

Proposed Rule: Approval and Promulgation of Air Quality Implementation Plans; State of Nevada; Regional Haze State and Federal Implementation Plans

**Technical Support Document (TSD)
Docket Number: EPA-R09-OAR-2011-0130**

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1. Relationship of this TSD to our Proposal

In a letter dated November 18, 2009, Nevada Division of Environmental Protection (NDEP) submitted the “Nevada Regional Haze State Implementation Plan” (Nevada RH SIP) to U.S. Environmental Protection Agency (EPA), Region 9. This SIP addressed regional haze program requirements for the first planning period through July 31, 2018. On June 22, 2011 (76 FR 36450), we proposed approval of the Nevada RH SIP. On December 13, 2011 we finalized approval of all elements of the Nevada RH SIP with the exception of the NOx BART determination for the Reid Gardner Generating Station.¹ As a result of certain comments received during the public comment period for the proposed approval, we took no action on this element of the RH SIP in order to perform additional analysis and supplement the administrative record. The results of our analysis support NDEP’s selection of control technology (ROFA with Rotamix). As a result, we are proposing to approve certain remaining elements of the RH SIP as listed in Table 1 below. In addition, there are certain SIP elements that we are not approving. For those elements, we are also proposing a Federal Implementation Plan (FIP).

Table 1. Approved Elements of RH SIP

| Unit | Plan Element | SIP | Approved? | FIP |
|------|--|------------------|-----------|----------------|
| 1 | Emission Limit (lb/MMBtu) ¹ | 0.20 | Y | |
| | Averaging Period | 12-month rolling | N | 30-day rolling |
| 2 | Emission Limit (lb/MMBtu) ¹ | 0.20 | Y | |
| | Averaging Period | 12-month rolling | N | 30-day rolling |
| 3 | Emission Limit (lb/MMBtu) ¹ | 0.28 | N | 0.20 |
| | Averaging Period | 12-month rolling | N | 30-day rolling |

¹ Although the emission limits are listed separately for each unit, compliance with the emission limits is determined based on a unit-wide average (heat input weighted)

This document provides technical information to support the proposed approval, and discuss the basis for our proposed disapproval and FIP. It provides additional information regarding the technical aspects of our proposed disapproval which we regard as too detailed for inclusion in the Federal Register notice. Specifically, this document contains our analysis of the two factors of the BART analysis that we consider most crucial to this approval, costs of

¹ 77 FR 17334

compliance and degree of visibility improvement. It also contains our rationale for disapproving the elements listed in Table 1, and the corresponding FIP element. The remaining sections of this TSD are numbered as follows:

- Section 2 – Background on Regional Haze and BART Requirements
- Section 3 – Reid Gardner NO_x BART Determination
- Section 4 – Costs of Compliance
- Section 5 – Degree of Visibility Improvement
- Section 6 – FIP elements

Please note that in this document, we often use language such as “we find” or other similar phrases that on the surface suggest a final determination has been made. However, the information presented in this TSD should be considered part of our proposal and subject to change based on comments and other additional information we may receive during the public comment period for this proposal.

2. Background on Regional Haze and BART Requirements

Our June 22, 2011 proposed approval of the Nevada RH SIP contains a general discussion of regional haze and EPA’s Regional Haze Rule (RHR), including BART requirements (76 FR at 36451-36455). The RHR provides the following six factors that a BART determination must take into account (40 CFR 51.308(e)(1)(ii)(A)):

- the available technology to control emissions and the technical feasibility of each technology;
- the cost of compliance for the technically feasible control technologies;
- the energy and non-air quality impacts of the control technologies;
- any existing air pollution control technologies at the source;
- the remaining useful life of the source; and
- the degree of visibility improvement which may reasonably be anticipated to result from the various control technologies.

All but the first of these factors are also expressly required to be taken into account under Section 169A(g)(2) of the Clean Air Act (CAA), 42 U.S.C. § 7491(g)(2). Although we list six factors, the first factor is not always explicitly stated and the remaining factors are frequently referred to as the “five-factor analysis” for the RHR BART determination.

3. Reid Gardner NO_x BART Determination

A. NDEP’s Analysis

RGGS consists of four coal-fired boilers, three of which are BART-eligible units with generating capacity of 100 megawatts (MW) each. A fourth unit (250 MW) is not BART-eligible. The units are wall-fired pulverized coal boilers that consume primarily bituminous coal, but currently also burn some Wyoming sub-bituminous coal. Nevada Energy, the owner of RGGS, performed a BART analysis for the three BART-eligible RGGS units and submitted the results of its analysis to NDEP and recommended new LoNO_x burners and 0.39 lb/MMbtu as

BART.² NDEP reviewed but disagreed with Nevada Energy's analysis and NDEP determined that, for each unit, rotating overfire air (ROFA) with Rotamix (a technology that combines a conventional selective non-catalytic reduction [SNCR] system with a proprietary injection system for air and reagent) was BART for NO_x.³ NDEP eliminated the next most effective control technologies, which consist of selective catalytic reduction (SCR)-based options, on the grounds that "the \$/ton of NO_x removed increased significantly . . . without correspondingly significant improvements in visibility."⁴

B. EPA's Analysis

Based upon comments received during the public comment period for our June 22, 2011 proposal, we conducted additional review of the five-factor analysis performed by NDEP. During the course of this review, we identified several aspects of NDEP's analysis that we considered either inconsistent with our regulations under 51.308(e) or unsupported by the record. As a result, we performed our own analysis in order to revise these inconsistencies and supplement the record with additional visibility modeling. Costs of compliance and degree of visibility improvement were the two statutory factors most crucial to our analysis, and are discussed at length in the remainder of this document.

In our analysis of costs of compliance, we find that control options more stringent than ROFA with Rotamix, such as SCR with LNB and OFA, are cost effective on an average and incremental basis. Our analysis of visibility improvement indicates small incremental visibility improvement between ROFA with Rotamix and more stringent control options, such as SCR control options. As a result, we agree that NDEP reasonably determined that the costs of further control are not warranted based on the low incremental visibility improvement.

4. Costs of Compliance

The BART guidelines state that "[i]n order to improve consistency, cost estimates should be based on the *OAQPS Control Cost Manual* [now called the *EPA Air Pollution Control Cost Manual*], where possible." The *EPA Air Pollution Control Cost Manual* (Sixth Edition, January 2002)⁵ provides guidance and methodologies for estimating the cost and economic feasibility of a project, with a nominal accuracy of $\pm 30\%$. The costs that are incorporated into estimates of capital and annual costs by the *Control Cost Manual* (CCM) are outlined in Section 1, Chapter 2⁶, which states that total capital costs may include equipment costs, freight, sales tax, and installation costs. For existing facilities, retrofit costs should also be considered, and may include auxiliary equipment, handling and erection, piping, insulation, painting, site preparation, off-site facilities, engineering, and lost production revenue. Finally, annual costs are estimated from costs of raw materials, maintenance labor and materials, utilities, waste treatment and disposal, replacement materials, overhead, property taxes, insurance, and administrative charges.

A. NDEP's Analysis

² Nevada Energy BART Analysis Reports, completed October 3, 2008. Available in Docket Item No. EPA-R09-OAR-2011-0130-0007.

³ Revised NDEP Reid Gardner BART Determination Review, available as Docket Item No. EPA-R09-OAR-2011-0130-0005.

⁴ *Id.* at page 6.

⁵ <http://epa.gov/ttn/catc/products.html#cccinfo>

⁶ Section 1: Introduction, Chapter 2: Cost Estimation: Concepts and Methodology, EPA/452/B-02-001, (01/2002)

In evaluating this factor, NDEP developed cost effectiveness values for each NOx control technology on an average and incremental basis. A summary of these values for Reid Gardner Units 1 through 3, as included in the RH SIP, are summarized in Table 2 below.

Table 2. NDEP Control Cost Effectiveness Summary

| Control Option | Control Efficiency ¹ (%) | Emission Rate ¹ (lb/ MMBtu) | Emission Reduction ¹ (ton/yr) | Annualized Costs ¹ (\$MM) | Average Cost Effectiveness ¹ (\$/ton) | Incremental Cost Effectiveness ¹ (\$/ton) |
|----------------------------|--|---|---|---|---|---|
| Reid Gardner Unit 1 | | | | | | |
| LNB + OFA | 21.3% | 0.36 | 483 | \$0.55 | \$1,143 | \$1,143 |
| LNB + OFA + SNCR | 40.9% | 0.27 | 927 | \$1.13 | \$1,222 | \$1,308 |
| ROFA + Rotamix | 57.7% | 0.2 | 1308 | \$1.45 | \$1,109 | \$833 |
| SCR + LNB + OFA | 81.6% | 0.085 | 1850 | \$4.75 | \$2,566 | \$6,085 |
| SCR + ROFA ³ | 81.6% | 0.085 | 1850 | \$5.39 | \$2,916 | \$7,280 |
| Reid Gardner Unit 2 | | | | | | |
| LNB + OFA | 23.7% | 0.355 | 580 | \$0.55 | \$952 | \$952 |
| LNB + OFA + SNCR | 42.7% | 0.267 | 1044 | \$1.16 | \$1,106 | \$1,299 |
| ROFA + Rotamix | 59.0% | 0.19 | 1443 | \$1.50 | \$1,038 | \$860 |
| SCR + LNB + OFA | 82.2% | 0.083 | 2010 | \$4.80 | \$2,386 | \$5,813 |
| SCR + ROFA ³ | 82.2% | 0.083 | 2010 | \$5.47 | \$2,721 | \$7,001 |
| Reid Gardner Unit 3 | | | | | | |
| LNB + OFA | 6.5% | 0.42 | 147 | \$0.55 | \$3,742 | \$3,742 |
| LNB + OFA + SNCR | 29.9% | 0.316 | 678 | \$1.08 | \$1,596 | \$1,000 |
| ROFA + Rotamix | 38.0% | 0.278 | 869 | \$1.38 | \$1,588 | \$1,560 |
| SCR + LNB + OFA | 78.2% | 0.098 | 1774 | \$4.72 | \$2,660 | \$3,688 |
| SCR + ROFA ² | 78.2% | 0.098 | 1774 | \$5.40 | \$3,045 | \$4,444 |

¹ As summarized in Table 1, NDEP Reid Gardner BART Determination, October 22, 2009. Available as Docket Item No. EPA-R09-OAR-2011-0130-0005.

² Incremental cost effectiveness based on ROFA + Rotamix as previous control technology

The annualized costs listed in Table 2 are based on total capital installation costs and certain annual operating costs provided to NDEP by Nevada Energy on October 22, 2008, and were included in the SIP without modification. These cost calculations provided line item summaries of capital costs and annual operating costs, but did not provide further supporting information such as detailed equipment lists, vendor quotes, or the design basis for line item costs.

In its RH SIP, NDEP indicated that it based its NOx BART determination of ROFA with Rotamix primarily on the costs of compliance. NDEP judged the costs of ROFA with Rotamix

as affordable based on an average cost effectiveness of approximately \$1100-1600/ton. NDEP eliminated more stringent control options, such as the SCR-based options, on the grounds that “the \$/ton of NO_x removed increased significantly . . . without correspondingly significant improvements in visibility.” Per NDEP estimates, the incremental cost effectiveness of SCR with LNB and OFA is approximately \$3600-6100/ton. NDEP determined that this additional cost per year for SCR technologies did not appear cost effective compared to the additional NO_x reduction for each unit

B. EPA’s Analysis

In reviewing the Nevada RH SIP, and as a result of several public comments we received, we identified several aspects of NDEP’s approach to this factor with which we disagree, and for which we have performed additional analysis.

We received several public comments alleging that NDEP/Nevada Energy’s cost calculations were unsupported by the record or lacked sufficient detail for critical review. We agree with these comments, and on December 22, 2011 sent a letter to NDEP in which we requested clarification on several items, among which was information that would provide additional detail and justification for control cost estimates.⁷ In response, NDEP provided certain documents, including a set of cost estimates updated in 2011. These updated cost estimates consist of updates to specific line items in order to reflect higher material costs, but did not include any supporting information such as detailed equipment lists, vendor quotes, or the design basis for line item costs.⁸

We also received several public comments alleging that NDEP/Nevada Energy’s cost calculations were overestimated and based on methodology inconsistent with EPA’s Control Cost Manual. In our analysis, we have excluded those costs that are not included in the CCM and adjusted the value of specific variables (e.g., interest rate) to conform to values allowed by the CCM. In particular, the NDEP/Nevada Energy cost estimates included “owner’s costs”, “surcharge”, and “authorization for funds used during construction (AFUDC).” These cost items are not allowed by the CCM, and in certain cases are redundant with “project contingency” costs, which are already included. While the CCM does provide flexibility in including some contingencies (such as degree of retrofit difficulty), neither Nevada Energy nor NDEP has provided documentation to justify the need to include contingency costs beyond standard allowances provided by the CCM. AFUDC is specifically set to zero in the CCM for SCR installations. In addition, we have also revised the interest rate used in calculating the capital recovery factor for annualizing these capital costs. Nevada Energy’s debt service calculations used an interest rate of 8.5% over the lifetime of the project. In our analysis, we have used a 7% interest rate as provided in CCM example calculations.

The public comments we received on the issue of cost calculations also identified other aspects of NDEP/Nevada Energy’s cost estimates that were alleged to be unjustified or overestimated. Examples include a failure to account for multiple unit discount and overestimated reagent costs. Although we agree that the record does not support the positions

⁷ Email dated December 22, 2011 from Colleen McKaughan (EPA) to Mike Elges (NDEP).

⁸ As provided via email dated February 14, 2012 from Rob Bamford (NDEP) to Eugene Chen (EPA)

that NDEP has taken on these cost items, at this time we decline to exclude or refine these items in our revised cost calculations.

Exclusion of costs not included in the CCM results in a decrease of 25-33% in the average and incremental cost effectiveness of the control technology options. Detailed cost calculations, in which we revise the original (as included in the RH SIP) and updated (as provided by NDEP February 14, 2012) cost calculations for each NOx control technology, is included in Appendix A. Summarized in Table 3 below is a comparison of the updated NDEP/Nevada Energy cost calculations (as provided on February 14, 2012) and our revised cost calculations for the SCR with LNB and OFA control technology option.

Table 3. Cost Effectiveness Comparison – SCR with LNB and OFA

| Unit No. | Average Cost Effectiveness (\$/ton) | | Incremental Cost Effectiveness (\$/ton) | |
|----------|-------------------------------------|-------------|---|-------------|
| | NDEP | EPA Revised | NDEP | EPA Revised |
| Unit 1 | \$2,827 | \$2,110 | \$6,370 | \$4,534 |
| Unit 2 | \$2,627 | \$1,967 | \$6,080 | \$4,330 |
| Unit 3 | \$2,932 | \$2,183 | \$3,856 | \$2,756 |

Based on our revised cost estimates for the higher, updated cost estimates provided February 14, 2012, we consider these average and incremental cost effectiveness values for SCR with LNB and OFA to be cost effective.

5. Degree of Visibility Improvement Which May Reasonably be Anticipated to Result from the Use of Such Technology

The BART Guidelines describe 1 deciview (dv)⁹ as the threshold for an impact that “causes” visibility impairment, and 0.5 dv as a threshold for an impact that “contributes” to visibility impairment (70 FR 39118, 39120-39121). The “cause and contribute” threshold is used for the purposes of determining if a BART-eligible source is exempt from BART requirements, or must proceed with a five-factor BART determination. In the context of performing a BART determination and evaluating the degree of visibility improvement, the BART Guidelines indicate that use of a comparison threshold is also an appropriate way of evaluating visibility improvement (70 FR 39129-30), but do not provide a single “bright line” threshold. Consistent with EPA’s BART Guidelines (40 CFR Part 51, Appendix Y, Section III.A.1), we note that Nevada uses the 0.5 dv threshold when considering if a BART-eligible source contributes to visibility impairment.¹⁰ Although use of this 0.5 dv threshold is required only in the context of determining whether a source is subject to BART, it can also function as a useful benchmark for comparing the incremental visibility improvement from the use of the control technologies considered as part of the five-factor analysis.

⁹ The deciview scale represents a standardized index that expresses changes in visibility, similar in manner to how the decibel scale is an index that expresses relative changes in sound levels. For a more full description, please refer to 62 FR 41145.

¹⁰ Per the Nevada RH SIP, page 5-5. Available in Docket Item EPA-R09-OAR-2011-0130-0003

A. NDEP’s Analysis

As part of their BART analysis, Nevada Energy performed visibility modeling in order to evaluate the visibility improvement attributable to each of the NOx control technologies that it considered. Results of the visibility modeling performed by Nevada Energy in their submittal to NDEP are summarized in Table 4 below.

Table 4. Summary of Nevada Energy Estimates of Visibility Benefit¹¹

| Control Option | Visibility Improvement (from WRAP baseline) ¹² | | | | Visibility Improvement (Incremental, from Control) |
|--------------------------|--|-------|-------|-------|--|
| | RGGS1 | RGGS2 | RGGS3 | Total | Total |
| | (dv) | | | (dv) | (dv) |
| LNB + OFA | 0.440 | 0.479 | 0.407 | 1.33 | -- |
| LNB + OFA + SNCR | 0.521 | 0.560 | 0.485 | 1.57 | 0.24 |
| ROFA + Rotamix | 0.592 | 0.630 | 0.514 | 1.74 | 0.17 |
| SCR + LNB + OFA | 0.698 | 0.735 | 0.652 | 2.09 | 0.35 |
| SCR + ROFA ¹³ | 0.698 | 0.735 | 0.652 | 2.09 | 0.35 |

Based upon these results, the installation of SCR with LNB and OFA would result in an incremental visibility improvement at Grand Canyon National Park of 0.35 deciviews (dv). This visibility improvement is based upon the NOx emission rates estimated by Nevada Energy in their BART analysis for each control technology option, and is relative to visibility impacts based on emissions used by the Western Regional Air Partnership (WRAP). In preparing the RH SIP, however, NDEP developed its own set of NOx emission estimates for the various control technology options. The differences between Nevada Energy’s estimates and the emission estimates that form the basis of the Nevada RH SIP are summarized in Table 5 below.

¹¹ Visibility improvement listed here are for the Class I area with the highest impact, Grand Canyon National Park. They represent the change in the 98th percentile impacts from three modeled years. The “total” is the simple total of the impacts from the three individual units, which Nevada Energy modeled separately..

¹² From Table 5-4 of NVE BART Analysis Reports, Reid_Gardner_1_10-03-08.pdf, Reid_Gardner_2_10-03-08.pdf, Reid_Gardner_3_10-03-08.pdf. Available in Docket Item No. EPA-R09-OAR-2011-0130-0007. The improvements here are relative to the “WRAP baseline”, impacts from emission levels used by the Western Regional Air Partnership and modeled by Nevada Energy. This is a different “baseline” than used for the cost estimates below.

¹³ Incremental visibility benefit of SCR + ROFA is based upon ROFA + Rotamix as previous control technology.

Table 5. Comparison of Nevada Energy and NDEP Control Technology Emission Estimates

| Control Option | Nevada Energy | | NDEP | |
|----------------------------|--|--|--|--|
| | Emission Factor ¹ (lb/MMBtu) | Control Efficiency ² (%) | Emission Factor ³ (lb/MMBtu) | Control Efficiency ³ (%) |
| Reid Gardner Unit 1 | | | | |
| Baseline (LNB + OFA) | 0.38 | -- | 0.462 | -- |
| LNB + OFA (enhanced) | 0.30 | 21.3% | 0.360 | 21.3% |
| LNB + OFA + SNCR | 0.23 | 40.9% | 0.270 | 40.9% |
| ROFA + Rotamix | 0.16 | 57.7% | 0.200 | 57.7% |
| SCR + LNB + OFA | 0.07 | 81.6% | 0.085 | 81.6% |
| SCR + ROFA | 0.07 | 81.6% | 0.085 | 81.6% |
| Reid Gardner Unit 2 | | | | |
| Baseline (LNB + OFA) | 0.39 | -- | 0.466 | -- |
| LNB + OFA (enhanced) | 0.30 | 23.7% | 0.355 | 23.7% |
| LNB + OFA + SNCR | 0.23 | 42.7% | 0.267 | 42.7% |
| ROFA + Rotamix | 0.16 | 59.0% | 0.190 | 59.0% |
| SCR + LNB + OFA | 0.07 | 82.2% | 0.083 | 82.2% |
| SCR + ROFA | 0.07 | 82.2% | 0.083 | 82.2% |
| Reid Gardner Unit 3 | | | | |
| Baseline (LNB + OFA) | 0.32 | -- | 0.451 | -- |
| LNB + OFA (enhanced) | 0.30 | 6.5% | 0.420 | 6.5% |
| LNB + OFA + SNCR | 0.23 | 29.9% | 0.316 | 29.9% |
| ROFA + Rotamix | 0.20 | 38.0% | 0.278 | 38.0% |
| SCR + LNB + OFA | 0.07 | 78.2% | 0.098 | 78.2% |
| SCR + ROFA | 0.07 | 78.2% | 0.098 | 78.2% |

¹ From each respective unit's NVE BART Analysis, Table 3-1. Available in Docket Item No. EPA-R09-OAR-2011-0130-0007

² From each respective unit's NVE BART Analysis, Table 3-2. Available in Docket Item No. EPA-R09-OAR-2011-0130-0007

³ As summarized in Table 1, NDEP Reid Gardner BART Determination, October 22, 2009. Available as Docket Item No. EPA-R09-OAR-2011-0130-0005. Baseline emission factor is not explicitly calculated by NDEP. The factor here represents the listed annual emissions divided by 'Base Heat Input'

As seen in these tables, NDEP's estimates of controlled emission rates differ from Nevada Energy's estimates. These differences are a result of NDEP's use of a different emission baseline in its calculations than Nevada Energy, which is discussed below in our discussion of existing pollution control technology. Since NDEP elected to calculate controlled emission rates by retaining the respective percent reduction values for each control technology, rather than each control technology's emission rate (lb/MMBtu), the use of a higher baseline emission rate results in higher

emission estimates for each control technology option. As a result, NDEP's estimated performance for each control technology is less stringent than Nevada Energy's estimates. NDEP, however, did not perform additional modeling to determine the visibility improvement attributable to its emission estimates, and continued to rely on the visibility modeling performed by Nevada Energy.

As noted in the discussion of cost of compliance, part of NDEP's basis for not determining a control technology more stringent than ROFA with Rotamix as NOx BART was that the incremental costs of more stringent control options were not justified relative to their corresponding increases in visibility benefit. However, without updated visibility modeling that indicates the visibility improvement attributable to NDEP's emission estimates, we do not consider NDEP to have properly considered the appropriate magnitude of incremental visibility improvement in reaching its determination. As discussed in our analysis below, we have performed our own visibility modeling in order to determine these visibility impacts.

B. EPA's Analysis

Under the BART Guidelines, the degree of visibility improvement from controls is one of the five factors to consider in making a BART determination for a facility. Of particular interest was the visibility benefit from the installation of Selective Catalytic Reduction (SCR), as compared to benefits from other, less expensive control technologies. As described in the following sections, we performed our own CALPUFF air quality modeling of the Reid Gardner Generating Station (RGGS) to assess the effect of NOx controls on visibility at nearby Class I areas as an aid in the review of NDEP's BART determination for RGGS.

1. Modeling Synopsis
2. Background on CALPUFF and visibility calculations
3. The old and the revised IMPROVE equations
4. Modeling Methodology
5. Stack Parameters and Source Emissions
6. Modeling Results
7. Comparison to other modeling

The modeling was performed using the current regulatory version of the CALPUFF modeling system, and generally followed procedures in the modeling protocol developed by the Western Regional Air Partnership ("WRAP protocol"), with some important changes for improved performance and regulatory requirements. Most of the modeled control scenarios used input emission rates from the NDEP SIP submittal, though with different chemical speciation for PM₁₀ emissions to better reflect their visibility effects. In order to focus on the impacts of alternative controls for NOx, most scenarios held SO₂ and PM₁₀ emissions rates constant at levels determined by NDEP to represent BART. Given that EPA has already approved NDEP's SO₂ and PM₁₀ BART determinations (77 FR 17334), we consider this procedure acceptable for making decisions about NOx controls in the present action.

1. Modeling Synopsis

EPA used the current regulatory version of the CALPUFF modeling system, which comprises the following source code versions:

- CALMET Version 5.8, Level: 070623
- CALPUFF Version 5.8, Level: 070623
- POSTUTIL Version 1.56, Level: 070627
- CALPOST Version 5.6394, Level: 070622
- CALPOST Version 6.221, Level 080724 (for visibility method 8)

The projection and coordinate system used was the same as used by the WRAP, and is illustrated in Figure 1 below.

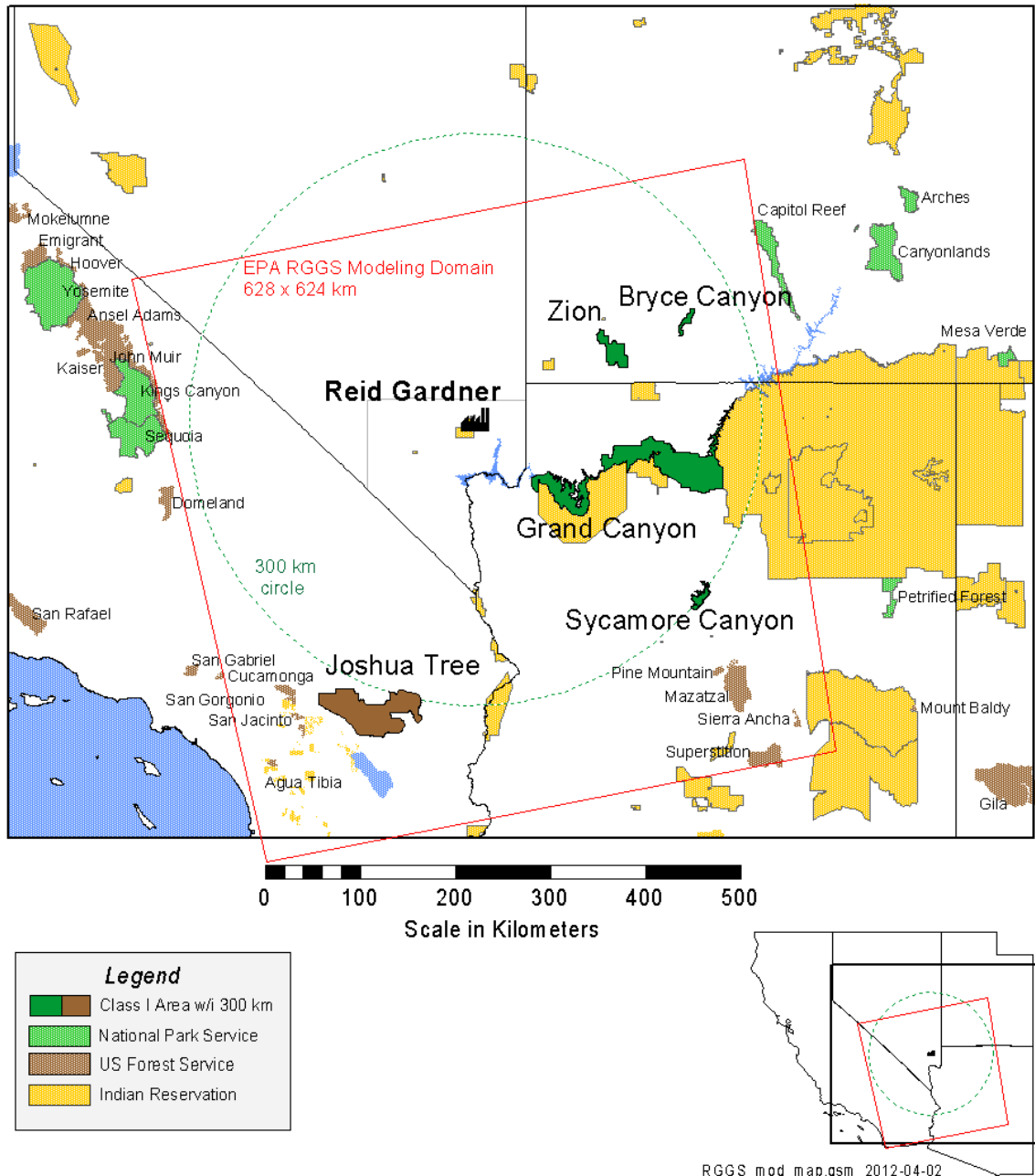
- Projection: Lambert Conformal Conic (LCC)
- Projection origin (lat, long): 40°, -97°
- Standard parallels: 33°, 45°
- False easting and northing: 0 m, 0 m
- Projection ellipsoid: "NWS-84", 6370 km radius sphere

The CALMET modeling domain was identical to the WRAP Arizona domain:
288 x 225 grid cells (X & Y), each 4 km, total size 1152 x 900 km;
southwest corner at LCC coordinates -1944 km, -900 km

The CALPUFF modeling domain was centered on RGGGS but within the above:
157 x 156 grid cells (X & Y), each 4 km, total size 628 x 624 km;
southwest corner at meteorological domain cell (20, 70)

Figure 1. Modeling Domain

Reid Gardner Generating Station and Nearby Class I Areas



Each Class I area located within 300 km of Reid Gardner was included in our modeling, as listed in Table 6 below. Modeling receptors for each Class I areas were downloaded from the National Park Service “Class I Receptors web site.”¹⁴

Table 6. Class I Areas

| abbr. | Name | min. distance from RGGGS, km | number of receptors | State | Agency |
|--------------|---------------------------------|-------------------------------------|----------------------------|--------------|---------------|
| brca | Bryce Canyon National Park | 226 | 213 | UT | NPS |
| grca | Grand Canyon National Park | 85 | 791 | AZ | NPS |
| jotr | Joshua Tree National Monument | 292 | 815 | CA | NPS |
| syca | Sycamore Canyon Wilderness Area | 288 | 316 | AZ | USFS |
| zion | Zion National Park | 148 | 224 | UT | NPS |

CALMET was run using the 2001, 2002, and 2003 MM5 simulations used by the WRAP for the Arizona domain as the prognostic meteorological input. In particular, the Arizona domain, rather than the Nevada domain, was used because the Arizona domain included the geographic area needed to ensure a model domain that extended to at least 50 km beyond the edge of each Class I area (as seen in Figure 1, most of the relevant Class I areas are in Arizona and Utah). In addition, the Arizona domain was available for CALMET 5.8 and with upper air data, which was not the case for the Nevada domain. CALMET was run with some radius of influence changes to smooth the wind fields, and with the incorporation of upper air data. For more details regarding specific CALMET settings, please consult Section 5.B.4.

CALPUFF was run with regulatory default settings. Ozone background was the same as that developed for the WRAP Arizona domain. The ammonia background was assumed constant at 1 ppb, the default in the IWAQM Phase 2 document for arid regions.¹⁵ A description of stack parameters and source emission rates used in the CALPUFF modeling can be found in Section 5.B.5, as well as in the spreadsheet contained in Appendix C.

