



State of Utah

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Department of
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DIVISION OF AIR QUALITY
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DAQ-066-08

MEMORANDUM

TO: Air Quality Board

THROUGH: Cheryl Heying, Executive Secretary

FROM: Colleen Delaney, Environmental Scientist

DATE: September 3, 2008

SUBJECT: FINAL ADOPTION: State Implementation Plan, Section XX. Regional Haze; Amend R307-110-28. Regional Haze.

On June 4, 2008, the Air Quality Board proposed for comment amendments to R307-110-28, Regional Haze, and State Implementation Plan (SIP), Section XX, Regional Haze. The Regional Haze SIP was adopted in 2003, and these amendments were required to address changes to the federal regional haze rule that were published in 2006. The changes occurred primarily in the stationary source provisions of the plan. The sulfur dioxide milestones were updated to use more recent inventory data and to address EPA's revised best available retrofit technology (BART) guidelines; however the overall approach has not changed from the 2003 SIP. The provisions in the 2003 SIP that address clean air corridors, mobile sources, fire, and pollution prevention were not changed.

A public hearing was held on July 17, 2008; several attended but none made comments. A summary of the comments received during the public comment period, July 1-31, 2008, are attached along with DAQ's responses.

Utah's Regional Haze SIP has been in place for nearly five years and has been very effective. Emissions of sulfur dioxide and nitrogen oxides have decreased dramatically since 1991 when the Grand Canyon Visibility Transport Commission was established, and will continue to decrease through 2018.

Staff Recommendation: Staff recommends that R307-110-28, and Utah State Implementation Plan Section XX. Regional Haze be adopted with the amendments displayed in the attachment

Comment 1: (Kathy Van Dame, Wasatch Clean Air Coalition)

SIP XX.E.3.a(1)(a)(i) & (ii) apparently refer to R307-250-4 (1) (a) & (b). In XX the different types of sources are named ‘Category 1’ & ‘Category 2’. In R307-250-4, there is no such simple descriptor. In XX, Category 2 sources are described as “WEB sources that commenced operation on January 1, 2008 or a later date” while in R307-250-4 (1) (b) they are described as “A new source that begins operation after the program trigger date.” If in fact, the two descriptions refer to each other, they should be harmonized. In any case the reference within XX.E.3.a (1) (a) to R307-250 should be to a specific part of R307-250.

Response: The two descriptions referred to in the comment are not intended to mean the same thing and do not need to be harmonized. The applicability language in the rule identifies the sources that are subject to the trading program. Applicability is determined based on actual emissions for existing sources and Potential to Emit (PTE) for new sources. The language in the state implementation plan (SIP) further divides the sources that are subject to the program into Category 1 and Category 2 sources. Category 1 sources will receive their floor allocation from either the utility or non-utility pool of allowances. These sources will also be eligible for a reducible allocation. Category 2 sources will receive their floor allowances from the new source set-aside, and will not be eligible for a reducible allocation. The reference within SIP Section XX.E.3.a(1)(a) has been changed as recommended to refer to R307-250-2 where the term “WEB source” is defined.

Comment 2: (Kathy Van Dame, Wasatch Clean Air Coalition)

In SIP XX.E.3.a(1)(c)(i) “early reduction credit,” XX E.3. “early reduction allocation,” and the title of R307-250-7(5) “Early Reduction Bonus Allocation,” these terms apparently all refer to the same item, if so, they should be harmonized. In the case of multiple, interlocking documents, lack of uniformity of terms contributes to misunderstandings & disputes.

Response: The SIP and rule text have been modified as recommended to use a consistent terminology “early reduction bonus allocation.”

Comment 3: (EPA Region 8)

There are a number of places where the Utah SIP differs from the 4/23/08 Model SIP/TIP on WRAP’s website. For example, Table 8 has different milestone values for the years 2003-2009, Table 10 has different numbers for the 2018 non-utility portion, and Section E.3(a)(2)(g)(ii) has 2000-2006 as the baseline period while the Model SIP/TIP has 2006 as the baseline. We recommend that Utah modify the 2008 SIP to match the 4/23/08 Model SIP/TIP on WRAP’s website.

Response: In earlier versions of the model SIP that was developed by the four participating states the tribal set-aside was inadvertently left out of the milestone calculation. When this error was discovered, it was corrected in the model SIP but not in Utah’s draft SIP. The milestone numbers in Table 8 have been corrected to match the milestones that were developed through the regional process and are included in the model SIP.

Comment 4: (EPA Region 8)

In the flow control example in provision E.(3)(h)(2) on page 60 of the 2008 SIP, the 2008 SIP refers to the 2010 milestone as “(5-state, no smelter)” which is not correct. We recommend that the parenthetical phrase be deleted. The corresponding reference in the Model SIP is provision C4.2(b)(3).

Response: The example has been changed as recommended.

Comment 5: (EPA Region 8)

Utah's RH SIP does not adequately address Utah's impacts from NO_x and PM on Class I areas, both in and out of state. 40 CFR Section 51.309(d)(4)(vii) requires that SIPs contain necessary long term strategies and best available retrofit technology (BART) requirements for stationary source emissions of NO_x and PM. Utah's NO_x emissions have a significant impact on several in-State and out-of-State Class I areas. Specific examples include Capital Reef National Park in Utah and Craters of the Moon National Monument and Preserve in Idaho.

In order to address impacts from NO_x and PM, 40 CFR Section 51.309(a) requires that each 309 State follow 51.308 requirements, both for BART and reasonable progress, in evaluating Class I areas outside of the Colorado Plateau affected by the State. 40 CFR Section 51.308(d)(3) requires that States must submit a long term strategy that addresses regional haze visibility impairment for each Class I area located outside the State which may be affected by emissions from the State. 40 CFR Section 51.308(d)(3) also requires that long-term strategies include enforceable emission limitations (see comments in 2. above), compliance schedules, and other measures necessary to achieve reasonable progress goals.

