Arizona Department of Environmental Quality

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Arizona State Implementation Plan

Revision to the Arizona Regional Haze Plan for Arizona Public Service Cholla Generating Station

Air Quality Division
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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

LIST OF APPENDICES

1.0 INTRODUCTION AND BACKGROUND

1.1 Introduction

The Arizona Department of Environmental Quality ("ADEQ") is proposing a source-specific revision to the Arizona State Regional Haze Implementation Plan ("Arizona RH SIP") that establishes best available retrofit technology ("BART") for Steam Units 2, 3, and 4 at Arizona Public Service Company's ("APS") Cholla Generating Station ("Cholla"). The revision is intended to replace elements of Arizona RH SIP pertaining to Cholla. The revision reflects the five- factor BART Reassessment for Cholla ("Cholla BART Reassessment" due to changes in circumstances affecting the BART determination.

As required, this document includes a technical analysis of the Five-Factor BART Reassessment for Cholla and a demonstration that this revision will not interfere with the ability of the program area to attain/maintain the National Ambient Air Quality Standards ("NAAQS") or any other requirement of the Clean Air Act ("CAA").

1.2 Regulatory Background

On February 28, 2011, ADEQ submitted a Regional Haze SIP under 40 CFR § 51.308 to the U.S. Environmental Protection Agency ("EPA" or "Agency"), which became complete as a matter of law. Several parties, including the Sierra Club and Grand Canyon Trust, filed a complaint in August 2011 for declaratory and injunctive relief in the United States Court of Appeals for the D.C. Circuit. The parties sought to compel EPA to perform a nondiscretionary duty of not approving various Regional Haze SIPs, including Arizona, or promulgating a Federal Implementation Plan ("FIP").

On November 9, 2011, EPA announced its intention to enter into a consent decree with the plaintiffs, which was granted on March 30, 2012. The decree included a court-ordered schedule to review and act on more than 40 state regional haze plans. The scheduled deadlines were administratively extended in May 2012, which allowed EPA to separate its actions on BART applicable to electric generating units ("EGUs") from the remaining components of the SIP.

EPA and the plaintiffs submitted a motion on June 14, 2012, to extend the deadlines for both actions as required by the consent decree. Even though Arizona opposed this motion, the United States Court of Appeals for the D.C. Circuit upheld the revised consent decree, setting dates for proposed action on the EGU BART portion of Arizona's SIP due by July 12, 2012, and remaining portions of the SIP due by December 8, 2012. Final action on the EGU BART portion of the SIP was required on or before November 15, 2012, and final action on the remainder of the SIP was required on or before July 15, 2013. Final action for the utility portion of the SIP was required on or before November 15, 2012, and final action for the balance of the SIP was required on or before July 15, 2013.

On July 20, 2012, EPA published a notice of proposed rule-making ("NPRM") that proposed partial approval and partial disapproval of Arizona's EGU BART determinations and a proposed EPA FIP.[1] This proposed rule was finalized on December 5, 2012, when EPA published a NFRM approving Arizona's SO_2 BART determination, disapproving its NO_X BART determination, and establishing a NO_X BART FIP for the three power plants impacted by the rule, which became effective January 4, 2013.[2]

On January 31, 2013, the State of Arizona filed a Petition for Review challenging the EPA's FIP

[1] 77 Fed. Reg. 42834 (July 20, 2012).
[2] 77 Fed. Reg. 72511 (Dec. 5, 2012)[hereinafter EPA Final Rule].

before the United States Court of Appeals for the Ninth Circuit. APS and PacifiCorp subsequently filed Petitions for Review of the same EPA final action. Briefing on the matter has completed, and oral argument was held on March 9, 2015.

On September 9, 2014, APS and PacifiCorp met with the ADEQ and EPA Region 9 to discuss a proposed BART Reassessment for Cholla that would resolve the litigation and result in greater long-term environmental benefits and be more cost-effective than EPA's BART determination. At this meeting, EPA indicated its belief that APS and PacifiCorp's BART Reassessment had sufficient merit to warrant a formal proposal for the Agency's consideration.

On January 15, 2015, APS and PacifiCorp submitted an Application for Significant Permit Revision and Five-Factor BART Reassessment for Cholla to ADEQ. In this submittal, APS and PacifiCorp requested ADEQ to adopt the BART Reassessment as a proposed revision to the Arizona Regional Haze SIP and to submit the revision to EPA for approval. To address some of ADEQ's comments, APS and PacifiCorp revised and resubmitted the application on March 12, 2015.

2.0 REVISION TO ARIZONA'S REGIONAL HAZE PROGRAM - 2015

2.1 Summary of Control Strategy Changes at Cholla

Cholla consists of four primarily coal-fired EGUs with a total plant-wide generating capacity of 1,180 gross megawatts (MW). Unit 1 is a 126 gross MW tangentially-fired, dry-bottom boiler that is not BART-eligible. Units 2, 3, and 4 have capacities of 272, 272, and 410 gross MW, respectively, and are tangentially-fired, dry-bottom boilers that are each BART-eligible (collectively "Cholla BART Units"). Units 1, 2, and 3 are owned and operated by APS, and Unit 4 is owned by PacifiCorp and operated by APS.

Effective January 4, 2013, EPA approved a portion of Arizona's RH SIP for the Cholla BART Units, establishing emissions limits for PM_{10} and SO_2.[3] In the same action, EPA disapproved a portion of the SIP for the Cholla BART Units and promulgated a corresponding FIP, which establishes control technology requirements and emission limits for NOx.[4] The FIP imposes an emission limit for NOx of 0.055 lb/MMBtu determined as an average of the Cholla BART Units, based on a rolling 30-boiler-operating-day average.[5] The final compliance date to install and operate selective catalytic reduction ("SCR") emission controls on the Cholla BART Units is December 5, 2017.[6] In addition, the FIP imposes a new SO_2 removal efficiency requirement of 95 percent for the scrubbers on the Cholla BART Units.[7] Cholla Units 3 and 4 were required to achieve this removal efficiency by December 5, 2013, and Cholla Unit 2 must comply by April 1, 2016.[8]

To meet the requirements of the regional haze program and act in the best interests of their respective customers, APS and PacifiCorp evaluated an alternative set of control strategies, including:

- Permanently shut down Cholla BART Unit 2 by April 1, 2016;
- Operate Cholla BART Units 3 and 4 with the currently installed low NOx burners ("LNB") with separated over-fired air ("SOFA"); and

[3] *EPA Final Rule*, at 72514.
[4] *Id*.
[5] *Id*.
[6] *Id*., at 72515.
[7] *Id*., at 72514.
[8] *Id*., at 72515.

- Cease burning coal at Cholla BART Units 3 and 4 by April 30, 2025 with the option to convert to pipeline-quality natural gas by July 31, 2025 with a ≤ 20 percent annual average capacity factor.

Upon reviewing the proposal and associated supporting documents from APS and PacifiCorp, ADEQ is proposing a source-specific revision to the Arizona RH SIP that establishes BART for Steam Units 2, 3, and 4 at Cholla. The revision is as follows:

Steam Unit 2

This SIP revision proposes to permanently shut down Cholla Unit 2 by April 1, 2016.

Steam Unit 3

This SIP revision proposes to operate Cholla Unit 3 with the currently installed LNB with SOFA. Additionally, this revision proposes to permanently cease burning coal at Unit 3 by April 30, 2025 with the option to convert to pipeline natural gas by July 31, 2025 with a ≤ 20% annual average capacity factor. The NOx emission limit will be revised from 0.055 lb/MMBtu (EPA FIP) to 0.22 lb/MMBtu (burning coal) or 0.08 lb/MMBtu (burning natural gas), based on a 30-boiler-operating-day average.

Steam Unit 4

This SIP revision proposes to operate Cholla Unit 4 with the currently installed LNB with SOFA. Additionally, this revision proposes to permanently cease burning coal at Unit 4 by April 30, 2025 with the option to convert to pipeline natural gas by July 31, 2025 with a ≤ 20% annual average capacity factor. The NOx emission limit will be revised from 0.055 lb/MMBtu (EPA FIP) to 0.22 lb/MMBtu (burning coal) or 0.08 lb/MMBtu (burning natural gas), based on a 30-boiler-operating-day average.

Although not a BART-eligible unit, APS also proposes to cease burning coal at Cholla Unit 1 by April 30, 2025 with an option to convert to pipeline-quality natural gas in 2025 to provide added visibility benefits.

Table 1 provides the proposed emission limits and compliance dates for Cholla. The new control strategies and compliance methods are incorporated as Appendix A to the facility's Operating Permit.[9]

[9] Significant Permit Revision No. 61713, Operating Permit No. 53399.

Table 1 Summary of Proposed Emission Limits and Compliance Dates for Cholla (lb/MMBtu)

Cholla Unit	NOx	SO_2	PM_{10}	Action
Unit 2	0.30 lb/MMBtu	0.25 lb/MMBtu and 90 percent removal efficiency	0.025 lb/MMBtu	Permanently shut down by April 1, 2016
Unit 3	0.22 lb/MMBtu	0.15 lb/MMBtu and 95 percent removal efficiency	0.015 lb/MMBtu	Permanently cease burning coal by April 30, 2025 with the option to convert to pipeline natural gas by July 31, 2025 with a ≤ 20% annual average capacity factor
	0.08 lb/MMBtu if converted to pipeline natural gas	0.0006 lb/MMBtu if converted to pipeline natural gas	0.01 lb/MMBtu if converted to pipeline natural gas	
Unit 4	0.22 lb/MMBtu	0.15 lb/MMBtu and 95 percent removal efficiency	0.015 lb/MMBtu	Permanently cease burning coal by April 30, 2025 with the option to convert to pipeline natural gas by July 31, 2025 with a ≤ 20% annual average capacity factor
	0.08 lb/MMBtu if converted to pipeline natural gas	0.0006 lb/MMBtu if converted to pipeline natural gas	0.01 lb/MMBtu if converted to pipeline natural gas	

2.2 Technical Analysis of Cholla BART Reassessment

ADEQ has identified two circumstances that would warrant a BART reassessment for Cholla: (i) shutdown of Unit 2 by April 1, 2016, and (ii) conversion to natural gas-firing at Units 3 and 4 by April 30, 2025. No BART determination for Unit 2 is required because the enforceable shutdown date is within the five-year BART window. Moreover, the proposed conversion to natural gas-firing at Units 3 and 4 will significantly affect the cost effectiveness analysis and consequently the BART determination for Units 3 and 4. Therefore, APS and PacifiCorp conducted the Five-Factor BART Reassessment for Cholla Units 3 and 4 based on the alternative controls they proposed.

2.2.1 BART Factor 1 – Cost of Compliance

The Cholla BART Reassessment addressed the cost of compliance for the following control options:

- LNB and SOFA;
- SNCR with LNB and SOFA; and
- SCR with LNB and SOFA.

Since the proposed conversion to natural gas-firing at Units 3 and 4 is beyond the five-year window for BART mandated by the CAA and Regional Haze Rule ("RHR"), this control strategy does not directly satisfy the BART option timing requirements for imposing BART. However, because APS and PacifiCorp are making a commitment to cease burning coal in 2025, the cost-effectiveness analysis included the conversion to natural gas option. The BART Reassessment analysis assumed the default 20-year amortization period in the EPA Cost Control Manual, and considered two fuel-use scenarios for comparison purposes:

- Twenty years of operation on coal; and
- Eight years of operation on coal and 12 years of operation on natural gas (Cholla BART Reassessment).

Table 2 summarizes the cost of compliance for the three control options under 20 years of operation on coal. Please refer to Appendix B for detailed cost calculations. As shown in Table 2, the SCR-based control options have an average cost effectiveness of $2,838/ton and $3,083/ton for Unit 3 and Unit 4, respectively. EPA indicates in its Arizona Regional Haze Technical Supporting Document that an average cost-effectiveness of $3,000-4,000/ton falls within an acceptable range to be considered cost-effective. [10] Therefore, assuming 20 years of coal operation at Units 3-4, the SCR-based control options would still be considered cost-effective, which is consistent with the EPA's evaluation of Cholla BART Units 3-4 in the FIP.

Table 3 summarizes the cost of compliance for the three control options under the Cholla BART Reassessment. Please refer to Appendix B for detailed cost calculations. As shown in Table 3, the cost-effectiveness values for both SNCR and SCR control options increase dramatically under the Cholla BART Reassessment when compared to the 20-year operation on coal discussed above. For example, the SCR-based control options have an average cost effectiveness of $6,286/ton and $6,810/ton for Unit 3 and Unit 4, respectively. Correspondingly, the SCR-based control options have an incremental cost-effectiveness of $9,237/ton and $10,539/ton for Unit 3 and Unit 4, respectively. The significant increase of the costs, expressed as dollars per ton of emission reduced under the Cholla BART Reassessment, is due to the following:

- If SCR or SNCR were installed by late 2017, the technology would be fully utilized for less than 8 years with coal-firing until 2025 instead of for 20 years as might otherwise be assumed; and

- Following the conversion of the unit to natural gas in 2025, the operation of either of SCR- or SNCR-based controls would result in low emission reductions. Once converted to natural gas, the use of SNCR-based controls would only reduce NOx emissions by an additional 37 tons/year and 46 tons/year for Unit 3 and Unit 4, respectively. The use of SCR-based controls would only reduce NOx emissions by an additional 92 tons/year and 116 tons/year for Unit 3 and Unit 4, respectively.

Due to the excessive cost of the SCR- and SNCR-based control options, ADEQ has determined that both SNCR and SCR are not cost-effective under the Cholla BART Reassessment.

[10] See EPA Region 9, Arizona Regional Haze Technical Support Document (July 2012), available at http://www.epa.gov/region9/air/actions/pdf/az/arizona-rh-tsd-final.pdf.

Table 2 Average and Incremental Cost Effectiveness for NOx Control Options Assuming 20 years of Operation on Coal

Control Options	Average			Incremental[1]		
	Annual Cost ($/yr)	Emission Reduction Relative To Baseline (ton/yr)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost ($/yr)	Incremental Emission Reduction (ton/yr)	Incremental Cost Effectiveness ($/ton)
Unit 3						
LNB+SOFA	$483,300	1,219	$396	-	-	-
SNCR with LNB+SOFA	$3,070,443	1,911	$1,607	$2,587,143	691	$3,742
SCR with LNB+SOFA	$9,448,912	3,300	$2,838	$8,965,612	2,110	$4,248
Unit 4						
LNB+SOFA	$673,550	1,756	$384	-	-	-
SNCR with LNB+SOFA	$4,086,366	2,643	$1,546	$3,412,816	887	$3,848
SCR with LNB+SOFA	$13,590,853	4,408	$3,083	$12,917,303	2,652	$4,871

[1]The incremental cost effectiveness results for SNCR and SCR are based on the emission and cost differences between these technologies and the proposed LNB +SOFA option.

Table 3 Average and Incremental Cost Effectiveness for NOx Control Options Assuming 8 years of Operation on Coal and 12 years of Operation on Natural Gas (Cholla BART Reassessment)

Control Options	Average			Incremental[1]		
	Annual Cost ($/yr)	Emission Reduction Relative To Baseline (ton/yr)	Average Cost Effectiveness ($/ton)	Incremental Annual Cost ($/yr)	Incremental Emission Reduction (ton/yr)	Incremental Cost Effectiveness ($/ton)
Unit 3						
LNB+SOFA	$411,300	488	$843	-	-	-
SNCR with LNB+SOFA	$2,497,743	786	$3,177	$2,086,443	299	$6,989
SCR with LNB+SOFA	$8,716,452	1,387	$6,286	$8,305,152	899	$9,237
Unit 4						
LNB+SOFA	$571,550	702	$814	-	-	-
SNCR with LNB+SOFA	$3,283,930	1,085	$3,027	$2,712,380	383	$7,091
SCR with LNB+SOFA	$12,480,744	1,833	$6,810	$11,909,194	1,130	$10,539

[1]The incremental cost effectiveness results for SNCR and SCR are based on the emission and cost differences between these technologies and the proposed LNB +SOFA option.

2.2.2 BART Factor 2 – Energy and Non-Air Environmental Impacts

The energy impacts of LNB/SOFA and SNCR are negligible. The energy requirement for SCR is in the range of 0.5 to 1 percent of the power plant output, because SCR incurs an additional parasitic load mainly due to pressure drop across the SCR system.

There are no non-air environmental impacts associated with the LNB/SOFA option. Non-air adverse environmental impacts of SNCR and SCR are primarily attributable to ammonia slip. In addition, transport and handling of anhydrous ammonia presents potential safety hazards.

2.2.3 BART Factor 3 – Existing Air Pollution Controls

The Cholla BART Reassessment proposes the continued use of LNB with SOFA as a cost-effective method to control NOx emissions from Units 3 and 4. It further proposes that no additional controls be added in recognition that these units will cease burning coal in mid-2025 through the conversion to pipeline natural gas with a maximum 20 percent annual average capacity factor. The Cholla BART Reassessment also proposes as part of this BART option that Unit 2 would be shut down in April 2016 and that Unit 1 will cease burning coal in 2025.

2.2.4 BART Factor 4 – Remaining Useful Life

Unit 2 would be subject to a federally enforceable shutdown date of April 1, 2016. Unit 3 and 4 are not subject to any enforceable shutdown dates. Therefore the default 20-year amortization period in the EPA Cost Control Manual was used to determine the remaining useful life of these facilities in the cost-effectiveness section.

2.2.5 BART Factor 5 – Degree of Visibility Improvement

APS and PacifiCorp predicted the degree of visibility improvement that may be reasonably expected from the use of BART emissions controls. The following cases (all with coal-firing assumed) were modeled:

- 2001-2003 baseline with all four units operating;
- BART Option 1: Unit 1 with 2001-2003 baseline controls (pre-LNB), Unit 2 shut down, LNB/SOFA on Units 3 and 4;
- BART Option 2: Unit 1 with 2001-2003 baseline controls (pre-LNB), Unit 2 shut down, LNB/SOFA and SNCR on Units 3 and 4; and
- BART Option 3: Unit 1 with 2001-2003 baseline controls (pre-LNB), Unit 2 shut down, LNB/SOFA and SCR on Units 3 and 4.

Please refer to Appendix C for detailed modeled emissions and stack parameters. APS and PacifiCorp conducted the visibility assessment with the CALPUFF model version 5.8 in the manner approved and used by EPA in its FIP. The CALPUFF modeling incorporated meteorological data for 2001-2003, an assumption of 1.0 part per billion background concentration for ammonia, and "Method 8b" 20 percent best days background conditions for all cases. The CALPUFF modeling predicted impacts to visibility at the thirteen Class I areas within 300 km of Cholla for the baseline, as well as the three control options. Table 4 and Table 5 illustrate the modeled visibility impacts and the corresponding visibility improvements, respectively.

As indicated in Tables 4 and 5, Petrified Forest National Park shows the highest predicted visibility impacts among the thirteen Class I areas. Under Option 1 (retirement of Unit 2 and installation of LNB/SOFA at Units 3 and 4), the visibility impact at Petrified Forest National Park is 4.33 deciview (dv) which is a 0.98 dv improvement over baseline. Alternatively, Option 3 (retirement of Unit 2 and installation of LNB/SOFA and SCR at Units 3 and 4) results in a visibility impact of 3.55 dv, which is a 1.77 dv improvement over baseline. Therefore, the installation of SCR at Units 3 and 4 results in a 0.79 dv additional visibility improvement over the LNB/SOFA controls until 2025 (the coal-firing time period).

As shown in Table 5, Option 1 results in a cumulative visibility improvement of 13.92 dv and an average visibility improvement of 1.07 dv across the thirteen Class I areas. Comparatively, Option 3 results in a cumulative visibility improvement of 17.89 dv and an average visibility improvement of 1.38 dv across the Class I areas. Therefore, the installation of SCR over the LNB/SOFA controls at Units 3 and 4 results in an additional 3.97 dv cumulative visibility improvement, and an additional 0.31 dv average visibility improvement across the thirteen Class I areas.

The additional visibility improvement provided by installation of SNCR controls (over the LNB/SOFA controls) ranges from 0.01 dv to 0.28 dv across the thirteen Class I areas. The additional visibility improvement due to the installation of SCR controls (over the LNB/SOFA controls) ranges from 0.07 dv to 0.79 dv across the thirteen Class I areas, only two of which reflect a visibility improvement exceeding 0.5 dv.

Table 6 presents the incremental cost per dv for SNCR- and SCR-based controls relative to LNB/SOFA. The incremental cost per dv was calculated based on the cumulative, average, and maximum visibility improvements across the thirteen Class I areas. As shown in Table 6, the incremental cost for SNCR- and SCR-based controls would range from $20 million to $38 million per year in order to achieve an average visibility improvement of 1 dv across the thirteen Class I areas. Following the conversion of the process units to natural gas in 2025, the use of SCR or SNCR over LNB/SOFA controls would result in low NOx emission reductions and, thus, negligible visibility improvements. Therefore, once converted to natural gas, the use of SNCR or SCR controls would result in enormous costs per dv.

Table 4 Predicted Visibility Impacts (22nd highest delta-dV over 3-year period)

Class I Area	Baseline	BART Option 1 (LNB/SOFA)	BART Option 2 (LNB/SOFA/SNCR)	BART Option 3 (LNB/SOFA/SCR)
Petrified Forest NP	5.31	4.33	4.05	3.55
Grand Canyon NP	3.40	1.79	1.62	1.20
Capitol Reef NP	2.19	1.04	0.91	0.62
Mazatzal WA	2.23	0.96	0.87	0.69
Sycamore Canyon	2.27	1.00	0.88	0.67
Mount Baldy WA	2.10	0.97	0.85	0.62
Gila WA	1.53	0.53	0.47	0.39
Sierra Ancha WA	2.28	1.05	0.97	0.81
Mesa Verde NP	2.08	0.88	0.78	0.60
Galiuro WA	0.96	0.34	0.31	0.27
Superstition WA	2.00	1.00	0.93	0.73
Saguaro NP	0.70	0.22	0.22	0.20
Pine Mountain WA	1.64	0.67	0.59	0.48

Table 5 Predicted Visibility Improvement over the Baseline Visibility Impacts (22nd highest delta-dV over 3-year period)

Class I Area	Baseline	BART Option 1 (LNB/SOFA)	BART Option 2 (LNB/SOFA /SNCR)	BART Option 3 (LNB/SOFA /SCR)	Option 2 over Option 1	Option 3 over Option 1
Petrified Forest NP	-	0.98	1.26	1.77	0.28	0.79
Grand Canyon NP	-	1.61	1.78	2.20	0.17	0.59
Capitol Reef NP	-	1.15	1.28	1.57	0.13	0.42
Mazatzal WA	-	1.27	1.36	1.54	0.09	0.27
Sycamore Canyon	-	1.27	1.39	1.60	0.12	0.33
Mount Baldy WA	-	1.14	1.26	1.48	0.12	0.34
Gila WA	-	1.00	1.06	1.14	0.06	0.14
Sierra Ancha WA	-	1.22	1.30	1.47	0.08	0.25
Mesa Verde NP	-	1.21	1.30	1.49	0.09	0.28
Galiuro WA	-	0.62	0.65	0.69	0.03	0.07
Superstition WA	-	1.00	1.07	1.28	0.07	0.28
Saguaro NP	-	0.48	0.49	0.50	0.01	0.02
Pine Mountain WA	-	0.97	1.04	1.16	0.07	0.19
Cumulative		13.92	15.24	17.89	1.32	3.97
Average		1.07	1.17	1.38	0.10	0.31

Table 6 Incremental Cost per dv for SNCR- and SCR-Based Controls (Relative to LNB+SOFA)[1]

		Unit 3		Unit 4	
		SNCR with LNB+SOFA	SCR with LNB+SOFA	SNCR with LNB+SOFA	SCR with LNB+SOFA
Incremental Annual Cost ($/yr)		$2,086,443	$8,305,152	$2,712,380	$11,909,194
Visibility Improvement (dV)	Maximum	0.28	0.79	0.28	0.79
	Cumulative	1.32	3.97	1.32	3.97
	Average	0.10	0.31	0.10	0.31
Incremental Cost per dv (million $/dV)	Maximum	7.45	10.51	9.69	15.07
	Cumulative	1.58	2.09	2.05	3.00
	Average	20.86	26.79	27.12	38.42

[1]*The incremental cost per dv analysis is applicable to coal operation only. Once converted to natural gas in the year 2025, use of SNCR or SCR controls would result in negligible visibility improvements and, thus enormous costs per dv.*

2.3 ADEQ's Determination on Cholla BART Reassessment

SNCR with LNB+SOFA

The SNCR-based control options (over the LNB/SOFA controls) have an incremental cost effectiveness of $6,989/ton and $7,091/ton for Unit 3 and Unit 4, respectively. The SNCR-based control options also result in an incremental visibility improvement ranging from 0.01 dv to 0.28 dv across the thirteen Class I areas. Considering the excessive cost and insignificant additional visibility improvements resulting from the SNCR-based control options, ADEQ has eliminated SNCR control as BART for Units 3 and 4.