CALPOST was run with visibility method (MVISBK) 6 to apply the original IMPROVE equation, as well as with method 8, mode 5 to apply the revised IMPROVE equation. For both visibility methods, both annual average and best 20%

¹⁴ <http://www.nature.nps.gov/air/maps/Receptors/>

¹⁵ *Interagency Workgroup On Air Quality Modeling (IWAQM) Phase 2 Summary Report And Recommendations For Modeling Long Range Transport Impacts* (EPA-454/R-98-019), EPA OAQPS, December 1998, <http://www.epa.gov/scram001/7thconf/calpuff/phase2.pdf>

of days (“B20”) natural background concentrations were used. Our analysis primarily relies upon method 8 results, with best 20% backgrounds, as this is most consistent with current Federal Land Manager guidance for assessing visibility impacts at Class I areas, while also remaining consistent with the BART Guidelines. For each Class I area, we developed visibility results using four visibility postprocessing methods as listed below. A description of these methods, and of visibility calculations in general, are contained in Sections 5.B.2 and 5.B.3.

Table 7. Visibility Methods Used

| abbr. | CALPOST Method No. (MVISBK) | natural background concentrations |
|--------------|------------------------------------|--|
| vm6a | 6 | annual average |
| vm6b | 6 | best 20% of days |
| vm8a | 8 | annual average |
| vm8b | 8 | best 20% of days |

There are 9 control scenarios, of which only 8 were modeled, since emissions from the SCR scenarios c14 and c15 are the same. Three years of meteorology were used for each model run, for a total of 24 CALPUFF and POSTUTIL runs. Each of these models runs required a CALPOST run for each of the 5 areas and 4 visibility methods, for a total of 480 CALPOST runs. The names used for the CALPUFF input and output files reflect these combinations. For example, the 2002 CALPUFF input file for control scenario c11 is “cf_c11_2002.inp”, and the corresponding CALPOST input file for the Zion area using visibility method 8a is “ct_c11_vm8a_zion_2002.inp”.

Table 8. Summary of Model Cases

| scen | scenario name | NDEP NO_x case | NO_x emissions | SO₂ and PM₁₀ emissions |
|-------------|--------------------------|---------------------------------|---------------------------------|---|
| c00 | WRAP | WRAP baseline | WRAP | WRAP |
| c02 | WRAP NO _x | NA | WRAP | NDEP BART |
| c04 | Baseline NO _x | Baseline | Base LNB+OFA | NDEP BART |
| c11 | Enh. LNB+OFA | 1 | Enhanced LNB+OFA | NDEP BART |
| c12 | SNCR | 2 | SNCR+LNB+OFA | NDEP BART |
| c13 | ROFA+Rotamix | 3 | ROFA+Rotamix | NDEP BART |
| c14 | SCR+ROFA | 4 | SCR+ROFA | NDEP BART |
| c15 | SCR | 5 | SCR+LNB+OFA | NDEP BART |
| c16 | SCR (0.06 lb/MMBtu) | NA | SCR+LNB+OFA at 0.06 lb/MMBtu | NDEP BART |

2. Background on CALPUFF and visibility calculations

CALMET is a pre-processor that creates meteorological data suitable for input to CALPUFF. It accepts terrain, land use, and meteorological data in a number of forms, including data observations from surface and upper air meteorological stations; it can also accept 3D data fields from meteorological models such as MM5. Three years of meteorological data is standard, and is recommended in the BART Guidelines.

CALPUFF is the air quality model, and simulates ambient concentrations of pollutants by portraying source plumes as a series of puffs that can expand and be transported independently, according to the meteorological conditions each encounters. In addition to meteorology input, CALPUFF requires emission rates for the following visibility-impairing pollutants: SO₂, SO₄, NO_x, secondary organic aerosol (SOA) or organic carbon (OC), elemental carbon (EC), and other fine particulate matter (PMF), and coarse particulate matter (PMC). Since data is not typically available for every one of the particulate matter (PM) components, some estimates must be made in order to speciate available PM data into SOA or OC, EC, PMF, and PMC. CALPUFF computes concentrations for every hour, and for every receptor location; there is a standard set of receptors for each Class I area.

POSTUTIL post-processes the concentrations from CALPUFF by apportioning the nitrate ion between its nitric acid and particulate nitrate forms; the amount in each form depends on the humidity and on the amount of sulfate and ammonia present.

Finally, CALPOST uses the IMPROVE equation to convert the various chemical species concentrations into extinction (b_{ext}), the fraction of light removed from a sight path. CALPOST then converts extinction into deciviews (dv), a visibility metric more in line with human perception of visibility impairment, and the main metric used in the Regional Haze Rule. There are several variants to the visibility impact calculation, including which version of the IMPROVE equation is used, and how background concentrations and humidity are accounted for. Extinction and deciviews are available for each day modeled, and for each receptor location.

Under the BART Guidelines, visibility impact of a source is assessed relative to natural background, that is, the impairment that would exist without any artificial pollution sources. Estimates of natural background concentrations are provided by EPA in the natural conditions guidance¹⁶ and by the Federal Land Managers in the

¹⁶ Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, U.S. Environmental Protection Agency, EPA-454/B-03-005, September 2003, on web page <http://www.epa.gov/ttn/oarpg/t1pgm.html>, with direct link http://www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf

FLAG 2010 guidance.¹⁷ Visibility impairment due to a particular source is usually expressed as percent extinction change (% increase over background extinction that is caused by including the source), or delta deciviews (increase over natural background deciviews caused by including the source).

Finally, of the visibility impacts computed for every modeled data and location, for each modeled day the receptor with the highest impact is chosen; and from among the resulting daily values, the 98th percentile is used as metric of visibility impact for a given Class I area. This would be the 8th high for a 365-day year, or the 22nd high if the 1095 days of the three years of data are considered together. Most often the average of three individual years' 98th percentiles is reported, rather than the 98th percentile of all three years' data merged together. Both the average and the merged value are reported here.

3. The original and the revised IMPROVE equations

The IMPROVE equation is used to convert measured or modeled concentrations into extinction for each pollutant chemical species, and then total them, accounting for the effect of relative humidity; it also includes the Rayleigh scattering that occurs in pure air. The extinction total is then used to calculate deciviews for use in visibility progress assessments. In December 2005 the IMPROVE Steering Committee revised the IMPROVE equation after a scientific assessment of its implications for regional haze planning. In particular, when compared to nephelometer direct measurements of visibility extinction, the original IMPROVE equation over-predicts for low extinction conditions and under-predicts for high extinction. These biases have direct relevance for estimates for the best 20% and worst 20% visibility days that are used to assess progress.

Original IMPROVE equation:

$$\begin{aligned} b_{\text{ext}} &= 3 * f(\text{RH}) * [\textit{sulfate}] \\ &+ 3 * f(\text{RH}) * [\textit{nitrate}] \\ &+ 4 * [\textit{organic mass}] \\ &+ 10 * [\textit{elemental carbon}] \\ &+ 1 * [\textit{fine soil}] \\ &+ 0.6 * [\textit{coarse mass}] \\ &+ 10 \end{aligned}$$

Each term in the equation is the extinction due to a particular measured component; bracketed quantities are concentrations of as measured at IMPROVE monitors. The

¹⁷ *Federal Land Managers' Air Quality Related Values Work Group (FLAG) Phase I Report—Revised (2010)*, U.S. Forest Service, National Park Service, U.S. Fish And Wildlife Service, October 2010. See <http://www.nature.nps.gov/air/Permits/flag/> Direct link: http://www.nature.nps.gov/air/Pubs/pdf/flag/FLAG_2010.pdf

organic mass is assumed to be 1.4 times the organic carbon mass that is measured by IMPROVE monitors. The 10 is for Rayleigh scattering which is due to the interaction of light with molecules of air itself with no pollutants, and is assumed to be the same for all locations, The $f(RH)$ is a water growth factor for sulfate and nitrate, which are hygroscopic (their particles tend to attract water). Its value depends on relative humidity, ranging from 1 at low humidity to 18 at 98% humidity.

New IMPROVE equation:

$$\begin{aligned}
 b_{\text{ext}} &= 2.2 * f_s(RH) * [\text{small sulfate}] + 4.8 * f_L(RH) * [\text{large sulfate}] \\
 &+ 2.4 * f_s(RH) * [\text{small nitrate}] + 5.1 * f_L(RH) * [\text{large nitrate}] \\
 &+ 2.8 * [\text{small organic mass}] + 6.1 * [\text{large organic mass}] \\
 &+ 10 * [\textit{elemental carbon}] \\
 &+ 1 * [\textit{fine soil}] \\
 &+ 1.7 * f_{ss}(RH) * [\text{sea salt}] \\
 &+ 0.6 * [\textit{coarse mass}] \\
 &+ \text{Rayleigh scattering (site-specific)} \\
 &+ 0.33 * [\text{NO}_2 \text{ (ppb)}]
 \end{aligned}$$

Sulfate is assumed to be all “large sulfate” if total sulfate is over $20 \mu\text{g}/\text{m}^3$, otherwise its fraction of the total is assumed to increase uniformly between 0 and 1 when the total is in the range between 0 and 20. *I.e.*, large sulfate = (total sulfate/20)*total. A similar definition applies for nitrate and for organic mass. The organic mass is assumed to be 1.8 times the organic carbon mass that is measured by IMPROVE monitors, an increase over the original 1.4. Sea salt is estimated as $1.8 * [\text{chloride}]$ (or chlorine if chloride not available) Finally, the f_s , f_L , f_{ss} are water growth factors for small (“S”) and large (“L”) fractions of sulfate and nitrate, and for sea salt (“SS”). Their values depend on relative humidity, ranging from 1 at low humidity to over 5 at 95% humidity.

The new equation has five changes: 1) greater completeness though the inclusion of sea salt, which can be important for coastal sites; 2) increased organic carbon mass estimate, based on more recent data for remote areas; 3) Rayleigh scattering using site-specific elevation and temperature, a refinement over the older network-wide constant; 4) separate estimates for small and large particles of visibility impacts and humidity-dependent particle size growth rates, which could affect estimates at the low and high ends; and 5) greater completeness though the inclusion of NO_2 (Pitchford, 2006)¹⁸.

The new equation shows broader scatter overall, but less bias in matching visibility measurements under high and low visibility conditions. That is, though it has a somewhat worse fit considering all the data, it has a better fit under visibility

¹⁸ Pitchford, Marc, 2006, "New IMPROVE algorithm for estimating light extinction approved for use", *The IMPROVE Newsletter*, Volume 14, Number 4, Air Resource Specialists, Inc.; web page: http://vista.cira.colostate.edu/improve/Publications/news_letters.htm
direct link: <http://vista.cira.colostate.edu/improve/Publications/NewsLetters/IMPNews4thQtr2005.pdf>

conditions most relevant to regional haze planning, the best and worst 20% of days. The looser overall fit can cause a slightly different set of days to be the ones chosen than the 20% worst, but the chemical species composition for such days is little changed (IMPROVE technical subcommittee for algorithm review, 2001, pp. 11-12), and so this makes little difference for assessing the contribution of emission sources to current conditions, and for projecting the effect of emission controls. The split between small and large particles was the main factor in reducing the biases.

The organic carbon (OC) measured by the IMPROVE network does not include all organic matter (OM); based on 1970's urban data, a scaling factor of 1.4 is embedded in the original equation to account for the full mass. Based on recent data more relevant to relatively remote Class I areas, the revised IMPROVE equation embeds an OM/OC factor of 1.8. In practice, for the worst days the biggest effect of switching to the revised IMPROVE equation is this increased organic carbon mass, since the worst days are dominated by organic carbon from fires, rather than the sulfates and nitrates that come more from anthropogenic sources.

4. Modeling Methodology

EPA generally used the WRAP protocol¹⁹ as a starting point, with some important changes. The WRAP protocol received wide review and approval, and was the basis for BART screening and BART determination modeling by number of western states and by individual facilities. In performing visibility modeling for the Navajo Generating Station (NGS), located near Page, AZ, AECOM (formerly ENSR) used the WRAP protocol and MM5 meteorology as a starting point and improved the modeled wind fields by introducing changes to some CALMET meteorological settings.²⁰ Following review and comment by the Federal Land Managers, AECOM made additional changes in accordance with FLM recommendations, including the incorporation of upper air data. For this action, EPA used the CALMET results from that AECOM work.

The WRAP protocol received extensive scrutiny during 2005-2006 by various States, EPA Regions, and Federal Land Managers (FLMs). Some key features of the protocol are listed here. Meteorological fields were derived from the MM5 prognostic meteorological model (Mesoscale Model version 5, Penn State University and the National Center for Atmospheric Research), using a 36 km grid resolution, for the years 2001, 2002, and 2003 and with the continental United States as the modeling domain. Subdomains were extracted for use by individual states, such as Arizona and Nevada. The MM5 fields were then processed using CALMET

¹⁹ "CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States", Western Regional Air Partnership (WRAP); Gail Tonnesen, Zion Wang; Ralph Morris, Abby Hoats and Yiqin Jia, August 15, 2006. Available on UCR Regional Modeling Center web site, BART CALPUFF Modeling, <http://pah.cert.ucr.edu/aqm/308/bart.shtml> Direct link: http://pah.cert.ucr.edu/aqm/308/bart/WRAP_RMC_BART_Protocol_Aug15_2006.pdf

²⁰ See "BART Analysis for the Navajo Generating Station Units 1 – 3", ENSR Corporation, November 2007, Document No.: 05830-012-300

(meteorological pre-processor, part of the CALPUFF modeling system) as preparation for use in the CALPUFF air quality model, using a 4 km grid resolution. After much discussion, WRAP elected to blend surface meteorological station observations into the MM5 fields, instead of relying on the CALMET “no observations” (“no obs”) mode. (The Federal Land Managers had wanted the blending in of upper air data as well, but this was not included in the WRAP modeling.)

The WRAP protocol specified CALMET version 6.211 and CALPUFF version 6.112, the latest versions at the time. However, since the time of the WRAP protocol, problems were discovered in CALMET version 6.2 that resulted in EPA affirming that CALMET version 5.8 and CALPUFF version 5.8 of CALPUFF, are the regulatory versions to be used.²¹

The AECOM CALMET modeling used by EPA differed from the WRAP protocol in using the regulatory version of the modeling system, and in several other ways. The CALMET settings were almost all the same; the WRAP-defined Arizona subdomain was used; all Class I Areas within 300 km of RGGS were included. However, when blending in meteorological station wind observations, AECOM used a lower radius of influence for stations (R1, R2, RMAX1). This resulted in smoother wind fields than those used for WRAP, which had some abrupt changes as one leaves the zone of influence of a given meteorological station. After initial input from the Federal Land Managers, EPA requested that certain other CALMET option settings be changed. These changes resulted in a more refined approach that is more consistent with approaches used in PSD permit application modeling. The revised modeling has more extensive use of meteorological station observations (e.g. IEXTR=-4 to extrapolate surface observations up to higher layers), and is responsive to the FLM concerns regarding adequacy of the surface-only observations used in the WRAP modeling. Various relevant CALMET option settings are listed in Table XX: Selected CALMET settings for RGGS. For meteorological input to CALPUFF, EPA used the AECOM CALMET results, per the “AECOM and EPA modeling” column of that table.

²¹ As indicated in June 29, 2007 letter from Tyler Fox (EPA) to Joe Scire (TRC). Also indicated in U.S. EPA’s Support Center for Regulatory Air Models (SCRAM), CALPUFF model change bulletin, June 29, 2007. http://www.epa.gov/ttn/scram/dispersion_prefrec.htm#calpuff

Table 9. Selected CALMET settings for RGGGS

| Option | Description | EPA default | WRAP protocol | AECOM and EPA modeling | Comments |
|---------|--|-------------------|---------------------|------------------------|--|
| version | CALMET version | 5.8, level 070623 | 6.211, level 060414 | 5.8, level 070623 | 5.8 is EPA regulatory version |
| NOOBS | No Observation Mode | 0 | 0 or 1 implied | 0 | Use both surface and upper air observations, per FLM recommendation |
| ICLOUD | gridded cloud fields | 0 | 0 | 0 | |
| IWFCOD | diagnostic winds | 1 | 1 | 1 | |
| IFRADJ | Froude wind adj. | 1 | 1 | 1 | |
| IKINE | kinematic effects | 0 | 0 | 0 | |
| IOBR | O'Brien vertical wind adj. | 0 | 0 | 0 | |
| ISLOPE | slope flows | 1 | 1 | 1 | |
| IEXTRP | extrapolate wind to upper air | -4 | 1 | -4 | To extrapolate from surface, per FLM recommendation |
| ICALM | extrapolate calm to upper air | 0 | 0 | 0 | |
| BIAS | layer biases sfc vs. UA | NZ*0 | NZ*0 | NZ*0 | |
| I PROG | gridded initial prognostic | 0 | 14 | 14 | Use prognostic inputs from MM5 |
| RMAX1 | max surface radius of influence | NA | 50 | 30 | Gives smoother wind fields, per AECOM |
| RMAX2 | max aloft radius of influence | NA | 100 | 100 | |
| RMAX3 | max over-water radius of influence. | NA | 100 | 100 | |
| RMIN | min wind radius of influence. | 0.1 | 0.1 | 0.1 | |
| RMIN2 | min dist sfc winds extrap | 4 | 4 | 4 | |
| TERRAD | terrain radius of in influence | NA | 10 | 10 | |
| R1 | weight surface Step 1 vs. obs | NA | 100 | 18 | Gives smoother wind fields, per AECOM |
| R2 | weight aloft Step 1 vs. obs | NA | 200 | 20 | Gives smoother wind fields, per AECOM |
| ITPROG | 3D T from obs or prognostic | 0 | 1 or 2 implied | 1 | Use surface station temperatures, per FLM recommendation |
| TRADKM | radius of influ. for T interp. | 500 | 500 | 500 | |
| I AVET | spatial T averaging | 1 | 0 | 1 | Smoothing turned on |
| JWAT1 | starting land use for T interp. over water | 999 | 51 | 51 | (Could set to 999 to disable overwater feature & avoid a CALMET bug; very little "water" land use here anyway) |
| JWAT2 | ending land use for T interp. over water | 999 | 55 | 55 | |

CALPOST visibility method 6 (MVISBK=6) had long been the recommended approach for assessing visibility impacts in Class I areas. It implements the original IMPROVE equation, with monthly average humidity adjustment factors from the

2000 version of the FLAG document.²² It is incorporated in the regulatory version of CALPOST, version 5.6394. The revised IMPROVE equation is incorporated into a later version of CALPOST, 6.221, and is implemented as visibility method 8 (MVISBK=8), mode 5, using monthly average humidity adjustment factors from the 2010 version of the FLAG document; this has updated values for each Class I area and includes adjustment factors for small and large sulfate and nitrate, and also sea salt, to accommodate the revised IMPROVE equation.

In order to use either of these methods, natural background concentrations are needed for each species in the respective IMPROVE equation. For method 8 and the revised IMPROVE equation, these are available for each Class I area in the FLAG 2010 document, for both the annual average and for the average over the best 20% of days (“B20”). For method 6, only annual average background species concentrations are available, in Table 2-1 the 2003 EPA natural conditions guidance cited above. However that document’s Appendix B also provides extinction and deciviews for the best 20% of days; the ratio of B20 extinction to annual extinction can be used to scale the annual average concentrations, yielding an estimate of the B20 concentrations, which were used for this action. Finally, the 2003 EPA guidance gives relative humidity adjustment factors $f(RH)$ for both the IMPROVE monitor location nearest a Class I area, and an interpolation from multiple monitors for the centroid of the Class I area; the latter was used here.

5. Stack Parameters and Source Emissions

Stack Parameters

Stack parameters used in the modeling are summarized in Table 10 below and were obtained from the Nevada Energy BART Analysis Reports²³, and WRAP Regional Modeling Center files.²⁴ There were certain discrepancies in the stack coordinates from these two information sources. In our modeling, we used the data from the WRAP files, since they more closely corresponded to the coordinates for the overall facility known to EPA’s Clean Air Markets Division.

²² *Federal Land Managers’ Air Quality Related Values Workgroup (FLAG) Phase I Report* (December 2000), U.S. Forest Service, National Park Service, U.S. Fish And Wildlife Service. See

<http://www.nature.nps.gov/air/Permits/flag/>; Direct link:
<http://www.nature.nps.gov/air/Pubs/pdf/flag/FlagFinal.pdf>

²³ “BART Analysis for Reid Gardner Station Unit 1, Prepared for NV Energy”, October 2008, CH2MHill. See <http://ndep.nv.gov/baqp/planmodeling/rhaze.html>, file “Reid_Gardner_1_10-03-08.pdf”. Similar names for Unit 2 and Unit 3 reports.

²⁴ “Summary of WRAP RMC BART Modeling for Nevada, Draft#7”, April 24, 2007, WRAP Regional Modeling Center. See: “Nevada Results Summary” at <http://pah.cert.ucr.edu/aqm/308/bart.shtml>. Direct Link:
http://pah.cert.ucr.edu/aqm/308/bart/calpuff/summary/NV_summary_May14_2007_v8-NoSRC02_SRC07.doc; also for stack locations see “NV_BART_emis”,
http://pah.cert.ucr.edu/aqm/308/bart/calpuff/emissions/nv_emis_Mar09_2007.xls

Table 10. Reid Gardner Generating Station Stack Parameters

| Stack Parameter | Unit 1 | Unit 2 | Unit 3 |
|-----------------------------|------------|------------|------------|
| SRCNAM in CALPUFF | RGGS1 | RGGS2 | RGGS3 |
| HS, Stack Height, m | 60.96 | 75.9 | 82.3 |
| ES, Stack Elevation, m AMSL | 487.68 | 487.68 | 487.68 |
| DS, Stack Diameter, m | 4.05 | 4.05 | 3.93 |
| VS, Exit Velocity, m/s | 15.96 | 15.34 | 21.75 |
| TS, Exit Temperature, K | 330.37 | 335.93 | 339.26 |
| Heat input, MMBtu/hr | 1215 | 1215 | 1237 |
| Location | | | |
| LCC X km | -1555.5060 | -1555.5120 | -1555.5210 |
| LCC Y km | -218.2230 | -218.2522 | -218.2911 |
| longitude | -114.63175 | -114.63175 | -114.63177 |
| latitude | 36.6580507 | 36.6577814 | 36.6574208 |

A discussion of the basis for each model case’s emission estimates is included in the following section, as well as a description of the various PM₁₀ speciation profiles and sulfuric acid emission calculation methodologies used for each model case. Detailed emission calculations for each model case, including particulate speciation profiles and sulfuric acid emission calculations, can be found in Appendix C.

Model Scenario Emission Factor Basis

Case 00 (WRAP) consists of WRAP baseline emission rates for each of the Reid Gardner units. The results of this case were compared to similar model runs performed by Nevada Energy and by WRAP that also made use of WRAP baseline emissions.

Case 02 (WRAP NO_x) consists of WRAP baseline emission rates for NO_x. For PM₁₀ and SO₂, this case consists of the emission rates corresponding to the BART determinations for these units in the Nevada RH SIP (0.015 lb/MMBtu and 0.15 lb/MMBtu, respectively) as approved by EPA on December 13, 2011.²⁵ The results of this case were used primarily for informational purposes in order to determine the visibility improvement associated with PM₁₀ and SO₂ BART control.

Case 04 (Baseline NO_x) uses the baseline emission factor for NO_x relied upon by NDEP in the RH SIP.²⁶ For PM₁₀ and SO₂, this case consists of the emission rates corresponding to the BART determinations for these units in the Nevada RH SIP. Although these BART determination emission rates do not necessarily represent historical emissions at Reid Gardner, they have been approved for inclusion into the Nevada SIP. As a result, we regard the use of these emission rates in this baseline

²⁵ 77 FR 17334

²⁶ Per Table 1, NDEP Reid Gardner BART Determination, October 22, 2009. Available as Docket Item No. EPA-R09-OAR-2011-0130-0005. Baseline emission factors are not explicitly calculated by NDEP. As illustrated in Appendix C, the baseline emission factor represents the listed annual emissions divided by “Base Heat Input.”

case and in control option cases to be the most accurate approach to predicting visibility impairment attributable to Reid Gardner.

Cases 11 through 15 (Control Options 1 through 5) use the NO_x emission factors for the various control technology options as indicated by NDEP in the RH SIP. For PM₁₀ and SO₂, these cases consist of the emission rates use in Case 04 in order to provide a clear estimate of the visibility improvement associated with each NO_x control technology.

Case 16 (Control Option 6) is an additional case that does not correspond to any of Nevada Energy's control technology options. This case uses a NO_x emission factor that corresponds to an approximately 86% SCR control efficiency from the NO_x emission rates of Case 04 (Baseline NO_x).

PM₁₀ Speciation

PM₁₀ emissions are not directly entered into the CALPUFF model but are instead speciated into constituent species. These PM₁₀ emissions were classified into the following particulate species using a combination of AP-42 emission data and Federal Land Managers' guidance:

- Coarse particulate matter (PMC)
- Fine particulate matter (PMF)
- Sulfates (SO₄)
- Secondary organic aerosols (SOA)
- Elemental carbon (EC)

Case 00 (WRAP) PM₁₀ emissions are based upon the WRAP PM₁₀ emission rate. These emissions were speciated based upon the assumption that the WRAP PM₁₀ emission rate represents total filterable PM (i.e., the result of a Method 5 test). This PM₁₀ emission rate was speciated into PMC, PMF, and EC based upon AP-42 emission factors, as shown in Appendix C. The condensable PM₁₀ fraction (SOA and SO₄ species), which would not be represented in the WRAP PM₁₀ emission rate, was calculated separately and included in the model.

The remaining cases' PM₁₀ emissions are based upon the Nevada RH SIP PM₁₀ BART determination of fabric filters and a 0.015 lb/MMBtu emission rate. Particulate emissions for these cases were speciated based upon the conservative assumption that the BART emission rate represents total PM₁₀ (i.e., filterable plus condensable fractions). As included in Appendix C, PM₁₀ emissions were speciated based upon AP-42 emission factors in a manner consistent with Federal Land Manager's guidance.

Sulfuric Acid (H₂SO₄) Emissions

For the cases modeled in our analysis, we accounted for two mechanisms of sulfur acid manufacture: (1) combustion from fuel and (2) production from use of SCR catalyst. These emissions were calculated using either AP-42 emission factor data or

the Electric Power Research Institute (EPRI) document “Estimating Total Sulfuric Acid Emissions from Stationary Power Plants.”²⁷

Case 00 (WRAP) relied upon a particulate speciation profile that did not include SO₄ emissions. As a result, sulfuric acid emissions from fuel combustion were calculated using the EPRI emission calculation methodology.

Cases 02, 04, and 11 through 16 relied upon particulate speciation profiles that did include SO₄ emissions. Sulfuric acid emissions from fuel combustion can safely be assumed to be represented in the SO₄ particulate fraction. As a result, no additional emission calculations were performed to quantify sulfuric acid from fuel combustion.

Cases 14 through 16 model the use of SCR. As a result, in addition to the sulfuric acid emissions from fuel combustion represented in the particulate speciation, an additional amount of sulfur acid manufactured from the use of SCR catalyst was calculated. The quantity of sulfuric acid was calculated using the EPRI calculation methodology for SCR.

6. Visibility Modeling Results

Visibility impacts for the Grand Canyon National Park, the Class I area where RGGGS has the highest impacts, are shown in the following table, for all visibility methods used. The results are for all three units modeled together, but only unit 1 NO_x emission factors are shown for reference (the other units are comparable). The full results, including all areas and modeled years, are shown in the tables later in this document. Additional results are available in Appendix E (spreadsheet (“RGGGS_TSD_CALPUFF_tables.xls”).

The benefit of SCR relative to the base case is only 0.38 dv (for the visibility method showing the highest impacts and benefits, “vm8b”). While this is not insignificant in the context of an overall regional haze plan, considering that visibility progress is dependent on the cumulative effect of controls for many sources, this is still not a large benefit. It does not in itself show whether SCR is warranted or not in the BART context.

The incremental benefit of SCR over ROFA+Rotamix, based on the 98th percentile impact of merged years, is only 0.09 dv (as seen in Table 14 below). Further, even the incremental benefit of SCR at a more stringent 0.06 lb/MMBtu emission rate is only 0.10 dv. This result is small enough that it tends to support NDEP’s consideration of incremental visibility benefit in its BART determination, and the conclusion that SCR is not required for BART.

²⁷ "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

**Table 11. EPA Modeling Results –
Visibility Impacts at the Grand Canyon**

| scen | Scenario | Unit 1 NO _x , lb/MMbtu ¹ | average of 3 individual year 98th percentiles | | | | 98th percentile of merged years | | | |
|------------|--|---|---|-------------|---------------------|-------------|---------------------------------|-------------|---------------------|-------------|
| | | | visibility method 6 | | visibility method 8 | | visibility method 6 | | visibility method 8 | |
| | | | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg |
| | | | vm6a | vm6b | vm8a | vm8b | vm6a | vm6b | vm8a | vm8b |
| c00 | WRAP for NO _x , SO ₂ , PM | 0.591 | 0.61 | 0.78 | 0.60 | 0.83 | 0.59 | 0.75 | 0.58 | 0.80 |
| c02 | WRAP NO _x , NDEP SO ₂ & PM | 0.591 | 0.56 | 0.72 | 0.56 | 0.77 | 0.55 | 0.71 | 0.54 | 0.74 |
| c04 | Baseline NO_x LNB+OFA | 0.462 | 0.46 | 0.60 | 0.45 | 0.63 | 0.44 | 0.58 | 0.42 | 0.59 |
| c11 | Enh. LNB+OFA | 0.364 | 0.40 | 0.52 | 0.40 | 0.54 | 0.38 | 0.50 | 0.37 | 0.51 |
| c12 | SNCR+LNB+OFA | 0.273 | 0.28 | 0.37 | 0.28 | 0.39 | 0.28 | 0.36 | 0.27 | 0.37 |
| c13 | ROFA+Rotamix | 0.195 | 0.24 | 0.31 | 0.24 | 0.33 | 0.22 | 0.29 | 0.22 | 0.31 |
| c15 | SCR+LNB+OFA | 0.085 | 0.19 | 0.24 | 0.18 | 0.25 | 0.17 | 0.22 | 0.16 | 0.22 |
| c16 | SCR+LNB+OFA 0.06 lb/MMBtu | 0.06 | 0.17 | 0.23 | 0.16 | 0.22 | 0.16 | 0.20 | 0.15 | 0.20 |

¹ The results are for all three units modeled together, but only unit 1 NO_x emission factors are shown for reference (the other units are comparable).