Response: Utah's SIP contains the "necessary long-term strategies and BART requirements for stationary source PM and NO_x emissions" as required by §309(d)(4)(vii) in several parts of the SIP. Section XX.D.6 includes a BART assessment for NO_x and PM, and Table 6 shows the emission reductions that will be achieved by the retrofitted units that are subject to BART: NO_x emissions are reduced by 6,206 tons/yr and PM₁₀ emissions are reduced by 926 tons/yr. Section XX.D.5 contains an assessment of NO_x and PM strategies that was prepared for the 2003 SIP. This analysis concluded that for the vast majority of Class I areas throughout the WRAP region NO_x and PM emissions are not a major contributor to visibility impairment on the average 20% best and 20% worst days. However, on some of the worst days nitrates and PM are the main components of visibility impairment. This assessment was consistent with the conclusions of the GCVTC that recommended focusing efforts on stationary source SO₂ emissions because of the widespread impact on visibility impairment. Finally, Section XX.K.1 of the SIP outlines the significant overall emission reductions in NO_x and PM in Utah and the region. NO_x emissions decline 36% between 1996 and 2018 and PM_{2.5} emissions decline 38% and SO₂ emissions decline 33% during this same time period. Coarse matter emissions are projected to increase, although there is much greater uncertainty in the emission inventories for windblown dust. Taken as a whole Utah's SIP shows the necessary long-term strategies for PM and NO_x emissions. Class I areas on the Colorado Plateau (including Capital Reef National Park), as well as all other Class I areas that are affected by emissions from Utah will benefit from these significant emissions reductions.

Utah has participated in the technical and policy forums of the Western Regional Air Partnership (WRAP) as described in Section XX.M of the plan, and further detailed in Appendix D of the plan. Through that process Utah has shared emissions data and other technical information with other states that have Class I areas that might be impacted by emissions from Utah. As described above, Section XX.K.1 of the SIP outlines the overall significant emission reductions in Utah, and these reductions will benefit all Class I areas that might be impacted by emissions from Utah. Utah's emissions reductions are included in the overall WRAP modeling analysis and will therefore be reflected in the reasonable progress demonstrations that are prepared by neighboring states. The following paragraph has been added to the end of Section XX.K.1 to clarify that the emission reductions are occurring throughout the state and will benefit all Class I areas that are impacted by emissions from Utah.

The emission reductions in Utah occur throughout the state and will therefore benefit all Class I areas outside of Utah that might be impacted by emissions from Utah.

Northern Utah. The urban area in northern Utah that may impact Class I areas in Idaho, Nevada and Wyoming will have a significant reduction in NO_x emissions from mobile

sources as described in Section XX.F of this plan. Mobile (on-road and non-road) NO_x emissions in the four main urban counties (Weber, Davis, Salt Lake, and Utah) are projected to decrease by 42,000 tons/yr or 61% between 2002 and 2018. Mobile sources dominate the NO_x emission inventory in Utah's urban area. Class I areas that have some days when nitrates are a significant contributor to visibility impairment, such as Craters of the Moon National Park, will benefit from the NO_x emission reductions during those episodes.

Central and Southern Utah. As described in Section XX.D.6 of this plan, two BART-eligible plants in central Utah are projected to decrease SO₂ emissions by 13,200 tons and NO_x emissions by 6,200 tons between 2002 and 2018. Central and Southern Utah are sparsely populated and the inventory is dominated by point sources. The exception is Washington County that is becoming more urban due to the growth of St. George and the inventory is therefore dominated by mobile source emissions. In Washington County, NO_x emissions from mobile sources (on-road and non-road) are projected to decrease by 2,300 tons or 57% between 2002 and 2018. These emission reductions will benefit Class I areas in southern Colorado, New Mexico and Arizona that may be affected by emissions from Utah.

Eastern Utah. Oil and Gas emissions dominate the inventory in eastern Utah and are increasing between 2002 and 2018. Approximately 90% of current emissions from oil and gas occur on land that is under the jurisdiction of the Ute Indian Tribe of the Uintah Ouray Reservation and is therefore not covered by Utah's SIP. The inventory compiled by the WRAP does not currently separate out these emissions that are not under Utah's jurisdiction. These emissions may affect Class I areas in Northeastern Colorado and the State of Utah expects that this impact will be addressed in the TIP or FIP that is developed for the Ute Tribe.

Comment 6: (National Parks Service)

Section 51.309(d)(4)(vii) required that the SIP contain provisions for a long term strategy for stationary source emissions of NO_x and PM. The Utah SIP provides some assessment of BART for NO_x and PM but does not address whether additional emissions controls, beyond those considered for BART, are appropriate to provide for reasonable progress. Given the importance of nitrate at a substantial number of worst days at Utah's Class I areas, we believe that an examination of stationary source controls for nitrogen oxides is required in a regional haze SIP.

Response: See response to Comment 5.

Comment 7: (National Parks Service)

According to WRAP's Technical Support System (TSS), the 20% worst days at Capitol Reef National Park are calculated based on 106 monitored days between 2000 and 2004. Of those, 23 days are dominated by nitrate and an additional 4 days have nitrate doing a close second to sulfate as the key pollutant contributing to haze. The TSS includes modeling for 2002, when 44 of the worse days are dominated by nitrate. That year Utah's sources are the major contributor on one day. While the SIP does not need to establish reasonable progress goals for Capitol Reef or the other Utah Class I Parks at this time, some decision and supporting assessments on additional NO_x controls must be included in this SIP.

Response: See response to Comment 5.

Comment 8: (National Parks Service)

One critical omission from the SIP is a discussion of how the programs contained in the SIP meet Utah's obligation to address the effects of its emissions on visibility in Class I areas out side of Utah.

Response: See response to Comment 5.

Comment 9: (National Parks Service)

The regional haze rule requires the SIP to examine how Utah's SIP addresses the State's contribution to reasonable progress at Craters of the Moon National Monument (CRMO). Utah could examine how emissions changes expected from implementation of its SIP would reduce Utah's impact on CRMO between the baseline period and 2018. If Utah reduces its contribution by the same or greater percent required to meet the uniform rate of progress target established by EPA, then the State would be clearly demonstrating that it is doing its fair share toward reasonable progress at CRMO. Otherwise, if the reduction is significantly less than the percent needed to achieve the uniform rate of progress, Utah should establish a list of stationary sources and a geographical area for mobile sources that are most influencing CRMO. The State should also assess, using the four reasonable progress factors, what an appropriate long term strategy should be.

Response: See response to Comment 5.

Comment 10: (National Parks Service)

Utah has provided specifics on the components listed in 40 CFR 50.309 for Class I areas on the Colorado Plateau. The specifics on programs related to sulfur dioxide backstop trading program, mobile sources, fire programs, road dust, and renewable energy highlight Utah's commitment to assuring reasonable progress. The SIP language is exemplary in the way it balances fire program permitting with appropriate assessment of air quality concerns.

Response: Thank you.

