary gas stream, converter tertiary ventilation, or the anode furnaces due to the low concentration of $SO_2$ present (estimated to be well below 1%).

An ESP is considered technically infeasible for the tertiary ventilation system because of very low inlet particulate loading.

An ESP is considered technically infeasible for the anode furnaces because of the explosion hazard that would result during poling operations when natural gas is introduced into the furnaces and subsequently evacuated to the baghouse.

**Step 4: Ranking of Control Effectiveness**

***Primary off-gas System***

Asarco utilizes cyclone, wet scrubber and double contact acid plant system for primary off gas system which is the best available technology. Therefore, no other technologies are considered for the primary off-gas stream.

***Secondary off-gas System***

Asarco utilizes secondary hood baghouse for the secondary off-gas system which is the most effective control technology. Hence, no other technologies are considered for secondary off-gas stream.

The remaining technologies considered for converter fugitives and the anode furnace particulate emissions are as follows:

Tertiary Ventilation System:

- Baghouse (99.5% control efficiency)
- Wet Scrubber (90% control efficiency)

Anode Furnaces:

- Baghouse (99.5% control efficiency)
- Wet Scrubber (90% control efficiency)

**Steps 5-7**

**(5) Evaluate energy and non-air quality environmental impacts; (6) Evaluate visibility impacts; and (7) select BART.**

*Primary Off-gas System*

The existing combination of cyclones, wet scrubbers, and double contact double absorption acid plant represents BART for the primary off-gas stream because it represents the best current technology. BART is therefore selected as no further control beyond the cyclones, wet scrubbers, double contact double absorption acid plant system. ADEQ has proposed a BART limit of 6.2 mg/dscm for non-sulfuric acid particulate matter emissions. This limit is taken from the National Emission Standard for Hazardous Air Pollutants (NESHAP) Subpart QQQ. Compliance would be demonstrated using the procedures in NESHAPS Subpart QQQ.

*Secondary Off-gas System*

The existing secondary hood baghouse is determined to be the best retrofit technology for the secondary off-gas. BART is therefore selected as no further controls beyond the secondary hood baghouse. ADEQ has proposed a BART limit of 23 mg/dscm for particulate matter emissions. This limit is taken from the National Emission Standard for Hazardous Air Pollutants (NESHAP) Subpart QQQ. Compliance would be demonstrated using the procedures in NESHAPS Subpart QQQ.

*Tertiary Ventilation System*

ADEQ has evaluated whether the addition of a tertiary collection and control system would reduce particulate matter emissions from the converters and correspondingly reduce visibility impacts.. Installation of a tertiary ventilation system would require addition of side walls to the converter aisle, installation of canopy hoods over the converters, installation of duct work and a fan to create a draft, and additional ductwork to the existing stack or a new stack. Asarco conducted a review of a tertiary ventilation system for the proposed converter aisle retrofit project, which utilizes only three converters instead of the existing five.. Cost of the sheeting, ductwork, foundation and supports, induced draft fan, and connection to the main stack annulus is estimated at $19 million. Operating costs are estimated at $400,000 a year. The total annualized cost of the tertiary ventilation system, before any control device is added, is $1.35 million. It is estimated by Asarco that approximately 17.34 tons of particulate matter/year are lost to the atmosphere through fugitive emissions, based on the highest emissions in 2001-2003. Based on this, the cost of installing the ventilation system would be $77,854/ton.

The modeled impact of the Hayden Smelter on the most affected Class I area is 0.04 dv. Thus, cost per deciview is approximately $33.75 million/dv. Given the extremely small visibility impact and the magnitude of the costs incurred, ADEQ has determined that tertiary ventilation control as BART is not a feasible option

*Anode Furnaces*

In 1977 through 2011, the anode furnaces were uncontrolled. Asarco installed the anode furnace baghouse in late 2011 to reduce lead emissions as the Hayden Smelter is located in an area that was being considered for lead Non-attainment designation.

Capital cost of anode furnace capture ducting:$5,700,000
Annualized capital cost (20 year amortization): $ 285,000
Operating cost of anode furnace capture system: $ 350,000

Annualized total cost for capture system only: $ 635,000
Total uncontrolled particulate matter emissions: 80.06 tons/yr
Total controlled particulate matter emissions (at 0.003 gr/scf): 7.85 tons/yr
Tons particulate matter controlled (assumes baghouse): 72.21 tons/yr
Maximum possible dv impact, any area: 0.04 dv
Cost, $/ton, for capture system only : $8,794/ton
Cost, $/dv, for capture system only: $15,875,000/dv

The cost of a baghouse, wet scrubber, or cyclone/multiclone would be in addition to the costs listed above. For example, the "beyond RACT" baghouse cost approximately $3 million (total project cost: $8.7 million) and if this were added, the costs would increase to approximately $10,870/ton and $19.6 million/dv.

*Wet scrubbers* also have a number of operational and environmental impacts. Initially, a wet scrubber would require approximately 25-50 gpm of scrubbing liquid. In addition to the water itself, the resulting sludge mixture must be treated and the solids either landfilled or recycled into the system. Establishing a sludge drying system would add to the cost and could add emissions if drying requires more than air assist. Natural gas drying adds to the emissions impacts, partially offsetting the benefits. Electric drying would be costly and would increase emissions elsewhere. Scrubbing reagents may render material less amenable to reprocessing. Based on the number and types of adverse environmental effects from wet scrubbing, it does not appear to be a desirable option for controlling this exhaust gas stream at the Hayden smelter.

Based on the foregoing evaluation, ADEQ believes that the benefits of control, which amount to at most 0.04 dv, are outweighed by the substantial costs and, for wet scrubbers, by the adverse environmental effects of water consumption and sludge management. The particulate matter reductions achieved by the anode furnace baghouse project were undertaken to prepare for the converter aisle retrofit project, which is relying in part upon the emissions reductions in the anode furnace project. The converter aisle retrofit project is anticipated to bring additional particulate matter reductions through a redesign of the converter aisle, which should provide "beyond BART" levels of control. BART is therefore determined to be no controls for the anode furnaces.

# XIII. FREEPORT-MCMORAN MIAMI INC (FMMI) SMELTER (FMMI SMELTER) BART ANALYSIS AND DETERMINATION

## A. Process Description

According to EPA's Air Pollution Manual (AP-42) Section 12.3.1, copper mining produces ores that contain less than 1 percent copper. In order to produce copper, the mined ore must be concentrated through crushing, grinding and flotation purification, which results in an enriched ore that contains approximately 15 to 35 percent copper. This is often referred to as "concentrate". In general, most concentrates processed at the FMMI primary copper smelter are equal parts (e.g., one third) sulfur, copper and iron.

At the FMMI smelter, the pyrometallurgical copper smelting process is a four step process consisting of smelting, slag separation, converting and fire refining. The concentrates are fed to the IsaSmelt ® vessel with enriched air, fluxes and natural gas. In this step, the concentrate is converted from a solid feed to a molten metal mix of matte (impure copper) and slag at a temperature of approximately 2300 F (1260 C). This mixture is composed of copper sulfide, copper oxide, iron sulfide, iron oxide, iron silicate and small amounts of trace metals such as gold, silver, lead and other metals. This mix is then transferred to an electric furnace where the matte and slag are separated.

In the electric furnace, electrical resistance is used to maintain temperature and facilitate the separation of slag from the matte by material density and retention time. The electrodes are submersed into the bath and a current is passed through the bath. Periodically, the slag is removed from the electric furnace and transferred to the slag stockpile. Concurrently, the matte (approximately 55% copper) is periodically transferred to the Hoboken Converters for further refining.

The FMMI smelter is the only copper smelter in the United States to use Hoboken converters. This type of converter is fitted with an inverted, u-shaped, side flue at one end that allows the siphoning of gases from the interior of the converter directly into an off gas collection system. This siphoning will also result in a slight vacuum at the mouth of the converter.

In the converters, the matte is converted to blister copper (approximately 99.7% copper) through a two step process of slag separation and oxidation. In the first step, the slag separation (or slag blow), the converters are charged with matte and periodic additions of silica fluxes to facilitate the separation of the residual iron and other impurities from the matte while blast air is introduced to oxidize the impurities. The slag generated in the converter (converter slag) is less dense than the copper portion of the matte, and "floats" on top. This converter slag can then be "skimmed" from the converter by rolling the converter out and pouring the slag into a ladle. The converter slag, which contains recoverable amounts of copper, is transferred to the electric furnace to ensure recovery of the copper values, from the slag. Throughout the slag blow, $SO_2$ is generated and captured. The captured $SO_2$ is transported via duct work to a sulfuric acid plant.

In the second stage of processing the matte, large quantities of enriched air (23+% oxygen) are blown into the matte to oxidize the copper sulfide, producing copper, copper oxide and sulfur dioxide. This step is also known as the copper blow. While the metals remain in the converter, the sulfur dioxide generated during the copper blow is transported via duct work to a sulfuric acid plant, which controls sulfur dioxide emissions by converting it to sulfuric acid. After several hours of oxidizing the matte, the sulfur levels are low enough that the matte is converted to blister copper (a mixture of primarily copper with some copper oxide and trace copper sulfide. The blister is then transferred to the Anode vessels for the final pyrometallurgical (fire) refining step.

During both the slag blow and the copper blow, secondary materials and scrap copper may be added to the converter for temperature control and to recover the copper values. Both slag and copper blows are highly exothermic, and the additions of secondary materials and scrap copper are important to control the temperature of the bath throughout the blowing cycles to prevent damage to the refractory and vessel.

In the anode vessels, the fire refining is a three step process of oxidation, slagging and reduction. In the oxidation step, air is introduced to the bath to remove residual sulfur. During the oxidations step, residual iron which may be present in low levels will be oxidized and create a high copper slag. This slag is skimmed from the anode vessel and returned to a converter to recover copper. After the skimming the slag, the bath is then reduced using a mixture of steam and natural gas. The natural gas removes excess oxygen from the molten copper to acceptable limits, while the steam prevents soot formation. After completion of the oxidation step, the copper is classified as anode copper (99.8+% copper) and is ready for casting into anodes, which are subsequently shipped from the smelter for electrolytic refining.

FMMI also operates a remelt/mold casting vessel. This vessel is similar to the anode vessel in that it has natural gas and steam injection installed for the control of oxidation of copper placed in it. The primary purpose of this vessel is to remelt scrap copper (copper foil, pipe and other grade 1 scrap), reduce oxygen to appropriate levels and pour molds used in the anode plant. The oxygen levels of the copper used in the molds must be very low to ensure that the molds can perform properly during the anode casting cycle. The natural gas and steam injection is used for oxygen control and prevention of soot formation. The vessel is also used as a holding vessel for molten blister copper in the event that there are operational issues at the anode plant with one of the two vessels. Typically, the blister is stored in the vessel, kept in a molten state in the event of an anode vessel having operational issues or taking longer for the fire refining cycle.

## B. Description of Emissions Units Subject-to-Best Available Retrofit Technology (BART)

On August 3, 2008, FMMI provided a letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/Mold Pouring Vessel (installed in approx. 1974)

## C. Streamlined $PM_{10}$ BART Analysis

<u>Step 1: Identify the Existing Control Technologies in Use at the Source</u>

In an earlier letter dated July 17, 2007, FMMI, stated that "we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area…"

On August 3, 2008, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)

- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/Mold Pouring Vessel (installed in approx. 1974)

The FMMI smelter is a major source of Hazardous Air Pollutants (HAPs), and is therefore subject to the requirements of 40 CFR 63 Subpart QQQ, National Emissions Standards for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelting. According to Section 2.1 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, the HAP emissions from primary copper smelters are primarily from metal impurities that naturally occur in copper ore concentrates. During the smelting process, the HAP metal species are eliminated in the molten slag that is tapped from the process vessels, or are vaporized and discharged in the process vessel off-gas. Upon the cooling of the off-gas, the volatilized HAP metal species condense, form aerosols, and behave as particulate matter.

The composition and concentration of HAP metals in the materials processed by the smelter tends to vary due to the different geological formations from where the copper ore was mined, and due to the different slag and scrap materials added during the processes. This inherent variability and unpredictability of the metal HAP compositions in the copper ores affects the amount of emissions of HAPs during the smelting process. As a result, EPA determined that prescribing individual numeric emissions limits for specific HAP metals was impractical, if not impossible.

EPA's alternative to promulgating specific HAP metal limitations in the NESHAP for Primary Copper Smelting was to use particulate matter as a surrogate pollutant for the HAP metals. All primary copper smelters and other smelter source categories are similar in the fact that the metal HAP compounds are a component of the particulate matter contained in the process off-gas discharged from the smelting and converting operations. In addition, controlling particulate matter process fugitive emissions will also result in the control of the metal HAPs that are contained in those emissions. Consequently, EPA determined that the emission limitations that are established to achieve a good control of particulate matter will also have the result of achieving a good control of metal HAP emissions. Therefore, EPA determined that it was appropriate to regulate particulate matter emissions as a surrogate for HAPs.

According to ADEQ Air Quality Permit Number 29622, the following particulate matter controls or emission limits apply to the emissions units that are subject-to-BART:

**Table 13.1 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the FMMI Smelter**

| Emissions Units Subject-to-BART | Current Control | Nonsulfuric Acid PM Emission Limit |
|---|---|---|
| Electric Furnace (Process Gases) | Acid plant tail gas system | 6.2 mg/dscm (40 CFR 63.1444(b)) |
| Electric Furnace (Captured Fugitive Emissions) | Wet scrubber and wet electrostatic precipitator | 23 mg/dscm (40 CFR 63.1444(b)(2)(ii)) |
| Hoboken Converters (Process Gases) | Acid plant tail gas system | 6.2 mg/dscm (40 CFR 63.1444(b)) |
| Hoboken Converters (Fugitive Emissions) | Copper converter capture system | 4% opacity (40 CFR 63.1444(d)(4)) |
| Remelt/Mold Pouring Vessel (similar to Anode Vessel) | Natural gas and steam injection | 20% opacity from the Roofline (A.A.C. R18-2-702.B) or 33% Opacity (A.A.C.-R18-2-702.E) |

When setting the particulate matter limits in the NESHAP, EPA determined that it was most appropriate to set the limitation based upon the particulate matter concentrations that do not include sulfuric acid. When sampling sulfuric acid plant tail gas using Method 5, condensed sulfuric acid mist and waters of hydration that were not driven off at the sampling temperature are included in the probe wash and filter catch, along with any metal HAP contained in the tail gas. As a result, EPA agreed that establishing and determining compliance with a total particulate matter emission limit based on Method 5 may include sulfuric acid mist condensables that are not related to the control or emission of metal HAPs. Given the gas stream characteristics of sulfuric acid plant tail gas, it was EPA's conclusion that Method 5B was the most appropriate test method to use for setting a particulate matter concentration limit that serves as a surrogate for metal HAP emissions contained in the tail gas from sulfuric acid plants.

Step 2 - 6: Streamlined Analysis

Section 2.3 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, stated that Section 112(d)(2) of the Clean Air Act allows EPA to select as MACT, an alternative that is more stringent that the MACT floor. In order to select an alternative, EPA must take into consideration the cost and any non-air quality health and environmental impacts and energy requirements. EPA stated that the objective is to achieve a maximum degree of HAP emissions reductions without imposing unreasonable economic or other impacts.

In response to public comments on the matter, EPA stated that it was aware that there were a number of process modifications and changes for refining copper ores as of December 2001. EPA went on to state, however, that the application of the available modifications and processes were either not applicable to, or not commercially viable for, the existing primary copper smelters that use batch copper converting.

The first alternative that EPA was encouraged to consider was a requirement that all existing primary copper smelting facilities be required to replace their existing batch converters with continuous flash converters. After considering the arguments, however, EPA stated that in its "...judgment that even though a beyond-the-floor alternative requiring the existing batch converters to be dismantled and replaced with continuous flash copper technology may be technically feasible to implement at some or all of the existing smelters potentially subject to the rule, it is not an economically viable alternative. The total cost paid for building the new Kennecott smelter using continuous flash copper converting technology is on the order of one billion dollars. Even using as much of the existing smelter equipment as possible, the total capital investment of replacing the existing batch copper converting process at a smelter with the new continuous flash copper converting process would be in hundreds of millions of dollars. Given the current economic condition of the copper industry in the United States and the fact that none of the companies operating primary copper smelters using batch copper converting plans to change to flash copper converting, a regulatory requirement to do so would impose an enormous economic burden on these smelters." (at p. 2-8)

Other alternatives that EPA considered at the time of the NESHAP proposal included the use of a solvent extraction process and material substitution. After considering these options, however, EPA determined that they were technically infeasible. The solvent extraction process is designed to work for copper oxide ores, not copper sulfide ores. Material substitution is not an option as the HAP emissions from smelters are primarily related to impurities in the copper ores processed by smelter. ADEQ's analysis has revealed that EPA's logic continues to hold true. With respect to material substitution, although the HAP content might be impacted, it is not expected to have any impact on overall particulate matter emissions from the facility.

EPA did specifically address beyond-the-floor alternatives for copper converter departments based upon the control technologies that were used at the ASARCO El Paso smelter. When the El Paso smelter was operating, however, it utilized Pierce-Smith converters which are fundamentally different in design than Hoboken converters. Each of the smelters that employ the Pierce-Smith converters has a system of primary and secondary hoods that are used to capture emissions that emanate out of the mouths of the converters. Hoboken converters, on the other hand, utilize twiers inside the molten bath. In addition to providing the air necessary to oxidize the metals in the molten bath, the movement of the air within the converter, and the draw from the acid plant creates a vacuum at the mouth of the Hoboken converter. This redirects emissions that emanate from the interior of the converter to the acid plant, reducing the amount of fugitive emissions that are allowed to escape from the Hoboken converter. As a result, ADEQ determined that EPA's beyond-the-floor alternatives for the copper converter departments to be non-transferable to the FMMI smelter.

EPA also considered several other beyond-the-floor alternative controls for all of the primary copper smelters. The other options that were considered included the use of air curtain hoods for each batch converter, and to use a converter building evacuation system. In each of these alternatives, EPA proposed that the captured emissions would be vented to a baghouse control device. To support the analysis of the beyond-the-floor alternatives, EPA prepared estimates of the additional HAP emission reduction and the additional costs associated with implementing each of the two alternatives in place. Taking into consideration the costs of implementing either of the alternative, beyond-the-MACT-floor versus the level of additional emissions reductions that were estimated to be achieved, EPA concluded that there are no reasonable alternatives beyond the MACT floor for the control of process fugitive HAP emissions from existing batch converters. Although the HAP emissions make up only a portion of the particulate matter emissions from the smelter, ADEQ has determined that both options are also not appropriate for consideration for BART.

In Appendix A of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, EPA estimated the costs for both beyond-the-floor alternatives for the FMMI smelter as follows (Table 13.2):

**Table 13.2 – 2001 Capital and Annual Costs for Alternative Control Strategies**

| Air Pollution Control Equipment | Estimated Costs (2001 Dollars) | |
|---|---|---|
| | Capital Costs | Annual Costs |
| 1A. Air curtain hood vented to existing PM control device | $10 million | $3 million |
| 1B. Air curtain hood vented to new baghouse | $16 million | $5 million |
| 2. Building evacuation system vented through separate baghouse | $23 million | $8 million |

The Bureau of Labor Statistics is responsible for, among other things, compiling information regarding inflation so that costs from previous years can be compared to modern day costs. On its Web site, the BLS has provided an inflation calculator[9]. According to the calculator's description: "the CPI inflation calculator uses the average Consumer Price Index for a given calendar year. This data represents changes in prices of all goods and services purchased for consumption by urban households. This index value has been calculated every year since 1913. For the current year, the latest monthly index value is used." Using this calculator, EPA's estimated costs in 2009 dollars would be as follows:

[9] http://data.bls.gov/cgi-bin/cpicalc.pl

| Table 13.3 – 2009 Capital and Annual Costs for Alternative Control Strategies | | |
|---|---|---|
| **Air Pollution Control Equipment** | **Estimated Costs (2009 Dollars)** | |
| | **Capital Costs** | **Annual Costs** |
| 1A. Air curtain hood vented to existing PM control device | $12.2 million | $3.6 million |
| 1B. Air curtain hood vented to new baghouse | $19.5 million | $6.1 million |
| 2. Building evacuation system vented through separate baghouse | $28.0 million | $9.7 million |

At the time that the FMMI Smelter was modeled for PM emissions, ADEQ estimated potential smelter fugitive particulate matter emissions to be 48.55 pounds per hour, or a maximum of 212 tons per year. Given the relatively small amount of particulate matter reductions and the high costs associated with achieving those reductions, ADEQ has determined that the two alternative approaches considered by EPA remain overly burdensome due to costs alone.

Finally, according to Section 6.1 of the *National Emissions Standard for Hazardous Air Pollutants (NESHAP) for Primary Copper Smelters – Background Information for Promulgated Standards*, dated December 2001, EPA reviewed the estimated costs for the primary copper smelters to comply with the standards under the final rule. Although EPA concluded that some of the smelters would need to install additional air pollution control equipment to meet the standards, EPA did state that the FMMI smelter, which operates Hoboken converters, was believed to be able to meet the standards under the final rule without having to install additional air pollution control equipment (at p. 6-2). Through inspections and performance testing that has been conducted at the FMMI smelter since the time that the NESHAP was promulgated, ADEQ has confirmed that the smelter is capable of being operated in compliance with the non-sulfuric acid particulate matter emission limitations in the NESHAP.

After the EPA promulgated the NESHAP for Primary Copper Smelting, there have been significant changes to the industry. Of the six primary copper smelting facilities that were potentially covered by the NESHAP, only three remain: the Kennecott Smelter in Utah, the ASARCO smelter in Hayden, Arizona, and the FMMI smelter in Miami, Arizona. The other facilities have been shut down or permanently dismantled.

As noted before, the Kennecott Smelter's continuous flash converter process is considered a different subcategory of primary copper smelting, and inherently different from the batch converter process. As a result, the controls and emissions limitations for the Kennecott Smelter are not considered to be transferable to FMMI smelter.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that no emission limitations or air pollution control devices have been approved for copper smelters since the institution of the NESHAP for Primary Copper Smelting. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the implementation of the NESHAP for Primary Copper Smelting there have been no changes at either the ASARCO Hayden smelter or the FMMI smelter that have triggered Prevention of Significant Deterioration review. As a result, ADEQ has determined that the most stringent controls for particulate matter emissions is the NESHAP for Primary Copper Smelting.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with FMMI's conclusion that the NESHAP for Primary Copper Smelting constitutes BART for PM emissions.

## D. Streamlined $SO_2$ BART Analysis

Step 1: Identify the Existing Control Technologies in Use at the Source

In a letter dated July 17, 2007, FMMI stated that "we do not disagree with the results that the Miami facility is subject-to-BART, because the visibility impact was greater than 0.5 dv at the Superstition Wilderness area…"

On August 3, 2008, FMMI provided another letter to ADEQ, presenting several bases for streamlining the BART review for the FMMI Smelter. According to the letter, FMMI stated that it believed that only the following emissions units at the facility constituted the "source subject-to-BART":

- The Electric Furnace (installed in 1974)
- The four Hoboken Converters (Converters Nos. 2-5) (installed in 1974) ; and
- The Remelt/mold pouring Vessel (installed in approx. 1974)

**Table 13.4 – Current Air Pollution Control Equipment and Emission Limits for Equipment Subject-to-BART at the FMMI Smelter.**

| Emissions Units Subject-to-BART | Current Control | $SO_2$ Emission Limit |
|---|---|---|
| Electric Furnace (Process Gases) | Acid plant tail gas system | 1. 820 pounds per hour [Installation Permit #1232] 2. 3,515 tons per year [Installation Permit #1232] 3. 0.065% concentration by volume [40 CFR 60.163(a)] |
| Electric Furnace (Captured Fugitive Emissions) | Vent fume stack scrubber | 1. 312 pounds per hour [Installation Permit #1232] 2. 1,336 tons per year [Installation Permit #1232] |
| Hoboken Converters (Process Gases) | Acid plant tail gas system | 1. 820 pounds per hour [Installation Permit #1232] 2. 3,515 tons per year [Installation Permit #1232] 3. 0.065% concentration by volume [40 CFR 60.163(a)] |
| Hoboken Converters (Fugitive Emissions) | Smelter fugitives | 1. 1,288 pounds per hour [Installation Permit #1232] 2. 5,517 tons per year [Installation Permit #1232] |
| Remelt/Mold Pouring Vessel | Natural gas and steam injection | 20% opacity from the Roofline (A.A.C. R18-2-702.B) or 33% Opacity (A.A.C.-R18-2-702.E) |

In addition to identifying the above controls for the BART-eligible equipment at the Miami primary copper smelter, ADEQ also determined that it is important to note the process changes and control equipment that have been installed over time at the facility.

According to ADEQ's *Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, smelting operations began in Miami in 1915. Prior to 1974, the facility operated reverberatory furnaces and Peirce Smith converters in order to process copper sulfide ore from the nearby mines. In 1974, however, an electric furnace and Hoboken or siphon converters were installed for processing dried copper ore concentrates. A double contact acid plant was also installed in order to reduce the amount of $SO_2$ gases that are produced and emitted during the smelting and converting operations.

Prior to the installation of the double contact acid plant in late 1974, all process gasses from the smelting operations were emitted into the atmosphere after particulate matter was first removed by an electrostatic precipitator. Sulfur balance data available from that time period indicated that emissions of $SO_2$ from the Miami smelter were at least 34,000 lbs/hr (17 tons/hr). Actual emissions of $SO_2$ in the time period were estimated to be greater than 175,000 tons per year.

In 1992, the Miami smelter undertook a series of pollution control improvements, including the installation of an IsaSmelt® furnace and a 528 ton per day oxygen plant to enrich the smelting blast air.

In particular, the IsaSmelt® furnace eliminated the Miami copper smelter's use of the electric furnace as the primary device for smelting. In addition to increasing the facility's efficiency in producing copper, the IsaSmelt® conversion also improved the control of $SO_2$ emissions, as the new furnace comprises a closed vessel that is designed to contain the emissions from the process and route the process gasses generated to the acid plant. The result of these upgrades reduced the amount of fugitive $SO_2$ emissions being directly vented to the atmosphere from the electric furnaces that it replaced.

The double contact sulfuric acid plant is the predominant control device for process gases containing $SO_2$ at the Miami smelter. Process gases that are produced by the IsaSmelt® furnace, electric furnace, and converters are first cooled and cleaned of particulates in a gas scrubbing and electrostatic precipitator system in order to prepare the gas stream for treatment in the acid plant. After cooling and cleaning, the gas stream is dried and the $SO_2$ is converted by catalyst to sulfur trioxide ($SO_3$). The $SO_3$ is then adsorbed in circulating sulfuric acid to become sellable grade acid. Overall efficiency of $SO_2$ recovery from the acid plant has been found to be 99.9%

According to ADEQ's Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan, dated June 2002, the complete list of $SO_2$ Process and Control Technologies employed by the Miami primary copper smelter throughout the years is as follows (Table 13.5):

**Table 13.5 – Implementation of $SO_2$ Process and Control Technology**

| Year | Equipment |
|---|---|
| 1974 | Replacement of reverberatory furnace and old converters with an Electric Furnace and Hoboken converters.<br><br>Installation of a double contact acid plant for treatment of primary process gases. |
| 1979 – 1981 | Installation of Electric Furnace matte fume hoods at matte tapping area for capture of fugitive emissions. |

| Table 13.5 – Implementation of $SO_2$ Process and Control Technology | |
|---|---|
| **Year** | **Equipment** |
| 1992 | Installation of an IsaSmelt® Furnace and new oxygen plant.<br><br>Installation of IsaSmelt® Furnace tapping launder covers, Electric Furnace slag tapping hoods, and vent fume scrubber for capture and control of fugitive emissions. Upgrade to increase the fan capacity of vent fume system for the two new fugitive emissions collection points.<br><br>Upgrades to the acid plant and installation of a 3rd stage electrostatic mist precipitator at the acid plant and acid plant tail gas peaking scrubber for control of primary process emissions. |
| 1997 | Replacement of the old intermediate absorption tower at the acid plant with a new tower to increase the efficiency of the acid plant. The replacement is equipped with high efficiency (candle type) mist eliminators.<br><br>Installation of a new catalytic converter, preheater, $SO_3$ cooler, product acid cooler and a final absorber, and replacement of two cold reheat exchangers at the acid plant. |
| 1998 | Intermediate absorber and cold reheat exchangers put into service. |

Steps 2 - 6: Streamlined Analysis

On November 27, 2007, FMMI submitted a letter to ADEQ indicating that in December 2003, the Western Regional Air Partnership (WRAP) had made a finding that "[a] double-contact acid plant will be considered the appropriate retrofit control equipment…" for $SO_2$ emissions. In support, FMMI referred ADEQ to see a November 2002 report from E.H. Pechan & Associates, Inc. entitled *WRAP Market Trading Forum Non-Utility Sector Allocations Final Report from the Allocations Working Group.*

ADEQ reviewed the November 2002 report, and found that, at the time the report was published, the WRAP did state that "[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.)" In addition, the report noted that there are six primary copper smelters in the WRAP region. Of the six, five are near copper mines in the southwest United States and use a batch process to produce copper. Of these five, only two of the smelters were producing copper, "…(the ASARCO smelter in Hayden, Arizona and the Phelps Dodge (now FMMI) smelter in Miami, Arizona.)"

The WRAP's report also stated that the sixth smelter, Kennecott Utah Copper Corporation's operation near Garfield, Utah, was constructed in the mid 1990's and that it uses a flash copper converting technology. This flash copper converting technology allows copper to be produced in a continuous process.

ADEQ's analysis of the copper smelting industry in the United States has revealed that there are currently three operating copper smelters. Those smelters are the ASARCO smelter in Hayden, Arizona, the FMMI smelter in Miami, Arizona, and the Kennecott Utah Copper Corporation's facility near Garfield, Utah. No other copper smelters have operated since the time that the WRAP's report has been published, and ADEQ is unaware of any plans to restart any of those smelters in the near future.

As previously noted, ADEQ's review of the Kennecott Utah Copper Corporation's operation has led to the determination that the continuous production of blister copper is a fundamentally different process than the process employed by the FMMI Smelter. ADEQ has also determined that BART does not contain a requirement that the source be redesigned when the Department considers the available control alternatives. As a result, ADEQ has concluded that it is not necessary to consider the use of Kennecott Utah Copper Corporation's process as a potential BART alternative.

Emissions from the Miami smelter have varied over the years due to a number of factors, including the price of, and demand for, copper. According to the *2018 $SO_2$ Emissions Evaluation For Non-Utility Sources Final Report, October 2006,* provided by Pechan to the WRAP's Stationary Sources Joint Forum, historical $SO_2$ emissions from the Miami smelter are as follows (Table 13.6):

**Table 13.6 – Annual $SO_2$ Emissions from the Miami Smelter**

| Year | $SO_2$ Emissions (Tons Per Year) |
|---|---|
| 1990 | 5,676 |
| 1996 | 5,737 |
| 1998 | 6,097 |
| 2000 | 6,810 |
| 2003 | 8,005 |
| 2004 | 8,754 |

As noted in Table 13.6, $SO_2$ emissions from this facility have been steadily increasing since 1990. It is understood that the emissions increase trend can be attributed to increased utilization of capacity that was already available at the facility. Air Quality Control Permit Number 29622 issued by ADEQ on July 5, 2006, however, limits overall $SO_2$ emissions from the facility to no more than 10,368 tons per year. In addition, short term emissions are addressed in the permit, as seen in Table 13.4 above.

According to ADEQ's *Final Miami Sulfur Dioxide Nonattainment Area State Implementation and Maintenance Plan*, dated June 2002, the process changes and installation of air pollution controls through the years has resulted in an increased overall $SO_2$ control efficiency at the Miami primary copper smelter. Since the 1970's, the $SO_2$ control rate has risen from approximately 5% to approximately 75% with the installation of the double contact acid plant in the 1974, to approximately 99% as a result of the activities identified in Table 13.5. Conversely, estimated $SO_2$ emissions from the facility fell from approximately 175,000 tons per year in the early 1970s, to less than 10,000 tons per year at the current time.