SCR with LNB+SOFA

The SCR-based control options (over the LNB/SOFA controls) have an incremental cost effectiveness of $9,237/ton and $10,539/ton for Unit 3 and Unit 4, respectively. The SCR-based control options result in an incremental visibility improvement ranging from 0.07 dv to 0.79 dv across the thirteen Class I areas, only two of which reflect a visibility improvement exceeding 0.5 dv. The installation of SCR over the LNB/SOFA controls result in a 3.97 dv cumulative incremental visibility improvement and a 0.31 dv average incremental visibility improvement across the Class I areas. These additional visibility improvements from SCR-based controls only last less than 8 years with coal-firing (late 2017-2025). Once the units are converted to natural gas in 2025, SCR-based controls would have negligible visibility improvements relative to LNB/SOFA controls. Overall, additional visibility improvements from SCR-based controls are not substantial. Considering the excessive cost and moderate additional visibility improvements resulting from the SCR-based control options, ADEQ has eliminated SCR controls as BART for Units 3 and 4.

LNB+SOFA

The LNB/SOFA controls have a reasonable average cost effectiveness of $843/ton and $814/ton for Unit 3 and Unit 4, respectively. The LNB/SOFA control options, along with the shutdown of Unit 2, results in a visibility improvement ranging from 0.48 dv to 1.61 dv over baseline across the thirteen Class I areas. There are no adverse energy or non-air environmental impacts associated with the LNB/SOFA option.

Based on the above analysis, ADEQ has determined that LNB with SOFA is BART for NOx at Units 3 and 4 under the Cholla BART Reassessment.

3.0 DEMONSTRATING NONINTERFERENCE UNDER CLEAN AIR ACT SECTION 110(l)

As described in the preceding sections, this revision to Arizona's Regional Haze program incorporates changes to the BART determination and control strategies for Cholla. The revised control strategies are intended to replace those contained in Arizona's February 28, 2011Arizona RH SIP. Revisions to a submitted Arizona RH SIP must not interfere with the requirements of the CAA, as described in CAA Section 110(l):

> (l) PLAN REVISIONS - Each revision to an implementation plan submitted by a State under this Act shall be adopted by such State after reasonable notice and public hearing. The Administrator shall not approve a revision of a plan if the revision would interfere with any applicable requirement concerning attainment and reasonable further progress (as defined in section 171), or any other applicable requirement of this Act.[11]

The evaluation in following Sections 3.1 and 3.2 demonstrate that the current SIP revision will not interfere with the ability of the program area to attain and maintain the NAAQS or any other requirement of the CAA.

3.1 Demonstrating Noninterference with Attainment of the National Ambient Air Quality Standards under Clean Air Act Section 110(l)

As indicated above, a state must accompany each revision to an air quality SIP with a demonstration that those changes will not interfere with attainment or maintenance of the NAAQS. An evaluation on the impact of the proposed control strategies within this Cholla Reassessment SIP revision indicates the changes would not impact the NAAQS. In determining noninterference, ADEQ conducted an analysis comparing the long-term emissions expectations during 2016-2046 for the relevant pollutants (PM_{10}, SO_2, and NOx) under the control strategies listed in this Cholla BART Reassessment and the prescribed control measures in the applicable SIP or FIP. ADEQ selected Year 2016 as the starting year for comparison purposes because, prior to 2016, there is no difference in PM_{10}, SO_2, and NOx emissions between the Cholla BART Reassessment and the applicable SIP or FIP[12].

The following comparisons were made: 1) NOx annual emission analysis for the EPA FIP and the Cholla BART Reassessment, 2) PM_{10} annual emission analysis for the 2011 State of Arizona's SIP ("2011 AZ SIP") and the Cholla BART Reassessment, and 3) SO_2 annual emission analysis for the 2011 AZ SIP and the Cholla BART Reassessment. ADEQ also went one step further to examine potential impacts the revised control measures may have on the attainment and maintenance of the Ozone NAAQS.

ADEQ's analysis and findings are described below, starting with the relevant regulatory background in Section 3.1.1. Section 3.1.2 follows with a discussion comparing changes to annual PM_{10} emissions that would result under the currently effective 2011 AZ SIP vs. the Cholla BART Reassessment. Next, Section 3.1.3 compares and discusses SO_2 annual emission changes that would result under the 2011 AZ SIP vs. the Cholla BART Reassessment. Then, Section 3.1.4 discusses the comparison of NOx annual emission changes that result from EPA FIP vs. the Cholla BART Reassessment. Finally, Section 3.1.5

[11] 42 U.S.C. § 7410(l), 2012; CAA § 110.

[12] There is no difference in PM_{10}/SO_2/NOx emissions because the installation of baghouses, flue-gas desulfurization (FGD), and LNB on Units 3 and 4 occurred prior to the 2011 Arizona SIP.

discusses the impact and long-term benefits the Cholla BART Reassessment would have to attainment and maintenance of Ozone NAAQS.

3.1.1 Regulatory Background

Title I of the CAA requires EPA to set NAAQS for pollutants that are designated harmful to public health or the environment. It must set both primary and secondary standards for each regulated pollutant that is designated by Agency. Primary standards must specify threshold levels that ensure the protection of public health, whereas secondary standards are designed to protect public welfare (i.e., decreased visibility, damage to animals, crops, vegetation, and buildings). To date, EPA has established primary and secondary NAAQS for six air pollutants, commonly referred to as criteria pollutants, which are: carbon monoxide (CO), lead (Pb), nitrogen dioxide (NO_2), ground-level ozone (O_3), particulate matter (PM), and sulfur dioxide (SO_2). EPA is required by the CAA to periodically evaluate and revise the air quality standards, when necessary, to ensure the protection of the public's health and welfare.

CAA Section 107(d) directs the states to make recommendations, and the EPA to designate as it sees fit, areas within its jurisdiction as either: 1) meeting the NAAQS ("attainment"), 2) not meeting the NAAQS ("nonattainment"), or 3) cannot be classified ("unclassifiable"). EPA will designate an area "nonattainment" when the air quality data shows that those locations are violating or contribute to violations of a NAAQS for a criteria pollutant. A state is required to create a nonattainment SIP describing its plan for achieving reasonable further progress towards attainment of the NAAQS. As those areas move towards establishing attainment status, they are then required to develop and submit a maintenance SIP for approval prior to re-designation.

EPA will designate an area as "attainment" or "unclassified" when the air quality data shows that those areas are not violating the NAAQS or there is not enough data to determine violations exist. Areas designated as attainment and unclassified are not required to create extensive nonattainment plans since those areas do not violate the relevant NAAQS. Instead, attainment areas must show noninterference with the continued attainment and maintenance of the NAAQS following the initial infrastructure SIP, which is submitted shortly after area designations are made. If air quality monitoring data later shows that an attainment area is in violation of the NAAQS following a prior designation, it will be reclassified as nonattainment and then required to develop an attainment plan.

The APS Cholla Generating Station is located in Navajo County. The area is currently designated as attainment or unclassifiable for CO, Pb, NO_2, O_3, $PM_{2.5}$ (1997 and 2006 NAAQS), PM_{10}, and SO_2 (1971 NAAQS).[13] Although designations have not yet been made for the 2012 $PM_{2.5}$ and 2010 SO_2 NAAQS, the area was recommended as attainment or unclassifiable for both pollutants under CAA Section 107(d)(1)(A).[14] Table 7 shows the current designation status of the area for each criteria pollutant listed in 40 CFR § 81.303.[15]

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[13] *See* EPA, *The Green Book Nonattainment Areas for Criteria Pollutants*, at http://www.epa.gov/airquality/greenbook/ (last visited Mar. 24, 2015).
[14] *See generally* ADEQ, *Air Quality Division: Plans*, at http://www.azdeq.gov/environ/air/plan/pm2.5.html and http://www.azdeq.gov/environ/air/plan/so2.html..
[15] 40 CFR § 81.303, 2013.

Table 7 Attainment Status for Navajo County

Pollutant	Primary/Secondary	Averaging Time	Designation
Carbon Monoxide	Primary (1971)	8-hour	Nonclassifiable/Attainment
		1-hour	Nonclassifiable/Attainment
Lead	Primary and Secondary (2008)	Rolling 3 Month Average	Unclassifiable/Attainment
Nitrogen Dioxide	Primary (2010)	1-hour	Unclassifiable/Attainment
	Primary and Secondary (1971)	Annual	Cannot be classified or better than national standards
Ozone	Primary and Secondary (2008)	8-hour	Unclassifiable/Attainment
$PM_{2.5}$	Primary (2012)	Annual	Not yet designated
	Secondary (1997)	Annual	Unclassifiable/Attainment
	Primary and Secondary (2006)	24-hour	Unclassifiable/Attainment
PM_{10}	Primary and Secondary (1987)	24-hour	Unclassifiable
Sulfur Dioxide	Primary (2010)	1-hour	Not yet designated
	Primary (1971)	24-hour	Better than national standards
	Primary (1971)	Annual	Better than national standards
	Secondary (1971)	3-hour	Better than national standards

3.1.2 Noninterference with Attainment of NAAQS for PM_{10}

A comparison of PM_{10} emission control strategies for the 2011 AZ SIP vs. Cholla BART Reassessment is provided below in Table 8. Table 9 summarizes the annual PM_{10} emissions of each relevant time period for the 2011 AZ SIP vs. Cholla BART Reassessment. Figure 1 shows the cumulative PM_{10} emissions for the 2011 AZ SIP vs. Cholla BART Reassessment over 2016-2046. Please refer to Appendix D for detailed PM_{10} annual emission estimations.

In general, the PM_{10} emissions control strategies proposed in the Cholla BART Reassessment are consistent with those of the 2011 AZ SIP except: 1) instead of installing a new baghouse at Unit 2, APS will cease operation of Unit 2 under the Reassessment, and 2) by 2025 Units 3 and 4 would be converted to natural gas-firing operation with a 20 percent annual average capacity factor. The drastic switch from a coal-firing operation to natural gas will have a prolonged impact on PM_{10} emissions for the remaining life of the facility.

Table 8 Comparison of PM_{10} Emission Control Strategies for 2011 AZ SIP vs. Cholla BART Reassessment

	Time Period	Controls Measures
2011 AZ SIP	2016-2046	Baghouses for Units 2, 3, and 4
Cholla BART Reassessment	2016-2025	Baghouses for Units 3 and 4; Unit 2 is shut down by April 1, 2016
	2026-2046	Units 1, 3, and 4 are operated on natural gas with a 20 percent annual average capacity factor; Unit 2 is shut down

As shown in Table 9, the control strategies of the Cholla BART Reassessment will result in greater reductions in PM_{10} emissions than the 2011 AZ SIP. The PM_{10} emissions levels are impacted initially by the shutdown of Unit 2 in 2016, and then the conversion to natural gas-firing at Units 3 and 4 in 2025. Overall, by 2046, the Cholla BART Reassessment will result in lower PM_{10} emissions relative to the 2011 AZ SIP by about 15,000 tons (See Figure 1).

Table 9 Comparison of PM_{10} Emissions for 2011 AZ SIP vs. Cholla BART Reassessment

Time Period	Unit Number	Annual PM_{10} (tpy)	
		2011 AZ SIP	Cholla BART Reassessment
2016	Unit 1	84	84
	Unit 2	214[1]	78[2]
	Unit 3	197	197
	Unit 4	269	269
	Total	764	628
2017-2025	Unit 1	84	84
	Unit 2	181	0
	Unit 3	197	197
	Unit 4	269	269
	Total	731	550
2026-2046	Unit 1	84	13
	Unit 2	181	0
	Unit 3	197	30
	Unit 4	269	39
	Total	731	82

[1] *The compliance date for the AZ SIP emission limit of 0.015 lb/MMBtu is April 1, 2016.*
[2] *Unit 2 will be permanently shut down by April 1, 2016. PM_{10} emission number for Unit 2 is based on operation of this unit until April 1, 2016.*

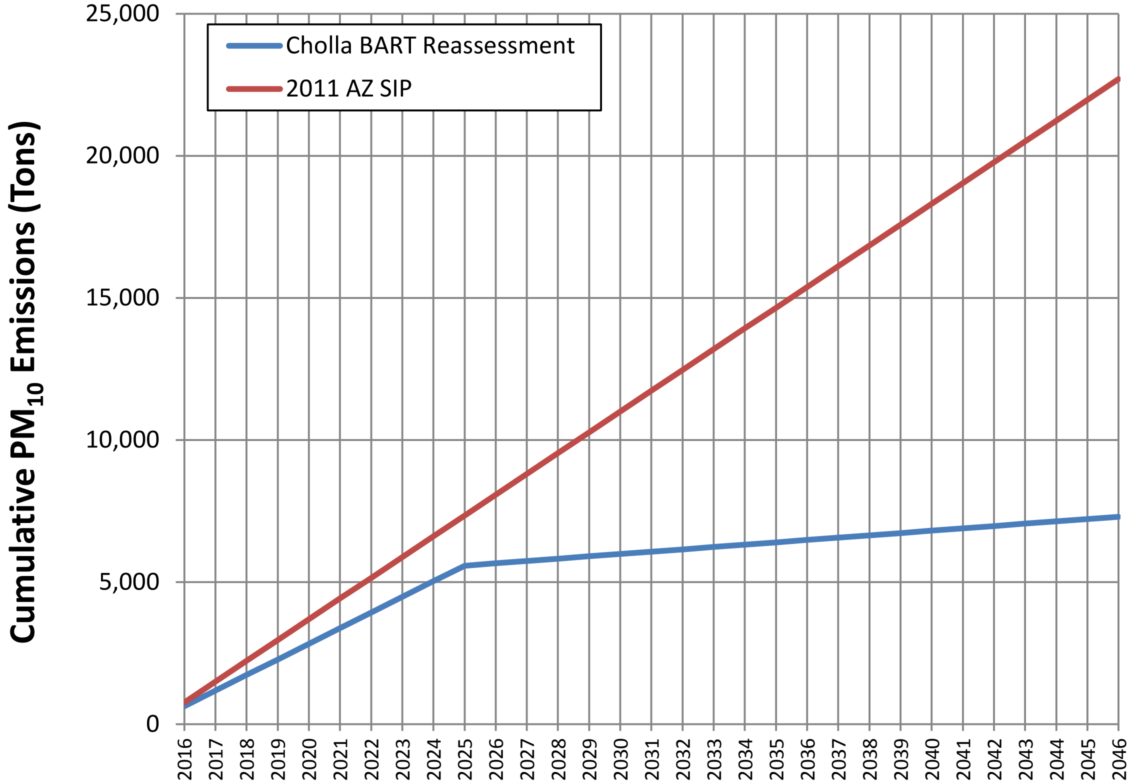

Figure 1 Cumulative PM_{10} Emissions Associated with 2011 AZ SIP vs. Cholla BART Reassessment over 2016-2046

Navajo County is designated attainment or unclassifiable for $PM_{10.}$ As such, there are no nonattainment or maintenance SIPs that would rely on emission reductions at Cholla to ensure continued attainment of the NAAQS. The significant PM_{10} emission reductions achieved by the control strategy in the Cholla BART Reassessment will not result in any interfere with attainment or maintenance of the PM_{10} NAAQS because the emissions will be further reduced. In addition, these revised control measures implement a strategic long-term plan to significantly lower emissions, which is likely to ensure attainment of lower standards that may be promulgated in the future.

3.1.3 Noninterference with Attainment of NAAQS for SO_2

A comparison of SO_2 emission control strategies for the 2011 AZ SIP vs. Cholla BART Reassessment is provided below in Table 10. Table 11 summarizes the annual SO_2 emissions of each relevant time period for the 2011 AZ SIP vs. Cholla BART Reassessment. Figure 2 shows the cumulative SO_2 emissions for the 2011 AZ SIP vs. Cholla BART Reassessment over 2016-2046. Please refer to Appendix D for detailed SO_2 annual emission estimations.

In general, the SO_2 emissions control strategies proposed in the Cholla BART Reassessment are consistent with those of the 2011 AZ SIP except: (1) instead of installing a FGD at Unit 2, APS will cease operation of Unit 2 under the Reassessment, and (2) by 2025 Units 3 and 4 would be converted to natural gas-firing operation with a 20 percent annual average capacity factor. The drastic switch from a coal-firing operation to natural gas will have a prolonged impact on SO_2 emissions for the remaining life of the facility.

Table 10 Comparison of SO_2 Emission Control Strategies for 2011 AZ SIP vs. Cholla BART Reassessment

	Time Period	Controls
2011 AZ SIP	2016-2040	FGD systems for Units 2, 3, and 4
Cholla BART Reassessment	2016-2025	FGD systems for Units 3 and 4; Unit 2 is shut down by April 1, 2016
	2026-2040	Units 1, 3, and 4 are operated on natural gas with a 20 percent annual average capacity factor; Unit 2 is shutdown

As shown in Table 11, the control strategies of the Cholla BART Reassessment will result in greater reductions to SO_2 emissions than the 2011 AZ SIP. The greater emission reductions are initially achieved by the shutdown of Unit 2 in 2016. In 2025, the conversion to natural gas-firing will result in significant reductions of SO_2 emissions at Unit 3 and 4. Overall, by 2046, the Cholla BART Reassessment will result lower SO_2 emissions relative to the 2011 AZ SIP by about 170,000 tons (See Figure 2).

Table 11 Comparison of SO_2 Emissions for 2011 AZ SIP vs. Cholla BART Reassessment

Time Period	Unit Number	Annual SO_2 (tpy)	
		2011 AZ SIP	Cholla BART Reassessment
2016	Unit 1	844	844
	Unit 2	1,614	452 [1]
	Unit 3	1,966	1,966
	Unit 4	2,688	2,688
	Total	7,112	5,950
2017-2025	Unit 1	844	844
	Unit 2	1,614	0
	Unit 3	1,966	1,966
	Unit 4	2,688	2,688
	Total	7,112	5,498
2026-2046	Unit 1	844	1
	Unit 2	1,614	0
	Unit 3	1,966	2
	Unit 4	2,688	2
	Total	7,112	5

[1] Unit 2 will be permanently shut down by April 1, 2016. SO_2 emission number for Unit 2 is based on operation of the unit until April 1, 2016.

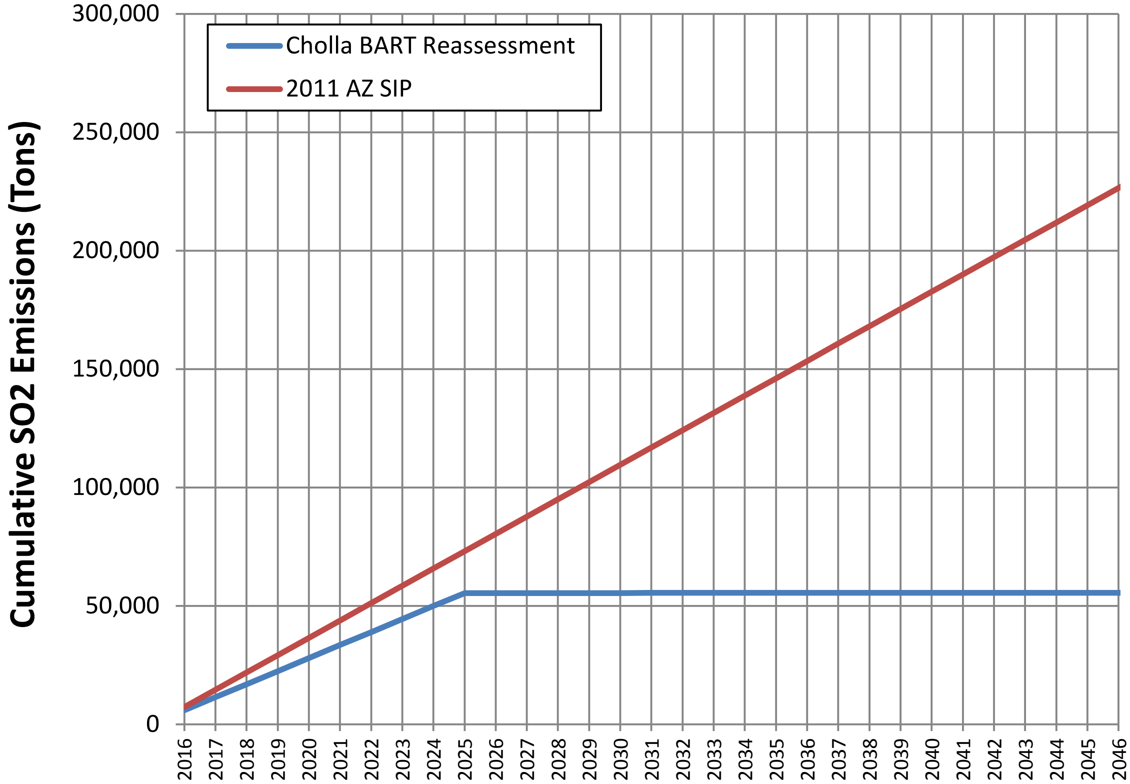

Figure 2 Cumulative SO_2 Emissions Associated with 2011 AZ SIP vs. Cholla BART Reassessment over 2016-2046

Navajo County is designated attainment or unclassifiable for SO_2. As such, there are no nonattainment or maintenance SIPs that might rely on emission reductions at Cholla to ensure continued attainment of the NAAQS. The significant SO_2 emission reductions achieved by the control strategy in the Cholla BART Reassessment will not interfere with attainment or maintenance of the SO_2 NAAQS. Further, these revised control measures implement a strategic long-term plan for significantly lower emissions, which is likely to ensure attainment of more stringent standards that may be promulgated in the future.

3.1.4 Noninterference with Attainment of NAAQS for NO_2

As previously discussed in Section 2.1, the EPA FIP requires the installation and operation of SCR controls with LNB/SOFA emission controls on Units 2, 3, and 4 by December 5, 2017. The Cholla BART Reassessment proposes to instead permanently shut down Unit 2 by April 1, 2016, to operate Units 3 and 4 with the currently installed LNB/SOFA, and to switch to natural gas-firing for Units 3 and 4 with a $\leq$ 20 percent annual average capacity factor. Table 12 provides a comparison of NOx emission control strategies for the EPA FIP vs. Cholla BART Reassessment.

Table 12 Comparison of NOx Emission Control Strategies for EPA FIP vs. Cholla BART Reassessment

	Time Period	Controls
EPA FIP	2016-2017	LNB/SOFA for Units 2, 3, and 4[1]
	2018-2046	SCR with LNB/SOFA for Units 2, 3, and 4
Cholla BART Reassessment	2016-2025	LNB/SOFA for Units 3 and 4; Unit 2 is shut down by April 1, 2016
	2026-2046	Units 1, 3, and 4 are operated on natural gas with a 20 percent annual average capacity factor; Unit 2 is shutdown

[1]EPA FIP does not require the installation of LNB/SOFA on Unit 2, 3, and 4 until December 5, 2017. However, the LNB/SOFA controls were already installed on Unit 1, 2, 3, and 4 before the 2011 AZ SIP. Therefore, it is assumed that theses controls have been in place during 2016-2017 under EPA FIP.

Table 13 summarizes a comparison of the annual NOx emissions for the Cholla BART Reassessment vs. EPA FIP during various time periods. Please refer to Appendix D for NO_X annual emission estimations.

Table 13 Comparison of NOx Annual Emissions for EPA FIP vs. Cholla BART Reassessment

Time Period	Unit Number	Annual NOx (tpy)		
		EPA FIP	Cholla BART Reassessment	Annual Emission Change (Cholla BART Reassessment to EPA FIP)
2016	Unit 1	1,131	1,131	0
	Unit 2	3,601	900[1]	-2,701
	Unit 3	2,766	2,766	0
	Unit 4	3,548	3,548	0
	Total	11,046	8,345	-2,701
2017	Unit 1	1,131	1,131	0
	Unit 2	3,601	0	-3,601
	Unit 3	2,766	2,766	0
	Unit 4	3,548	3,548	0
	Total	11,046	7,445	-3,601
2018-2025	Unit 1	1,131	1,131	0
	Unit 2	602	0	-602
	Unit 3	655	2,766	2,111
	Unit 4	896	3,548	2,652
	Total	3,284	7,445	4,161
2026-2046	Unit 1	1,131	105	-1,026
	Unit 2	602	0	-602
	Unit 3	655	244	-411
	Unit 4	896	308	-588
	Total	3,284	657	-2,627

[1]Unit 2 will be permanently shut down by April 1, 2016. NOx emission number for Unit 2 is based on operation of

the unit until April 1, 2016.