Comment 11: (EPA Region 8)

Utah's RH SIP does not contain a five factor BART analysis for NO_x and PM, as required by 40 CFR §51.309(d)(4)(vii). States doing a 309 RH SIP must still do a BART analyses according to 40 CFR §51.308(e). Under 40 CFR §51.308(e)(1)(ii)(A), states "must take into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, and the remaining useful life of the source." The CAA also requires States to consider the five factors in making their BART determinations (see Clean Air Act §169A(g)(2)).

Response: The latest revision of Section 51.309 Regional Haze "Requirements related to the Grand Canyon Visibility Transport Commission" has new provisions for stationary source emissions of NO_x and PM. (71 Federal Register 60632, October 13, 2006). The rule requires Regional Haze SIPs to contain any necessary long term strategies and BART requirements for stationary source PM and NO_x emissions (40 CFR §51.309(d)(4)(vii). BART provisions may be submitted pursuant to either 51.308(e)(1) or 51.308(e)(2).

308(e)(1) requires a source by source five factor determination of BART for sources subject to BART in the State. 308 (e) (2) allows a State to participate in an emissions trading program or other alternative measure instead of a source by source BART analysis. Utah, for NO_x and PM emissions, has opted to use the 308(e)(1) source by source BART approach and an alternative backstop trading program for SO₂ emissions.

308(e)(1)(ii)(A) requires a five factor analysis to determine the best system of continuous emission control technology available and associated emission reductions achievable for each subject to BART source.

However, 308(e)(1)(ii)(B) requires that EGU's, with generating capacity greater than 750 MW, to make BART determinations pursuant to guidelines in Appendix Y to Part 51.

In 40 CFR Part 51 "Regional Haze Regulations and Guidelines for BART Determinations; Final Rule" (July, 6 2005) and in Appendix Y Part 51, EPA requires that coal-fired EGU's meet presumptive limits for NO_x and SO₂. EPA gives the option to States to challenge presumptive limits based on consideration of the five statutory factors. In effect EPA has determined that presumptive limits for NO_x and SO₂, are equivalent to a five factor BART analysis.

"States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits... a State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors." (40 CFR Part 51 Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39135)).

"For Coal-fired EGU's greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls (i.e. SCR or SNCR), we have provided presumptive NO_x limits, differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on careful consideration of the statutory factors." (Appendix Y Part 51 – IV (E)(5) FR July 6, 2005 39171).

EPA determined presumptive limits for SO₂ and NO_x, for EGU sources greater than 750 MW, based on a five factor methodology as required in 50 CFR 51 Appendix Y of the BART Rule. The EPA determination of presumptive limits included:

1. Identification of all potential BART-eligible EGUs.
2. Presumption that BART eligible units were also Subject to BART.
3. Technical analyses and industry research to determine applicable and appropriate SO₂ and NO_x control options.
4. Economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and evaluation of historical emissions and forecast emission reductions for each BART-eligible EGU.
5. NO_x and SO₂ CALPUFF modeling of emission impacts at model Class I areas.

The analysis included 419 potential BART EGUs including the Hunter units 1 and 2 and Huntington units 1 and 2. The technical analysis conducted by EPA to determine presumptive BART limits for SO₂ and NO_x is equivalent to five factors BART determination of the 419 EGUs reviewed including the Hunter and Huntington Units.

Under Appendix Y States are given the discretion to challenge presumptive limits through a five factor analysis but presumptive limits were developed by EPA as a reasonable, equivalent and mandatory substitution for a five factor analysis.

Comment 12: (EPA Region 8)

The CAA also requires States to consider the five factors in making their BART determinations (see Clean Air Act §169A(g)(2)).

Response: EPA codified the CAA requirements under 169 A (g) (2) in 40 CFR 51.308 (e) (1) (ii) in the July 6, 2005 Final Rule “Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations: Final Rule”.

“Section 169 (g) (2) of the CAA requires that States must consider the following factors in making BART determinations: (1) cost of compliance (2) the energy and non-air quality environmental impacts of compliance (3) Any existing pollution control technology in use at the source (4) The remaining life of the source and (5) the degree of improvement in visibility which may reasonable be anticipated to result from the use of such technology. These statutory factors for BART were codified at 40 CFR 51.308 (e) (1) (ii)”. (Federal Register 70 39105)

As outlined above (question #11) CFR 51.308 (e) (1) (ii) (B) requires determination of BART for coal-fired EGU’s with generating capacity above 750 MW, to be made pursuant to Appendix Y Part 51. Section IV (E) (5) of Appendix Y Part 51 clearly requires the implementation of presumptive NOx limits for coal-fired EGU’s greater than 200 MW located at greater than 750 MW power plants. Under Appendix Y States are given the discretion to challenge presumptive limits through a five factor analysis but presumptive limits were developed by EPA as a reasonable, equivalent and mandatory substitution for a five factor analysis.

It is UDAQ’s position that EPA has codified BART requirements under CAA §169 A (g) (2) in the July 6, 2005 Final BART Rule and it is not within the purview of UDAQ, or Region 8, to re-codify CAA statutes.

Comment 13: (EPA Region 8)

The State’s RH SIP does not contain the elements necessary to make BART limits practically enforceable. Utah’s SIP contains controls, emission limits and general schedules but does not include permit conditions specifying averaging times, record-keeping, monitoring, and specific schedules for compliance. The CAA requires that SIPs, including the RH SIP, contain elements sufficient to ensure emission limits are practically enforceable. It is not sufficient to include these elements in a separate permit or agreement that is not made part of the SIP. EPA does not consider permit conditions adequate to meet this enforceability requirement, as permit conditions may be modified. We also note that the BART guidelines require a 30-day averaging period for BART limits (see 70 FR 39172, col. 3, July 6, 2005). We view a 30-day or shorter averaging period as being necessary to protect visibility in the nearby Class I areas, since visibility is sensitive to short term spikes in pollutants which contribute to visibility impairment.

Response: The Utah Regional Haze SIP includes all elements required under CAA §110 and specifically §110 (a) (2) including:

1. Emission reduction control technology
2. Emission Limits
3. Construction schedules
4. Record-keeping requirements
5. Monitoring and compliance requirements

The first three conditions are specified explicitly in the DAQ’s Regional Haze SIP submittal (SIP XX §D). The other above conditions are contained in three DAQ Approval Orders (AO) for the Huntington

and Hunter units 1 and 2. The DAQ Regional Haze SIP specifically requires the implementation of the requirements of the Hunter and Huntington Approval Orders.