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) revealed that no emission limitations or air pollution control devices have been approved for copper smelters for sulfur oxides since the installation of the double contact acid plant in 1974. In addition, the only two remaining primary copper smelting operations that use batch converters are in Arizona and are subject to ADEQ's jurisdiction. Since the installation of the double contact acid plant there have been no changes at either the ASARCO Hayden smelter or the FMMI smelter that have triggered Prevention of Significant Deterioration review for sulfur oxides ($SO_2$). As a result, ADEQ has determined that the most stringent control available to control $SO_2$ emissions from primary copper smelting operations is the double contact acid plant.

It should also be noted that EPA non-attainment designations for the new 1-hour SO2 standard are required to be completed in June 2013. EPA has proposed to accept the Governor's recommendation to

designate the Miami area as non-attainment for the new standard. This designation will result in an obligation for the State of Arizona to work on a State Implementation Plan to prescribe control strategies to bring the area to compliance with the 1-hour SO2 standard within 5 years of designation. That timeline will ensure that additional SO2 emission reductions that are necessary to protect human health will be in place prior to the end of the BART period, which will be no sooner than July 15, 2018. It clearly creates certainty with both regulatory processes where the establishment of any new controls to achieve compliance with the NAAQS will essentially translate into significant improvement from a visibility perspective. It should be noted that the control technology evaluation from a NAAQS compliance standpoint does not have built-in cost considerations. From that standpoint, that process will result in emission reductions that may otherwise be considered cost-prohibitive in a conventional BART analysis.

Step 7: Select BART

Based upon ADEQ's review of all of the above, ADEQ concurs with FMMI's conclusion that the installation and operation of the double contact acid plant with the New Source Performance Standard of 650 ppm constitutes BART for $SO_2$.

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## XIV. SRP CORONADO GENERATING STATION BART ANALYSIS AND DETERMINATION

### A. Process Description

SRP Coronado Generating Station (CGS) is comprised of two coal-fired electric utility steam generating units, specifically Unit 1 and Unit 2. These are dry-turbo-fired boilers with a net rated output of 395 MW and 390 MW respectively. CGS generates electricity by combustion of pulverized coal that heats water in boiler tubes to produce steam. This steam is then used to turn a turbine which is connected on a common shaft to a generator rotor. As the rotor in the generator is turned, it induces an electrical current in the stator windings of the generator, making electricity.

### B. Consent Decree

On December 22, 2008, SRP and EPA entered into entered into a Consent Decree which requires the implementation of the following pollution control projects for $SO_2$ and $NO_X$ at SRP's CGS facility.

- Addition of LNB to Units 1 and 2 to reduce $NO_X$ emissions. Coupled with the burner additions will be modifications to the furnace combustion air system on each Unit (ACC).
- Addition of a Selective Catalytic Reduction (SCR) to Unit 2. The SCR will further reduce $NO_X$ emissions from Unit 2.
- Replacement of the existing Pullman Kellog wet limestone Flue Gas Desulfurization systems on Unit 1 and Unit 2 with new wet limestone FGD (WFGD) systems to further reduce $SO_2$ emissions.

The implementation schedule as laid out in the Consent Decree is as follows:.

**Table 14.1 – Implementation Summary of Pollution Control Projects**

| Unit | Projected Operational Date | Expected Emission Rates |
|---|---|---|
| 1 or 2 | ACC – June 1, 2009 | $NO_X$ - 0.320 lb / MMBtu |
| 2 or 1 | ACC – June 1, 2011 | $NO_X$ - 0.320 lb / MMBtu |
| 2 | SCR – June 1, 2014 | $NO_X$ - 0.080 lb / MMBtu |
| 2 | FGD – January 1, 2012 | $SO_2$ – 95% control or 0.080 lb / MMBtu |
| 1 | FGD – January 1, 2013 | $SO_2$ – 95% control or 0.080 lb / MMBtu |

### C. Description of Emissions Units Subject to Best Available Retrofit Technology (BART)

The BART– affected emission units at the CGS are Units 1 and 2. These units are BART- eligible since they meet the following requirements:

1. They were "in existence" between 1962 and 1977. Units 1 and 2 were in the construction phase in this period.
2. The emissions from the combined BART-eligible units are greater than 250 tons/year. Emissions of sulfur dioxide ($SO_2$), nitrogen oxides ($NO_X$), and particulate matter below 10 micron size ($PM_{10}$) are 29,384, 20,361, and 1,008 tons per year respectively.

3. These units belong to one of the 26 categories of sources identified in the Regional Haze Rule.

Further in order to confirm that the CGS has visibility impacts on the Class I areas, CALPUFF modeling was conducted by SRP to assess impacts at 17 Class I areas. Modeling was conducted with three years of CALMET meteorological data (2001-2003). The results of the baseline CALPUFF modeling are listed in Table 2. This table provides the $8^{th}$ highest delta-deciview and the total $8^{th}$ highest deciview (Source contribution plus the natural background).

As demonstrated in Table 2, the impact of CGS on the visibility in Class I areas is more than 0.5 dv threshold that is used as a trigger for BART applicability. Therefore, Units 1 and 2 at CGS are presumed to cause or contribute to visibility impairment and are, therefore, subject-to-BART for $SO_2$, $NO_X$, and $PM_{10}$.

| Table 14.2 – Regional Haze Impacts Due to Baseline Emissions | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Class I Area | Ave. Annual Natural Background | Met Year 2001 | | Met Year 2002 | | Met Year 2003 | | Average Highest Total Δdv |
| | | 8th Highest Δdv | 8th Highest Total Δdv | 8th Highest Δdv | 8th Highest Total Δdv | 8th Highest Δdv | 8th Highest Total Δdv | |
| Bandalier, NM | 4.46 | 1.0 | 5.4 | 1.1 | 5.5 | 1.0 | 5.5 | 5.46 |
| Bosque del Apache | 4.41 | 1.5 | 5.9 | 1.7 | 6.1 | 1.5 | 5.9 | 5.96 |
| Chiricahua, NM | 4.36 | 0.8 | 5.2 | 0.6 | 5.0 | 1.1 | 5.5 | 5.23 |
| Chiricahua, W | 4.35 | 0.7 | 5.1 | 0.6 | 5.0 | 1.2 | 5.6 | 5.23 |
| Galiuro W | 4.32 | 1.0 | 5.3 | 0.8 | 5.1 | 0.9 | 5.2 | 5.2 |
| Gila W | 4.39 | 2.0 | 6.4 | 2.0 | 6.4 | 2.3 | 6.7 | 6.5 |
| Grand Canyon NP | 4.39 | 1.1 | 5.5 | 0.8 | 5.2 | 0.5 | 4.9 | 5.2 |
| Mazatzal W | 4.35 | 0.9 | 5.2 | 1.0 | 5.4 | 1.4 | 5.8 | 5.45 |
| Mesa Verde NP | 4.53 | 1.1 | 5.6 | 1.1 | 5.6 | 1.2 | 5.7 | 5.63 |
| Mount Baldy W | 4.39 | 1.6 | 6.0 | 1.4 | 5.8 | 2.0 | 6.4 | 6.1 |
| Petrified Forest NP | 4.41 | 2.5 | 6.9 | 2.8 | 7.2 | 2.7 | 7.1 | 7.1 |
| San Pedro Parks W | 4.47 | 0.9 | 5.4 | 1.3 | 5.8 | 1.3 | 5.7 | 5.6 |
| Sierra Ancha W | 4.36 | 1.0 | 5.3 | 1.3 | 5.6 | 1.7 | 6.0 | 5.6 |
| Superstition W | 4.32 | 1.1 | 5.4 | 1.0 | 5.3 | 1.4 | 5.7 | 5.5 |
| Pine Mountain W | 4.36 | 0.5 | 4.8 | 0.7 | 5.1 | 1.0 | 5.3 | 5.1 |
| Saguaro W & NP | 4.28 | 0.8 | 5.1 | 0.6 | 4.9 | 0.7 | 4.9 | 5.0 |
| Sycamore Canyon W | 4.40 | 0.8 | 5.2 | 0.7 | 5.1 | 0.8 | 5.2 | 5.2 |

Notes:
W: Wilderness Area; NP: National Park; NM: National Monument

## D. BART for $NO_X$

Step 1: Identify the Existing Control Technologies in Use at the Source

$NO_X$ emissions from both Units 1 and 2 are currently controlled by good combustion practices and overfire air. The resulting emission rate ranges from 0.45 to 0.50 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

The alternative $NO_X$ control technologies for limiting $NO_X$ emissions from Unit 1 and Unit 2 are listed as follows:

- Advanced Combustion Control-Low $NO_X$ burners (LNB) and over fire air (OFA)
- Selective non-catalytic reduction (SNCR)
- Selective catalytic reduction (SCR)

The brief evaluation of the above control technologies is provided below:

**Advanced Combustion Control (ACC).** ACC, including LNB and OFA, on a dry-turbo-fired boilers are designed to control fuel and air mixing to reduce peak flame temperatures resulting in less $NO_X$ formation. Combustion reduction and burnout are achieved in three stages within a conventional low $NO_X$ burner. In the initial stage, combustion occurs in a fuel rich, oxygen deficient zone where the $NO_X$ is formed. In the second stage, the exhaust gases from Stage 1 are exposed to a reducing atmosphere where hydrocarbons that react with the already formed $NO_X$ are formed. In the third stage, internal air staging completes the combustion, but may result in additional $NO_X$ formation. This, however, can be minimized by completing the combustion in an air lean environment. Combustion air is separated into primary and secondary flow sections to achieve complete burnout and to encourage the formation of nitrogen, rather than $NO_X$. Primary air (70-90%) is mixed with the fuel producing a relatively low temperature, oxygen deficient, fuel-rich zone thereby reducing the formation of fuel-bound $NO_X$. Secondary air representing 10-30% of the combustion air is injected above the combustion zone through a special wind-box with air introducing ports and/or nozzles mounted above the burners. Combustion is completed at this increased flame volume. This process limits the production of thermal $NO_X$.

**Selective Non-Catalytic Reduction (SNCR).** SNCR is based on a gas-phase homogeneous reaction that involves the injection of an-amine based compound into the fuel at an appropriate temperature range for reduction of $NO_X$. An amine-based compound such as ammonia ($NH_3$) or urea ($(NH_2)_2$ CO) is used as the $NO_X$ reducing agent. When ammonia or urea is injected into the flue gas stream, it selectively reduces the $NO_X$ into molecular nitrogen and water. At stoichiometric conditions, when the adequate residence time is reached, the overall reactions that occur may be characterized by:

Ammonia

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

Urea

$$2\ (NH_2)_2\ CO + 4\ NO + O_2 \rightarrow 4\ N_2 + 2\ CO_2 + 4\ H_2O$$

In an SNCR system, $NO_X$ reduction does not take place in the presence of a catalyst, but rather is driven by the thermal decomposition of ammonia and urea and the subsequent reduction of $NO_X$. Consequently, the SNCR process operates at higher temperatures than the SCR process. The temperature of the flue gas is critical to the successful reduction of $NO_X$ with SNCR at the point where the reagent is injected. For the ammonia injection process, the necessary temperature range is 1700 to 1900°F. The other factors affecting the performance of SNCR performance are gas mixing, residence time at operating temperatures, and ammonia slip. Since ammonia is present in the flue gas, a portion of the ammonia may oxidize at temperatures greater than 2000°F. Above 2000°F, the reaction of ammonia oxidation becomes predominant. Nitrogen monoxide is formed as a product of the reaction. Thus, when the flue gas temperature at reagent injection locations is higher than the appropriate temperature window, the SNCR process results in increased $NO_X$ formation rather than $NO_X$ reduction. At temperatures lower than the required temperature window, the $NO_X$ reduction rates becomes lower, and unreacted ammonia may slip through and be emitted to the atmosphere.

**Selective Catalytic Reduction (SCR).** SCR is a process that involves post-combustion removal of $NO_X$ from the flue gas utilizing a catalytic reactor. In the SCR process, ammonia injected into the flue gas reacts with the $NO_X$ and oxygen to form Nitrogen and water by the following general reactions:

$$4\ NO + 4\ NH_3 \rightarrow 4\ N_2 + 6\ H_2O$$

$$2\ NO_2 + 4\ NH_3 + O_2 \rightarrow 3\ N_2 + 6\ H_2O$$

These reactions take place on the surface of the catalyst. The function of the catalyst is to effectively lower the activation energy of the $NO_X$ decomposition reaction to about 375 to 750°F, depending on the specific catalyst and other contaminants in the flue gas. The factors affecting SCR performance are catalyst reactor design, optimum operating temperature, sulfur content of the fuel, catalyst deactivation due to aging or poisoning, ammonia slip emissions, and design of the ammonia injection system.

The SCR system is comprised of a number of subsystems, including the SCR reactor, ammonia injection system, and ammonia storage and delivery system. The SCR reactor would be located downstream of the economizer and ESP, and upstream of the air pre-heater. From the ESP outlet, the flue gas would first pass through a low-pressure ammonia/air injection grid designed to provide optimal mixing of ammonia with flue gas. The ammonia treated flue gas would then flow through the catalyst bed and exit to the air pre-heater. The SCR system for a pulverized coal boiler typically uses a fixed bed catalyst in a vertical down-flow, multi-stage reactor.

Reduction catalysts are divided into two groups: base metal, primary vanadium, platinum, or titanium (lower temperature) and zeolite (higher temperature). Both groups exhibit advantages and disadvantages in terms of operating temperature, ammonia- $NO_X$ ratio, and optimum oxygen concentration. The optimum operating temperature for a vanadium-titanium catalyst system is in the range of 550° to 800°F, which is significantly higher than the optimum operating temperature for the platinum catalyst systems. The vanadium-titanium catalyst begins to break down, however, when continuously operating at temperatures above this range. Operation above the maximum temperature results in oxidation of ammonia to either ammonium sulfate or $NO_X$, thereby actually increasing the $NO_X$ emissions.

To achieve high $NO_X$ control efficiencies, the SCR vendor suggests a higher ammonia injection rate than is stoichiometrically required to react all of $NO_X$ in the combustion gases. This results in emissions of un-reacted ammonia or "ammonia slip". The various SCR vendors typically guarantee ammonia slip of about 2 ppm for systems designed for very high $NO_X$ performance levels. This excess ammonia may react with $SO_3$ and water to form ammonium bisulfate $(NH_4)\ HSO_4$ and ammonium sulfate, $(NH_4)_2\ SO_4$. Higher levels of ammonia and $SO_2$ results in formation of higher levels of these salts. These ammonium

salts may condense as the flue gases cool and can lead to increased emissions of both $PM_{10}$ and $PM_{2.5}$. Furthermore the catalyst promotes the partial oxidation of $SO_2$ to $SO_3$, which in turn combines with water thereby increasing the formation of these ammonia salts and potential emissions of $PM_{10}$ and $PM_{2.5}$.

Some SCR installations have experienced significant air pre-heater plugging and corrosion resulting from the deposition of ammonium bisulfate. The plugging and corrosion can cause reduced boiler efficiency, higher flue gas pressure drop, more frequent air pre-heater cleaning and washing, increased boiler downtime, and increased maintenance cost. The primary factors for controlling the formation and deposition of ammonium bisulfate are the levels of ammonia, the level of $SO_3$, the air pre-heater surface temperature profile, the air pre-heater surface material, and the air pre heater physical configuration. The temperature window for ammonium bisulfate formation is as wide as 300° to 425°F.

The SCR system is subject to catalyst deactivation over time. Catalyst deactivation occurs through two primary mechanisms: physical deactivation and chemical poisoning. Physical deactivation usually results from either prolonged exposure to excessive temperatures or masking of the catalyst due to entrainment of particulate from ambient air or air contaminants. Chemical poisoning is caused by the irreversible reaction of the catalyst with a contaminant in the gas stream and thus a permanent condition. Catalyst suppliers typically guarantee a limited lifetime for high performance catalyst systems. Fly ash plugging generally results from excessive carryover to the catalyst or poor catalyst gas flow design.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the above control technologies are feasible options for BART at CGS.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

The alternative $NO_X$ control technologies, ACC, SNCR, and SCR, have been successfully applied to new utility coal fired boilers, as well as retrofitted to existing coal fired boilers. The effectiveness of these technologies in reducing $NO_X$ emissions is dependent primarily on the inlet $NO_X$ concentrations, residence time, and operating temperatures. ACC has been demonstrated to achieve 25% to 35% reduction in uncontrolled $NO_X$ emissions. SNCR has been demonstrated to achieve $NO_X$ control efficiencies ranging from 30% to 50% with inlet $NO_X$ concentration of 300 to 400 ppmvd. If staged combustion is used to reduce inlet $NO_X$ concentrations to less than 250 ppmvd, SNCR is capable of achieving $NO_X$ control efficiencies of only 20% to 40%. Likewise, SCR can achieve $NO_X$ control efficiencies as high as 90% with inlet concentrations in the range of 300 to 400 ppmvd. If inlet $NO_X$ concentrations are less than 250 ppmvd, SCR can achieve $NO_X$ control efficiencies ranging from 70% to 80%.

In its BART analysis, CGS considered the above technologies for control of $NO_X$ in the following sequence: ACC in both Unit 1 and Unit 2, ACC with SNCR in both Unit 1 and Unit 2, ACC in both Unit 1 and Unit 2 with SCR in Unit 2, and ACC and SCR in both Unit 1 and Unit 2. Based on the information provided by the equipment vendors, the controls listed above were estimated to reduce $NO_X$ emissions as demonstrated in Table 14.3.

| Table 14.3 – $NO_X$ Emission Factors resulting from $NO_X$ Controls | | | |
|---|---|---|---|
| Control Option | Control Technology | Unit 1 | Unit 2 |
| | | Pounds/MMBtu | |
| | Baseline | 0.433 | 0.433 |
| 3 | ACC- Both Units | 0.32 | 0.32 |
| 4a | ACC and SNCR- Both Units | 0.224 | 0.224 |
| 4 b | ACC (Both Units) and SCR on Unit 2 | 0.32 | 0.08 |
| 5 | ACC and SCR on both Units | 0.08 | 0.08 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Costs of Compliance*

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 14.4 provides the information on the annual costs associated with each of the control options.

| Table 14.4 – Total Capital and Annual Costs associated with $NO_X$ Controls | | | | | |
|---|---|---|---|---|---|
| Control Option | Control Technology | Total Capital (Million $) | Fixed Capital (Million $) | Annual O&M (Million $) | Total Annual Cost (Million $) |
| 3 | ACC- Both Units | $13.00 | $1.227 | 0 | $1.227 |
| 4a | ACC and SNCR- Both Units | $26.00 | $2.454 | $2.200 | $4.654 |
| 4 b | ACC (Both Units) and SCR on Unit 2 | $79.00 | $7.4570 | $1.100 | $8.557 |
| 5 | ACC and SCR on both Units | $145.0 | $13.69 | $3.400 | $17.09 |

* Fixed capital cost calculation is based on a CRF of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 14.5 provides annual estimated emission numbers for $NO_X$ and cost figures relating to the implementation of various control options for $NO_X$.

| Table 14.5: Total Annual Emissions of $NO_X$ with different options of $NO_X$ Controls | | | | | |
|---|---|---|---|---|---|
| Factor | Baseline | Option 3 | Option 4a | Option 4b | Option 5 |
| Unit 1 | 10,332 tpy | 7,636 tpy | 5,345 tpy | 7,636 tpy | 1,909 tpy |
| Unit 2 | 10,029 tpy | 6,887 tpy | 4,821 tpy | 1,722 tpy | 1,722 tpy |
| Total (Both Units) | 20,361 tpy | 14,523 tpy | 10,166 tpy | 9,358 tpy | 3,631 tpy |
| Reduction from Baseline | - | 5,838 tpy | 10,195 tpy | 11,003 tpy | 16,730 tpy |
| Incremental Reduction from earlier option | - | 5,838 tpy | 4,357 tpy | 808 tpy | 5,727 tpy |

| Table 14.5: Total Annual Emissions of $NO_X$ with different options of $NO_X$ Controls | | | | | |
|---|---|---|---|---|---|
| **Factor** | **Baseline** | **Option 3** | **Option 4a** | **Option 4b** | **Option 5** |
| Annualized Cost (Million $) | - | $1.227 | $4.654 | $8.556 | $17.09 |
| Cost of reduction (Dollar per ton) | - | $210 | $457 | $778 | $1,021 |
| Incremental cost of reduction (Dollar per ton) | - | $210 | $787 | $4,830 | $1,489 |

*Energy Impacts*

SCR will consume significantly more energy as compared to the energy consumption in SNCR. This is due to the power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower. Assuming a pressure drop of 14 inches of water across the catalyst bed, SCR applied to both units will consume 7,300 kWh more electrical power per year than SNCR (approaching 1% of the total power generation of the CGS).

*Non-Air Quality Environmental Impacts*

One of the most significant impacts of retrofitting SCR and SNCR is the addition of ammonia and urea storage and handling systems. Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health. An accidental release of anhydrous ammonia or 20% or greater aqueous ammonia is reportable to local, state, and federal agencies. In anticipation of such an incident, the site will need to develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures (PSM) Program.

Ammonia associated with fly ash has the potential to present several problems with the disposal and/or the use of fly ash. Once the fly ash is exposed to the SNCR process, there will be a significant quantity of soluble salts associated with fly ash. These salts are expected to be $(NH_4)HSO_4$ and $(NH_4)_2SO_4$.

Dry disposal of ash can cause the leachate and/or runoff water to contain increased concentrations of ammonia. If and when these salts are contacted with water, they will most likely be dissolved and the resulting aqueous concentration of nitrogen-containing compounds can increase in the waters associated with the ash. Table 10 below summarizes the non-air quality environmental impacts associated with the proposed BART control options.

| Table 14.6 – Summary of Non-Air Quality Environmental Impacts | |
|---|---|
| **Control Option** | **Summary of Non-Air Quality Environmental Impacts** |
| ACC | - Potential to increase in loss of ignition (LOI) of flyash, which could reduce recycling sales.<br>- Slight increase in $CO_2$ emissions/kWH associated with reduced boiler efficiency.<br>- Potential for incomplete combustion (lost energy).<br>- Potential for increased corrosion and more frequent replacement of furnace water tubes. |

| Table 14.6 – Summary of Non-Air Quality Environmental Impacts | |
|---|---|
| **Control Option** | **Summary of Non-Air Quality Environmental Impacts** |
| SNCR | - Addition of ammonia or urea storage and handling systems.<br>- Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies.<br>- The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safety Measures Program (PSM).<br>- Sulfuric acid in the flue gas can cause various power plant operation and maintenance problems. Condensation of sulfuric acid has a significant detrimental effect on downstream equipment, including fouling and corrosion of heat transfer surfaces in the air pre heater.<br>- Ammonia associated with flyash has the potential to present several problems with the disposal and/or use of flyash.<br>- Dry disposal of flyash can cause leachate and/or runoff water to contain increased concentrations of ammonia and/or nitrogen-containing compounds. |
| SCR | - Addition of Ammonia handling system.<br>- Anhydrous ammonia and aqueous ammonia above 20% are considered dangerous to human health and accidental releases are reportable to local, state, and federal agencies.<br>- The facility must develop, implement, and maintain a Risk Management Plan (RMP) and Process Safely Measures Program (PSM).<br>- Disposal of spent catalyst containing heavy metals such as vanadium, tungsten, or molybdenum.<br>- Increase in $CO_2$ emissions from power required for the increased fan static pressure required to overcome the pressure drop across the catalyst bed, as well as for pumps and evaporator blower. |

Step 6: Evaluate Visibility Impacts

Four different scenarios for control of $NO_x$ emissions were modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. Brief details of the modeling results are as under:

**Option 3: WFGD with ACC.** The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.11dv.

**Option 4a: WFGD with ACC and SNCR on both units.** The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.19 dv.

**Option 4b: WFGD with ACC on both units and SCR on Unit 2.** The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.22 dv.

**Option 5: WFGD with ACC and SCR on both units.** The modeling result indicates that this control option provides an improvement in visibility index by approximately 0.34 dv.

Table 12.7 below provides information on the cost in dollars per deciview improvement in visibility achieved by implementing the respective control options. The table also presents details on the incremental cost in dollars per deciview improvement over different control options.

| Table 12.7 – Summary for $NO_X$ BART | | | | | |
|---|---|---|---|---|---|
| **Factor** | **Option 2 Baseline, WFGD** | **Option 3 ACC** | **Option 4a ACC w/ SNCR** | **Option 4b ACC w/ SCR for Unit 2** | **Option 5 ACC w/ SCR** |
| Reduction in Emission (tpy) | - | 5,838 | 10,195 | 11,003 | 16,730 |
| Annualized Cost (Million $) | - | $1.227 | $4.654 | $8.557 | $17.09 |
| Visibility Index Improvement Over Baseline (Δ dv) | - | 0.11 | 0.19 | 0.22 | 0.34 |
| Incremental Cost Effectiveness (Million $/dv) | - | $11.15 | $24.50 | $38.89 | $50.25 |

Step 7: Select BART

After reviewing the BART analysis provided by the company, and based upon the information above, ADEQ has determined that BART control at CGS for $NO_x$ is ACC (Low $NO_x$ burners with OFA) with an associated $NO_x$ emission rate of 0.32 lbs/MMBtu on 30-day rolling average basis.

## E. $PM_{10}$ BART

Step 1: Identify the Existing Control Technologies in Use at the Source

$PM_{10}$ emissions from the facility are currently controlled through the use of a hot-side ESP.

Steps 2-6: Streamlined Review

SRP's BART analysis for $PM_{10}$ was limited to a statement that the current emission levels associated with the existing controls at the Coronado Generating Station range from 0.01 to 0.03 lb/MMBtu. As noted in Section X, $PM_{10}$ BART for similar emissions units with similar emissions controls was determined to be 0.03 lb/MMBtu. Since SRP's CGS is already meeting or exceeding the stringency of the emissions limitation, further analysis was determined to be unnecessary.

Step 7: Select BART

After reviewing the analysis provided by SRP, and the information presented above, ADEQ has determined that BART for $PM_{10}$ from Units 1 and 2 is no further control, and an emissions limitation of 0.03 lb/MMBtu.

## F. $SO_2$ BART

Step 1: Identify the Existing Control Technologies in Use at the Source

$SO_2$ emissions are currently controlled with the use of low-sulfur coal and partial wet flue gas desulfurization. The resulting emission rate ranges from 0.6 to 0.7 lbs/MMBtu.

Step 2: Identify All Available Retrofit Control Options

Following control options are available for control of $SO_2$.

- Wet Flue Gas Desulfurization
- Spray Dryer Absorber
- Dry Sorbent Injection

A brief evaluation of the above control technologies is provided below:

**Wet Flue Gas Desulfurization (WFGD).** This control option uses limestone or lime to react with $SO_2$ in the flue gas. The temperature of the flue gas is reduced to its adiabatic saturation temperature and the $SO_2$ is removed from the flue gas by reaction with the alkaline medium. $SO_2$ and other acid gases are absorbed into the scrubbing slurry, which falls into the lower section of the reaction tank. Finely ground limestone and make-up water are added to the reaction tank to neutralize and regenerate the scrubbing slurry.

Limestone scrubbing introduces limestone slurry into the scrubber. The $SO_2$ is absorbed, neutralized, and partly oxidized to calcium sulfite and calcium sulfate in line with the following reaction:

$$CaCO_3 + SO_2 + \tfrac{1}{2} H_2O \rightarrow CaSO_3 \cdot H_2O + CO_2$$

$$CaSO_3 \cdot H_2O + 1\tfrac{1}{2} H_2O + \tfrac{1}{2} O_2 \rightarrow CaSO_4 \cdot 2H_2O$$

Lime scrubbing is similar to limestone scrubbing in equipment and process flow, except that lime is a more reactive reagent than limestone. The reactions for lime scrubbing are as follows:

$$Ca(OH)_2 + SO_2 \rightarrow CaSO_3 \cdot \tfrac{1}{2}H_2O + \tfrac{1}{2}H_2O$$

$$Ca(OH)_2 + SO_2 + \tfrac{1}{2}O_2 + H_2O \rightarrow CaSO_4 \cdot 2H_2O$$

If lime or limestone is used as the reagent for $SO_2$ removal, additional equipment is needed to prepare the lime/limestone slurry and collecting and dewatering the resultant sludge. Calcium sulfite sludge is difficult to mechanically dewater and is typically stabilized with fly ash for landfilling. Calcium sulfate is stable and is easily dewatered through mechanical processes. To produce calcium sulfate, an air injection blower is needed to supply oxygen for the second reaction to occur (forced oxidation).

**Dry Sorbent Injection (DSI).** In DSI systems, a dry powdered alkaline material is injected into the hot gas stream to neutralize the acidic species like $SO_2$, and the resulting solid salts and remaining excess alkaline material is collected by a downstream particulate capture device. Various alkaline materials, both chemically processed and naturally occurring, have seen application in dry scrubbing. Dry hydrated lime, a calcium based alkaline sorbent, is in wide use in dry scrubbing.

**Spray Dryer Absorber (SDA).** The process consists of the SDA module, a down-stream fabric filter, a reagent preparation system and a product handling system. Hot, untreated flue gas is introduced into a spray dryer absorption chamber contacts a fine spray of reagent slurry. A significant part of the $SO_2$ in the flue gas is rapidly absorbed into the alkaline droplets. The control of gas distribution, slurry flow rate, and droplet size ensure that the droplets are dried to a fine powder before they touch the chamber walls of the spray dryer absorber.

A portion of the dry product, consisting of fly ash and reaction product, drops to the bottom of the absorption chamber and is discharged. The treated flue gas flows to a particle separator, where the remaining suspended solids are removed. Outlet gasses from the particulate separator pass on to the stack by means of an induced draft fan.

Step 3: Eliminate All Technically Infeasible Control Options

ADEQ has determined that all of the referenced control technologies are technically feasible.

Step 4: Evaluate Control Effectiveness of Remaining Technologies

SRP and EPA's consent decree stipulates the installation of WFGDs for both the units. WFGD is the most effective control technology available for controlling $SO_2$ emissions. Since SRP is committing to the WFGD technology, other control technologies are not evaluated from this point forward in the BART analysis.

**Table 12.8 – Annual $SO_2$ Emissions resulting from $SO_2$ Controls**

| Control Option | Control Technology | Unit 1 | Unit 2 |
|---|---|---|---|
| | | Pounds/MMBtu | |
| 1 | Baseline-Partial FGD | 0.610 | 0.689 |
| 2 | Wet FGD | 0.08 | 0.08 |

Step 5: Evaluate the Energy and Non-Air Quality Environmental Impacts and Document Results

*Costs of Compliance*

Based on the vendor data on the capital cost and operation & maintenance cost for different control options, Table 9 provides the information on the annual costs associated with each of the control options.

**Table 12.9 – Total Capital and Annual Costs associated with $SO_2$ Controls**

| Control Option | Control Technology | Total Capital Cost | Fixed Capital Cost | Annual O&M | Total Annualized Cost |
|---|---|---|---|---|---|
| 1 | Baseline- Partial FGD | -- | -- | -- | -- |
| 2 | WFGD | $347,000,000 | $32,753,330 | $11,600,000 | $44,353,330 |

* Fixed capital cost calculation is based on a Capital Recovery Factor (CRF) of 0.09439, assuming an interest rate of 7%, and amortization period of 20 years.