**Table 12. EPA Modeling Results –
Visibility Improvement at the Grand Canyon (relative to baseline)**

| scen | Scenario | Unit 1 NO _x , lb/MMbtu ¹ | average of 3 individual year 98th percentiles | | | | 98th percentile of merged years | | | |
|------------|--|---|---|--------|---------------------|--------|---------------------------------|--------|---------------------|--------|
| | | | visibility method 6 | | visibility method 8 | | visibility method 6 | | visibility method 8 | |
| | | | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg |
| | | | vm6a | vm6b | vm8a | vm8b | vm6a | vm6b | vm8a | vm8b |
| c00 | WRAP for NO _x , SO ₂ , PM | 0.591 | 0.15 | 0.18 | 0.15 | 0.20 | 0.14 | 0.18 | 0.16 | 0.21 |
| c02 | WRAP NO _x , NDEP SO ₂ & PM | 0.591 | 0.10 | 0.13 | 0.11 | 0.15 | 0.10 | 0.13 | 0.11 | 0.16 |
| c04 | Baseline NO_x LNB+OFA | 0.462 | | | | | | | | |
| c11 | Enh. LNB+OFA | 0.364 | -0.06 | -0.08 | -0.06 | -0.08 | -0.06 | -0.08 | -0.06 | -0.08 |
| c12 | SNCR+LNB+OFA | 0.273 | -0.18 | -0.23 | -0.17 | -0.24 | -0.17 | -0.22 | -0.16 | -0.21 |
| c13 | ROFA+Rotamix | 0.195 | -0.22 | -0.29 | -0.22 | -0.30 | -0.22 | -0.29 | -0.20 | -0.28 |
| c15 | SCR+LNB+OFA | 0.085 | -0.27 | -0.35 | -0.28 | -0.38 | -0.28 | -0.36 | -0.26 | -0.36 |
| c16 | SCR+LNB+OFA 0.06 lb/MMBtu | 0.06 | -0.29 | -0.37 | -0.29 | -0.41 | -0.29 | -0.37 | -0.28 | -0.38 |

¹ The results are for all three units modeled together, but only unit 1 NO_x emission factors are shown for reference (the other units are comparable).

**Table 13. EPA Modeling Results –
Incremental Visibility Improvement at the Grand Canyon (SCR vs. ROFA/Rotamix)**

| scen | | Scenario | average of 3 individual year 98th percentiles | | | | 98th percentile of merged years | | | |
|------|------------------------------|--|---|--------|---------------------|--------|---------------------------------|--------|---------------------|--------|
| | | | visibility method 6 | | visibility method 8 | | visibility method 6 | | visibility method 8 | |
| | | | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg | annl. avg bg | B20 bg |
| | | Unit 1 NO _x , lb/MMbtu ¹ | vm6a | vm6b | vm8a | vm8b | vm6a | vm6b | vm8a | vm8b |
| c13 | ROFA+Rotamix | 0.195 | | | | | | | | |
| c15 | SCR+LNB+OFA | 0.085 | -0.05 | -0.07 | -0.06 | -0.08 | -0.05 | -0.07 | -0.06 | -0.09 |
| c16 | SCR+LNB+OFA 0.06 lb/MMBtu | 0.06 | -0.07 | -0.09 | -0.08 | -0.11 | -0.06 | -0.08 | -0.08 | -0.10 |

¹ The results are for all three units modeled together, but only unit 1 NO_x emission factors are shown for reference (the other units are comparable).

Using natural background concentrations from the best 20% of days (“B20”) increases visibility impacts estimates by about 30% relative to using the annual average (going from vm6a to vm6b, or from vm8a to vm8b). This makes sense because natural visibility impairment is lower on the best days, so any given impact will be a larger percentage of the best values than of the annual average. States are free to use annual average background concentrations in assessing visibility impacts,²⁸ and NDEP did so, but even if B20 is used, the visibility benefit of SCR is relatively small.

The effect of changing to the revised IMPROVE equation varies by area and scenario, but on average decreases 98th percentile delta deciviews by about 5%.

7. Comparison to other modeling

Overview

RGGGS has been modeled several times in recent years, by the WRAP Regional Modeling Center²⁹, by CH2MHill³⁰ for Nevada Energy, and by Gray Sky Solutions.³¹ The differences between their applications of the CALPUFF modeling system are summarized in Table 14 below, “CALPUFF settings differences for various model applications.” The various modeling domains are illustrated in Figure 2, “Reid Gardner Generating Station CALPUFF and CALMET Modeling Domains.”

²⁸ “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations”, Memorandum from Joseph W. Paisie, EPA OAQPS Geographic Strategies Group, to Kay Prince, EPA Region 5, July 19, 2006. Available at: http://www.epa.gov/visibility/pdfs/memo_2006_07_19.pdf

²⁹ WRAP Regional Modeling Center, “Summary of WRAP RMC BART Modeling for Nevada, Draft#7, cited above.

³⁰ CH2MHill, “BART Analysis for Reid Gardner Station Unit 1, Prepared for NV Energy”, cited above

³¹ “Modeling for the Reid Gardner Generating Station: Visibility Impacts in Class I Areas”, H. Andrew Gray, Gray Sky Solutions, August 2011

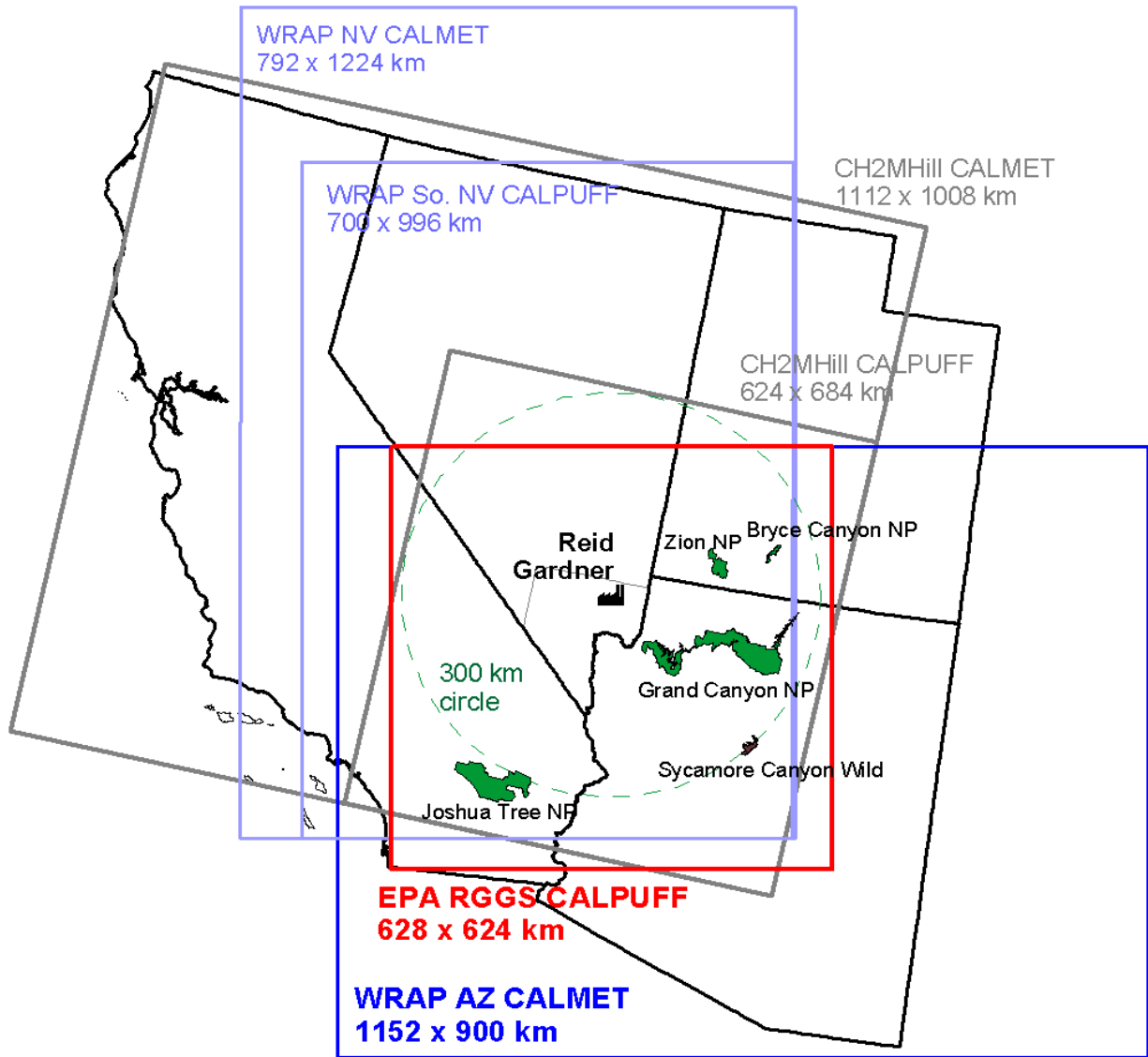
Compared to other modeling efforts involving RGGGS, the results of our CALPUFF modeling indicate lower visibility impacts, as well as lower visibility improvement attributable to the various NO_x control technologies (both from baseline and incremental). As described further below, we examined the sensitivity of visibility impacts to multiple variables in order to better understand our model results. Based on the results of our sensitivity analysis, we have identified the most important differences as 1) the use of different CALMET versions, and 2) the use of certain non-default puff control parameters by the WRAP.

Regarding CALMET versions, EPA used the regulatory version of CALMET (version 5.8), while others used post-5.8 versions. The particular non-default puff parameters used by WRAP were not addressed in the WRAP protocol. While these alternative values are not necessarily wrong for application of the model to this area, they are not further explained in the WRAP documentation, and make a substantial difference to the modeled impacts:

- MXSAM Max sampling steps for one time step: 99 (default) vs. 5 (WRAP)
- CDIV(2) divergence criteria: 0 & 0 (default) vs. .01 & .01 (WRAP)
- SL2PF Slug-to-puff transition: 10 (default) vs. 5 (WRAP)
- NSPLIT number of puffs after split 3 (default) vs. 2 (WRAP)

Figure 2. Model Domains for Various CALPUFF Modeling Efforts

Reid Gardner Generating Station CALPUFF and CALMET Modeling Domains



Projection:
Lambert Conformal Conic
Projection Origin: -97°, 40°
Standard Parallels: 33°, 45°
Spheroid: 6370 km sphere "NWS-84"

0 100 200 300 400 500
Scale in Kilometers

RGGGS_domains.gsm 2012-04-02

Table 14. CALPUFF settings differences for various model applications

| Processor | Item | WRAP | Nevada Energy | Gray | EPA |
|-----------------|----------------------------------|--|--|--|---|
| CALMET | CALMET version | 6.211 | 6.211 | 6.211 | 5.8 |
| | parameters | mainly default | mainly default | mainly default | mainly default; smaller influence radii |
| | MM5 inputs | 2001: Alpine Geophysics; 2002: WRAP RMC; 2003: LADCO | 2001 & 2002: Alpine Geophysics; 2003: LADCO | same as Nevada Energy | same as WRAP |
| | upper air obs. | Not included | Not included | Not included | Included |
| | domain | NV WRAP domain; includes all of NV | RGGS-centered, includes all of NV and most of California | RGGS-centered, includes all of NV and most of California | AZ WRAP domain; includes half of NV and all of AZ |
| | domain size, km | 792 x 1224 | 1112 x 1008 | 1112 x 1008 | 1152 x 900 |
| | proj. (origin); parallels; datum | LCC (40, 97); 33; 45; NWS-84 | LCC (40, 117); 33; 45; NAD83 | LCC (40, 117); 33; 45; NAD83 | LCC (40, 97); 33; 45; NWS-84 |
| CALPUFF | CALPUFF version | 6.112 | 6.112 | 6.262 | 5.8 |
| | parameters | some puff non-defaults | defaults | defaults | defaults |
| | domain | So. NV WRAP domain; almost all of NV | square about RGGS (CH2M coords) | square about RGGS (CH2M coords) | square about RGGS (WRAP coords) |
| | domain size, km | 700 x 996 | 624 x 684 | 624 x 684 | 628 x 624 |
| | max mix ht, m | 4500 (orig. 3000) | 4500 | 4500 | 4500 |
| | PM speciation | Total PM as PM fine | SO4, EC, OC, PMF, PMC | SO4, EC, OC, PMF, PMC | SO4, EC, OC, PMF, PMC |
| POSTUTIL | POSTUTIL version | <1.5? | 1.52 | 1.52? | 1.56 |
| CALPOST | CALPOST version | 6.1? | 6.131 | 6.221 | 6.221 (also 5.6394) |
| | visibility method | 6 | 6 | 8 | 6 and 8 |
| | natural background | annual average | annual average | annual average | annual average and B20 |

Comparison of Baseline Impacts

The EPA-modeled impacts for Grand Canyon National Park are roughly one-third of those modeled by Nevada Energy for the base case (EPA “c04”; Nevada Energy “Base/LNB+OFA”). For visibility method 6, annual average background (“vm6a”), the EPA modeled impact for the all three units for the base case is 0.46 dv (average of the three years); Nevada Energy found an impact of 0.46 dv for Unit 1 alone. Summing the Nevada Energy impact for all three units, and discounting by 8% (to account for the difference between modeling units separately vs. together, as shown in Table 15 for GRCA) gives $(0.46+0.45+0.36)*92\% = 1.17$ dv for Nevada Energy, as compared to 0.46 dv for EPA.

A similar ratio applies to the WRAP base case (EPA “c00”; Nevada Energy “rm” or “WRAP baseline”), where EPA modeled 0.61 dv, roughly a third of the Nevada Energy modeled $(0.81+0.80+0.76)*92\% = 2.18$ dv. The comparable result for the modeling by Gray was 2.17 dv (though this used visibility method 8 instead of 6). For comparison, the WRAP itself found 1.25 dv for all three units for the base case. The EPA results are thus roughly 50% lower than WRAP, whereas the Nevada Energy and Gray results are about 50% higher than WRAP’s for the WRAP base case.

The modeling performed by Gray Sky Solutions matched the modeling by Nevada Energy in most particulars, however it did use a slightly later CALPUFF version. In addition, the SCR scenario modeled included a substantial SO₂ reduction, so the results are not directly comparable to the NO_x-only reductions in the Nevada Energy and EPA modeling of SCR.

Sensitivity Analysis

There are substantial differences between the visibility impacts modeled by the WRAP, Nevada Energy, and EPA, even with (nearly) identical emission inputs. This is because of the different meteorological inputs to CALMET used, and by the different versions of CALMET and CALPUFF.

To better understand these differences, EPA conducted a series of sensitivity simulations for the 2001 meteorology year (the one with the highest impacts). The series started with EPA’s WRAP base case (c00) input files, and changed various inputs to make them more like the inputs used by the WRAP. (Actually, in preparing the model input files, the WRAP’s own input files were used as a starting point, except for the “c00” and “cwe” scenarios.) All runs used visibility method 6, with annual average natural background concentrations. The results are detailed in the accompanying table below, “Comparison of EPA’s RGGGS CALPUFF modeling and variants to WRAP BART modeling results” (also available in accompanying spreadsheet, “WRAP_compare_tables.xls”), but the results are summarized here.

Starting from EPA’s c00 base case, a new “cwe” control case (WRAP emissions) was run that used the same NO_x emissions and PM emissions and speciation that the

WRAP used, that is, total particulate matter (PM) modeled as fine particulate (PMF), rather than separated into chemical components. The results of this model run resulted in a decrease in 98th percentile delta deciview visibility impacts by only a few percent.

The next simulation was WRAP's own CALPUFF input files, including the puff parameter changes noted above. This resulted in over a 50% increase in Grand Canyon impacts, with smaller changes at the other areas (and a 2% decrease at Sycamore Canyon). Thus, the puff parameters account for a large proportion of the difference between the EPA and the WRAP results.

The CALPOST post-processor version was next changed from 5.6394 to 6.131, which was the version available around the time that the WRAP and Nevada Energy were performing modeling. Thus, the CALPOST version had no effect on the visibility impacts.

The CALPUFF model itself was then changed, from 5.8 to the 6.112 version used by the WRAP. This had essentially no effect on the visibility impacts, although they appear shifted by one day due to the convention used in later versions of stating dates in terms of their ending hour, rather than their starting hour. (So, 2001-01-01 appears as 2000-12-31 in the later CALPUFF version.) Thus, the CALPUFF version had essentially no effect on the visibility impacts.

The remaining comparison is between the WRAP modeling itself and EPA modeling using the same emissions, PM speciation, CALPUFF settings, and CALPUFF and CALPOST versions that the WRAP used, but with different meteorology and CALMET versions. In changing from the AECOM meteorology used by EPA to the meteorology used by WRAP, visibility impacts increased by some 60%. Thus, the CALMET version, incorporation of upper air data, and possibly meteorological domain account for a large proportion of the difference between the EPA and the WRAP results.

The substantial differences between EPA and WRAP results for the WRAP base case for RGGS can therefore be attributed in part to differences in CALPUFF puff parameters, and especially to differences in the version of CALMET used. Differences in model domains may also play a role. The CALMET and CALPUFF domains cover different territory and thus will have slightly different meteorology; in addition, puffs that advect out of one domain and are lost to the simulation may remain within the other domain and affect visibility estimates.

Additional Analysis of Model Results

As an additional check, EPA examined visibility, sulfate, and nitrate over the entire modeling domain, i.e. with "gridded" receptors, instead of the receptor sets within the Class I areas. It is possible that overall visibility impacts were similar between the various simulations, but they occurred at different locations; that is, a dense plume may have hit the Grand Canyon in the WRAP simulation, but missed it in the EPA

simulation because of wind direction differences. Little was discovered from the gridded simulations, but the biggest shift was seen with the change from default to WRAP non-default puff parameters (gridded results from the WRAP modeling itself were not available for comparison). Extinction and concentration isopleths for these simulations are shown in Figure 3, “Reid Gardner, 8th High at Each Gridded Receptor” and Figure 4 “Reid Gardner, 1st High at Each Gridded Receptor.” For both figures, the main difference between the two simulations appears to be that the zone of higher visibility and nitrate impacts has a lobe to the northeast, suggesting stronger wind transport in that direction, and resulting in higher impact regions reaching the western end of the Grand Canyon. Because these plots are of the ranked values, e.g. the 8th high over the entire year, the plots are composites of results on many days; a much more detailed analysis would be needed to understand why the results differ between the simulations. However, the overall similarity of the impact patterns at least gives some assurance that no gross error was made in preparing the simulation inputs.

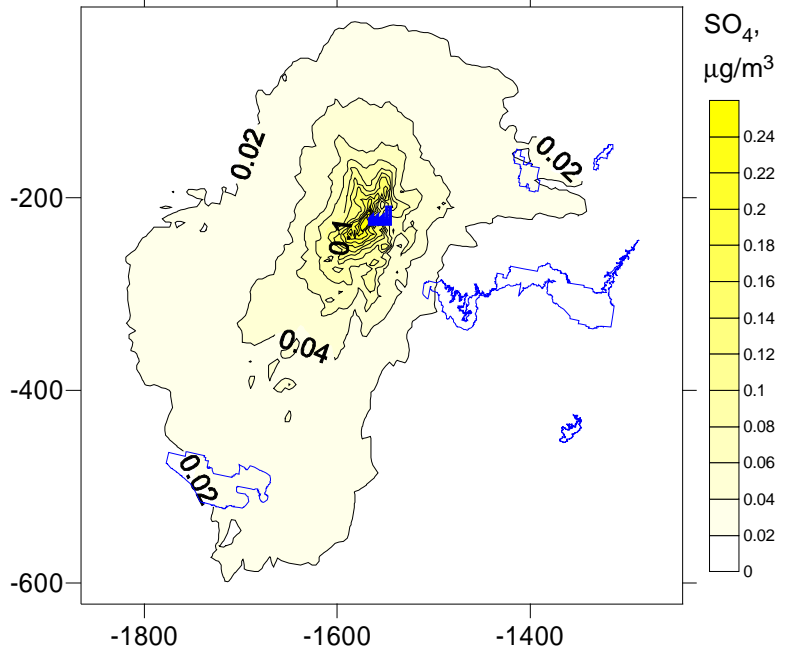
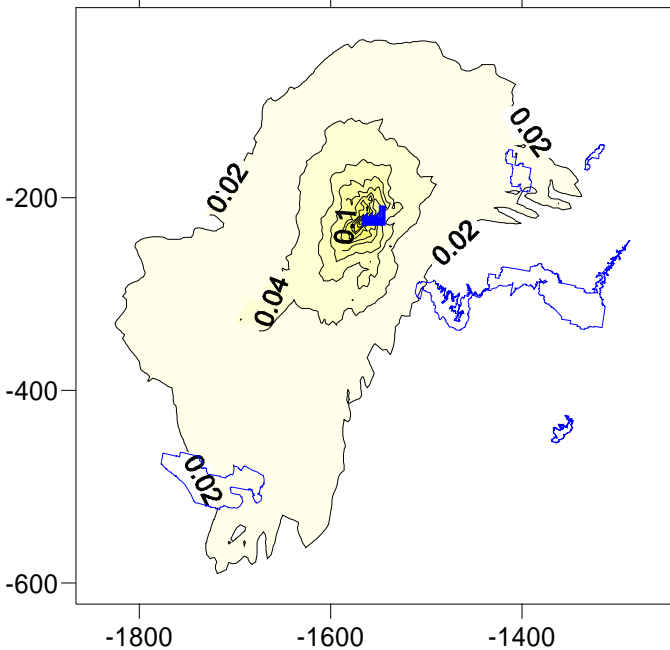
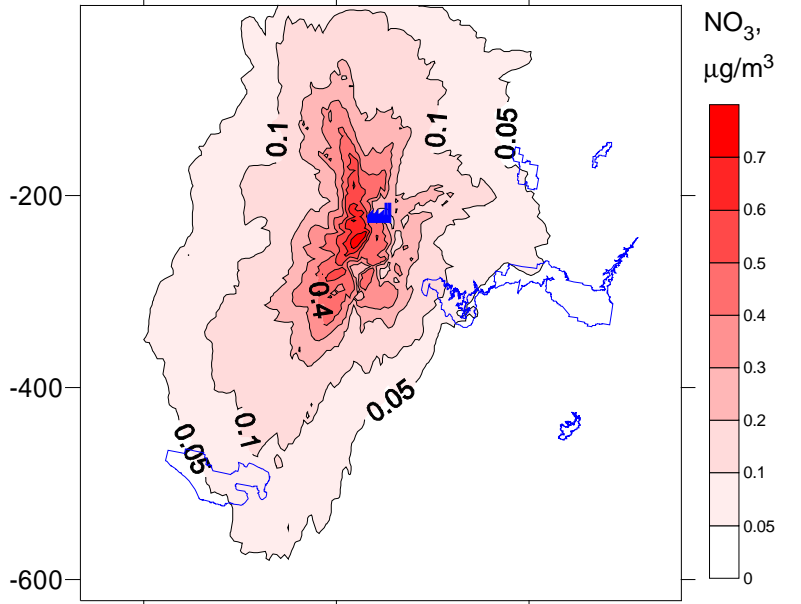
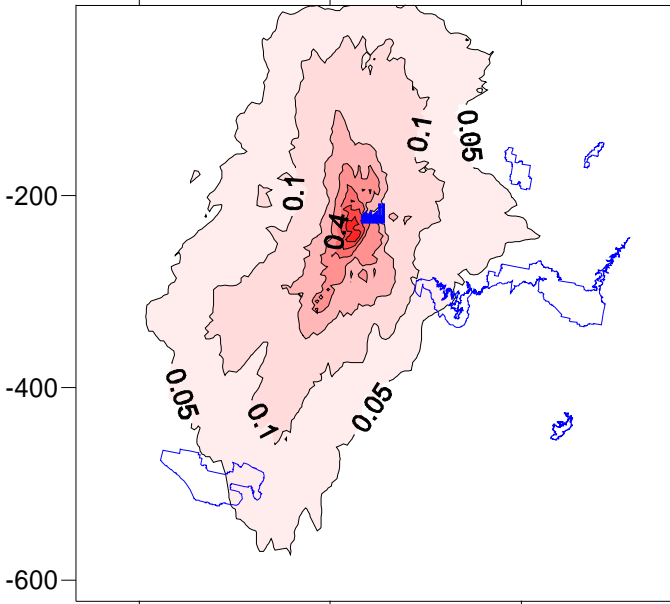
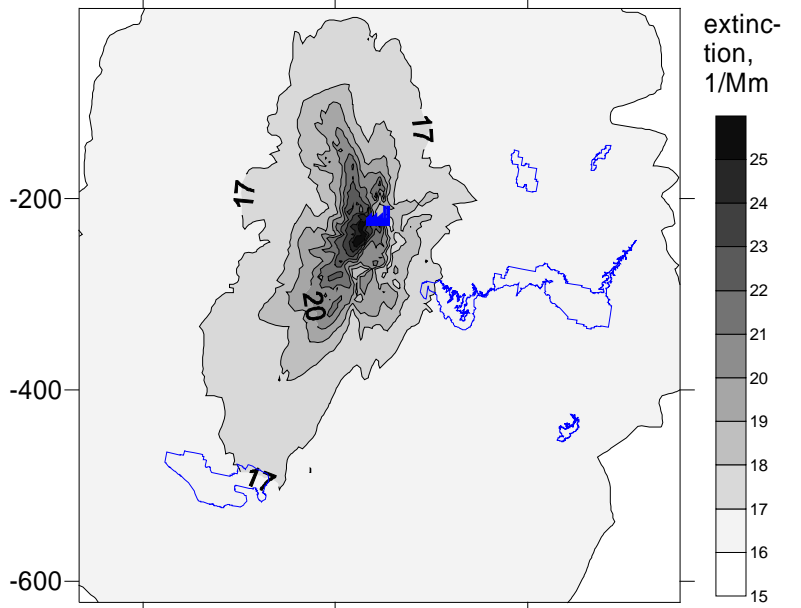
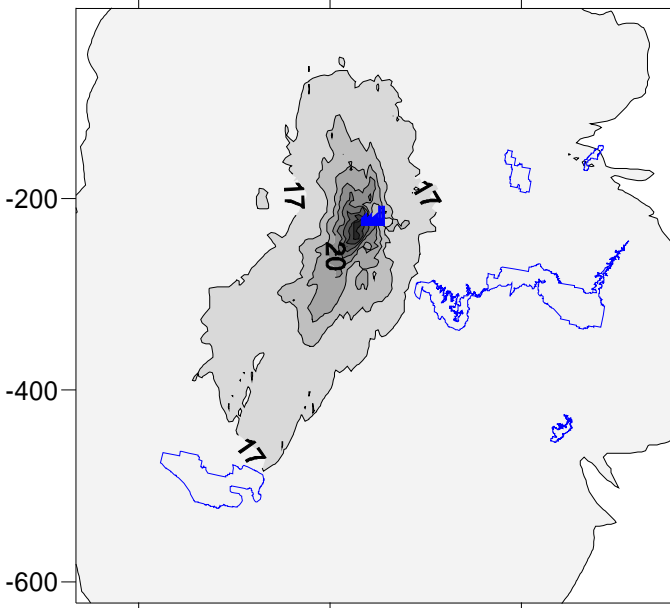
A few additional test runs showed that on average, modeling the three units separately and adding the results gave 98th percentile delta deciview impacts about 4% higher than when the units are modeled together in a single CALPUFF run. This may reflect the competition of sulfate and nitrate in the plumes for available ammonia when the units are modeled together. The results for Grand Canyon are the basis for the “8% discount” applied above to the sum of impacts from individually modeled units.