Both the Regional Haze SIP and the DAQ Approval Orders are federally enforceable and enforceable as a practical matter as defined in the New Source Review Manual (October 1990):

“Federally-enforceable refers to all limitations and conditions which are enforceable by the Administrator, including:

- a. Requirements developed pursuant to any new source performance standards (NSPS) or national emission standards for hazardous air pollutants (NESHAP)
- b. Requirements within any applicable federally-approved State Implementation Plan
- c. Requirements contained in a permit issued pursuant to federal PSD regulations, or pursuant to PSD or operating permit provisions in a SIP which has been federally approved in accordance with 40 CFR 51 Subpart I.” (Review of New Sources and Modifications) (New Source Review Manual (October 1990) p.A.5-6)

“Practical enforceability means the source and/or enforcement authority must be able to show continual compliance (or non-compliance) with each limitation or requirement. In other words, adequate testing, monitoring, and record-keeping procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or permit issued under the same.” (New Source review Manual p. A.5-6).

The Utah Regional Haze SIP will be federally enforceable when approved by EPA and the NSR AO will be federally enforceable both as a component of the RH SIP and as NSR permits. Both the RH SIP and the NSR permits will be enforceable as a practical matter given that DAQ can show continual compliance either through the SIP conditions or the SIP required conditions in the NSR permits.

The EPA comment above seems to indicate that if NSR permits can be modified then they are not enforceable. (“EPA does not consider permit conditions adequate to meet this enforceability requirement, as permit conditions may be modified”.) The “practical enforceability” requirement is not dependent on the possibility of a permit modification but rather on the ability of the regulating agency to show continual compliance with permits requirements during the effective life of the SIP or permit. If “enforceability as a practical matter” was dependent on the immutability of SIPs and NSR permits than there would not be an enforceable permit anywhere in the country.

EPA and UDAQ worked in conjunction on the most recent Utah PM10 SIP (submitted September 2005) to develop an “enforceable framework” for the relationship between SIPs and the NSR permit conditions referenced in a SIP. The Regional Haze SIP was developed around the PM10 collaboration and DAQ is uncertain why Region 8 has chosen to unilaterally ignore the progress made on this issue during the development of the PM10 SIP.

Comment 14: (National Parks Service)

In Section D.1 on page 20-24 of the Draft, Utah addresses BART requirements for NO_x and direct PM emissions. We agree with Utah’s determination of sources subject to BART, since it is based on procedures developed by the WRAP. Table 4 indicates that many Class I areas are affected by emissions from Hunter Units 1&2 and Huntington Units 1&2 as levels above 0.5 deciviews for the 98th %. Except for Huntington Unit 2, the State has or is permitting the remaining three units (all owned by PacifiCorp) with specific control technologies listed on page 24, and compares those technologies with Presumptive BART limits developed by EPA in 40 CFR 52 Appendix Y. These permitted and proposed emissions limits do not appear to be developed by examining the five BART factors for an appropriate array of alternative control options. A showing that permitted or proposed emission rates are slightly below the

presumptive rates established by the EPA in its rulemaking is not sufficient since EPA's costs, a primary factor, were based on industry averages. In addition, there are multiple Class I areas (all those listed in Table 4) likely to see substantial improvements on worst days by control cost higher than the average from these units. Improvement at many Class I areas could warrant control cost higher than average by EPA in establishing the presumptive levels. Fish and Wildlife and Parks: We request Utah to examine a full array of control technologies, the associated costs of these different levels of technology, as well as anticipated improvements in the visibility impacts for the Class I areas listed in Table 4 to fulfill the requirement of a BART determination. We recognize Table 7 (on page 26) presents a "post control" assessment of visibility change based on the emission rates permitted or proposed and that there is little change in the modeled impact. This type of information provided for an array of technologies and their associated costs would address the major regulatory and statutory factors regarding degree of visibility improvement to be expected and cost of controls.

Response: see Question 11 and 12 above and Question 15 below.

Comment 15: (National Parks Service)

In addition, Utah should elaborate on the reasons why the sources have such a large impact on the 98th% when assessing whether the source is subject to BART (Table 4), yet controlling emissions to approximately presumptive BART limits show such a small amount of improvement. For example, does Table 7 only represent improvements from changes in NO_x and PM? Are the modeling systems used in Table 4 and Table 7 identical?

Response: Pursuant to 40 CFR 51.308(e)(1)(ii) the State is required to determine which BART-eligible sources are also "subject to BART." BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area.

Both Rocky Mountain Power plants Hunter and Huntington were determined by the State to be subject to BART. The State utilized the technical modeling services of the WRAP Regional Modeling Center (RMC). Modeling was performed according to the RMC modeling protocols¹. For the WRAP BART exemption screening modeling, the RMC followed the EPA BART Guidelines in 40 CFR 51, Appendix Y and the applicable CALMET/CALPUFF modeling guidance (e.g., IWAQM, 1998; FLAG, 2000; EPA, 2003c) including EPA's March 16, 2006 memorandum: "Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF"².

The basic assumptions of the WRAP BART CALMET/CALPUFF modeling protocols are as follows:

1. Three years of modeling (2001, 2002 and 2003) were used.
2. Visibility impacts due to emissions of SO₂, NO_x and primary PM emissions were calculated
3. Visibility was calculated using the Original IMPROVE equation and Annual Average Natural Conditions.
4. The effective range of CALPUFF modeling was set at 300km from the sources
5. For pre-control modeling maximum 24-hour average actual emissions from the Acid Rain database were used in CALPUFF model.
6. For post-control modeling expected New Source Review (NSR) permitted limits were used in the CALPUFF model.

¹ CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States

² Atkinson and Fox, 2006

As outlined in Question 11 and 12 above Appendix Y Part 51 requires coal-fired power plants greater than 750 MW to meet presumptive NO_x limits in place of a five factor analysis. DAQ is not required to undertake an extensive series of modeling runs for each feasible BART control option an analysis already completed by EPA as a part of the determination of presumptive limits. BART CALPUFF modeling for the subject to BART determination utilized maximum 24 hour average actual emissions from EPA's Acid Rain (Clean Air Markets) database. Post-control modeling was based on emissions calculated on expected NSR permit limits (Section XX D (6) Table 5).

Comments on Technical Support Documents

The following comments were received on the Greater Reasonable Progress than BART Demonstration that was prepared by the WRAP and is referenced on page 19 of the SIP. This document is included in the Board packet to help the reader understand the comments and UDAQ's response.