Table 12.10 provides annual estimated emission numbers for $SO_2$ and cost figures relating to the implementation of WFGDs.

| Table 12.10 – Total Annual Emissions of $SO_2$ and cost of reduction with WFGD | | |
|---|---|---|
| | **Baseline, Option 1** | **Option 2, WFGD** |
| Unit 1 | 14,556 tpy | 1,909 tpy |
| Unit 2 | 14,828 tpy | 1,722 tpy |
| Total (Both Units) | 29,384 tpy | 3,631 tpy |
| Reduction from Baseline | - | 25,753 tpy |
| Annualized Cost | - | $ 44,353,330 |
| Cost of reduction ($ per ton) | - | $1,722 |

Step 6: Evaluate Visibility Impacts

The new WFGD control scenario was modeled for each meteorological year (2001-2003) and for all 17 Class I areas within 300 km. The modeling result indicates that the installation of a WFGD will provide for significant visibility benefit. The highest visibility improvement will occur at the Petrified National Forest where an improvement of 1.38 Δdv is expected.

Table 12.11 provides information on annualized cost and the cost in dollars per deciview average improvement in visibility achieved by implementing the control option.

| Table 12.11 – Summary for $SO_2$ BART | | |
|---|---|---|
| | **Option 1, Baseline** | **Option 2, WFGD** |
| Reduction in Emission (tpy) | - | 25,753 |
| Annualized Cost | - | $44,353,330 |
| Visibility index (dv) | 2.66 | 1.28 |
| Improvement in Visibility Index (dv) | - | 1.38 |
| Incremental Cost Effectiveness ($ per dv) | - | $32,140,094 |

Step 7: Select BART

Based on its review of the company's analysis and the information above, the Department accepts SRP's recommended BART control of WFGDs for both units with an associated $SO_2$ emission rate of 0.08 lbs/MMBtu on 30-day rolling average basis.

# ENCLOSURE 4

***Proposed***
***Arizona Regional Haze State Implementation Plan Revision***

***Technical Support Document***

***March 20, 2013***

# Arizona Regional Haze State Implementation Plan Revision Technical Support Document

**March 20, 2013**
**PROPOSED DRAFT**

**Arizona Department of Environmental Quality**

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# I. Introduction

In 2011, the State of Arizona submitted a Regional Haze State Implementation Plan (SIP) to the Environmental Protection Agency (EPA) to fulfill the requirements of 40 CFR § 51.308. On December 21, 2012 the EPA published within the Federal Register[i] a partial approval / partial disapproval of Arizona's Regional Haze State Implementation Plan. This document was created to address certain deficiencies identified by the EPA, specifically 40 CFR § 51.308(d)(4)(v) which requires submission of the most recently available Emissions Inventory in a Regional Haze SIP. Furthermore, this document presents an alternative methodology, which has been used by the EPA in previous studies, for the analysis of visibility trends and provides supplemental information to address visibility trends within the State of Arizona between the years of 2000 and 2009 and how these trends compare to Reasonable Progress Goals and Uniform Rates of Progress.

# II. 2002 and 2008 Emission Inventories

The 2002 Arizona Emission Inventory (EI) was originally constructed to fulfill the requirement of 40 CFR § 51.308(d)(4)(v)[ii], which states a baseline year emission inventory must be contained within a State's implementation plan for regional haze. On December 21, 2012 EPA published within the Federal Register[iii] a partial disapproval of Arizona's Regional Haze State Implementation Plan. One disapproved provision was based on 40 CFR § 51.308(d)(4)(v) which further requires a submission of a statewide emission inventory for the most recent year of which data are available. In order to fulfill this requirement, the Arizona Department of Environmental Quality (ADEQ) is presenting a 2008 emission inventory calculated and compiled by the Western Regional Air Partnership (WRAP) WESTJUMP project.

The 2002 and 2008 emission inventories calculate emissions of the regional haze contributing pollutants: Sulfur Dioxide ($SO_2$), Nitric Oxide ($NO_x$), Ammonia ($NH_3$), Volatile Organic Compounds (VOCs), Primary Organic Aerosols (POA), Elemental Carbon (EC), Fine Particulate Matter (Fine), and Coarse Particulate Matter (CM). For the purpose of consistency, these pollutants were reported for all major source categories. Where possible these source categories were further partitioned into anthropogenic and natural sources. Source categories for both anthropogenic and natural sources are listed and described briefly here, followed by information related to the inventories.

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[i] Environmental Protection Agency (EPA). Federal Register Volume 77, No. 246. Dec. 21, 2012.
[ii] Environmental Protection Agency (EPA). Code of Federal Regulations Title 40 Volume 2 Section 51. 2011.
[iii] Environmental Protection Agency (EPA). Federal Register Volume 77, No. 246. Dec. 21, 2012.

- *Point Sources:* These are sources that are identified by point locations, typically because they are regulated and their locations are available in regulatory reports. Point sources can be further subdivided into electric generating unit (EGU) sources and non-EGU sources, particularly in criteria inventories in which EGUs are a primary source of $NO_X$ and $SO_2$. Examples of non-EGU point sources include chemical manufacturers and furniture refinishers.
- *Area Sources:* Sources that are treated as being spread over a spatial extent (usually a county or air district) and that are not movable (as compared to non-road mobile and on-road mobile sources). Because it is not possible to collect the emissions at each point of emission, they are estimated over larger regions. Examples of stationary area sources are residential heating and architectural coatings. Numerous sources, such as dry cleaning facilities, may be treated either as stationary area sources or as point sources.
- *On-Road Mobile Sources:* Vehicular sources that travel on roadways. Emissions are estimated as the product of emissions factors and activity data, vehicle miles traveled (VMT). Examples of on-road mobile sources include light-duty gasoline vehicles and heavy-duty diesel vehicles.
- *Off-Road Mobile Sources:* Off-road mobile sources are vehicles and engines that encompass a wide variety of equipment types that either move under their own power or are capable of being moved from site to site. Examples include agricultural equipment such as tractors or combines, locomotives and oil field equipment such as mechanical drilling engines.
- *Oil and Gas Sources:* Oil and gas sources consist of a number of different types of activities from engine sources for drill rigs and compressor engines, to sources such as condensate tanks and fugitive gas emissions. The variety of emissions types for sources specific to oil and gas activity can, in some cases, overlap with mobile, area or point sources, but these can also be extracted and treated separately. As can be seen in the 2008 emission inventory for Arizona, accept for fugitive emissions associated with mobile sources, oil and gas sources are virtually non-existent in Arizona. Arizona represents the second lowest contributing State to annual U.S. oil production. 2008 State oil production totaled 52,000 barrels or 0.003% of the national total[iv]. Therefore, calculated and reported emissions from Oil and Gas production are negligible in comparison to other Source Categories.
- *Biogenic Emissions:* Biogenic emissions are based on the activity fluxes modeled from biogenic land use data, which characterize the types of vegetation that exist in particular areas. Emissions are generally derived using modeled estimates of biogenic gas-phase pollutants from land use

[iv] U.S. Energy Information Administration. http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_a.htm.

information, emissions factors for different plant species, and meteorology data.

- *Dust:* Dust emissions may have a variety of sources that could include anthropogenic sources, natural sources, and natural sources that may be influenced by anthropogenic activity. For emissions summary purposes, dust is classified here as fugitive dust and windblown dust. Fugitive dust includes sources such as road dust, agricultural operations, construction and mining operations and windblown dust from vacant lands.

- *Fire:* Fire sources are difficult to predict and control, and may have a mix of natural and anthropogenic influences. Natural sources include wildland fires, while anthropogenic sources can include agricultural and prescribed fires.

## *II.A. 2002 Arizona Emission Inventory Methodology*

The 2002 Arizona Emission Inventory calculations and results are described in detail in the Arizona Regional Haze SIP[v]. Please refer to Chapter 8 of the document for detailed calculation methodology of the 2002 Arizona Emission Inventory.

The 2002 Arizona Emission Inventory served as the baseline inventory for the 2018 emission inventory estimation. The methodology by which 2018 emissions were estimated from the 2002 emission inventory can be found in detail in the Arizona Regional Haze SIP and an overview of these methodologies are shown in Table 1.

## *II.B. 2008 Arizona Emission Inventory Methodology*

The creation of the 2008 State of Arizona Emission Inventory was a collection of efforts by WRAP's WESTJUMP Project and ADEQ. This inventory represents the most complete and recent calculation of pollutant emissions from all identified sources currently available at the time of this document's preparation. Portions of this inventory were derived from the 2008 EPA National Emissions Inventory, while other portions were calculated using a variety of emission models and techniques. Source data and emission estimation methodologies are discussed in the following section and compared to those methods utilized during the creation of the 2002 EI.

The 2002 emission inventory reported emissions based on the most readily available and accurate source data and methods at the time of preparation; however, many of the calculated source category emissions methodologies and input data changed between the 2002 and 2008 emission inventory preparations in order to enhance the accuracy of estimated statewide emissions. For this reason, many of the source category emission

[v] "Arizona State Implementation Plan: Regional Haze Under Section 308 of the Federal Regional Haze Rule" Arizona Department of Environmental Quality (ADEQ) Air Quality Division, 2011.

differences between the 2002 and 2008 inventories presented in this document should be viewed as a mixture of methodology, input data, and actual emissions changes. Furthermore, since the Arizona 2018 EI was estimated through the adjustment of the 2002 baseline Arizona emission inventory, emissions from these two EIs are more readily comparable than emissions from the 2008 EI presented here due to the aforementioned methodology and source data differences.

### *II.C. 2002 & 2008 Emission Inventory Methodology Comparisons*

Table 1 presents the input data and methodologies utilized to calculate each source category for the 2002 and 2008 EIs. This table illustrates how some source category methodologies, input data, or modeling resolutions changed dramatically, which in some cases is reflected in estimated emissions between the two inventories.

**Table 1: Emission Inventory Methodology Comparison for 2002 and 2008.**

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| Point Sources | The WRAP generated point source inventories for both actual reported 2002 (Base02b) Electric Generating Units (EGU) and all other point source data, and for a 2000-2004 average of EGU point sources (Plan02d).<br><br>Inventories were generated using hourly EPA CAMD CEM data for EGUs. Other point sources for both Base02b and Plan02d were developed in consultation with states by the Eastern Research Group (ERG) contractor.<br><br>Plan02d emissions are used here because they are consistent with what was reported as baseline conditions for most WRAP region SIPs.<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and http://www.wrapair.org/forums/ssjf/pivot.html | 2008 inventories were generated using hourly EPA Clean Air Markets Division (CAMD) Continuous Emissions Monitor (CEM) data for EGUs. Other point sources are from the 2008 NEI v2.<br><br>More details are available here: http://wrapair2.org/WestJumpAQMS.aspx | Baseline conditions presented here represent a 5-year average for EGUs, while progress period conditions are represented with 2008 data. |
| Area Sources | Plan02d emissions inventories were developed in consultation with Arizona Regional Planning Organizations (RPOs) by the ERG contractor.<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissio | Arizona reported area sources from the 2008 NEI v2.<br><br>More details are available here: | Note that area oil and gas sources are reported separately. |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | ns.aspx | http://wrapair2.org/WestJumpAQMS.aspx | |
| Point Oil and Gas | State reported point oil and gas sources for 2002 are included here in the point source inventory totals.<br><br>More details are available here: http://www.wrapair.org/forums/ssjf/pivot.html | Different basins are comprised of a combination of state reported point oil and gas from the 2008 NEI v2 for some areas and updated WRAP Phase III inventories for other areas.<br><br>These emissions were developed separately in some cases, but are included in the point source inventory totals (see above).<br><br>More details are available here: http://wrapair2.org/WestJumpAQMS.aspx | This industry has expanded and evolved considerably since 2002. |
| Area Oil and Gas | Developed using WRAP Phase II emissions methodologies. Emissions process estimated included:<br><br>• Drill Rigs | Developed using WRAP Phase III emissions methodologies using 2008 production data. The following additional | Note that many more source categories were counted in 2008 than in 2002.<br><br>Other differences between 2002 |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | • Wellhead Compressor Engines<br>• CBM Pump Engines<br>• Heaters<br>• Pneumatic Devices<br>• Condensate and oil tanks<br>• Dehydrators<br>• Completion Venting<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and http://www.wrapair.org/forums/ogwg/documents/2007-10_Phase_II_O&G_Final)Report(v10-07%20rev.s).pdf | categories were included in addition to those listed for 2002:<br><br>• Lateral compressor engines<br>• Workover rigs<br>• Salt-water disposal engines<br>• Artificial lift engines<br>• Vapor recovery units (VRUs)<br>• Miscellaneous or exempt engines<br>• Flaring<br>• Fugitive emissions<br>• Well blowdowns<br>• Truck loading<br>• Amine units (and gas removal)<br>• Water tanks<br><br>More details are available here: http://wrapair2.org/WestJumpAQMS.aspx | Phase II O&G emissions vs. Phase III/WestJumpAQMS 2008 O&G emissions:.<br><br>1)Phase III 2008 estimates included new and/or revised estimation methodologies for each of the equipment types and processes included, e.g., the surveys provided counts by device type (low-bleed vs. high-bleed) and specific information on control device efficiency, among other improvements to activity data. Phase II did not have that information available, since no surveys were made in Phase II.<br><br>2)Phase III used detailed surveys of operators in each basin to determine activities, practices, and counts of small "area-source" equipment not typically permitted by the state. WestJumpAQMS then carried forward these survey data and adjusted emissions to 2008 based on production data and any controls added after Phase III.<br><br>3)Phase III/WestJumpAQMS used the high-quality and complete IHS commercial database of O&G production data by well by basin. This was not used in Phase II, instead the state O&G Commission databases, which have been improved quite a bit over time, were used. |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | | | 4) Phase III used more refined methodologies to estimate emissions, Phase III also asked states and operators for gas composition data by basin that greatly increased the information available about VOC emissions rates. |
| On-Road Mobile | EPA MOBILE6 model applied by ENVIRON contractor using National Mobile Inventory Model (NMIM) Vehicle Miles Traveled (VMT) defaults for all counties except Maricopa, for which local inputs were provided.<br><br>More information is available in the Emissions Method section of the WRAP TSS documentation: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx and http://www.wrapair.org/forums/ef/UMSI/0606_WRAP_Mobile_Source_EI_Final_Report.pdf | EPA MOVES2010a model in inventory mode utilizing national default data for each county and MET4MOVES for meteorological data.<br><br>More details are available here: http://wrapair2.org/WestJumpAQMS.aspx | Differences in models contributed to some differences in emissions reported, but other disparities are due to a combination of VMT changes and new controls on vehicles. |
| Off-Road Mobile | EPA draft NONROAD2004 model version data by ENVIRON with inputs from Arizona for vehicle population allocation and county level locomotive emissions.<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissio | State reported off-road mobile sources for 2008 (NEI08v2).<br><br>More details are available here: http://wrapair2.org/WestJ | The off-road models include both emission factors and default county-level population and activity data. |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | ns.aspx<br>and<br>http://www.wrapair.org/forums/ef/UMSI/0606_WRAP_Mobile_Source_EI_Final_Report.pdf | umpAQMS.aspx | |
| Fugitive Dust and Road Dust | Emission Methodology based on AP-42 guidance and CARB procedures for the following source categories:<br>• Agricultural Operations – County specific cropland acreage provided by the State.<br>• Construction Operations – data obtained from the US Census Bureau and the Department of Commerce.<br>• Road Dust – data obtained from the Federal Highway Administration and State and local datasets.<br><br>Vegetative scavenging factors were applied pre-processing at the county level<br><br>More details are available here:<br>http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx | Extracted from state reported area sources for 2008 (NEI08v2).<br><br>Vegetative scavenging factors were applied post-processing at the higher resolution grid cell level, compared to 2002 data.<br><br>More details are available here:<br>http://wrapair2.org/WestJumpAQMS.aspx | Note that fugitive dust and road dust categories were available separately in WRAP Plan02d inventories, but are combined for summary purposes here. For the 2008 inventory, vegetative scavenging factors were applied to the combined sources; thus these source categories are not easily separated. |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| Windblown Dust | Generated using WRAP Windblown Dust Model and 2002 MM5 meteorology, at 36km grid cell resolution.<br><br>Vegetative scavenging factors applied pre-processing at the county level<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx | Generated using WRAP Windblown Dust Model and 2008WRF meteorology, at 4km and 12km grid cell resolution for the WRAP region.<br><br>Vegetative scavenging factors applied post-processing at the grid cell level.<br><br>More details are available here: http://wrapair2.org/WestJumpAQMS.aspx | Difference between 2002 and 2008 meteorology introduce factors that make judgment of progress for this category difficult.<br><br>1)MM5 vs. WRF met models – different actual meteorology in each year and increased grid cell resolution in 2008.<br>2)Higher resolution of grid cells leads to higher average wind speeds in individual cells, which leads to increased windblown dust emissions aggregated at the county level.<br>3)MM5 Layer 1 36 meter height winds vs. WRF average winds across lowest 3 layers spanning ~40 meter height.<br>Error in 2002 WBD model application treating rainfall in cm as inches. |
| Biogenic | BEIS3.12 with BELD3 landuse and 2002 MM5 meteorology data, at 36km grid cell resolution.<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx | MEGAN2.10 with 2008 WRF meteorology data, at 4 and 12 km grid cell resolution<br><br>More details are available here: http://www.wrapair2.org/emissions.aspx# | Comparisons of biogenic inventories between baseline and progress years will show large differences due to methodology, and not actual changes in emissions. Examples of biogenic emissions input factors that may affect differences between the BEIS3.12 and MEGAN2.10 model outputs include:<br><br>• Different meteorological years and models |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | | | (2002 MM5 vs. 2008 WRF).<br>• Higher temporal and spatial variability of land cover and other environmental input factors.<br>• Improved emissions factors based on better sources of data (e.g., satellites and field studies).<br><br>A model comparison study between BEIS3.12 and MEGAN2.10 was performed by WRAP and can be found at: http://wrapair2.org/pdf/Memo_9_Biogenics_May9_2012_Final.pdf |
| Fires | WRAP Phase III fire inventory<br><br>More details are available here: http://vista.cira.colostate.edu/TSS/Results/Emissions.aspx | Current summaries use interim WESTJUMP08 fire data currently based on satellite fire data for 2008. This inventory does not separate anthropogenic from natural fire.<br><br>DEASCO3 fire summaries will include separate reporting of anthropogenic and natural fires. | Baseline conditions are represented with a 5-year average of fire activity at the same locations and occurrence dates as actually occurred in 2002, while progress period conditions are represented with actual 2008 data.<br><br>Comparisons between these inventories are complicated by the variable and sporadic nature of wildfires. |

| Inventory Sector | 2002 Baseline Inventory (WRAP Plan02d) | 2008 Emission Inventory (WRAP WestJump08 and DEASCO$_3$) | Comments |
|---|---|---|---|
| | | More details are available here: http://www.wrapfets.org/deasco3.cfm | |

## *II.D. 2002 and 2008 Emissions*

The 2008 Arizona statewide EI was originally created by the WRAP WESTJUMP project to fulfill the requirements of 40 CFR § 51.308(g)(4) which states individual States must address the change in the emissions of pollutants which contribute to visibility impairment every 5 years for all sources and activities. ADEQ is currently submitting the WRAP WESTJUMP version of the 2008 EI to fulfill the requirement of 40 CFR § 51.308(d)(4)(v). While the WESTJUMP 2008 emission inventory provides the most consistent inventory available in relation to the baseline 2002 State of Arizona EI, Table 1 illustrates the differences which occurred during the calculation of these inventories. Inferences related to emission changes between 2002 and 2008 should not be made for many of the source sectors due to these emission changes likely resulting from model resolution, methodology, and input data enhancements. Despite this concern, general observations regarding emission differences between the two inventories are listed below.

- For sulfur dioxide, all categories except area sources exhibited lower emissions in the 2008 inventory as compared to the 2002 inventory, with the largest difference reported in point sources.

- For nitrogen dioxide, all source categories except area sources exhibited lower emissions in the 2008 inventory as compared to the 2002 inventory, with the largest difference reported for mobile sources.

- Ammonia emissions remained relatively similar between inventories, with 2008 area sources showing slightly higher estimated emissions than 2002 and 2008 on-road mobile sources showing lower estimated emissions.

- 2008 EI volatile organic compound emissions were much lower than 2002 in biogenic sector, due to enhancements in biogenic inventory methodology.

- Primary organic aerosol emissions from fire were higher in 2002 than 2008. Note that current year inventories represent only snapshots of fire emissions for the year 2008.

- Elemental carbon showed large decreases in fire emissions, but on-road mobile emissions were higher in the 2008 inventory than the 2002 inventory.

- Fine particulate matter (crustal) and coarse mass were much larger for windblown, fugitive and road dust sectors of the 2008 EI as compared to the 2002 EI. The increase in windblown dust is thought to be due in part to enhancements in dust inventory methodology. The 2008 EI was also slightly higher for area and point sources for the crustal components of fine particulate matter as compared to the 2002 EI.

## II.D.1.Estimated 2002 and 2008 Arizona Emissions

Table 2 and Figure 1 present 2002 and 2008 estimated $SO_2$ emissions by source category. Tables 3 and Figure 2 present data for $NO_x$, and subsequent Tables and Figures (Tables 4 through 9 and Figures 3 through 8) present $NH_3$, VOCs, POA, EC, Fines and CM emissions for the years of 2002 and 2008. Source categories are qualified (highlighted) where methodology, input data, or modeling resolution enhancements are believed to significantly affect emission differences between the 2002 and 2008 EIs.

**Table 2: Arizona Sulfur Dioxide Emissions by Source Category**

| Source Category | Sulfur Dioxide Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 94,716 | 79,015 | -15,700 |
| Area | 2,677 | 3,678 | 1,001 |
| On-Road Mobile | 2,715 | 812 | -1,904 |
| Off-Road Mobile | 4,223 | 673 | -3,550 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Anthropogenic Fire* | NA | NA | NA |
| Wind Blown Dust | NA | 0 | NA |
| **Total Anthropogenic** | **104,330** | **84,177** | **-20,153 (-19%)** |
| **Natural Sources** | | | |
| Natural Fire* | 4,559 | 607 | -3,952 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **4,559** | **607** | **-3,952 (-87%)** |
| **All Sources** | | | |
| **Total Emissions** | **108,890** | **84,784** | **-24,105 (-22%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

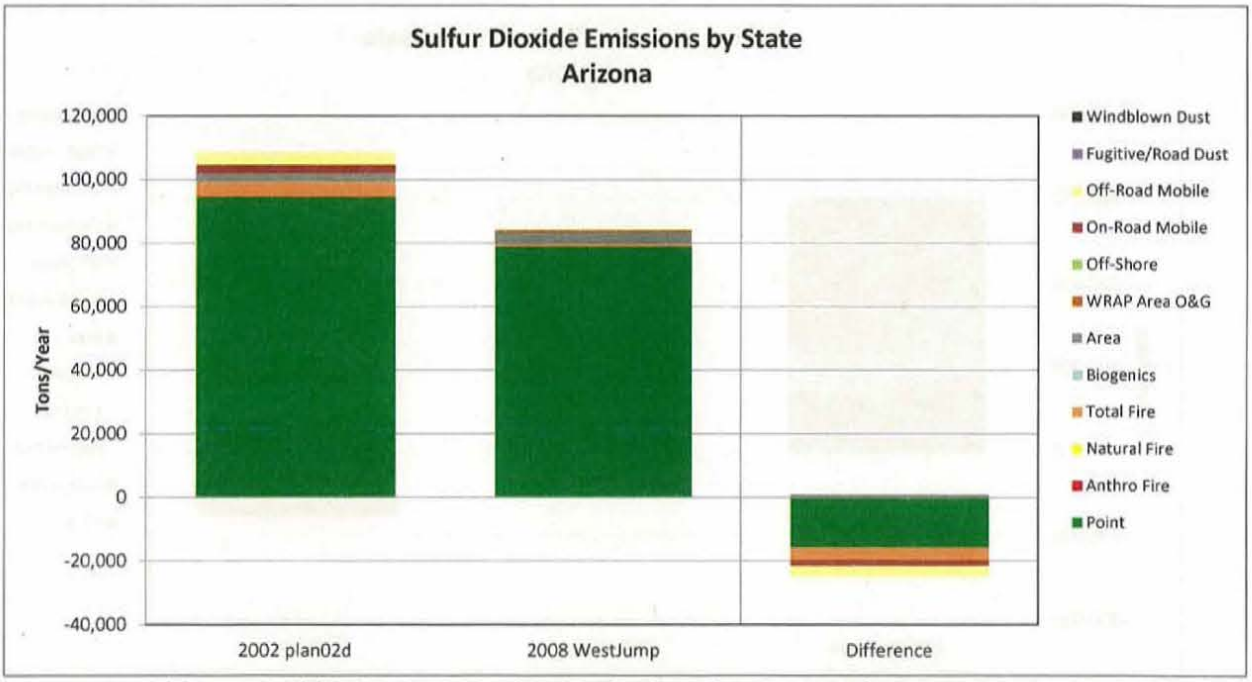


**Figure 1: 2002 and 2008 Sulfur Dioxide Emissions by Source Category**

**Table 3: Arizona Nitrogen Oxide Emissions by Source Category**

| Source Category | Nitrogen Oxides Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 69,968 | 60,759 | -9,209 |
| Area | 9,049 | 39,403 | 30,354 |
| On-Road Mobile | 178,009 | 137,555 | -40,453 |
| Off-Road Mobile | 66,414 | 33,857 | -32,557 |
| Area Oil and Gas | 17 | 0 | -17 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Wind Blown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **323,458** | **271,575** | **-51,882 (-16%)** |
| **Natural Sources** | | | |
| Natural Fire* | 17,218 | 3,513 | -13,704 |
| Biogenic | 27,664 | 15,256 | -12,408 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **44,881** | **18,769** | **-26,112 (-58%)** |
| **All Sources** | | | |
| **Total Emissions** | **368,339** | **290,344** | **-77,995 (-21%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

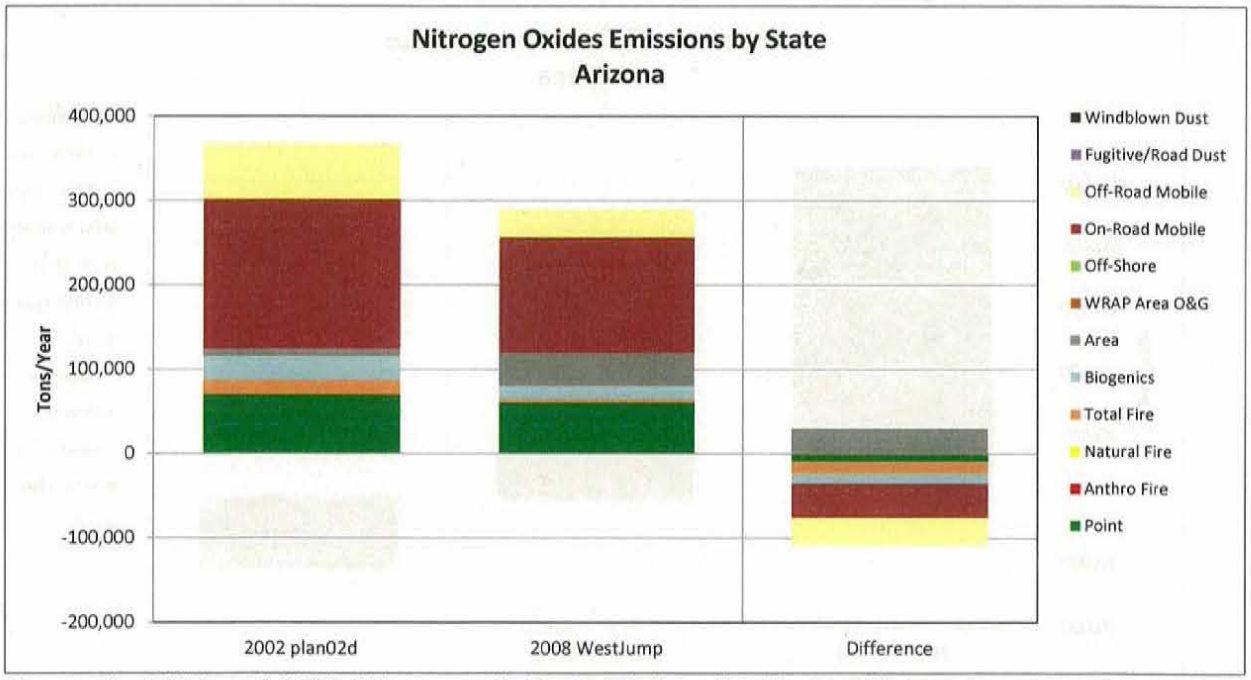


**Figure 2: 2002 and 2008 Nitrogen Oxide Emissions by Source Category**

**Table 4: Arizona Ammonia Emissions by Source Category**

| Source Category | Ammonia Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 531 | 971 | 440 |
| Area | 32,713 | 34,878 | 2,165 |
| On-Road Mobile | 5,035 | 2,377 | -2,658 |
| Off-Road Mobile | 48 | 40 | -8 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Anthropogenic Fire* | NA | NA | NA |
| Windblown Dust | NA | 0 | NA |
| **Total Anthropogenic** | **38,326** | **38,265** | **-61 (0%)** |
| **Natural Sources** | | | |
| Natural Fire* | 3,878 | 0 | -3,878 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **3,878** | **0** | **-3,878 (-100%)** |
| **All Sources** | | | |
| **Total Emissions** | **42,203** | **38,265** | **-3,939 (-9%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

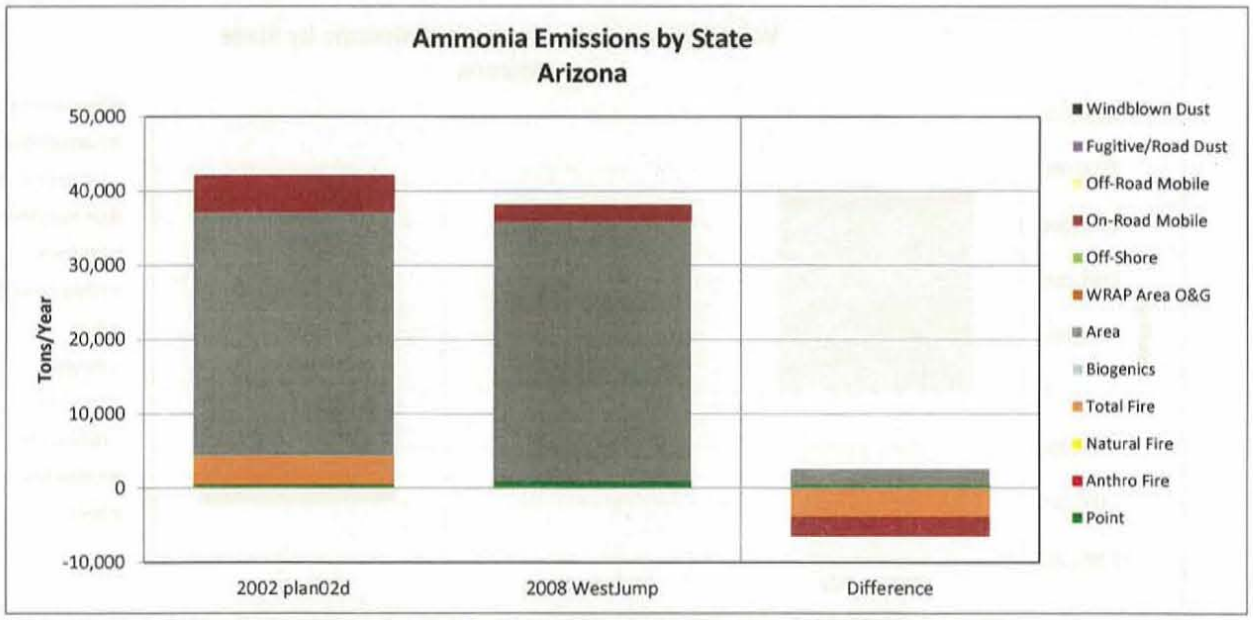


**Figure 3: 2002 and 2008 Ammonia Emissions by Source Category**

**Table 5: Arizona Volatile Organic Compound Emissions by Source Category**

| Source Category | Volatile Organic Compound Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 5,464 | 3,489 | -1,975 |
| Area | 102,918 | 100,256 | -2,661 |
| On-Road Mobile | 110,424 | 54,589 | -55,834 |
| Off-Road Mobile | 56,901 | 42,297 | -14,604 |
| Area Oil and Gas | 46 | 12 | -34 |
| Fugitive and Road Dust | 0 | 0 | 0 |
| Windblown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **275,753** | **200,644** | **-75,109 (-27%)** |
| **Natural Sources** | | | |
| Natural Fire* | 37,232 | 4,989 | -32,243 |
| Biogenic | 1,576,698 | 686,255 | -890,443 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **1,613,930** | **691,243** | **-922,686 (-57%)** |
| **All Sources** | | | |
| **Total Emissions** | **1,889,682** | **891,887** | **-997,795 (-53%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