**Table 15. Comparison of CALPUFF Results:
Sum of individual unit results vs. Modeling all units together in single model run**

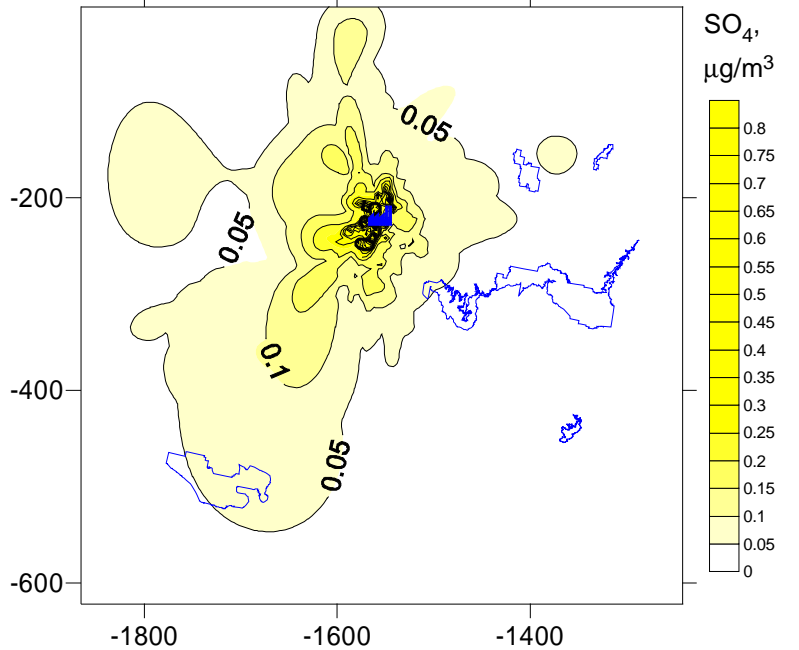
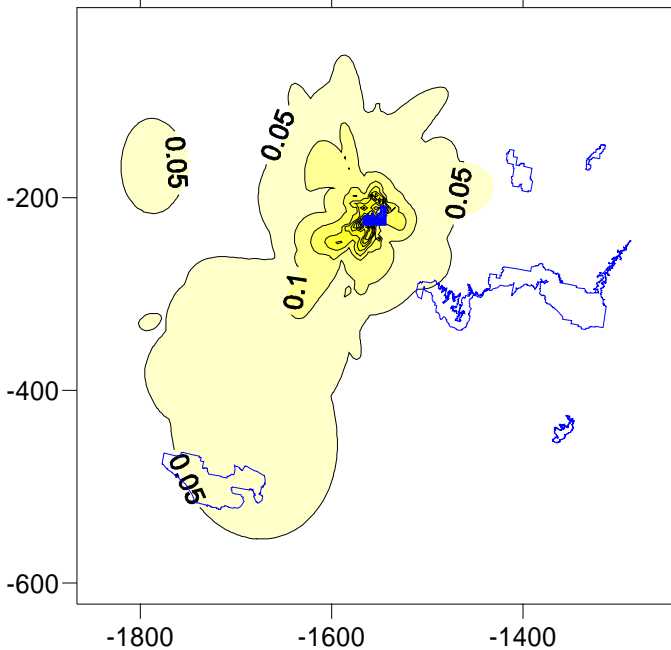
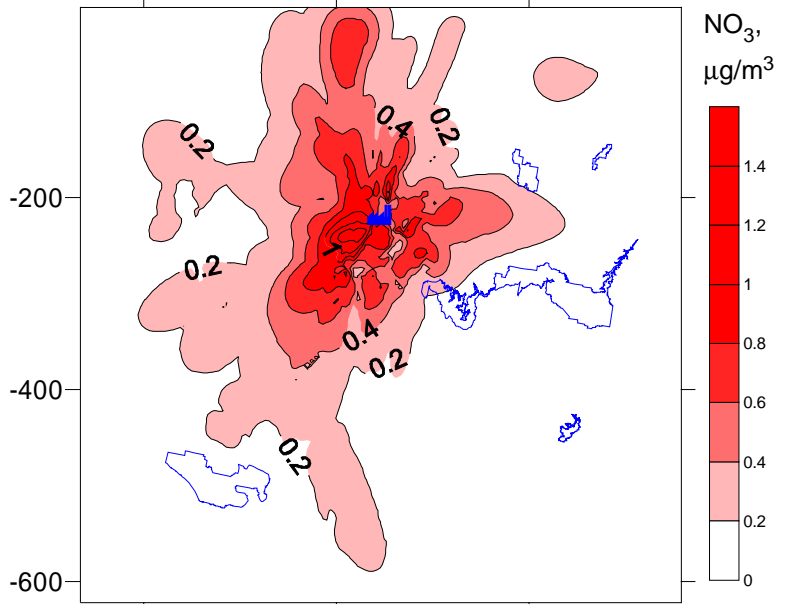
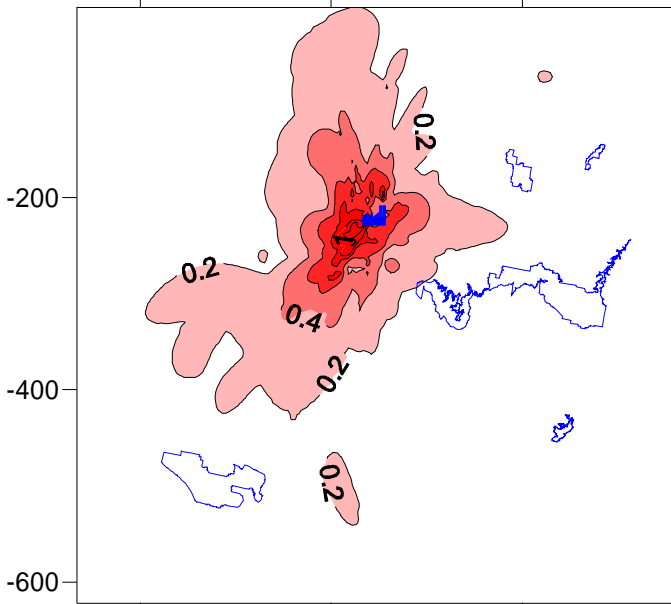
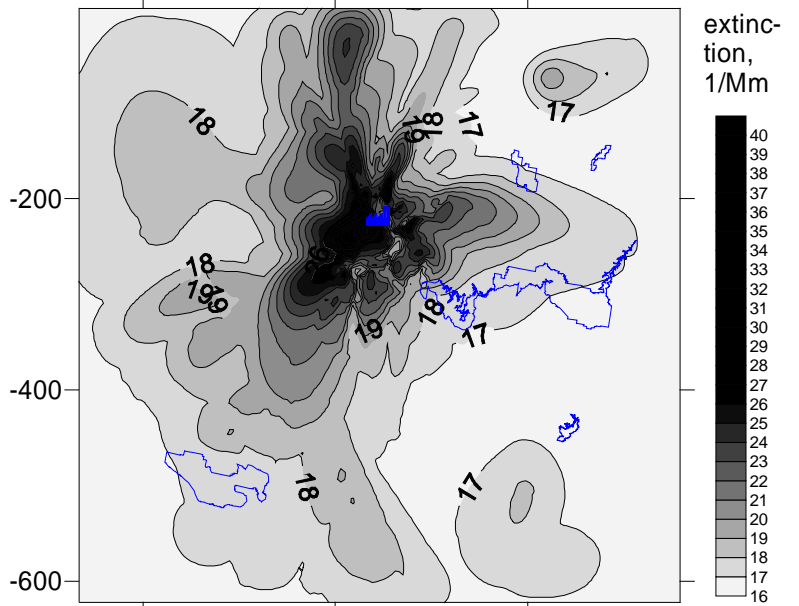
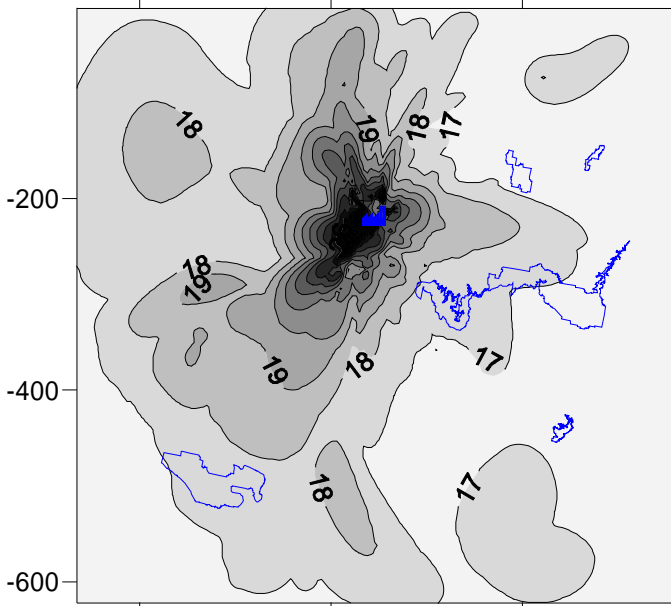
| Class I Area | Visibility Impact (dv) ¹ | | | | | % difference |
|--------------|-------------------------------------|--------|--------|--------------|------------------|--------------|
| | Unit 1 | Unit 2 | Unit 3 | simple sum | modeled together | |
| brca | 0.059 | 0.061 | 0.061 | 0.181 | 0.181 | 0% |
| grca | 0.254 | 0.264 | 0.264 | 0.782 | 0.725 | 8% |
| jotr | 0.233 | 0.229 | 0.229 | 0.691 | 0.663 | 4% |
| sycr | 0.045 | 0.039 | 0.039 | 0.123 | 0.127 | -3% |
| zion | 0.103 | 0.105 | 0.105 | 0.313 | 0.307 | 2% |
| Total | -- | -- | -- | 2.090 | 2.003 | 4% |

¹Based on 98th percentile impact using visibility method 6 and annual average natural background

Reid Gardner, 8th High at Each Gridded Receptor (628 x 624 km domain, 4 km grid cells)
EPA CALPUFF parameters WRAP CALPUFF parameters



Reid Gardner, 1st High at Each Gridded Receptor (628 x 624 km domain, 4 km grid cells)
EPA CALPUFF parameters WRAP CALPUFF parameters



6. Federal Implementation Plan (FIP) Elements

We are proposing to disapprove certain elements of the Nevada RH SIP and propose a corresponding FIP for these elements. The RH SIP elements we are disapproving include 1) the NO_x emission limit of 0.28 lb/MMBtu for Unit 3, and 2) the rolling 12-month averaging period for monitoring NO_x emissions for Units 1 through 3.

A. Unit 3 Emission Limit

We are proposing to promulgate a FIP to establish a NO_x emission limit of 0.20 lb/MMBtu for Unit 3. In its RH SIP, NDEP proposed a NO_x emission limit of 0.28 lb/MMBtu for Unit 3. This limit for Unit 3 (0.28 lb/MMBtu) was higher than the emission limit NDEP proposed for Units 1 or 2 (0.20 lb/MMBtu each). The higher emission limit appears to be partially attributable to the fact that the application of control technology to Unit 3 results in less stringent levels of performance relative to Units 1 and 2. As shown in Table 5 of this notice, Nevada Energy's emission estimates indicate that application of ROFA with Rotamix achieves nearly 60 percent reduction from baseline on Units 1 and 2, but only a 38 percent reduction from baseline on Unit 3. These percent reduction values were used by NDEP in developing its own estimate of NO_x emissions, which form the basis for the proposed NO_x limits.

Nevada Energy's BART analysis for Unit 3 did not provide a unit-specific explanation for this difference in control effectiveness. In responding to comments on this issue, NDEP indicated that it deferred to Nevada Energy's operational experience in developing control efficiency data, and had no reason to question their estimates.³² The case-by-case nature of the BART determination process does provide for the consideration of site-specific and unit-specific characteristics in the BART analysis.³³ While there may be unique characteristics associated with Unit 3 that justify the lower percent reduction values used by Nevada Energy and NDEP, we do not find the information in the record on this issue to be at a sufficient level of detail to support this determination.

In the absence of what we consider sufficient justification by Nevada Energy and NDEP, we have evaluated Unit 3 control option emissions predicated upon similar levels of performance relative to Units 1 and 2. Based upon the Unit 3 baseline emissions relied upon by NDEP (described in the 'NDEP' column in Table 5), if a percent reduction similar to Units 1 and 2 were applied to Unit 3 baseline emissions, it can be expected to attain a NO_x emission rate of 0.20 lb/MMBtu using the ROFA with Rotamix control option.

B. Averaging Period

In its RH SIP, NDEP proposed NO_x limits with a 12-month rolling averaging period for Unit 1 through 3, which is a longer averaging period than the 30-day rolling

³² Page D-37, Appendix D and C-9, Appendix C, Nevada RH SIP. Available as attachments to EPA-R09-OAR-2011-0130-0003

³³ For example, when determining what control options are considered technically feasible at a specific unit, 70 FR 39165

average indicated by the BART Guidelines. Longer averaging periods allow operators the flexibility to “smooth out” short-term emission spikes by averaging those values with periods of lower emission rates. In responding to comments on this issue in their RH SIP, NDEP indicated that Nevada Energy expected a high degree of operational variability with the ROFA with Rotamix control option based upon previous operational experience with ROFA.³⁴

A summary of NOx emission rates from Units 1 through 3 as reported by the Clean Air Markets Division (CAMD) is included in Appendix D, and includes annual and monthly average emissions over a 2001-11 time frame. Monthly average NOx data over a 2010-11 time period indicates a certain degree of fluctuation, as well as a general downward trend in NOx emissions. NDEP has indicated that the downward trend in NOx emissions is partially due to the use of a coal fuel stream that consists of a mixture of bituminous and sub-bituminous coal. Specifically, the Utah/Colorado coal that has historically represented the entirety of the fuel stream to Units 1 through 3 has recently been supplemented with varying amounts of lower-nitrogen content Wyoming sub-bituminous coal.³⁵ Although operational flexibility can be a legitimate consideration when establishing an enforceable limit, we consider use of a rolling 12-month averaging period instead of a rolling 30-day average to be inconsistent with BART Guidelines.³⁶ We believe the fluctuations of the NOx emissions from each of the units is better dealt with by averaging the emissions from the three units to determine compliance over the 30-day rolling average.

³⁴ Page D-60, Appendix D, Nevada RH SIP. A

³⁵ Email dated March 18, 2012, from Mike Elges (NDEP) to Colleen McKaughan (EPA)

³⁶ 70 FR 39172

Appendix A:

EPA Analysis of NOx Control Cost Estimates (from original RH SIP) for Reid Gardner
Generating Station

See www.regulations.gov, docket ID number EPA-R09-OAR-2011-0130

Comparison of SCR Control Costs (Original, 2008)

| Parameter | Reid Gardner | | | | | |
|-----------------------------------|---------------|---------------|---------------|--------------|---------------|--------------|
| | Unit 1 | | Unit 2 | | Unit 3 | |
| | NDEP | Revised EPA | NDEP | Revised EPA | NDEP | Revised EPA |
| Unit Output (kW) | 100,000 | | 100,000 | | 100,000 | |
| Heat Input (MMBtu/hr) | 1132 | | 1132 | | 1132 | |
| Boiler Type | Wall-fired | | Wall-fired | | Wall-fired | |
| Ctrl technology | SCR+LNB+OFA | | SCR+LNB+OFA | | SCR+LNB+OFA | |
| Ctrl Emission Rate (lb/MMBtu) | 0.085 | 0.085 | 0.083 | 0.083 | 0.098 | 0.098 |
| Total Capital Costs | \$35,048,000 | \$26,840,000 | \$35,048,000 | \$26,840,000 | \$35,048,000 | \$26,840,000 |
| Total Annual Costs | | | | | | |
| Fixed Costs | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 |
| Variable Costs | \$699,801 | \$699,801 | \$748,551 | \$748,551 | \$670,893 | \$670,893 |
| Capital Recovery | \$3,703,556 | \$2,533,506 | \$3,703,556 | \$2,533,506 | \$3,703,556 | \$2,533,506 |
| | 20 yrs @ 8.5% | 20 yrs @ 7.0% | 20 yrs @ 8.5% | 20 yrs @ 7% | 20 yrs @ 8.5% | 20 yrs @ 7% |
| Total Annual Costs | \$4,733,357 | \$3,563,307 | \$4,782,107 | \$3,612,057 | \$4,704,449 | \$3,534,399 |
| NOx Removed from baseline (tpy) | 1,850 | 1,850 | 2,010 | 2,009 | 1,774 | 1,775 |
| Average Cost per ton (\$/ton) | \$2,559 | \$1,926 | \$2,379 | \$1,798 | \$2,652 | \$1,991 |
| Incremental Cost per ton (\$/ton) | \$5,684 | \$4,067 | \$5,425 | \$3,885 | \$3,446 | \$2,477 |
| Previous ctrl technology | ROFA+Rotamix | | ROFA+Rotamix | | ROFA+Rotamix | |

Reid Gardner NOx Control Effectiveness Summary - EPA Revised Costs

| Unit No. | Annual Heat Input ¹ (MMBtu/yr) |
|----------|--|
| Unit 1 | 9,818,313 |
| Unit 2 | 10,501,749 |
| Unit 3 | 10,063,851 |

| Unit No. | Parameter | Units | Baseline ² | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | SCR+LNB+OFA | SCR+ROFA |
|----------|--------------------------------|------------|-----------------------|-----------|--------------|--------------|--------------|--------------|
| Unit 1 | Emission Rate | (tpy) | 2,267 | 1,784 | 1,340 | 959 | 417 | 417 |
| | Removed | (tpy) | -- | 483 | 927 | 1,308 | 1,850 | 1,850 |
| | Removal Rate | (%) | -- | 21.3% | 40.9% | 57.7% | 81.6% | 81.6% |
| | Emission Factor | (lb/MMBtu) | 0.462 | 0.363 | 0.273 | 0.195 | 0.085 | 0.085 |
| | Annual Cost | (\$) | | \$442,469 | \$946,040 | \$1,360,867 | \$3,563,307 | \$4,084,427 |
| | Average Cost Effectiveness | (\$/ton) | | \$916 | \$1,021 | \$1,040 | \$1,926 | \$2,208 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$1,135 | \$1,088 | \$4,067 | \$5,030 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |
| Unit 2 | Emission Rate | (tpy) | 2,445 | 1,866 | 1,401 | 1,003 | 436 | 436 |
| | Removed | (tpy) | -- | 579 | 1,044 | 1,442 | 2,009 | 2,009 |
| | Removal Rate | (%) | -- | 23.7% | 42.7% | 59.0% | 82.2% | 82.2% |
| | Emission Factor | (lb/MMBtu) | 0.466 | 0.355 | 0.267 | 0.191 | 0.083 | 0.083 |
| | Annual Cost | (\$) | | \$442,469 | \$968,449 | \$1,408,676 | \$3,612,057 | \$4,159,306 |
| | Average Cost Effectiveness | (\$/ton) | | \$764 | \$928 | \$977 | \$1,798 | \$2,070 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$1,131 | \$1,106 | \$3,885 | \$4,850 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |
| Unit 3 | Emission Rate | (tpy) | 2,268 | 2,118 | 1,590 | 1,399 | 493 | 493 |
| | Removed | (tpy) | -- | 150 | 678 | 869 | 1,775 | 1,775 |
| | Removal Rate | (%) | -- | 7% | 30% | 38% | 78% | 78% |
| | Emission Factor | (lb/MMBtu) | 0.451 | 0.421 | 0.316 | 0.278 | 0.098 | 0.098 |
| | Annual Cost | (\$) | | \$442,469 | \$895,762 | \$1,290,483 | \$3,534,399 | \$4,091,349 |
| | Average Cost Effectiveness | (\$/ton) | | \$2,958 | \$1,321 | \$1,485 | \$1,991 | \$2,305 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$858 | \$2,064 | \$2,477 | \$3,092 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |

1) Based on NDEP Reid-Gardner BART Determination, October 22, 2009, Table 1. Heat input values appear to be based on 1.0 capacity factor and 1152 MMBtu/hr

2) Baseline emissions and control option emissions based upon NDEP's October 22, 2009 BART determination, Table 1. Based on NDEP baseline, which is higher than NVE submittal. By comparison, NVE's Unit 1 baseline was 1625 tpy NOx

Reid Gardner NOx Emission Estimates (Based upon NDEP Cost and Control Estimates)

| Unit No. | Annual Heat Input ¹ (MMBtu/yr) |
|----------|--|
| Unit 1 | 9,818,313 |
| Unit 2 | 10,501,749 |
| Unit 3 | 10,063,851 |

| Unit No. | Parameter | Units | Baseline ² | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | SCR+LNB+OFA | SCR+ROFA |
|----------|---|------------|-----------------------|-----------|--------------|--------------|-------------|-------------|
| Unit 1 | Emission Rate | (tpy) | 2,267 | 1,784 | 1,340 | 959 | 417 | 417 |
| | Removed | (tpy) | -- | 483 | 927 | 1,308 | 1,850 | 1,850 |
| | Removal Rate | (%) | -- | 21.3% | 40.9% | 57.7% | 81.6% | 81.6% |
| | Emission Factor | (lb/MMBtu) | 0.462 | 0.363 | 0.273 | 0.195 | 0.085 | 0.085 |
| | Annual Cost | (\$) | | \$550,024 | \$1,130,186 | \$1,652,724 | \$4,733,357 | \$5,379,929 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$1,139 | \$1,219 | \$1,264 | \$2,559 | \$2,908 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$1,307 | \$1,371 | \$5,684 | \$6,877 |
| Unit 2 | Emission Rate | (tpy) | 2,445 | 1,866 | 1,401 | 1,003 | 435 | 435 |
| | Removed | (tpy) | -- | 579 | 1,044 | 1,442 | 2,010 | 2,010 |
| | Removal Rate | (%) | -- | 23.7% | 42.7% | 59.0% | 82.2% | 82.2% |
| | Emission Factor | (lb/MMBtu) | 0.466 | 0.355 | 0.267 | 0.191 | 0.083 | 0.083 |
| | Annual Cost | (\$) | | \$550,024 | \$1,152,595 | \$1,700,533 | \$4,782,107 | \$5,454,808 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$950 | \$1,104 | \$1,179 | \$2,379 | \$2,714 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$1,296 | \$1,377 | \$5,425 | \$6,610 |
| Unit 3 | Emission Rate | (tpy) | 2,268 | 2,121 | 1,590 | 1,400 | 494 | 494 |
| | Removed | (tpy) | -- | 147 | 678 | 868 | 1,774 | 1,774 |
| | Removal Rate | (%) | -- | 6.5% | 29.9% | 38.3% | 78.2% | 78.2% |
| | Emission Factor | (lb/MMBtu) | 0.451 | 0.421 | 0.316 | 0.278 | 0.098 | 0.098 |
| | Annual Cost | (\$) | | \$550,024 | \$1,079,908 | \$1,582,340 | \$4,704,449 | \$5,386,851 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$3,742 | \$1,593 | \$1,823 | \$2,652 | \$3,037 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$998 | \$2,644 | \$3,446 | \$4,199 |

- 1) As listed in NDEP Reid-Gardner BART Determination, October 22, 2009, Table 1, "Base Heat Input." Based on listed emission rates and emission factors, "base heat input" and not "total heat input" was used.
- 2) Baseline emissions and control option emissions based upon NDEP's October 22, 2009 BART determination, Table 1. Based on NDEP baseline, which is higher than NVE submittal. By comparison, NVE's Unit 1 baseline was 1625 tpy NOx
- 3) Average and incremental cost effectiveness values as reported in NDEP's October 22, 2009 BART determination, Table 1.

Control Cost Comparison - LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | | | Unit 2 | | Unit 3 | | Comments |
|--|--------------------|-----|------------------------|-----|--------------------|--------------------|--------------------|--------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP | EPA Revised Cost | NDEP | EPA Revised Cost | |
| Capital Costs | | | | | | | | | |
| Low Nox Burners (Upgrade) + OFA/ROFA | | | | | | | | | |
| Major Materials Design and Supply Construction | \$1,600,000 | | \$1,600,000 | | \$1,600,000 | \$1,600,000 | \$1,600,000 | \$1,600,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$1,120,000 | 70% | \$1,120,000 | 70% | \$1,120,000 | \$1,120,000 | \$1,120,000 | \$1,120,000 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not |
| Balance of Plant | \$800,000 | 50% | \$800,000 | 50% | \$800,000 | \$800,000 | \$800,000 | \$800,000 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$80,000 | 5% | \$80,000 | 5% | \$80,000 | \$80,000 | \$80,000 | \$80,000 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$160,000 | 10% | \$0 | 0% | \$160,000 | \$0 | \$160,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$256,000 | 16% | \$0 | 0% | \$256,000 | \$0 | \$256,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$192,000 | 12% | \$0 | 0% | \$192,000 | \$0 | \$192,000 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, LNB+OFA Capital Cost | \$4,208,000 | | \$3,600,000 | | \$4,208,000 | \$3,600,000 | \$4,208,000 | \$3,600,000 | |
| Contingency | \$240,000 | 15% | \$240,000 | 15% | \$240,000 | \$240,000 | \$240,000 | \$240,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total LNB+OFA Capital Cost | \$4,448,000 | | \$3,840,000 | | \$4,448,000 | \$3,840,000 | \$4,448,000 | \$3,840,000 | |
| Total Capital Cost | \$4,448,000 | | \$3,840,000 | | \$4,448,000 | \$3,840,000 | \$4,448,000 | \$3,840,000 | |

Control Cost Comparison - LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|------------|--------------------|------------|--------------------|------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$32,000 | \$32,000 | \$32,000 | \$32,000 | \$32,000 | \$32,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$80,000 | \$80,000 | \$80,000 | \$80,000 | \$80,000 | \$80,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | |
| Debt Service/Capital Recovery ¹⁾ | \$470,024 | \$362,469 | \$470,024 | \$362,469 | \$470,024 | \$362,469 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$550,024 | \$442,469 | \$550,024 | \$442,469 | \$550,024 | \$442,469 | |

- 1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - LNB+OFA+SNCR

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Capital Costs | | | | | | | |
| Low NOx Burners (Upgrade) + OFA | | | | | | | |
| Major Materials Design and Supply Construction | \$1,600,000 | | \$1,600,000 | | \$1,600,000 | \$1,600,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$1,120,000 | 70% | \$1,120,000 | 70% | \$1,120,000 | \$1,120,000 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP |
| Balance of Plant | \$800,000 | 50% | \$800,000 | 50% | \$800,000 | \$800,000 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$80,000 | 5% | \$80,000 | 5% | \$80,000 | \$80,000 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$160,000 | 10% | \$0 | 0% | \$160,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$256,000 | 16% | \$0 | 0% | \$256,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$192,000 | 12% | \$0 | 0% | \$192,000 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, LNB+OFA Capital Cost | \$4,208,000 | | \$3,600,000 | | \$4,208,000 | \$3,600,000 | |
| Contingency | \$240,000 | 15% | \$240,000 | 15% | \$240,000 | \$240,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total LNB+OFA Capital Cost | \$4,448,000 | | \$3,840,000 | | \$4,448,000 | \$3,840,000 | |
| Selective Non-Catalytic Reduction (SNCR) | | | | | | | |
| Major Materials Design and Supply Construction | \$1,350,000 | | \$1,350,000 | | \$1,350,000 | \$1,350,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in |
| Construction | \$202,500 | 15.0% | \$202,500 | 15% | \$202,500 | \$202,500 | See comments in LNB+OFA section above. While these costs do not directly correspond to EPA CCM line items, they are comparable to certain allowed costs. As a result, these costs are retained without revision. |
| Balance of Plant | \$162,000 | 12.0% | \$162,000 | 12% | \$162,000 | \$162,000 | |
| Electrical (Allowance) | \$67,500 | 5.0% | \$67,500 | 5% | \$67,500 | \$67,500 | |
| Owner's Costs | \$135,000 | 10.0% | \$0 | 0% | \$135,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$216,000 | 16.0% | \$0 | 0% | \$216,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$162,000 | 12.0% | \$0 | 0% | \$162,000 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual |
| Subtotal, SCR Capital Cost | \$2,295,000 | | \$1,782,000 | | \$2,295,000 | \$1,782,000 | |
| Contingency | \$202,500 | 15% | \$202,500 | 15% | \$202,500 | \$202,500 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total SNCR Capital Cost | \$2,497,500 | | \$1,984,500 | | \$2,497,500 | \$1,984,500 | |
| Total Capital Cost | \$6,945,500 | | \$5,824,500 | | \$6,945,500 | \$5,824,500 | |

Control Cost Comparison - LNB+OFA+SNCR

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|-------------|--------------------|-------------|--------------------|-------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$83,000 | \$83,000 | \$83,000 | \$83,000 | \$83,000 | \$83,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$124,500 | \$124,500 | \$124,500 | \$124,500 | \$124,500 | \$124,500 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$207,500 | \$207,500 | \$207,500 | \$207,500 | \$207,500 | \$207,500 | |
| Variable Costs | | | | | | | |
| Reagent | \$151,080 | \$151,080 | \$169,985 | \$169,985 | \$98,612 | \$98,612 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$37,668 | \$37,668 | \$41,172 | \$41,172 | \$39,858 | \$39,858 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$188,748 | \$188,748 | \$211,157 | \$211,157 | \$138,470 | \$138,470 | |
| Debt Service/Capital Recovery ¹ | \$733,938 | \$549,792 | \$733,938 | \$549,792 | \$733,938 | \$549,792 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$1,130,186 | \$946,040 | \$1,152,595 | \$968,449 | \$1,079,908 | \$895,762 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - ROFA+Rotami

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|--------------------|-------|------------------------|-----|--------------------|--------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP Value | EPA Revised Value | |
| Capital Costs | | | | | | | |
| Rotating Overfire Air (ROFA) | | | | | | | |
| Major Materials Design and Supply Construction | \$2,880,000 | | \$2,880,000 | | \$2,880,000 | \$2,880,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$742,500 | | \$742,500 | | \$742,500 | \$742,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$1,440,000 | 50% | \$1,440,000 | 50% | \$1,440,000 | \$1,440,000 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$864,000 | 30% | \$864,000 | 30% | \$864,000 | \$864,000 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$288,000 | 10% | \$0 | 0% | \$288,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$460,800 | 16% | \$0 | 0% | \$460,800 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$345,600 | 12% | \$0 | 0% | \$345,600 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, ROFA Capital Cost | \$7,020,900 | | \$5,926,500 | | \$7,020,900 | \$5,926,500 | |
| Contingency | \$864,000 | 30% | \$432,000 | 15% | \$864,000 | \$432,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total ROFA Capital Cost | \$7,884,900 | | \$6,358,500 | | \$7,884,900 | \$6,358,500 | |
| Rotamix | | | | | | | |
| Major Materials Design and Supply Construction | \$1,029,000 | | \$1,029,000 | | \$1,029,000 | \$1,029,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA above. |
| Construction | \$247,500 | | \$247,500 | | \$247,500 | \$247,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$123,480 | 12.0% | \$123,480 | 12% | \$123,480 | \$123,480 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Owner's Costs | \$102,900 | 10.0% | \$0 | 0% | \$102,900 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$164,640 | 16.0% | \$0 | 0% | \$164,640 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$123,480 | 12.0% | \$0 | 0% | \$123,480 | \$0 | AFUDC is not allowed for SNCR (comparable to Rotamix) in the EPA Control Cost Manual |
| Subtotal, Rotamix Capital Cost | \$1,791,000 | | \$1,399,980 | | \$1,791,000 | \$1,399,980 | |
| Contingency | \$154,350 | 15% | \$154,350 | 15% | \$154,350 | \$154,350 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total Rotamix Capital Cost | \$1,945,350 | | \$1,554,330 | | \$1,945,350 | \$1,554,330 | |
| Total Capital Cost | \$9,830,250 | | \$7,912,830 | | \$9,830,250 | \$7,912,830 | |

Control Cost Comparison - ROFA+Rotami

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised % | NDEP Value | EPA Revised % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$72,000 | \$72,000 | \$72,000 | \$72,000 | \$72,000 | \$72,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$120,000 | \$120,000 | \$120,000 | \$120,000 | \$120,000 | \$120,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$213,062 | \$213,062 | \$234,741 | \$234,741 | \$126,347 | \$126,347 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | |
| Auxiliary Power | \$280,890 | \$280,890 | \$307,020 | \$307,020 | \$297,221 | \$297,221 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SNCR (comparable to Rotamix) equipment. |
| Subtotal, variable costs | \$493,952 | \$493,952 | \$541,761 | \$541,761 | \$423,568 | \$423,568 | |
| Debt Service/Capital Recovery ¹ | \$1,038,772 | \$746,915 | \$1,038,772 | \$746,915 | \$1,038,772 | \$746,915 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Cost: | \$1,652,724 | \$1,360,867 | \$1,700,533 | \$1,408,676 | \$1,582,340 | \$1,290,483 | |

- 1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - SCR+LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | | | Unit 2 | | Unit 3 | | Comments |
|--|---------------------|-------|------------------------|-----|---------------------|---------------------|---------------------|---------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP | EPA Revised Cost | NDEP | EPA Revised Cost | |
| Capital Costs | | | | | | | | | |
| Low NOx Burners (Upgrade) + OFA | | | | | | | | | |
| Major Materials Design and Supply Construction | \$1,600,000 | | \$1,600,000 | | \$1,600,000 | \$1,600,000 | \$1,600,000 | \$1,600,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in t |
| Construction | \$1,120,000 | 70% | \$1,120,000 | 70% | \$1,120,000 | \$1,120,000 | \$1,120,000 | \$1,120,000 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix |
| Balance of Plant | \$800,000 | 50% | \$800,000 | 50% | \$800,000 | \$800,000 | \$800,000 | \$800,000 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$80,000 | 5% | \$80,000 | 5% | \$80,000 | \$80,000 | \$80,000 | \$80,000 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$160,000 | 10% | \$0 | 0% | \$160,000 | \$0 | \$160,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$256,000 | 16% | \$0 | 0% | \$256,000 | \$0 | \$256,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$192,000 | 12% | \$0 | 0% | \$192,000 | \$0 | \$192,000 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual, Section 4.2, Chap 2, Table 2.5 |
| Subtotal, LNB+OFA Capital Cost | \$4,208,000 | | \$3,600,000 | | \$4,208,000 | \$3,600,000 | \$4,208,000 | \$3,600,000 | |
| Contingency | \$240,000 | 15% | \$240,000 | 15% | \$240,000 | \$240,000 | \$240,000 | \$240,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total ROFA Capital Cost | \$4,448,000 | | \$3,840,000 | | \$4,448,000 | \$3,840,000 | \$4,448,000 | \$3,840,000 | |
| Selective Catalytic Reduction (SCR) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$20,000,000 | | \$20,000,000 | | \$20,000,000 | \$20,000,000 | \$20,000,000 | \$20,000,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA |
| Construction | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Balance of Plant | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Owner's Costs | \$2,000,000 | 10.0% | \$0 | 0% | \$2,000,000 | \$0 | \$2,000,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$3,200,000 | 16.0% | \$0 | 0% | \$3,200,000 | \$0 | \$3,200,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$2,400,000 | 12.0% | \$0 | 0% | \$2,400,000 | \$0 | \$2,400,000 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual |
| Subtotal, SCR Capital Cost | \$27,600,000 | | \$20,000,000 | | \$27,600,000 | \$20,000,000 | \$27,600,000 | \$20,000,000 | |
| Contingency | \$3,000,000 | 15% | \$3,000,000 | 15% | \$3,000,000 | \$3,000,000 | \$3,000,000 | \$3,000,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total SCR Capital Cost | \$30,600,000 | | \$23,000,000 | | \$30,600,000 | \$23,000,000 | \$30,600,000 | \$23,000,000 | |
| Total Capital Cost | \$35,048,000 | | \$26,840,000 | | \$35,048,000 | \$26,840,000 | \$35,048,000 | \$26,840,000 | |