Comment 1: (EPA Region 8)

WRAP needs to justify using 0.5 deciviews as a threshold for determining whether sources are subject to BART.

Response: EPA's BART guidelines state that "As a general matter, any threshold that you use for determining whether a source 'contributes' to visibility impairment should not be higher than 0.5 deciviews." The guidelines give states the discretion to establish a lower threshold "if they conclude that the location of a large number of BART-eligible sources within the State and in proximity to a Class I area justify this approach. When developing the modeling protocols for the visibility analysis, the four participating states established the threshold at 0.5 deciviews because it is consistent with EPA guidelines, and is consistent with long-standing visibility modeling practices. Significant BART-eligible sources that are in proximity to Class I areas in the west have been addressed through the reasonably attributable visibility impairment process, and there is not a large concentration of BART eligible sources that is in proximity to a Class I area. In addition, the backstop trading program will include all sources with emissions over 100 tons/year and will therefore still include sources that may not be subject to BART. The guidelines do not require states to establish a lower threshold, and the four participating states do not believe that a lower threshold is needed or justified.

Language has been added to the Better than BART demonstration to explain that the 0.5 deciview threshold is consistent with EPA's BART guidelines.

Comment 2: (EPA Region 8)

When estimating BART, emission reductions the WRAP excluded some non-utility sources that it characterizes as potentially subject to BART. This is not consistent with regulatory requirements.

Response: The analysis excluded a small number of non-utility sources that in aggregate represent 1% of the regional milestone. EPA has not established a presumptive control level for these sources and there is little benefit to doing a case-by-case analysis because the results would have a negligible impact on the regional milestone. These sources will still be included in the backstop trading program.

Comment 3: (EPA Region 8)

When establishing milestones, WRAP used presumptive levels in some cases and source specific information in others. A consistent approach is needed.

Response: The WRAP addressed this issue in the Better than BART demonstration in response to earlier comments from EPA (see the end of section D, page 7). An alternate analysis was conducted that assumed that all EGUs that were subject to BART (including units that are smaller than 750 MWs or are

already operating at greater than 50% control) would be operating at the presumptive SO₂ emission rate of 0.15 lb/MMBtu. The estimated SO₂ emission reductions using this simpler approach were 91,872 tons. This is comparable to the estimated reduction of 91,760 that was calculated using the more detailed method. The participating states chose to use the more detailed method because it was based on the best information that was available rather than relying on the presumptive level for all sources. However, the alternate analysis is useful to show that a simpler consistent approach achieves the same result.

Comment 4: (EPA Region 8)

The alternative program must include all BART-eligible sources not just sources that are subject to BART.

Response: As recognized in EPA's comments, the alternative program applies to all sources with actual emissions greater than 100 tons/year SO₂ and is likely to include all BART-eligible sources. However, to address the possibility that there may be an unusual source that would not be included based on actual emissions, each of the participating states will either include language in their backstop trading rule to ensure that all BART-eligible sources that are BART-eligible due to SO₂ emissions are subject to the backstop trading program, or will include an analysis in their SIP that demonstrates that all BART-eligible sources meet the 100 ton SO₂ threshold.

Comment 5: (EPA Region 8)

The alternative program does not directly address the distribution of emissions. At a minimum the SIP should include a determination, supported by a clear weight of evidence that Section 309 achieves greater reasonable progress than would be achieved through the installation and operation of BART.

Response: The WRAP conducted modeling that compared command and control BART to a trading program during the development of the Annex. A new section H has been added to the end of the Better than BART demonstration to reference the results of that analysis that was submitted to EPA in 2000.

1 **R307. Environmental Quality, Air Quality.**

2 **R307-110. General Requirements: State Implementation Plan.**

3 **R307-110-28. Regional Haze.**

4 The Utah State Implementation Plan, Section XX, Regional
5 Haze, as most recently amended by the Utah Air Quality Board on
6 September 3, 2008, pursuant to Section 19-2-104, is hereby
7 incorporated by reference and made a part of these rules.

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11 **KEY: air pollution, PM10, PM2.5, ozone**

12 **Date of Enactment or Last Substantive Amendment: 2008**

13 **Notice of Continuation: March 15, 2007**

14 **Authorizing, and Implemented or Interpreted Law: 19-2-104(3)(e)**

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Utah State Implementation Plan

Section XX

Regional Haze

Addressing Regional Haze Visibility Protection for the Mandatory Federal Class I Areas Required Under 40 CFR 51.309

Adopted by the Air Quality Board
2008

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APPENDICES TO THE SIP

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Appendix C	Projection of Visibility Improvement
Appendix D	WRAP Interstate and Regional Planning Activities

1 **A. EXECUTIVE SUMMARY**

2
 3 This document comprises the State of Utah's State Implementation Plan (SIP) submittal
 4 to the U.S. Environmental Protection Agency (EPA) under the Regional Haze Rule in
 5 Section 309 of Title 40 of the Code of Federal Regulations, Part 51 (40 CFR 51.309).
 6 Part B includes introductory and background information. The remaining parts identify
 7 the SIP requirements under Section 309 and detail how Utah is addressing those
 8 requirements, and appendices include more detail about certain parts. Table 1 is a brief
 9 summary of each of the 309 SIP requirements along with Utah's approach in addressing
 10 those requirements.

11 **Table 1. Executive Summary of Long-Term Strategies**

12

Clean Air Corridors <i>309(d)(3)</i>	Part C documents that emission growth inside and outside of the Clean Air Corridor is not shown to be contributing currently to impairment within the Clean Air Corridor.
Stationary Sources <i>309(d)(4)</i>	Part D includes proof of a 13% reduction in sulfur dioxide emissions between 1990 and 2000, Best Available Retrofit Technology (BART) for NO _x and PM , geographic enhancement provisions, and other stationary source materials.
Sulfur Dioxide Milestones and Backstop Trading Program <i>309(d)(4)</i>	Part E includes milestones for sulfur dioxide emissions along with a backstop market cap and trade program for sulfur dioxide emissions from specific sources.
Mobile Sources <i>309(d)(5)</i>	Part F demonstrates that federal programs (such as low sulfur diesel, vehicle emission standards, etc.) lead to decreasing mobile source emissions throughout the planning period.
Programs Related to Fire <i>309(d)(6)</i>	Part G demonstrates that Utah has developed a smoke management regulation (R307-204) that implements the Western Regional Air Partnership (WRAP) <i>Enhanced Smoke Management Programs for Visibility Policy</i> .
Paved and Unpaved Road Dust <i>309(d)(7)</i>	Part H discusses the WRAP finding that dust emissions are not now a significant regional contributor to visibility impairment within the Colorado Plateau 16 Class I areas.
Pollution Prevention <i>309(d)(8)</i>	Part I describes programs and policies within Utah related to renewable energy and energy efficiency. Utah's anticipated contribution to the pollution prevention goals is outlined.
Additional Recommendations <i>309(d)(9)</i>	Part J summarizes that Utah has not identified any other recommendations in the Grand Canyon Visibility Transport Commission Report to implement in Utah at this time. A report on each recommendation is included in the Utah Technical Support Document Supplement.