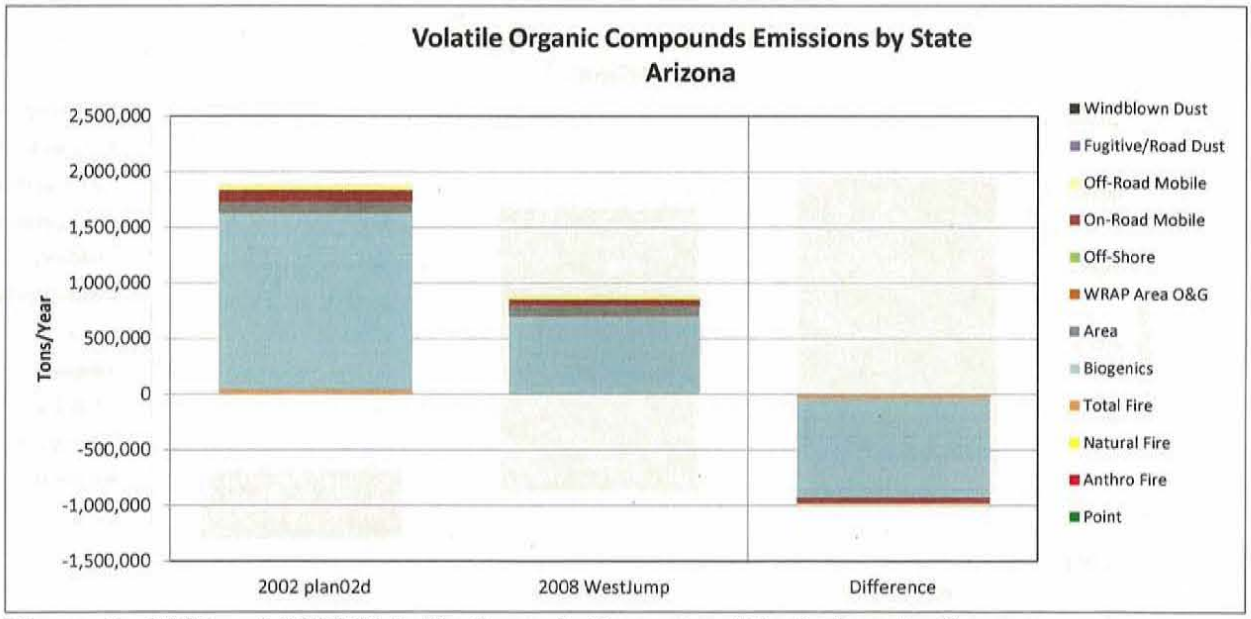


**Figure 4: 2002 and 2008 Volatile Organic Compound Emissions by Source Category**

**Table 6: Arizona Primary Organic Aerosol Emissions by Source Category**

| Source Category | Primary Organic Aerosol Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 276 | 410 | 134 |
| Area | 4,728 | 6,445 | 1,718 |
| On-Road Mobile | 1,583 | 2,666 | 1,083 |
| Off-Road Mobile | 2,006 | 1,383 | -624 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 535 | 1,393 | 858 |
| Windblown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **9,128** | **12,298** | **3,169 (35%)** |
| **Natural Sources** | | | |
| Natural Fire* | 48,625 | 5,669 | -42,957 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **48,625** | **5,669** | **-42,957 (-88%)** |
| **All Sources** | | | |
| **Total Emissions** | **57,754** | **17,966** | **-39,787 (-69%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

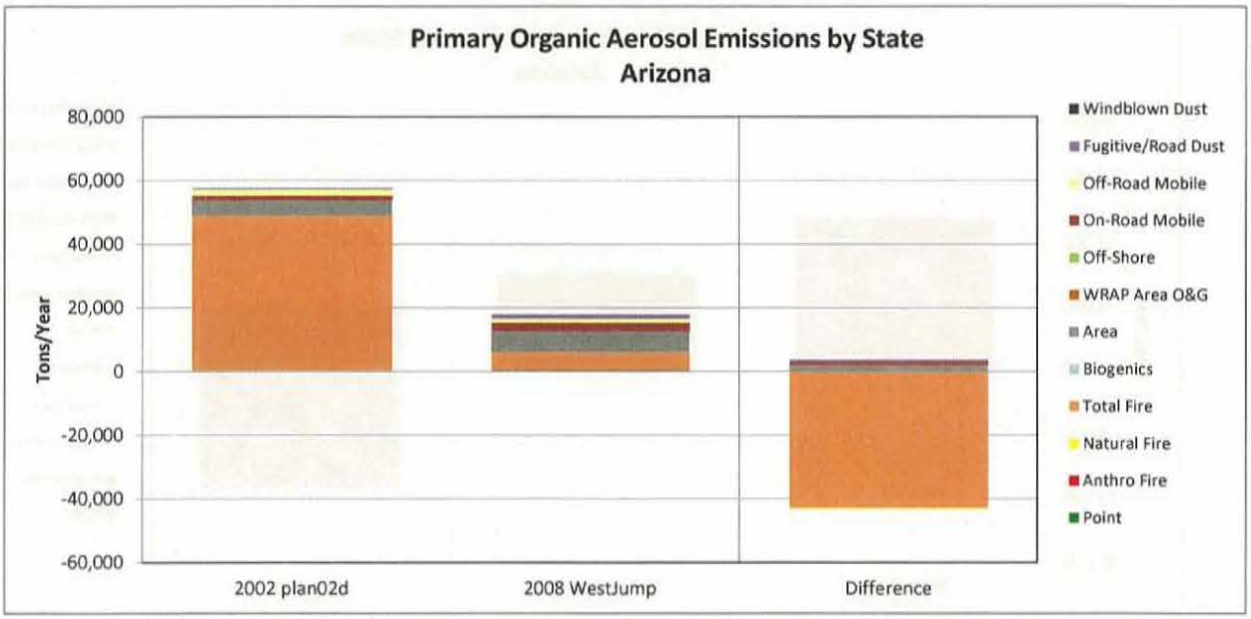


**Figure 5: 2002 and 2008 Primary Organic Aerosol Emissions by Source Category**

**Table 7: Arizona Elemental Carbon Emissions by Source Category**

| Source Category | Elemental Carbon Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 26 | 283 | 257 |
| Area | 449 | 1,337 | 889 |
| On-Road Mobile | 1,761 | 5,559 | 3,798 |
| Off-Road Mobile | 2,752 | 1,813 | -940 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 39 | 47 | 8 |
| Windblown Dust | NA | 0 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **5,027** | **9,039** | **4,012 (80%)** |
| **Natural Sources** | | | |
| Natural Fire* | 9,719 | 412 | -9,307 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 0 | 0 | 0 |
| **Total Natural** | **9,719** | **412** | **-9,307 (-96%)** |
| **All Sources** | | | |
| **Total Emissions** | **14,745** | **9,450** | **-5,295 (-36%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

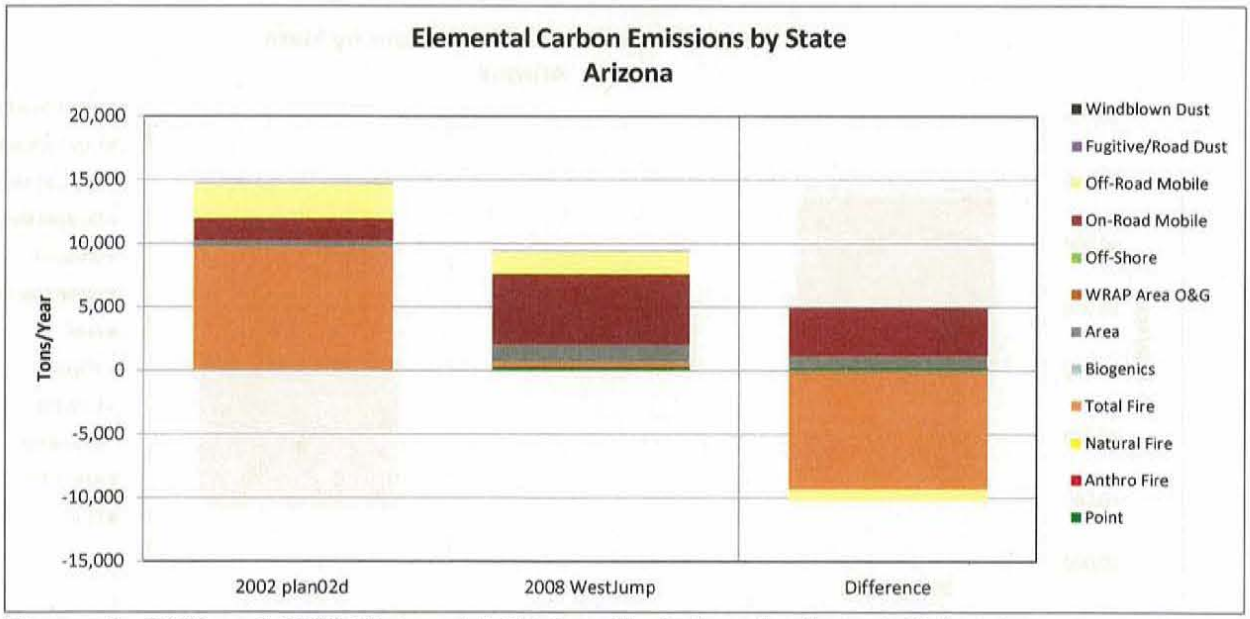


**Figure 6: 2002 and 2008 Elemental Carbon Emissions by Source Category**

**Table 8: Arizona Fine Particulate Matter Emissions by Source Category**

| Source Category | Fine Particulate Matter Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 632 | 4,434 | 3,801 |
| Area | 4,223 | 7,906 | 3,684 |
| On-Road Mobile | 1,080 | 511 | -569 |
| Off-Road Mobile | 0 | 97 | 97 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 10,072 | 24,592 | 14,520 |
| Windblown Dust | NA | 67 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **16,007** | **37,607** | **21,600 (>100%)** |
| **Natural Sources** | | | |
| Natural Fire* | 3,945 | 1,938 | -2,006 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 6,422 | 9,647 | 2,885 |
| **Total Natural** | **10,367** | **11,585** | **1,218 (12%)** |
| **All Sources** | | | |
| **Total Emissions** | **26,374** | **49,192** | **22,818 (87%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

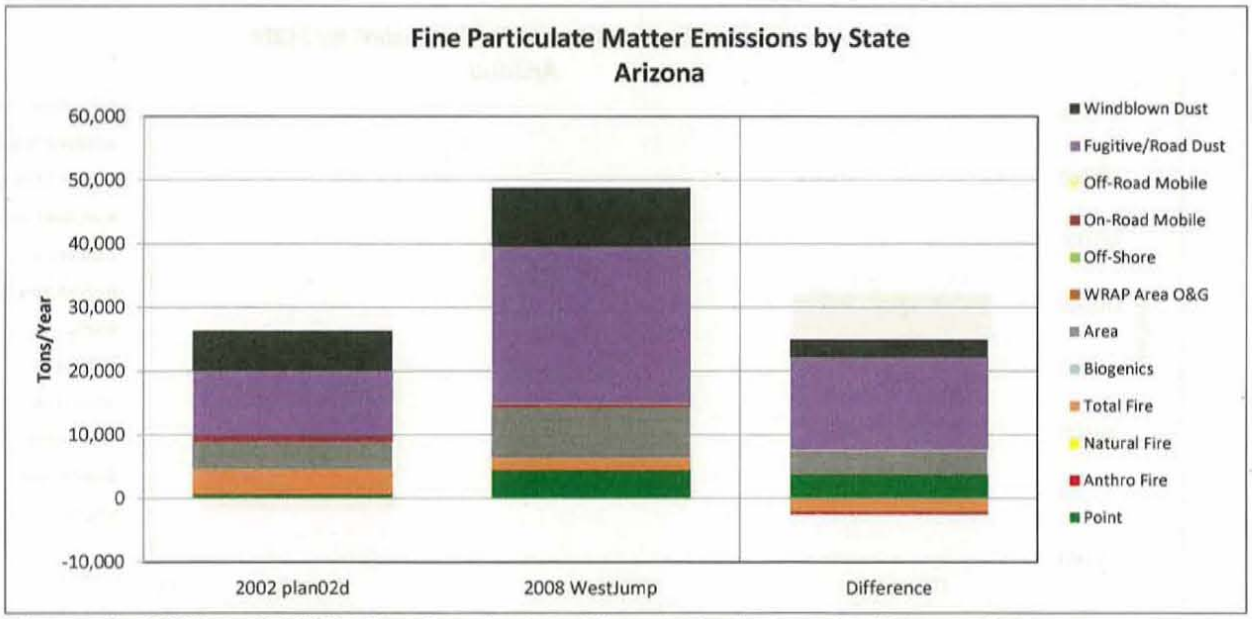


**Figure 7: 2002 and 2008 Fine Particulate Matter Emissions by Source Category**

**Table 9: Arizona Coarse Particulate Matter Emissions by Source Category**

| Source Category | Coarse Particulate Matter Emissions (tons/year) | | |
|---|---|---|---|
| | 2002 (Plan02d) | 2008 (WestJump2008) | Difference (Percent Change) |
| **Anthropogenic Sources** | | | |
| Point | 8,473 | 5,260 | -3,214 |
| Area | 1,384 | 2,389 | 1,005 |
| On-Road Mobile | 1,004 | 5,597 | 4,593 |
| Off-Road Mobile | 0 | 162 | 162 |
| Area Oil and Gas | 0 | 0 | 0 |
| Fugitive and Road Dust | 79,316 | 141,117 | 61,801 |
| Windblown Dust | NA | 604 | NA |
| Anthropogenic Fire* | NA | NA | NA |
| **Total Anthropogenic** | **90,178** | **155,129** | **64,951 (72%)** |
| **Natural Sources** | | | |
| Natural Fire* | 10,125 | 1,692 | -8,433 |
| Biogenic | 0 | 0 | 0 |
| Wind Blown Dust | 57,796 | 86,827 | 29,031 |
| **Total Natural** | **67,921** | **88,519** | **20,598 (30%)** |
| **All Sources** | | | |
| **Total Emissions** | **158,099** | **243,648** | **85,549 (54%)** |

*Natural fire totals for the 2008 inventory include both anthropogenic and natural sources. Updated data distinguishing these sources are expected.

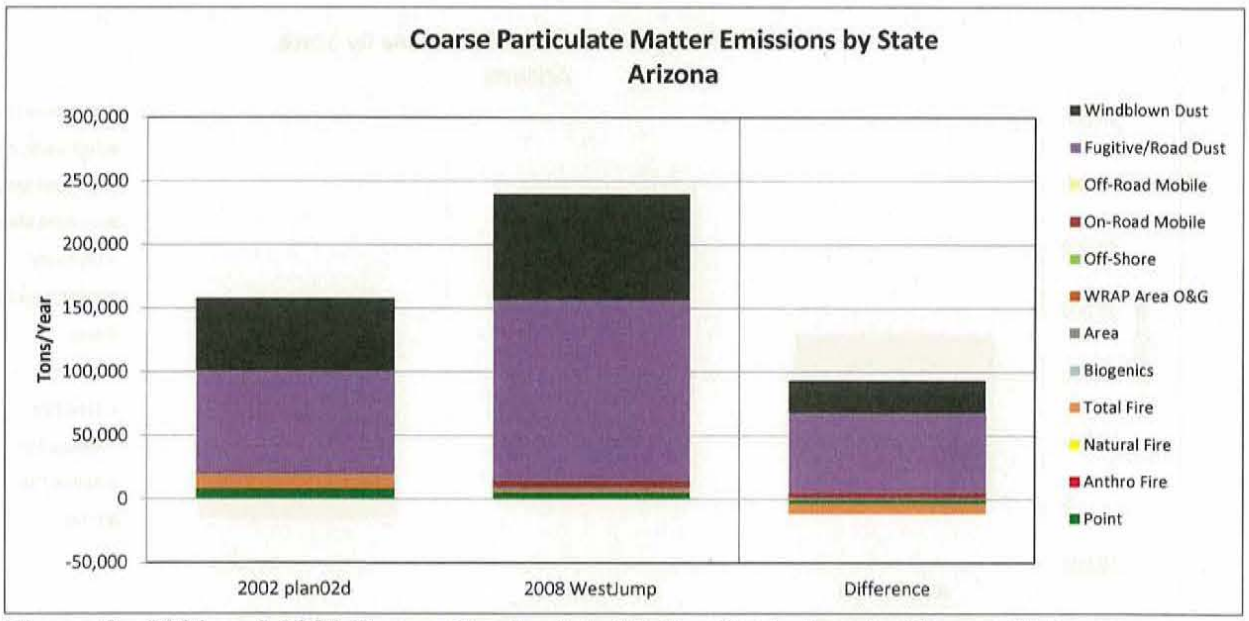


**Figure 8: 2002 and 2008 Coarse Particulate Matter Emissions by Source Category**

## II.D.2.Summary of Major Methodological Changes

The Arizona Department of Administration (ADOA) provides publicly available records of State and County estimated populations for each year dating to 1980[vi]. For the years of 2002 and 2008, ADOA estimates Arizona state-wide populations to be 5,470,720 and 6,629,455 respectively. This is an increase in state-wide population of 21.2%. An increase in population this significant will undoubtedly lead to pollutant emission changes for a number of source categories; however, the extreme degree to which certain pollutants change for given source categories indicate that population increases are not solely responsible for emission changes between the 2002 and 2008 EIs. Below is a list of methodology, input data, and model resolution changes which are believed to significantly contribute to emission differences between the 2002 and 2008 EIs. This list describes the possible changes which could affect all qualified data from Tables 2-9.

1. ADEQ has reviewed emission estimates to understand the drastic changes in Area Source $SO_2$ and $NO_x$ emissions between the 2002 and 2008 EIs. This review indicated that these changes are due to a mixture of methodological changes and data completion issues. Therefore, ADEQ believes a more accurate indicator of $NO_x$ and $SO_2$ emission changes between the baseline and progress periods can be obtained through an analysis of the IMPROVE data. Some identified issues between 2002 and 2008 Area Source $NO_x$ and $SO_2$ emission estimates are presented below.
   - When extracting Area source emissions data from the 2008 NEI by SCC code for the State of Arizona, several reported emissions contained neither physical descriptors nor SCC codes. It is possible that these unidentified sources could represent sources which are being double counted in another portion of the inventory. All 2002 data were resolved by SCC code and physical descriptors, eliminating the possibility of double counting.
   - When extracting area source $NO_x$ emissions data from the 2008 NEI by SCC code, data can be sorted by the submitting agency or agencies. Submitting agencies include: AZDEQ, EPA, Railroad Companies, "AgFire", and "Multiple". The "Multiple" submitting agency label submitted 25 unidentifiable $NO_x$ area emission categories for the 15 Arizona counties. These $NO_x$ emissions totaled 23,371 tons. ADEQ is unable to assess the origin of these emissions.
   - $NO_x$ area source emissions reported to the NEI increased from 4736 tons in 2002 to 13,563 tons in 2008 for Maricopa County alone. Direct contact with Maricopa County revealed that the county was presenting a more accurate fuel burning emission inventory in 2008 and that the County raised the emission limit of point source classification to more accurately reflect the CERR definition in 2008. In 2002 they reported 170+ point sources and in 2008 they only reported 18 point source facilities, with the remaining sources becoming Area Source emitters.

[vi] Arizona Department of Administration (ADOA).
http://www.workforce.az.gov/pubs/demography/Estimates1980_2009With2000CensusWithNotes.xls

2. Biogenic emission differences for $NO_x$ and VOCs are primarily due to methodology, source data, and modeling resolution enhancements between 2002 and 2008.
3. Ammonia emission differences for On-road Mobile are primarily due to a switch from the MOBILE6 model to the MOVES model. The 2008 EPA NEI Technical Support Document (TSD)[vii] reported a 54% decrease in highway vehicle $NH_3$ for 2008.
4. VOC emission differences for On-road Mobile are primarily due to a switch from the MOBILE6 model to the MOVES model.
5. On-road Elemental Carbon (EC) and Coarse Particulate Matter (CM) emission differences are primarily due to the switch between MOBILE6 and MOVES (which estimates higher PM emissions).
6. Reported Point Source Fines emissions exhibit a dramatic increase between 2002 and 2008, while CM decreases between 2002 and 2008. In theory, these two pollutants should track fairly closely to one another. ADEQ internal review revealed that many, if not most, sources within the State of Arizona were not reporting $PM_{2.5}$ prior to 2006 which likely explains the drastic change in Fines emissions between the 2002 and 2008 EIs.
7. Area source Fines emission differences are partially due to NEI changes. Calculation methodology changes resulted in an overall increase in Agricultural Tilling and Livestock emissions of 67% for the 2008 NEI.
8. Fugitive and Road Dust Fines and CM emission differences are primarily due to NEI changes. Calculation methodology changes resulted in an overall increase in Paved Road Dust emission of 128% for the 2008 NEI.
9. Windblown Dust Fines and CM emission differences are primarily due to the WRAP Windblown Dust (WBD) Model enhancing meteorological inputs and model resolution between the 2002 and 2008 emissions calculations. Appendix A gives a more complete overview of how windblown dust emissions were partitioned into natural and anthropogenic sources. 2002 windblown emissions were not partitioned into natural and anthropogenic sources and are thus presented only as natural emissions above.

### II.D.3. Regional Inventory Trends for Emissions

Most of the emission difference qualifying statements ADEQ presents in Section V.D.2. are attributable to changes in input data origination or calculation methodologies for emission estimations by sector. Since the WRAP WESTJUMP project created statewide emission inventories for all of the western US using similar methodology, it is reasonable to believe that these qualifying statements would hold true for all of the compiled emission inventories. In this section ADEQ presents WRAP and Air Resource Specialists, Inc (ARS) produced figures of differences in 2002 and 2008 emission

[vii] EPA. 2012. 2008 National Emissions Inventory v. 2 Technical Support Document. http://www.epa.gov/ttn/chief/net/2008neiv2/2008_neiv2_tsd_draft.pdf

inventories by state for three different pollutants to determine if the previously mentioned qualifiers hold true. These graphs split State emissions into emitting source categories to identify trends for each of the calculated or reported sources.

VOC emissions by State are presented in Figure 9. This figure easily illustrates qualifiers #2 and #4 from Section V.D.2. The most evident trend in this figure is the drastic decrease in Biogenic emissions for each State. These decreases are extreme and ubiquitous throughout the region. This trend supports qualifier #2, that Biogenic VOC emission differences are primarily due to enhancements in calculation methodology. In addition, On-road Mobile emissions show reasonably large decreases for each State. While EPA reports a decrease of national VMT by 0.8% for 2005-2008[viii], it is unlikely that this small decrease in VMT would be seen in every state. The state of Arizona showed a 21.2% population increase between 2002 and 2008, which would likely result in a substantial VMT increase. Therefore, it is reasonable to believe that qualifier #4, that VOC decreases are likely due to a switch from the MOBILE6 model to the MOVES model, is true.

Figure 10 presents State emissions for CM for the western US. The trends within this figure are more regionally based, rather than characteristic of the entire western US. Coarse Mass emissions are due to physical disturbance of an area of land by anthropogenic activities (e.g. construction, driving on unpaved roadways, etc), natural activities (e.g. animal movement or burrowing), or a mixture of the natural and anthropogenic activities (e.g. wind suspension of dust from a cleared area). While the activity which creates the emissions may change, the magnitude of emissions created is going to be primarily dependant on the local environment. Meteorology, soil characteristics, and vegetation coverage are going to play a large role in the magnitude of emissions produced from a certain area. Therefore, when examining Figure 10, it is important to group the States which have a similar local environment. Arizona, South-eastern California, Nevada, New Mexico, and Utah comprise the southwestern US which is characterized by its arid nature, in turn leading to sparse vegetation coverage. When examining Figure 10 for these five states, it is evident that local environmental factors play a large role in how Windblown Dust emissions differed between the 2002 and 2008 EIs. All five southwestern US States exhibit similar emission differences for Windblown Dust and Fugitive and Road Dust. Southwestern US State Windblown Dust emissions are likely to be more affected by WRAP WBD model resolution increases and the decreased precipitation, as reported in Table 1, than surrounding States due to higher local wind speeds increasing dust suspension into the atmosphere from dry, unvegetated soils. ADEQ believes that Road Dust is primarily responsible for the emission changes seen in the Fugitive and Road Dust category. The 2008 NEI reports that road dust emissions increased by 128% over the previous NEI for the US. Since the 2008 NEI v1.5 was used for this source category, it is believed that this is the reason for the difference between 2002 and 2008 emissions for the combined categories of Fugitive and Road Dust. Furthermore, the aridity of the southwestern US would likely result in road dust

[viii] EPA. 2012. 2008 National Emissions Inventory v. 2 Technical Support Document. http://www.epa.gov/ttn/chief/net/2008neiv2/2008_neiv2_tsd_draft.pdf

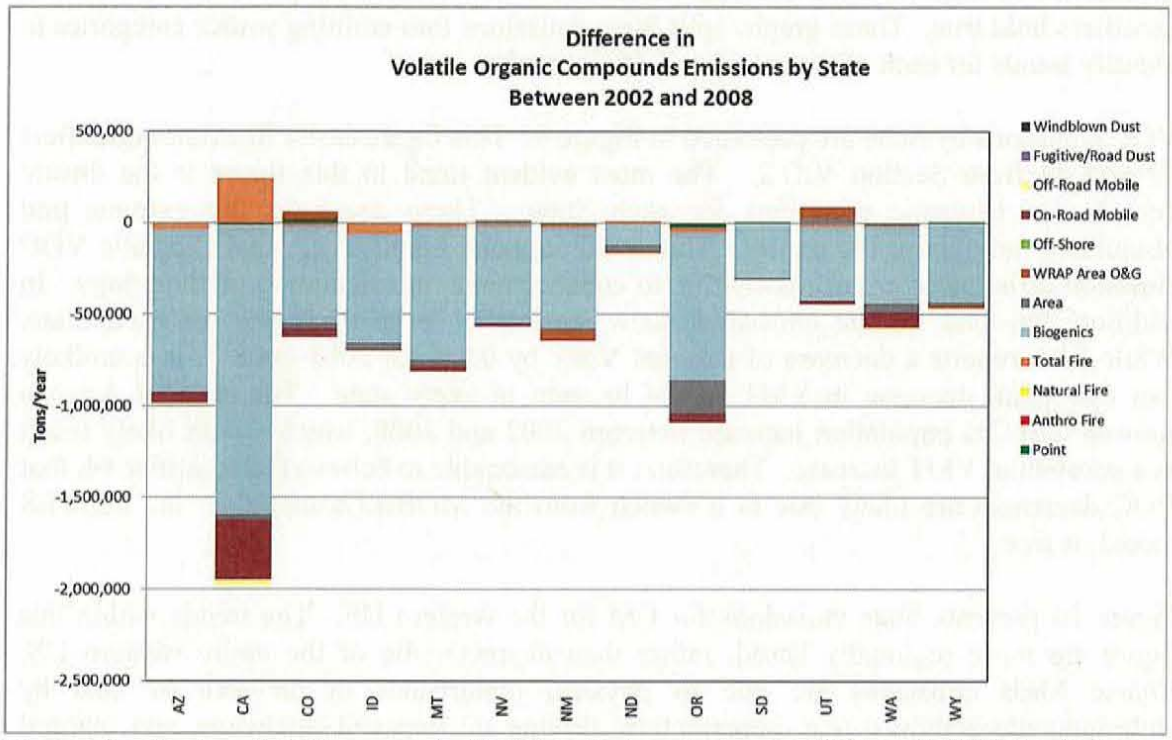


**Figure 9: Regional differences in VOC emissions between 2002 and 2008 Emission Inventories**

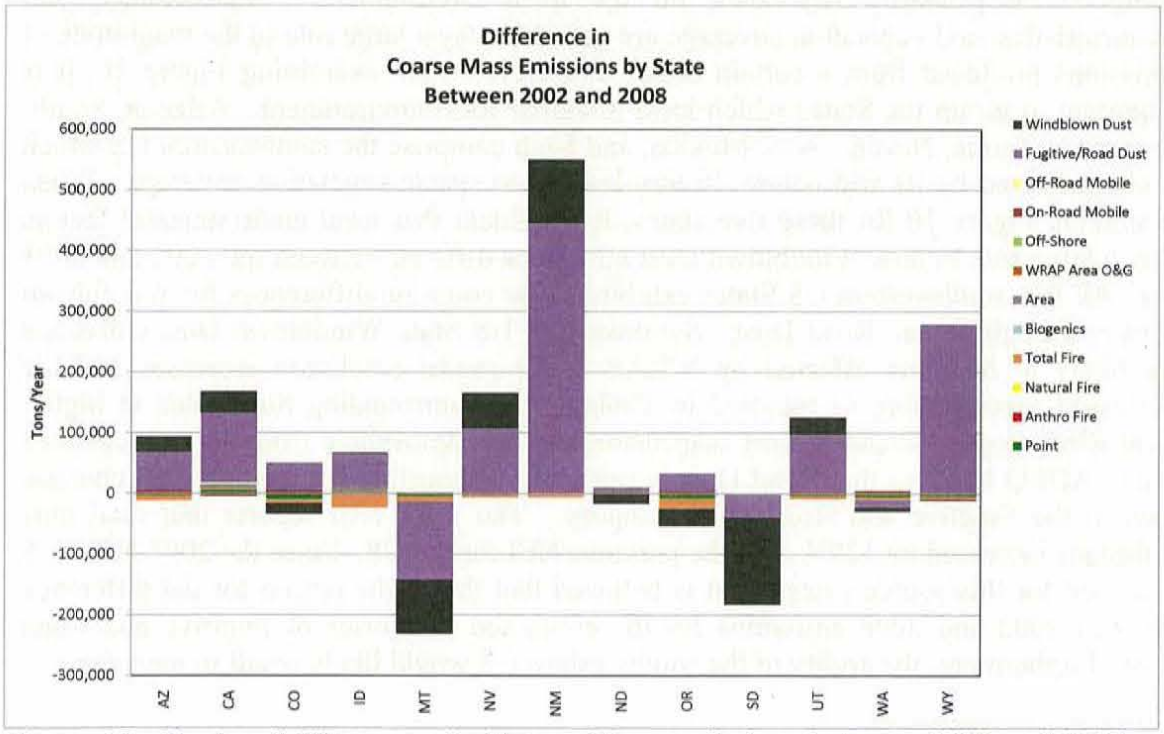


**Figure 10: Regional differences in Coarse Mass emissions between 2002 and 2008 Emission Inventories**

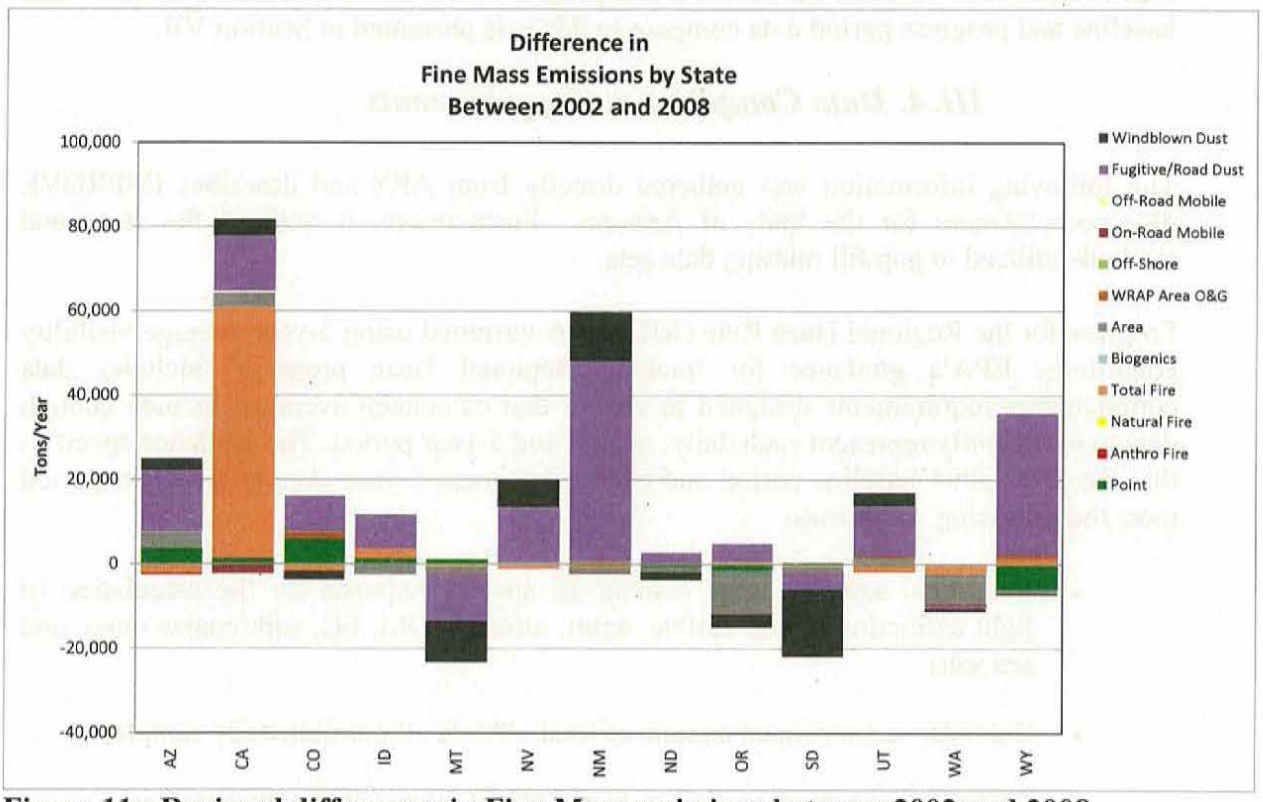


**Figure 11: Regional differences in Fine Mass emissions between 2002 and 2008 Emission Inventories**

calculation disparities being maximized in this region, when compared to other regions of the US. Fines (Figure 11) show similar regional trends for Windblown Dust and Fugitive and Road Dust for the arid southwestern US as was reported for CM, further supporting the theory that particulate matter emission differences are at least partially due to calculation methodology changes. While not proving qualifying statement #7, the lack of a regional trend for Fines originating from Point sources provides credence to this point.