Control Cost Comparison - SCR+LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$132,000 | \$132,000 | \$132,000 | \$132,000 | \$132,000 | \$132,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$198,000 | \$198,000 | \$198,000 | \$198,000 | \$198,000 | \$198,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$301,192 | \$301,192 | \$326,816 | \$326,816 | \$257,830 | \$257,830 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$150,000 | \$150,000 | \$150,000 | \$150,000 | \$150,000 | \$150,000 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$248,609 | \$248,609 | \$271,735 | \$271,735 | \$263,063 | \$263,063 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$699,801 | \$699,801 | \$748,551 | \$748,551 | \$670,893 | \$670,893 | |
| Debt Service/Capital Recovery ¹⁾ | \$3,703,556 | \$2,533,506 | \$3,703,556 | \$2,533,506 | \$3,703,556 | \$2,533,506 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SCR example calculations (Section 4-2, Chap 2, p2-57). In addition, the CCM also recommends a 20 year economic lifetime for SCR (p2-57), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$4,733,357 | \$3,563,307 | \$4,782,107 | \$3,612,057 | \$4,704,449 | \$3,534,399 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - SCR+ROFA

NDEP costs not allowed by EPA Control Cost Manual
 NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | | | Unit 2 | | Unit 3 | | Comments |
|--|---------------------|-------|------------------------|-----|---------------------|---------------------|---------------------|---------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP | EPA Revised Cost | NDEP | EPA Revised Cost | |
| Capital Costs | | | | | | | | | |
| Rotating Overfire Air (ROFA) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$2,880,000 | | \$2,880,000 | | \$2,880,000 | \$2,880,000 | \$2,880,000 | \$2,880,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$742,500 | | \$742,500 | | \$742,500 | \$742,500 | \$742,500 | \$742,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$1,440,000 | 50% | \$1,440,000 | 50% | \$1,440,000 | \$1,440,000 | \$1,440,000 | \$1,440,000 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$864,000 | 30% | \$864,000 | 30% | \$864,000 | \$864,000 | \$864,000 | \$864,000 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$288,000 | 10% | \$0 | 0% | \$288,000 | \$0 | \$288,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$460,800 | 16% | \$0 | 0% | \$460,800 | \$0 | \$460,800 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$345,600 | 12% | \$0 | 0% | \$345,600 | \$0 | \$345,600 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, ROFA Capital Cost | \$7,020,900 | | \$5,926,500 | | \$7,020,900 | \$5,926,500 | \$7,020,900 | \$5,926,500 | |
| Contingency | \$864,000 | 30% | \$432,000 | 15% | \$864,000 | \$432,000 | \$864,000 | \$432,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total ROFA Capital Cost | \$7,884,900 | | \$6,358,500 | | \$7,884,900 | \$6,358,500 | \$7,884,900 | \$6,358,500 | |
| Selective Catalytic Reduction (SCR) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$20,000,000 | | \$20,000,000 | | \$20,000,000 | \$20,000,000 | \$20,000,000 | \$20,000,000 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA |
| Construction | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Balance of Plant | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Owner's Costs | \$2,000,000 | 10.0% | \$0 | 0% | \$2,000,000 | \$0 | \$2,000,000 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$3,200,000 | 16.0% | \$0 | 0% | \$3,200,000 | \$0 | \$3,200,000 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$2,400,000 | 12.0% | \$0 | 0% | \$2,400,000 | \$0 | \$2,400,000 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual, Section 4.2, Chap 2, Table 2.5 |
| Subtotal, SCR Capital Cost | \$27,600,000 | | \$20,000,000 | | \$27,600,000 | \$20,000,000 | \$27,600,000 | \$20,000,000 | |
| Contingency | \$3,000,000 | 15% | \$3,000,000 | 15% | \$3,000,000 | \$3,000,000 | \$3,000,000 | \$3,000,000 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. |
| Total SCR Capital Cost | \$30,600,000 | | \$23,000,000 | | \$30,600,000 | \$23,000,000 | \$30,600,000 | \$23,000,000 | |
| Total Capital Cost | \$38,484,900 | | \$29,358,500 | | \$38,484,900 | \$29,358,500 | \$38,484,900 | \$29,358,500 | |

Control Cost Comparison - SCR+ROFA

 NDEP costs not allowed by EPA Control Cost Manual

 NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$148,000 | \$148,000 | \$148,000 | \$148,000 | \$148,000 | \$148,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$222,000 | \$222,000 | \$222,000 | \$222,000 | \$222,000 | \$222,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$370,000 | \$370,000 | \$370,000 | \$370,000 | \$370,000 | \$370,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$301,192 | \$301,192 | \$326,816 | \$326,816 | \$257,830 | \$257,830 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$112,500 | \$112,500 | \$112,500 | \$112,500 | \$132,000 | \$132,000 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$529,500 | \$529,500 | \$578,755 | \$578,755 | \$560,284 | \$560,284 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$943,192 | \$943,192 | \$1,018,071 | \$1,018,071 | \$950,114 | \$950,114 | |
| Debt Service/Capital Recovery ¹⁾ | \$4,066,737 | \$2,771,235 | \$4,066,737 | \$2,771,235 | \$4,066,737 | \$2,771,235 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SCR example calculations (Section 4-2, Chap 2, p2-57). In addition, the CCM also recommends a 20 year economic lifetime for SCR (p2-57), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$5,379,929 | \$4,084,427 | \$5,454,808 | \$4,159,306 | \$5,386,851 | \$4,091,349 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Appendix B:

EPA Analysis of NOx Control Cost Estimates (2011 update) for Reid Gardner Generating Station

See www.regulations.gov, docket ID number EPA-R09-OAR-2011-0130

Comparison of SCR Control Costs (Updated, 2011)

| Parameter | Reid Gardner | | | | | |
|-----------------------------------|---------------|---------------|---------------|--------------|---------------|--------------|
| | Unit 1 | | Unit 2 | | Unit 3 | |
| | NDEP | Revised EPA | NDEP | Revised EPA | NDEP | Revised EPA |
| Unit Output (kW) | 100,000 | | 100,000 | | 100,000 | |
| Heat Input (MMBtu/hr) | 1132 | | 1132 | | 1132 | |
| Boiler Type | Wall-fired | | Wall-fired | | Wall-fired | |
| Ctrl technology | SCR+LNB+OFA | | SCR+LNB+OFA | | SCR+LNB+OFA | |
| Ctrl Emission Rate (lb/MMBtu) | 0.085 | 0.085 | 0.083 | 0.083 | 0.098 | 0.098 |
| Total Capital Costs | \$39,754,076 | \$30,443,946 | \$39,754,076 | \$30,443,946 | \$39,754,076 | \$30,443,946 |
| Total Annual Costs | | | | | | |
| Fixed Costs | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 |
| Variable Costs | \$699,801 | \$699,801 | \$748,551 | \$748,551 | \$670,893 | \$670,893 |
| Capital Recovery | \$4,200,852 | \$2,873,693 | \$4,200,852 | \$2,873,693 | \$4,200,852 | \$2,873,693 |
| | 20 yrs @ 8.5% | 20 yrs @ 7.0% | 20 yrs @ 8.5% | 20 yrs @ 7% | 20 yrs @ 8.5% | 20 yrs @ 7% |
| Total Annual Costs | \$5,230,653 | \$3,903,494 | \$5,279,403 | \$3,952,244 | \$5,201,745 | \$3,874,586 |
| NOx Removed from baseline (tpy) | 1,850 | 1,850 | 2,010 | 2,009 | 1,774 | 1,775 |
| Average Cost per ton (\$/ton) | \$2,827 | \$2,110 | \$2,627 | \$1,967 | \$2,932 | \$2,183 |
| Incremental Cost per ton (\$/ton) | \$6,370 | \$4,534 | \$6,080 | \$4,330 | \$3,856 | \$2,756 |
| Previous ctrl technology | ROFA+Rotamix | | ROFA+Rotamix | | ROFA+Rotamix | |

Reid Gardner NOx Control Effectiveness Summary - EPA Revised Costs

| Unit No. | Annual Heat Input ¹ (MMBtu/yr) |
|----------|--|
| Unit 1 | 9,818,313 |
| Unit 2 | 10,501,749 |
| Unit 3 | 10,063,851 |

| Unit No. | Parameter | Units | Baseline ² | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | SCR+LNB+OFA | SCR+ROFA |
|----------|--------------------------------|------------|-----------------------|-----------|--------------|--------------|--------------|--------------|
| Unit 1 | Emission Rate | (tpy) | 2,267 | 1,784 | 1,340 | 959 | 417 | 417 |
| | Removed | (tpy) | -- | 483 | 927 | 1,308 | 1,850 | 1,850 |
| | Removal Rate | (%) | -- | 21.3% | 40.9% | 57.7% | 81.6% | 81.6% |
| | Emission Factor | (lb/MMBtu) | 0.462 | 0.363 | 0.273 | 0.195 | 0.085 | 0.085 |
| | Annual Cost | (\$) | | \$491,140 | \$1,019,864 | \$1,448,604 | \$3,903,494 | \$4,447,126 |
| | Average Cost Effectiveness | (\$/ton) | | \$1,017 | \$1,100 | \$1,107 | \$2,110 | \$2,404 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$1,191 | \$1,124 | \$4,534 | \$5,538 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |
| Unit 2 | Emission Rate | (tpy) | 2,445 | 1,866 | 1,401 | 1,003 | 436 | 436 |
| | Removed | (tpy) | -- | 579 | 1,044 | 1,442 | 2,009 | 2,009 |
| | Removal Rate | (%) | -- | 23.7% | 42.7% | 59.0% | 82.2% | 82.2% |
| | Emission Factor | (lb/MMBtu) | 0.466 | 0.355 | 0.267 | 0.191 | 0.083 | 0.083 |
| | Annual Cost | (\$) | | \$491,140 | \$1,042,273 | \$1,496,413 | \$3,952,244 | \$4,522,005 |
| | Average Cost Effectiveness | (\$/ton) | | \$848 | \$998 | \$1,038 | \$1,967 | \$2,251 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$1,185 | \$1,141 | \$4,330 | \$5,334 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |
| Unit 3 | Emission Rate | (tpy) | 2,268 | 2,118 | 1,590 | 1,399 | 493 | 493 |
| | Removed | (tpy) | -- | 150 | 678 | 869 | 1,775 | 1,775 |
| | Removal Rate | (%) | -- | 7% | 30% | 38% | 78% | 78% |
| | Emission Factor | (lb/MMBtu) | 0.451 | 0.421 | 0.316 | 0.278 | 0.098 | 0.098 |
| | Annual Cost | (\$) | | \$491,140 | \$969,586 | \$1,378,220 | \$3,874,586 | \$4,454,048 |
| | Average Cost Effectiveness | (\$/ton) | | \$3,284 | \$1,430 | \$1,586 | \$2,183 | \$2,510 |
| | Incremental Cost Effectiveness | (\$/ton) | | -- | \$906 | \$2,137 | \$2,756 | \$3,396 |
| | Previous ctrl technology | | | -- | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | ROFA+Rotamix |

1) Based on NDEP Reid-Gardner BART Determination, October 22, 2009, Table 1. Heat input values appear to be based on 1.0 capacity factor and 1152 MMBtu/hr

2) Baseline emissions and control option emissions based upon NDEP's October 22, 2009 BART determination, Table 1. Based on NDEP baseline, which is higher than NVE submittal. By comparison, NVE's Unit 1 baseline was 1625 tpy NOx

Reid Gardner NOx Emission Estimates (Based upon NDEP Cost and Control Estimates)

| Unit No. | Annual Heat Input ¹ (MMBtu/yr) |
|----------|--|
| Unit 1 | 9,818,313 |
| Unit 2 | 10,501,749 |
| Unit 3 | 10,063,851 |

| Unit No. | Parameter | Units | Baseline ² | LNB+OFA | LNB+OFA+SNCR | ROFA+Rotamix | SCR+LNB+OFA | SCR+ROFA |
|----------|---|------------|-----------------------|-----------|--------------|--------------|-------------|-------------|
| Unit 1 | Emission Rate | (tpy) | 2,267 | 1,784 | 1,340 | 959 | 417 | 417 |
| | Removed | (tpy) | -- | 483 | 927 | 1,308 | 1,850 | 1,850 |
| | Removal Rate | (%) | -- | 21.3% | 40.9% | 57.7% | 81.6% | 81.6% |
| | Emission Factor | (lb/MMBtu) | 0.462 | 0.363 | 0.273 | 0.195 | 0.085 | 0.085 |
| | Annual Cost | (\$) | | \$613,138 | \$1,228,736 | \$1,778,147 | \$5,230,653 | \$5,915,459 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$1,269 | \$1,325 | \$1,359 | \$2,827 | \$3,198 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$1,386 | \$1,442 | \$6,370 | \$7,633 |
| Unit 2 | Emission Rate | (tpy) | 2,445 | 1,866 | 1,401 | 1,003 | 435 | 435 |
| | Removed | (tpy) | -- | 579 | 1,044 | 1,442 | 2,010 | 2,010 |
| | Removal Rate | (%) | -- | 23.7% | 42.7% | 59.0% | 82.2% | 82.2% |
| | Emission Factor | (lb/MMBtu) | 0.466 | 0.355 | 0.267 | 0.191 | 0.083 | 0.083 |
| | Annual Cost | (\$) | | \$613,138 | \$1,251,145 | \$1,825,956 | \$5,279,403 | \$5,990,338 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$1,059 | \$1,198 | \$1,266 | \$2,627 | \$2,980 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$1,372 | \$1,444 | \$6,080 | \$7,332 |
| Unit 3 | Emission Rate | (tpy) | 2,268 | 2,121 | 1,590 | 1,400 | 494 | 494 |
| | Removed | (tpy) | -- | 147 | 678 | 868 | 1,774 | 1,774 |
| | Removal Rate | (%) | -- | 6.5% | 29.9% | 38.3% | 78.2% | 78.2% |
| | Emission Factor | (lb/MMBtu) | 0.451 | 0.421 | 0.316 | 0.278 | 0.098 | 0.098 |
| | Annual Cost | (\$) | | \$613,138 | \$1,178,458 | \$1,707,763 | \$5,201,745 | \$5,922,381 |
| | Average Cost Effectiveness ³ | (\$/ton) | | \$4,171 | \$1,738 | \$1,967 | \$2,932 | \$3,338 |
| | Incremental Cost Effectiveness ³ | (\$/ton) | | -- | \$1,065 | \$2,786 | \$3,856 | \$4,652 |

1) As listed in NDEP Reid-Gardner BART Determination, October 22, 2009, Table 1, "Base Heat Input."

Based on listed emission rates and emission factors, "base heat input" and not "total heat input" was used.

2) Baseline emissions and control option emissions based upon NDEP's October 22, 2009 BART determination, Table 1.

Based on NDEP baseline, which is higher than NVE submittal. By comparison, NVE's Unit 1 baseline was 1625 tpy NOx

3) Average and incremental cost effectiveness values as reported in NDEP's October 22, 2009 BART determination, Table 1.

Control Cost Comparison - LNB+OFA (enhanced)

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Capital Costs | | | | | | | |
| Low NOx Burners (Upgrade) + OFA/ROFA | | | | | | | |
| Major Materials Design and Supply Construction | \$1,814,842 | | \$1,814,842 | | \$1,814,842 | \$1,814,842 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$1,270,389 | 70% | \$1,270,389 | 70% | \$1,270,389 | \$1,270,389 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix |
| Balance of Plant | \$907,421 | 50% | \$907,421 | 50% | \$907,421 | \$907,421 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$90,742 | 5% | \$90,742 | 5% | \$90,742 | \$90,742 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$181,484 | 10% | \$0 | 0% | \$181,484 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$290,375 | 16% | \$0 | 0% | \$290,375 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$217,781 | 12% | \$0 | 0% | \$217,781 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, LNB+OFA Capital Cost | \$4,773,034 | | \$4,083,395 | | \$4,773,034 | \$4,083,395 | |
| Contingency | \$272,226 | 15% | \$272,226 | 15% | \$272,226 | \$272,226 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total LNB+OFA Capital Cost | \$5,045,261 | | \$4,355,621 | | \$5,045,261 | \$4,355,621 | |
| Total Capital Cost | \$5,045,261 | | \$4,355,621 | | \$5,045,261 | \$4,355,621 | |

Control Cost Comparison - LNB+OFA (enhanced)

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|------------|--------------------|------------|--------------------|------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$32,000 | \$32,000 | \$32,000 | \$32,000 | \$32,000 | \$32,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$80,000 | \$80,000 | \$80,000 | \$80,000 | \$80,000 | \$80,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | |
| Debt Service/Capital Recovery ¹ | \$533,138 | \$411,140 | \$533,138 | \$411,140 | \$533,138 | \$411,140 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$613,138 | \$491,140 | \$613,138 | \$491,140 | \$613,138 | \$491,140 | |

- 1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - LNB+OFA+SNCR

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|--|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Capital Costs | | | | | | | |
| Low NOx Burners (Upgrade) + OFA | | | | | | | |
| Major Materials Design and Supply Construction | \$1,814,842 | | \$1,814,842 | | \$1,814,842 | \$1,814,842 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$1,270,389 | 70% | \$1,270,389 | 70% | \$1,270,389 | \$1,270,389 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP |
| Balance of Plant | \$907,421 | 50% | \$907,421 | 50% | \$907,421 | \$907,421 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$90,742 | 5% | \$90,742 | 5% | \$90,742 | \$90,742 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$181,484 | 10% | \$0 | 0% | \$181,484 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$290,375 | 16% | \$0 | 0% | \$290,375 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$217,781 | 12% | \$0 | 0% | \$217,781 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, LNB+OFA Capital Cost | \$4,773,034 | | \$4,083,395 | | \$4,773,034 | \$4,083,395 | |
| Contingency | \$272,226 | 15% | \$272,226 | 15% | \$272,226 | \$272,226 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR |
| Total LNB+OFA Capital Cost | \$5,045,261 | | \$4,355,621 | | \$5,045,261 | \$4,355,621 | |
| Selective Non-Catalytic Reduction (SNCR) | | | | | | | |
| Major Materials Design and Supply Construction | \$1,531,273 | | \$1,531,273 | | \$1,531,273 | \$1,531,273 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in |
| Construction | \$229,691 | 15.0% | \$229,691 | 15% | \$229,691 | \$229,691 | See comments in LNB+OFA section above. While these costs to not directly correspond to EPA CCM line items, they are comparable to certain allowed costs. As a result, these costs are retained without revision. |
| Balance of Plant | \$183,753 | 12.0% | \$183,753 | 12% | \$183,753 | \$183,753 | |
| Electrical (Allowance) | \$76,564 | 5.0% | \$76,564 | 5% | \$76,564 | \$76,564 | |
| Owner's Costs | \$153,127 | 10.0% | \$0 | 0% | \$153,127 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$245,004 | 16.0% | \$0 | 0% | \$245,004 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$183,753 | 12.0% | \$0 | 0% | \$183,753 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual |
| Subtotal, SCR Capital Cost | \$2,603,164 | | \$2,021,280 | | \$2,603,164 | \$2,021,280 | |
| Contingency | \$229,691 | 15% | \$229,691 | 15% | \$229,691 | \$229,691 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total SNCR Capital Cost | \$2,832,855 | | \$2,250,971 | | \$2,832,855 | \$2,250,971 | |
| Total Capital Cost | \$7,878,116 | | \$6,606,592 | | \$7,878,116 | \$6,606,592 | |

Control Cost Comparison - LNB+OFA+SNCR

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|-------------|--------------------|-------------|--------------------|-------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$83,000 | \$83,000 | \$83,000 | \$83,000 | \$83,000 | \$83,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$124,500 | \$124,500 | \$124,500 | \$124,500 | \$124,500 | \$124,500 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$207,500 | \$207,500 | \$207,500 | \$207,500 | \$207,500 | \$207,500 | |
| Variable Costs | | | | | | | |
| Reagent | \$151,080 | \$151,080 | \$169,985 | \$169,985 | \$98,612 | \$98,612 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$37,668 | \$37,668 | \$41,172 | \$41,172 | \$39,858 | \$39,858 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$188,748 | \$188,748 | \$211,157 | \$211,157 | \$138,470 | \$138,470 | |
| Debt Service/Capital Recovery ¹ | \$832,488 | \$623,616 | \$832,488 | \$623,616 | \$832,488 | \$623,616 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$1,228,736 | \$1,019,864 | \$1,251,145 | \$1,042,273 | \$1,178,458 | \$969,586 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - ROFA+Rotami

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|---------------------|-------|------------------------|-----|---------------------|------------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP Value | EPA Revised Cost Value | |
| Capital Costs | | | | | | | |
| Rotating Overfire Air (ROFA) | | | | | | | |
| Major Materials Design and Supply Construction | \$3,266,715 | | \$3,266,715 | | \$3,266,715 | \$3,266,715 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$742,500 | | \$742,500 | | \$742,500 | \$742,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$1,633,358 | 50% | \$1,633,358 | 50% | \$1,633,358 | \$1,633,358 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$980,015 | 30% | \$980,015 | 30% | \$980,015 | \$980,015 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$326,672 | 10% | \$0 | 0% | \$326,672 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$522,674 | 16% | \$0 | 0% | \$522,674 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$392,006 | 12% | \$0 | 0% | \$392,006 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, ROFA Capital Cost | \$7,863,939 | | \$6,622,587 | | \$7,863,939 | \$6,622,587 | |
| Contingency | \$980,015 | 30% | \$490,007 | 15% | \$980,015 | \$490,007 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total ROFA Capital Cost | \$8,843,953 | | \$7,112,594 | | \$8,843,953 | \$7,112,594 | |
| Rotamix | | | | | | | |
| Major Materials Design and Supply Construction | \$1,167,100 | | \$1,167,100 | | \$1,167,100 | \$1,167,100 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA above. |
| Construction | \$247,500 | | \$247,500 | | \$247,500 | \$247,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$140,052 | 12.0% | \$140,052 | 12% | \$140,052 | \$140,052 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Owner's Costs | \$116,710 | 10.0% | \$0 | 0% | \$116,710 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$186,736 | 16.0% | \$0 | 0% | \$186,736 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$140,052 | 12.0% | \$0 | 0% | \$140,052 | \$0 | AFUDC is not allowed for SNCR (comparable to Rotamix) in the EPA Control Cost Manual |
| Subtotal, Rotamix Capital Cost | \$1,998,150 | | \$1,554,652 | | \$1,998,150 | \$1,554,652 | |
| Contingency | \$175,065 | 15% | \$175,065 | 15% | \$175,065 | \$175,065 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total Rotamix Capital Cost | \$2,173,215 | | \$1,729,717 | | \$2,173,215 | \$1,729,717 | |
| Total Capital Cost | \$11,017,168 | | \$8,842,311 | | \$11,017,168 | \$8,842,311 | |

Control Cost Comparison - ROFA+Rotami

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|--|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised % | NDEP Value | EPA Revised % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | \$48,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$72,000 | \$72,000 | \$72,000 | \$72,000 | \$72,000 | \$72,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$120,000 | \$120,000 | \$120,000 | \$120,000 | \$120,000 | \$120,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$213,062 | \$213,062 | \$234,741 | \$234,741 | \$126,347 | \$126,347 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | |
| Auxiliary Power | \$280,890 | \$280,890 | \$307,020 | \$307,020 | \$297,221 | \$297,221 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SNCR (comparable to Rotamix) equipment. |
| Subtotal, variable costs | \$493,952 | \$493,952 | \$541,761 | \$541,761 | \$423,568 | \$423,568 | |
| Debt Service/Capital Recovery ¹ | \$1,164,195 | \$834,652 | \$1,164,195 | \$834,652 | \$1,164,195 | \$834,652 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SNCR example calculations (Section 4-2, Chap 1, p1-37). In addition, the CCM also recommends a 20 year economic lifetime for SNCR (p1-37), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Cost: | \$1,778,147 | \$1,448,604 | \$1,825,956 | \$1,496,413 | \$1,707,763 | \$1,378,220 | |

- 1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - SCR+LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | | | Unit 2 | | Unit 3 | | Comments |
|--|---------------------|-------|------------------------|-----|---------------------|---------------------|---------------------|---------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP Value | EPA Revised Cost | NDEP Value | EPA Revised Cost | |
| Capital Costs | | | | | | | | | |
| Low NOx Burners (Upgrade) + OFA | | | | | | | | | |
| Major Materials Design and Supply Construction | \$1,814,842 | | \$1,814,842 | | \$1,814,842 | \$1,814,842 | \$1,814,842 | \$1,814,842 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in t |
| Construction | \$1,270,389 | 70% | \$1,270,389 | 70% | \$1,270,389 | \$1,270,389 | \$1,270,389 | \$1,270,389 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix |
| Balance of Plant | \$907,421 | 50% | \$907,421 | 50% | \$907,421 | \$907,421 | \$907,421 | \$907,421 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$90,742 | 5% | \$90,742 | 5% | \$90,742 | \$90,742 | \$90,742 | \$90,742 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$181,484 | 10% | \$0 | 0% | \$181,484 | \$0 | \$181,484 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$290,375 | 16% | \$0 | 0% | \$290,375 | \$0 | \$290,375 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$217,781 | 12% | \$0 | 0% | \$217,781 | \$0 | \$217,781 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual, Section 4.2, Chap 2, Table 2.5 |
| Subtotal, LNB+OFA Capital Cost | \$4,773,034 | | \$4,083,395 | | \$4,773,034 | \$4,083,395 | \$4,773,034 | \$4,083,395 | |
| Contingency | \$272,226 | 15% | \$272,226 | 15% | \$272,226 | \$272,226 | \$272,226 | \$272,226 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total ROFA Capital Cost | \$5,045,261 | | \$4,355,621 | | \$5,045,261 | \$4,355,621 | \$5,045,261 | \$4,355,621 | |
| Selective Catalytic Reduction (SCR) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$22,685,500 | | \$22,685,500 | | \$22,685,500 | \$22,685,500 | \$22,685,500 | \$22,685,500 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA |
| Construction | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Balance of Plant | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Owner's Costs | \$2,268,550 | 10.0% | \$0 | 0% | \$2,268,550 | \$0 | \$2,268,550 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that dete |
| Surcharge | \$3,629,680 | 16.0% | \$0 | 0% | \$3,629,680 | \$0 | \$3,629,680 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$2,722,260 | 12.0% | \$0 | 0% | \$2,722,260 | \$0 | \$2,722,260 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual |
| Subtotal, SCR Capital Cost | \$31,305,990 | | \$22,685,500 | | \$31,305,990 | \$22,685,500 | \$31,305,990 | \$22,685,500 | |
| Contingency | \$3,402,825 | 15% | \$3,402,825 | 15% | \$3,402,825 | \$3,402,825 | \$3,402,825 | \$3,402,825 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total SCR Capital Cost | \$34,708,815 | | \$26,088,325 | | \$34,708,815 | \$26,088,325 | \$34,708,815 | \$26,088,325 | |
| Total Capital Cost | \$39,754,076 | | \$30,443,946 | | \$39,754,076 | \$30,443,946 | \$39,754,076 | \$30,443,946 | |

Control Cost Comparison - SCR+LNB+OFA

NDEP costs not allowed by EPA Control Cost Manual

NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$132,000 | \$132,000 | \$132,000 | \$132,000 | \$132,000 | \$132,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$198,000 | \$198,000 | \$198,000 | \$198,000 | \$198,000 | \$198,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | \$330,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$301,192 | \$301,192 | \$326,816 | \$326,816 | \$257,830 | \$257,830 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$150,000 | \$150,000 | \$150,000 | \$150,000 | \$150,000 | \$150,000 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$248,609 | \$248,609 | \$271,735 | \$271,735 | \$263,063 | \$263,063 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$699,801 | \$699,801 | \$748,551 | \$748,551 | \$670,893 | \$670,893 | |
| Debt Service/Capital Recovery ¹⁾ | \$4,200,852 | \$2,873,693 | \$4,200,852 | \$2,873,693 | \$4,200,852 | \$2,873,693 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SCR example calculations (Section 4-2, Chap 2, p2-57). In addition, the CCM also recommends a 20 year economic lifetime for SCR (p2-57), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$5,230,653 | \$3,903,494 | \$5,279,403 | \$3,952,244 | \$5,201,745 | \$3,874,586 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Control Cost Comparison - SCR+ROFA

NDEP costs not allowed by EPA Control Cost Manual
 NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | | | Unit 2 | | Unit 3 | | Comments |
|--|---------------------|-------|------------------------|-----|---------------------|---------------------|---------------------|---------------------|--|
| | NDEP Value | % | EPA Revised Cost Value | % | NDEP Value | EPA Revised Cost | NDEP Value | EPA Revised Cost | |
| Capital Costs | | | | | | | | | |
| Rotating Overfire Air (ROFA) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$3,266,715 | | \$3,266,715 | | \$3,266,715 | \$3,266,715 | \$3,266,715 | \$3,266,715 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. The CCM provides more detailed guidance on what constituent elements may be included in this line item, but the NDEP appendix does not provide sufficient detail to make more specific determinations. |
| Construction | \$742,500 | | \$742,500 | | \$742,500 | \$742,500 | \$742,500 | \$742,500 | Vendor estimate. Comparable to Indirect installation costs as described in EPA CCM. Again, more detailed guidance on what constituent elements are allowed in this line item, but the NDEP appendix does not provide sufficient detail to make this evaluation |
| Balance of Plant | \$1,633,358 | 50% | \$1,633,358 | 50% | \$1,633,358 | \$1,633,358 | \$1,633,358 | \$1,633,358 | Balance of plant is construed to refer to other capital expenditures beyond PEC. Such costs are allowed in the CCM, and are considered part of direct capital costs (DCC). |
| Electrical (Allowance) | \$980,015 | 30% | \$980,015 | 30% | \$980,015 | \$980,015 | \$980,015 | \$980,015 | Electrical equipment is included in the EPA control cost manual as part of direct capital costs (DCC), and so are retained here without revision |
| Owner's Costs | \$326,672 | 10% | \$0 | 0% | \$326,672 | \$0 | \$326,672 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$522,674 | 16% | \$0 | 0% | \$522,674 | \$0 | \$522,674 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$392,006 | 12% | \$0 | 0% | \$392,006 | \$0 | \$392,006 | \$0 | AFUDC is not allowed for any of the applications listed in the EPA Control Cost Manual |
| Subtotal, ROFA Capital Cost | \$7,863,939 | | \$6,622,587 | | \$7,863,939 | \$6,622,587 | \$7,863,939 | \$6,622,587 | |
| Contingency | \$980,015 | 30% | \$490,007 | 15% | \$980,015 | \$490,007 | \$980,015 | \$490,007 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total ROFA Capital Cost | \$8,843,953 | | \$7,112,594 | | \$8,843,953 | \$7,112,594 | \$8,843,953 | \$7,112,594 | |
| Selective Catalytic Reduction (SCR) | | | | | | | | | |
| Major Materials Design and Supply Construction | \$22,685,522 | | \$22,685,522 | | \$22,685,522 | \$22,685,522 | \$22,685,522 | \$22,685,522 | Vendor estimate. Comparable to Purchased Equipment Cost (PEC) as described in EPA CCM, although this line item description suggests it includes more than just PEC. See comments in ROFA |
| Construction | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | Zero estimate provided by NDEP. Based upon the documentation provided, it is unclear if these costs are accounted for elsewhere |
| Balance of Plant | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Electrical (Allowance) | \$0 | 0.0% | \$0 | 0% | \$0 | \$0 | \$0 | \$0 | |
| Owner's Costs | \$2,268,552 | 10.0% | \$0 | 0% | \$2,268,552 | \$0 | \$2,268,552 | \$0 | Owner's costs such as project management, advisory fees, legal, etc., are not included in the Control Cost Manual. Although it is possible that certain CCM-allowed costs are included in this line item, additional details would be needed to make that determination. |
| Surcharge | \$3,629,684 | 16.0% | \$0 | 0% | \$3,629,684 | \$0 | \$3,629,684 | \$0 | There is no provision for surcharge in the EPA Control Cost Manual |
| AFUDC | \$2,722,263 | 12.0% | \$0 | 0% | \$2,722,263 | \$0 | \$2,722,263 | \$0 | AFUDC is not allowed for SCR in the EPA Control Cost Manual, Section 4.2, Chap 2, Table 2.5 |
| Subtotal, SCR Capital Cost | \$31,306,020 | | \$22,685,522 | | \$31,306,020 | \$22,685,522 | \$31,306,020 | \$22,685,522 | |
| Contingency | \$3,402,828 | 15% | \$3,402,828 | 15% | \$3,402,828 | \$3,402,828 | \$3,402,828 | \$3,402,828 | EPA Control Cost Manual provides for project contingency costs of up to 15% of the total of direct capital costs (DCC) and indirect installation costs. For example, Section 4.2 (NOx Post-Combustion), Tables 1.4 and 2.5 allow a project contingency of 15% for SNCR and SCR applications. |
| Total SCR Capital Cost | \$34,708,849 | | \$26,088,350 | | \$34,708,849 | \$26,088,350 | \$34,708,849 | \$26,088,350 | |
| Total Capital Cost | \$43,552,802 | | \$33,200,945 | | \$43,552,802 | \$33,200,945 | \$43,552,802 | \$33,200,945 | |