1

Projection of Visibility Improvement <i>309(d)(2)</i>	Part K projects visibility improvement for the 20% best and worst days for each of the Class I areas on the Colorado Plateau (Arches, Bryce, Canyonlands, Capitol Reef, and Zion National Parks in Utah and the other 11 Class I areas in adjacent states that were addressed by the Grand Canyon Visibility Transport Commission)
Periodic Revisions <i>309(d)(10)</i>	Part L commits the State of Utah to submit periodic revisions to this SIP every five years.
State Planning and Interstate Coordination <i>309(d)(11)</i>	Part M describes Utah's participation in the Western Regional Air Partnership.
Reasonable Progress for Additional Class I Areas <i>309(g)</i>	Utah has no additional Class I areas.

2

3

Technical Support Documents

4

5 Accompanying this implementation plan and associated appendices are two other
6 documents. The first is a Technical Support Document (TSD) developed by the Western
7 Regional Air Partnership (WRAP) that contains the results of numerous collaborative
8 studies by the WRAP members on which the State of Utah relied in the development of
9 the 2003 SIP. In the implementation plan, this is referred to as the “WRAP TSD.” The
10 WRAP TSD also includes appendices. In addition, there are other supplemental
11 materials that are state-specific technical support information. In the implementation
12 plan, these are referred to as the “Utah TSD Supplement.”

13

14

15 In 2008, the Regional Haze SIP was updated to address changes in the regional haze rule
16 and EPA’s BART Guidelines. The WRAP developed a new TSD, a Technical Support
17 System (TSS) that contains the results of updated modeling, and an Emission Data
18 Management System (EDMS). In the implementation plan these combined materials are
19 referred to as the 2008 WRAP TSD and updated state-specific materials are referred to as
20 the 2008 Utah TSD supplement.

1 **B. BACKGROUND ON THE REGIONAL HAZE RULE**

2 **1. Introduction**

3 Good visibility is important to fully enjoy the experience of visiting our national parks
4 and wilderness areas. Visibility is impaired by light scattering and absorption caused by
5 particulate matter and gases in the atmosphere that occur from both natural and human-
6 caused activities. Visibility can be impaired by natural sources such as rain, wildland
7 fires, volcanic activity, sea mists, and wind blown dust from undisturbed desert areas.
8 Visibility also can be impaired by human-caused sources of air pollution such as
9 industrial processes, (utilities, smelters, refineries, etc.), mobile sources (cars, trucks,
10 trains, etc.) and area sources (residential wood burning, prescribed burning on wild and
11 agricultural lands, wind blown dust from disturbed soils, etc.) These sources emit
12 pollutants that, in higher concentrations, also can affect public health.

13
14 The State of Utah has implemented this section of the State Implementation Plan to
15 address visibility protection in the mandatory Federal Class I areas (Class I areas)
16 required under 40 CFR 51.309. It contains all measures necessary to address regional
17 haze visibility impairment to ensure the State of Utah makes reasonable progress toward
18 the national goal contained in 42 U.S.C. 7491.

19 **2. Definitions**

20 This Plan contains terms and phrases that have formal definitions under 40 CFR 51.301,
21 40 CFR 51.309(b), and other terms specific to the programs set forth in this Plan. These
22 definitions are contained in Appendix A of this section and shall prevail over other
23 interpretations as to the meaning and intent of this Plan.

24 **3. 1977 Clean Air Act**

25 In the 1977 Clean Air Act, Congress established requirements for the prevention of
26 significant deterioration of air quality in areas within the United States and for the review
27 of pollution controls on new sources.¹ Coupled with this, Congress established a
28 visibility protection program for those larger national parks and wilderness areas
29 designated as mandatory Federal Class I areas (Class I areas).² This program established
30 a national goal of "...the prevention of any future, and remedying of any existing
31 impairment of visibility in mandatory Federal class I areas, which impairment results
32 from man-made air pollution" and requires states to develop long-term strategies to

¹ *Clean Air Act Amendments of 1977*, United States Congress. 42 U.S.C. 7470-7479. Government Printing Office: Washington, D.C. August 7, 1977.

² *Clean Air Act Amendments of 1977, Section 169A*, United States Congress. 42 U.S.C. 7491. Government Printing Office: Washington, D.C. August 7, 1977.

1 assure reasonable progress toward this national goal. The program also requires states to
2 address any visibility impairment caused by emissions of air pollutants from certain large
3 industrial sources if the source was less than 15 years old as of August 1977, through the
4 establishment of emission limits based on best available retrofit technology (BART).
5 Congress also established mandatory criteria for states to use when establishing BART
6 emission limits and developing long-term strategies for reasonable progress toward
7 meeting the national goal.

8 **4. Reasonably Attributable Visibility Impairment SIP**

9 In 1980, the United States Environmental Protection Agency (EPA) issued final
10 regulations to address the requirements of the 1977 Clean Air Act, requiring states with
11 Class I areas to submit State Implementation Plan (SIP) revisions with new source review
12 plans, monitoring plans, BART implementation plans, and long-term strategies to address
13 reasonable progress toward the national visibility goal.³ Utah's SIP for visibility
14 protection was submitted to EPA on April 26, 1985, and approved on May 30, 1986.
15

16 In the mid-1980s, Governor Bangerter appointed a Task Force on Visibility Protection to
17 determine the appropriate level of protection for Utah's Class I areas, and to determine
18 the sources of impairment of visibility in those areas. The Task Force included
19 representatives of industry, environmental groups, local governments, and citizens at
20 large. The Task Force visited many sites within Utah's five Class I areas and heard
21 presentations from technical experts in the science of visibility. After more than a year of
22 investigation, the Task Force recommended that all Utah Class I areas need protection,
23 and that the biggest cause of visibility impairment is not individual industrial sources, but
24 rather the regional haze from a multitude of sources that is transported over long
25 distances.
26

27 In 1985, the Interagency Monitoring of Protected Visual Environments (IMPROVE)
28 program was established to coordinate the monitoring of air quality in national parks and
29 wilderness areas and to ensure sound and consistent scientific methods were being used.⁴
30 The IMPROVE Steering Committee established monitoring protocols for visibility
31 measurement, particulate matter measurement, and scientific photography of the Class I
32 areas. IMPROVE monitoring is designed to establish reference information on
33 visibility conditions and trends to aid in the development of visibility protection
34 programs. Monitoring from the IMPROVE network demonstrated that visibility in all the
35 Class I areas is impaired to some degree by regional haze.