As indicated in Table 13, due to the shutdown of Unit 2 the Cholla BART Reassessment will result in lower NOx emissions in 2016 and 2017 when compared with the EPA FIP. However, the Cholla BART Reassessment will result in 4,161 tpy more NOx emissions than the EPA FIP during 2018-2025. After 2025, due to the conversion to natural gas the Cholla BART Reassessment will result in greater and more continuous NOx emission reductions than the EPA FIP.

Based on Table 13, ADEQ further performed a cumulative NOx emission analysis for the Cholla BART Reassessment vs. EPA FIP during 2016-2046. The results are shown below in Figure 3.

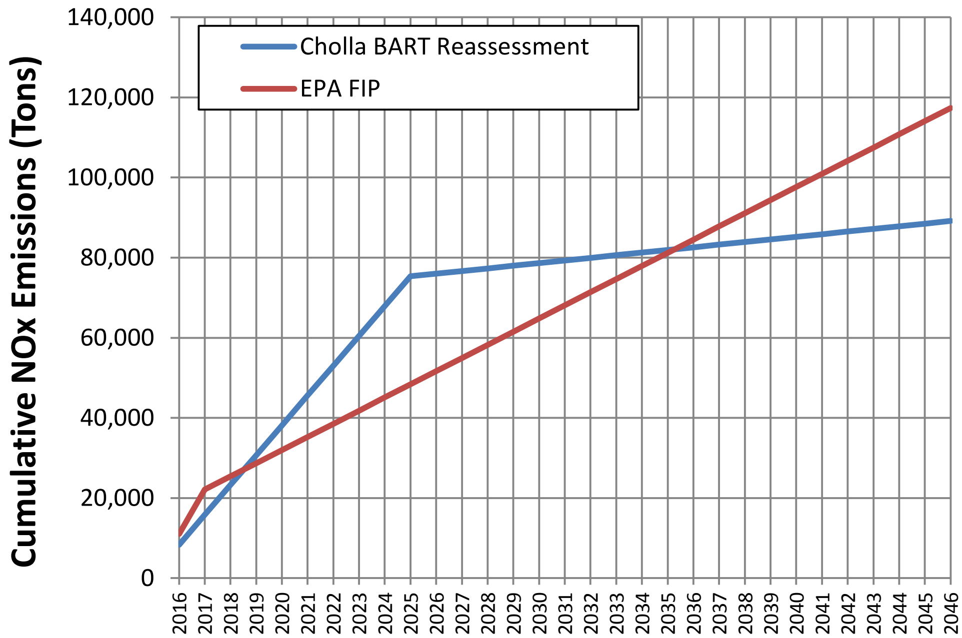

Figure 3 Cumulative NOx Emissions Associated with EPA's FIP vs. Cholla BART Reassessment over 2016-2046

As indicated in Figure 3, at the initial stage (2016-2017), the Cholla BART Reassessment will achieve greater NOx emission reductions than the EPA FIP due to the complete shutdown of Unit 2. After that, the EPA FIP will achieve greater NOx emission reductions than the Cholla BART Reassessment for a limited period of time (2018-2025) due to the installation of SCR controls on Units 2, 3, and 4. However, under the Cholla BART Reassessment, the BART units (Units 3 and 4) along with the non-BART unit (Unit 1) will be converted to natural gas-firing operation in 2025, resulting in significant NOx emission reductions. Comparatively, the EPA FIP envisions that the Cholla BART units will use coal as fuel for the entirety of the remaining life of the facility. Overall, the Cholla BART Reassessment will result in greater NOx emission reductions than the EPA FIP when considering the overall, long-term environmental impacts. As is illustrated in Figure 3, the long-term benefits of natural gas conversion far outweigh those of SCR controls. The Cholla BART Reassessment will result in 28,000 fewer tons of NOx emissions relative to the EPA FIP by 2046.

Navajo County is designated attainment or unclassifiable for NOx. As such, there are no nonattainment or maintenance SIPs that might rely on emission reductions at Cholla to ensure continued attainment of the NAAQS. Figure 4 shows the changes of the facility-wide NOx emissions from Cholla during 2010-2046 under the Cholla BART Reassessment. It is clear from Figure 4 that the NOx emissions from Cholla drop with time. Since the Cholla BART Reassessment will result in NOx emission reductions relative to the existing operating conditions of the facility, it will not interfere with attainment or maintenance of the current NO_2 NAAQS. Further, the Cholla BART Reassessment implements a strategic long-term plan that will significantly lower emissions, which is likely to ensure continued attainment of more stringent standards that may be promulgated in the future.

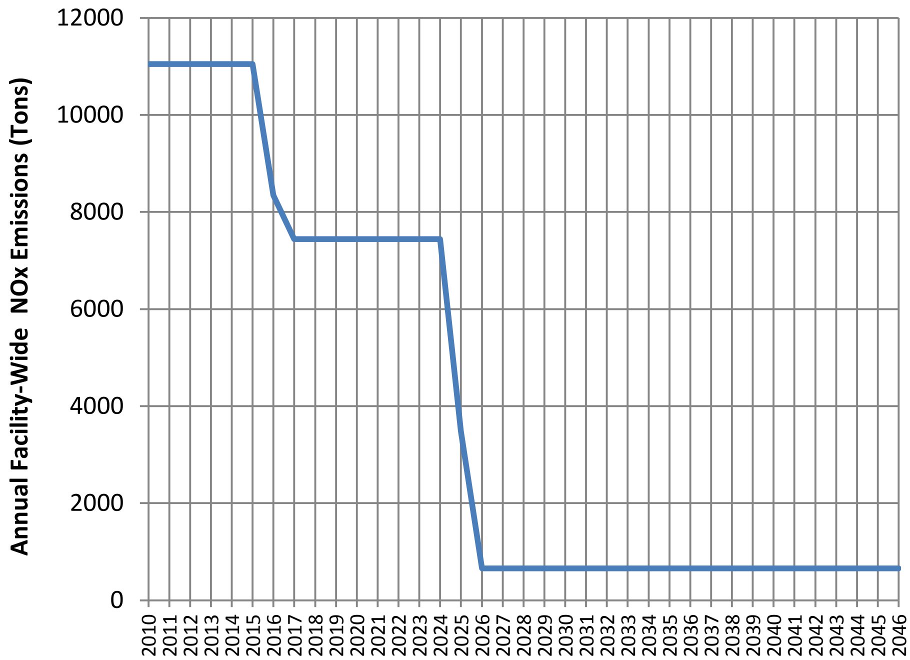

Figure 4 Annual Facility-wide NOx Emissions under Cholla BART Reassessment

3.1.5. Noninterference with the Attainment of NAAQS for Ozone

Ozone is formed when volatile organic compounds, NO_x, and oxygen combine in the atmosphere in the presence of sunlight. Navajo County is designated attainment or unclassifiable for ozone. As such, there are no nonattainment or maintenance SIPs that might rely on emission reductions at Cholla to ensure continued attainment of the NAAQS. As shown in Figure 4, the Cholla BART Reassessment will result in greater long-term NO_x (a precursor for ozone) emission reductions, thereby resulting in greater long-term ozone reductions. Therefore, the Cholla BART Reassessment will not interfere with attainment or maintenance of the current NAAQS for ozone. Further, the anticipated long-term reduction expected for NO_x will be advantageous in working toward achieving the anticipated lower ozone NAAQS.

3.2 Demonstrating Noninterference with Other Applicable Requirements under Clean Air Act Section 110(l)

Cholla is also subject to visibility protection requirements for Federal Class I areas under CAA Section 169A, as well as air toxics under Section 112.

3.2.1 Regional Haze Program

To address the problem of regional haze, EPA adopted the Regional Haze Rule in 1999. This rule requires states to adopt regional haze plans to incrementally improve visibility in all Class 1 areas over the next 60 years. The first regional haze plan must include Reasonable Progress Goals ("RPG") for each Class I area, for the year 2018, also known as the "2018 milestone year."

The CAA requires the installation and operation of BART as expeditiously as practicable, but in no event later than five years after the date of approval of a SIP or promulgation of a FIP.[16] Therefore, the EPA FIP for Cholla will take effect in late 2017. Arizona's RH SIP also included a long-term strategy for making reasonable progress toward restoring visibility at Class I areas to natural conditions by 2064. The CAA defines long-term as ten to fifteen years and Arizona's long-term strategy, submitted to EPA in 2011, includes emission reductions and visibility improvements that are expected by 2018.

The visibility impact analysis presented in the Cholla BART Reassessment Section 2.2.5 focuses on the "2018 milestone year." However, to support the CAA Section 110(l) analysis, APS and PacifiCorp have conducted additional modeling to compare long-term visibility impact benefits of the Cholla BART Reassessment with those of the EPA FIP for the period of 2016 to 2046, which is consistent with long-term emissions analysis as presented in Section 3.1. Further, to simplify the visibility analysis, the modeling neglected the difference between the EPA FIP and the Cholla BART Reassessment during 2016-2017 and focused the comparison for the period of 2018 to 2046. In fact, the Cholla BART Reassessment will achieve greater visibility improvement than the EPA FIP during 2016-2017, since the EPA FIP imposes additional controls at Unit 2 while the Cholla BART Reassessment proposes to permanently shut down Unit 2. Detailed modeling scenarios for the long-term visibility improvement from the Cholla BART Reassessment vs. EPA FIP are shown in Table 14.

APS and PacifiCorp conducted the visibility assessment with the CALPUFF model version 5.8 in the manner approved and used by EPA in its FIP. The CALPUFF modeling involved meteorological data for 2001-2003, an assumption of 1.0 part per billion background concentration for ammonia, and "Method 8b" 20 percent best days background conditions for all cases. Based on various modeling scenarios, as shown in Table 14, APS and PacifiCorp predicted the visibility impacts at the thirteen Class I areas within 300 km of Cholla. Table 15 summaries the modeled results. Figure 5 provides a comparison of the total visibility impacts over the thirteen Class I areas from the Cholla BART Reassessment vs. the EPA FIP for various time periods.

[16] 42 U.S.C. § 7491, 2012; CAA § 169A.

Table 14 Modeling Scenarios for Long-term Visibility Improvement from EPA FIP vs. Cholla BART Reassessment

	Time Period	Modeling Scenarios
EPA FIP	2018-2046	SCR with LNB/SOFA controls for Units 2, 3, and 4 and LNB/SOFA controls for Unit 1; FGD systems for Units 2, 3, and 4; new baghouses for Units 2, 3, and 4.
Cholla BART Reassessment	2018-2025	LNB/SOFA controls for Units 1, 3, and 4; FGD systems for Units 3 and 4; new baghouses for Units 3 and 4; Unit 2 is shutdown.
	2026-2046	Units 1, 3, and 4 are operated on natural gas with a 20 percent annual average capacity factor; Unit 2 is shutdown.

Table 15 Predicted Visibility Impacts at Class I Areas Associated with EPA FIP vs. Cholla BART Reassessment

Class I Areas	EPA FIP	Cholla BART Reassessment	
	2018-2046	2018-2025	2026-2046
Petrified Forest NP	2.64	3.75	1.45
Grand Canyon NP	1.11	1.48	0.45
Capitol Reef NP	0.62	0.92	0.29
Mazatzal W A	0.75	0.83	0.30
Sycamore Canyon WA	0.73	0.94	0.29
Mount Baldy WA	0.69	0.87	0.28
Gila WA	0.46	0.47	0.17
Sierra Ancha WA	0.82	0.94	0.36
Mesa Verde NP	0.63	0.84	0.30
Galiuro WA	0.29	0.30	0.09
Superstition WA	0.73	0.88	0.30
Saguaro NP	0.20	0.19	0.05
Pine Mountain WA	0.51	0.58	0.17
Cumulative impacts over thirteen Class I Areas	10.18	12.99	4.50

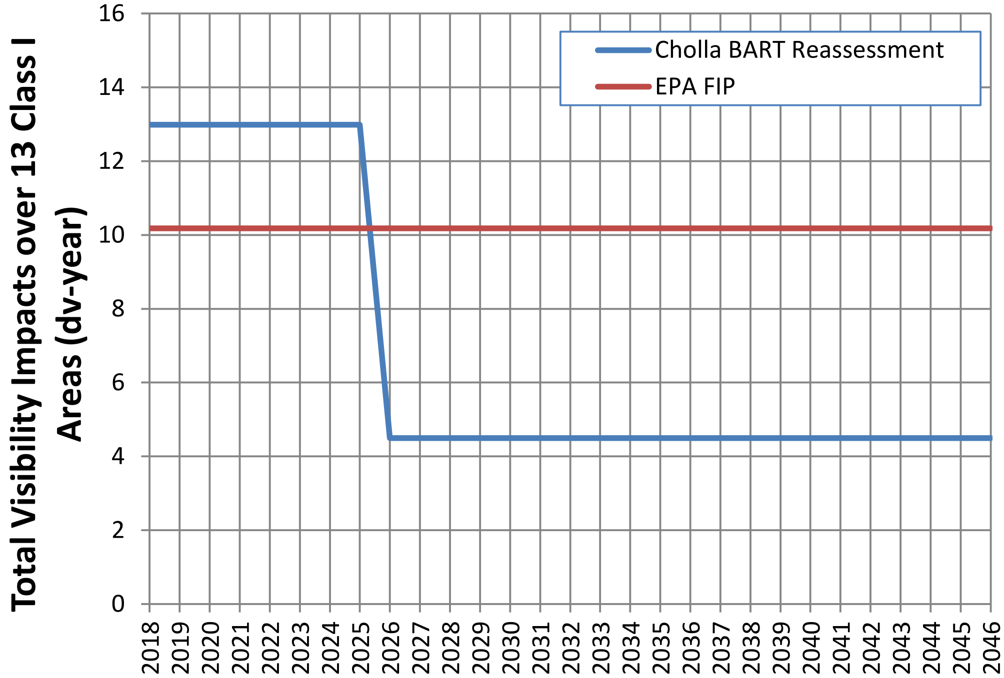

Figure 5 Comparison of Total Visibility Impacts over Thirteen Class I Areas Associated with EPA FIP vs. Cholla BART Reassessment

As indicated in Table 15 and Figure 5, the EPA FIP will achieve greater visibility improvements than the Cholla BART Reassessment after 2017 and until 2025, due primarily to the installation of SCR controls. After the natural gas conversion in 2025, the Cholla BART Reassessment will result in greater visibility improvements compared with the EPA FIP.

APS and PacifiCorp further performed a comparison of integrated visibility impact benefits between the Cholla BART Reassessment and the EPA FIP for each Class I area during the 2018-2046 period. Figure 6 presents the integrated visibility impacts at Petrified Forest National Park (the closest Class I area) for the Cholla BART Reassessment as well as the EPA FIP. As shown in Figure 6, the EPA FIP (the red curve) has lower integrated visibility impacts than the Cholla BART Reassessment (the blue curve) at the initial time period. The two curves then intersect at a certain point after the natural gas conversion in 2025. After that, the Cholla BART Reassessment shows greater integrated visibility improvements through 2046. Overall, the long-term visibility benefits are greater with the Cholla BART Reassessment than the EPA FIP. The general pattern of the integrated visibility results for the other twelve Class I areas is similar to that for Petrified Forest National Park. A more detailed description of visibility impacts due to the proposed BART Reassessment is provided in Appendix E.

The RHR sets a goal of achieving natural visibility conditions at every Class I area by 2064, and the EPA has directed States to make incremental, reasonable progress toward that goal. Although the proposed natural gas conversion under the Cholla BART Reassessment falls beyond the five-year window for BART, as is mandated by the CAA and RHR, it would result in significant long-term visibility improvements, which are consistent with the long-term goals and plans of the RHR. Therefore, ADEQ concludes that the Cholla BART Reassessment will not interfere with the regional haze program.

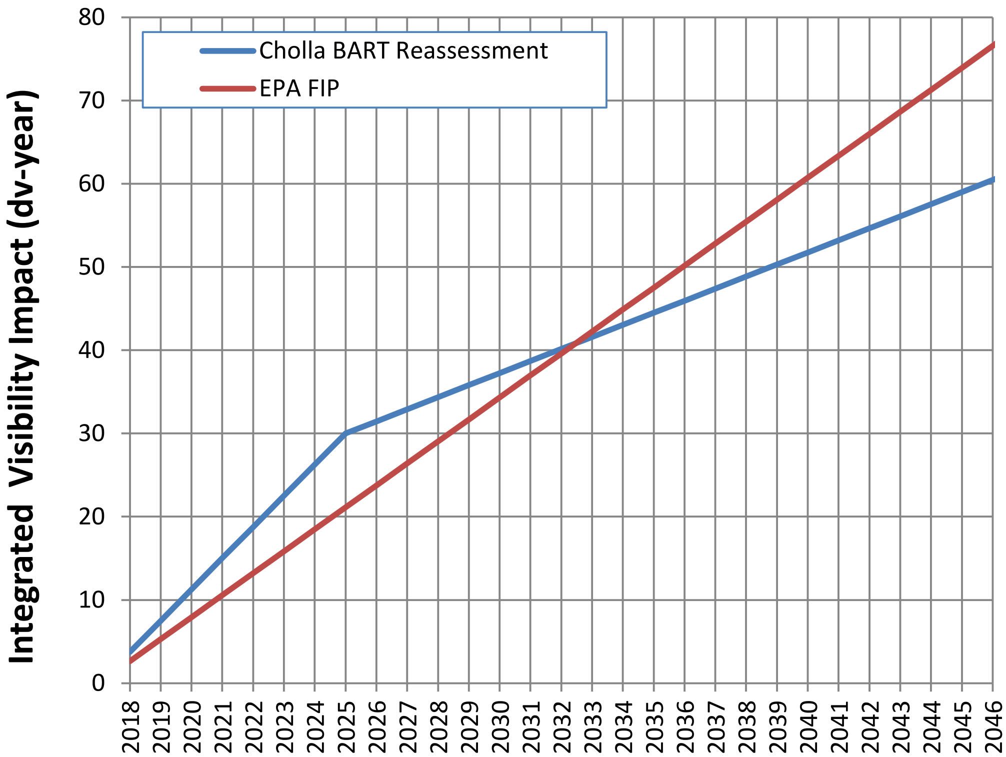

Figure 6 Comparison of Integrated Visibility Impacts at Petrified Forest National Park Associated with EPA FIP vs. Cholla BART Reassessment

3.2.2 Air Toxics

EPA developed standards for mercury and other air toxics for coal- and oil-fired electric generating units, effective April 2015. ADEQ approved APS's request for a one-year extension for implementation of the MATS rule to April 2016.

Cholla proposes to implement sorbent injection at Units 1, 3, and 4 by March 2016, and proposes to permanently cease operation of Unit 2 by April 2016. These actions are designed to reduce air toxics from the facility and achieve compliance with MATS rule emission limits.

Arizona thus concludes that this SIP revision will not interfere with any applicable air toxics requirements of the CAA.

3.3 Conclusions of Clean Air Act Section 110(l) Analysis

The RHR sets a goal of achieving natural visibility conditions at every Class I area by 2064, and the EPA has directed states to make incremental, reasonable progress toward that goal. In this technical analysis, ADEQ evaluated emission reductions and visibility improvements of the Cholla BART Reassessment against the EPA FIP, not only based on the 2018 time frame, but also from a more long-term perspective. ADEQ found that the proposed Cholla BART Reassessment would result in greater reductions in long-term emission, as well as greater visibility benefits than the EPA FIP. Although the proposed natural gas conversion falls beyond the five-year window for BART, as is mandated by the CAA and RHR, it would result in significant long-term emission reductions and visibility improvements, which are consistent with the long-term goals and plans of the RHR. Moreover, the proposed shutdown of Unit 2 in 2016 will further reduce pollutant emissions, and the resulting environmental benefits will occur two years earlier than the 2018 deadline. The foregoing demonstrates that the proposal under the Cholla BART Reassessment will not interfere with the attainment of the NAAQS or any other requirement under CAA 110(l).

APPENDIX A

Arizona Public Service Company (APS) Cholla Generating Station Operating Permit

SIGNIFICANT PERMIT REVISION DESCRIPTION

This Significant Permit Revision No. 61713 to Operating Permit No. 53399 is issued to the Arizona Public Service Company (APS) Cholla Generating Station. The revision incorporates the following changes to the permit:

- Retirement of Unit 2 by April 1, 2016;
- Voluntary emission reductions for Unit 1 for NOx, SO_2, and PM_{10};
- Permanent cessation of coal firing at Units 3 and 4 by April 30, 2025; and
- Optional conversion of Units 1, 3, and 4 to pipeline-quality natural gas fuel by July 31, 2025 with voluntary lower emission limits and an annual capacity factor not to exceed 20 percent.

Attachment "F" is hereby added to Permit No. 53399:

ATTACHMENT "F": SPECIFIC CONDITIONS

Addenda - Significant Revision #61713 to Operating Permit # 53399
For
Arizona Public Service Company – Cholla Generating Station

I. GENERAL

[A.A.C. R18-2-306.A.2]

A. The requirements under this Attachment "F" shall become effective on the date of final action by the U.S. Environmental Protection Agency (EPA), approving Attachment "F" as part of the State Implementation Plan for Arizona, provided that such final EPA action also revokes or rescinds EPA's Federal Implementation Plan (published in 77 Federal Register 72512 (December 5, 2012)), insofar as that Federal Implementation Plan establishes emission limits or other requirements for one or more units of the Cholla Generating Station.

B. Where multiple emission limits, standards, or requirements apply to a unit, the most stringent limit, standard, or requirement shall be applicable.

C. Compliance Schedule

1. Unit 2 shall be permanently retired by no later than April 1, 2016.

2. Units 1, 3, and 4 shall permanently stop burning coal or fuel oil or used oil by April 30, 2025.

3. By July 31, 2025, the Permittee may convert any or all of Units 1, 3, and 4 to natural gas operation.

D. If the Permittee chooses to convert any of the Units 1, 3, and 4 to natural gas operation, these units shall be limited to an annual capacity factor of 20 percent or less.

E. When this Attachment "F" becomes effective in accordance with Condition I.A above, the Regional Haze State Implementation Plan (SIP) and Federal Implementation Plan (FIP) requirements incorporated by Permit Revision No. 60129 will no longer be applicable.

F. Definitions

1. Boiler-operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the unit.

2. Operating hour means any hour that fossil fuel is fired in the unit.

3. PM_{10} means filterable total particulate matter less than 10 microns and the condensable material in the impingers as measured by Methods 201A and 202.

4. Valid data means data recorded when the CEMS is not out-of-control as defined by 40 CFR Part 75.

G. All reports and notifications under this Section shall be submitted to the EPA Administrator at the following address:

The Director of Enforcement Division
U.S. EPA Region IX
75 Hawthorne Street,
San Francisco, CA 94105

II. REQUIREMENTS FOR UNIT 1

A. Emission Limitations

1. Until the permanent cessation of coal burning or April 30, 2025, whichever is earlier, Unit 1 shall comply with the following emission limits:

   a. Nitrogen Oxides (NO_X)

   The Permittee shall not cause to be discharged into the atmosphere from Steam Boiler Unit 1 any gases that contain NO_X in excess of 0.22 lb/MMBtu heat input, averaged over 30 boiler-operating days.

   [A.A.C. R18-2-306.A.2]

   b. Sulfur Dioxide (SO_2)

   (1) The Permittee shall not cause to be discharged into the atmosphere from Unit 1 any gases that contain SO_2 in excess of 0.15 lb/MMBtu heat input, averaged over 30 boiler-operating days.

   (2) The Permittee shall not cause to be discharged into the atmosphere from Unit 1 any gases that contain SO_2 in excess of 5 percent of the potential combustion concentration (95 percent reduction), averaged over 30 boiler-operating days.

   [A.A.C. R18-2-306.A.2]

   c. Particulate Matter less than 10 microns (PM_{10})

   The Permittee shall not cause to be discharged into the atmosphere from Unit 1 any gases that contain PM_{10} in excess of 0.015 lb/MMBtu heat input.

   [A.A.C. R18-2-306.A.2]

2. Upon conversion of the Unit 1 to natural gas operation, the Permittee shall comply with the following emission limits:

a. Nitrogen Oxides (NO_X)

The Permittee shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of 0.08 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

b. Sulfur Dioxide (SO_2)

The Permittee shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 0.0006 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

c. Particulate Matter less than 10 microns (PM_{10})

The Permittee shall not cause to be discharged into the atmosphere any gases that contain total PM_{10} in excess of 0.01 lb/MMBtu heat input.