Control Cost Comparison - SCR+ROFA

 NDEP costs not allowed by EPA Control Cost Manual

 NDEP costs allowed by EPA Control Cost Manual, but modified from NDEP estimate

| | Unit 1 | | Unit 2 | | Unit 3 | | Comments |
|---|--------------------|--------------------|--------------------|--------------------|--------------------|--------------------|---|
| | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | NDEP Value | EPA Revised Cost % | |
| Annual Costs | | | | | | | |
| Fixed O&M Costs | | | | | | | |
| Operating Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional operating labor was provided. |
| Maintenance Materials | \$148,000 | \$148,000 | \$148,000 | \$148,000 | \$148,000 | \$148,000 | The EPA Control Cost Manual provides for maintenance materials and labor. These costs are included in the revised EPA estimate, although no basis was provided. |
| Maintenance Labor | \$222,000 | \$222,000 | \$222,000 | \$222,000 | \$222,000 | \$222,000 | |
| Administrative Labor | \$0 | \$0 | \$0 | \$0 | \$0 | \$0 | No estimate of additional administrative labor was provided. |
| Subtotal, fixed O&M costs | \$370,000 | \$370,000 | \$370,000 | \$370,000 | \$370,000 | \$370,000 | |
| Variable Costs | | | | | | | |
| Reagent | \$301,192 | \$301,192 | \$326,816 | \$326,816 | \$257,830 | \$257,830 | EPA CCM does provide for certain raw material costs such as reagent costs. |
| Catalyst Replacement | \$112,500 | \$112,500 | \$112,500 | \$112,500 | \$132,000 | \$132,000 | The EPA Control Cost Manual does provide for SCR catalyst replacement costs. The basis for NDEP's estimate is not clear, however, and it is difficult to determine how catalyst costs determined using the CCM might compare. |
| Auxiliary Power | \$529,500 | \$529,500 | \$578,755 | \$578,755 | \$560,284 | \$560,284 | The EPA Control Cost Manual does provide for utility costs, such as those needed to operate SCR equipment. |
| Subtotal, variable costs | \$943,192 | \$943,192 | \$1,018,071 | \$1,018,071 | \$950,114 | \$950,114 | |
| Debt Service/Capital Recovery ¹⁾ | \$4,602,267 | \$3,133,934 | \$4,602,267 | \$3,133,934 | \$4,602,267 | \$3,133,934 | Regarding interest rates, EPA calculated capital recoveries using 3% and 7% interest rates in determining cost effectiveness for the Regulatory Impact Analysis for the Final Clean Air Visibility rule and the Guidelines for BART Determinations under the Regional Haze regulations. The EPA Control Cost Manual uses 7% interest rate in SCR example calculations (Section 4-2, Chap 2, p2-57). In addition, the CCM also recommends a 20 year economic lifetime for SCR (p2-57), although 30 year lifetimes have often been specified in BART and BACT analyses. |
| Total Annual Costs | \$5,915,459 | \$4,447,126 | \$5,990,338 | \$4,522,005 | \$5,922,381 | \$4,454,048 | |

1) Debt Service/Capital Recovery
 Interest rate (%) = 8.5% 7.0%
 Equipment lifetime (years) = 20 20

Appendix C:

Model Emission Rate Calculations for Reid Gardner Generating Station

See www.regulations.gov, docket ID number EPA-R09-OAR-2011-0130

Modeling Scenarios for EPA's RH SIP Action on Reid Gardner Generating Station

updated 2012-03-07

| Code | Name | Description | NOx | Control Technology | |
|------|------------------|---|-----------------------|----------------------------------|-----------------------------|
| | | | | SO2 | PM10 |
| 00 | Baseline 1 | WRAP Baseline | None | Wet Soda Ash Scrubber | Mechanical Flyash Collector |
| 02 | Baseline 1a | WRAP Baseline (NOx), NDEP BART determination (PM10, SO2) | None | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 04 | Baseline 2 | NDEP adjusted baseline (NOx), NDEP BART determination (PM10, SO2) | LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 11 | Control Option 1 | LNB + OFA (enhanced) | LNB + OFA (enhanced) | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 12 | Control Option 2 | SNCR + LNB w/ OFA | SNCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 13 | Control Option 3 | ROFA w/ Rotamix | ROFA w/ Rotamix | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 14 | Control Option 4 | SCR + ROFA | SCR + ROFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 15 | Control Option 5 | SCR + LNB w/ OFA | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |
| 16 | Control Option 6 | SCR + LNB w/ OFA @.06 | SCR + LNB w/ OFA @.06 | Wet Soda Ash Scrubber (upgraded) | Fabric Filter |

Code is the number appearing in the CALPUFF model file name, e.g. cf_c11_2002.inp for CALPUFF, code 11 for control option 1, 2002 meteorol

| | Elevation above MSL (feet) | Stack Height (feet) | Stack Diameter (feet) | Stack Crossec Area (ft2) | Exit Temp (deg F) | Exit Velocity (ft/s) | Exit Flowrate (acfm) | Annual Unit Capacity Factor (percent) | Boiler Heat Input (100% load) (MMBtu/hr) | Notes |
|---------------------|----------------------------------|---------------------------|-----------------------------|--------------------------------|----------------------|-------------------------|-------------------------|--|---|-------|
| Reid Gardner Unit 1 | 1573 | 200 | 13.3 | 139 | 135 | 52.4 | 436702 | 86% | 1215 | 1 |
| Reid Gardner Unit 2 | 1572 | 249 | 13.3 | 139 | 145 | 50.3 | 419288 | 94% | 1215 | 2 |
| Reid Gardner Unit 3 | 1570 | 270 | 12.9 | 131 | 151 | 71.4 | 559911 | 91% | 1237 | 3 |
| | | | | | | | 436793.0311 | | | |

1 Per Table 2-1, Reid Gardner 1 NVE BART Analysis submittal to NDEP, p.2-2 (p.13 in PDF)

2 Per Table 2-1, Reid Gardner 2 NVE BART Analysis submittal to NDEP, p.2-2 (p.13 in PDF)

3 Per Table 2-1, Reid Gardner 3 NVE BART Analysis submittal to NDEP, p.2-2 (p.13 in PDF)

in metric units, converted from the above

m_per_ft 0.3048
kJ_per_BTU 1.05506

| stack parm abbrevs | ES | HS | DS | TS | VS | | Annual Unit Capacity Factor (percent) | Boiler Heat Input (100% load) (GJ/hr) |
|---------------------|-------------------------------|------------------------|--------------------------|-------------------------------|----------------------|------------------------|--|--|
| | Elevation above MSL (m) | Stack Height (m) | Stack Diameter (m) | Stack Crossec Area (m2) | Exit Temp (deg K) | Exit Velocity (m/s) | Exit Flowrate (acmm) | |
| Reid Gardner Unit 1 | 479.5 | 60.96 | 4.05 | 12.9 | 330.37 | 15.97 | 12366 | 86% |
| Reid Gardner Unit 2 | 479.1 | 75.90 | 4.05 | 12.9 | 335.93 | 15.33 | 11873 | 94% |
| Reid Gardner Unit 3 | 478.5 | 82.30 | 3.93 | 12.1 | 339.26 | 21.76 | 15855 | 91% |

The stack parameters are identical to those used in BART modeling for the WRAP, except WRAP elevations were about 8 m higher.

Since WRAP stack coordinates (latitude and longitude) are about 700 m away from plant location in CAMD, whereas the values used in the CH2MHill modeling were about 7000 m away, WRAP stack location and elevations will be used.

(The meteorological inputs are in the WRAP coordinate system for Arizona, which we will be using.)

Calculated values below are in italics (coordinate conversions done using Golden Software's MapViewer 6.2)

| | info source | Dist. from CAMD, km | WRAP coordinate system | | Geographic coordinates | | CH2MHill coordinate system | |
|---------------------|-------------|---------------------------|------------------------|-----------|------------------------|----------|----------------------------|----------|
| | | | X km | Y km | longitude | latitude | X km | Y km |
| Plant location | CAMD | 0 | -1556.0167 | -218.6810 | -114.6364 | 36.6531 | | |
| Reid Gardner Unit 1 | WRAP | 0.7 | -1555.5060 | -218.2230 | -114.6318 | 36.6581 | | |
| Reid Gardner Unit 2 | WRAP | 0.7 | -1555.5120 | -218.2522 | -114.6318 | 36.6578 | | |
| Reid Gardner Unit 3 | WRAP | 0.6 | -1555.5210 | -218.2911 | -114.6318 | 36.6574 | | |
| Reid Gardner Unit 1 | CH2MHill | 7.0 | -1550.0586 | -222.4074 | | | 210.827 | -366.266 |
| Reid Gardner Unit 2 | CH2MHill | 7.0 | -1550.0649 | -222.4367 | | | 210.827 | -366.296 |
| Reid Gardner Unit 3 | CH2MHill | 7.1 | -1550.0731 | -222.4757 | | | 210.82729 | -366.336 |

| Unit No. | Heat Input (MMBtu/hr) | |
|---------------------|----------------------------|---------------------------|
| | (1-hr, 24-hr) ¹ | (Annual Ave) ² |
| Reid Gardner Unit 1 | 1215 | 1132 |
| Reid Gardner Unit 2 | 1215 | 1082 |
| Reid Gardner Unit 3 | 1237 | 1135 |

¹ Max heat input as listed in TV Permit No. AP4911-0897. These values were also used by NV Energy to develop the maximum 24-hr ave emission rates used in visibility mode

² Annual average based on 0.86 annual capacity factor, as indicated by Nevada Energy in Appendix A of each unit's respective NVE BART Analysis (October 22, 2008).

Baseline Emission Factors

| | | NO _x | | SO ₂ | | PM ₁₀ | | Notes |
|---------------------|---------------------|-----------------|---------|-----------------|---------|------------------|---------|-------|
| | | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | |
| Reid Gardner Unit 1 | WRAP Emission Rate | 0.591 | 718 | 0.329 | 400 | 0.0474 | 58 | 2 |
| | NDEP baseline (SIP) | 0.462 | 561 | -- | -- | -- | -- | 3 |
| | CAMD 2001-03 (NVE) | 0.576 | 700 | 0.332 | 403 | -- | -- | 2 |
| | CAMD 2001-03 (EPA) | 0.566 | 731 | 0.36 | 400 | -- | -- | |
| | CAMD 2005-07 (EPA) | 0.458 | 545 | 0.19 | 236 | -- | -- | |
| Reid Gardner Unit 2 | WRAP Emission Rate | 0.635 | 772 | 0.28 | 340 | 0.044 | 53 | 2 |
| | NDEP baseline (SIP) | 0.466 | 566 | -- | -- | -- | -- | 3 |
| | CAMD 2001-03 (NVE) | 0.613 | 745 | 0.277 | 337 | -- | -- | 2 |
| | CAMD 2001-03 (EPA) | 0.571 | 804 | 0.276 | 375 | -- | -- | |
| | CAMD 2005-07 (EPA) | 0.425 | 655 | 0.39 | 399 | -- | -- | |
| Reid Gardner Unit 3 | WRAP Emission Rate | 0.592 | 732 | 0.32 | 396 | 0.04 | 49 | 2 |
| | NDEP baseline (SIP) | 0.451 | 558 | -- | -- | -- | -- | 3 |
| | CAMD 2001-03 (NVE) | 0.579 | 716 | 0.29 | 359 | -- | -- | 2 |
| | CAMD 2001-03 (EPA) | 0.548 | 732 | 0.29 | 396 | -- | -- | |
| | CAMD 2005-07 (EPA) | 0.448 | 658 | 0.195 | 246 | -- | -- | |

| | | | | | |
|---------------------|-------------|----------------------|------|------|-----|
| Reid Gardner Unit 1 | from | Title V permit limit | 0.46 | 0.55 | 0.2 |
| Reid Gardner Unit 2 | NVE reports | Title V permit limit | 0.46 | 0.55 | 0.2 |
| Reid Gardner Unit 3 | Table 2- 1 | Title V permit limit | 0.46 | 0.55 | 0.1 |

¹ lb/MMBtu value based on Table 2-1 from each unit's respective NVE BART Analysis submittal to NDEP (October 22, 2008)

² Corresponds to the revised NO_x emission rate used as the baseline in the Nevada RH SIP. NDEP did not revise SO₂ or PM₁₀ emissions.

NOx Control Scenario Emission Factors

| | Control Technology | NOx | | | | PM10 ³ | | SO2 ⁴ | |
|---------------------|--------------------------|-------------------------------|---------|----------------------------------|---------|-------------------|---------|------------------|---------|
| | | NDEP Estimates ^{1,5} | | NV Energy Estimates ² | | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) |
| | | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | | | | |
| Reid Gardner Unit 1 | LNB w/ OFA (enhancement) | 0.364 | 442 | 0.30 | 365 | 0.015 | 18 | 0.15 | 182 |
| | SNCR w/ LNB and OFA | 0.273 | 332 | 0.23 | 279 | 0.015 | 18 | 0.15 | 182 |
| | ROFA w/ Rotamix | 0.195 | 237 | 0.16 | 194 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ ROFA | 0.085 | 103 | 0.07 | 85 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ LNB and OFA | 0.085 | 103 | 0.07 | 85 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ LNB and OFA @.06 | 0.06 | 73 | | | 0.015 | 18 | 0.15 | 182 |
| Reid Gardner Unit 2 | LNB w/ OFA (enhancement) | 0.355 | 431 | 0.30 | 365 | 0.015 | 18 | 0.15 | 182 |
| | SNCR w/ LNB and OFA | 0.267 | 324 | 0.23 | 279 | 0.015 | 18 | 0.15 | 182 |
| | ROFA w/ Rotamix | 0.191 | 232 | 0.16 | 194 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ ROFA | 0.083 | 101 | 0.07 | 85 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ LNB and OFA | 0.083 | 101 | 0.07 | 85 | 0.015 | 18 | 0.15 | 182 |
| | SCR w/ LNB and OFA @.06 | 0.06 | 73 | | | 0.015 | 18 | 0.15 | 182 |
| Reid Gardner Unit 3 | LNB w/ OFA (enhancement) | 0.421 | 521 | 0.30 | 371 | 0.015 | 19 | 0.15 | 186 |
| | SNCR w/ LNB and OFA | 0.316 | 391 | 0.23 | 285 | 0.015 | 19 | 0.15 | 186 |
| | ROFA w/ Rotamix | 0.278 | 344 | 0.16 | 198 | 0.015 | 19 | 0.15 | 186 |
| | SCR w/ ROFA | 0.098 | 121 | 0.07 | 87 | 0.015 | 19 | 0.15 | 186 |
| | SCR w/ LNB and OFA | 0.098 | 121 | 0.07 | 87 | 0.015 | 19 | 0.15 | 186 |
| | SCR w/ LNB and OFA @.06 | 0.06 | 74 | | | 0.015 | 19 | 0.15 | 186 |

¹ Control technology performance as used by NDEP in development of the Regional Haze SIP. As summarized in Table 1, NDEP Reid Gardner BART Determination Review (October 2008)

² Control technology performance as indicated by Nevada Energy in Appendix A of each unit's respective NVE BART Analysis (October 2008)

³ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber. Per the NV RH SIP, this emission rate is based on a 24-hr average

⁴ PM10 emissions based upon Nevada's PM10 BART determination of fabric filters. Per the NV RH SIP, this emission rate is based on a 3-hr averaging period

⁵ EPA estimate for SCR of 0.06 lb/MMBtu NOx

Coal Properties

| Property | | Coal Type ¹ | | | | | | | Average ² Value | Highest Value |
|-----------------|--------|------------------------|---------|--------|--------|----------|----------|------------|-------------------------------|------------------|
| | | Bowie | Skyline | Sufco | Dugout | Aberdeen | Crandall | West Ridge | | |
| Moist. | % | 8.5 | 9.79 | 9.69 | 5.53 | 6.83 | 7.5 | 5.78 | 7.66 | 9.79 |
| Ash | % | 9.06 | 7.64 | 7.97 | 8.65 | 8.5 | 8 | 7.48 | 8.19 | 9.06 |
| Volatile Matter | % | 33.53 | 38.2 | 35.95 | 33.05 | 38 | 41.05 | 34.91 | 36.38 | 41.05 |
| Fixed Carbon | % | 48.91 | 44.37 | 46.39 | 52.77 | 46.16 | 43 | 51.84 | 47.63 | 52.77 |
| Sulfur | % | 0.46 | 0.57 | 0.29 | 0.51 | 0.51 | 0.45 | 1.35 | 0.59 | 1.35 |
| HHV | Btu/lb | 12,012 | 11,712 | 11,463 | 12,469 | 12,276 | 12,400 | 12,856 | 12,170 | 12,856 |

Notes:

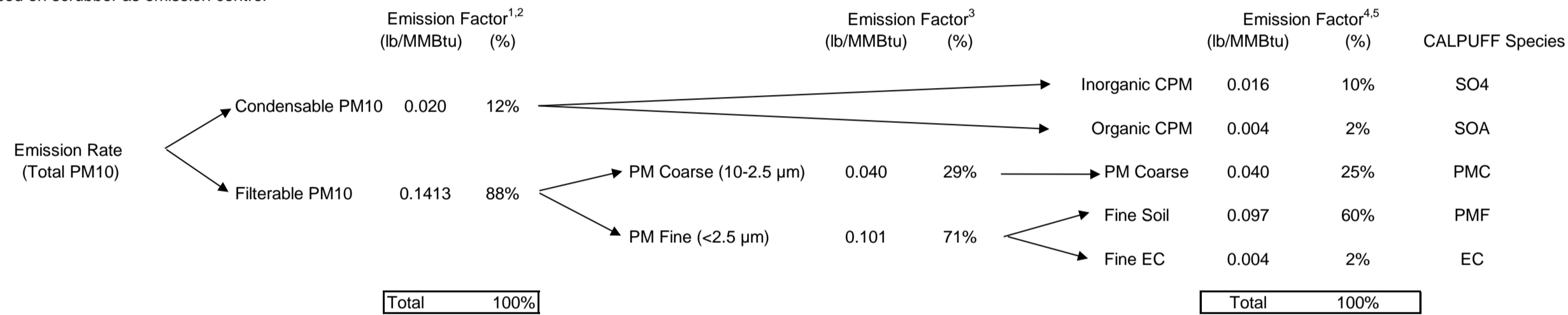
1 Coal properties as presented in Table 2-2 of respective NVE BART Analyses

2 Average values used in calculations below, where necessary. Note that NV Energy used Skyline coal in most of its calculations (per Appendix A of NVE BART Analyses)

PM10 Speciation

Option 1a (Total PM10, scrubber)

Assuming WRAP emissions represent Total PM10 (filterable PM10 + condensable PM10). This option is basically identical to NPS' approach
Based on scrubber as emission control



1 Condensable PM10 EF calculated using , AP-42, Table 1.1-5 (9/98), PC boiler, with FGD control

2 Filterable PM10 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 10 μm. Based on scrubber as particulate control.

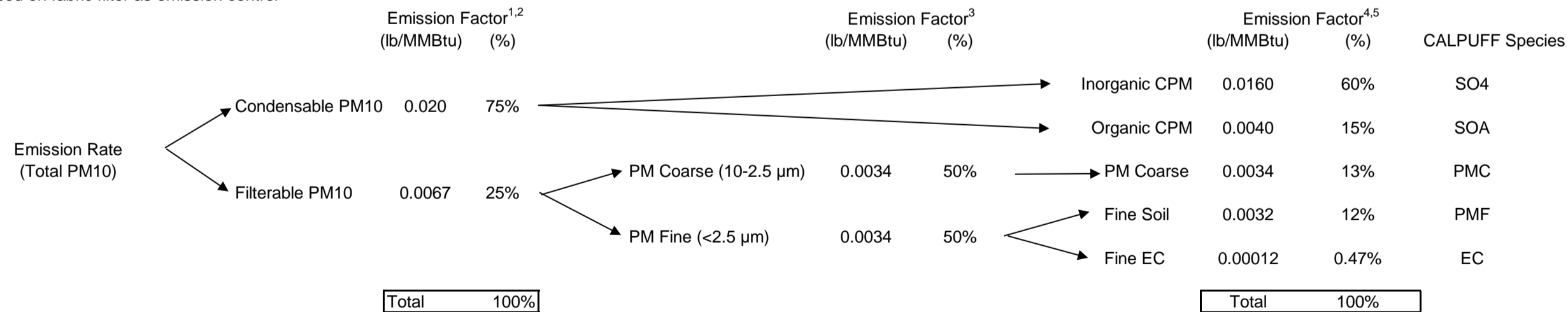
3 PM2.5 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 2.5 μm. Based on scrubber as particulate control.

4 Organic/Inorganic CPM emission factors based upon AP-42, Table 1.1-5 (9/98), PC boiler

5 EC fraction based on black carbon % as listed in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon, Jan 2002 Draft"

Option 1b (Total PM10, fabric filter/baghouse)

Assuming WRAP emissions represent Total PM10 (filterable PM10 + condensable PM10). This option is basically identical to NPS' approach
Based on fabric filter as emission control



1 Condensable PM10 EF calculated using , AP-42, Table 1.1-5 (9/98), PC boiler, with FGD control

2 Filterable PM10 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 10 μm. Based on baghouse as particulate control.

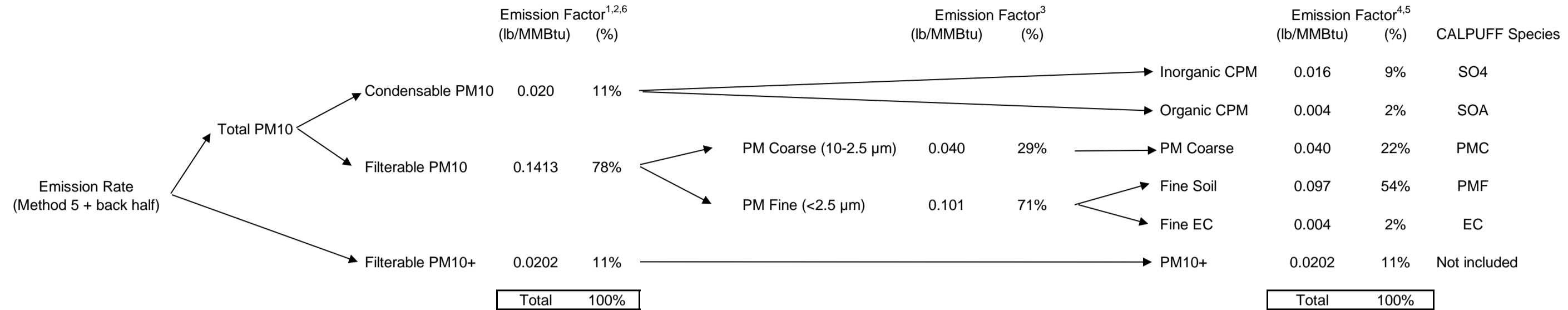
3 PM2.5 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 2.5 μm, based on baghouse as particulate control

4 Organic/Inorganic CPM emission factors based upon AP-42, Table 1.1-5 (9/98), PC boiler

5 EC fraction based on black carbon % as listed in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon, Jan 2002 Draft"

Option 2 (Method 5 + back half, scrubber)

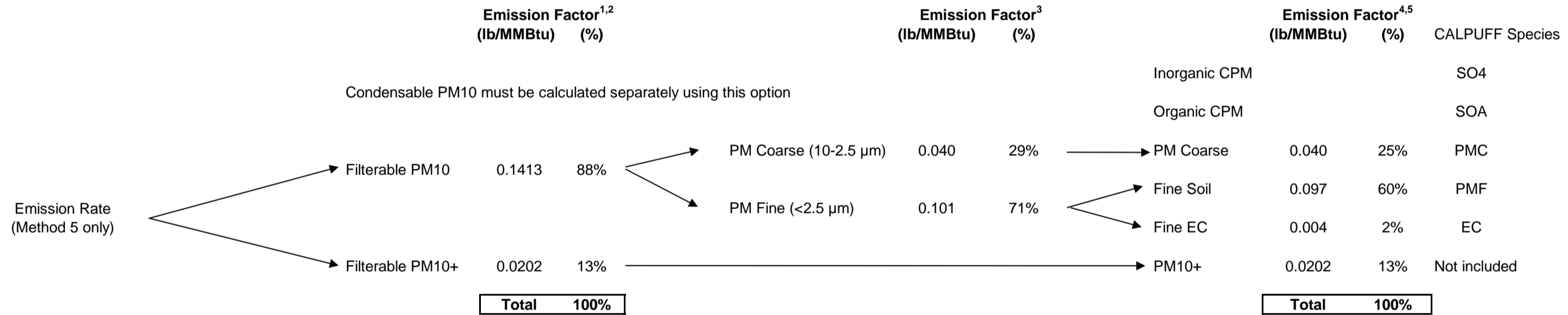
Assuming WRAP emissions are based on Method 5 (Total filterable PM) including back-half catch (condensables). Reid Gardner's 2004 TV permit renewal requires Method 5 + back half catch testing for compliance demonstration. Based on scrubber as emission control



- 1 Condensable PM10 EF calculated using , AP-42, Table 1.1-5 (9/98), PC boiler
- 2 Filterable PM10 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 10 μm. Based on scrubber as particulate control.
- 3 PM2.5 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 2.5 μm. Based on scrubber as particulate control.
- 4 Organic/Inorganic CPM emission factors based upon AP-42, Table 1.1-5 (9/98), PC boiler
- 5 EC fraction based on black carbon % as listed in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon, Jan 2002 Draft"
- 6 Filterable PM10+ EF calculated based on AP-42, Table 1.1-6 (9/98), using the difference between PM10 and PM15 Efs. Scrubber as particulate control

Option 3 (Filterable PM, scrubber)

Assuming WRAP emissions are based on Method 5 only (Total filterable PM). No back-half catch (condensables). Based on scrubber as emission control



- 1 Filterable PM10+ EF calculated based on AP-42, Table 1.1-6 (9/98), using the difference between PM10 and PM15 Efs. Scrubber as particulate control
- 2 Filterable PM10 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 10 μm. Based on scrubber as particulate control.
- 3 PM2.5 EF calculated based on AP-42, Table 1.1-6 (9/98) for particles < 2.5 μm. Based on scrubber as particulate control.
- 4 Organic/Inorganic CPM emission factors based upon AP-42, Table 1.1-5 (9/98), PC boiler
- 5 EC fraction based on black carbon % as listed in Table 6 of "Catalog of Global Emissions Inventories and Emission Inventory Tools for Black Carbon, Jan 2002 Draft"

Reid Gardner Generating Station
 Baseline Emission Calculations
 Baseline 1: WRAP emission baseline

| Unit Name | Control Technology | | | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|--------------------|--------------------------|-----------------------------------|--------------------------|-----------------|--------------------|-----------------|
| | NOx | SO2 | PM10 | | | | |
| Reid Gardner Unit 1 | None | Wet Soda Ash Scrubber | Mechanical Flyash Collector | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | None | Wet Soda Ash Scrubber | Mechanical Flyash Collector | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | None | Wet Soda Ash Scrubber | Mechanical Flyash Collector | 1237 | 12,170 | 0.59 | 7.66 |

00 Baseline 1 uses WRAP emission factors for NOx, SO2, and filterable PM

| Unit Name | NOx | | SO2 | | H2SO4 ¹ | SO4 | Filterable PM ² | | SO4 | Speciated PM10 Emissions ³ | | | |
|---------------------|------------|---------|------------|---------|--------------------|---------|----------------------------|---------|-----|---------------------------------------|-------------------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/hr) | (lb/hr) | (lb/MMBtu) | (lb/hr) | | SOA | Coarse (lb/hr) | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.591 | 718 | 0.329 | 400 | 0.572 | 0.560 | 0.0474 | 58 | | 4.86 | 14.40 | 34.66 | 1.33 |
| Reid Gardner Unit 2 | 0.635 | 772 | 0.28 | 340 | 0.572 | 0.560 | 0.044 | 53 | | 4.86 | 13.37 | 32.18 | 1.24 |
| Reid Gardner Unit 3 | 0.592 | 732 | 0.32 | 396 | 0.582 | 0.570 | 0.04 | 49 | | 4.95 | 12.37 | 29.78 | 1.14 |

¹H2SO4 Emission Calculations based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

$$ER = E2 * K * F1 * F2, \text{ based upon Equations 4-1 and 4-3 (fuel combustion only)}$$

Where,

ER = H2SO4 emissions, (lb/hr)

E2 = SO2 emissions, (lb/hr)

K = 1.53 SO2 to H2SO4 mol wt conversion

F1 = 0.00111 Fuel impact factor, western bituminous coal, dry bottom boiler

F2 = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using lo

0.65 Table 4-5, wet venturi scrubber

$E2 = K1 * K2 * C1 * S1$, based upon Equation 4-2b. Although SO2 CEMS data exists, it was not used in the calculation because insufficient data exists to calculate the

$E2 =$ SO2 emissions (lb/hr)
 $K1 =$ 2.00 S to SO2 mol wt ratio
 $K2 =$ 0.95 Sulfur Conversion to SO2, bituminous coal
 $C1 =$ Dry coal burn rate (ton/hr)
 $S1 =$ Coal sulfur dry wt fraction

² Although these emissions are represented in WRAP documentation as PM10, they were represented in NV Energy visibility modeling as filterable PM and speciated as such. They are also considered filterable PM in this baseline run in order to be consistent.