36 **5. 1990 Clean Air Act**

37 Although the 1980 regulations addressed reasonably attributable visibility impairment
38 from specific sources, also known as plume blight, it did not adequately address visibility

³ 40 CFR Part 51 - Protection of Visibility, United States Environmental Protection Agency, 45 FR 80089.
Government Printing Office: Washington, D.C. December 2, 1980.

⁴ IMPROVE Home Page. <http://vista.cira.colostate.edu/improve> (accessed April 2003).

1 impairment from large collections of sources whose emissions are mixed and transported
2 over long distances, creating a uniform haze (regional haze). In the 1990 amendments to
3 the Clean Air Act, Congress established the requirements to address regional haze
4 visibility impairment, giving the EPA authority to establish visibility transport
5 commissions and promulgate regulations to address regional haze, and requiring the
6 establishment of a visibility transport commission to investigate and report on regional
7 haze visibility impairment in the Grand Canyon National Park located in northern
8 Arizona.⁵

9 **6. Grand Canyon Visibility Transport Commission**

10 The Grand Canyon Visibility Transport Commission (GCVTC) was established by EPA
11 in November of 1991, consisting of seven western governors (or their designees), and
12 five ex-officio members representing federal land management agencies and EPA. When
13 establishing the GCVTC, EPA designated a transport region including seven western
14 states: California, Oregon, Nevada, Idaho, Utah, Arizona, Colorado, and New Mexico.
15 Although part of the Transport Region, the State of Idaho declined the invitation to
16 participate in the GCVTC. Utah's governor was vice-chair of the GCVTC. Although
17 Congress required a commission to be established for the Grand Canyon National Park,
18 the member states agreed to expand the scope of the GCVTC to address all 16 of the
19 Class I areas on the Colorado Plateau. The GCVTC elected to use a stakeholder-driven
20 process to accomplish its objectives. Ultimately, the organization included 200+
21 political, policy and technical stakeholders who staffed a variety of committees and
22 subcommittees to perform policy analysis and technical studies, and to participate in the
23 public debate. The GCVTC was funded by EPA grants and contributions from
24 stakeholders, including substantial in-kind labor. During its four-and-one-half year
25 development, the GCVTC was expanded to include the State of Wyoming and tribal
26 leaders as members. The GCVTC appointed a Public Advisory Committee (PAC)
27 representing broad stakeholder interests to provide input and feedback to the GCVTC.
28 Many Utahns were members of the PAC, with two serving on the PAC Steering
29 Committee, and one serving on the Executive Committee as Vice-Chair of the PAC. The
30 80+ member Public Advisory Committee developed a consensus report of
31 recommendations for the GCVTC that was ultimately adopted by the GCVTC and
32 submitted to EPA in June 1996.⁶

33
34 Recommendations of the GCVTC include the following:

- 35 • Policies based on energy conservation, increased energy efficiency and promotion
36 of the use of renewable resources for energy production;
- 37 • Careful tracking of emissions growth that may affect air quality in clean air
38 corridors;

⁵ *Clean Air Act Amendments of 1990, Section 169B*, United States Congress. 42 U.S.C. 7492.
Government Printing Office: Washington, D.C. November 15, 1990.

⁶ Grand Canyon Visibility Transport Commission. *Recommendations for Improving Western Vistas*.
Western Governors' Association: Denver, CO, June 10, 1996.

- 1 • Regional targets for sulfur dioxide emissions with a backstop program, probably
2 including a regional cap and possibly a market-based trading program;
- 3 • Cooperatively developed strategies, expanded data collection and improved
4 modeling for reducing or preventing visibility impairment in areas within and
5 adjacent to Class I areas, pending further studies of sources adjacent to Class I
6 areas;
- 7 • Emissions cap for mobile sources at the lowest level (expected to occur in 2005)
8 and establishment of a regional emissions budget, as well as implementation of
9 national strategies aimed at reducing tailpipe emissions;
- 10 • Further study to resolve issues regarding the modeled contribution to visibility
11 impairment of dust from paved and unpaved roads;
- 12 • Continued bi-national cooperation to resolve data gaps and jurisdictional issues
13 around emissions from Mexico;
- 14 • Programs to minimize emissions and visibility impacts and to educate the public
15 about impacts from prescribed fire and wildfire, because emissions are projected
16 to increase significantly through 2040; and
- 17 • Creation of an entity like the GCVTC to promote, support and oversee the
18 implementation of many of the recommendations in this report.

19
20 EPA initially proposed regional haze regulations in 1997.⁷ The proposed regulations
21 described a generic program to apply nationally and did not include provisions to address
22 the recommendations of the GCVTC. The Western Governors' Association (WGA)
23 engaged key stakeholders to develop a recommendation on how to transform the GCVTC
24 recommendations into a Regional Haze Rule. WGA approved their recommendation and
25 transmitted it to EPA in June 1998.⁸ Based on this and other public input, EPA issued
26 the final Regional Haze Rule in July 1999 with a national program (§ 308) that could
27 apply to any state or tribe and an optional program (§ 309) relying on the work of the
28 GCVTC that is available to the states and tribes in the nine-state GCVTC transport
29 region.⁹

30 **7. Western Regional Air Partnership**

31 The GCVTC recognized the need for a long-term organization to address the policy and
32 technical studies needed to address regional haze. The Western Regional Air Partnership
33 (WRAP) was formed in September 1997. The WRAP's charter allows it to address any
34 air quality issue of interest to WRAP members, though most current work is focused on
35 developing the policy and technical work products needed by states and tribes in writing

⁷ 40 CFR Part 51 - Regional Haze Regulations; Proposed Rule - 62 FR 41138. United States
Environmental Protection Agency, Government Printing Office: Washington, D.C. July 31, 1997.