[A.A.C. R18-2-306.A.2]

B. Air Pollution Control Requirements

At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain *and operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Director and EPA Administrator, which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit*.

[A.A.C. R18-2-306.A.3.c and A.A.C. R-18-2-331A.3.e]
[Material Permit Condition indicated by italics and underline]

C. Monitoring Requirements

1. *At all times, the Permittee shall calibrate*, maintain, *and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO_2, NO_X, diluent, and stack gas volumetric flow rate from each unit*.

[A.A.C. R18-2-306.A.3.c and A.A.C R-18-2-331A.3.c]
[Material Permit Condition indicated by italics and underline]

2. *At all times, the Permittee shall calibrate*, maintain, *and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO_2 emissions and diluent at the inlet of the sulfur dioxide control device*.

[A.A.C. R18-2-306.A.3.c and A.A.C R-18-2-331A.3.c]
[Material Permit Condition indicated by italics and underline]

3. All valid CEMS hourly data shall be used to determine compliance with the emission limitations for NO_X and SO_2 in Conditions II.A.1 and II.A.2 for each unit.

[A.A.C. R18-2-306.A.3.c]

4. When the CEMS is out-of-control as defined by Part 75, the CEMS data shall be treated as missing data and not be used to calculate the emission average of the affected unit. Each required CEMS shall obtain valid data for at least 90 percent of the unit operating hours, on an annual basis.

[A.A.C. R18-2-306.A.3.c]

5. The Permittee shall comply with the quality assurance procedures for CEMS found in 40 CFR Part 75. In addition to these Part 75 requirements, relative accuracy test audits shall be calculated for both the NO_X and SO_2 pounds per hour measurement and the heat input measurement, and such hourly CEMS monitoring data shall not be bias adjusted. The inlet SO_2 and diluent monitors shall also meet the Quality Assurance/Quality Control (QA/QC) requirements of 40 CFR Part 75. The testing and evaluation of the inlet monitors and the calculations of relative accuracy for lb/hr of NO_X, SO_2, and heat input shall be performed each time the CEMS undergo relative accuracy testing. In addition, relative accuracy test audits shall be performed in the units of lb/MMBtu for the inlet and outlet SO_2 monitors.

[A.A.C. R18-2-306.A.3.c]

D. Compliance Requirements

1. Nitrogen Oxides (NO_X)

a. The 30-day rolling average NO_X emission rate shall be calculated for each calendar day, even if the unit is not in operation on that calendar day, in accordance with the following procedure:

[A.A.C. R18-2-306.A.3.c]

(1) Step 1 – sum the hourly pounds of NO_X emitted during the current boiler-operating day (or most recent boiler-operating day if the unit is not in operation), and the preceding twenty-nine (29) boiler-operating days, to calculate the total pounds of NO_X emitted over the most recent thirty (30) boiler-operating-day period;

(2) Step 2 – sum the hourly heat input, in MMBtu, during the current boiler-operating day (or most recent boiler-operating day if the unit is not in operation), and the preceding twenty-nine (29) boiler-operating days, to calculate the total heat input, in MMBtu over the most recent thirty (30) boiler-operating-day period;

(3) Step 3 – Divide the total pounds of NO_X emitted from step one by the total heat input from step two to calculate the 30 day rolling average NO_X emission rate in pounds of NO_X per MMBtu, for each calendar day for the unit.

b. Each 30-day rolling average NO_X emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

[A.A.C. R18-2-306.A.3.c]

c. If a valid NO_X pounds per hour or heat input is not available for any hour, that heat input and NO_X pounds per hour shall not be used in the calculation of the 30-day rolling average.

[A.A.C. R18-2-306.A.3.c]

2. Sulfur Dioxide (SO_2)

a. The 30-day rolling average SO_2 emission rate shall be calculated in accordance with the following procedure:

[A.A.C. R18-2-306.A.3.c]

(1) Step one – Sum the total pounds of SO_2 emitted from the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days;

(2) Step two – Sum the total heat input to the unit in MMBtu during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days; and

(3) Step three – Divide the total number of pounds of SO_2 emitted during the thirty (30) boiler-operating days by the total heat input during the thirty (30) boiler-operating days.

(4) A new 30-day rolling average SO_2 emission rate shall be calculated for each new boiler-operating day.

(5) Each 30-day rolling average SO_2 emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

(6) If a valid SO_2 pounds per hour at the outlet of the FGD system or heat input is not available for any hour for the unit, that heat input and SO_2 pounds per hour shall not be used in the calculation of the 30-day rolling average.

b. The 30-day rolling average SO_2 removal efficiency for each unit shall be calculated as follows:

[A.A.C. R18-2-306.A.3.c]

(1) Step one – Sum the total pounds of SO_2 emitted as measured at the outlet of the FGD system for the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days as measured at the outlet of the FGD system for the unit;

(2) Step two – Sum the total pounds of SO_2 delivered to the inlet of the FGD system for the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days as measured at the inlet to the FGD system for the unit (for each hour, the total pounds of SO_2 delivered to the inlet of the FGD system shall be calculated by measuring the ratio of the lb/MMBtu SO_2 inlet to the lb/MMBtu SO_2 outlet and multiplying the outlet pounds of SO_2 by that ratio);

(3) Step three – Subtract the outlet SO_2 emissions calculated in step one from the inlet SO_2 emissions calculated in step two;

(4) Step four – Divide the remainder calculated in step three by the inlet SO_2 emissions calculated in step two; and

(5) Step five – Multiply the quotient calculated in step four by 100 to express as percent removal efficiency.

(6) A new 30-day rolling average SO_2 removal efficiency shall be calculated for each new boiler-operating day, and shall include all emissions that occur during all periods within each boiler-operating day, including emissions from startup, shutdown, and malfunction.

(7) If both a valid inlet and outlet SO_2 lb/MMBtu and an outlet value of lb/hr of SO_2 are not available for any hour, that hour shall not be included in the efficiency calculation.

3. Particulate Matter less than 10 microns (PM_{10})

a. Until permanent cessation of coal burning in Unit 1, the Permittee shall demonstrate compliance with the PM_{10} emission limitations specified in Condition II.A.1.c by conducting annual stack tests. The Permittee shall use EPA Method 5 or Method 5B in 40 CFR Part 60, Appendix A, or Method 5 as described in 40 CFR Part 63, Subpart UUUUU, Table 5 or Method 201A in 40 CFR Part 51, Appendix M for filterable PM_{10} and Method 202 in 40 CFR Part 51, Appendix M for condensable PM_{10}.

[A.A.C. R18-2-312]

b. Within 90 days of conversion to pipeline-quality natural gas, the Permittee shall demonstrate compliance with the PM_{10} emission limitation in Condition II.A.2.c by conducting performance test using the test method specified in Condition III.D.3.a above. After the initial performance test, the Permittee shall demonstrate continuous compliance through use of pipeline-quality natural gas.

[A.A.C. R18-2-312 and A.A.C. R18-2-306.A.3.c]

c. A test protocol shall be submitted to ADEQ a minimum of thirty (30) days prior to the scheduled testing. The protocol shall identify which method(s) will be used to demonstrate compliance.

[A.A.C. R18-2-312]

d. The performance test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR Part 60, Appendix A, Method 19.

[A.A.C. R18-2-312]

e. In addition to required stack tests, the Permittee shall monitor particulate emissions for compliance with the emission limitations in accordance with any applicable Compliance Assurance Monitoring (CAM) plan in Attachment "E" of the permit. The averaging time for any other demonstration of PM_{10} compliance or exceedance shall be based on a 6-hour average.

[A.A.C. R18-2-312]

E. Recordkeeping Requirements

The Permittee shall maintain the following records for at least five years:

1. All CEMS data, including the date, place, and time of sampling or measurement;

parameters sampled or measured; and results.

[A.A.C. R18-2-306.A.3.c]

2. Daily 30-day rolling emission rates for NO_X and SO_2, and SO_2 removal efficiency, when applicable, for each unit, calculated in accordance with II.D.1 and II.D.2 of this Section.

[A.A.C. R18-2-306.A.3.c]

3. Records of quality assurance and quality control activities for emissions measuring systems, including, but not limited to, any records required by 40 CFR Part 75.

[A.A.C. R18-2-306.A.3.c]

4. Records of the relative accuracy test for hourly NO_x and SO_2 lb/hr measurement and hourly heat input measurement.

[A.A.C. R18-2-306.A.3.c]

5. Records of all major maintenance activities conducted on the emission units, air pollution control equipment, and CEMS.

[A.A.C. R18-2-306.A.3.c]

6. Any other records required by 40 CFR Part 75

[A.A.C. R18-2-306.A.3.c]

7. If the unit is converted to natural gas operation in 2025, a record of a current valid purchase contract, tariff sheet, transportation contract, or other acceptable documentation specifying the maximum total sulfur content of the pipeline-quality natural gas. This record shall be updated annually.

[A.A.C. R18-2-306.A.4]

F. Reporting Requirements

1. All reports and notifications under this Section shall be submitted to the ADEQ Director and EPA Administrator:

[A.A.C. R18-2-306.A.3.c]

2. Within 15 days of permanent cessation of coal burning in Unit 1, the Permittee shall notify the Director and the EPA Administrator.

[A.A.C. R18-2-306.A.5]

3. If the Permittee chooses to convert Unit 1 to natural gas operation, the Permittee shall notify the Director and the EPA Administrator at least 30 days prior to such conversion.

[A.A.C. R18-2-306.A.5]

4. Within 30 days of every second calendar quarter (i.e., semi-annually), the Permittee shall submit a report that lists the 30-day-rolling emission rate for NO_x and SO_2, and SO_2 removal efficiency calculated in accordance with Conditions II.D.1, II.D.2.a, and II.D.2.b, respectively, including the results of any relative accuracy test audit performed during the two preceding calendar quarters.

[A.A.C. R18-2-306.A.3.c]

5. Within 30 days of conversion to pipeline-quality natural gas, and within 30 days of every second calendar quarter thereafter (i.e., semi-annually), the Permittee shall submit a report that lists the daily 30-day rolling emission rates for NO_x and SO_2 for the unit, calculated in accordance with Conditions II.D.1 and II.D.2.a, respectively, including the results of any relative accuracy test audit performed

during the two preceding calendar quarters.

[A.A.C. R18-2-306.A.5]

6. For the purpose of Conditions II.F.4 and 5 above, the Permittee may request, and the Department may authorize in writing, different semi-annual reporting dates to harmonize with other semi-annual reporting requirements in the permit.

[A.A.C. R18-2-306.A.5]

III. REGIONAL HAZE REQUIREMENTS FOR UNITS 2, 3, AND 4

A. Emission Limitations

1. Unit 2

Until April 1, 2016, Unit 2 shall comply with the following emission limits:

a. Nitrogen Oxides (NO_x)

The Permittee shall not cause to be discharged into the atmosphere from Steam Boiler Unit 2 any gases that contain NO_X in excess of 0.30 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

b. Sulfur Dioxide (SO_2)

(1) The Permittee shall not cause to be discharged into the atmosphere from Steam Boiler Unit 2 any gases that contain SO_2 in excess of 0.25 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

(2) The Permittee shall not cause to be discharged into the atmosphere from Steam Boiler Unit 2 any gases that contain SO_2 in excess of 10 percent of the potential combustion concentration (90 percent reduction), averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

c. Particulate Matter less than 10 microns (PM_{10})

The Permittee shall not cause to be discharged into the atmosphere from Steam Boiler Unit 2 any gases that contain PM_{10} in excess of 0.025 lb/MMBtu heat input.

[A.A.C. R18-2-306.A.2]

2. Units 3 and 4

a. Until the permanent cessation of coal burning or April 30, 2025, whichever is earlier, Units 3 and 4 shall comply with the following emission limits:

(1) Nitrogen Oxides (NO_X)

The Permittee shall not cause to be discharged into the atmosphere from each unit any gases that contain NO_X in excess of 0.22 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

(2) Sulfur Dioxide (SO_2)

(a) The Permittee shall not cause to be discharged into the atmosphere from each unit any gases that contain SO_2 in excess of 0.15 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[40 CFR 52.145(e)(1)]

(b) The Permittee shall not cause to be discharged into the atmosphere from each unit any gases that contain SO_2 in excess of 5 percent of the potential combustion concentration (95 percent reduction), averaged over 30 boiler-operating days.

[40 CFR 52.145(f)(3)(ii)]

(3) Particulate Matter less than 10 microns (PM_{10})

The Permittee shall not cause to be discharged into the atmosphere from each unit any gases that contain PM_{10} in excess of 0.015 lb/MMBtu heat input.

[40 CFR 52.145(e)(1)]

b. Upon conversion of any of the Units 3 and 4 to natural gas operation, the Permittee shall comply with the following emission limits:

(1) Nitrogen Oxides (NO_X)

The Permittee shall not cause to be discharged into the atmosphere any gases that contain NO_X in excess of 0.08 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

(2) Sulfur Dioxide (SO_2)

The Permittee shall not cause to be discharged into the atmosphere any gases that contain SO_2 in excess of 0.0006 lb/MMBtu heat input, averaged over 30 boiler-operating days.

[A.A.C. R18-2-306.A.2]

(3) Particulate Matter less than 10 microns (PM_{10})

The Permittee shall not cause to be discharged into the atmosphere any gases that contain total PM_{10} in excess of 0.01 lb/MMBtu heat input.

[A.A.C. R18-2-306.A.2]

B. Air Pollution Control Requirements

At all times, including periods of startup, shutdown, and malfunction, the owner or operator shall, to the extent practicable, maintain and *operate the unit including associated air pollution control equipment in a manner consistent with good air pollution control practices for minimizing emissions. Pollution control equipment shall be designed and capable of operating properly to minimize emissions during all expected operating conditions. Determination of whether acceptable operating and maintenance* *procedures are being used will be based on information available to the EPA Administrator which may include, but is not limited to, monitoring results, review of operating and maintenance procedures, and inspection of the unit*.

[40 CFR 145(f)(10), A.A.C.R 18-2-331A.3.e]
[Material Permit Condition indicated by italics and underline]

C. Monitoring Requirements

1. *At all times, the Permittee shall calibrate*, maintain, *and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO_2, NO_X, diluent, and stack gas volumetric flow rate from each unit*.

[40 CFR 145(f)(5)(i)(A), A.A.C R-18-2-331A.3.c]
[Material Permit Condition indicated by italics and underline]

2. *At all times, the Permittee shall calibrate*, maintain, *and operate CEMS, in full compliance with the requirements found at 40 CFR Part 75, to accurately measure SO_2 emissions and diluent at the inlet of the sulfur dioxide control device*.

[40 CFR 145(f)(5)(i)(A), A.A.C R-18-2-331A.3.c]
[Material Permit Condition indicated by italics and underline]

3. All valid CEMS hourly data shall be used to determine compliance with the emission limitations for NO_X and SO_2 in Conditions III.A.1.a, III.A.1.b, III.A.2.a(1), III.A.2.a(2), III.A.2.b(1), and III.A.2.b(2) for each unit.

[40 CFR 145(f)(5)(i)(A)]

4. When the CEMS is out-of-control as defined by Part 75, that CEMS data shall be treated as missing data and not be used to calculate the emission average of the affected unit. Each required CEMS shall obtain valid data for at least 90 percent of the unit operating hours, on an annual basis.

[40 CFR 145(f)(5)(i)(A)]

5. The Permittee shall comply with the quality assurance procedures for CEMS found in 40 CFR Part 75. In addition to these Part 75 requirements, relative accuracy test audits shall be calculated for both the NO_X and SO_2 pounds per hour measurement and the heat input measurement, and such hourly CEMS monitoring data shall not be bias adjusted. The inlet SO_2 and diluent monitors shall also meet the Quality Assurance/Quality Control (QA/QC) requirements of 40 CFR Part 75. The testing and evaluation of the inlet monitors and the calculations of relative accuracy for lb/hr of NO_X, SO_2, and heat input shall be performed each time the CEMS undergo relative accuracy testing. In addition, relative accuracy test audits shall be performed in the units of lb/MMBtu for the inlet and outlet SO_2 monitors.

[40 CFR 145(f)(5)(i)(B)]

D. Compliance Requirements

1. Nitrogen Oxides (NO_X)

a. The 30-day rolling average NO_X emission rate for each unit shall be calculated for each calendar day, even if a unit is not in operation on that calendar day, in accordance with the following procedure:

[40 CFR 145(f)(5)(ii)(A)]

(1) Step 1 – sum the hourly pounds of NO_X emitted during the current boiler-operating day (or most recent boiler-operating day if the unit is not in operation), and the preceding twenty-nine

(29) boiler-operating days, to calculate the total pounds of NO_X emitted over the most recent thirty (30) boiler-operating-day period for each coal-fired unit;

(2) Step 2 – sum the hourly heat input, in MMBtu, during the current boiler-operating day (or most recent boiler-operating day if the unit is not in operation), and the preceding twenty-nine (29) boiler-operating days, to calculate the total heat input, in MMBtu over the most recent thirty (30) boiler-operating-day period for each coal-fired unit;

(3) Step 3 – Divide the total pounds of NO_X emitted from step one by the total heat input from step two for each unit to calculate the 30-day rolling average NO_X emission rate in pounds of NO_X per MMBtu, for each calendar day.

b. Each 30-day rolling average NO_X emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

[40 CFR 145(f)(5)(ii)(A)]

c. If a valid NO_X pounds per hour or heat input is not available for any hour for a unit, that heat input and NO_X pounds per hour shall not be used in the calculation of the 30-day rolling average.

[40 CFR 145(f)(5)(ii)(C)]

2. Sulfur Dioxide (SO_2)

a. The 30-day rolling average SO_2 emission rate for each unit shall be calculated in accordance with the following procedure:

[40 CFR 145(f)(5)(iii)(A) and (C)]

(1) Step one – Sum the total pounds of SO_2 emitted from the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days;

(2) Step two – Sum the total heat input to the unit in MMBtu during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days; and

(3) Step three – Divide the total number of pounds of SO_2 emitted during the thirty (30) boiler-operating days by the total heat input during the thirty (30) boiler-operating days.

(4) A new 30-day rolling average SO_2 emission rate shall be calculated for each new boiler-operating day.

(5) Each 30-day rolling average SO_2 emission rate shall include all emissions and all heat input that occur during all periods within any boiler-operating day, including emissions from startup, shutdown, and malfunction.

(6) If a valid SO_2 pounds per hour at the outlet of the FGD system or heat input is not available for any hour for a unit, that heat input and SO_2 pounds per hour shall not be used in the calculation of

the 30-day rolling average.

b. The 30-day rolling average SO_2 removal efficiency for each unit shall be calculated as follows:

[40 CFR 145(f)(5)(iii)(B) and (D)]

(1) Step one – Sum the total pounds of SO_2 emitted as measured at the outlet of the FGD system for the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days as measured at the outlet of the FGD system for that unit;

(2) Step two – Sum the total pounds of SO_2 delivered to the inlet of the FGD system for the unit during the current boiler-operating day and the previous twenty-nine (29) boiler-operating days as measured at the inlet to the FGD system for that unit (for each hour, the total pounds of SO_2 delivered to the inlet of the FGD system for a unit shall be calculated by measuring the ratio of the lb/MMBtu SO_2 inlet to the lb/MMBtu SO_2 outlet and multiplying the outlet pounds of SO_2 by that ratio);

(3) Step three – Subtract the outlet SO_2 emissions calculated in step one from the inlet SO_2 emissions calculated in step two;

(4) Step four – Divide the remainder calculated in step three by the inlet SO_2 emissions calculated in step two; and

(5) Step five – Multiply the quotient calculated in step four by 100 to express as percent removal efficiency.

(6) A new 30-day rolling average SO_2 removal efficiency shall be calculated for each new boiler-operating day, and shall include all emissions that occur during all periods within each boiler-operating day, including emissions from startup, shutdown, and malfunction.

(7) If both a valid inlet and outlet SO_2 lb/MMBtu and an outlet value of lb/hr of SO_2 are not available for any hour, that hour shall not be included in the efficiency calculation.

3. Particulate Matter less than 10 microns (PM_{10})

a. Until retirement of Unit 2, and permanent cessation of coal burning in Units 3 and 4, the Permittee shall demonstrate compliance with the PM_{10} emission limitations specified in Condition III.A.1.c and III.A.2.a(3) by conducting annual stack tests. The Permittee shall use EPA Method 5 or Method 5B in 40 CFR Part 60, Appendix A, or Method 5 as described in 40 CFR Part 63, Subpart UUUUU, Table 5 or Method 201A in 40 CFR Part 51, Appendix M for filterable PM_{10}, and Method 202 in 40 CFR Part 51, Appendix M for condensable PM_{10}.

[40 CFR 145(f)(6), A.A.C. R18-2-312]

b. Within 90 days of conversion to pipeline-quality natural gas operation for Units 3 and/or Unit 4, the Permittee shall demonstrate compliance with the PM_{10} emission limitations in Condition III.A.2.b(3) by conducting a performance test in accordance with the test method specified in Condition III.D.3.a above. After completion of the initial performance test, continuous compliance shall be demonstrated through use of pipeline-quality natural gas.

[A.A.C. R18-2-312]

c. A test protocol shall be submitted to ADEQ a minimum of thirty (30) days prior to the scheduled testing. The protocol shall identify which method(s) will be used to demonstrate compliance.

[40 CFR 145(f)(6), A.A.C. R18-2-312]

d. Each test shall consist of three runs, with each run at least 120 minutes in duration and each run collecting a minimum sample of 60 dry standard cubic feet. Results shall be reported in lb/MMBtu using the calculation in 40 CFR Part 60, Appendix A, Method 19.

[40 CFR 145(f)(6), A.A.C. R18-2-312]

e. In addition to required stack tests, the Permittee shall monitor particulate emissions for compliance with the emission limitations in accordance with any applicable Compliance Assurance Monitoring (CAM) plan in Attachment "E" of the permit. The averaging time for any other demonstration of PM_{10} compliance or exceedance shall be based on a 6-hour average.

[40 CFR 145(f)(6)]

E. Recordkeeping Requirements

The Permittee shall maintain the following records for at least five years:

1. All CEMS data, including the date, place, and time of sampling or measurement; parameters sampled or measured; and results.

[40 CFR 145(f)(7)(i)]

2. Daily 30-day rolling emission rates for NO_x and SO_2, and SO_2 removal efficiency, when applicable, for each unit, calculated in accordance Conditions III.D.1, III.D.2.a, and III.D.2.b of this Section.

[40 CFR 145(f)(7)(ii)]

3. Records of quality assurance and quality control activities for emissions measuring systems, including, but not limited to, any records required by 40 CFR Part 75.

[40 CFR 145(f)(7)(iii)]

4. Records of the relative accuracy test for hourly NO_X and SO_2 lb/hr measurement and hourly heat input measurement.

[40 CFR 145(f)(7)(iv)]

5. Records of all major maintenance activities conducted on emission units, air pollution control equipment, and CEMS.

[40 CFR 145(f)(7)(v)]

6. Any other records required by 40 CFR Part 75.

[40 CFR 145(f)(7)(vi)]

7. If any of the Units 3 and 4 are converted to natural gas operation in 2025, a record of a current valid purchase contract, tariff sheet, transportation contract, or other acceptable documentation specifying the maximum total sulfur content of

the pipeline-quality natural gas. This record shall be updated annually.

[A.A.C. R18-2-306.A.4]

F. Reporting Requirements

1. All reports and notifications under this Section shall be submitted to the ADEQ Director and the EPA Administrator.

   [40 CFR 145(f)(8)]

2. The Permittee shall notify the Director and the EPA Administrator within 15 days of the permanent shut down of Unit 2.

   [A.A.C. R18-2-306.A.5]

3. Within 15 days of permanent cessation of coal burning coal in Units 3 and 4, the Permittee shall notify the Director and the EPA Administrator.

   [A.A.C. R18-2-306.A.5]

4. If the Permittee chooses to convert any of Units 3 and 4 to natural gas operation, the Permittee shall notify the Director and the EPA Administrator at least 30 days prior to such conversion.

   [A.A.C. R18-2-306.A.5]

5. Within 30 days of every second calendar quarter (i.e., semi-annually), the Permittee shall submit a report that lists the 30-day-rolling emission rate for NO_x and SO_2, and SO_2, removal efficiency calculated in accordance with Conditions III.D.1, III.D.2.a, and III.D.2.b, respectively, including the results of any relative accuracy test audit performed during the two preceding calendar quarters.