# III. IMPROVE Monitoring Data

As discussed in Section 3, comparisons between the 2002 and 2008 State of Arizona EIs are problematic due to source data and methodology changes. Therefore, ADEQ has determined that IMPROVE monitoring data are more appropriate surrogates for assessing visibility change due to emission increases or decreases within the State of Arizona. Comparisons between the baseline (2000-2004) and progress (2005-2009) periods are presented in this document in order to address EPA's assessment within the Federal Register that the State of Arizona Reasonable Progress Goals (RPGs) are not acceptable

for reaching the 2064 natural visibility standards[ix]. In this section we present IMPROVE data comparisons between the baseline and progress periods. A discussion of how these baseline and progress period data compare to RPGs is presented in Section VII.

### *III.A. Data Completeness Requirements*

The following information was gathered directly from ARS and describes IMPROVE data completeness for the State of Arizona. Furthermore, it outlines the steps and methods utilized to gap fill missing data sets.

Progress for the Regional Haze Rule (RHR) is determined using 5-year average visibility conditions. EPA's guidance for tracking Regional Haze progress[x] includes data completeness requirements designed to ensure that calculated averages include enough data to sufficiently represent each daily, annual and 5-year period. The guidance specifies that the 2000-2004 baseline period and each subsequent 5-year average progress period meet the following conditions:

- Individual samples must contain all species required for the calculation of light extinction (amm. sulfate, amm. nitrate, POM, EC, soil, coarse mass, and sea salt)
- Calendar seasons must contain at least 50% of all possible daily samples
- Calendar years must contain at least 75% of all possible daily samples
- Calendar years must not contain more than 10 consecutive missing daily samples
- The 5-year baseline and each 5-year progress period averages must contain at least 3 complete years of data

RHR guidance specifies that if a 5-year period has less than three complete years of data, then estimates should be prepared through consultation with EPA/OAQPS. For the state of Arizona, the 2005-2009 progress period did not have complete data available for one site. The SIAN1 site, the Sierra Ancha Wilderness Area, did not meet RHR data completeness criteria for the years 2006, 2007 and 2008, which interrupted the requirement for 3 complete years required for a 5-year average. Substitution methodology was consistent with methodology previously applied to the 2000-2004 baseline period for seven WRAP sites.

The data substitution methods include estimating missing species from other on-site measurements and appropriately scaling data collected at a nearby site which demonstrated favorable long-term comparisons. Only years deemed incomplete under RHR guidance were candidates for additional data substitutions, which included for the

[ix] Environmental Protection Agency (EPA). Federal Register Volume 77, No. 246. Dec. 21, 2012.
[x] EPA. 2003. Guidance for Tracking Progress Under the Regional Haze Rule.

SIAN1 the years 2006, 2007 and 2008. Years deemed complete were not changed, although there may have been missing samples during those years. Substitution methodology is described in detail below.

### III.A.1. SIAN1 Site data substitution methodology

The first substitution method applied uses organic hydrogen as a surrogate for organic carbon (OC) and elemental carbon (EC), which are collected on the IMPROVE C module. Hydrogen (H) is measured on the A module filter, and is assumed to be primarily associated with organic carbon and inorganic compounds such as ammonium sulfate. Therefore, OC can be estimated using the historical comparison between estimated organic H and OC. Organic H is estimated by subtracting the portion of H that is assumed to be associated with the inorganic compounds from the total H (Org_H = H – 0.25*S). Linear regression statistics were used to correlate all organic H and OC mass collected at the SIAN1 site during the 2005-2009 period, and regression statistics were applied to organic H to estimate OC on days where organic H was available, but OC was not. OC and EC correlations for the period were then used to calculate EC from OC. Regression statistics for these substitutions were calculated and applied quarterly to account for seasonal variations.

Because the carbon data substitution methods were not sufficient to complete the required years, a second method was applied that involved scaling data from the closest neighboring IMPROVE site, TONT1. This site had previously been determined to have favorable long-term comparisons and similar regional characteristics for substitutions performed on the 2000-2004 baseline period, when the SIAN1 site was selected, in consultation with the state of Arizona, as a donor site for TONT1. Species specific correlations between SIAN1 and TONT1 of mass data collected during the 2005-2009 period were calculated quarterly, and applied to adjust TONT1 data to apply to missing SIAN1 days.

Figure 12 presents bar charts showing daily SIAN1 extinction data, including substituted data, for the 2005-2009 progress period years. Original RHR data in blue and substituted data by species in the standard IMPROVE colors. Substituted days are also indicated by a black bar underneath the day, and the red line indicates the threshold above which days are counted in the 20% worst days for that year. Note that some of the missing extinction days had partial data available and only individual species missing in a given sample were substituted. Figure 13 presents similar bar charts indicating speciation of all data, with days in which all or part of the day was substituted indicated by a black bar underneath the day. Note that very few of the substituted days were counted among the 20% worst days for the substituted years. All summaries for the SIAN1 site in this progress report support document include these substituted data, and substituted data and detailed methodology information will also be made available on the WRAP TSS website (http://vista.cira.colostate.edu/tss/).

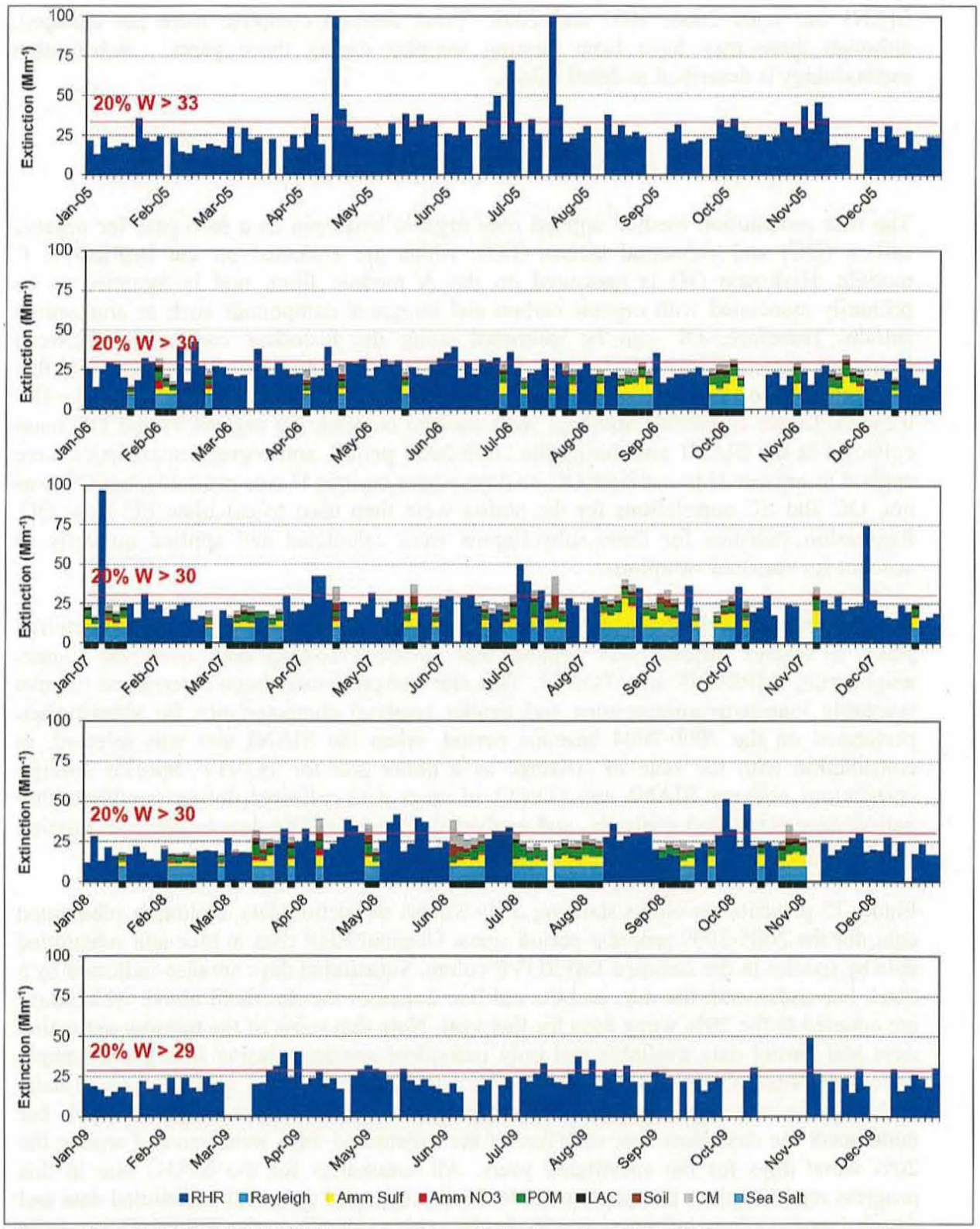


**Figure 12: IMPROVE SIAN1 data collected during the 2005-2009 progress period, where original SIAN1 RHR data are depicted in dark blue, and substituted data are depicted with separate colors by species.**

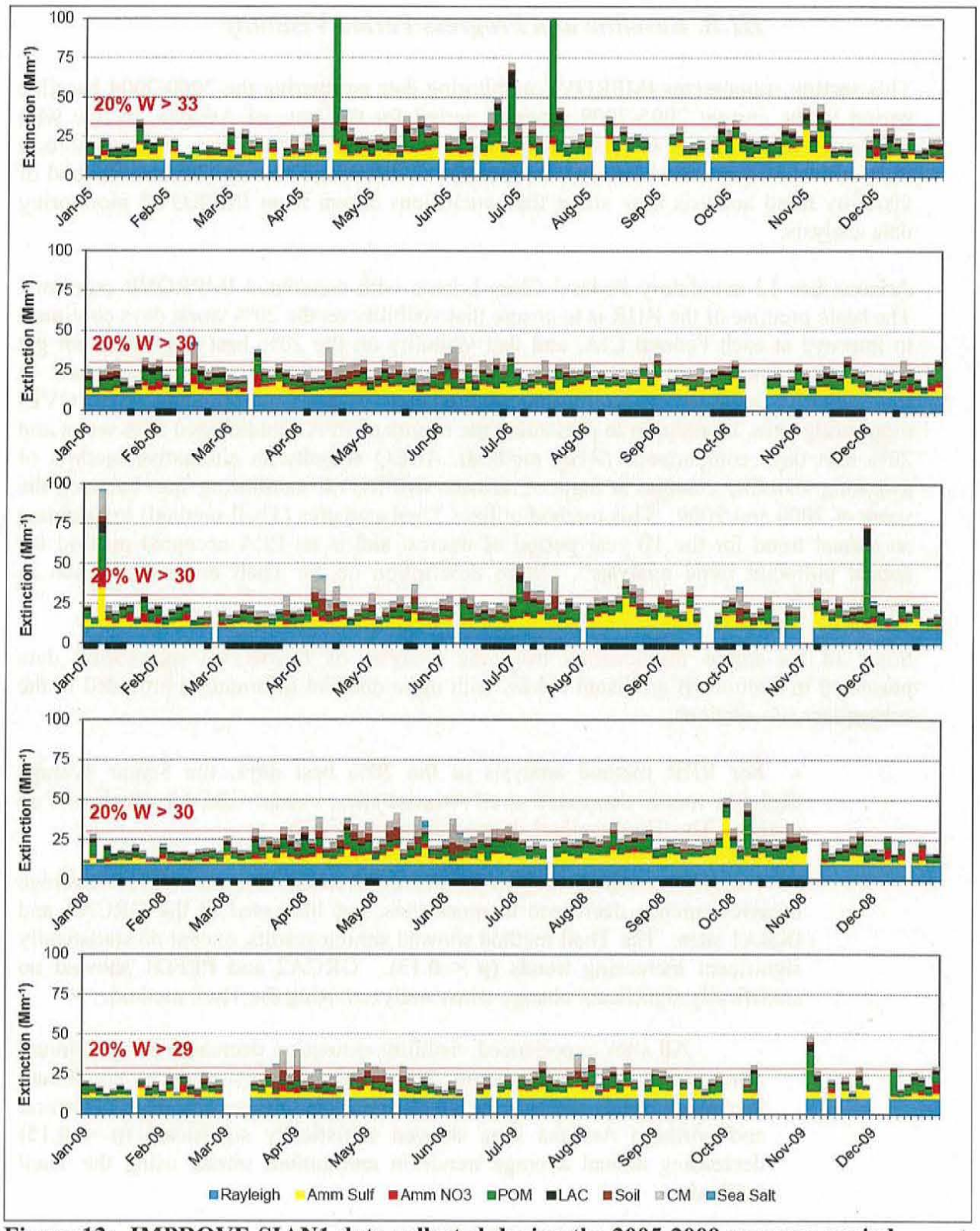


**Figure 13: IMPROVE SIAN1 data collected during the 2005-2009 progress period, where substituted days are depicted with a black bar beneath the data.**

## *III.B. Baseline and Progress Period Visibility*

This section summarizes IMPROVE monitoring data comparing the 2000-2004 baseline period to the current 2005-2009 progress period for the state of Arizona, in line with regulatory requirements for periodic progress (CFR 51.308(g)(3)(iii)). Furthermore, a more robust 10 year trend analysis is presented to determine how an alternate method of visibility trend analysis may affect the conclusions drawn from IMPROVE monitoring data analysis.

Arizona has 12 mandatory Federal Class I areas with associated IMPROVE monitors. The basic premise of the RHR is to ensure that visibility on the 20% worst days continues to improve at each Federal CIA, and that visibility on the 20% best days does not get worse, as measured in units of deciviews (dv) calculated from data collected at representative Interagency Monitoring of Protected Visual Environments (IMPROVE) monitoring sites. In addition to presenting the results of EPA standardized 20% worst and 20% best days comparisons (RHR method), ADEQ submits an alternative method of assessing visibility changes at State of Arizona IMPROVE monitoring sites between the years of 2000 and 2009. This method utilizes Theil statistics (Theil method) to calculate an annual trend for the 10 year period of interest and is an EPA accepted method for annual pollutant trend analysis[xi]. More description of the Theil method is given in Section III.B.2.

Some of the major implications from the analysis of IMPROVE monitoring data presented in Section III are listed below, with more detailed information provided in the subsequent sub-sections.

- For RHR method analysis of the 20% best days, the 5-year average deciview metric decreased at all Arizona sites, except GRCA2 which saw no change. The Theil method showed the same results.

- For RHR method analysis of the 20% worst days, the 5-year average deciview metric decreased at most sites, but increased at the GRCA2 and IKBA1 sites. The Theil method showed similar results, except no statistically significant increasing trends ($p < 0.15$). GRCA2 and PEFO1 showed no statistically significant change when analyzed using the Theil method.

  - All sites experienced visibility extinction decreases of ammonium nitrate using the RHR method. The Thiel method showed no significant increasing trends and four sites with significant decreasing trends. Central and northern Arizona sites showed statistically significant ($p < 0.15$) decreasing annual average trends in ammonium nitrate using the Theil method.

[xi] EPA. Trends in Monitored Concentrations of Carbon Monoxide. National Air Quality and Emissions Trends Report, 2003.

- RHR method analysis showed that ammonium sulfate increased at most sites, though 20% worst days for ammonium sulfate showed no increases using the Theil method. Observations regarding ammonium sulfate were as follows:

  - Ammonium sulfate RHR method increases were primarily due to higher than average ammonium sulfate measured in 2005.

  - When selecting the 20% worst days for ammonium sulfate alone, no sites showed increases when using the Theil method, and five sites showed statistically significant decreasing trends ($p < 0.15$).

- RHR method analysis exhibited decreases in visibility extinction from particulate organic mass at all sites except GRCA2 and IKBA1. Theil method analysis showed statistically significant particulate organic mass decreases at four Arizona sites and no statistically significant increasing trends at any of the other sites ($p < 0.15$).

- An overall visibility deciview increase at the GRCA2 site was seen when analyzing the data using the RHR method. Two visibility components contributing to this increase were particulate organic mass and elemental carbon. In June 2009, the GRCA2 was in close proximity to 3 simultaneous, lightening induced wildfires. Observations regarding two visibility components associated with wildfire emissions are given below. These results indicate GRCA2 visibility deciview changes were at least partially due to the 2009 wildfires:

  - Elemental carbon showed a fairly large increase in visibility extinction using the RHR method; however, annual average elemental carbon measurements did not show increasing trends using the Theil method.

  - GRCA2 showed an increase in visibility extinction using the RHR method for particulate organic mass; however, annual average particulate organic mass measurements did not show increasing trends using the Theil method.

  - ADEQ performed a separate analysis for the GRCA2 site where the EC and POM extinction values for 2009 were replaced with longer term average extinction values in an attempt to exclude the extreme effect of the above mentioned fires. The average baseline period (2000-2004) was then compared to the average altered progress period (2005-2009) total extinction ($Mm^{-1}$). A decrease from 34.6 $Mm^{-1}$ for the baseline period to 32.8 $Mm^{-1}$ for the altered progress period was seen. This is further evidence that the 2009 fires played an important role in the increases seen using

the RHR method. A similar analysis was conducted replacing the EC and POM values for 2003 with longer term averages, which acted to increase the total extinction change from 32.9 $Mm^{-1}$ in the adjusted baseline period to 35.1 $Mm^{-1}$ in the progress period. A summary of these results can be found in Table 19. These results illustrate how specific fire events can have a significant effect on the trends as determined by the RHR method.

- The overall visibility deciview increase at IKBA1 was affected by high measurements in 2005. POM and ammonium sulfate are the primary contributing visibility components to the overall increasing deciview trend. These two visibility components are discussed below:

  - Particulate organic mass showed a large increase visibility extinction using the RHR method, but did not show an increasing trend using the Theil method. Particulate matter increases were strongly controlled by a large wildfire in July of 2005.

  - Ammonium sulfate showed a large increase in visibility extinction using the RHR method, but did not show an increasing trend using the Theil method. This large increase in ammonium sulfate using the RHR method was a regional trend (discussed later).

  - ADEQ performed a separate analysis for the IKBA1 site where the EC and POM extinction values for 2005 were replaced with longer term extinction values in an attempt to exclude the extreme effect of the above mentioned fire. The average baseline period (2000-2004) was then compared to the average altered progress period (2005-2009) total extinction ($Mm^{-1}$). A decrease from 38.9 $Mm^{-1}$ for the baseline period to 37.7 $Mm^{-1}$ for the altered progress period was seen. A summary of these results can be found in Table 19. This is further evidence that the 2005 fire played an important role in the increases seen using the RHR method.

### III.B.1. Progress Period (2005-2009) Visibility

This section addresses the regulatory question, ***what are the current visibility conditions for the most impaired and least impaired days (40 CFR 51.308 (g)(3)(i))?*** RHR guidance specifies that 5-year averages be calculated over successive 5-year periods, i.e. 2000-2004, 2005-2009, 2010-2014, etc. (EPA 2003). Current visibility conditions are represented here as the most recent successive 5-year average period available, or the 2005-2009 period average, although the most recent IMPROVE monitoring data currently available includes 2010.

Tables 10 and 11 present the calculated deciview values for each site, along with the percent contribution to extinction from each aerosol component for the 20% most impaired and 20% least impaired days for each of the Federal CIA IMPROVE monitors in Arizona. Figure 14 presents 5-year average extinction for the current progress period for both 20% most impaired and 20% least impaired days.

Specific observations for the current visibility conditions on the 20% most impaired days are as follows:

- The largest contributors to aerosol extinction on the 20% most impaired days at Arizona sites were particulate organic mass, ammonium sulfate and coarse mass.

- The highest aerosol extinction (15.2 dv) was measured at the SYCA1 site, where particulate organic mass was the largest contributor to aerosol extinction, followed by coarse mass. The lowest aerosol extinction (11.8 dv) was measured at the BALD1 site.

Specific observations for the current visibility conditions on the 20% least impaired days are as follows:

- Rayleigh, or the background visibility impairment due to atmospheric gases in clean air, was the largest contributor to light extinction at all sites for the 20% least impaired days. Average extinction for the least impaired visibility days at the Arizona sites ranged between 2.2 deciview (GRCA2) and 8.0 deciview (SAWE1).

- For all Arizona sites except SIAN1 and SAWE1, ammonium sulfate was the largest contributor to aerosol extinction for the 20% least impaired days.

- At the SIAN1 site, particulate organic mass was the largest contributor to aerosol extinction for the best days, followed by ammonium sulfate. At the SAWE1 site, coarse mass was the largest contributor, followed by ammonium sulfate.

**Table 10: Relative Contribution of Pollutants to Visibility Conditions on the 20% Most Impaired Days at Arizona Class I area IMPROVE Sites for the Progress Period (2005-2009).**

| Site | Deciviews (dv) | Percent Contribution by Component (% of $Mm^{-1}$) and Rank* | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| BALD1 | 11.8 | 25% (2) | 4% (6) | **42% (1)** | 8% (4) | 6% (5) | 16% (3) | 0% (7) |
| CHIR1 | 12.2 | **36% (1)** | 5% (5) | 16% (3) | 5% (6) | 10% (4) | 27% (2) | 1% (7) |
| GRCA2 | 12.0 | 22% (2) | 7% (5) | **41% (1)** | 11% (4) | 6% (6) | 12% (3) | 0% (7) |
| IKBA1 | 13.4 | 26% (2) | 8% (5) | **29% (1)** | 8% (6) | 8% (4) | 21% (3) | 1% (7) |
| PEFO1 | 13.0 | 23% (2) | 5% (6) | **31% (1)** | 11% (4) | 8% (5) | 21% (3) | 1% (7) |
| SAGU1 | 13.6 | 25% (2) | 9% (5) | 18% (3) | 8% (6) | 11% (4) | **28% (1)** | 1% (7) |
| SAWE1 | 14.9 | 21% (2) | 11% (5) | 16% (3) | 8% (6) | 13% (4) | **31% (1)** | 1% (7) |
| SIAN1 | 13.0 | 25% (2) | 6% (6) | **33% (1)** | 9% (4) | 8% (5) | 19% (3) | 1% (7) |
| SYCA1 | 15.2 | 15% (4) | 4% (6) | **29% (1)** | 9% (5) | 15% (3) | 28% (2) | 0% (7) |
| TONT1 | 13.8 | **28% (1)** | 8% (5) | 21% (3) | 7% (6) | 9% (4) | 26% (2) | 1% (7) |

*Highest contribution per site is highlighted in bold.

**Table 11: Relative Contribution of Pollutants to Visibility Conditions on the 20% Least Impaired Days at Arizona Class I area IMPROVE Sites for the Progress Period (2005-2009).**

| Site | Deciviews (dv) | Percent Contribution by Component (% of $Mm^{-1}$) and Rank* | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| BALD1 | 2.9 | **35% (1)** | 7% (5) | 26% (2) | 13% (4) | 5% (6) | 13% (3) | 1% (7) |
| CHIR1 | 4.4 | **38% (1)** | 7% (5) | 17% (3) | 10% (4) | 6% (6) | 21% (2) | 1% (7) |
| GRCA2 | 2.2 | **45% (1)** | 13% (4) | 15% (2) | 9% (5) | 4% (6) | 14% (3) | 1% (7) |
| IKBA1 | 5.1 | **29% (1)** | 10% (5) | 28% (2) | 12% (4) | 5% (6) | 14% (3) | 1% (7) |
| PEFO1 | 4.6 | **31% (1)** | 9% (5) | 21% (2) | 19% (3) | 6% (6) | 14% (4) | 0% (7) |
| SAGU1 | 6.7 | **28% (1)** | 8% (6) | 20% (3) | 12% (4) | 8% (5) | 21% (2) | 2% (7) |
| SAWE1 | 8.0 | 24% (2) | 8% (6) | 18% (3) | 11% (4) | 10% (5) | **26% (1)** | 2% (7) |
| SIAN1 | 5.3 | 27% (2) | 7% (5) | **32% (1)** | 17% (3) | 5% (6) | 13% (4) | 1% (7) |
| SYCA1 | 5.1 | **27% (1)** | 10% (5) | 23% (2) | 17% (3) | 7% (6) | 15% (4) | 1% (7) |
| TONT1 | 5.7 | **33% (1)** | 9% (5) | 23% (2) | 12% (4) | 6% (6) | 16% (3) | 1% (7) |

*Highest contribution per site is highlighted in bold.

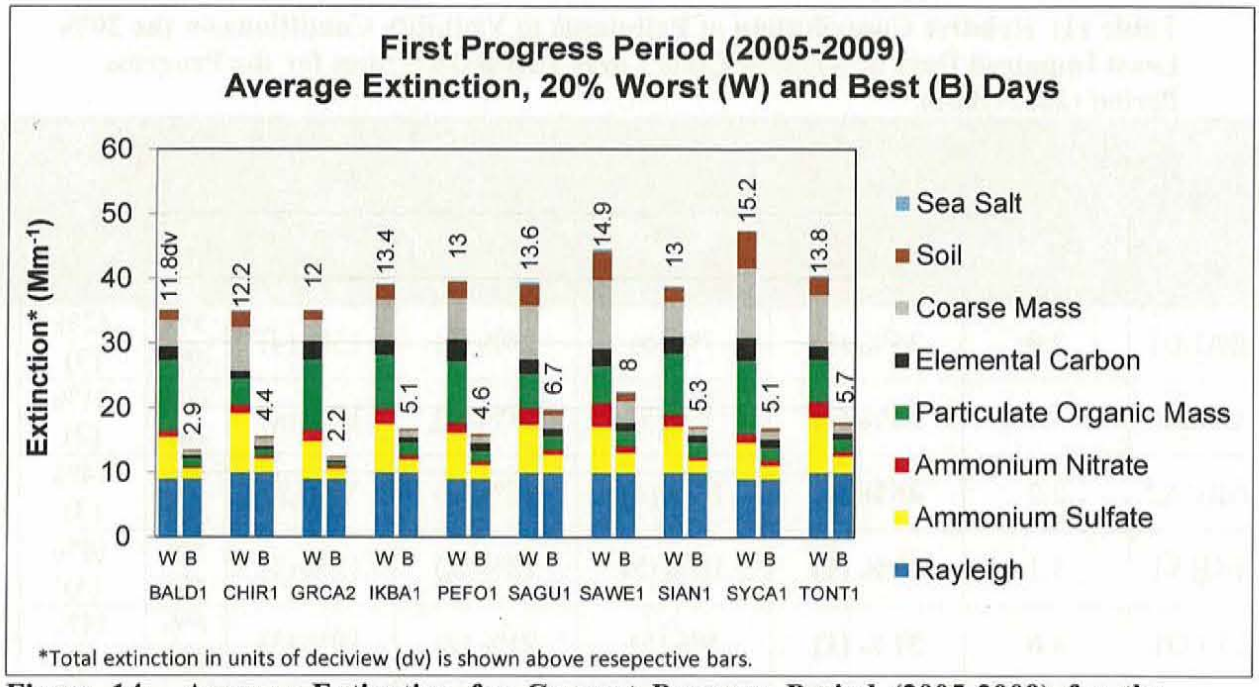


**Figure 14: Average Extinction for Current Progress Period (2005-2009) for the Worst (Most Impaired) and Best (Least Impaired) Days Measured at Arizona Class I area IMPROVE Sites.**

### III.B.2. Visibility Trend Analyses

This section addresses the regulatory question, ***what is the difference between current visibility conditions for the most impaired and least impaired days and baseline visibility conditions (40 CFR 51.308 (g)(3)(ii))?*** Baseline visibility conditions are the basis against which improvements in worst day visibility, and lack of degradation for the best day visibility, are judged. Included here are comparisons between the 5-year average baseline conditions (2000-2004) and the current progress period extinction (2005-2009). ADEQ refers to this method as the RHR method within this document.

ADEQ further presents an alternative analysis for visibility trend analysis for the 2000-2009 period. The alternative methodology is presented to better understand how anomalous years may have affected visibility changes as measured at Arizona Class I Areas. The Theil method was chosen to characterize visibility trends, as this method has been generally accepted by EPA in previous trend analyses, most notably in previously prepared EPA National Air Quality and Emissions Trends Reports[xii]. While the RHR method is the important metric for RHR regulatory purposes, trend statistics (e.g. the Theil Method) may be of value to understand and address visibility impairment issues for planning purposes.

[xii] EPA. Trends in Monitored Concentrations of Carbon Monoxide. National Air Quality and Emissions Trends Report, 2003.

### III.B.2.i. Theil Trend

Ten-year visibility trends were analyzed for the State or Arizona in order to better understand how anomalous years may have affected visibility changes as measured at Arizona Class I Areas. The Theil method was chosen to characterize visibility trends, as this method has been generally accepted by EPA in previous trend analyses, most notably in previously prepared EPA National Air Quality and Emissions Trends Reports[xiii]. EPA described the statistical method as follows:

"The Theil test is a nonparametric statistical test that can be used instead of regression-based methods for discerning a monotonic trend. It examines whether the concentration from year to year tends to increase or decrease consistently, making it a test of monotonicity. This test is not concerned with the magnitude of the year-to-year differences. The null hypothesis is that there is no monotonic trend in the data.