³ PM10 speciation is based upon Option 3, which assumes the WRAP PM10 emission rate represents results of Method 5 testing (filterable PM)

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | -- |
| Organic CPM (SOA) | -- |
| Coarse (PMC) | 25% |
| Fine Soil (PMF) | 60% |
| Elemental Carbon (EC) | 2% |

Inorganic CPM based upon SO4 emissions generated from H2SO4
 Organic CPM emissions based upon AP-42 (9/98), Table 1.1-5 (20% of CPM-TOT emission factor)

**Reid Gardner Generating Station
Baseline Emission Calculations**

Baseline 1a: WRAP emission baseline NOx, NDEP BART for SO2 and PM10

| Unit Name | Control Technology | | | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|--------------------|--|---------------|--------------------------|-----------------|--------------------|-----------------|
| | NOx | SO2 | PM10 | | | | |
| Reid Gardner Unit 1 | None | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | None | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | None | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

02 Baseline 1a uses WRAP emission factors for NOx, and NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | PM10 ² | | SO4 (pre-rxn) | Speciated PM10 Emissions ³ | | | EC |
|---------------------|------------|---------|------------------|---------|-------------------|---------|---------------|---------------------------------------|-------------------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | | SOA | Coarse (lb/hr) | Fine Soil | |
| Reid Gardner Unit 1 | 0.591 | 718 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.635 | 772 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.592 | 732 | 0.15 | 186 | 0.015 | 19 | 11.11 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Per TV Permit No. AP4911-0897, PM10 source testing must consist of Method 201A and 202, which would indicate that total PM10 test dat

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

**Reid Gardner Generating Station
Baseline Emission Calculations**

Baseline 2: EPA baseline (NDEP baseline NOx, NDEP BART for SO2 and PM10)

| Unit Name | Control Technology | | | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|--------------------|--|---------------|--------------------------|-----------------|--------------------|-----------------|
| | NOx | SO2 | PM10 | | | | |
| Reid Gardner Unit 1 | LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

04 Baseline 2 uses NDEP SIP's baseline emission factors for NOx, and NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | PM10 ² | | SO4 (pre-rxn) | Speciated PM10 Emissions ³ | | | EC |
|---------------------|------------|---------|------------------|---------|-------------------|---------|---------------|---------------------------------------|-------------------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | | SOA | Coarse (lb/hr) | Fine Soil | |
| Reid Gardner Unit 1 | 0.462 | 561 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.466 | 566 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.451 | 558 | 0.15 | 186 | 0.015 | 19 | 11.11 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Per TV Permit No. AP4911-0897, PM10 source testing must consist of Method 201A and 202, which would indicate that

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

**Reid Gardner Generating Station
NOx Control Scenario Emission Calculations**

Control Scenario 1: Upgraded LNB

| Unit Name | Control Technology | | | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|-------------------------|--|---------------|--------------------------|-----------------|--------------------|-----------------|
| | NOx | SO2 | PM10 | | | | |
| Reid Gardner Unit 1 | LNB + OFA (enhanced) | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | LNB + OFA (enhanced) | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | LNB + OFA (enhanced) | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 1 emissions based on NDEP estimate of NOx for LNB+OFA, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | PM10 ² | | SO4 (pre-rxn) | Speciated PM10 Emissions ³ | | | EC |
|---------------------|------------|---------|------------------|---------|-------------------|---------|---------------|---------------------------------------|-------------------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | | SOA | Coarse (lb/hr) | Fine Soil | |
| Reid Gardner Unit 1 | 0.364 | 442 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.355 | 431 | 0.15 | 182 | 0.015 | 18 | 10.91 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.421 | 521 | 0.15 | 186 | 0.015 | 19 | 11.11 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testin

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

**Reid Gardner Generating Station
NOx Control Scenario Emission Calculations**

Control Scenario 2: SNCR with LNB w/ OFA

| Unit Name | Control Technology | | | Heat Input | HHV | Fuel Sulfur | Moisture |
|---------------------|-------------------------|--|---------------|------------|----------|-------------|----------|
| | NOx | SO2 | PM10 | (MMBtu/hr) | (Btu/lb) | wt% | wt% |
| Reid Gardner Unit 1 | SNCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | SNCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | SNCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 2 emissions based on NDEP estimate of NOx for SNCR+LNB+OFA, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | PM10 ² | | Speciated PM10 Emissions ³ | | | | | |
|---------------------|------------|---------|------------------|---------|-------------------|---------|---------------------------------------|-----------------------------|----------------|--------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | SO4 (pre-rxn) | SO4 (post rxn) ⁴ | SOA (lb/hr) | Coarse | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.273 | 332 | 0.15 | 182 | 0.015 | 18 | 10.91 | 0.00 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.267 | 324 | 0.15 | 182 | 0.015 | 18 | 10.91 | 0.00 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.316 | 391 | 0.15 | 186 | 0.015 | 19 | 11.11 | 0.00 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testing must consist of

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

⁴ H2SO4 from SCR based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

ER[NH3] = Ammonia Slip calculation

9780 dscf/MMBtu, from Method 19, Table 19-2 "Fuel F-factors". Fd-factor listed for bituminous coal @ 0% O2.
 5 ppmv @ 6% O2 (ammonia slip). ROFA+Rotamix guarantee, as indicated in NVE BART analyses, p3-6
 385.6 SCF/lbmol, molar volume @ STP.
 17.0 lb/lbmol, NH3 MW

| Unit No. | Ammonia Emission Rate | | |
|----------|-----------------------|----------|-------|
| | SCFH | lbmol/hr | lb/hr |
| Unit 1 | 83.34 | 0.216 | 3.67 |
| Unit 2 | 83.34 | 0.216 | 3.67 |
| Unit 3 | 84.85 | 0.220 | 3.74 |

Sample Calc (Unit 1):

$$\frac{1215 \text{ MMBtu}}{\text{hr}} \times \frac{9780 \text{ dscf}}{\text{MMBtu}} \times \frac{5 \text{ parts NH}_3}{1,000,000} \times \frac{(20.9 - 0) \text{ O}_2}{(20.9 - 6) \text{ O}_2} \times \frac{\text{lbmol}}{385.6 \text{ SCF}} \times \frac{17 \text{ lb NH}_3}{\text{lbmol}} = 3.67 \text{ lb/hr}$$

ER = ((EM_{SO4} - ER_{NH3})*98.6) * F2, based on modified equation 4-7

Where,

ER = H2SO4 emitted (lb/hr)

EM = H2SO4 manufactured (lbmol/hr)

ER[NH3] = Ammonia slip (lbmol/hr)

F2 = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using low S eastern bituminous factor per EPF
 0.10 Table 4-4, baghouse
 0.65 Table 4-5, wet venturi scrubber

| Unit No. | H2SO4 | | | |
|----------|----------------------|----------|-----------------------|-------|
| | EM (pre-reaction) | | ER (post-reaction) | |
| | lb/hr | lbmol/hr | lbmol/hr | lb/hr |
| Unit 1 | 10.91 | 0.111 | -0.105 | -0.34 |
| Unit 2 | 10.91 | 0.111 | -0.105 | -0.34 |
| Unit 3 | 11.11 | 0.113 | -0.107 | -0.34 |

**Reid Gardner Generating Station
NOx Control Scenario Emission Calculations**

Control Scenario 3: ROFA w/ Rotamix

| Unit Name | Control Technology | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|--|-----------------------|--------------|-----------------|--------------|
| | NOx SO2 PM10 | | | | |
| Reid Gardner Unit 1 | ROFA w/ Rotamix Wet Soda Ash Scrubber (upgraded) Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | ROFA w/ Rotamix Wet Soda Ash Scrubber (upgraded) Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | ROFA w/ Rotamix Wet Soda Ash Scrubber (upgraded) Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 3 emissions based on NDEP estimate of NOx for ROFA+Rotamix, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | PM10 ² | | Speciated PM10 Emissions ³ | | | | | |
|---------------------|------------|---------|------------------|---------|-------------------|---------|---------------------------------------|-----------------------------|-------------|--------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | SO4 (pre-rxn) | SO4 (post rxn) ⁴ | SOA (lb/hr) | Coarse | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.195 | 237 | 0.15 | 182 | 0.015 | 18 | 10.91 | 0.00 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.191 | 232 | 0.15 | 182 | 0.015 | 18 | 10.91 | 0.00 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.278 | 344 | 0.15 | 186 | 0.015 | 19 | 11.11 | 0.00 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testing must consist of

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

⁴ H2SO4 from SCR based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

ER[NH3] = Ammonia Slip calculation

9780 dscf/MMBtu, from Method 19, Table 19-2 "Fuel F-factors". Fd-factor listed for bituminous coal @ 0% O2.
 5 ppmv @ 6% O2 (ammonia slip). ROFA+Rotamix guarantee, as indicated in NVE BART analyses, p3-6
 385.6 SCF/lbmol, molar volume @ STP.
 17.0 lb/lbmol, NH3 MW

| Unit No. | Ammonia Emission Rate | | |
|----------|-----------------------|----------|-------|
| | SCFH | lbmol/hr | lb/hr |
| Unit 1 | 83.34 | 0.216 | 3.67 |
| Unit 2 | 83.34 | 0.216 | 3.67 |
| Unit 3 | 84.85 | 0.220 | 3.74 |

Sample Calc (Unit 1):

$$\frac{1215 \text{ MMBtu}}{\text{hr}} \times \frac{9780 \text{ dscf}}{\text{MMBtu}} \times \frac{5 \text{ parts NH}_3}{1,000,000} \times \frac{(20.9 - 0) \text{ O}_2}{(20.9 - 6) \text{ O}_2} \times \frac{\text{lbmol}}{385.6 \text{ SCF}} \times \frac{17 \text{ lb NH}_3}{\text{lbmol}} = 3.67 \text{ lb/hr}$$

ER = ((EM_{SO4} - ER_{NH3})*98.6) * F2, based on modified equation 4-7

Where,

ER = H2SO4 emitted (lb/hr)

EM = H2SO4 manufactured (lbmol/hr)

ER[NH3] = Ammonia slip (lbmol/hr)

F2 = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using low S eastern bituminous factor per EPF)
 0.10 Table 4-4, baghouse
 0.65 Table 4-5, wet venturi scrubber

| Unit No. | H2SO4 | | | |
|----------|----------------------|----------|-----------------------|-------|
| | EM (pre-reaction) | | ER (post-reaction) | |
| | lb/hr | lbmol/hr | lbmol/hr | lb/hr |
| Unit 1 | 10.91 | 0.111 | -0.105 | -0.34 |
| Unit 2 | 10.91 | 0.111 | -0.105 | -0.34 |
| Unit 3 | 11.11 | 0.113 | -0.107 | -0.34 |

Reid Gardner Generating Station
NOx Control Scenario Emission Calculations
Control Scenario 4: SCR with ROFA

| Unit Name | Control Technology | | | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|--------------------|--|---------------|--------------------------|-----------------|--------------------|-----------------|
| | NOx | SO2 | PM10 | | | | |
| Reid Gardner Unit 1 | SCR + ROFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | SCR + ROFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | SCR + ROFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 4 emissions based on NDEP estimate of NOx for SCR+ROFA, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | H2SO4 ⁴ (from SCR) | SO4 | PM10 ² | | Speciated PM10 Emissions ³ | | | | | |
|---------------------|------------|---------|------------------|---------|----------------------------------|---------|-------------------|---------|---------------------------------------|-------------|----------------|--------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/hr) | (lb/hr) | (lb/MMBtu) | (lb/hr) | SO4 | SO4 (total) | SOA (lb/hr) | Coarse | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.085 | 103 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.083 | 101 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.098 | 121 | 0.15 | 186 | 0.15 | 0.148 | 0.015 | 19 | 11.11 | 11.26 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testing must consist of Method 201A and

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

⁴ H2SO4 from SCR based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

$E2 = K1 * K2 * C1 * S1$, based upon Equation 4-2b. Although SO2 CEMS data exists, it was not used in the calculation because insufficient data exists to calculate the CEMS correction factor

Where,

- E2 = SO2 emissions (lb/hr)
- K1 = 2.00 S to SO2 mol wt ratio
- K2 = 0.95 Sulfur Conversion to SO2, bituminous coal
- C1 = Dry coal burn rate (lb/hr)
- S1 = Coal sulfur dry wt fraction

| Unit No. | SO2 | |
|----------|---------------|---------------|
| | C1 (lb/hr) | E2 (lb/hr) |
| Unit 1 | 99838 | 1034.66 |
| Unit 2 | 99838 | 1034.66 |
| Unit 3 | 101646 | 1053.40 |

$EM = K * S2 * f[sops] * E2 * F3[scr]$, based on equation 4-6

Where,

- EM = H2SO4 manufactured (lb/hr)
- K = 1.53 SO2 to H2SO4 molecular wt conversion
- S2 = 0.0050 SCR catalyst SO2 oxidation rate, based upon 3 layers of catalyst
- f[sops] = 0.98 Operating factor of SCR system. Corresponds to baseload operation, per Equation 4-6
- F3[scr] = 1 SCR technology impact factor, non-PRB coal, per Equation 4-6
- E2 = SO2 emissions, (lb/hr)

| Unit No. | H2SO4 |
|----------|----------------|
| | EM (ton/hr) |
| Unit 1 | 7.76 |
| Unit 2 | 7.76 |
| Unit 3 | 7.90 |

ER_{NH3} = Ammonia Slip calculation

- 9780 dscf/MMBtu, from Method 19, Table 19-2 "Fuel F-factors". Fd-factor listed for bituminous coal @ 0% O2.
- 0.75 ppmv @ 6% O2 (ammonia slip), per Equation 4-6.
- 385.6 SCF/lbmol, molar volume @ STP.
- 17.0 lb/lbmol, NH3 MW

| Unit No. | Ammonia Emission Rate | | |
|----------|-----------------------|----------|-------|
| | SCFH | lbmol/hr | lb/hr |
| Unit 1 | 12.50 | 0.032 | 0.55 |
| Unit 2 | 12.50 | 0.032 | 0.55 |
| Unit 3 | 12.73 | 0.033 | 0.56 |

Sample Calc (Unit 1):

$$\frac{1215 \text{ MMBtu}}{\text{hr}} \times \frac{9780 \text{ dscf}}{\text{MMBtu}} \times \frac{0.75 \text{ parts NH}_3}{1,000,000} \times \frac{(20.9 - 0) \text{ O}_2}{(20.9 - 6) \text{ O}_2} \times \frac{\text{lbmol}}{385.6 \text{ SCF}} \times \frac{17 \text{ lb NH}_3}{\text{lbmol}} = \frac{0.55 \text{ lb}}{\text{hr}}$$

$$ER = ((EM_{H_2SO_4} - ER_{NH_3}) * MW_{H_2SO_4}) * F_2, \text{ based on modified equation 4-7}$$

Where,

ER = H2SO4 emitted (lb/hr)

EM_{SO4} = H2SO4 manufactured (lbmol/hr)

ER_{NH3} = Ammonia slip (lbmol/hr)

MW_{H2SO4} = 98.6 lb/lbmol

F2 = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using low S eastern bituminous factor per EPRI recommendation)
 0.10 Table 4-4, baghouse
 0.65 Table 4-5, wet venturi scrubber

| Unit No. | H2SO4 | | | |
|----------|----------------------|----------|-----------------------|-------|
| | EM (pre-reaction) | | ER (post-reaction) | |
| | lb/hr | lbmol/hr | lbmol/hr | lb/hr |
| Unit 1 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 2 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 3 | 7.90 | 0.080 | 0.047 | 0.15 |

**Reid Gardner Generating Station
NOx Control Scenario Emission Calculations**

Control Scenario 5: SCR with LNB and OFA

| Unit Name | Control Technology | | | Heat Input | HHV | Fuel Sulfur | Moisture |
|---------------------|------------------------|--|---------------|------------|----------|-------------|----------|
| | NOx | SO2 | PM10 | (MMBtu/hr) | (Btu/lb) | wt% | wt% |
| Reid Gardner Unit 1 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 5 emissions based on NDEP estimate of NOx for SCR+LNB+OFA, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | H2SO4 ⁴ (from SCR) | SO4 | PM10 ² | | Speciated PM10 Emissions ³ | | | | | |
|---------------------|------------|---------|------------------|---------|----------------------------------|---------|-------------------|---------|---------------------------------------|-------------|----------------|--------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/hr) | (lb/hr) | (lb/MMBtu) | (lb/hr) | SO4 | SO4 (total) | SOA (lb/hr) | Coarse | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.085 | 103 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.083 | 101 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.098 | 121 | 0.15 | 186 | 0.15 | 0.148 | 0.015 | 19 | 11.11 | 11.26 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testing must consist of Meth

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

⁴ H2SO4 from SCR based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

$E2 = K1 * K2 * C1 * S1$, based upon Equation 4-2b. Although SO2 CEMS data exists, it was not used in the calculation because insufficient data exists to calculate the CEMS correction factor

Where,

- E2 = SO2 emissions (lb/hr)
- K1 = 2.00 S to SO2 mol wt ratio
- K2 = 0.95 Sulfur Conversion to SO2, bituminous coal
- C1 = Dry coal burn rate (lb/hr)
- S1 = Coal sulfur dry wt fraction

| Unit No. | SO2 | |
|----------|---------------|---------------|
| | C1 (lb/hr) | E2 (lb/hr) |
| Unit 1 | 99838 | 1034.66 |
| Unit 2 | 99838 | 1034.66 |
| Unit 3 | 101646 | 1053.40 |

$EM = K * S2 * f[sops] * E2 * F3[scr]$, based on equation 4-6

Where,

- EM = H2SO4 manufactured (lb/hr)
- K = 1.53 SO2 to H2SO4 molecular wt conversion
- S2 = 0.0050 SCR catalyst SO2 oxidation rate, based upon 0.5% conversion at 3 layers of catalyst
- f[sops] = 0.98 Operating factor of SCR system. Corresponds to baseload operation, per Equation 4-6
- F3[scr] = 1 SCR technology impact factor, non-PRB coal, per Equation 4-6
- E2 = SO2 emissions, (lb/hr)

| Unit No. | H2SO4 |
|----------|----------------|
| | EM (ton/hr) |
| Unit 1 | 7.76 |
| Unit 2 | 7.76 |
| Unit 3 | 7.90 |

ER_{NH3} = Ammonia Slip calculation

- 9780 dscf/MMBtu, from Method 19, Table 19-2 "Fuel F-factors". Fd-factor listed for bituminous coal @ 0% O2.
- 0.75 ppmv @ 6% O2 (ammonia slip), per Equation 4-6.
- 385.6 SCF/lbmol, molar volume @ STP.
- 17.0 lb/lbmol, NH3 MW

| Unit No. | Ammonia Emission Rate | | |
|----------|-----------------------|----------|-------|
| | SCFH | lbmol/hr | lb/hr |
| Unit 1 | 12.50 | 0.032 | 0.55 |
| Unit 2 | 12.50 | 0.032 | 0.55 |
| Unit 3 | 12.73 | 0.033 | 0.56 |

Sample Calc (Unit 1):

$$\frac{1215 \text{ MMBtu}}{\text{hr}} \left| \frac{9780 \text{ dscf}}{\text{MMBtu}} \right| \frac{0.75 \text{ parts NH}_3}{1,000,000} \left| \frac{(20.9 - 0) \text{ O}_2}{(20.9 - 6) \text{ O}_2} \right| \frac{\text{lbmol}}{385.6 \text{ SCF}} \left| \frac{17 \text{ lb NH}_3}{\text{lbmol}} \right| = \frac{0.55 \text{ lb}}{\text{hr}}$$

$$ER = ((EM_{H_2SO_4} - ER_{NH_3}) * MW_{H_2SO_4}) * F_2, \text{ based on modified equation 4-7}$$

Where,

ER = H2SO4 emitted (lb/hr)

EM_{SO4} = H2SO4 manufactured (lbmol/hr)

ER_{NH3} = Ammonia slip (lbmol/hr)

MW_{H2SO4} = 98.6 lb/lbmol

F2 = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using low S eastern bituminous factor per EPRI record)
 0.10 Table 4-4, baghouse
 0.65 Table 4-5, wet venturi scrubber

| Unit No. | H2SO4 | | | |
|----------|----------------------|----------|-----------------------|-------|
| | EM (pre-reaction) | | ER (post-reaction) | |
| | lb/hr | lbmol/hr | lbmol/hr | lb/hr |
| Unit 1 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 2 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 3 | 7.90 | 0.080 | 0.047 | 0.15 |

**Reid Gardner Generating Station
NOx Control Scenario Emission Calculations**

Control Scenario 6: SCR with LNB and OFA, EPA estimate of 0.06 lb/MMBtu NOx

| Unit Name | Control Technology NOx | SO2 | PM10 | Heat Input (MMBtu/hr) | HHV (Btu/lb) | Fuel Sulfur wt% | Moisture wt% |
|---------------------|---------------------------|--|---------------|--------------------------|-----------------|--------------------|-----------------|
| Reid Gardner Unit 1 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 2 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1215 | 12,170 | 0.59 | 7.66 |
| Reid Gardner Unit 3 | SCR + LNB w/ OFA | Wet Soda Ash Scrubber (upgraded) | Fabric Filter | 1237 | 12,170 | 0.59 | 7.66 |

Control 6 emissions based on EPA estimate of NOx for SCR+LNB+OFA, NDEP's BART determination for SO2 and PM10

| Unit Name | NOx | | SO2 ¹ | | H2SO4 ⁴ (from SCR) | SO4 | PM10 ² | | Speciated PM10 Emissions ³ | | | | | |
|---------------------|------------|---------|------------------|---------|----------------------------------|---------|-------------------|---------|---------------------------------------|-------------|----------------|--------|-----------|------|
| | (lb/MMBtu) | (lb/hr) | (lb/MMBtu) | (lb/hr) | (lb/hr) | (lb/hr) | (lb/MMBtu) | (lb/hr) | SO4 | SO4 (total) | SOA (lb/hr) | Coarse | Fine Soil | EC |
| Reid Gardner Unit 1 | 0.060 | 73 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 2 | 0.060 | 73 | 0.15 | 182 | 0.15 | 0.145 | 0.015 | 18 | 10.91 | 11.06 | 2.73 | 2.29 | 2.21 | 0.08 |
| Reid Gardner Unit 3 | 0.060 | 74 | 0.15 | 186 | 0.15 | 0.148 | 0.015 | 19 | 11.11 | 11.26 | 2.78 | 2.33 | 2.25 | 0.09 |

¹ SO2 emissions based upon Nevada's SO2 BART determination of upgraded wet soda ash scrubber

² PM10 emissions based upon Nevada's PM10 BART determination of fabric filters.

³ PM10 speciation is based upon Option 1b (Total PM10, fabric filter/baghouse). Although the basis for the BART PM10 limit is unclear, TV Permit No. AP4911-0897 requires that PM10 source testing must consist of Method 201A and

| PM species | (wt%) |
|-----------------------|-------|
| Inorganic CPM (SO4) | 60% |
| Organic CPM (SOA) | 15% |
| Coarse (PMC) | 13% |
| Fine Soil (PMF) | 12% |
| Elemental Carbon (EC) | 0.47% |

⁴ H2SO4 from SCR based upon "Estimating Total Sulfuric Acid Emissions from Stationary Power Plants," EPRI, Technical Update, April 2010

$E2 = K1 * K2 * C1 * S1$, based upon Equation 4-2b. Although SO2 CEMS data exists, it was not used in the calculation because insufficient data exists to calculate the CEMS correction factor

Where,

- E2 = SO2 emissions (lb/hr)
- K1 = 2.00 S to SO2 mol wt ratio
- K2 = 0.95 Sulfur Conversion to SO2, bituminous coal
- C1 = Dry coal burn rate (lb/hr)
- S1 = Coal sulfur dry wt fraction

| Unit No. | SO2 | |
|----------|---------------|---------------|
| | C1 (lb/hr) | E2 (lb/hr) |
| Unit 1 | 99838 | 1034.66 |
| Unit 2 | 99838 | 1034.66 |
| Unit 3 | 101646 | 1053.40 |

$EM = K * S2 * f[sops] * E2 * F3[scr]$, based on equation 4-6

Where,

- EM = H2SO4 manufactured (lb/hr)
- K = 1.53 SO2 to H2SO4 molecular wt conversion
- S2 = 0.0050 SCR catalyst SO2 oxidation rate, based upon 0.5% conversion at 3 layers of catalyst
- f[sops] = 0.98 Operating factor of SCR system. Corresponds to baseload operation, per Equation 4-6
- F3[scr] = 1 SCR technology impact factor, non-PRB coal, per Equation 4-6
- E2 = SO2 emissions, (lb/hr)

| Unit No. | H2SO4 |
|----------|----------------|
| | EM (ton/hr) |
| Unit 1 | 7.76 |
| Unit 2 | 7.76 |
| Unit 3 | 7.90 |

ER_{NH3} = Ammonia Slip calculation

- 9780 dscf/MMBtu, from Method 19, Table 19-2 "Fuel F-factors". Fd-factor listed for bituminous coal @ 0% O2.
- 0.75 ppmv @ 6% O2 (ammonia slip), per Equation 4-6.
- 385.6 SCF/lbmol, molar volume @ STP.
- 17.0 lb/lbmol, NH3 MW

| Unit No. | Ammonia Emission Rate | | |
|----------|-----------------------|----------|-------|
| | SCFH | lbmol/hr | lb/hr |
| Unit 1 | 12.50 | 0.032 | 0.55 |
| Unit 2 | 12.50 | 0.032 | 0.55 |
| Unit 3 | 12.73 | 0.033 | 0.56 |

Sample Calc (Unit 1):

$$\frac{1215 \text{ MMBtu}}{\text{hr}} \times \frac{9780 \text{ dscf}}{\text{MMBtu}} \times \frac{0.75 \text{ parts NH}_3}{1,000,000} \times \frac{(20.9 - 0) \text{ O}_2}{(20.9 - 6) \text{ O}_2} \times \frac{\text{lbmol}}{385.6 \text{ SCF}} \times \frac{17 \text{ lb NH}_3}{\text{lbmol}} = 0.55 \frac{\text{lb}}{\text{hr}}$$

$$ER = ((EM_{H_2SO_4} - ER_{NH_3}) * MW_{H_2SO_4}) * F_2, \text{ based on modified equation 4-7}$$

Where,

ER = H₂SO₄ emitted (lb/hr)

EM_{SO₄} = H₂SO₄ manufactured (lbmol/hr)

ER_{NH₃} = Ammonia slip (lbmol/hr)

MW_{H₂SO₄} = 98.6 lb/lbmol

F₂ = 0.5 Table 4-3, air heater removal factor. Although fuel sulfur content is low, Reid Gardner coal ash is still assumed to be acidic (using low S eastern bituminous factor per EPRI recommendation)

0.10 Table 4-4, baghouse

0.65 Table 4-5, wet venturi scrubber

| Unit No. | H ₂ SO ₄ | | | |
|----------|--------------------------------|----------|-----------------------|-------|
| | EM (pre-reaction) | | ER (post-reaction) | |
| | lb/hr | lbmol/hr | lbmol/hr | lb/hr |
| Unit 1 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 2 | 7.76 | 0.079 | 0.046 | 0.15 |
| Unit 3 | 7.90 | 0.080 | 0.047 | 0.15 |

Appendix D:

Historical Emissions for Reid Gardner Generating Station (as reported in CAMD)