   [40 CFR 145(f)(8)(ii)]

6. Within 30 days after conversion to pipeline-quality natural gas, and within 30 days of every second calendar quarter thereafter (i.e., semi-annually), the Permittee shall submit a report that lists the daily 30-day rolling emission rates for NO_x and SO_2, for each unit, calculated in accordance with Conditions III.D.1 and III.D.2.a, respectively, including the results of any relative accuracy test audit performed during the two preceding calendar quarters.

   [A.A.C. R18-2-306.A.5]

7. The Permittee may request, and the Department may authorize in writing, different semi-annual reporting dates to harmonize with other semi-annual reporting under the then-effective permit.

   [A.A.C. R18-2-306.A.5]

APPENDIX B

BART Reassessment - Cost of Compliance

B.1 Cost of Compliance for Unit 3

B.1.1 Cost-Effectiveness for Twenty Years of Operation on Coal

Table B-1: Capital and Annualized Cost for NOx Controls for Cholla Unit 3 assuming 20 years of Operation on Coal

Control Option	Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual O&M ($/yr)	Total Annual Cost ($/yr)
OFA (only)[a]	-	-	-	-
LNB+SOFA [a]	$3,848,807	$363,300	$120,000	$483,300
SNCR w/ LNB+SOFA [a]	$19,238,125	$1,815,943	$1,254,500	$3,070,443
SCR w/ LNB+SOFA [a]	$83,461,195	$7,878,146	$1,570,766	$9,448,912

[a] *Costs are based on 77 Fed. Reg. 72512, 72548, Table 12 (Dec. 5, 2012).*

Table B-2: Emission Reductions for NOx Control Options for Cholla Unit 3 assuming 20 years of Operation on Coal

Control Option	Emission Factor (lb/MMBtu)	Heat Rate (MMBtu/hr) [c]	Annual Capacity Factor (%)	Emission Rate		Emission Reduction (ton/yr)
				(lb/hour)	(ton/yr)	
OFA (only)	0.304	3,480	86	1,058	3,985	-
LNB+SOFA	0.211[a]	3,480	86	734	2,766	1,219
SNCR w/LNB+SOFA	0.158 [b]	3,480	86	551	2,074	1,911
SCR w/LNB+SOFA	0.050	3,480	86	174	655	3,330

[a] *Average actual NOx emission rate from June 1, 2009 through December 31, 2013 after the installation of LNB+SOFA*
[b] *25% reduction from average actual NOx emission rate*
[c] *77 Fed. Reg. 72512, 72548, Table 11 (Dec. 5, 2012)*

Table B-3: Average and Incremental Cost Effectiveness for NOx Control Options for Cholla Unit 3 assuming 20 years of Operation on Coal

Control Option	Total Annual Cost ($/yr)	Emission Reduction (ton/yr)	Average Cost Effectiveness ($/ton)	Incremental Total Annual Cost ($/yr) [a]	Incremental Emission Reduction (ton/yr) [a]	Incremental Cost Effectiveness ($/ton) [a]
LNB+SOFA	$483,300	1,219	$396			
SNCR w/ LNB+SOFA	$3,070,443	1,911	$1,607	$2,587,143	691	$3,742
SCR w/ LNB+SOFA	$9,448,912	3,330	$2,838	$8,965,612	2,110	$4,248

[a] The incremental cost effectiveness results for SNCR and SCR are based on the emission and cost differences between these technologies and the proposed LNB+SOFA option

B.1.2 BART Reassessment - Eight Years of Operation on Coal and Twelve Years of Operation on Natural Gas

Table B-4: LNB+SOFA Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 3

LNB + SOFA Control Costs and Cost Effectiveness Years 1-8			
	Cost and Emission Reductions [a]		
	Annual Cost/Tons	Years	Totals
Annualized Capital Cost ($)	$363,300	8	$2,906,400
Annual O&M Costs Years 1-8 ($)	$120,000	8	$960,000
Emission Reduction Years 1-8 (tons)	1,219	8	9,753
Cost Effectiveness, Years 1-8 ($/ton)			$396
LNB + SOFA Costs and Cost Effectiveness Years 9-20			
Annualized Capital Cost Years 9-20 ($)	$363,300	12	$4,359,600
Annual O&M Costs, Years 9-20 ($) [b]	$0	12	$0
Emission Reduction Years 9-20 (tons) [b]	0	12	0
Cost Effectiveness, Years 9-20 ($/ton)			NA
LNB + SOFA Cost Effectiveness over 20-Year Life			
Annualized Capital Costs ($)			$7,266,000
Annual O&M Costs ($)			$960,000
Total Annual Costs ($)			$8,226,000
Average Annual Costs over 20 Years ($/yr)			$411,300
Emission Reduction (tons)			9,753
Average Emission Reduction over 20 Years (tons/yr)			488
Cost Effectiveness ($/ton)			$843

[a] See Tables B-1 and B-2
[b] LNB + SOFA installed for coal will not be applicable to natural gas

Table B-5: SNCR Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 3

SNCR Control Costs and Cost Effectiveness Years 1-8						
	Total Cost and Emission Reductions [a]			Incremental Cost and Emission Reductions [b]		
	Annual Cost/Tons	Years	Totals	Annual Cost/Tons	Years	Totals
Annualized Capital Cost ($)	$1,815,943	8	$14,527,544	$1,452,643	8	$11,621,144
Annual O&M Costs, Years 1-8 ($)	$1,254,500	8	$10,036,000	$1,134,500	8	$9,076,000
Emission Reduction, Years 1-8 (tons)	1,911	8	15,284	691	8	5,532
Cost Effectiveness, Years 1-8 ($/ton)			$1,607			$3,742
SNCR Costs and Cost Effectiveness Years 9-20						
Annualized Capital Cost, Years 9-20 ($)	$1,815,943	12	$21,791,316	$1,452,643	12	$17,431,716
Annual O&M Costs, Years 9-20 ($)	$300,000	12	$3,600,000	$300,000	12	$3,600,000
Emission Reduction, Years 9-20 (tons)	36.6[c]	12	439	36.6[c]	12	439
Cost Effectiveness, Years 9-20 ($/ton)			$57,841			$47,910
SNCR Cost Effectiveness over 20-Year Life						
Annualized Capital Costs ($)			$36,318,860			$29,052,860
Annual O&M Costs ($)			$13,636,000			$12,676,000
Total Annual Costs ($)			$49,954,860			$41,728,860
Average Annual Costs ($/yr)			$2,497,743			$2,086,443
Emission Reduction (tons)			15,723			5971
Average Annual Emission Reduction (tons/yr)			786			299
Cost Effectiveness ($/ton)			$3,177			$6,989

[a] *See Tables B-1 and B-2*
[b] *Incremental costs and emission reductions are the differences between SNCR in this table and LNB + SOFA in Table B-4*
[c] *Emissions before control are 243.9 ton/yr (0.08 lb/MMBtu x 3,480 MMBtu/hr x 8.760 hr/yr x 20% x 1 ton/2,000 lb). The emission reduction is assumed to be 15% because the effectiveness of SNCR decreases as the NOx emission rate before control decreases*

Table B-6: SCR Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 3

SCR Costs and Cost Effectiveness Years 1-8						
	Total Cost and Emission Reductions [(a)]			Incremental Cost and Emission Reductions [(b)]		
	Annual Cost/Tons	Years	Totals	Annual Cost/Tons	Years	Totals
Annualized Capital Cost ($)	$7,878,146	8	$63,025,168	$7,514,846	8	$60,118,768
Annual O&M Costs Years 1-8 ($)	$1,570,766	8	$12,566,128	$1,450,766	8	$11,606,128
Emission Reduction Years 1-8 (tons)	3,330	8	26,636	2,110	8	16,884
Cost Effectiveness, Years 1-8 ($/ton)			$2,838			$4,248
SCR Costs and Cost Effectiveness Years 9-20						
Annualized Capital Cost Years 9-20 ($)	$7,878,146	12	$94,537,752	$7,514,846	12	$90,178,152
Annual O&M Costs, Years 9-20 ($)	$350,000	12	$4,200,000	$350,000	12	$4,200,000
Emission Reduction Years 9-20 (tons)	91.5	12	1,098	91.5	12	1,098
Cost Effectiveness, Years 9-20 ($/ton)			$89,925			$85,955
SCR Cost Effectiveness over 20-Year Life						
Total Annualized Capital Costs ($)			$157,562,920			$150,296,920
Total Annual O&M Costs ($)			$16,766,128			$15,806,128
Total Annual Costs ($)			$174,329,048			$166,103,048
Average Annual Costs ($/yr)			$8,716,452			$8,305,152
Total Emission Reduction (tons)			27,734			17,982
Average Annual Emission Reduction (tons/yr)			1,387			899
Cost Effectiveness ($/ton)			$6,286			$9,237

[(a)] *See Tables B-1 and B-2*

[(b)] *Incremental costs and emission reductions are the differences between SCR in this table and LNB + SOFA in Table B-4*

[(c)] *Emission rate factor before control is 0.08 lb/MMBtu. With SCR, emissions are reduced to 0.05 lb/MMBtu. Therefore, emissions reduction is: (0.08 -0.05) lb/MMBtu x 3,480 MMBtu/hr x 8.760 hr/yr x 20% x 1 ton/2,000 lb = 91.5 tons/yr*

B.2 Cost of Compliance for Unit 4

B.2.1 Cost Effectiveness for Twenty Years of Operation on Coal

Table B-7: Capital and Annualized Cost for NOx Controls for Cholla Unit 4 assuming 20 years of Operation on Coal

Control Option	Capital Cost ($)	Annualized Capital Cost ($/yr)	Annual O&M ($/yr)	Total Annual Cost ($/yr)
OFA (only) [a]	-	-	-	-
LNB+SOFA [a]	$5,334,618	$503,550	$170,000	$673,550
SNCR w/ LNB+SOFA [a]	$24,885,052	$2,348,973	$1,737,393	$4,086,366
SCR w/ LNB+SOFA [a]	$119,083,832	$11,240,671	$2,350,182	$13,590,853

[a]Costs are based on 77 Fed. Reg. 72512, 72547, Table 12 (Dec. 5, 2012)

Table B-8: Emission Reductions for NOx Control Options for Cholla Unit 4 assuming 20 years of Operation on Coal

Control Option	Emission Factor (lb/MMBtu)	Heat Rate [c] (MMBtu/hr)	Annual Capacity Factor (%)	Emission Rate		Emission Reduction (ton/yr)
				(lb/hour)	(ton/yr)	
OFA (only)	0.296	4,399	93	1302	5,304	-
LNB+SOFA	0.20 [a]	4,399	93	871	3,548	1,756
SNCR w/ LNB+SOFA	0.15 [b]	4,399	93	653	2,661	2,643
SCR w/ LNB+SOFA	0.050	4,399	93	220	896	4,408

[a] Average actual NOx emission rate from May 1, 2008 through December 31, 2013 after the installation of LNB+SOFA. Expected emission rate with a 30-day rolling average limit of 0.22 lb/MMBtu
[b] 25 percent reduction from average actual NOx emission rate
[c]77 Fed. Reg.72512, 72548, Table 11 (Dec. 5, 2012)

Table B-9: Average and Incremental Cost Effectiveness for NOx Control Options for Cholla Unit 4 assuming 20 years of Operation on Coal

Control Option	Total Annual Cost	Emission Reduction	Average Cost Effectiveness	Incremental Total Annual Cost	Incremental Emission Reduction	Incremental Cost Effectiveness
	($/yr)	(ton/yr)	($/ton)	($/yr)	(ton/yr)	($/ton)
LNB+SOFA	$673,550	1,756	$384	-	-	-
SNCR w/LNB+SOFA	$4,086,366	2,643	$1,546	$3,412,816	887	$3,848
SCR w/ LNB+SOFA	$13,590,853	4,408	$3,083	$12,917,303	2,652	$4,871

[a] *The incremental cost effectiveness results for SNCR and SCR are based on the emission and cost differences between these technologies and the proposed LNB +SOFA option*

B.2.2 BART Reassessment - Eight Years of Operation on Coal and Twelve Years of Operation on Natural Gas

Table B-10: LNB+SOFA Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 4

LNB + SOFA Costs and Cost Effectiveness Years 1-8			
	Cost and Emission Reductions (a)		
	Annual	Years	Totals
Annualized Capital Cost ($)	$503,550	8	$4,028,400
Annual O&M Costs Years 1-8 ($)	$170,000	8	$1,360,000
Emission Reduction Years 1-8 (tons)	1,756	8	14,048
Cost Effectiveness, Years 1-8 ($/ton)			$384
LNB + SOFA Costs and Cost Effectiveness Years 9-20			
Annualized Capital Cost Years 9-20 ($)	$503,550	12	$6,042,600
Annual O&M Costs, Years 9-20 ($) (b)	$0	12	$0
Emission Reduction Years 9-20 (tons) (b)	0	12	0
Cost Effectiveness, Years 9-20 ($/ton)			NA
LNB + SOFA Cost Effectiveness over 20-Year Life			
Total Annualized Capital Costs ($)			$10,071,000
Total Annual O&M Costs ($)			$1,360,000
Total Annual Costs ($)			$11,431,000
Average Annual Costs over 20 Years ($/yr)			$571,550
Total Emission Reduction (tons)			14,048
Average Emission Reduction over 20 Years (tons/yr)			702
Cost Effectiveness ($/ton)			$814

[a] *See Tables B-7 and B-8*
[b] *LNB + SOFA installed for coal will not be applicable to natural gas*

Table B-11: SNCR Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 4

SNCR Costs and Cost Effectiveness Years 1-8						
	Total Cost and Emission Reductions (a)			Incremental Cost and Emission Reductions (b)		
	Annual Cost/Tons	Years	Totals	Annual Cost/Tons	Years	Totals
Annualized Capital Cost ($)	$2,348,973	8	$18,791,784	$1,845,423	8	$14,763,384
Annual O&M Costs Years 1-8 ($)	$1,737,393	8	$13,899,144	$1,567,393	8	$12,539,144
Emission Reduction Years 1-8 (tons)	2,643	8	21,144	887	8	7,096
Cost Effectiveness, Years 1-8 ($/ton)			$1,546			$3,848
SNCR Costs and Cost Effectiveness Years 9-20						
Annualized Capital Cost Years 9-20 ($)	$2,348,973	12	$28,187,676	$1,845,423	12	$22,145,076
Annual O&M Costs, Years 9-20 ($)	$400,000	12	$4,800,000	$400,000	12	$4,800,000
Emission Reduction Years 9-20 (tons)	46.2	12	554	46.2	12	554
Cost Effectiveness, Years 9-20 ($/ton)			$59,502			$48,602
SNCR Average Cost Effectiveness over 20-Year Life						
Total Annualized Capital Costs ($)			$46,979,460			$36,908,460
Total Annual O&M Costs ($)			$18,699,144			$17,339,144
Total Costs ($)			$65,678,604			$54,247,604
Average Annual Costs ($/yr)			$3,283,930			$2,712,380
Total Emission Reduction (tons)			21,699			7,650
Average Annual Emission Reduction (tons/yr)			1,085			383
Cost Effectiveness ($/ton)			$3,027			$7,091

[a] *See Tables B-7 and B-8*
[b] *Incremental costs and emission reductions are the differences between SNCR in this table and LNB + SOFA in Table B-10*
[c] *Emissions before control are 308.3 ton/yr (0.08 lb/MMBtu x 4,399 MMBtu/hr 8.760 hr/yr x 20% x 1 ton/2,000 lb). The emission reduction is 15% because the effectiveness of SNCR decreases as the NOx emission rate before control decreases*

Table B-12: SCR Cost Effectiveness with Conversion to Natural Gas in 2025 for Cholla Unit 4

SCR Costs and Cost Effectiveness Years 1-8						
	Total Cost and Emission Reductions [(a)]			Incremental Cost and Emission Reductions [(b)]		
	Annual Cost/Tons	Years	Totals	Annual Cost/Tons	Years	Totals
Annualized Capital Cost ($)	$11,240,671	8	$89,925,368	$10,737,121	8	$85,896,968
Annual O&M Costs Years 1-8 ($)	$2,350,182	8	$18,801,456	$2,180,182	8	$17,441,456
Emission Reduction Years 1-8 (tons)	4,408	8	35,264	2,652	8	21,216
Cost Effectiveness, Years 1-8 ($/ton)			$3,083			$4,871
SCR Costs and Cost Effectiveness Years 9-20						
Annualized Capital Cost Years 9-20 ($)	$11,240,671	12	$134,888,052	$10,737,121	12	$128,845,452
Annual O&M Costs, Years 9-20 ($)	$500,000	12	$6,000,000	$500,000	12	$6,000,000
Emission Reduction Years 9-20 (tons)	116 [(C)]	12	1,387	116 [(C)]	12	1,387
Cost Effectiveness, Years 9-20 ($/ton)			$101,563			$97,207
SCR Average Cost Effectiveness over 20-Year Life						
Total Annualized Capital Costs ($)			$224,813,420			214,742,420
Total Annual O&M Costs ($)			$24,801,456			23,441,456
Total Costs ($)			$249,614,876			238,183,876
Average Annual Costs ($/yr)			$12,480,744			11,909,194
Total Emission Reduction (tons)			36,652			22,603
Average Annual Emission Reduction (tons/yr)			1,833			1,130
Cost Effectiveness ($/ton)			$6,810			$10,539

[(a)] *See Tables B-7 and B-8*
[(b)] *Incremental costs and emission reductions are the differences between SCR in this table and LNB + SOFA in Table B-10*
[(c)] *Emission rate factor before control is 0.08 lb/MMBtu. With SCR, emissions are reduced to 0.05 lb/MMBtu. Therefore, emissions reduction is: (0.08 -0.05) lb/MMBtu x 4,399 MMBtu/hr x 8.760 hr/yr x 20% x 1 ton/2,000 lb = 116 tons/yr*

Appendix C

Modeled Exhaust Parameters and Emission Rates Used in BART Reassessment

Table C-1: Modeled Stack Exhaust Parameters for Coal-Firing

Unit	Fuel	GEP Creditable Stack Height (m)	Stack Elevation (m)	Stack Diameter (m)	Stack Temperature (K)	Exit Velocity (m/s)
Unit 1	Coal	76.20	1533	3.43	322.0	20.73
Unit 2&3 Merged	Coal	144.81	1530	6.88	396.0	29.60
Unit 3	Coal	144.81	1530	5.23	322.0	22.25
Unit 4	Coal	167.64	1530	5.85	324.0	23.50

Table C-2: Cholla Unit 1 NOx Emissions Data Estimates for Modeling

CAMD Historic Emissions Data, 2001-2003 [a]			
Annual Ave lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Model Input Emission Rate (g/s)
	lb/hr	Date	
0.371	683.9	5/6/2001	86.17
Expected Annual LNB/OFA Rate w ith a 30-Day Rolling Average Limit of 0.22 lb/MMBtu [b]			
Annual Ave lb/MMBtu	Reduction from Baseline Year	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.201	45.8%	370.5	46.68
SNCR + LNB/OFA Rates (as a Percent of LNB/OFA Rates) [c]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.151	25.0%	277.9	35.01
SCR + LNB/OFA Rates (as a Percent of LNB/OFA Rate) [d]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input EmissionRate (g/s)
0.050	75.1%	92.1	11.61
Natural Gas Rate (as a Percent of LNB/OFA Rate) [e]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.080	60.2%	147.4	18.57

Notes:

[a] 2001-2003 data is used to identify the maximum 24-hour emission rate.

[b] Expected annual emission rate, based on actaul emissions from 11/01/2007 through 12/31/2013, is projected at 0.201 lb/MMBtu, which is a 45.8% reduction from 2001 annual rate. The 2001 hourly rate is reduced by this amount for modeling the LNB/OFA scenarios.

[c] Given an annual LNB/OFA rate of 0.201, SNCR is expected to reduce the LNB/OFA emissions by 25%. The hourly LNB/OFA rate for modeling is reduced by this amount to reflect SNCR modeling.

[d] An annual SCR rate of 0.050 lb/MMBtu is a 75.1% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the SCR case.

[e] An annual Gas rate of 0.080 lb/MMBtu is a 60.2% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the gas conversion case. This is not a BART case but will be included in a supplemental analysis.

Table C-3: Cholla Unit 2 NOx Emissions Data Estimates for Modeling

CAMD Historic Emissions Data, 2001-2003 [(a)]			
Annual Ave lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Model Input Emission Rate (g/s)
	lb/hr	Date	
0.335	1,629.8	7/20/2001	205.35
Expected Annual LNB/OFA Rate w ith a 30-Day Rolling Average Limit of 0.22 lb/MMBtu [(b)]			
Annual Ave lb/MMBtu	Reduction from Baseline Year	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.299	10.8%	1,454.2	183.23
SNCR + LNB/OFA Rates (as a Percent of LNB/OFA Rates) [(c)]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.224	25.0%	1,090.7	137.42
SCR + LNB/OFA Rates (as a Percent of LNB/OFA Rate) [(d)]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate forModeling	Model Input Emission Rate (g/s)
0.050	83.3%	243.2	30.64
Natural Gas Rate (as a Percent of LNB/OFA Rate) [(e)]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.080	73.2%	389.1	49.02

Notes:

[(a)] 2001-2003 data is used to identify the maximum 24-hour emission rate.

[(b)] Expected annual emission rate, based on actaul emissions from 03/01/2008 through 12/31/2013, is projected at 0.299 lb/MMBtu, which is a 10.4% reduction from 2001 annual rate. The 2001 hourly rate is reduced by this amount for modeling the LNB/OFA scenarios.

[(c)] Given an annual LNB/OFA rate of 0.299, SNCR is expected to reduce the LNB/OFA emissions by 25%. The hourly LNB/OFA rate for modeling is reduced by this amount to reflect SNCR modeling.

[(d)] An annual SCR rate of 0.050 lb/MMBtu is a 76.3% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the SCR case.

[(e)] An annual Gas rate of 0.080 lb/MMBtu is a 62.1% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the gas conversion case. This is not a BART case but will be included in a supplemental analysis.

Table C-4: Cholla Unit 3 NOx Emissions Data Estimates for Modeling

CAMD Historic Emissions Data, 2001-2003 [a]			
Annual Ave lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Model Input Emission Rate (g/s)
	lb/hr	Date	
0.317	1,199.7	9/11/2002	151.16
Expected Annual LNB/OFA Rate with a 30-Day Rolling Average Limit of 0.22 lb/MMBtu [b]			
Annual Ave lb/MMBtu	Reduction from Baseline Year	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.211	33.4%	798.5	100.61
SNCR + LNB/OFA Rates (as a Percent of LNB/OFA Rates) [c]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.158	25.0%	598.9	75.46
SCR + LNB/OFA Rates (as a Percent of LNB/OFA Rate) [d]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.050	76.3%	189.2	23.84
Natural Gas Rate (as a Percent of LNB/OFA Rate) [e]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.080	62.1%	302.8	38.15

Notes:

[a] 2001-2003 data is used to identify the maximum 24-hour emission rate.

[b] Expected annual emission rate is projected at 0.211 lb/MMBtu, which is a 33.4% reduction from 2002 annual rate. The 2002 hourly rate is reduced by this amount for modeling the LNB/OFA scenarios.

[c] Given an annual LNB/OFA rate of 0.211, SNCR is expected to reduce the LNB/OFA emissions by 25%. The hourly LNB/OFA rate for modeling is reduced by this amount to reflect SNCR modeling.

[d] An annual SCR rate of 0.050 lb/MMBtu is a 76.3% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the SCR case.

[e] An annual Gas rate of 0.080 lb/MMBtu is a 62.1% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the gas conversion case. This is not a BART case but will be included in a supplemental analysis.

Table C-5: Cholla Unit 4 NOx Emissions Data Estimates for Modeling

CAMD Historic Emissions Data, 2001-2003 [a]			
Annual Ave lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Model Input Emission Rate (g/s)
	lb/hr	Date	
0.322	1,771.7	8/13/2003	223.23
Expected Annual LNB/OFA Rate w ith a 30-Day Rolling Average Limit of 0.22 lb/MMBtu [b]			
Annual Ave lb/MMBtu	Reduction from Baseline Year	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.200	37.9%	1,100.8	138.69
SNCR + LNB/OFA Rate (as a Percent of LNB/OFA Rate) [c]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.150	25.0%	825.6	104.02
SCR + LNB/OFA Rate (as a Percent of LNB/OFA Rate) [d]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.050	75.0%	275.2	34.67
Natural Gas Rate (as a Percent of LNB/OFA Rate) [e]			
Annual Ave lb/MMBtu	Reduction from LNB/OFA Rate	Max lb/Hour Rate for Modeling	Model Input Emission Rate (g/s)
0.080	60.0%	440.3	55.48

Notes:

[a] 2001-2003 data is used to identify the maximum 24-hour emission rate

[b] Expected annual emission rate is projected at 0.20 lb/MMBtu, which is a 37.9% reduction from 2003 annual rate. The 2003 hourly rate is reduced by this amount for modeling the LNB/OFA scenarios.