The first step in the test is to examine all possible [n(n-1)/2] pairs of data points from a given monitor, where n = 8, 9, 10, or 11. Next, a count is taken of all the pairs that show an increasing or decreasing trend. The null hypothesis will be rejected and the test results will indicate a significant monotonic increasing (or decreasing) trend if this count of the data point pairs is greater than (or less than) a certain critical value. A large positive value indicates a positive trend, and a large negative value indicates a negative trend.

The Theil test was applied for two reasons. First, it is appropriate when the errors from a linear regression are not normally, or close to normally, distributed. The data here may not meet the normality assumption. Second, this test was recommended to EPA for determining whether an area has a significant trend. Therefore, this test is used in EPA's annual Trends Reports."[xiv]

Annual trends reported here were calculated by ARS for the years 2000-2009, with a trend defined as the slope derived using the Thiel method. Trend statistics are useful in analyzing changes in air quality data, because these statistics can show the overall tendency of measurements over long periods of time to increase or decrease, while minimizing the effects of the year-to-year fluctuations which are common in air quality data. The significance of the trend is represented using p-values calculated using Mann-Kendall trend statistics. Determining a significance level helps to distinguish random variability in data from a tendency to increase or decrease over time, where lower p-values indicate higher confidence levels in the computed slopes. In some cases, trends may show decreasing tendencies where the difference between the 5-year averages do not. In these cases, the 5-year average is the important metric for RHR regulatory purposes, but trend statistics may be of value to understand and address visibility impairment issues for planning purposes.

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[xiii] EPA. Trends in Monitored Concentrations of Carbon Monoxide. National Air Quality and Emissions Trends Report, 2003.
[xiv] ibid

### III.B.2.ii. 2000-2009 Visibility Trend Analyses Results

This section presents visibility progress between 2000-2009 through the use of the two previously discussed methodologies: 1) the RHR method and 2) the Theil method.

Table 12 presents the differences between the 2000-2004 baseline period average and the 2005-2009 progress period average for each site in Arizona for the 20% most impaired days by use of the RHR method, and Table 13 presents similar data for the least impaired days. Averages that increased are depicted in red text and averages that decreased in blue. Figure 15 presents the 5-year average extinction for the baseline and current progress period averages for 20% most impaired days and Figure 16 presents the differences in averages by component, with increases represented above the zero line and decreases below the zero line. Figures 17 and 18 present similar plots for the 20% least impaired days using the RHR method.

Ten-year trends for individual visibility extinction components using the Theil method are presented in Table 14. Only averages with p-value statistics less than 0.15 (85% confidence level) are presented in Table 14, with increasing slopes in red and decreasing slopes in blue. The regional haze regulations refer specifically to changes in extinction for the 20% most impaired and least impaired days, but trend statistics are also presented in Table 14 for an average of all sampled days. Selection of the most impaired and least impaired days can vary seasonally from year to year, so in some cases the annual average of all sampled days may better represent actual aerosol component trends over time.

Some general observations regarding changes in visibility impairment at sites in Arizona are as follows:

For the 20% most impaired days, the RHR method exhibited deciview metric increases between the 2000-2004 and 2005-2009 periods at the GRCA2 and IKBA1 sites and decreases at all other Arizona sites. Theil method analysis showed no sites with significant increasing deciview metric trends between 2000-2009. Significant decreasing deciview metric trends occurred at all sites except BALD1, GRCA2, IKBA1, PEFO1, and SYCA1. Notable differences for individual components extinctions ($mM^{-1}$) on the 20% most impaired days were as follows:

- All sites except GRCA2 and IKBA1 measured decreases in particulate organic mass using the RHR method. No sites showed significant increasing trends using the Theil method and four sites showed significant decreasing trends.

- The RHR method analysis of ammonium sulfate showed increased extinction at all Arizona sites except SAGU1 and SAWE1, with the largest increases in ammonium sulfate occuring at the CHIR1, IKBA1 and TONT1

sites. In contrast, no statistically significant ($p < 0.15$) increasing annual trends in ammonium sulfate were measured using the Theil method. Decreasing annual ammonium sulfate trends on the order of about 0.1 $Mm^{-1}$/year were measured at the BALD1, CHIR1, SAGU1 and SAWE1 sites. Anomalously high ammonium sulfate occurred in 2005 at most Arizona sites, which influenced the increases noted using the RHR method.

- RHR method analysis of ammonium nitrate extinction showed decreases at all Arizona sites for the 20% most impaired days. Analysis of all measured days showed no increasing trends, and decreasing trends on the order of 0.1 $Mm^{-1}$/year at the IKBA1, SAGU1, SAWE1, SIAN1 and TONT1 sites.

- RHR method analysis of coarse mass revealed increasing extinction values at BALD1, SAGU1, SYCA1, and TONT1. However, only the BALD1 site showed a statistically significant increasing trend for coarse mass for all measured days on the order of approximately 0.1 $Mm^{-1}$/year ($p < 0.15$).

- Soil progress and baseline average differences decreased for five sites using the RHR method while measuring highest at the PEFO1, BALD1, and TONT1 sites for the 20% most impaired days. Theil method analysis showed increasing trends at only two Arizona sites for the 20% most impaired days (BALD1 and PEFO1) while SYCA1 showed a significant decreasing trend.

- Increases in deciview at the GRCA2 site using the RHR method were mostly due to increases in ammonium sulfate and elemental carbon and the lack of a decreasing particulate organic mass extinction which occurred at most other Arizona Class 1 Areas. Higher progress period measurements at GRCA2 were influenced by large wildfire events between June and August of 2009. These increases were partially offset by decreases in ammonium nitrate and coarse mass. This site did not show significant increasing ammonium sulfate trends using the Theil method.

- Increases in deciview at the IKBA1 site were mostly due to increased ammonium sulfate and particulate organic mass measurements. Higher progress period measurements at IKBA1 were influenced by large events in July 2005. These increases were partially offset by decreases in ammonium nitrate and soil. This site did not show significant increasing ammonium sulfate trends using the Theil method.

**Table 12: Difference in Aerosol Extinction by Component between the Baseline Period (2000-2004) and the Progress Period (2005-2009) on the 20% Most Impaired Days for Arizona Class I IMPROVE Sites.**

| Site | Deciview (dv) | | | Change in Extinction by Component ($Mm^{-1}$)* | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2000-2004 Baseline Period | 2005-2009 Progress Period | Change in dv* | Amm. Sulfate | Amm. Nitrate | POM | EC | Soil | CM | Sea Salt |
| BALD1 | 11.8 | 11.8 | 0.0 | +0.3 | -0.1 | -2.1 | -0.7 | +0.4 | +1.3 | +0.1 |
| CHIR1 | 13.4 | 12.2 | -1.2 | +1.0 | -0.1 | -3.2 | -0.5 | -0.3 | -1.9 | +0.2 |
| GRCA2 | 11.7 | 12.0 | +0.3 | +0.5 | -0.4 | +0.1 | +0.5 | +0.1 | -0.3 | 0.0 |
| IKBA1 | 13.3 | 13.4 | +0.1 | +1.0 | -1.2 | +0.7 | 0.0 | -0.3 | 0.0 | +0.1 |
| PEFO1 | 13.2 | 13.0 | -0.2 | +0.5 | -0.3 | -1.4 | +0.5 | +0.6 | -1.0 | +0.1 |
| SAGU1 | 14.8 | 13.6 | -1.2 | -0.1 | -3.2 | -4.1 | -0.9 | -0.1 | +1.2 | +0.2 |
| SAWE1 | 16.2 | 14.9 | -1.3 | -0.7 | -2.3 | -1.9 | -0.5 | -1.4 | -2.2 | +0.2 |
| SIAN1 | 13.7 | 13.0 | -0.7 | +0.7 | -0.3 | -2.5 | +0.1 | +0.1 | -0.6 | +0.2 |
| SYCA1 | 15.3 | 15.2 | -0.1 | +0.7 | -0.7 | -0.5 | +0.4 | -1.0 | +1.4 | 0.0 |
| TONT1 | 14.2 | 13.8 | -0.4 | +1.3 | -0.5 | -3.5 | -0.6 | +0.4 | +0.5 | +0.2 |

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction, values in blue indicate decreases.

For the 20% least impaired days, the RHR method exhibited decreasing deciview metrics at all sites except GRCA2, where the measured deciview average remained the same. Notable differences for individual component averages on the 20% least impaired days were as follows:

- The largest decreases were due to particulate organic mass, which decreased at all sites except IKBA1 using the RHR method. Theil method analysis revealed significant decreasing trends at seven of the sites.

- Ammonium sulfate decreased at most sites, but increased slightly at the GRCA2, SAGU1 and SYCA1 sites using the RHR method. Theil methodology revealed no statistically significant increasing trends and three sites experienced statistically significant decreases in ammonium sulfate trends ($p < 0.15$).

- Ammonium nitrate decreased at all but the GRCA2 site using the RHR method and four of the decreasing sites were found to be statistically significant using the Theil method ($p < 0.15$).

**Table 13: Difference in Aerosol Extinction by Component between the Baseline Period (2000-2004) and the Progress Period (2005-2009) on the 20% Least Impaired Days for Arizona Class I IMPROVE Sites.**

| Site | Deciview (dv) | | | Change in Extinction by Component ($Mm^{-1}$)* | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2000-2004 Baseline Period | 2005-2009 Progress Period | Change in dv* | Amm. Sulfate | Amm. Nitrate | POM | EC | Soil | CM | Sea Salt |
| BALD1 | 3.0 | 2.9 | -0.1 | -0.1 | -0.1 | -0.1 | 0.0 | 0.0 | +0.1 | 0.0 |
| CHIR1 | 4.9 | 4.4 | -0.5 | -0.2 | -0.1 | -0.5 | -0.1 | 0.0 | 0.0 | 0.0 |
| GRCA2 | 2.2 | 2.2 | 0.0 | +0.1 | 0.0 | -0.1 | 0.0 | 0.0 | 0.0 | 0.0 |
| IKBA1 | 5.4 | 5.1 | -0.3 | -0.3 | -0.2 | +0.1 | 0.0 | -0.1 | -0.1 | +0.1 |
| PEFO1 | 5.0 | 4.6 | -0.4 | -0.1 | -0.2 | -0.4 | 0.0 | +0.1 | 0.0 | 0.0 |
| SAGU1 | 6.9 | 6.7 | -0.2 | +0.1 | -0.2 | -0.2 | -0.1 | -0.3 | +0.3 | +0.1 |
| SAWE1 | 8.6 | 8.0 | -0.6 | -0.2 | -0.1 | -0.5 | -0.4 | -0.3 | +0.2 | +0.2 |
| SIAN1 | 6.2 | 5.3 | -0.9 | -0.3 | -0.4 | -0.7 | -0.1 | 0.0 | 0.0 | 0.0 |
| SYCA1 | 5.6 | 5.1 | -0.5 | +0.1 | -0.1 | -0.6 | -0.2 | -0.1 | +0.1 | 0.0 |
| TONT1 | 6.5 | 5.7 | -0.8 | -0.2 | -0.2 | -0.5 | -0.2 | -0.1 | -0.2 | +0.1 |

*Change is calculated as progress period average minus baseline period average. Values in red indicate increases in extinction, values in blue indicate decreases.

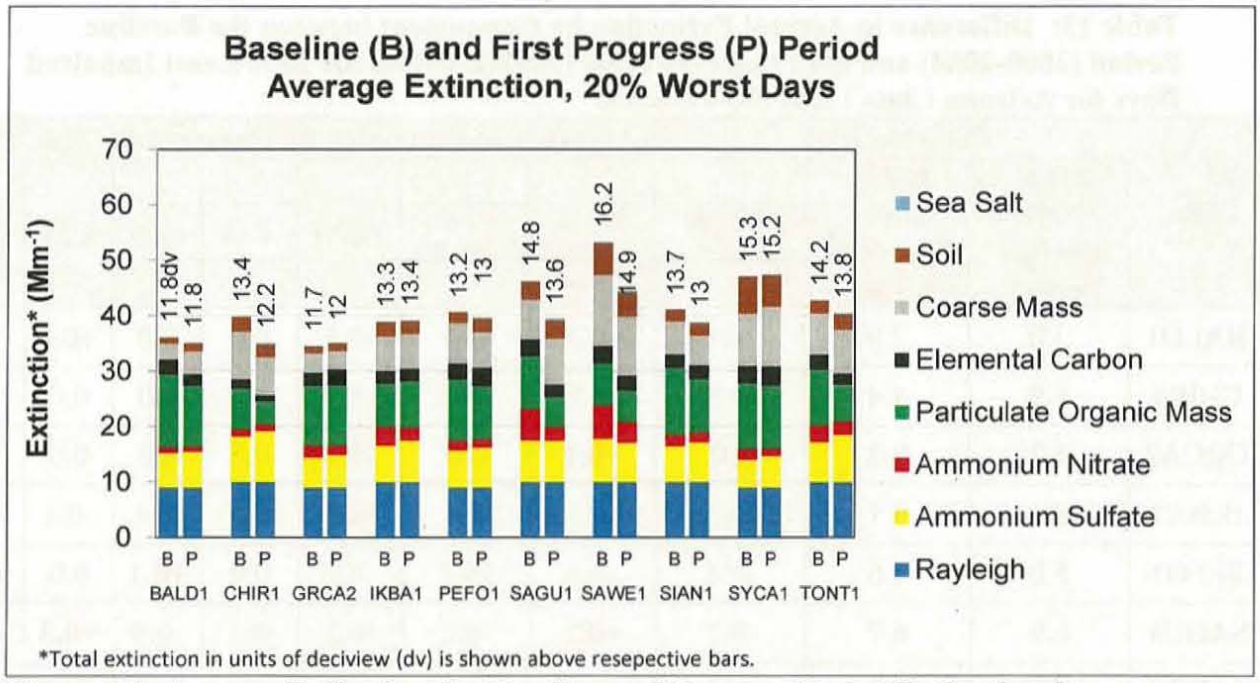



**Figure 15: Average Extinction for Baseline and Progress Period Extinction for Worst (Most Impaired) Days Measured at Arizona Class I area IMPROVE Sites.**

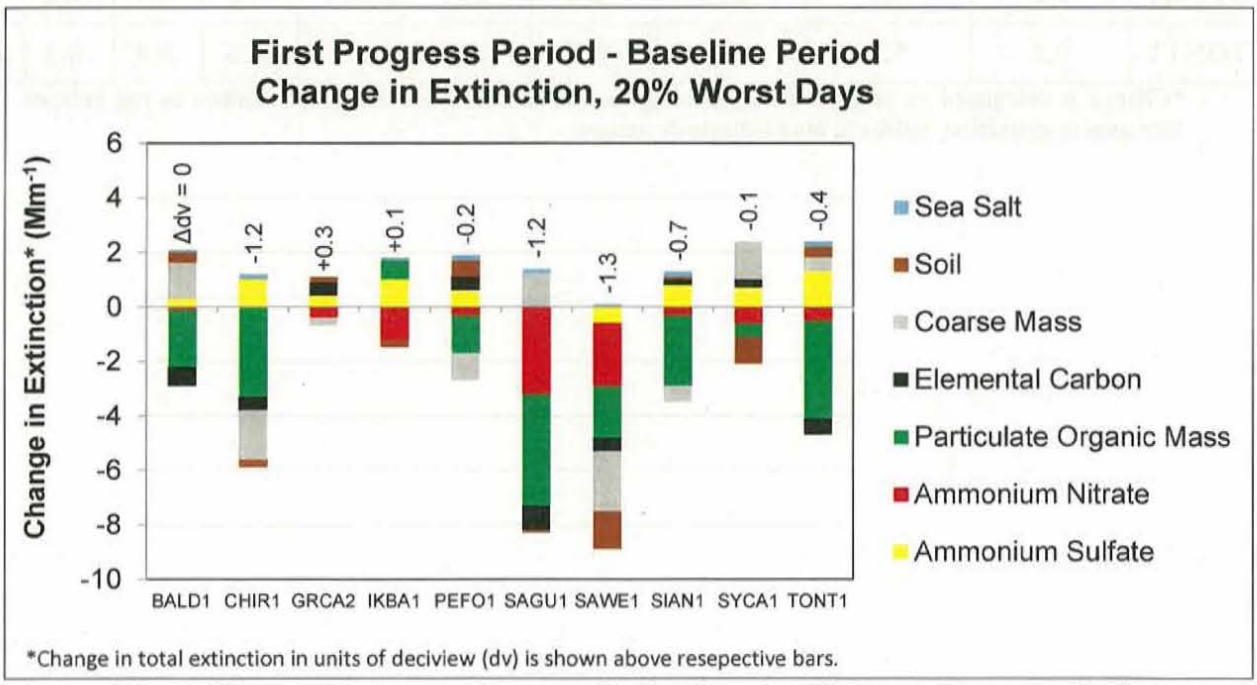



**Figure 16: Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Worst (Most Impaired) Days Measured at Arizona Class I area IMPROVE Sites.**

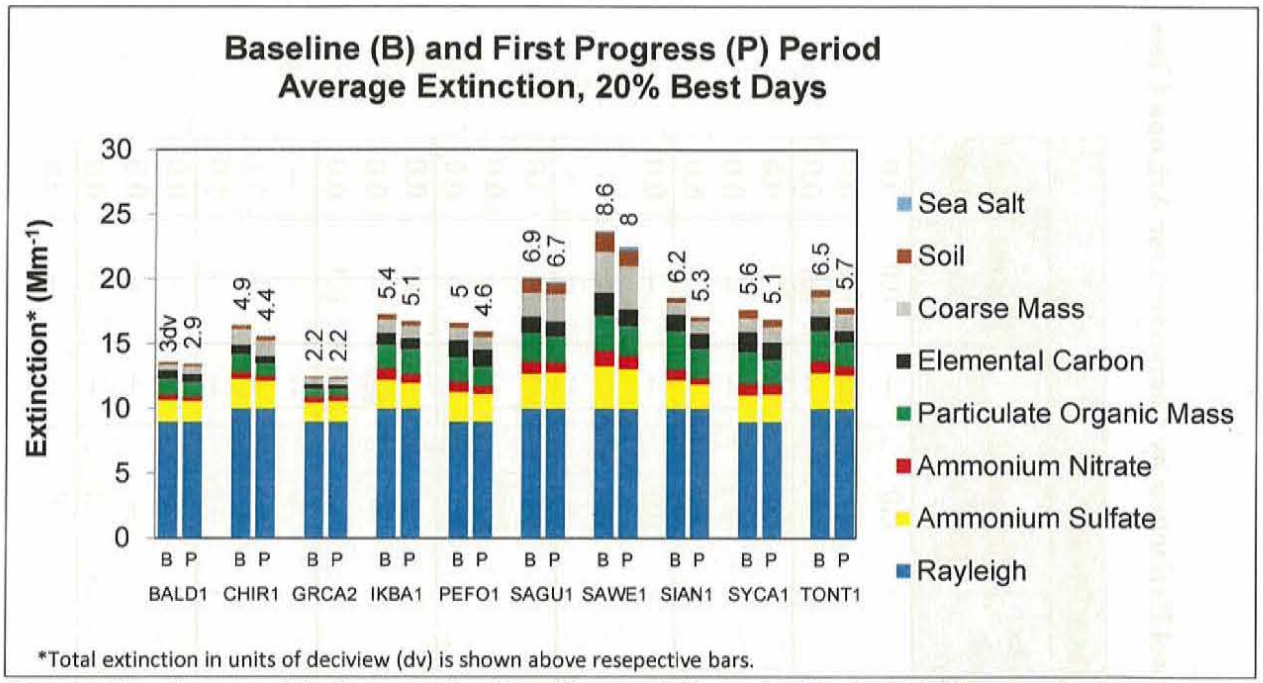



**Figure 17: Average Extinction for Baseline and Progress Period Extinction for Best (Least Impaired) Days Measured at Arizona Class I area IMPROVE Sites.**

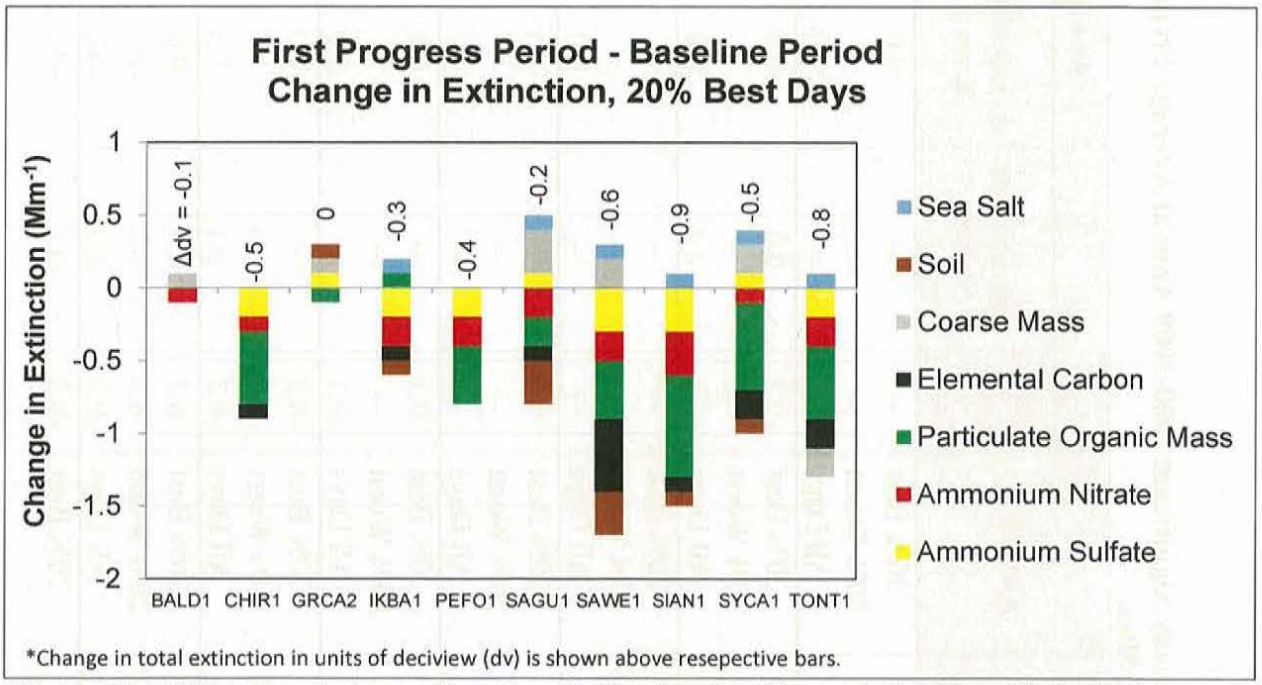



**Figure 18: Difference between Average Extinction for Current Progress Period (2005-2009) and Baseline Period (2000-2004) for the Best (Least Impaired) Days Measured at Arizona Class I area IMPROVE Sites.**

**Table 14: Statistically Significant 2000-2009 Annual Average Trends for Aerosol Extinction by Component for Arizona Class I area IMPROVE Sites.**

| Site | Group | Annual Trend* ($Mm^{-1}$/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Site Total (dv) | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| BALD1 | 20% Best | -- | -- | 0.0 | -- | 0.0 | -- | 0.0 | 0.0 |
| | 20% Worst | -- | -0.2 | -- | -- | -- | **0.1** | **0.3** | 0.0 |
| | All Days | -- | -0.1 | 0.0 | -- | -- | -- | **0.1** | 0.0 |
| CHIR1 | 20% Best | **-0.1** | 0.0 | 0.0 | -0.1 | 0.0 | -- | 0.0 | 0.0 |
| | 20% Worst | **-0.3** | -- | -- | -0.7 | -0.1 | -- | -- | 0.0 |
| | All Days | **-0.2** | -0.1 | 0.0 | -0.2 | -0.1 | -- | -0.1 | 0.0 |
| GRCA2 | 20% Best | -- | -- | -- | -- | 0.0 | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -0.1 | -- | -- | -- | -- | -- |
| | All Days | -- | -- | 0.0 | -- | -- | -- | -- | -- |
| IKBA1 | 20% Best | **-0.2** | -0.1 | -0.1 | 0.0 | 0.0 | 0.0 | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | 0.0 | -- | -- | 0.0 |
| | All Days | -- | -- | -0.1 | -- | 0.0 | -- | -- | 0.0 |
| PEFO1 | 20% Best | **-0.1** | -- | 0.0 | -0.1 | -- | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | -- | **0.1** | -- | 0.0 |
| | All Days | **-0.1** | -- | 0.0 | -- | -- | 0.0 | **0.1** | 0.0 |
| SAGU1 | 20% Best | **-0.2** | -- | -0.1 | -0.1 | -- | -- | -- | -- |
| | 20% Worst | **-0.3** | -0.4 | -0.5 | -0.6 | -0.3 | -- | -- | **0.1** |
| | All Days | **-0.2** | -0.1 | -0.1 | -0.2 | -0.1 | -- | -- | 0.0 |
| SAWE1 | 20% Best | **-0.2** | 0.0 | 0.0 | -0.1 | -0.1 | -0.1 | -- | 0.0 |
| | 20% Worst | **-0.3** | -0.3 | -0.6 | -0.5 | -- | -- | -- | 0.0 |
| | All Days | **-0.2** | -0.1 | -0.1 | -0.3 | -0.1 | -- | -- | 0.0 |
| SIAN1 | 20% Best | **-0.2** | -0.1 | -0.1 | -0.1 | 0.0 | -- | -- | 0.0 |

| Site | Group | Annual Trend* ($Mm^{-1}$/year) | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Site Total (dv) | Ammonium Sulfate | Ammonium Nitrate | Particulate Organic Mass | Elemental Carbon | Soil | Coarse Mass | Sea Salt |
| | 20% Worst | -0.2 | -- | -- | -- | -- | -- | -- | 0.0 |
| | All Days | -0.2 | -- | -0.1 | -0.4 | -0.1 | -- | -- | 0.0 |
| SYCA1 | 20% Best | -0.1 | -- | -- | -0.1 | -- | -- | -- | 0.0 |
| | 20% Worst | -- | -- | -- | -- | 0.1 | -0.3 | -- | -- |
| | All Days | -0.1 | -- | 0.0 | -- | -- | -0.1 | -- | -- |
| TONT1 | 20% Best | -0.2 | -0.1 | -0.1 | -0.1 | -0.1 | -- | -0.1 | 0.0 |
| | 20% Worst | -0.2 | -- | -0.1 | -0.8 | -0.2 | -- | -- | 0.1 |
| | All Days | -0.1 | -- | -0.1 | -0.2 | -0.1 | -- | -- | 0.0 |

*(--) Indicates statistically insignificant trend (<85% confidence level).

## *III.C. Ammonium Sulfate Analysis*

Several analyses have been presented in this document to examine how Ammonium sulfate extinction has changed within the 2000-2009 period at IMPROVE monitoring sites within the State of Arizona. When examining the State as a whole, ammonium sulfate has shown increases at the IMPROVE sites between the baseline period and progress period averages for the 20% most impaired days. No significant increasing trends were observed using the Theil method and several sites saw statistically significant decreasing Theil statistic trends for the 20% most impaired, least impaired, and all days (Section III.B.2.).

### III.C.1. 20% Most Impaired Ammonium Sulfate Days

In this section ADEQ presents an alternate analysis performed by ARS in which the 20% most impaired ammonium sulfate days were isolated, averaged annually and then averaged for the baseline and progress periods. This analysis was performed in order to better understand how the worst 20% visibility days for a particular pollutant change between the baseline and progress periods rather than examining the 20% worst visibility days for all combined pollutants. The combination analysis required by the RHR can cause seasonal shifts in the days chosen within the baseline and progress periods which in turn can miss seasonal highs for certain pollutant classes. A Theil statistics trend analysis is also performed for each monitor on the annually averaged 20% most impaired days for the period of 2000-2009. Figure 19 presents the annual average of the 20% most impaired days. Extinction decreases between 2000 and 2004, while the years of 2005 and 2007 show exceptionally high ammonium sulfate averages, followed by consecutive decreasing years between 2007 and 2009. When baseline and progress period extinction averages are compared, all IMPROVE sites show increasing ammonium sulfate extinctions except SAWE1. However, when 2000-2009 worst 20% ammonium sulfate days trends are analyzed, no sites show increasing trends (Figure 21). BALD1, CHIR1, PEFO1, SAGU1, and SAWE1 all exhibit statistically significant decreasing ammonium sulfate extinction trends. The extreme differences are strongly influenced by ammonium sulfate concentrations measured in 2005. Since this year is more like a midpoint, the data have a more neutral effect using the Theil method ($p < 0.15$). To illustrate the effect of the 2005 year, ADEQ presents the results of an analysis in Table 15 where the RHR method is altered to include the year 2005 in the baseline period rather than the progress period. This altered RHR method resulted in reduced ammonium sulfate extinction values between the altered progress period (2006-2009) when compared to the altered baseline period (2000-2005) for all sites except TONT1 for the 20% most impaired ammonium sulfate days. This illustrates the strong effect that one year can have in the RHR methodology.