See www.regulations.gov, docket ID number EPA-R09-OAR-2011-0130

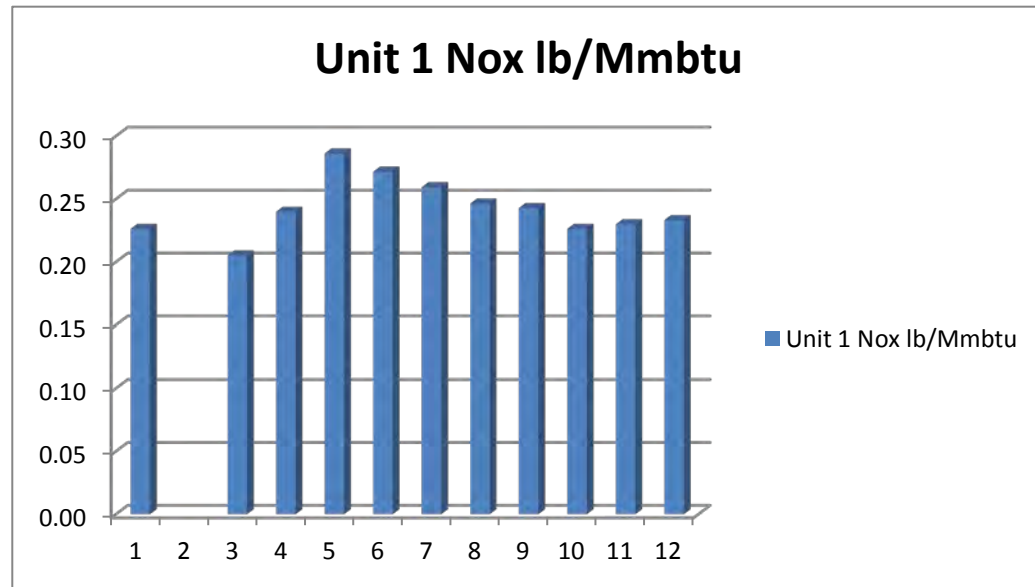
| STATE | FACILITY_NAME | ORISPL_CO | UNITID | OP_YEAR | ASSOC_ST# | PRG_CODE | SUM_OP_T | NUM_MO | SO2_MASS (tons/yr) | SO2_RATE (lb/MMBtu) | NOX_RATE (lb/MMBtu) | NOX_MASS (tons/yr) | CO2_MASS (tons/yr) | HEAT_INPUT (MMBtu/yr) | CO2_RATE (tons/MMBtu) | OWN_DISPLAY | UNIT_TYPE_INFO | PRIMARY_P | SECONDAR | SO2_CONT | NOX_CONT | PART_CON | CAPACITY_INPUT (MMBtu/hr) |
|-------|---------------|-----------|--------|---------|-----------|----------|----------|--------|-----------------------|------------------------|------------------------|-----------------------|-----------------------|--------------------------|--------------------------|---------------------------------------|----------------------|-----------|----------|----------|--------------------------------|----------|------------------------------|
| NV | Reid Gardner | 2324 | 1 | 2001 | ARP | | 7211.5 | 12 | 587.506 | 0.15 | 0.42 | 1652.943 | 790,945 | 7,894,057 | 0.100 | NV Energy (Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2002 | ARP | | 7673.5 | 12 | 492.827 | 0.10 | 0.47 | 2221.394 | 956,356 | 9,491,928 | 0.101 | NV Energy (Operator) (Ended Dec 2002) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2003 | ARP | | 8271.5 | 12 | 749.629 | 0.15 | 0.45 | 2312.514 | 1,031,866 | 10,138,698 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2004 | ARP | | 7598.5 | 12 | 215.018 | 0.05 | 0.38 | 1771.312 | 933,887 | 9,237,466 | 0.101 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2005 | ARP | | 7902.75 | 12 | 186.87 | 0.04 | 0.37 | 1780.584 | 974,563 | 9,578,809 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2006 | ARP | | 7911.25 | 12 | 247.374 | 0.05 | 0.36 | 1663.686 | 934,613 | 9,088,376 | 0.103 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2007 | ARP | | 6583.68 | 12 | 132.603 | 0.04 | 0.38 | 1412.933 | 732,650 | 7,345,334 | 0.100 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2008 | ARP | | 6665.5 | 12 | 137.398 | 0.04 | 0.39 | 1340.789 | 671,618 | 6,732,582 | 0.100 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2009 | ARP | | 6235.59 | 12 | 172.236 | 0.05 | 0.31 | 997.701 | 645,540 | 6,374,908 | 0.101 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2010 | ARP | | 6481.17 | 12 | 200.513 | 0.06 | 0.27 | 856.633 | 631,645 | 6,339,957 | 0.100 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 1 | 2011 | ARP | | 6386.3 | 12 | 275.563 | 0.10 | 0.24 | 677.033 | 569,220 | 5,440,729 | 0.105 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2001 | ARP | | 7492.5 | 12 | 436.285 | 0.10 | 0.43 | 1947.113 | 905,107 | 9,031,359 | 0.100 | NV Energy (Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2002 | ARP | | 8074.75 | 12 | 254.464 | 0.05 | 0.46 | 2504.151 | 1,099,225 | 10,841,071 | 0.101 | NV Energy (Operator) (Ended Dec 2002) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2003 | ARP | | 7599 | 12 | 527.698 | 0.10 | 0.46 | 2386.279 | 1,034,507 | 10,162,427 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2004 | ARP | | 8035 | 12 | 268.916 | 0.05 | 0.40 | 2285.593 | 1,165,348 | 11,556,209 | 0.101 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2005 | ARP | | 6992.5 | 12 | 224.022 | 0.05 | 0.39 | 1861.09 | 961,732 | 9,530,909 | 0.101 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2006 | ARP | | 7590.75 | 12 | 249.144 | 0.05 | 0.39 | 2053.589 | 1,058,480 | 10,323,703 | 0.103 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2007 | ARP | | 8157.26 | 12 | 188.967 | 0.04 | 0.40 | 1952.307 | 1,006,145 | 9,771,674 | 0.103 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2008 | ARP | | 7752.75 | 12 | 122.196 | 0.03 | 0.40 | 1606.043 | 821,436 | 8,048,541 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2009 | ARP | | 5406.78 | 12 | 153.722 | 0.05 | 0.33 | 949.288 | 572,183 | 5,590,251 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2010 | ARP | | 6755.55 | 12 | 219.063 | 0.06 | 0.29 | 1045.961 | 699,409 | 6,967,468 | 0.100 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 2 | 2011 | ARP | | 6065.84 | 12 | 261.760 | 0.10 | 0.25 | 669.406 | 546,329 | 5,287,823 | 0.103 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1215 | |
| NV | Reid Gardner | 2324 | 3 | 2001 | ARP | | 8172.25 | 12 | 571.735 | 0.11 | 0.44 | 2216.213 | 995,971 | 9,973,357 | 0.100 | NV Energy (Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2002 | ARP | | 8068.25 | 12 | 272.945 | 0.05 | 0.45 | 2320.33 | 1,014,028 | 10,154,344 | 0.100 | NV Energy (Operator) (Ended Dec 2002) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2003 | ARP | | 7698 | 12 | 519.154 | 0.11 | 0.36 | 1665.226 | 1,010,950 | 9,453,692 | 0.107 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2004 | ARP | | 8022.5 | 12 | 235.284 | 0.05 | 0.32 | 1672.191 | 1,041,994 | 10,365,003 | 0.101 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2005 | ARP | | 7875.25 | 12 | 270.388 | 0.06 | 0.30 | 1440.373 | 1,031,676 | 9,590,769 | 0.108 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2006 | ARP | | 6948.25 | 12 | 195.758 | 0.04 | 0.33 | 1504.294 | 943,403 | 9,009,871 | 0.105 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2007 | ARP | | 6833.33 | 12 | 141.604 | 0.03 | 0.28 | 1176.845 | 840,818 | 8,126,408 | 0.103 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2008 | ARP | | 7091.43 | 12 | 160.794 | 0.04 | 0.25 | 1032.485 | 841,932 | 8,101,831 | 0.104 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Other | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2009 | ARP | | 6747.79 | 12 | 221.27 | 0.06 | 0.26 | 969.336 | 783,836 | 7,549,004 | 0.104 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2010 | ARP | | 7231.19 | 12 | 243.069 | 0.06 | 0.23 | 930.935 | 828,066 | 8,080,157 | 0.102 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1237 | |
| NV | Reid Gardner | 2324 | 3 | 2011 | ARP | | 5965.13 | 12 | 295.296 | 0.10 | 0.21 | 578.259 | 592,631 | 5,642,747 | 0.105 | NV Energy (Owner/Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 1237 | |
| NV | Reid Gardner | 2324 | 4 | 2001 | ARP | | 7979.75 | 12 | 571.831 | 0.06 | 0.30 | 3221.881 | 2,118,040 | 20,697,548 | 0.102 | NV Energy (Operator) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2002 | ARP | | 8379.5 | 12 | 957.296 | 0.09 | 0.33 | 3688.655 | 2,282,248 | 21,802,457 | 0.105 | NV Energy (Operator) (Ended Dec 2002) | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2003 | ARP | | 7528.25 | 12 | 2843.657 | 0.25 | 0.37 | 4347.952 | 2,401,537 | 23,157,911 | 0.104 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2004 | ARP | | 7537.5 | 12 | 1017.362 | 0.10 | 0.29 | 3189.406 | 2,147,230 | 21,031,588 | 0.102 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2005 | ARP | | 7893 | 12 | 1412.474 | 0.13 | 0.34 | 3933.081 | 2,285,140 | 22,583,722 | 0.101 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2006 | ARP | | 7690.5 | 12 | 1322.722 | 0.12 | 0.30 | 3421.548 | 2,230,077 | 22,152,886 | 0.101 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2007 | ARP | | 7802.58 | 12 | 689.848 | 0.07 | 0.27 | 2829 | 2,139,141 | 20,913,608 | 0.102 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2008 | ARP | | 6792.28 | 12 | 520.515 | 0.07 | 0.22 | 1684.931 | 1,538,533 | 14,757,038 | 0.104 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2009 | ARP | | 7918.23 | 12 | 698.18 | 0.09 | 0.23 | 1725.657 | 1,558,907 | 14,863,684 | 0.105 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2010 | ARP | | 6974.02 | 12 | 576.771 | 0.10 | 0.20 | 1232.07 | 1,260,586 | 12,019,305 | 0.105 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |
| NV | Reid Gardner | 2324 | 4 | 2011 | ARP | | 6034.2 | 12 | 595.557 | 0.11 | 0.19 | 1141.287 | 1,126,632 | 10,742,124 | 0.105 | NV Energy (Owner/Operator) Calif | Dry bottom wall-fire | Coal | | | Sodium Bas: Low NOx B Baghouse | 2956 | |

| STATE | FACILITY_NORISPL | UNITID | OP_YEAR | ASSOC_NTH | PRG_CODE | SUM_OP_TIME (hours/month) | GLOAD (MWh/month) | SLOAD | SO2_MASS (tons/month) (Measured) | NOX_RATE (lb/MMBtu) (Measured) | NOX_MASS (tons/month) (Calculated) | CO2_MASS (tons/month) | HEAT_INPUT (MMBtu/month) | CO2_Rate (tons/MMBtu) | PRIMARY_F | SECONDAR | SO2_CONT | NOX_CONT | PART_CONTROL_INFO |
|-------|------------------|--------|---------|-----------|----------|------------------------------|----------------------|-------|--|--------------------------------------|--|--------------------------|-----------------------------|--------------------------|-----------|----------|----------|----------|-------------------------------|
| NV | Reid Gardn | 2324 | 1 | 2010 | 1 ARP | 730 | 77698 | | 18 | 0.27 | 107 | 77321 | 780991 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 2 ARP | 672 | 73606 | | 31 | 0.28 | 104 | 75374 | 748523 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 3 ARP | 595 | 63029 | | 29 | 0.30 | 99 | 63854 | 642373 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 4 ARP | 515 | 48364 | | 15 | 0.27 | 68 | 48722 | 488562 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 5 ARP | 744 | 69680 | | 14 | 0.28 | 99 | 70021 | 707571 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 6 ARP | 636 | 59186 | | 22 | 0.25 | 78 | 61609 | 618698 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 7 ARP | 744 | 75120 | | 26 | 0.28 | 111 | 78330 | 790081 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 8 ARP | 557 | 53008 | | 20 | 0.22 | 63 | 54948 | 554486 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 9 ARP | 412 | 32317 | | 12 | 0.24 | 41 | 33507 | 334823 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 10 ARP | 222 | 18579 | | 6 | 0.25 | 24 | 18835 | 189179 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 11 ARP | 22 | 77 | | 0 | 0.09 | 0 | 213 | 2468 | 0.086 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2010 | 12 ARP | 633 | 43695 | | 7 | 0.25 | 62 | 48909 | 482204 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 1 ARP | 474 | 38998 | | 12 | 0.23 | 48 | 43574 | 422126 | 0.103 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 2 ARP | 0 | | | | | | | | | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 3 ARP | 58 | 1837 | | 1 | 0.21 | 3 | 2096 | 22714 | 0.092 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 4 ARP | 294 | 23626 | | 11 | 0.24 | 33 | 26733 | 259754 | 0.103 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 5 ARP | 565 | 43573 | | 26 | 0.29 | 71 | 49012 | 479250 | 0.102 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 6 ARP | 720 | 66595 | | 56 | 0.27 | 98 | 77082 | 727630 | 0.106 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 7 ARP | 743 | 66981 | | 44 | 0.26 | 88 | 72052 | 681521 | 0.106 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 8 ARP | 744 | 65516 | | 27 | 0.25 | 77 | 65492 | 624454 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 9 ARP | 717 | 58036 | | 29 | 0.24 | 67 | 58399 | 556823 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 10 ARP | 608 | 45449 | | 20 | 0.23 | 54 | 49091 | 468074 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 11 ARP | 720 | 59924 | | 29 | 0.23 | 70 | 64074 | 610917 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 1 | 2011 | 12 ARP | 744 | 57604 | | 20 | 0.23 | 68 | 61613 | 587467 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 1 ARP | 684 | 70401 | | 17 | 0.31 | 117 | 77549 | 752217 | 0.103 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 2 ARP | 630 | 67548 | | 24 | 0.31 | 112 | 73781 | 726047 | 0.102 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 3 ARP | 595 | 63169 | | 27 | 0.35 | 123 | 68485 | 681122 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 4 ARP | 547 | 54346 | | 22 | 0.32 | 97 | 58932 | 588523 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 5 ARP | 744 | 70012 | | 24 | 0.31 | 117 | 76517 | 763142 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 6 ARP | 650 | 62525 | | 21 | 0.30 | 107 | 69091 | 693868 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 7 ARP | 483 | 41873 | | 17 | 0.28 | 69 | 46135 | 475897 | 0.097 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 8 ARP | 660 | 64159 | | 22 | 0.26 | 96 | 72586 | 728205 | 0.100 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 9 ARP | 675 | 54543 | | 21 | 0.25 | 79 | 63156 | 626957 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 10 ARP | 426 | 33888 | | 13 | 0.26 | 53 | 39289 | 387095 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 11 ARP | 10 | 0 | | 0 | 0.04 | 0 | 47 | 713 | 0.066 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2010 | 12 ARP | 652 | 47943 | | 11 | 0.27 | 75 | 53841 | 543682 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 1 ARP | 514 | 41314 | | 12 | 0.29 | 69 | 46580 | 459082 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 2 ARP | 310 | 25868 | | 19 | 0.26 | 39 | 29417 | 289361 | 0.102 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 3 ARP | 0 | | | | | | | | | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 4 ARP | 0 | | | | | | | | | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 5 ARP | 621 | 46425 | | 26 | 0.25 | 72 | 53342 | 537280 | 0.099 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 6 ARP | 563 | 45916 | | 38 | 0.24 | 68 | 55171 | 544195 | 0.101 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 7 ARP | 743 | 65741 | | 48 | 0.25 | 88 | 73730 | 711074 | 0.104 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 8 ARP | 744 | 62252 | | 30 | 0.24 | 75 | 65999 | 629266 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 9 ARP | 599 | 44743 | | 20 | 0.26 | 61 | 48819 | 465481 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 10 ARP | 744 | 54721 | | 23 | 0.23 | 68 | 61974 | 590899 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 11 ARP | 720 | 59202 | | 30 | 0.24 | 76 | 65626 | 625716 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |
| NV | Reid Gardn | 2324 | 2 | 2011 | 12 ARP | 507 | 40950 | | 18 | 0.25 | 54 | 45671 | 435468 | 0.105 | Coal | | | | Sodium Bas Low NOx B Baghouse |

| STATE | FACILITY_NORISPL | UNITID | OP_YEAR | ASSOC_NTH | PRG_CODE | SUM_OP_TIME (hours/month) | GLOAD (MWh/month) | SLOAD | SO2_MASS (tons/month) (Measured) | NOX_RATE (lb/MMBtu) (Measured) | NOX_MASS (tons/month) (Calculated) | CO2_MASS (tons/month) | HEAT_INPUT (MMBtu/month) | CO2_Rate (tons/MMBtu) | PRIMARY_F | SECONDAR | SO2_CONT | NOX_CONT | PART_CONTROL | CONTROL_INFO |
|-------|------------------|--------|---------|-----------|----------|------------------------------|----------------------|-------|--|--------------------------------------|--|--------------------------|-----------------------------|--------------------------|-----------|----------|----------|----------|-------------------------------|--------------|
| NV | Reid Gardn | 2324 | 3 | 2010 | 1 ARP | 707 | 77024 | 23 | 0.25 | 106 | 87858 | 842894 | 0.104 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 2 ARP | 670 | 74279 | 21 | 0.24 | 97 | 84132 | 813445 | 0.103 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 3 ARP | 593 | 64219 | 19 | 0.26 | 95 | 73197 | 710223 | 0.103 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 4 ARP | 719 | 73106 | 25 | 0.24 | 98 | 84712 | 827120 | 0.102 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 5 ARP | 564 | 49496 | 17 | 0.22 | 63 | 57475 | 565832 | 0.102 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 6 ARP | 712 | 69416 | 23 | 0.23 | 92 | 80183 | 793660 | 0.101 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 7 ARP | 716 | 73449 | 30 | 0.23 | 99 | 86489 | 851718 | 0.102 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 8 ARP | 695 | 65800 | 25 | 0.20 | 84 | 84691 | 818442 | 0.103 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 9 ARP | 658 | 54401 | 19 | 0.20 | 66 | 66451 | 650978 | 0.102 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 10 ARP | 482 | 46185 | 24 | 0.23 | 65 | 58265 | 562684 | 0.104 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 11 ARP | 79 | 5175 | 1 | 0.19 | 7 | 6411 | 63216 | 0.101 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2010 | 12 ARP | 635 | 46988 | 16 | 0.19 | 58 | 58201 | 579944 | 0.100 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 1 ARP | 685 | 60715 | 24 | 0.20 | 75 | 76920 | 735798 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 2 ARP | 412 | 37941 | 23 | 0.20 | 45 | 47706 | 455431 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 3 ARP | 0 | | | | | | | | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 4 ARP | 260 | 20360 | 6 | 0.21 | 27 | 25497 | 238626 | 0.107 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 5 ARP | 445 | 27936 | 22 | 0.23 | 40 | 34850 | 328082 | 0.106 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 6 ARP | 709 | 67371 | 65 | 0.19 | 78 | 84044 | 797957 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 7 ARP | 682 | 63662 | 49 | 0.21 | 75 | 73278 | 699952 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 8 ARP | 715 | 63312 | 35 | 0.21 | 72 | 71198 | 678864 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 9 ARP | 568 | 43737 | 22 | 0.20 | 46 | 50155 | 478210 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 10 ARP | 590 | 45679 | 22 | 0.20 | 48 | 51578 | 491782 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 11 ARP | 650 | 52704 | 23 | 0.19 | 54 | 59156 | 564046 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 3 | 2011 | 12 ARP | 250 | 16643 | 4 | 0.24 | 19 | 18249 | 173998 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 1 ARP | 633 | 147714 | 88 | 0.22 | 160 | 149597 | 1426374 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 2 ARP | 321 | 85569 | 39 | 0.21 | 89 | 87140 | 830860 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 3 ARP | 56 | 0 | 0 | 0.03 | 0 | 400 | 3817 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 4 ARP | 627 | 96658 | 33 | 0.21 | 107 | 102556 | 977833 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 5 ARP | 639 | 72380 | 27 | 0.21 | 84 | 82594 | 787501 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 6 ARP | 572 | 97455 | 46 | 0.21 | 104 | 100665 | 959813 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 7 ARP | 744 | 146529 | 76 | 0.20 | 137 | 150608 | 1436003 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 8 ARP | 733 | 136697 | 51 | 0.19 | 127 | 141694 | 1351015 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 9 ARP | 616 | 110989 | 47 | 0.19 | 107 | 116637 | 1112104 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 10 ARP | 669 | 106081 | 33 | 0.19 | 109 | 116342 | 1109292 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 11 ARP | 647 | 82251 | 42 | 0.21 | 93 | 95108 | 906817 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2010 | 12 ARP | 718 | 103274 | 97 | 0.20 | 115 | 117244 | 1117877 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 1 ARP | 15 | 0 | 0 | 0.06 | 0 | 246 | 2347 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 2 ARP | 620 | 89922 | 55 | 0.22 | 110 | 101878 | 971377 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 3 ARP | 192 | 17585 | 7 | 0.17 | 22 | 20377 | 194295 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 4 ARP | 0 | | | | | | | | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 5 ARP | 556 | 102011 | 44 | 0.18 | 98 | 107913 | 1028925 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 6 ARP | 648 | 130140 | 80 | 0.22 | 142 | 134642 | 1283777 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 7 ARP | 744 | 157867 | 97 | 0.20 | 151 | 162505 | 1549441 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 8 ARP | 686 | 136139 | 90 | 0.21 | 144 | 141577 | 1349895 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 9 ARP | 647 | 137850 | 94 | 0.22 | 147 | 142205 | 1355874 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 10 ARP | 561 | 116332 | 55 | 0.20 | 116 | 117480 | 1120130 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 11 ARP | 666 | 86361 | 28 | 0.21 | 90 | 88739 | 846115 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |
| NV | Reid Gardn | 2324 | 4 | 2011 | 12 ARP | 699 | 103695 | 44 | 0.22 | 121 | 109070 | 1039947 | 0.105 | Coal | | | | | Sodium Bas Low NOx B Baghouse | |

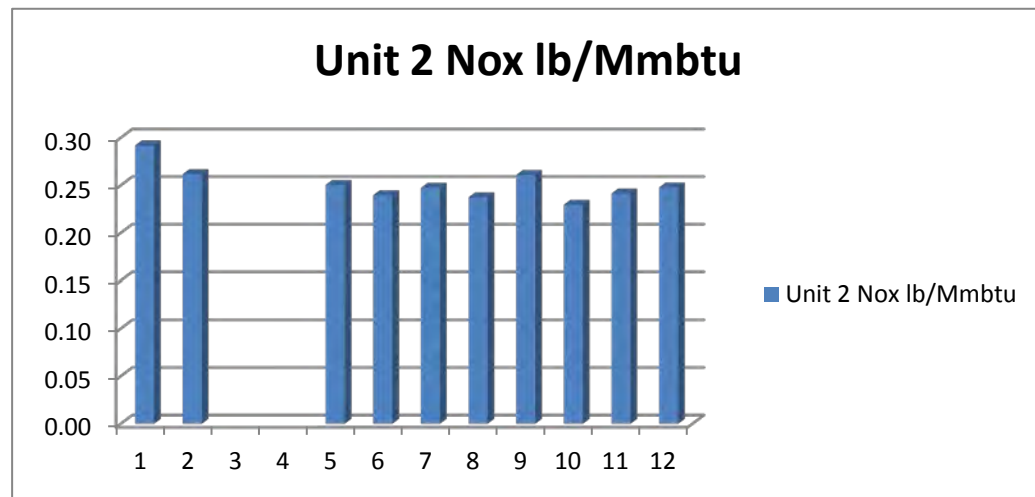
2011 Unit 1 Nox lb/Mmbtu

| | |
|------|-------|
| 0.23 | 0.000 |
| 0.21 | 0.000 |
| 0.24 | 0.000 |
| 0.29 | 0.000 |
| 0.27 | 0.000 |
| 0.26 | 0.000 |
| 0.25 | 0.000 |
| 0.24 | 0.000 |
| 0.23 | 0.000 |
| 0.23 | 0.000 |
| 0.23 | 0.000 |



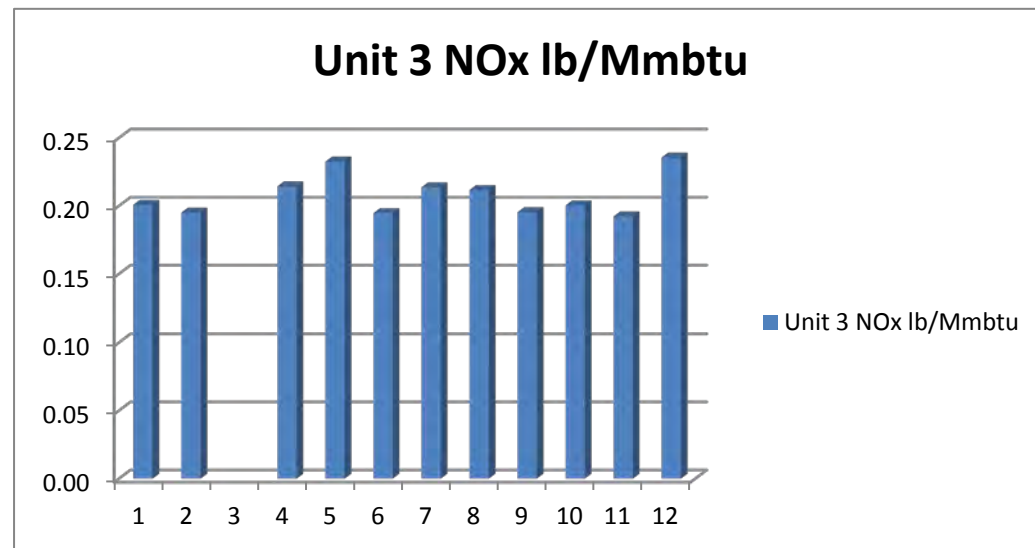
Unit 2 Nox lb/Mmbtu

| |
|------|
| 0.29 |
| 0.26 |
| 0.25 |
| 0.24 |
| 0.25 |
| 0.24 |
| 0.26 |
| 0.23 |
| 0.24 |
| 0.25 |



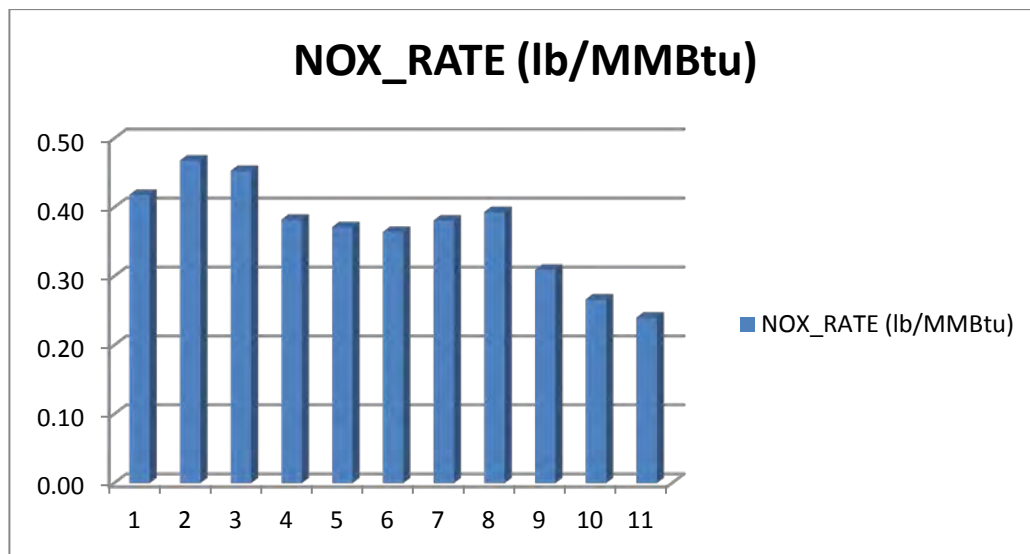
Unit 3 NOx lb/Mmbtu

| |
|------|
| 0.20 |
| 0.20 |
| 0.21 |
| 0.23 |
| 0.19 |
| 0.21 |
| 0.21 |
| 0.20 |
| 0.20 |
| 0.19 |
| 0.24 |



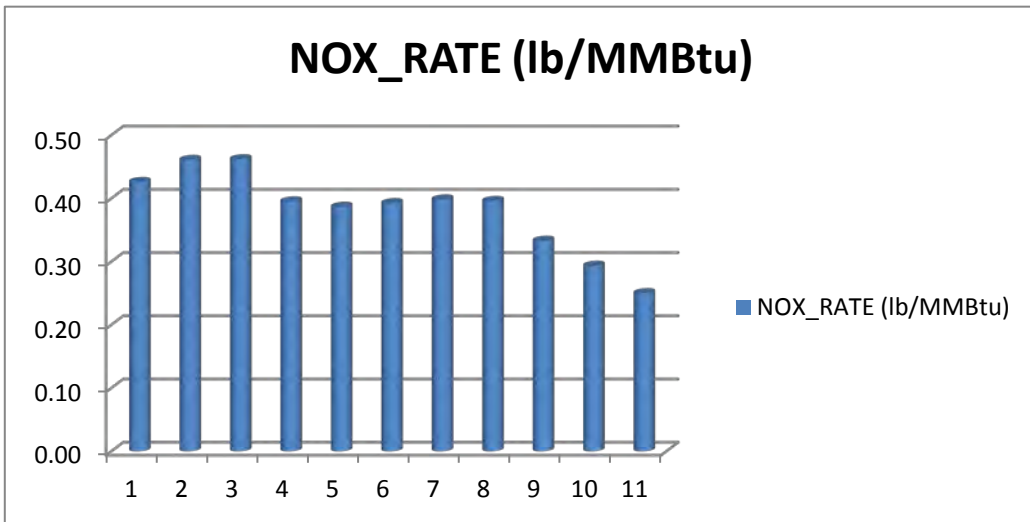
NOX_RATE
(lb/MMBtu) year

| | |
|------|------|
| 0.42 | 2001 |
| 0.47 | 2002 |
| 0.45 | 2003 |
| 0.38 | 2004 |
| 0.37 | 2005 |
| 0.36 | 2006 |
| 0.38 | 2007 |
| 0.39 | 2008 |
| 0.31 | 2009 |
| 0.27 | 2010 |
| 0.24 | 2011 |



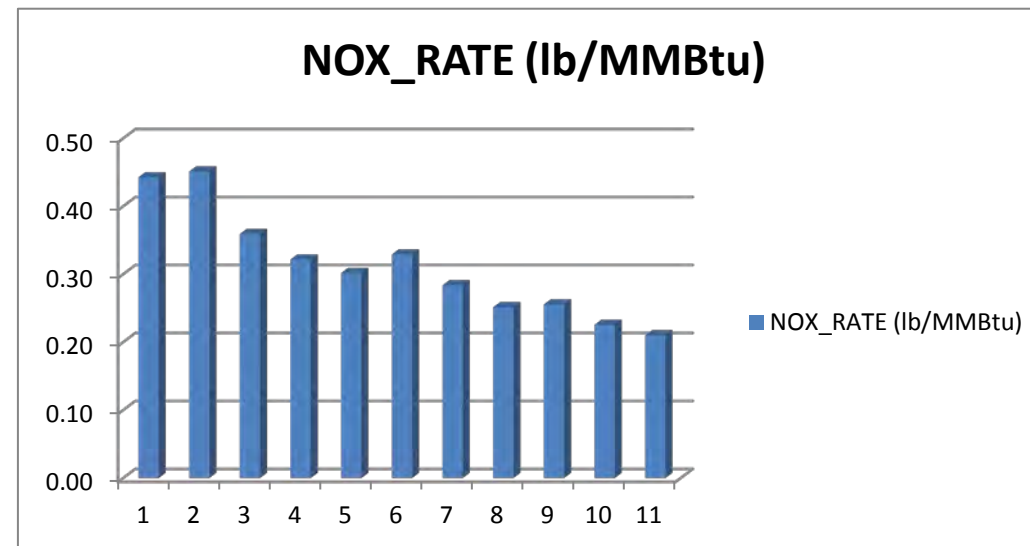
NOX_RATE
(lb/MMBtu)

| | |
|------|------|
| 0.43 | 2001 |
| 0.46 | 2002 |
| 0.46 | 2003 |
| 0.40 | 2004 |
| 0.39 | 2005 |
| 0.39 | 2006 |
| 0.40 | 2007 |
| 0.40 | 2008 |
| 0.33 | 2009 |
| 0.29 | 2010 |
| 0.25 | 2011 |



NOX_RATE
(lb/MMBtu)

| | |
|------|------|
| 0.44 | 2001 |
| 0.45 | 2002 |
| 0.36 | 2003 |
| 0.32 | 2004 |
| 0.30 | 2005 |
| 0.33 | 2006 |
| 0.28 | 2007 |
| 0.25 | 2008 |
| 0.26 | 2009 |
| 0.23 | 2010 |
| 0.21 | 2011 |



Appendix E:

The files and spreadsheets listed below are too voluminous to be included in a hardcopy version, and are available electronically on www.regulations.gov, under Docket ID number EPA-R09-OAR-2011-0130

In addition, the CALPUFF modeling input and output files, including meteorological data, will be made available electronically upon request.

Model File list (mod_files.txt)

Comparison of EPA's RGGGS CALPUFF modeling and variants to WRAP BART modeling results (WRAP_compare_tables.xls)

CALPUFF Model Results (RGGGS_TSD_CALPUFF_tables.xls)

EPA results for 98th percentile delta deciviews, with NOx emissions

Visibility Method 6, annual avg. background

Visibility Method 6, best 20% background

Visibility Method 8, annual avg. background

Visibility Method 8, best 20% background

EPA results for 98th percentile delta deciviews, with individual years

Visibility Method 6, annual avg. background

Visibility Method 6, best 20% background

Visibility Method 8, annual avg. background

Visibility Method 8, best 20% background

EPA results for Number of days over 0.5 and 1.0 deciviews

Visibility Method 6, annual avg. background

Visibility Method 6, best 20% background

Visibility Method 8, annual avg. background

Visibility Method 8, best 20% background

Modeling results from CH2MHill for Nevada Energy

RGGGS control scenario names in Nevada Energy in BART analysis

Unit 1 Reid Gardner G.S. Visibility Impacts as Modeled by CH2MHill in 2008

Unit 2 Reid Gardner G.S. Visibility Impacts as Modeled by CH2MHill in 2008

Unit 3 Reid Gardner G.S. Visibility Impacts as Modeled by CH2MHill in 2008