[c] Given an annual LNB/OFA rate of 0.20, SNCR is expected to reduce the LNB/OFA emissions by 25%. The hourly LNB/OFA rate for modeling is reduced by this amount to reflect SNCR modeling.

[d] An annual SCR rate of 0.050 lb/MMBtu is a 75% reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the SCR case.

[e] An annual Gas rate of 0.080 lb/MMBtu is 60% percent reduction from the annual LNB/OFA rate. The hourly LNB/OFA rate is reduced by this amount to reflect the modeling for the gas conversion case. This is not a BART case but will be included in a supplemental analysis.

Table C-6: Cholla SO_2 Emissions Data Estimates for Modeling

BART Baseline Emissions

Unit ID	Calculated Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Heat Input on Max Day	Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	Date	MMBtu/hr	g/s	g/s
Unit 1	0.3878	486.3	5/3/2002	1,254	61.28	61.28
Unit 2	0.5024	1,630.4	3/12/2001	3,245	205.43	205.43
Unit 3	0.9609	2,931.2	4/19/2001	3,050	369.32	301.64
Unit 4	0.7623	3,134.8	3/2/2002	4,112	394.98	352.40

BART LNB/OFA, SNCR and SCR Options

Unit ID	Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Heat Input on Modeled Day	Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	Date	MMBtu/hr	g/s	g/s
Unit 1 [(a)]	0.3878	486.3		1,254	61.28	28.23
Unit 2	0.0000	0.0000		0.0000	0.0000	57.12
Unit 3	0.1500	522.0		3,480 [(b)]	65.77	65.77
Unit 4	0.1500	659.9		4,399 [(b)]	83.14	83.14

[(a)] Non-BART source, emissions are assumed to be the same as the baseline.
[(b)] Heat input/rate is consistent with EPA BART rule (Table 11, 77 FR 72548).

Post 2025 (not a BART case) Natural Gas

Unit ID	Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling		Heat Input on Modeled Day	Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	Date	MMBtu/hr	g/s	g/s
Unit 1	0.0006	0.846		1,411 [(c)]	0.107	0.110
Unit 2	0.0000	0.0000		0.0000	0.000	0.000
Unit 3	0.0006	2.088		3,480	0.263	0.263
Unit 4	0.0006	2.639		4,399	0.333	0.333

[(c)] Maximum daily heat input in the 2001 to 2003 period, 05/13/2001

Table C-7: Cholla PM10 Emissions Data Estimates for Modeling

BART Baseline Emissions

Unit ID	Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling	Maximum 24-hr Heat Input		Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	MMBtu/hr	Date	g/s	g/s
Unit 1	0.030 [a]	42.32	1,411	5/13/2001	5.33	5.65
Unit 2	0.026 [a]	89.86	3,456	5/10/2001	11.32	9.90
Unit 3	0.021 [a]	66.17	3,151	5/21/2001	8.34	9.21
Unit 4	0.031 [a]	140.46	4,531	12/28/2003	17.70	17.18

[a] Emission rate provided by APS

BART LNB/OFA, SNCR and SCR Options

Unit ID	Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling	Maximum 24-hr Heat Input		Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	MMBtu/hr		g/s	g/s
Unit 1 [a]	0.0300	42.3	1,411		5.33	2.82
Unit 2	0.0000	0.0000	0.0000		0.0000	5.71
Unit 3	0.0150	52.2	3,480 [b]		6.58	6.58
Unit 4	0.0150	66.0	4,399 [b]		8.31	8.31

[a] Non-BART source, emissions are assumed to be the same as the baseline.
[b] Heat input/rate is consistent with EPA BART rule (77 Fed. Reg. 72548, Table 11).

Post 2025 (not a BART case) Natural Gas - PM10total

Unit ID	Max 24 hr lb/MMBtu	Max Rate 24 hr lb/hr for Modeling	Maximum 24-hr Heat Input		Re- calculated Emissions	Previous model runs Emissions
	lb/MMBtu	lb/hr	MMBtu/hr		g/s	g/s
Unit 1	0.0100	14.108	1,411		1.78	1.88
Unit 2	0.0000	0.0000	0.0000		-	0.00
Unit 3	0.0100	34.800	3,480		4.38	4.38
Unit 4	0.0100	43.990	4,399		5.54	5.54

Table C-8: 2001-2003 Baseline Emissions

Unit	Fuel	NOx Controls	NOx Max Daily	SO2 Max Daily	PM10 filt Emission	Max. Daily Heat Input for PM10	PM10 filt	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	lb/hr	lb/MMBtu	MMBtu/hr	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1	Coal	pre-LNB	684 [a]	486 [b]	0.030 [c]	1,411 [d]	42.32	86.2	61.3	5.33	1.52 [e]	3.67 [e]	0.14 [e]	0.60 [e]	0.15 [e]
Unit 2	Coal	pre-LNB	1,630 [a]	1,630 [b]	0.026 [c]	3,456 [d]	89.86	205.3	205.4	11.32	3.23 [e]	7.79 [e]	0.30 [e]	1.27 [e]	0.32 [e]
Unit 3	Coal	pre-LNB	1,200 [a]	2,931 [b]	0.021 [c]	3,151 [d]	66.17	151.2	369.3	8.34	4.63 [f]	3.57 [f]	0.14 [f]	7.29 [f]	1.82 [f]
U2+3		pre-LNB						356.5	574.8	19.66	7.87	11.36	0.44	8.56	2.14
Unit 4	Coal	pre-LNB	1,772 [a]	3,135 [b]	0.031 [c]	4,531 [d]	140.46	223.2	395.0	17.70	9.83 [g]	7.57 [g]	0.29 [g]	5.53 [g]	1.38 [g]

[a] Maximum NOx daily 24 hour actual emissions based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 (05/06/01), Unit 2 (07/20/01), Unit 3 (09/11/02), and Unit 4 (08/13/03).

[b] Maximum SO2 daily 24 hour actual emissions based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 (05/03/02), Unit 2 (03/12/01), Unit 3 (04/19/01), and Unit 4 (03/02/02).

[c] Maximum lb/MMBtu filterable PM10 emission rates provided by APS and PacifiCorp.

[d] Maximum daily 24 hour heat input based on Part 75 monitoring data for the 2001 - 2003 period. Unit 1 (05/13/01), (Unit 2 (05/10/01), Unit 3 (05/21/01), and Unit 4 (12/28/03).

[e] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with a wet scrubber http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPCScrubberPmSpeciationProfile.xls

[f] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with ESP http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_ESPpmSpeciationProfile.xls

[g] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+ESP http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_ESPpmSpeciationProfile.xls

Table C-9: BART Option 1: Unit 2 Shutdown, LNB & SOFA on Units 3 and 4

Unit	Fuel	NOx Controls	NOx Max Daily	Max. Daily Heat Input for SO2 and PM	SO2 Emission Factor	SO2 Max Daily	PM10 filt Emission Factor	PM10 filt Max Daily	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1 [(a)]	Coal	Pre-LNB	684	NA	NA	486.33	NA	42.32	86.18	61.28	5.33	1.52	3.67	0.14	0.60	0.15
Unit 2	Shutdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit 3	Coal	LNB & SOFA	799 [(b)]	3,480 [(c)]	0.150 [(d)]	522.0	0.015 (d)	52.20	100.61	65.77	6.58	3.29 [(e)]	3.17 [(e)]	0.12 [(e)]	5.55 [(e)]	1.39 [(e)]
Unit 4	Coal	LNB & SOFA	1,101 [(b)]	4,399 [(c)]	0.150 [(d)]	659.9	0.015 (d)	65.99	138.70	83.14	8.31	4.16 [(e)]	4.00 [(e)]	0.15 [(e)]	7.01 [(e)]	1.75 [(e)]

[(a)] Unit 1 is not BART eligible. Emissions are assumed to be the same as baseline emissions in Table C-8.

[(b)] See Table C-4 and C-5.

[(c)] Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72548).

[(d)] EPA BART rule (Table 1, 77 FR 72515).

[(e)] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+FF
http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_FFpmSpeciationProfile.xls

Table C-10: BART Option 2: Unit 2 Shutdown, LNB & SOFA and SNCR on Units 3 and 4

Unit	Fuel	NOx Controls	NOx Max Daily	Max. Daily Heat Input for SO2 and PM	SO2 Emission Factor	SO2 Max Daily	PM10 filt Emission Factor	PM10 filt Max Daily	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1 [a]	Coal	Pre-LNB	684	NA	NA	486.33	NA	42.32	86.18	61.28	5.33	1.52	3.67	0.14	0.60	0.15
Unit 2	Shutdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit 3	Coal	LNB & SOFA and SNCR	599 [b]	3,480 [c]	0.150 [d]	522.0	0.015 [d]	52.20	75.46	65.77	6.58	3.29 [e]	3.17 [e]	0.12 [e]	5.55 [e]	1.39 [e]
Unit 4	Coal	LNB & SOFA and SNCR	826 [b]	4,399 [c]	0.150 [d]	659.9	0.015 [d]	65.99	104.02	83.14	8.31	4.16 [e]	4.00 [e]	0.15 [e]	7.01 [e]	1.75 [e]

[a] Unit 1 is not BART eligible. Emissions are assumed to be the same as baseline emissions in Table C-8.

[b] See Table C-4 and C-5.

[c] Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72548).

[d] EPA BART rule (Table 1, 77 FR 72515).

[e] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+FF

http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_FFpmSpeciationProfile.xls

Table C-11: BART Option 3: Unit 2 Shutdown, LNB & SOFA and SCR on Units 3 and 4

Unit	Fuel	NOx Controls	NOx Max Daily	Max. Daily Heat Input for SO2 and	SO2 Emission Factor	SO2 Max Daily	PM10 filt Emission Factor	PM10 filt Max Daily	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1 [(a)]	Coal	Pre-LNB	684	NA	NA	486.33	NA	42.32	86.18	61.28	5.33	1.52	3.67	0.14	0.60	0.15
Unit 2	Shutdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit 3	Coal	LNB & SOFA and SCR	189 [(b)]	3,480 [(c)]	0.150 [(d)]	522.0	0.015 [(d)]	52.20	23.84	65.77	6.58	3.29 [(e)]	3.17 [(e)]	0.12 [(e)]	5.55 [(e)]	1.39 [(e)]
Unit 4	Coal	LNB & SOFA and SCR	275 [(b)]	4,399 [(c)]	0.150 [(d)]	659.9	0.015 [(d)]	65.99	34.67	83.14	8.31	4.16 [(e)]	4.00 [(e)]	0.15 [(e)]	7.01 [(e)]	1.75 [(e)]

[(a)] Unit 1 is not BART eligible. Emissions are assumed to be the same as baseline emissions in Table C-8.

[(b)] See Table C-4 and C-5.

[(c)] Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72548).

[(d)] EPA BART rule (Table 1, 77 FR 72515).

[(e)] PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+FF

http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_FFpmSpeciationProfile.xls

Appendix D

Supplemental Annual Emissions Analysis for Long-Term Benefits of the BART Reassessment

D-1 Overview of Approach

ADEQ conducted an analysis comparing the long-term emissions expectations during 2016-2046 for the relevant pollutants (PM_{10}, SO_2, and NOx) under the control strategies listed in this Cholla BART Reassessment and the prescribed control measures in the applicable SIP or FIP. ADEQ selected Year 2016 as the starting year for comparison purposes because, prior to 2016, there is no difference in PM_{10}, SO_2, and NOx emissions between the Cholla BART Reassessment and the application SIP or FIP.

The following comparisons are made:

1. NOx annual and cumulative emission analysis for EPA FIP and the Cholla BART Reassessment (Section D-2)

2. PM_{10} annual and cumulative emission analysis for the 2011 State of Arizona's SIP ("2011 AZ SIP") and the Cholla BART Reassessment (Section D-3), and

3. SO_2 annual and cumulative emission analysis for the 2011 AZ SIP and the Cholla BART Reassessment (Section D-4)

D-2 Annual NO_X Emission Calculations

D-2-1 NOx Emissions - Cholla BART Reassessment

Emission factors and annual capacity factors for the Cholla BART Reassessment are shown in Table D-1.

Table D-1: Annual NOx Emission Calculations for Cholla BART Reassessment

2016: LNB and SOFA, Unit 2 Shutdown by April 1, 2016

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.201 [1]	1494 [2]	86% [2]	1,131
Unit 2	0.299 [1]	3,022 [3]	91% [3]	900 [4]
Unit 3	0.211 [1]	3,480 [3]	86% [3]	2,766
Unit 4	0.198 [1]	4,399 [3]	93% [3]	3,548

[1] Average actual emission factors are from the installation of LNB and SOFA through the end of 2013.
[2] Heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[3] Heat input and annual capacity factors for Units 2, 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.
[4] NOx emission numbers for Unit 2 are based on the operation of the unit until April 1, 2016.

2017 – 2025: LNB+SOFA, Unit 2 Shutdown

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.201 [1]	1494 [2]	86% [2]	1,131
Unit 2				0
Unit 3	0.211 [1]	3,480 [3]	86% [3]	2,766
Unit 4	0.198 [1]	4,399 [3]	93% [3]	3,548

[1] Average actual emission factors are from the installation of LNB and SOFA through the end of 2013.
[2] Heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[3] Heat input and annual capacity factors for Units 2, 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.

2026- 2046: Units 1, 3 and 4 on Natural Gas, Unit 2 Shutdown

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.080 [1]	1,494 [1]	20% [1]	105
Unit 2				0
Unit 3	0.080 [1]	3,480 [2]	20% [1]	244
Unit 4	0.080 [1]	4,399 [2]	20% [1]	308

[1] Heat input and annual capacity factor are based on the information in Cholla application.
[2] Heat input for Units 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.

Annual NOx emissions for each year as well as cumulative emissions for BART Reassessment are presented in Table D-2.

Table D-2: Cholla BART Reassessment Annual NOx Emissions for 2016 through 2046 (tons)

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	1131	900	2,766	3,548	8,345	8,345
2017	1131	0	2,766	3,548	7,445	15,790
2018	1131	0	2,766	3,548	7,445	23,234
2019	1131	0	2,766	3,548	7,445	30,679
2020	1131	0	2,766	3,548	7,445	38,124
2021	1131	0	2,766	3,548	7,445	45,569
2022	1131	0	2,766	3,548	7,445	53,014
2023	1131	0	2,766	3,548	7,445	60,459
2024	1131	0	2,766	3,548	7,445	67,903
2025	1131	0	2,766	3,548	7,445	75,348
2026	105	0	244	308	657	76,005
2027	105	0	244	308	657	76,662
2028	105	0	244	308	657	77,319
2029	105	0	244	308	657	77,976
2030	105	0	244	308	657	78,633
2031	105	0	244	308	657	79,290
2032	105	0	244	308	657	79,947
2033	105	0	244	308	657	80,604
2034	105	0	244	308	657	81,261
2035	105	0	244	308	657	81,918
2036	105	0	244	308	657	82,575
2037	105	0	244	308	657	83,232
2038	105	0	244	308	657	83,889
2039	105	0	244	308	657	84,546
2040	105	0	244	308	657	85,203
2041	105	0	244	308	657	85,860
2042	105	0	244	308	657	86,517
2043	105	0	244	308	657	87,174
2044	105	0	244	308	657	87,831
2045	105	0	244	308	657	88,488
2046	105	0	244	308	657	89,145

D-3-2: NOx Emission for EPA FIP

Table D-3: Annual NOx Emission Calculations for EPA FIP

2016- 2017: LNB+SOFA

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.201 [1]	1494 [2]	86% [2]	1,131
Unit 2	0.299 [1]	3,022 [3]	91% [3]	3,601
Unit 3	0.211 [1]	3,480 [3]	86% [3]	2,766
Unit 4	0.198 [1]	4,399 [3]	93% [3]	3,548

[1] Average actual emission factors are from the installation of LNB and SOFA through the end of 2013.
[2] Heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[3] Heat input and annual capacity factors for Units 2, 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.

2018-2046: SCR with LNB+SOFA for Units 2, 3, 4, LNB+SOFA for Unit 1

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.201 [1]	1,494 [3]	86% [3]	1,131
Unit 2	0.05 [2]	3,022 [2]	91% [2]	602
Unit 3	0.05 [2]	3,480 [2]	86% [2]	655
Unit 4	0.05 [2]	4,399 [2]	93% [2]	896

[1] Average actual emission factors are from the installation of LNB and SOFA through the end of 2013.
[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4 are from EPA FIP FR 72548 Table 11,dated December 5, 2012.
[3] Heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.

Annual NOx emissions for each year as well as cumulative emissions for EPA FIP case are presented in Table D-4.

Table D-4: Annual NOx Emissions for EPA FIP 2016 through 2046 (tons)

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	1131	3,601	2,766	3,548	11,046	11,046
2017	1131	3,601	2,766	3,548	11,046	22,093
2018	1131	602	655	896	3,285	25,377
2019	1131	602	655	896	3,285	28,662
2020	1131	602	655	896	3,285	31,947
2021	1131	602	655	896	3,285	35,231
2022	1131	602	655	896	3,285	38,516
2023	1131	602	655	896	3,285	41,801
2024	1131	602	655	896	3,285	45,085
2025	1131	602	655	896	3,285	48,370
2026	1131	602	655	896	3,285	51,655
2027	1131	602	655	896	3,285	54,939
2028	1131	602	655	896	3,285	58,224
2029	1131	602	655	896	3,285	61,509
2030	1131	602	655	896	3,285	64,793
2031	1131	602	655	896	3,285	68,078
2032	1131	602	655	896	3,285	71,363
2033	1131	602	655	896	3,285	74,647
2034	1131	602	655	896	3,285	77,932
2035	1131	602	655	896	3,285	81,217
2036	1131	602	655	896	3,285	84,501
2037	1131	602	655	896	3,285	87,786
2038	1131	602	655	896	3,285	91,071
2039	1131	602	655	896	3,285	94,356
2040	1131	602	655	896	3,285	97,640
2041	1131	602	655	896	3,285	100,925
2042	1131	602	655	896	3,285	104,210
2043	1131	602	655	896	3,285	107,494
2044	1131	602	655	896	3,285	110,779
2045	1131	602	655	896	3,285	114,064
2046	1131	602	655	896	3,285	117,348

D-3 Annual SO_2 Emission Calculations

D-3-1 SO_2 Emissions Cholla BART Reassessment

Emission factors and annual capacity factors for the Cholla BART Reassessment are shown in Table D-5.

Table D-5: Annual SO_2 Emission Calculations for Cholla BART Reassessment

2016: Unit 2 Shutdown by April 1, 2016

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.150 [1]	1,494 [1]	86% [1]	844
Unit 2	0.150 [2]	3,022 [2]	91% [2]	452 [3]
Unit 3	0.150 [2]	3,480 [2]	86% [2]	1,966
Unit 4	0.150 [2]	4,399 [2]	93% [2]	2,688

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4, are from EPA FIP FR 72548 Table 11, dated December 5, 2012.
[3] SO_2 emission numbers for Unit 2 are based on the operation of this unit until April 1, 2016.

2017 – 2025: Unit 2 Shutdown, Units 1, 3 and 4 Coal Firing

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.150 [1]	1,494 [1]	86% [1]	844
Unit 2				0
Unit 3	0.150 [2]	3,480 [2]	86% [2]	1,966
Unit 4	0.150 [2]	4,399 [2]	93% [2]	2,688

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4, are from EPA FIP FR 72548 Table 11, dated December 5, 2012.

2026 – 2046: Unit 2 shutdown, Units 1, 3 and 4 Natural Gas Firing

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.0006 [1]	1,494 [2]	20% [1]	0.79
Unit 2				0
Unit 3	0.0006 [1]	3,480 [2]	20% [1]	1.83
Unit 4	0.0006 [1]	4,399 [2]	20% [1]	2.31

[1] Emission factor, heat input and annual capacity factor for Unit 1, and emission factors and capacity factors for Units 3 and 4 are based on the information in Cholla application.
[2] Heat inputs for Units 2, 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.

Annual SO_2 emissions for each year as well as cumulative emissions for BART Reassessment are presented in Table D-6.

Table D-6: Cholla BART Reassessment Annual SO_2 Emissions for 2016 through 2046 (tons)

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	844	452	1,966	2,688	5,950	5,950
2017	844	0	1,966	2,688	5,498	11,448
2018	844	0	1,966	2,688	5,498	16,946
2019	844	0	1,966	2,688	5,498	22,444
2020	844	0	1,966	2,688	5,498	27,942
2021	844	0	1,966	2,688	5,498	33,440
2022	844	0	1,966	2,688	5,498	38,938
2023	844	0	1,966	2,688	5,498	44,436
2024	844	0	1,966	2,688	5,498	49,934
2025	844	0	1,966	2,688	5,498	55,432
2026	1	0	2	2	5	55,437
2027	1	0	2	2	5	55,442
2028	1	0	2	2	5	55,447
2029	1	0	2	2	5	55,452
2030	1	0	2	2	5	55,457
2031	1	0	2	2	5	55,462
2032	1	0	2	2	5	55,467
2033	1	0	2	2	5	55,472
2034	1	0	2	2	5	55,477
2035	1	0	2	2	5	55,482
2036	1	0	2	2	5	55,487
2037	1	0	2	2	5	55,492
2038	1	0	2	2	5	55,497
2039	1	0	2	2	5	55,502
2040	1	0	2	2	5	55,507
2041	1	0	2	2	5	55,512
2042	1	0	2	2	5	55,517
2043	1	0	2	2	5	55,522
2044	1	0	2	2	5	55,527
2045	1	0	2	2	5	55,532
2046	1	0	2	2	5	55,537

D-3-2 SO_2 Emissions 2011 AZ SIP

Emission factors and annual capacity factors for the 2011 AZ SIP are shown in Table D-7.

Table D-7: Annual SO_2 Emission Calculations for 2011 AZ SIP

2016 – 2046: Units 1-4 Coal Firing

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.150 [1]	1,494 [1]	86% [1]	1,069
Unit 2	0.150 [2]	3,022 [2]	91% [2]	1,614
Unit 3	0.150 [2]	3,480 [2]	86% [2]	1,966
Unit 4	0.150 [2]	4,399 [2]	93% [2]	2,688

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.

[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4, are from EPA FIP FR 72548 Table 11, dated December 5, 2012.

Annual SO_2 emissions for each year as well as cumulative emissions are presented in Table D-8

Table D-8: Annual SO_2 Emissions for 2011 AZ SIP 2016 through 2046 (tons)

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	844	1,807	1,966	2,688	7,305	7,305
2017	844	1,807	1,966	2,688	7,305	14,610
2018	844	1,807	1,966	2,688	7,305	21,915
2019	844	1,807	1,966	2,688	7,305	29,220
2020	844	1,807	1,966	2,688	7,305	36,525
2021	844	1,807	1,966	2,688	7,305	43,830
2022	844	1,807	1,966	2,688	7,305	51,135
2023	844	1,807	1,966	2,688	7,305	58,440
2024	844	1,807	1,966	2,688	7,305	65,745
2025	844	1,807	1,966	2,688	7,305	73,050
2026	844	1,807	1,966	2,688	7,305	80,355
2027	844	1,807	1,966	2,688	7,305	87,660
2028	844	1,807	1,966	2,688	7,305	94,965
2029	844	1,807	1,966	2,688	7,305	102,270
2030	844	1,807	1,966	2,688	7,305	109,575
2031	844	1,807	1,966	2,688	7,305	116,880
2032	844	1,807	1,966	2,688	7,305	124,185
2033	844	1,807	1,966	2,688	7,305	131,490
2034	844	1,807	1,966	2,688	7,305	138,795
2035	844	1,807	1,966	2,688	7,305	146,100
2036	844	1,807	1,966	2,688	7,305	153,405
2037	844	1,807	1,966	2,688	7,305	160,710
2038	844	1,807	1,966	2,688	7,305	168,015
2039	844	1,807	1,966	2,688	7,305	175,320
2040	844	1,807	1,966	2,688	7,305	182,625
2041	844	1,807	1,966	2,688	7,305	189,930
2042	844	1,807	1,966	2,688	7,305	197,235
2043	844	1,807	1,966	2,688	7,305	204,540
2044	844	1,807	1,966	2,688	7,305	211,845
2045	844	1,807	1,966	2,688	7,305	219,150
2046	844	1,807	1,966	2,688	7,305	226,455

D-4 Annual PM_{10} Emission Calculations

D-4-1 PM_{10} Emissions Cholla BART Reassessment

Emission factors and annual capacity factors for the Cholla BART Reassessment are shown in Table D-9.