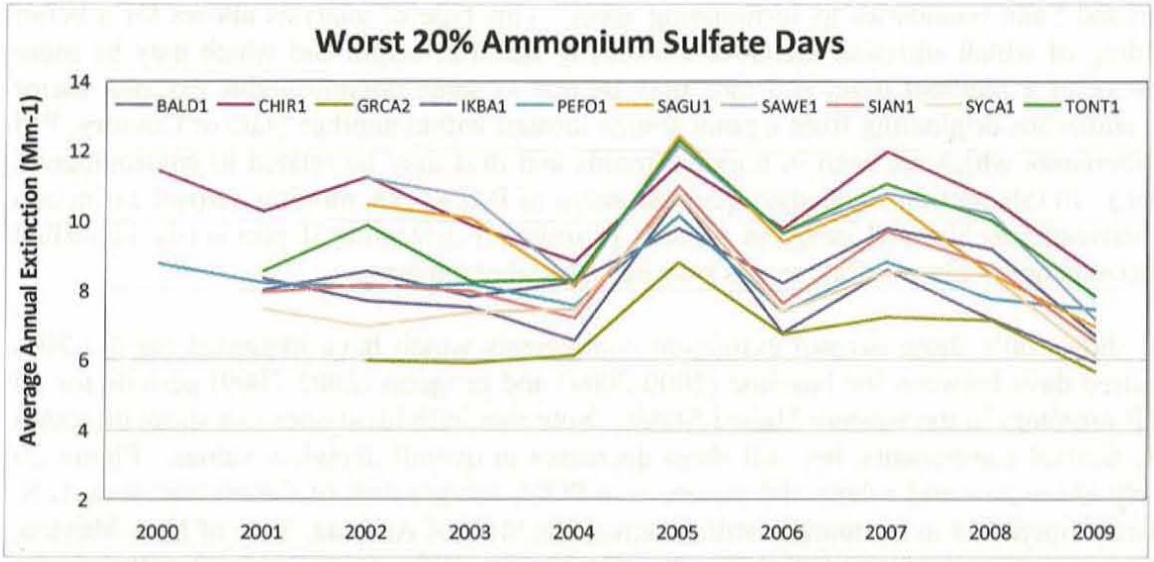



**Figure 19: Average Annual Ammonium Sulfate Extinction ($mM^{-1}$) at each Arizona Class I area IMPROVE Site for the 20% Worst Ammonium Sulfate Days.**

**Table 15: 2000-2009 Ammonium Sulfate Visibility Extinction ($mM^{-1}$) Trends, Baseline (2000-2004) vs. Progress (2005-2009) Period Comparisons, and Altered Baseline (2000-2005) vs. Altered Progress (2005-2009) Period Comparisons at each Arizona Class I area IMPROVE Site for the 20% Worst Ammonium Sulfate Days.**

| SiteCode | Slope | p-value | Baseline (2000-2004) | Period 1 (2005-2009) | Difference | Altered Baseline (2000-2005) | Altered Period 1 (2006-2009) | Difference |
|---|---|---|---|---|---|---|---|---|
| BALD1 | **-0.18** | **0.08** | 7.52 | 7.84 | **0.32** | 8.15 | 7.13 | **-1.02** |
| CHIR1 | **-0.15** | **0.14** | 10.33 | 10.51 | **0.18** | 10.55 | 10.22 | **-0.32** |
| GRCA2 | -0.05 | 0.24 | 6.39 | 7.12 | **0.73** | 6.87 | 6.70 | **-0.17** |
| IKBA1 | -0.09 | 0.36 | 8.16 | 8.73 | **0.57** | 8.48 | 8.47 | **-0.02** |
| PEFO1 | **-0.15** | **0.03** | 8.16 | 8.31 | **0.15** | 8.49 | 7.86 | **-0.64** |
| SAGU1 | **-0.29** | **0.13** | 9.54 | 9.58 | **0.05** | 10.26 | 8.87 | **-1.39** |
| SAWE1 | **-0.33** | **0.09** | 10.05 | 10.00 | **-0.05** | 10.58 | 9.45 | **-1.13** |
| SIAN1 | -0.07 | 0.30 | 7.81 | 8.71 | **0.90** | 8.45 | 8.14 | **-0.31** |
| SYCA1 | -0.04 | 0.43 | 7.30 | 8.24 | **0.94** | 7.99 | 7.62 | **-0.37** |
| TONT1 | 0.00 | 0.50 | 8.75 | 10.18 | **1.43** | 9.46 | 9.65 | **0.19** |

### III.C.2. Regional Ammonium Sulfate Trends

While the State of Arizona SIP only addresses the pollutant emissions and progress goals for areas within Arizona's State boundary, it is important to analyze regional trends in pollutants in order to better understand which phenomena are more representative of State issues and which

extend beyond State boundaries to surrounding areas. This type of analysis allows for a better understanding of which emission increases are locally based in origin and which may be more representative of a regional trend and thus may be due to some uncontrollable external factor (e.g. $NO_x$ emissions originating from a point source located within another State or Country, PM emission increases which are seen in regional trends and thus may be related to environmental factors, etc.). In this section we analyze regional maps of IMPROVE monitor aerosol extinction changes between baseline and progress periods in order to determine if previously identified State of Arizona ammonium sulfate trends may be regional phenomena.

Figure 20 shows only those aerosol extinction components which have increased for the 20% most impaired days between the baseline (2000-2004) and progress (2005-2009) periods for all IMPROVE monitors in the western United States. Note that individual sites can show increases in specific aerosol components, but still show decreases in overall deciview values. Figure 20 shows fairly ubiquitous and substantial increases in POM across much of the northwestern U.S. and substantial increases in ammonium sulfate across the State of Arizona, State of New Mexico, western Texas, and south-central Colorado. The ammonium sulfate increases seen in this figure are obviously regional in extent; however, it is difficult to determine an origination point. These increases could be due to a singular or combination of point or area sources within the above mentioned States and/or Mexico.

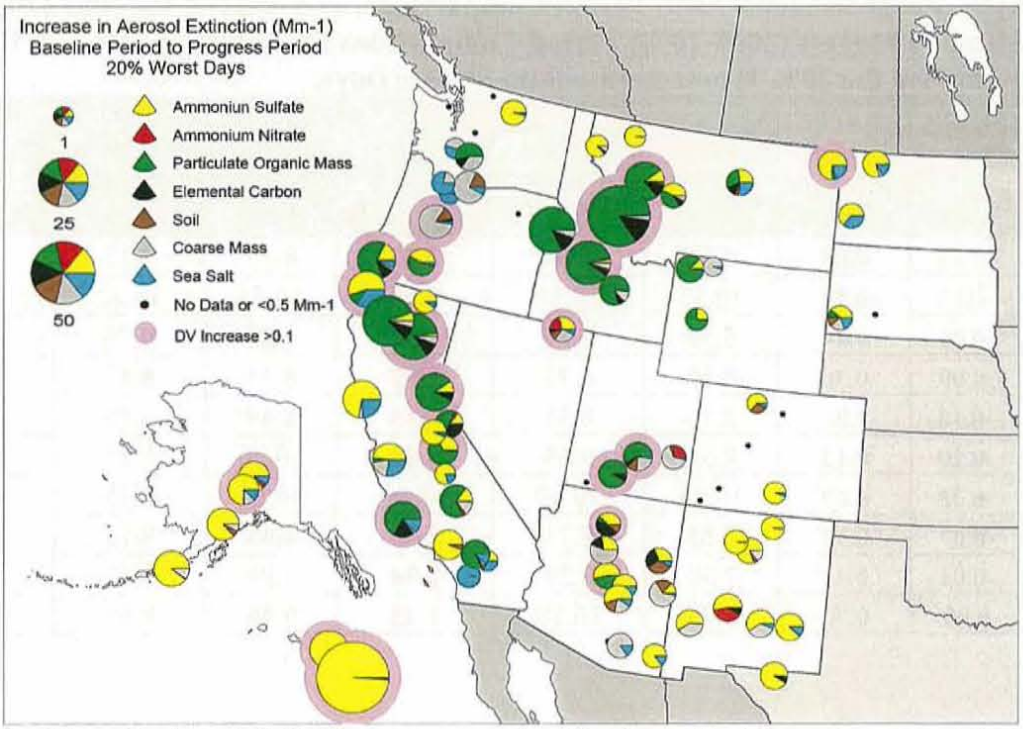



**Figure 20: Magnitude of visibility component extinctions that have increased between the baseline average (2000-2004) and the first progress period average (2005-2009) for the 20% worst visibility days.**

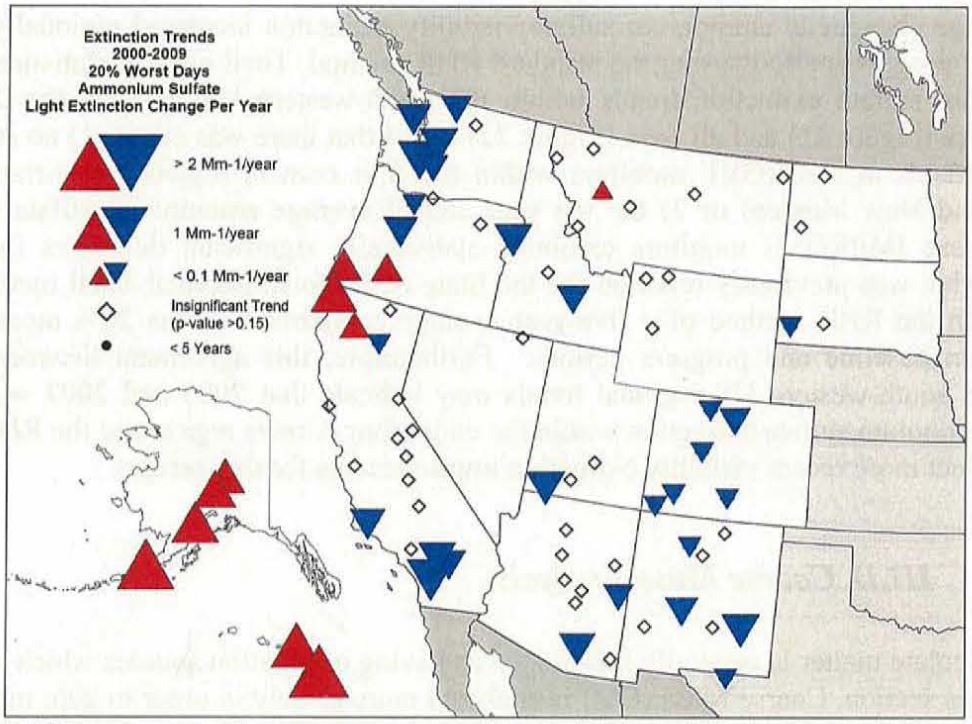



**Figure 21: 10-year annual average ammonium sulfate extinction trends for 20% worst days at CIA IMPROVE sites in the WRAP region.**

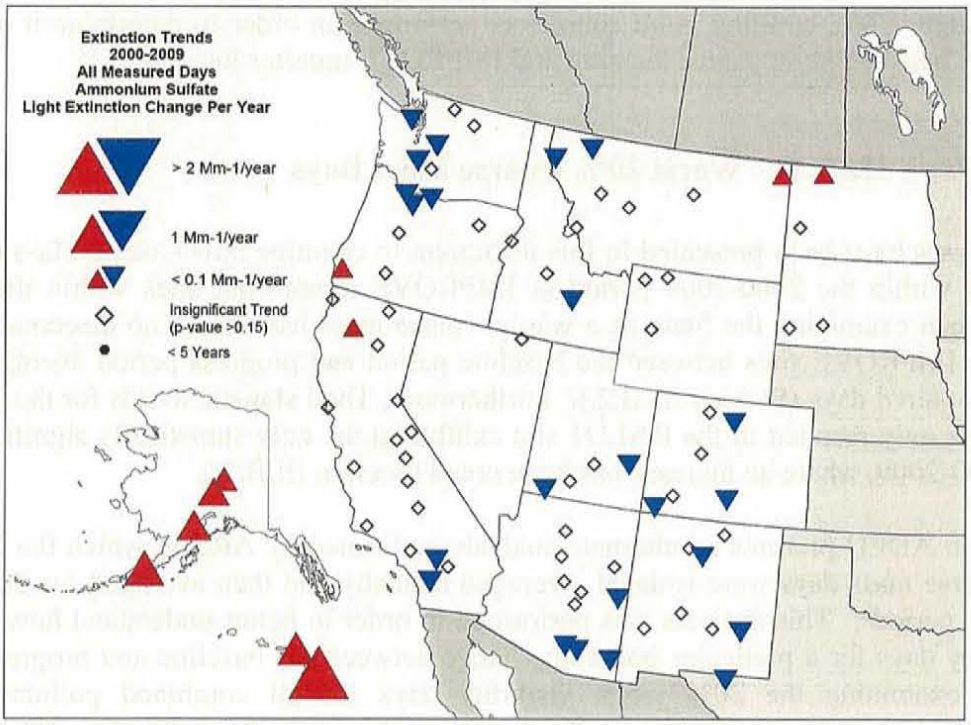



**Figure 22: 10-year annual average ammonium sulfate extinction trends for all measured days at CIA IMPROVE sites in the WRAP region.**

While average changes in ammonium sulfate visibility extinction increased regionally between baseline and progress periods using the standard RHR method, Theil method statistical analysis of ammonium sulfate extinction trends within the south-western US for both the 20% most impaired days (Figure 21) and all days (Figure 22) found that there was either: 1) no statistically significant trends at IMPROVE monitors within the four corners region (i.e. Arizona, Utah, Colorado, and New Mexico) or 2) the ten year annual average ammonium sulfate extinction trends at these IMPROVE monitors exhibited statistically significant decreases ($p < 0.15$). Similar to what was previously reported for the State of Arizona, regional Theil method trends disagree with the RHR method of a five-year average comparison of the 20% most impaired days between baseline and progress periods. Furthermore, this agreement between State of Arizona and south-western US regional trends may indicate that 2005 and 2007 were outlier years for ammonium sulfate extinction within the entire four corners region and the RHR method does not reflect more recent visibility extinction improvements for this aerosol.

## *III.D. Coarse Mass Analysis*

Coarse Particulate matter is generally recognized as having origination sources which are locally based. In this section, Coarse Mass (CM) is analyzed more closely in order to gain more insight into trends for this particular pollutant seen between the baseline and progress period for all IMPROVE sites around the State. This section presents the results of an alternate approach in selecting the 20% most impaired day analysis, similar to the trend performed for ammonium sulfate in Section III.C. Furthermore, a qualitative analysis of IMPROVE site location in relation to major $PM_{10}$ emitting point sources is performed in order to determine if an evident pattern exists between point source location and IMPROVE monitor location.

### III.D.1. Worst 20% Coarse Mass Days

Several analyses have been presented in this document to examine how Coarse Mass extinction has changed within the 2000-2009 period at IMPROVE monitoring sites within the State of Arizona. When examining the State as a whole, coarse mass has shown no discernable spatial trends at the IMPROVE sites between the baseline period and progress period averages for the 20% most impaired days (Section III.B.2.). Furthermore, Theil statistic trends for the 20% most impaired days only resulted in the BALD1 site exhibiting the only statistically significant trend between 2000-2009, where an increase has been noted (Section III.B.2.).

In this section ADEQ presents an alternate analysis performed by ARS in which the 20% most impaired coarse mass days were isolated, averaged annually and then averaged for the baseline and progress periods. This analysis was performed in order to better understand how the worst 20% visibility days for a particular pollutant change between the baseline and progress periods rather than examining the 20% worst visibility days for all combined pollutants. The combination analysis required by the RHR can cause seasonal shifts in the days chosen within the baseline and progress periods which in turn can miss seasonal highs for certain pollutant classes. A Theil statistics trend analysis is also performed for each monitor on the annually averaged 20% most impaired days for the period of 2000-2010. This trend analysis was

extended past prior analyses (2000-2009) to include 2010 since this year was shown to be fairly unique in how coarse mass responded across Arizona. As shown in Figure 23, coarse mass is generally low in the years of 2008 and 2009, but in the year 2010 coarse mass extinction dramatically increases at some sites while continuing to decrease at others on the 20% most impaired days. When comparing the baseline period to the progress period for the 20% worst coarse mass visibility days (Table 16) all monitors except BALD1, PEFO1, and TONT1 recorded decreased extinction. Furthermore, the CHIR1, SAWI1, SAGU1, and SIAN1 monitors exhibited drastic decreases in CM extinction for the 20% most impaired CM days. Theil statistics over the 11 year period showed decreasing trends at all sites except two; however, only CHIR1 and SIAN1 showed statistically significant decreases, while BALD1 and PEFO exhibited statistically significant increasing trend for CM on the 20% most impaired CM days ($p < 0.15$).

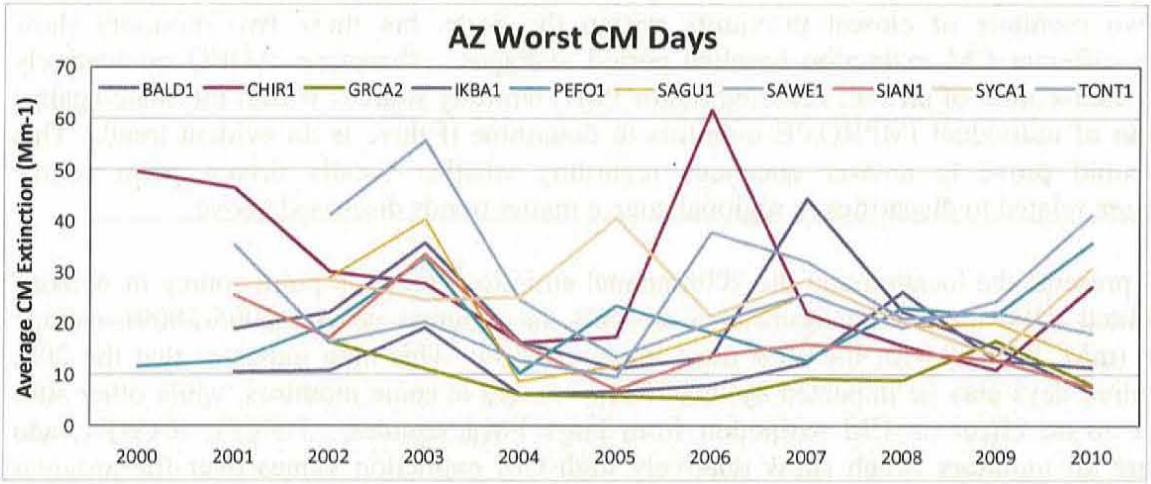



**Figure 23: Average Annual Coarse Mass Extinction (mM-1) at each Arizona Class I area IMPROVE Site for the 20% Worst Coarse Mass Days.**

**Table 16: 2000-2010 Coarse Matter Visibility Extinction ($mM^{-1}$) Trends and Baseline vs. Progress Period Comparisons at each Arizona Class I area IMPROVE Site for the 20% Worst Coarse Matter Days.**

| SiteCode | 11-year trend (2000-2010) | p-value | Baseline (2000-2004) | Period 1 (2005-2009) | Period Difference |
|---|---|---|---|---|---|
| BALD1 | **0.29** | **0.15** | 11.66 | 13.12 | **1.46** |
| CHIR1 | **-2.73** | **0.02** | 33.92 | 25.47 | **-8.45** |
| GRCA2 | -0.38 | 0.24 | 11.38 | 9.04 | **-2.34** |
| IKBA1 | -1.10 | 0.19 | 23.27 | 21.24 | **-2.03** |
| PEFO1 | **1.12** | **0.06** | 17.42 | 19.80 | **2.38** |
| SAGU1 | -1.26 | 0.38 | 25.88 | 18.83 | **-7.05** |
| SAWE1 | -0.56 | 0.31 | 40.47 | 20.49 | **-19.98** |
| SIAN1 | **-1.56** | **0.01** | 22.97 | 12.76 | **-10.21** |
| SYCA1 | -1.04 | 0.24 | 26.36 | 24.77 | **-1.59** |
| TONT1 | -0.32 | 0.50 | 21.08 | 24.47 | **3.38** |

### III.D.2. Large Point Source Locations

Previous analyses of coarse mass extinction between 2000 and 2009/2010 have shown fairly mixed results; however, there is evidence which suggests coarse mass emissions originate from areas close to the individual IMPROVE monitors. Table 16 presents baseline vs. progress period differences which generally show decreasing trends across the state, but it is difficult to discern regional trends from monitors within close proximity of one another. IKBA1, SIAN1, and TONT1 are three monitors which are centrally located within the state within relatively close proximity; however, these three show a respective small decrease, large decrease, and small increase in CM extinction for the 20% most impaired CM days. Similarly, SAWE1 and SAGU1 are the two monitors of closest proximity within the State, but these two monitors show drastically different CM extinction baseline period averages. Therefore, ADEQ qualitatively examined the location of all NEI reported major $PM_{10}$ emitting sources within the State against the location of individual IMPROVE monitors to determine if there is an evident trend. This analysis could prove to answer questions regarding whether locally driven point source emissions are related to disparities in regional coarse matter trends discussed above.

Figure 24 presents the location and the 2008 annual emissions for each point source in Arizona which emitted >100 tons. The figure also presents the progress period (2005-2009) average extinction ($mM^{-1}$) for CM for the 20% most impaired days. This map indicates that the 20% most impaired days may be impacted by local $PM_{10}$ sources at some monitors, while other sites show little to no effect on CM extinction from large $PM_{10}$ sources. TONT1, SAWE1, and SAGU1 are all monitors which show relatively high CM extinction values over the progress period and are located relatively close to several large $PM_{10}$ emitting point sources. However, SYCA1 is a monitor which recorded high extinction values for the 20% most impaired days over the progress period and it is only located near one large source, which is a relatively small $PM_{10}$ emitter in comparison with other large sources on the map. Also, PEFO1 and BALD1 are located near very large $PM_{10}$ emitting sources, yet have some of the lowest CM extinction values for the 20% most impaired days recorded over the progress period. Overall, it is difficult to discern a visual relationship between large $PM_{10}$ point sources and IMPROVE monitor CM extinctions for the 20% most impaired days in the State of Arizona. A finer scale EI around each monitor site may be needed in order to better understand individual site trends for CM extinction.

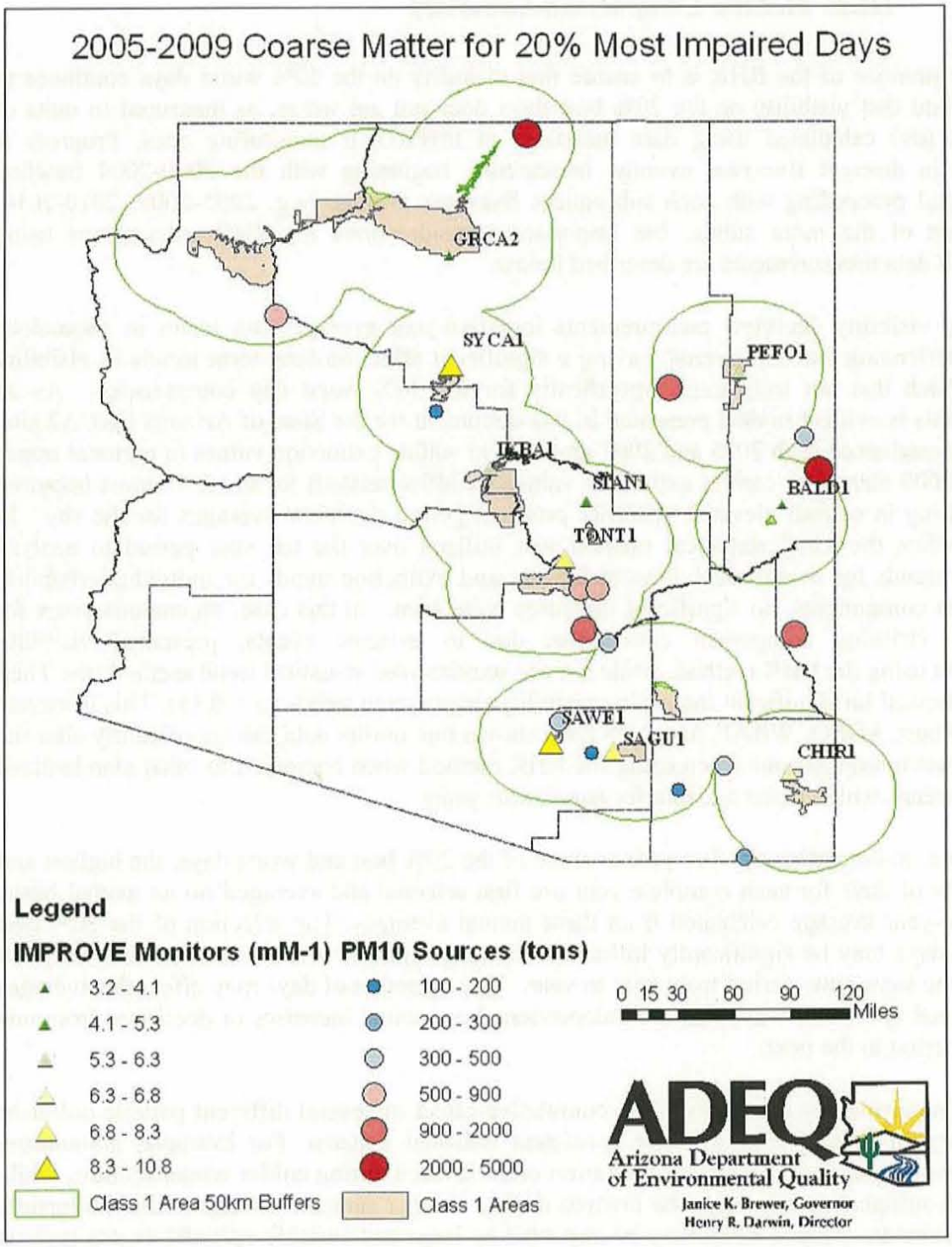



**Figure 24: Locations of Arizona Class I areas, Class I area 50 km buffers, Class I area IMPROVE monitors, and Large Point Source Emitters of PM10 (>100 tons/year). IMPROVE site values correspond to Visibility Extinction (mM-1) of Coarse Mass averaged over the progress period (2005-2009).**

## *III.E. Method Comparison Summary*

The basic premise of the RHR is to ensure that visibility on the 20% worst days continues to improve, and that visibility on the 20% best days does not get worse, as measured in units of deciviews (dv) calculated using data measured at IMPROVE monitoring sites. Progress is measured in discreet five-year average increments, beginning with the 2000-2004 baseline average, and proceeding with each subsequent five-year average (e.g. 2005-2009, 2010-2014, etc.). Some of the more subtle, but important, considerations for RHR calculations using IMPROVE data measurements are described below.

Compiling visibility deciview measurements into five-year averages can result in anomalous years, experiencing extreme events, having a significant affect on long-term trends in visibility change which due not truly exist, specifically for the 20% worst day comparisons. As an example, this is evident in data presented in this document for the State of Arizona GRCA2 site. This site experienced high 2005 and 2007 ammonium sulfate extinction values (a regional trend) and high 2009 elemental carbon extinction values (wildfire related) for the 20% most impaired days resulting in overall elevated visibility progress period deciview averages for the site. In contrast, when the Theil statistical method was utilized over the ten year period to analyze extinction trends for overall deciviews at the site and extinction trends for individual visibility impairment components, no significant increases were seen. In this case, anomalous years for individual visibility component extinctions, due to extreme events, presented visibility degradation using the RHR method, while a more standardized statistical trend method (the Theil method) showed no significant increasing visibility degradation trends ($p < 0.15$). This is merely one case where ADEQ, WRAP, and ARS have shown that outlier data can significantly alter the data progress interpretations when using the RHR method when compared to other standardized statistical trends which better account for anomalous years.

Furthermore, to determine the five-year average of the 20% best and worst days, the highest and lowest 20% of days for each complete year are first selected and averaged on an annual basis, with a five-year average calculated from these annual averages. The selection of the 20% best and worst days may be significantly influenced by large episodic events, and as such, may not represent the same time period from year to year. This selection of days may affect the averages for individual species in ways that are independent from actual increases or decreases from one five-year period to the next.

Visibility impairment is the result of the cumulative effect of several different particle pollutant types. Many of these pollutants have consistent seasonal patterns. For example, ammonium nitrate is temperature sensitive, with formation often favored during colder winter months, while ammonium sulfate formation may be favored during warmer summer months. Other pollutants, such as particulate organic mass, may be impacted by large and variable episodic events such as wildland fires. Variable occurrence of large episodic events may cause high extinction measurements that will drive selection of 20% worst days to coincide with the episodic events, effectively introducing the possibility that the worst days occur at different times each year.

As an illustration of events driving the selection of the worst days, consider daily average aerosol extinction calculated from IMPROVE data at the CHIR1 site in Arizona. Figures 25 and 26

present daily aerosol extinction measurements for 2002 and 2008 at CHIR1, with the 20% worst days represented by an orange box with an "x" below the day. For 2002, large wildfire events in June and July contributed to high POM measurements, resulting in more of the worst days selected during this period. In 2008, more of the worst days were selected in August and October.

As an illustration of the seasonal patterns of individual compounds, consider the monthly averages of aerosol extinction calculated from IMPROVE data at the CHIR1 site. Figure 27 presents monthly average aerosol pollution for CHIR1 measured during 2002, and Figure 28 presents monthly averages in 2008. For both years, plots show that ammonium sulfate is highest between July and September. The monthly plots also show the higher POM that coincided with wildfire events in 2002, which affected the selection of more of the worst days between May and July in 2002, and more worst days in August and October in 2008. The seasonal patterns of ammonium sulfate mean that even if annual ammonium sulfate stayed the same, worst days in May and July will have higher ammonium sulfate than worst days that occur between August and October.

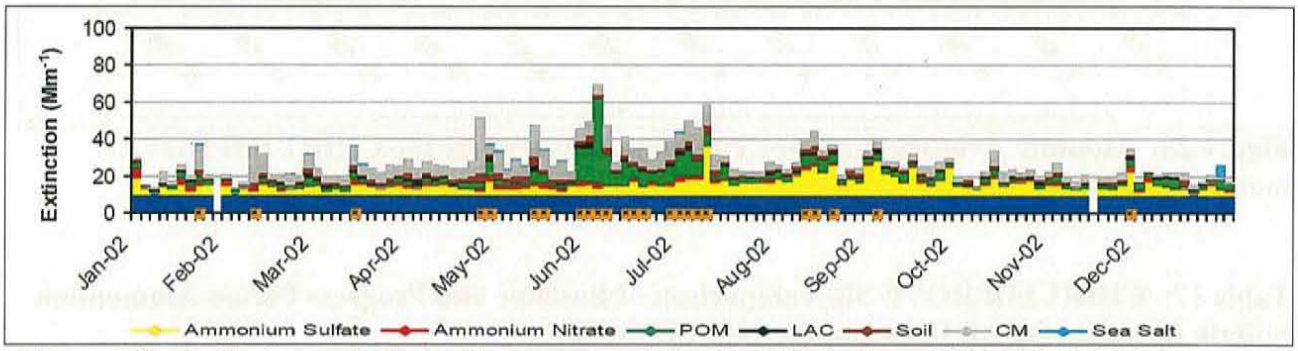



**Figure 25: Daily Aerosol Extinction measured by the Chiricahua CHIR1 IMPROVE monitor during 2002.**

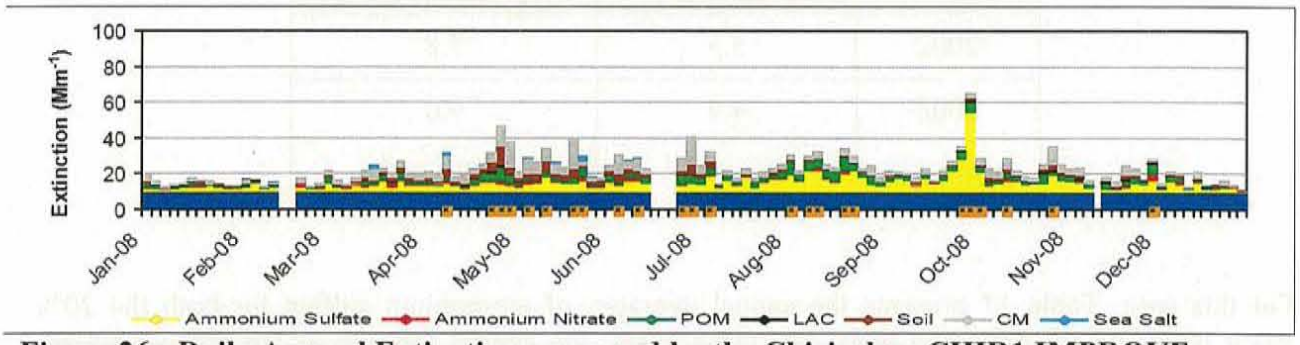



**Figure 26: Daily Aerosol Extinction measured by the Chiricahua CHIR1 IMPROVE monitor during 2008.**

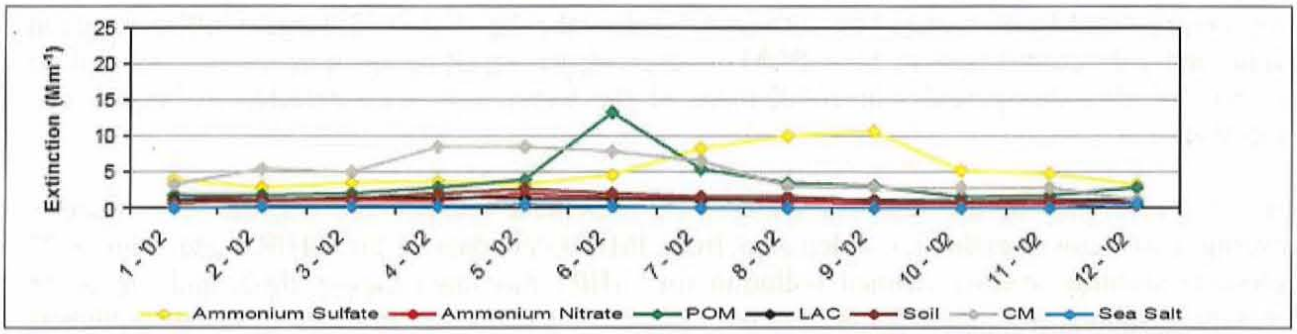



**Figure 27: Monthly Average Aerosol Extinction measured by the CHIR1 IMPROVE monitor in 2002.**

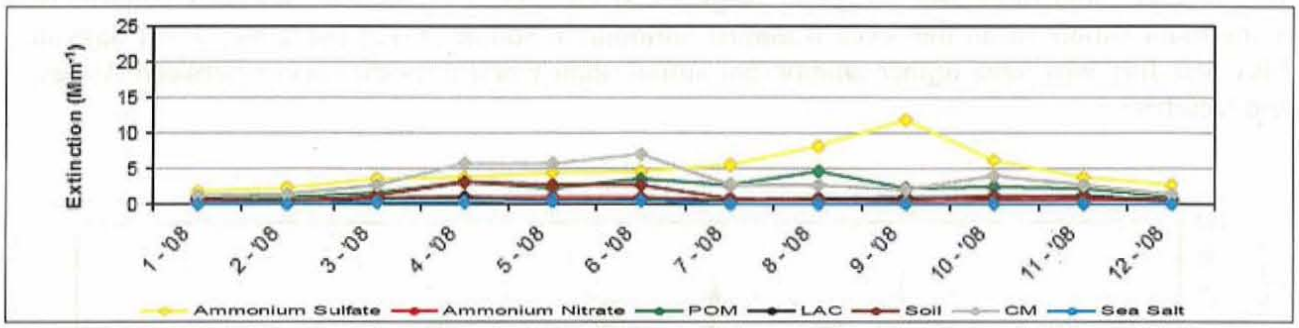



**Figure 28: Monthly Average Aerosol Extinction measured by the CHIR1 IMPROVE monitor in 2008.**

**Table 17: CHIR1 IMPROVE Site comparison of Baseline and Progress Period Ammonium Sulfate Averages for All Days and the 20% Worst Days**

| Year | All Days Amm. Sulfate Average ($Mm^{-1}$) | 20% Worst Days Amm. Sulfate Average ($Mm^{-1}$) |
|---|---|---|
| 2002 | 5.3 | 7.8 |
| 2008 | 4.9 | 9.0 |
| Difference | -0.4 $Mm^{-1}$ | +2.2 $Mm^{-1}$ |

For this case, Table 17 presents the annual averages of ammonium sulfate for both the 20% worst days and all measured days. For these years, the annual average of ammonium sulfate extinction decreases, while the 20% worst day average actually increased.

Within this document ADEQ, WRAP, and ARS have presented several different methods of analyzing IMPROVE data in order to best understand the trends which are occurring at each of the IMPROVE sites between the years of 2000-2009. These methods are slight alterations in how the analyzed data are chosen (i.e. choosing the 20% most/least impaired days particular to a certain pollutant rather than for the entire suite of pollutants) and how the variability inevitably

seen with pollution data can be analyzed to account for the effects of large individual events which may skew overall pollution trends (i.e. the utilization of the Theil statistical trend analysis). ADEQ contests that these analyses represent logical methods which are comparable to and in some ways improve upon the standardized methodology required by the RHR. Furthermore, these methods are not drastically different from previous EPA methodology, and in the case of Theil statistical comparison, actually represent previously utilized EPA methodology for similar comparisons.

# IV. Reasonable Progress Goals

## *IV.A. Overview*

EPA proposed to disapprove Arizona's Reasonable Progress Goals (RPGs) for 2018 based on the reasoning that they did not feel ADEQ demonstrated that the goals constituted reasonable progress[15]. In this section ADEQ presents Arizona's progress towards reaching the previously presented RPGs and Uniform Rates of Progress (URPs) as interpreted through IMPROVE monitoring data. ADEQ chose to present IMPROVE data trends, as opposed to surrogate measures such as Emission Inventory trends, as monitoring data most accurately measure visibility changes within a region. However, ADEQ also provides analysis within this section relating trends seen at the IMPROVE monitors to those noted within the emission inventories where appropriate. Finally, ADEQ compares State-wide extinction trends for individual visibility impairment components to regional trends.

This section compares the rate of progress between the baseline and progress periods towards the goal of natural visibility at each of the Arizona IMPROVE monitors and how that rate compares to RPGs and URPs for the 20% most impaired and least impaired days. An alternate analysis of RP is also included which illustrates the effect that one single year (2005) has on the original results. Furthermore, additional analyses are provided which show 1.) how specific fire events can have a large impact on the baseline versus progress period comparison and 2.) ammonium nitrate trends for specific Class I areas that may have the potential for being impacted by nearby large sources of $NO_x$.

## *IV.B. Reasonable Progress as Determined by IMPROVE Monitoring Data*

Tables 18 and 19 present the baseline visibility, progress period visibility, URP visibility for 2018 (not included in Table 19), and the 2018 RPGs for each of the IMPROVE monitor sites for the 20% most impaired days and the 20% least impaired days, respectively. The Tables further present 2018 projected visibility based on the visibility rate of change between the baseline period and progress periods. The 2018 projected visibility was calculated for each IMPROVE monitoring site using the following equation:

[15] Environmental Protection Agency (EPA). Federal Register Volume 77, No. 246. Dec. 21, 2012.

$$PV = BP - 16 * \left( \frac{(BP - PP)}{5} \right)$$

where:

$PV$ = 2018 projected visibility (dV)
$BP$ = Average baseline period visibility (dV)
$PP$ = Average progress period visibility (dV)

This equation assumes a linear rate of progress between the baseline and progress period that can be extrapolated to 2018, that the average baseline period visibility is the visibility for the midpoint year of the baseline period (2002), and that the average progress period visibility is the visibility for the midpoint year of the progress period (2007). The 2018 projected visibility values can be utilized in two ways: 1) comparison with ADEQ's previously calculated RPGs, or 2) comparison with ADEQ's previously calculated URPs. This method is a rather simplistic method but is believed to be more representative of actual progress compared to utilization of a highly uncertain EI.

Table 18 presents the projected visibility for each IMPROVE site as compared to ADEQ's RPGs and URPs for the 20% most impaired days. Six monitoring locations (shown in blue) are expected to surpass ADEQ's RPGs for 2018. Furthermore, CHIR1, SAWE1, SAGU1, and SIAN1 are projected to surpass the URPs calculated for these sites for 2018. While BALD1 and SYCA1 (shown in black) are expected to experience visibility improvements by 2018, these improvements are not expected to meet the RPGs calculated by ADEQ. Two sites are projected to experience visibility degradation by 2018 when compared to 2002 (shown in red); these sites are GRCA2 and IKBA1.

Table 19 presents the projected visibility for each IMPROVE site as compared to the ADEQs RPGs for the 20% least impaired days. None of the sites are projected to experience visibility degradation on the 20% least impaired days. Furthermore, all sites except GRCA2 are projected to surpass 2018 RPGs for the 20% least impaired days.

**Table 18: Arizona Class I Area Reasonable Progress Goals Comparison to Progress Period Visibility for the 20% Worst Days. '2018 Projected Visibility' was extrapolated based on the rate of Visibility change between the Baseline and Progress Period Visibilities.**

| Reasonable Progress Goals for 20% Worst Days for Arizona Class I Areas | | | | | | |
|---|---|---|---|---|---|---|
| **Arizona Class I Area** | **Site ID** | **Baseline (dV)** | **Progress (dV)** | **URP based 2018 visibility** | **2018 RPG (dV)** | **2018 Projected visibility** |
| Chiricahua NM, Chiricahua W, Galiuro W | CHIR1 | 13.4 | 12.2 | 12.0 | 13.4 | 9.6 |
| Grand Canyon NP | GRCA2 | 11.7 | 12.0 | 10.6 | 11.1 | 12.7 |
| Mazatzal W, Pine Mountain W | IKBA1 | 13.4 | 13.4 | 11.8 | 12.8 | 13.4 |
| Mount Baldy W | BALD1 | 11.9 | 11.8 | 10.5 | 11.5 | 11.6 |
| Petrified NP | PEFO1 | 13.2 | 13.0 | 11.6 | 12.9 | 12.6 |
| Saguaro NP - West Unit | SAWE1 | 16.2 | 14.9 | 13.9 | 16.0 | 12.0 |
| Saguaro NP - East Unit | SAGU1 | 14.8 | 13.6 | 12.9 | 14.8 | 11.0 |
| Sierra Ancha W | SIAN1 | 13.7 | 13.0 | 12.0 | 13.2 | 11.5 |
| Superstition W | TONT1 | 14.2 | 13.8 | 12.4 | 13.9 | 12.9 |
| Sycamore Canyon W | SYCA1 | 15.3 | 15.2 | 13.3 | 15.0 | 15.1 |

**Table 19: Arizona Class I Area Reasonable Progress Goals Comparison to Progress Period Visibility for the 20% Best Days. '2018 Projected Visibility' was extrapolated based on the rate of Visibility change between the Baseline and Progress Period Visibilities.**

| Reasonable Progress Goals for 20% Best Days for Arizona Class I Areas | | | | | |
|---|---|---|---|---|---|
| **Arizona Class I Area** | **Site ID** | **Baseline (dV)** | **Progress (dV)** | **2018 RPG (dV)** | **2018 Projected visibility** |
| Chiricahua NM, Chiricahua W, Galiuro W | CHIR1 | 4.9 | 4.4 | 4.9 | 3.3 |
| Grand Canyon NP | GRCA2 | 2.2 | 2.2 | 2.1 | 2.2 |
| Mazatzal W, Pine Mountain W | IKBA1 | 5.4 | 5.1 | 5.2 | 4.4 |
| Mount Baldy W | BALD1 | 3.0 | 2.9 | 2.9 | 2.7 |
| Petrified NP | PEFO1 | 5.0 | 4.6 | 4.7 | 3.7 |
| Saguaro NP - West Unit | SAWE1 | 8.6 | 8.0 | 8.3 | 6.7 |
| Saguaro NP - East Unit | SAGU1 | 6.9 | 6.7 | 7.0 | 6.3 |
| Sierra Ancha W | SIAN1 | 6.2 | 5.3 | 5.9 | 3.3 |
| Superstition W | TONT1 | 6.5 | 5.7 | 6.2 | 3.9 |
| Sycamore Canyon W | SYCA1 | 5.6 | 5.1 | 5.5 | 4.0 |

Visibility degradation at GRCA2 and IKBA1 are most accurately explained through large, singular wildfire events which skew RHR method results for the 20% most impaired days. Within this document ADEQ has shown evidence of the effect individual events at an IMPROVE monitoring location can have in misrepresenting visibility trends when using the RHR method. Table 20 supplements previously overviewed data to show this issue more clearly. Table 20 presents an analysis where two years' (2003 and 2009) EC and POM visibility extinction data from GRCA2 are adjusted to ten-year averages in order to reduce the effects of wildfires located near the monitor. In the year of 2003, total extinction for the GRCA2 monitor was recalculated using the ten-year average extinction values for EC (2.7 $Mm^{-1}$) and POM (10.7 $Mm^{-1}$). This was repeated for the year of 2009. Both years, 2003 and 2009, experienced large wildfire events near the GRCA2 monitor and this substitution method was utilized in an attempt to reduce the effects of these wildfire events on the overall trends of the RHR method. Table 20 shows that without substitution, total visibility extinction increases by 0.5 $mM^{-1}$ using the RHR method, while EC and POM extinction normalization for the year of 2003 caused this degradation to increase to 2.2 $Mm^{-1}$, and 2009 extinction normalization caused the trend to reverse with total visibility improvement on the order of 1.8 $Mm^{-1}$ at GRCA2. A similar analysis was performed on IKBA1 IMPROVE data where 2005 EC and POM extinction values were replaced with ten-year average values (2.3 $Mm^{-1}$ and 8.0 $Mm^{-1}$, respectively). This exercise expresses the degree to which one large event can skew visibility trends for the 20% most impaired days.

While individual events can cause skewed results, the same can be said for individual years. In previous sections of this document ADEQ has discussed the exceptionality of the year of 2005 when compared to other years' visibility. While ADEQ had data for the more recent visibility year of 2010 available for use in tracking trends at Class I Areas, RHR method requires the use of the immediate five-year period following the baseline period when analyzing visibility trends. The year of 2005 was an exceptionally high year for visibility extinction throughout the State. In Table 21, ADEQ performed an altered version of the RHR method where the baseline period was shifted to include the year 2005 (i.e. 2000-2005) and the progress period was shifted to include the most recently available IMPROVE monitoring data for the progress period (2006-2010). This table presents the data in a format similar to Table 18 in order to see how these updated trends track to the year 2018 for comparison with RPGs and URPs. It is evident from the information contained in Table 20, the strong effect that the year 2005 has on the overall trends. In this comparison, all IMPROVE monitor sites are not just meeting Arizona's previously set RPG values, but are also exceeding URPs by 2018. Again, this analysis shows the limitations of the RHR methodology as one year near the mid-point has a strong influence on the overall trends.

**Table 20: Alternative method for the 20% Most Impaired Days at GRCA2 and IKBA1. EC and POM visibility extinctions are replaced by ten-year average for 2003 and 2009 (GRCA2) and 2005 (IKBA1).**

| Alternative RHR Analysis Results for the 20% Worst Days at GRCA2 (2003 & 2009) and IKBA1 (2005) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | | Total Extinction (Mm-1) | | | | | |
| Site | Year Adjusted | Baseline | Adjusted Baseline | Progress | Adjusted Progress | Standard Change | Adjusted Change |
| GRCA2 | 2003 | 34.6 | 32.9 | 35.1 | -- | 0.5 | 2.2 |
| GRCA2 | 2009 | 34.6 | -- | 35.1 | 32.8 | 0.5 | -1.8 |
| IKBA1 | 2005 | 38.9 | -- | 39.2 | 37.7 | 0.3 | -1.2 |

**Table 21: Arizona Class I Area RPGs Adjusted Comparison to the Altered Progress Period Visibility (2006-2010) for the 20% Worst Days. '2018 Projected Visibility' was extrapolated based on the rate of visibility change between the Baseline and Progress Period Visibilities. In this case the Baseline period was altered to the years 2000-2005 and the Progress Period was adjusted to the years 2006-2010.**

| Adjusted Reasonable Progress Goals for 20% Worst Days for Arizona Class I Areas | | | | | | |
|---|---|---|---|---|---|---|
| Arizona Class I Area | Site ID | 2000-2005 Baseline (dV) | 2006-2010 Progress (dV) | URP based 2018 visibility | 2018 RPG (dV) | 2018 Projected visibility |
| Chiricahua NM, Chiricahua W, Galiuro W | CHIR1 | 13.3 | 11.8 | 12.0 | 13.4 | 8.5 |
| Grand Canyon NP | GRCA2 | 11.8 | 11.4 | 10.6 | 11.1 | 10.5 |
| Mazatzal W, Pine Mountain W | IKBA1 | 13.6 | 12.6 | 11.8 | 12.8 | 10.4 |
| Mount Baldy W | BALD1 | 11.9 | 11.1 | 10.5 | 11.5 | 9.3 |
| Petrified NP | PEFO1 | 13.3 | 12.5 | 11.6 | 12.9 | 10.7 |
| Saguaro NP - West Unit* | SAWE 1 | 16.0 | 14.8 | 13.9 | 16.0 | 12.2 |
| Saguaro NP - East Unit | SAGU1 | 14.7 | 13.3 | 12.9 | 14.8 | 10.2 |
| Sierra Ancha W | SIAN1 | 13.9 | 12.3 | 12.0 | 13.2 | 8.8 |
| Superstition W | TONT1 | 14.2 | 13.3 | 12.4 | 13.9 | 11.3 |
| Sycamore Canyon W | SYCA1 | 15.5 | 14.7 | 13.3 | 15.0 | 12.9 |

*2010 data was not included for this unit do to uncertainty of data's accuracy.

## *IV.C. Ammonium Nitrate Q/D Analysis*

EPA has performed an initial Q/D analysis for the determination of those Point Sources which need to be evaluated further for controls based on $NO_x$ emissions. In this section ADEQ presents information which shows that all Class I Areas identified by EPA as potentially impaired by these identified sources have exhibited decreased visibility impairment from ammonium nitrate between the baseline period (2000-2004) and the progress period (2005-2009). Table 22 presents the initial results of EPA's Q/D analysis for those sources identified as impairing or possibly impairing Arizona Class I Areas. This analysis presented four Arizona Class 1 Areas which were possibly impacted by $NO_x$ emissions from Point Sources, including: SAGU1, PEFO1, SYCA1, and SIAN1. IMPROVE data from all four areas were analyzed according to the RHR method for changes in ammonium nitrate extinction for the 20% least and most impaired days (Table 23). Table 23 shows that all sites exhibited improved visibility between 8% and 44% for the 20% least impaired days for ammonium nitrate. The 20% most impaired days exhibited even greater visibility improvements for ammonium nitrate with extinctions decreasing between the baseline and progress period between 15% and 55% at the four Class I Areas identified. Analysis of IMPROVE monitoring data by ADEQ at the SAGU1, PEFO1, SYCA1, and SIAN1 sites indicate that these sites are showing significantly improved visibility directly due to ammonium nitrate extinction reductions.

**Table 22: NOx emissions (Q) over distance (D) analysis for AZ facilities with Q/D values > 10. Also included is the nearest Class 1 Area to the facilities.**

| Source | Q (tpy) | D (km) | Q/D | Closest Class I Area | Class I Abbr. |
|---|---|---|---|---|---|
| Arizona Portland Cement Co | 5,635 | 6.99 | 806 | Saguaro Wilderness | SAGU |
| ASARCO Ray Ops Mine | 1,290 | 66.02 | 20 | Sierra Ancha Wilderness | SIAN |
| Cholla Plant | 34,066 | 31.75 | 1073 | Petrified Forest NP | PEFO |
| El Paso Nat Gas (Tucson Compr Station) | 336 | 14.72 | 23 | Saguaro Wilderness | SAGU |
| Flagstaff Comp Stn | 1,013 | 34.94 | 29 | Sycamore Canyon Wild. | SYCA |
| Irvington Gen Stn | 5,797 | 15.84 | 366 | Saguaro Wilderness | SAGU |
| Phoenix Cement | 3,224 | 12.65 | 255 | Sycamore Canyon Wild. | SYCA |
| Pima Co. Sewage Plant | 258 | 12.56 | 21 | Saguaro Wilderness | SAGU |
| TEP Springerville | 32,973 | 60.46 | 545 | Petrified Forest NP | PEFO |
| Williams Comp Stn | 1,388 | 19.12 | 73 | Sycamore Canyon Wild. | SYCA |

**Table 23: IMPROVE monitoring ammonium nitrate trend results for Class I Areas located near facilities that exhibited high Q/D results.**

| Change in Ammonium Nitrate Visibility Extinction | | | |
|---|---|---|---|
| **Class I Area** | **Abbreviation** | **20% Least Impaired [mM-1]** | **20% Most Impaired [mM-1]** |
| **Saguaro Wilderness** | **SAGU1** | **-0.2 (-19%)** | **-3.2 (-55%)** |
| **Petrified Forest NP** | **PEFO1** | **-0.2 (-22%)** | **-0.3 (-17%)** |
| **Sycamore Canyon Wilderness** | **SYCA1** | **-0.1 (-8%)** | **-0.7 (-33%)** |
| **Sierra Ancha Wilderness** | **SIAN1** | **-0.4 (-44%)** | **-0.3 (-15%)** |

# V. Conclusions

This document fills the required EPA Regional Haze SIP deficiency for the State of Arizona regarding the submission of a complete and recent emission inventory. In this document ADEQ presents a 2008 Emission Inventory which is comparable to the 2002 EI in some Source Categories for a variety of pollutants. Where this inventory is not reliably comparable to the 2002 State of Arizona EI, ADEQ has provided an overview of the methodology, input data, and model resolution enhancements that have changed between the 2002 and 2008 inventory preparations.

ADEQ has also included a review of IMPROVE monitor data between the years of 2000 and 2009. This review presented standardized 20% best and worst visibility day comparisons between the baseline and progress periods as well as Theil statistical trend analyses as an alternative approach for understanding ten-year trends. Visibility aerosol extinction indicates that ammonium nitrate, organic mass, and elemental carbon extinctions are improving within almost all Arizona Class 1 areas. Fine Soil and Coarse Mass extinction values seem dependant of the local environment surrounding the Class 1 Areas and show no discernable increasing or decreasing spatial trends across the State. Anomalously high years (2005 and 2007) for ammonium sulfate extinction revealed increasing ammonium sulfate visibility extinction between the baseline and progress periods; however, decreasing trends in ammonium sulfate in previous and more recent years resulted in Theil statistics which either showed no statistically significant visibility extinction increases or statistically significant visibility decreases across the State ($p < 0.15$). Furthermore, similar trends for ammonium sulfate were noted for the four corners region.

Finally, ADEQ compared overall visibility trends at each of the IMPROVE monitor locations against previously submitted RPGs and URPs for 2018. These data indicated that if the current pace of visibility change was continued, no site would experience increased visibility impairment for the 20% least impaired visibility days in 2018. Six monitoring locations are expected to surpass ADEQ's previously submitted RPGs for 2018 for the 20% most impaired days. Furthermore, four sites, CHIR1, SAWE1, SAGU1, and SIAN1 are projected to surpass the previously accepted URPs for the 20% most impaired days in 2018. Only two sites are projected to experience visibility degradation for the 20% most impaired days in 2018 when compared to 2002, these sites are GRCA2 and IKBA1. However, the visibility degradation noted at these sites is most likely due to wildfires located close to these monitors during the progress period. ADEQ has shown that if EC and POM extinction values are standardized for years during which fires have occurred close to a monitor, the entire progress period trends can be altered, exhibiting how data influenced by specific events can significantly affect the overall trends when using the RHR method. ADEQ also showed that the exceptionally high extinction value year of 2005 was skewing data trends when using the RHR method. If this year was included in the baseline period and 2010 was added to the progress period, every site is projected to exceed URP visibility standards.

# Appendix A: Windblown Dust Partitioning

The following information was provided to ADEQ by ENVIRON, the consultant which performed the windblown analysis for the 2008 emission inventory. ADEQ requested a separate analysis from the company to partition windblown dust emissions into natural and anthropogenic sources. Methodology and results are given below.

***Windblown Methodology***

As part of the West-wide Jump-start Air Quality Modeling Study (WestJumpAQMS[16]), the WRAP Wind Blown Dust (WBD) model (Mansell et al., 2006[17,18,19,20]) was used with the WestJumpAQMS 2008 WRF meteorological model output (ENVIRON and Alpine, 2012[21]) to generate WBD fugitive dust emissions inputs for the 36 km CONUS, 12 km WESTUS and 4 km IMWD modeling domains. The WRAP WBD model uses threshold friction velocities ($u_*$) as a function of surface roughness above which the surface playa is assumed to start emitting WBD emissions. The approach of Marticorena (1997) is used that matches wind tunnel measurements fairly well (see Figure 2-1 of Mansell et al., 2006[2]). The friction velocity ($u_*$) depends on the surface roughness ($z_0$) and the WRF surface wind speed ($u_z$) at height z above the ground using the following relationship:

$u_z/u_* = 1/k * \ln(z/z_0)$

where k is the von Karmen constant (0.4).

There are separate emissions factors as a function of friction velocity for four soil groups based upon the estimated geometric mean diameter of the soil particles. WBD emissions are calculated for each grid cell using the fractional coverage of each land cover type within the grid cell, friction velocity, surface roughness and WBD emissions factor for soil groups. Fugitive Dust Transport Factors (FDTFs) are then applied to reduce the WBD emissions to account for the fact that some WBD emissions are deposited locally in the grid cell where they are emitted and are not transported. For example, barren land has a FDTF of 0.0 that means all WBD emissions are transported, whereas forested land has a FDTF of 1.0 that means all of the emissions are deposited locally and none are transported away from the cell where they are emitted. The WRAP WBD model has 6 land cover types with Agricultural and Urban assumed to have disturbed land and the other four categories assumed to have un-disturbed land. Table 24 describes the key parameters for the six land use land cover (LULC) types in the WRAP WBD model. These assumptions about disturbance were implemented for the Regional Haze planning process, where Class I area IMPROVE monitoring sites are generally distant from urban and

[16] http://www.wrapair2.org/WestJumpAQMS.aspx
[17] http://www.wrapair.org/forums/dejf/documents/WRAP_WBD_PhaseII_Final_Report_050506.pdf
[18] http://www.wrapair.org/forums/dejf/documents/AppendixA.pdf
[19] http://www.wrapair.org/forums/dejf/documents/AppendixB.pdf
[20] http://www.wrapair.org/forums/dejf/documents/WRAP_DEJF_WBDust_smry_060606.pdf
[21] http://www.wrapair2.org/pdf/WestJumpAQMS_2008_Annual_WRF_Final_Report_February29_2012.pdf

other highly disturbed areas. In reality, all land cover types would have some level of disturbance at some time, whether from naturally or anthropogenically dominated causes. The level of disturbance varies in space and time, and is not explicitly known for the WestJumpAQMS 2008 study period.

**Table 24: Parameters and assumptions used in the WRAP WBD PM Emissions model.**

| LULC | FDTF | Disturbed | $Z_0$ (cm) |
|---|---|---|---|
| Barren | 1.0 | Un-Disturbed | 0.0020 |
| Agricultural | 0.75 | Disturbed | 0.0310 |
| Grassland | 0.75 | Un-Disturbed | 0.1000 |
| Scrubland | 0.75 | Un-Disturbed | 0.0500 |
| Forest | 0.0 | Un-Disturbed | 50.0 |
| Urban | 0.0 | Disturbed | 50.0 |

WBD emissions can occur naturally in nature. However, human activities can affect WBD emissions either through stabilization of the ground surface (e.g., paving) or through disturbing or changing the ground surface. The classification of WBD emissions as anthropogenic versus natural depends on how human activity affects the land cover. We classify three levels of human activity that can affect land cover and consequently WBD emissions as follows.

Level 1: Anthropogenic Land Cover

This category includes LULC types that are clearly man-made. In Table 24 Agricultural and Urban land cover types would fall into this category.

Level 2: Human Caused Disturbed Land

Human activity can disturb a land cover type making it more emissive. For example All-Terrain Vehicles (ATVs or OHVs) can disturb a land so that it becomes emissive at and lower wind speed and has higher WBD emissions. Note that in Table 24 the four non-anthropogenic LULCs assumed un-disturbed land so these extra anthropogenic WBD emissions are not accounted for in the current WRAP WBD model simulations.

Level 3: Human Caused LULC Changes

Like Level 1, this category covers human changes in LULC from one category to another. However, in this case the changes are from one "natural" category to another "natural" category. An example of this is clear cutting for timber harvesting that turns forest land into grassland.

Due to the complexity and subjectivity of partitioning levels 2 and 3 above, ENVIRON was only able to partition land uses as either anthropogenic or natural to Level 1. This is the simplest approach using the former method above to update the Urban LULC category FDTF from 0.0 to 0.5 and classify the Agricultural and Urban LULC categories WBD PM emissions as anthropogenic and the other four LULC categories as natural (i.e., Level 1 division). The results

of this analysis are presented below in Tables 25 and 26. Figure 29 shows a spatial distribution map of windblown emissions throughout the State of Arizona.

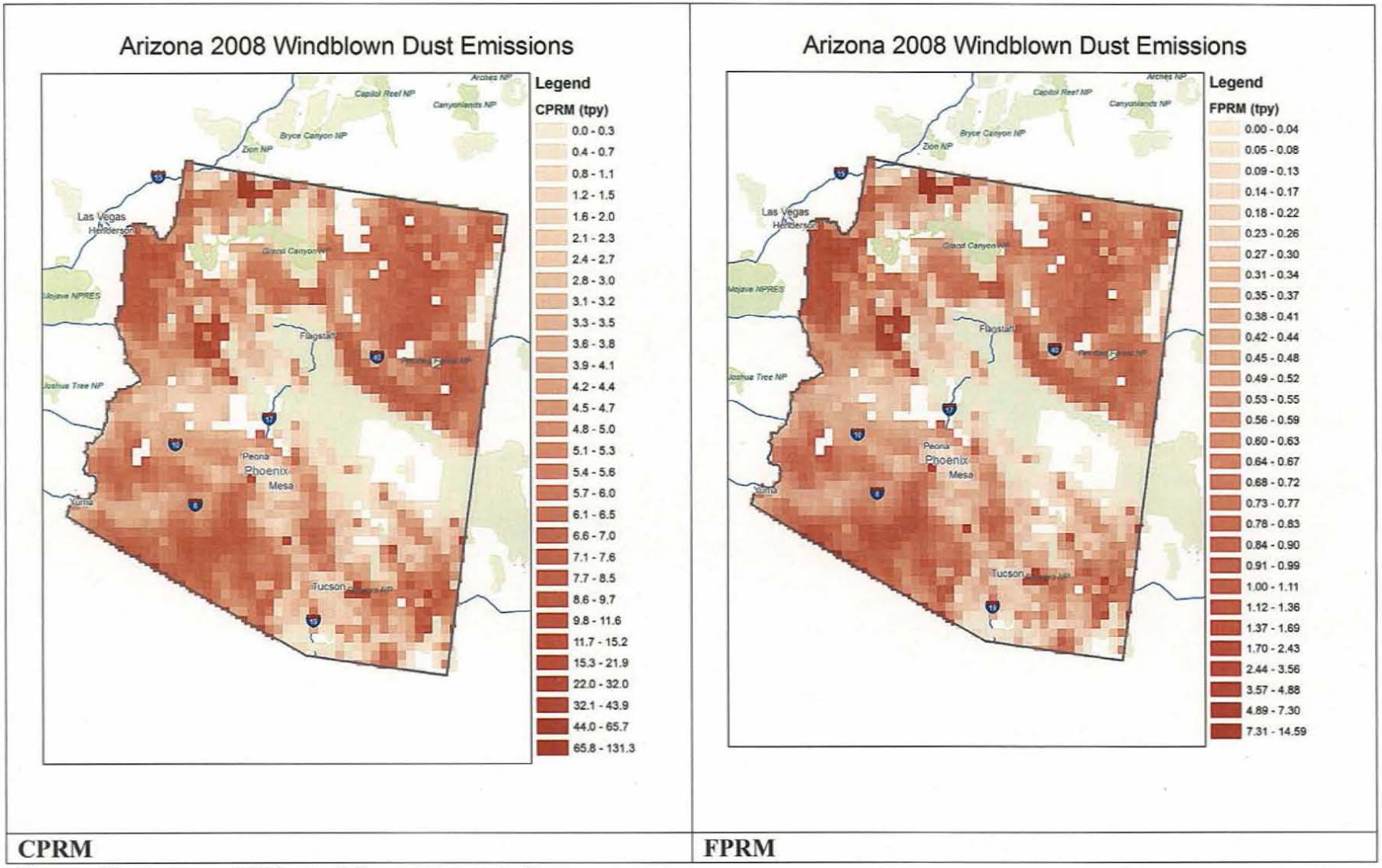
### *Windblown Partitioning Results*

**Table 25: Partitioning of 2008 Arizona Coarse and Fine PM emissions to six land use categories.**

| | Emissions (tpy) | | | |
|---|---|---|---|---|
| **Landuse** | **PMC** | **PMFINE** | **Landuse Category** | **Landuse Percent** |
| Agricultural | 604 | 67 | Anthropogenic | 0.31% |
| Grassland | 1,796 | 200 | Natural | 4.45% |
| Shrubland | 78,815 | 8,757 | Natural | 62.52% |
| Barren | 6,216 | 691 | Natural | 6.09% |
| Urban | 0.112 | 0.012 | Anthropogenic | 0.34% |
| Other (forest/water) | | | Natural | 26.29% |

**Table 26: Arizona Statewide Coarse and Fine PM emissions by landuse category.**

| Landuse Category | PMC | PMFINE | Land use |
|---|---|---|---|
| Natural | 86,827 | 9,647 | 99.35% |
| Anthropogenic | 604 | 67 | 0.65% |




**CPRM** | **FPRM**

**Figure 29: Arizona 2008 windblown dust emission**