2016: Unit 2 Shutdown by April 1, 2016

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.015 [1]	1,494 [1]	86% [1]	84.4
Unit 2	0.026 [3]	3,022 [2]	91% [2]	78.0
Unit 3	0.015 [2]	3,480 [2]	86% [2]	196.6
Unit 4	0.015 [2]	4,399 [2]	93% [2]	268.8

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.
[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4, are from EPA FIP FR 72548 Table 11,dated December 5, 2012.
[3] Emission factors for Unit 2 are from Cholla application.

2017 – 2025: Unit 2 shutdown

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.015 [1]	1,494 [1]	86% [1]	84.4
Unit 2				0
Unit 3	0.015 [2]	3,480 [2]	86% [2]	196.6
Unit 4	0.015 [2]	4,399 [2]	93% [2]	268.8

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application
[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4, are from EPA FIP FR 72548 Table 11, dated December 5, 2012.

2026 – 2046: Units 1, 3 and 4 on Natural Gas, Unit 2 Shutdown

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.01 [1]	1,494 [1]	20% [1]	13.1
Unit 2				0
Unit 3	0.01 [1]	3,480 [2]	20% [1]	30.5
Unit 4	0.01 [1]	4,399 [2]	20% [1]	38.5

[1] Emission factor, heat input and annual capacity factor for Unit 1, and emission factors and capacity factors for Units 3 and 4 are based on the information in Cholla application.
[2] Heat inputs for Units 2, 3 and 4 are taken from EPA FIP FR 72548 Table 11, dated December 5, 2012.

Annual PM_{10} emissions for each year as well as cumulative emissions are presented in Table D-10.

Table D-10: Cholla BART Reassessment Annual PM_{10} Emissions for 2016 through 2046 (tons)

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	84	78	197	269	628	628
2017	84	0	197	269	550	1,178
2018	84	0	197	269	550	1,728
2019	84	0	197	269	550	2,278
2020	84	0	197	269	550	2,828
2021	84	0	197	269	550	3,378
2022	84	0	197	269	550	3,928
2023	84	0	197	269	550	4,478
2024	84	0	197	269	550	5,028
2025	84	0	197	269	550	5,578
2026	13	0	30	39	82	5,660
2027	13	0	30	39	82	5,742
2028	13	0	30	39	82	5,824
2029	13	0	30	39	82	5,906
2030	13	0	30	39	82	5,988
2031	13	0	30	39	82	6,070
2032	13	0	30	39	82	6,152
2033	13	0	30	39	82	6,234
2034	13	0	30	39	82	6,316
2035	13	0	30	39	82	6,398
2036	13	0	30	39	82	6,480
2037	13	0	30	39	82	6,562
2038	13	0	30	39	82	6,644
2039	13	0	30	39	82	6,726
2040	13	0	30	39	82	6,808
2041	13	0	30	39	82	6,890
2042	13	0	30	39	82	6,972
2043	13	0	30	39	82	7,054
2044	13	0	30	39	82	7,136
2045	13	0	30	39	82	7,218
2046	13	0	30	39	82	7,300

D-4-2 PM_{10} Emissions 2011 AZ SIP

Emission factors and annual capacity factors for the 2011 AZ SIP are shown in Table D-11.

Table D-11: Annual PM_{10} Emission Calculations for2011 AZ SIP

2016: Coal Firing

Unit Number	Emission Factor)	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.015[1]	1,494[1]	86%[1]	84
Unit 2	0.026[2]/0.015[3]	3,022[3]	91%[3]	214
Unit 3	0.015[3]	3,480[3]	86%[3]	197
Unit 4	0.015[3]	4,399[3]	93%[3]	269

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.

[2] Per Cholla application, 0.026 lb/MMBtu is used for Unit 2 prior to April 1, 2016.

[3]Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4 are from EPA FIP FR 72548 Table 11, dated December 5, 2012.

2017 – 2046: Coal Firing

Unit Number	Emission Factor	Heat Input	Annual Capacity Factor	Annual Emissions
	lb/MMBtu	MMBtu/hr	%	tons
Unit 1	0.015 [1]	1,494 [1]	86% [1]	84
Unit 2	0.015 [2]	3,022 [2]	91% [2]	181
Unit 3	0.015 [2]	3,480 [2]	86% [2]	197
Unit 4	0.015 [2]	4,399 [2]	93% [2]	269

[1] Emission factor, heat input and annual capacity factor for Unit 1 are based on the information in Cholla application.

[2] Emission factors for Units 2, 3 and 4 are taken from EPA FIP FR 72515 Table 1; heat input and annual capacity factors for Units 2, 3 and 4 are from EPA FIP FR 72548 Table 11,dated December 5, 2012.

Annual PM_{10} emissions for each year as well as cumulative emissions are presented in Table D-12.

Table D-12: Annual PM_{10} Emissions for 2011 AZ SIP 2016 through 2046

Year	Unit 1	Unit 2	Unit 3	Unit 4	SUM	CUMULATIVE
2016	84	214	197	269	764	764
2017	84	181	197	269	731	1,495
2018	84	181	197	269	731	2,226
2019	84	181	197	269	731	2,957
2020	84	181	197	269	731	3,688
2021	84	181	197	269	731	4,419
2022	84	181	197	269	731	5,150
2023	84	181	197	269	731	5,881
2024	84	181	197	269	731	6,612
2025	84	181	197	269	731	7,343
2026	84	181	197	269	731	8,074
2027	84	181	197	269	731	8,805
2028	84	181	197	269	731	9,536
2029	84	181	197	269	731	10,267
2030	84	181	197	269	731	10,998
2031	84	181	197	269	731	11,729
2032	84	181	197	269	731	12,460
2033	84	181	197	269	731	13,191
2034	84	181	197	269	731	13,922
2035	84	181	197	269	731	14,653
2036	84	181	197	269	731	15,384
2037	84	181	197	269	731	16,115
2038	84	181	197	269	731	16,846
2039	84	181	197	269	731	17,577
2040	84	181	197	269	731	18,308
2041	84	181	197	269	731	19,039
2042	84	181	197	269	731	19,770
2043	84	181	197	269	731	20,501
2044	84	181	197	269	731	21,232
2045	84	181	197	269	731	21,963
2046	84	181	197	269	731	22,694

D-5 Emission Comparison – Cholla BART Reassessment vs. Applicable 2011 AZ SIP / EPA FIP

Table D-13 provides cumulative emissions for the Cholla BART Reassessment vs. the applicable 2011 AZ SIP/EPA FIP.

Table D-13: Annual and Cumulative NOx, SO_2 and PM_{10} Emissions (tons)

Year	BART Reassessment Cumulative NOx	EPA FIP Cumulative NOx	BART Reassessment Cumulative SO_2	2011 AZ SIP Cumulative SO_2	BART Reassessment Cumulative PM_{10}	2011 AZ SIP Cumulative PM_{10}
2016	8,345	11,046	5,950	7,305	628	764
2017	15,790	22,093	11,448	14,610	1,178	1,495
2018	23,234	25,377	16,946	21,915	1,728	2,226
2019	30,679	28,662	22,444	29,220	2,278	2,957
2020	38,124	31,947	27,942	36,525	2,828	3,688
2021	45,569	35,231	33,440	43,830	3,378	4,419
2022	53,014	38,516	38,938	51,135	3,928	5,150
2023	60,459	41,801	44,436	58,440	4,478	5,881
2024	67,903	45,085	49,934	65,745	5,028	6,612
2025	75,348	48,370	55,432	73,050	5,578	7,343
2026	76,005	51,655	55,437	80,355	5,660	8,074
2027	76,662	54,939	55,442	87,660	5,742	8,805
2028	77,319	58,224	55,447	94,965	5,824	9,536
2029	77,976	61,509	55,452	102,270	5,906	10,267
2030	78,633	64,793	55,457	109,575	5,988	10,998
2031	79,290	68,078	55,462	116,880	6,070	11,729
2032	79,947	71,363	55,467	124,185	6,152	12,460
2033	80,604	74,647	55,472	131,490	6,234	13,191
2034	81,261	77,932	55,477	138,795	6,316	13,922
2035	81,918	81,217	55,482	146,100	6,398	14,653
2036	82,575	84,501	55,487	153,405	6,480	15,384
2037	83,232	87,786	55,492	160,710	6,562	16,115
2038	83,889	91,071	55,497	168,015	6,644	16,846
2039	84,546	94,356	55,502	175,320	6,726	17,577
2040	85,203	97,640	55,507	182,625	6,808	18,308
2041	85,860	100,925	55,512	189,930	6,890	19,039
2042	86,517	104,210	55,517	197,235	6,972	19,770
2043	87,174	107,494	55,522	204,540	7,054	20,501
2044	87,831	110,779	55,527	211,845	7,136	21,232
2045	88,488	114,064	55,532	219,150	7,218	21,963
2046	89,145	117,348	55,537	226,455	7,300	22,694

Appendix E

Supplemental Visibility Analysis for Long-Term Benefits of the Proposed BART Reassessment

E-1 Overview of Approach

The visibility impact analysis presented in the Cholla BART Reassessment Section 2.2.5 focuses on the "2018 milestone year." However, to support the CAA Section 110(l) analysis, APS and PacifiCorp have conducted additional modeling to compare long-term visibility impact benefits of the Cholla BART Reassessment with those of the EPA FIP for the period of 2016 to 2046. Year 2016 was selected as the starting year for comparison purposes because, prior to 2016, there is no difference in visibility impacts between the Cholla BART Reassessment and the FIP. Further, to simplify the visibility analysis, the modeling neglected the difference between the EPA FIP and the Cholla BART Reassessment during 2016-2017 and focused the comparison for the period of 2018 to 2046. In fact, the Cholla BART Reassessment will achieve greater visibility improvement than the EPA FIP during 2016-2017, since the EPA FIP imposes additional controls at Unit 2 while Cholla BART Reassessment proposes to permanently shut down Unit 2.

This document provides a comparison of integrated visibility impact benefits of the Cholla BART Reassessment to the EPA FIP for the 2018 to 2046 period. Detailed modeling Scenarios for long-term visibility improvement from Cholla BART Reassessment vs. EPA FIP are shown in Table E-1.

Table E-1: Modeling Scenarios for Long-term Visibility Improvement from EPA FIP vs. Cholla BART Reassessment

	Time Period	Modeling Scenarios
EPA FIP	2018-2046	SCR with LNB/SOFA controls for Units 2, 3, and 4 and LNB/SOFA controls for Unit 1; FGD systems for Units 2, 3 and 4; New baghouses for Units 2, 3, and 4.
Cholla BART Reassessment	2018-2025	LNB/SOFA controls for Units 1, 3, and 4; FGD systems for Units 3 and 4; New baghouses for Units 3 and 4; Unit 2 is shutdown.
	2026-2046	Units 1, 3, and 4 are operated on natural gas with a 20 percent annual average capacity factor; Unit 2 is shutdown.

E-2 CALPUFF Modeling Input Data

The supplemental visibility assessment to compute the haze impact was conducted with the CALPUFF model version 5.8 in the manner approved and used by EPA in its FIP. The CALPUFF modeling involved meteorological data for the years 2001-2003, an assumption of 1.0 part per billion background ammonia concentration, and "Method 8b" 20 percent best days background conditions for all cases.

The visibility impacts were predicted at the thirteen Class I areas within 300 km of Cholla. Table E-2 lists the exhaust parameters. Tables E-3, E-4 and E-5 list input emissions data for different modeling scenarios.

Table E-2: Modeled Stack Exhaust Parameters

Unit	Fuel	GEP Creditable Stack Height (m)	Stack Elevation (m)	Stack Diameter (m)	Stack Temperature (K)	Exit Velocity (m/s)
Unit 1	Coal	76.20	1533	3.43	322.0	20.73
Unit 2&3 Merged	Coal	144.81	1530	6.88	396.0	29.60
Unit 3	Coal	144.81	1530	5.23	322.0	22.25
Unit 4	Coal	167.64	1530	5.85	324.0	23.50
Unit 1	Natural Gas	76.20	1533	3.43	405.4	19.66
Unit 2	Natural Gas	144.81	1530	4.47	405.4	25.91
Unit 3	Natural Gas	144.81	1530	5.23	405.4	19.78
Unit 4	Natural Gas	167.64	1530	5.85	405.4	22.19

Table E-3: Modeling Emissions for the 2018 to 2025 Period: SO_2 Controls, PM_{10} Emission Reductions, LNB & SOFA on Units 1, 3, and 4, Unit 2 Shut Down (BART Reassessment Modeling Case)

Unit	Fuel	NOx Controls	NOx Max Daily	Max. Daily Heat Input for SO2 and PM	SO2 Emission Factor	SO2 Max Daily	PM10 filt Emission Factor	PM10 filt Max Daily	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	MMBtu/hr	lb/MMBtu	lb/hr	lb/MMBtu	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1 [(a)]	Coal	LNB & SOFA	371[(b)]	1,494[(a)]	0.150	224.1	0.015	22.41	46.68	28.24	2.82	0.81[(e)]	1.94[(e)]	0.07[(e)]	0.32[(e)]	0.08[(e)]
Unit 2	Shutdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit 3	Coal	LNB & SOFA	799[(b)]	3,480[(c)]	0.150[(d)]	522.0	0.015[(d)]	52.20	100.61	65.77	6.58	3.29 [(f)]	3.17[(f)]	0.12[(f)]	5.55[(f)]	1.39[(f)]
Unit 4	Coal	LNB & SOFA	1,101[(b)]	4,399[(c)]	0.150[(d)]	659.9	0.015[(d)]	65.99	138.70	83.14	8.31	4.16 [(f)]	4.00[(f)]	0.15[(f)]	7.01[(f)]	1.75[(f)]

(a) Unit 1 is not BART eligible. Assumed LNB+SOFA based on further reasonable progress. Heat input is based on EPA's max daily heat input rate over 2008-2010 period for Unit 1. Table 2-A(a) "Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 8: Five-Factor BART Analysis for AEPCO Apache, APS Cholla and SRP Coronado". July 16, 2012.
(b) See Table C-2 to C-5 in Appendix C.
(c) Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72548).
(d) EPA BART rule (Table 1, 77 FR 72515).
(e) PM speciation based on the National Park Service spreadsheet for coal-fired boilers with a wet scrubber http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPCScrubberPmSpeciationProfile.xls
(f) PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+FF http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_FFpmSpeciationProfile.xls

Table E-4: Modeling Emissions for the 2018 to 2046 Period: LNB & SOFA on Unit 1, Baghouses, FGD, LNB & SOFA, and SCR on Units 2, 3, and 4 (EPA FIP Modeling Case)

Unit	Fuel	NOx Controls	NOx Max Daily	Max. Daily Heat Input for SO2 and PM	SO2 Emission Factor	SO2 Max Daily	PM10 filt Emission Factor	PM10 filt Max Daily	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			lb/hr	lb/hr	lb/hr	lb/hr	lb/MMBtu	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1[(a)]	Coal	LNB & SOFA	371[(b)]	1,494[(a)]	0.150[(d)]	224.1	0.015	22.41	46.68	28.24	2.82	0.81	1.94	0.07	0.32	0.08
Unit 2	Coal	LNB & SOFA and SCR	243[(b)]	3,022[(c)]	0.150[(d)]	453.3	0.015[(d)]	45.33	30.64	57.12	5.71	2.86[(e)]	2.75[(e)]	0.11[(e)]	4.82[(e)]	1.20[(e)]
Unit 3	Coal	LNB & SOFA and SCR	189[(b)]	3,480[(c)]	0.150[(d)]	522.0	0.015[(d)]	52.20	23.84	65.77	6.58	3.29[(e)]	3.17[(e)]	0.12[(e)]	5.55[(e)]	1.39[(e)]
Unit 4	Coal	LNB & SOFA and SCR	275[(b)]	4,399[(c)]	0.150[(d)]	659.9	0.015[(d)]	65.99	34.67	83.14	8.31	4.16[(e)]	4.00[(e)]	0.15[(e)]	7.01[(e)]	1.75[(e)]

(a) Unit 1 is not BART eligible. Assumed LNB+SOFA based on further reasonable progress. Heat input is based on EPA's max daily heat input rate over 2008-2010 period for Unit1. Table 2-A(a) "Technical Analysis for Arizona and Hawaii Regional Haze FIPs: Task 8: Five-Factor BART Analysis for AEPCO Apache, APS Cholla and SRP Coronado". July 16, 2012.
(b) See Table C-2 to C-5 in Appendix C
(c) Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72548).
(d) EPA BART rule (Table 1, 77 FR 72515).
(e) PM speciation based on the National Park Service spreadsheet for coal-fired boilers with FGD+FF http://www.nature.nps.gov/air/permits/ect/docs/coalBoiler/2006FinalDryBottomPC_FGD_FFpmSpeciationProfile.xls

Table E-5: Modeling Emissions for the 2026 to 2046 Period: LNB & SOFA on Units 1, 3, and 4, Unit 2 Shut Down, Natural Gas (BART Reassessment Modeling Case)

Unit	Fuel	NOx Controls	Heat Input	NOx Emission	SO2 Emission	PM10 total	NOx	SO2	PM10	NOx	SO2	PM	PMC	PMF	EC	SO4	SOA
			MMBtu/hr	lb/MMBtu	lb/MMBtu	lb/MMBtu	lb/hr	lb/hr	lb/hr	g/s	g/s	g/s	g/s	g/s	g/s	g/s	g/s
Unit 1	NG	NG	1411 (a)	0.080 (c)	0.0006 (c)	0.010 (c)	135.4 (e)	0.85	14.11	17.07	0.11	1.78	0.00 (d)	0.00 (d)	0.44 (d)	0.05 (d)	1.28 (d)
Unit 2	Shutdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Unit 3	NG	NG	3480 (b)	0.080 (c)	0.0006 (c)	0.010 (c)	302.75	2.09	34.80	38.15	0.26	4.38	0.00 (d)	0.00 (d)	1.10 (d)	0.13 (d)	3.16 (d)
Unit 4	NG	NG	4399 (b)	0.080 (c)	0.0006 (c)	0.010 (c)	440.30	2.64	43.99	55.48	0.33	5.54	0.00 (d)	0.00 (d)	1.39 (d)	0.17 (d)	3.99 (d)

(a) Maximum daily heat input in the 2001 to 2003
(b) Heat rate is consistent with EPA BART rule (Table 11, 77 FR 72515).
(c) NOx and SO2 are based on future expected 30 boiler operating day permit limits. PM is based on expected short term permit limit (stack test)
(d) PM speciation based on the National Park Service spreadsheet for natural gas-fired boilers http://www.nature.nps.gov/air/permits/ect/docs/gasCT/EdRevConsensusGasCTexample.xls
(e) Unit 1 NOx is based on 1) the maximum daily heat input, 2) the expected 30 boiler operating day permit limit, and 3) a 20% margin to estimate the maximum daily lb/MMbtu emission limit.

E-3 CALPUFF Modeling Results

Table E-6 summarizes the 2001-2003 3-year average modeling results for all modeled cases and Class I areas. The results from Table E-6 were used to construct a timeline of cumulative visibility impacts in delta-deciviews for the period of 2018-2046.

The modeled FIP cumulative visibility impact (shown by the red solid line) is compared against the cumulative visibility impact associated with the BART Reassessment proposed controls (shown as blue dashed line), and presented in a the time-integrated graphical form in Figure E-1 for Petrified Forest National Park. The results for the other twelve Class I areas are plotted in Figures E-2 through E-13.

As shown in Figures E-1, the EPA FIP (the red curve) has lower integrated visibility impacts than the Cholla BART Reassessment (the blue curve) at the initial time period. The two curves then intersect at a certain point after the natural gas conversion in 2025. After that, the Cholla BART Reassessment shows greater integrated visibility improvements through 2046. Overall, the long-term visibility benefits are greater with the Cholla BART Reassessment than the EPA FIP. The general pattern of the integrated visibility results for the other twelve Class I areas is similar to that for Petrified Forest National Park (see Figures E-2 through E-13).

Table E-6: Predicted Visibility Impacts at Class I Areas Associated with EPA FIP vs. Cholla BART Reassessment

Class I Areas	EPA FIP	Cholla BART Reassessment	
	2018-2046	2018-2025	2026-2046
Petrified Forest NP	2.64	3.75	1.45
Grand Canyon NP	1.11	1.48	0.45
Capitol Reef NP	0.62	0.92	0.29
Mazatzal W A	0.75	0.83	0.30
Sycamore Canyon WA	0.73	0.94	0.29
Mount Baldy WA	0.69	0.87	0.28
Gila WA	0.46	0.47	0.17
Sierra Ancha WA	0.82	0.94	0.36
Mesa Verde NP	0.63	0.84	0.30
Galiuro WA	0.29	0.30	0.09
Superstition WA	0.73	0.88	0.30
Saguaro NP	0.20	0.19	0.05
Pine Mountain WA	0.51	0.58	0.17
Cumulative impacts over thirteen Class I Areas	10.18	12.99	4.50

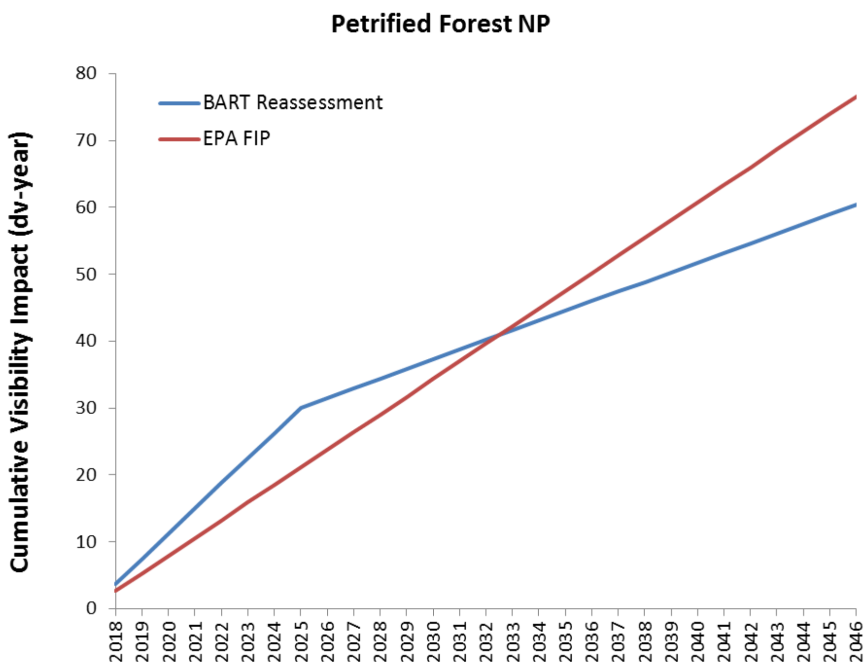

Figure E-1: Plot of Predicted Cumulative Visibility Impacts at Petrified Forest National Park Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

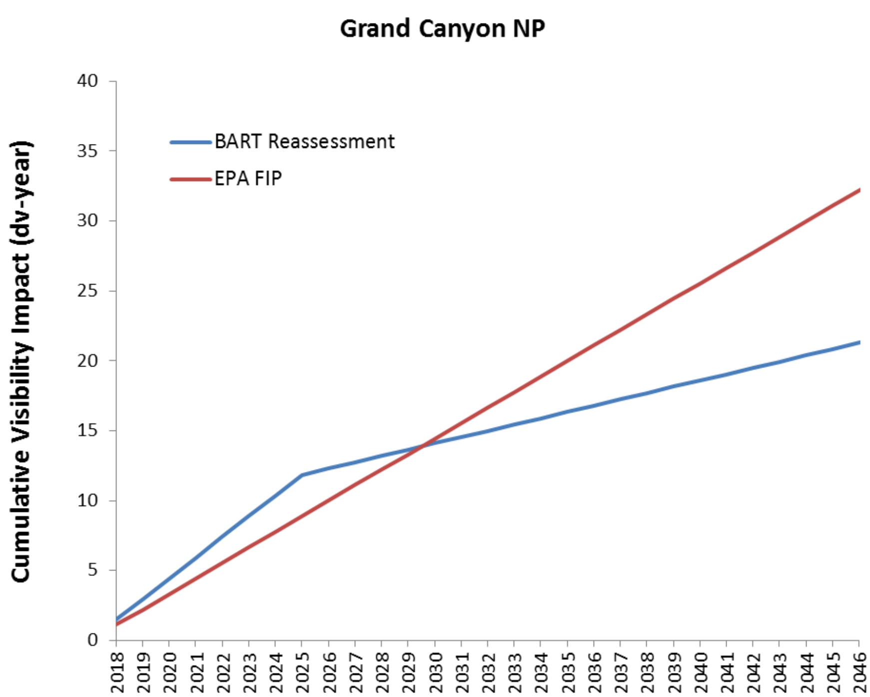

Figure E-2: Plot of Predicted Cumulative Visibility Impacts at Grand Canyon National Park Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

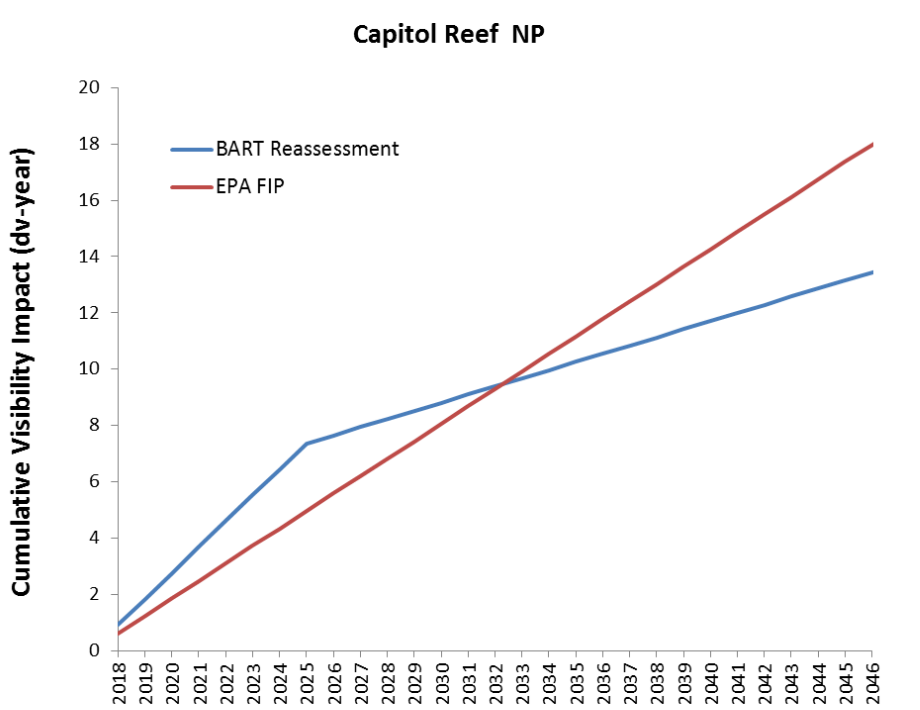

Figure E-3: Plot of Predicted Cumulative Visibility Impacts at Capitol Reef National Park Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

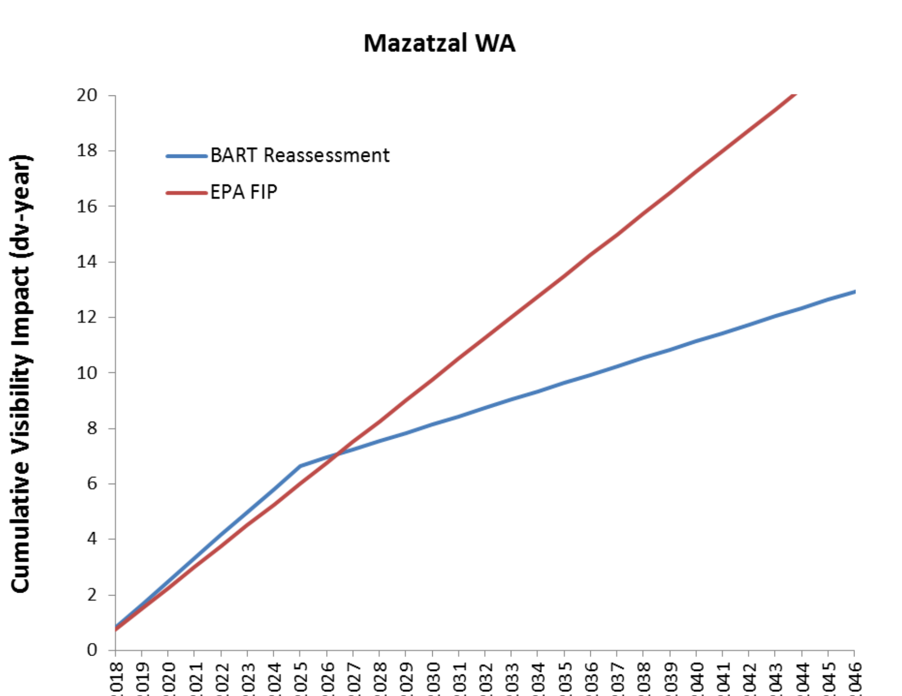

Figure E-4: Plot of Predicted Cumulative Visibility Impacts at Mazatzal Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

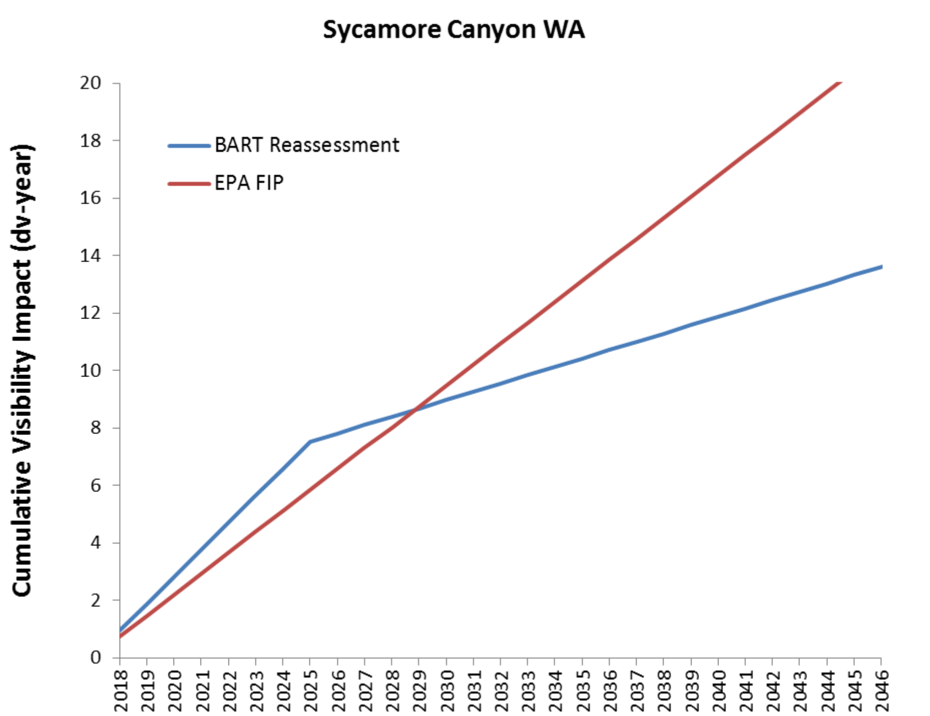

Figure E-5: Plot of Predicted Cumulative Visibility Impacts at Sycamore Canyon Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

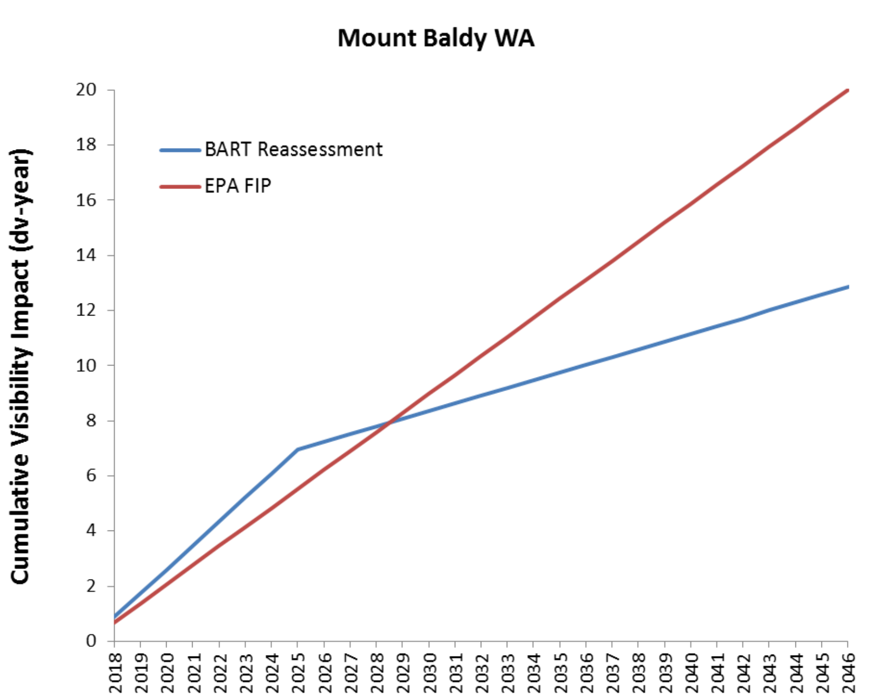

Figure E-6: Plot of Predicted Cumulative Visibility Impacts at Mount Baldy Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

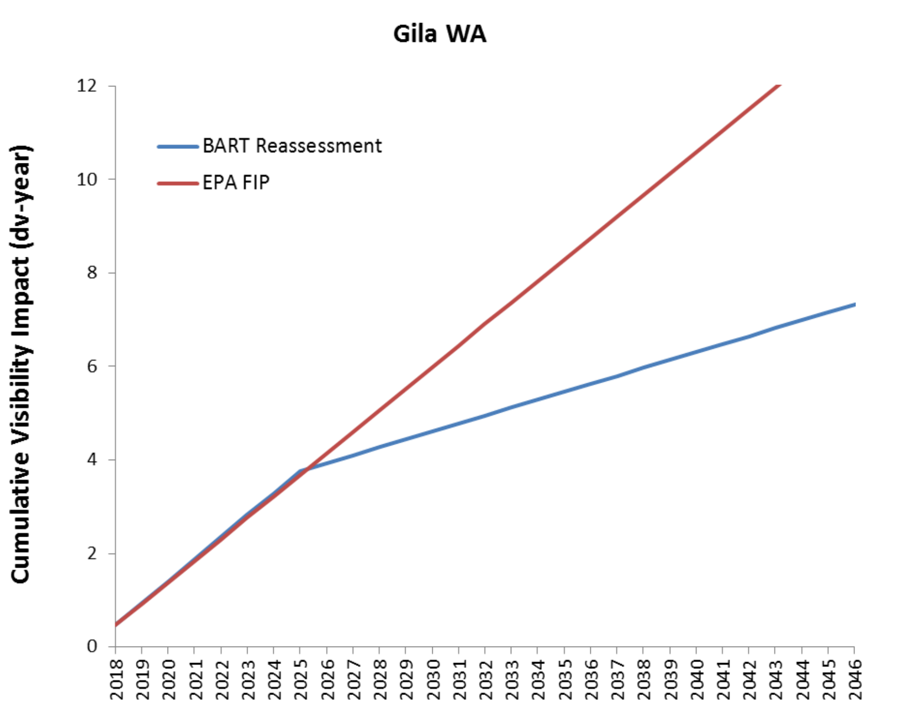

Figure E-7: Plot of Predicted Cumulative Visibility Impacts at Gila Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

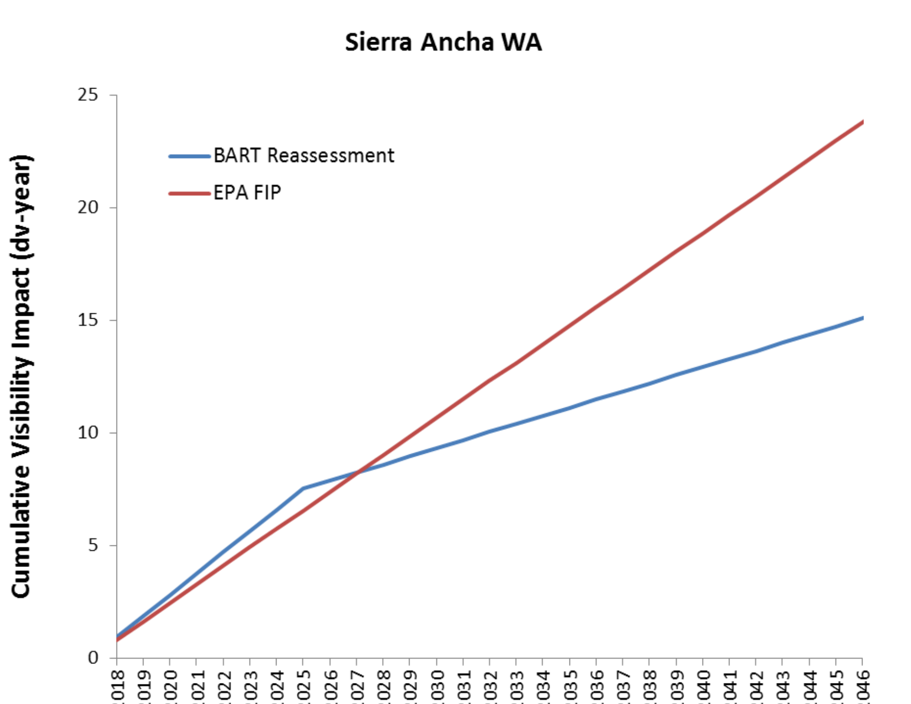

Figure E-8: Plot of Predicted Cumulative Visibility Impacts at Sierra Ancha Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

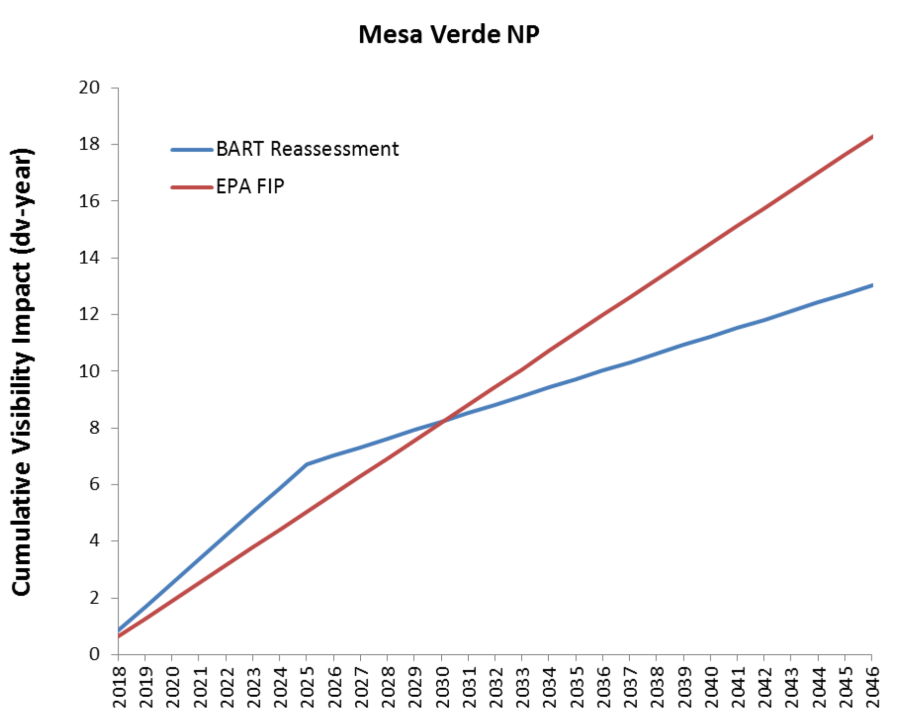

Figure E-9: Plot of Predicted Cumulative Visibility Impacts at Mesa Verde National Park Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

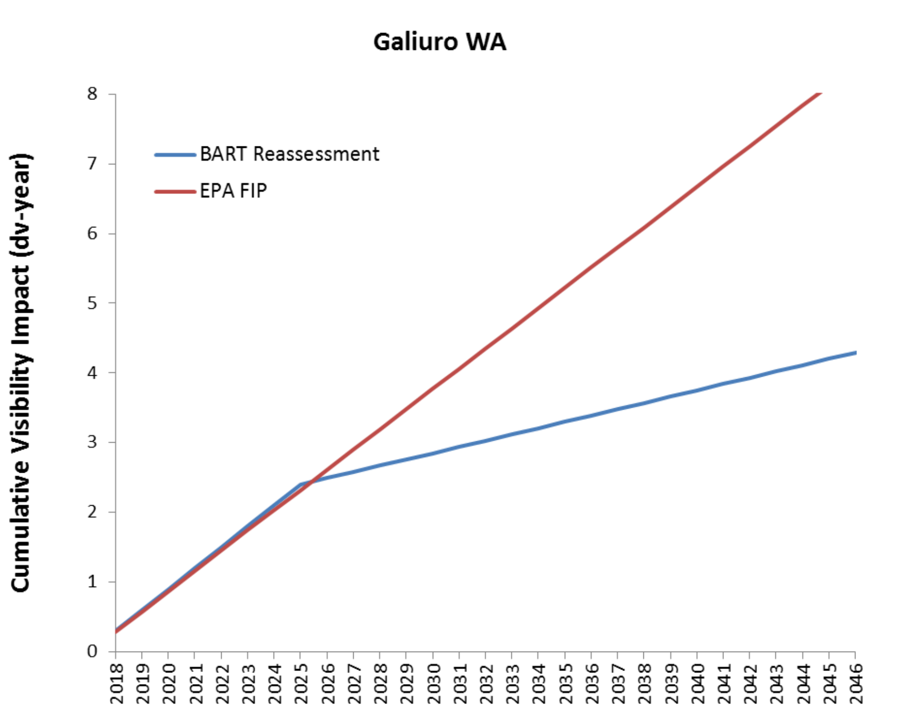

Figure E-10: Plot of Predicted Cumulative Visibility Impacts at Galiuro Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

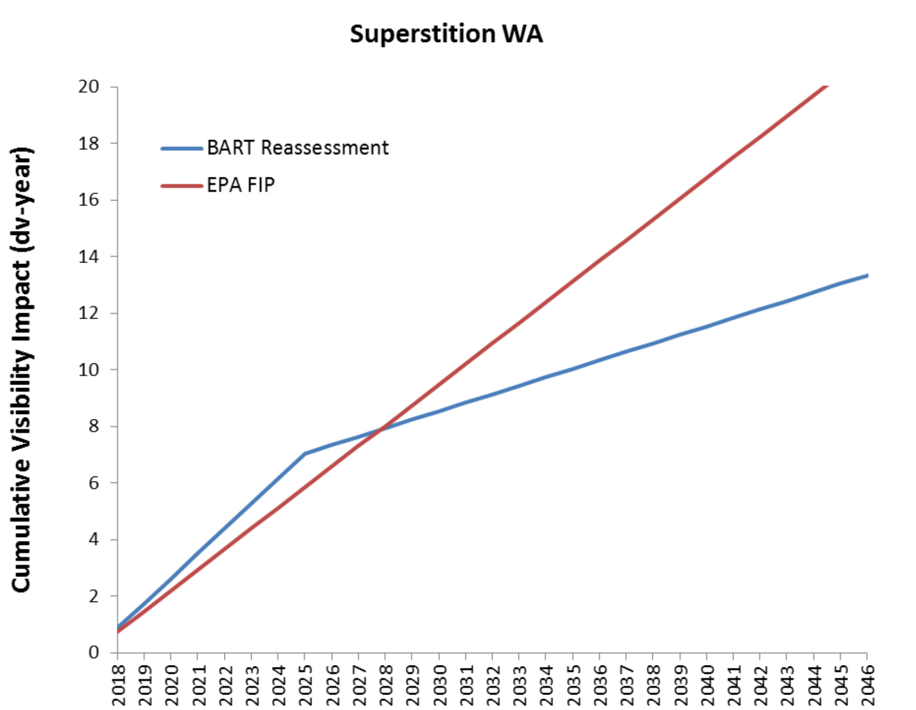

Figure E-11: Plot of Predicted Cumulative Visibility Impacts at Superstition Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

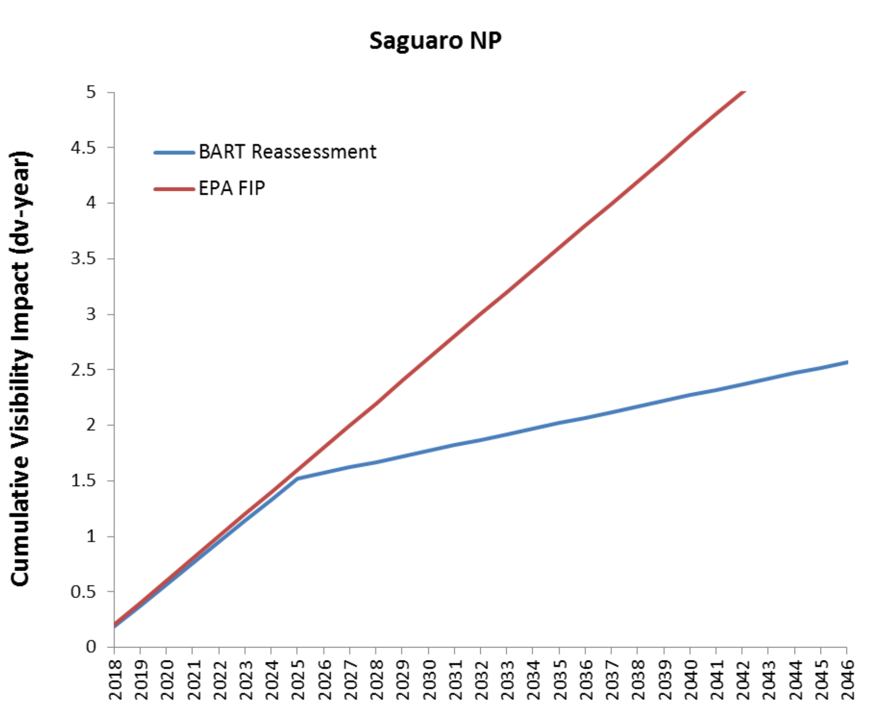

Figure E-12: Plot of Predicted Cumulative Visibility Impacts at Saguaro National Park Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)

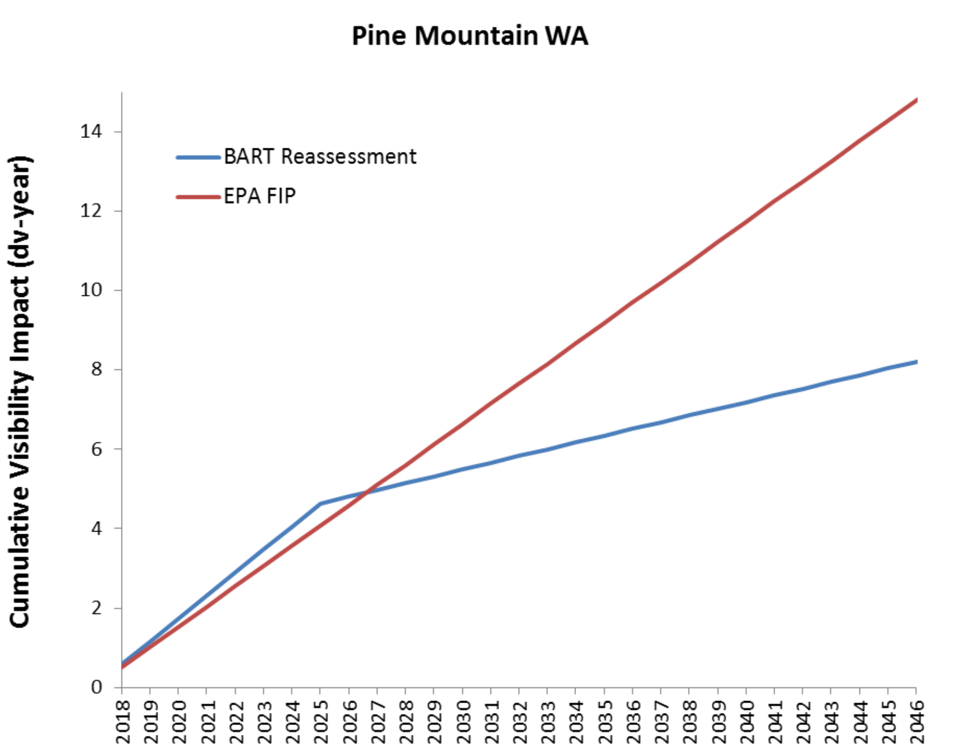

Figure E-13: Plot of Predicted Cumulative Visibility Impacts at Pine Mountain Wilderness Associated with EPA FIP (red) vs. Proposed BART Reassessment (blue)