⁸ Leavitt, M. O., Governor of Utah, Letter to EPA Administrator Browner on behalf of the Western
Governors' Association, June 29, 1998.

⁹ 40 CFR Part 51 - Regional Haze Rule; Final Rule, 64 FR 35714. United States Environmental Protection
Agency, Government Printing Office: Washington, D.C. July 1, 1999.

1 their regional haze state implementation plans (SIPs) and tribal implementation plans
2 (TIPs). The WRAP has been co-chaired by the governor of Utah and the governor of the
3 Acoma Pueblo. The WRAP Board is currently composed of representatives from 13
4 states, 13 tribes, the U.S. Department of Agriculture, the U.S. Department of the Interior,
5 and the Environmental Protection Agency. The WRAP operates on a consensus basis
6 and receives financial support from EPA. The WRAP established stakeholder-based
7 technical and policy oversight committees to assist in managing the development process
8 of regional haze work products. Stakeholder-based working groups and forums were
9 established to focus attention on the policy and technical work products the states and
10 tribes need to develop their implementation plans.

11
12 The WRAP developed and submitted an Annex to the GCVTC recommendations to
13 define a voluntary program of sulfur dioxide emission reduction milestones coupled with
14 a backstop market-trading program to assure emission reductions. EPA proposed
15 changes to the Regional Haze Rule to incorporate the GCVTC Annex, and the final rule
16 was published on June 5, 2003.¹⁰ The WRAP is completing a suite of work products to
17 support states and tribes developing GCVTC-based regional haze implementation plans.
18 Additional information about the WRAP can be found on the WRAP web site at
19 <http://www.wrapair.org>.

20 **8. Mandatory Federal Class I Areas Addressed in 2003 SIP**

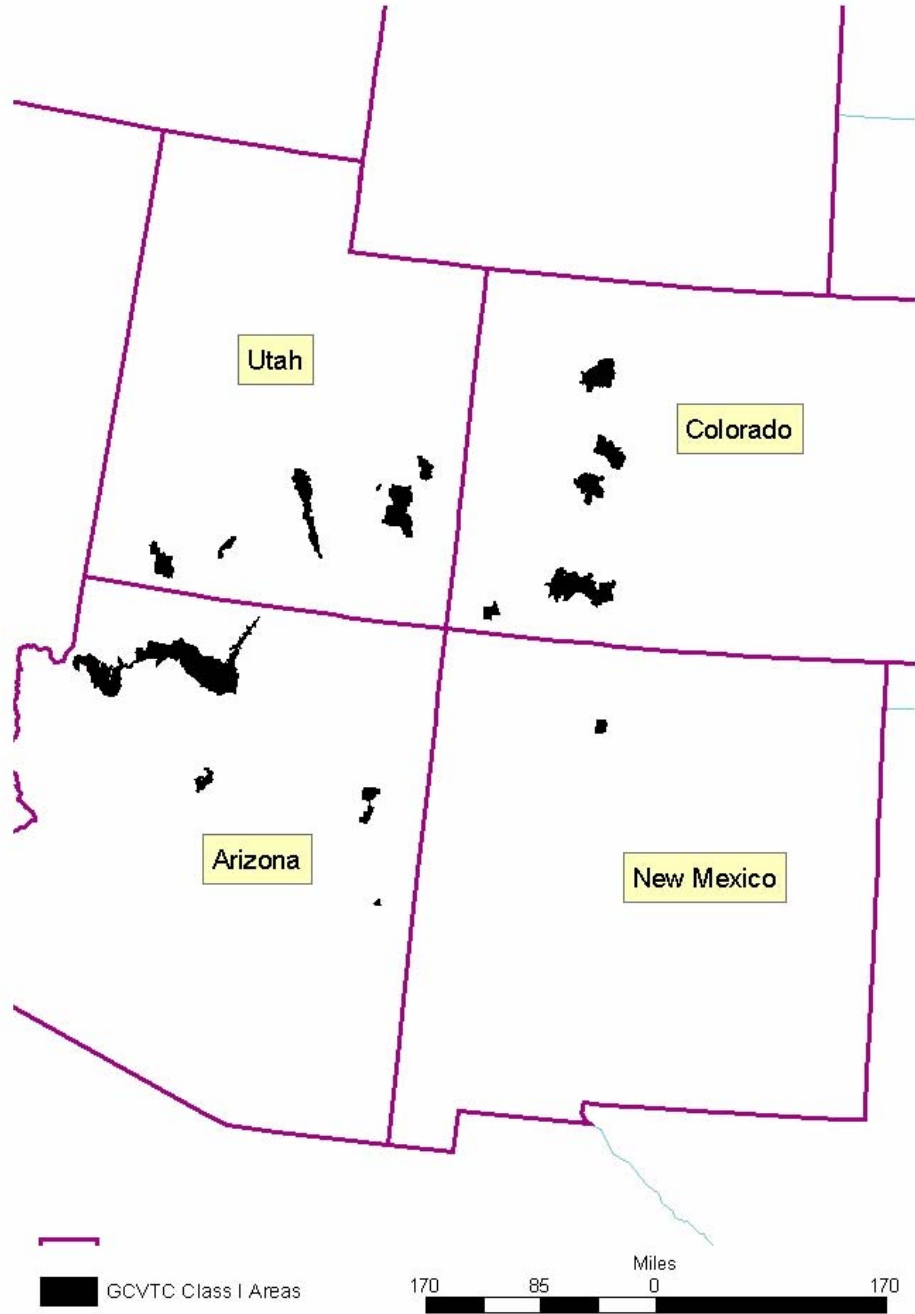
21 The Regional Haze Rule under 40 CFR 51.309 requires states to address visibility
22 protection for regional haze in the 16 Class I areas studied by the GCVTC in the initial
23 regional haze SIP submitted by December 31, 2003. Other Class I areas are to be
24 addressed after interstate consultation. These will be addressed in future SIP revisions as
25 necessary.

26
27 Five of the 16 GCVTC Class I areas are in Utah, and Utah has no other Class I areas not
28 covered under this initial SIP for regional haze. The Class I areas addressed are shown in
29 Figure 1. The areas within the state of Utah are shown in Figure 2.

¹⁰ 40 CFR Part 51 - Regional Haze Regulations; Final Rule, 68 FR 33764, United States Environmental Protection Agency. Government Printing Office: Washington, D.C. June 5, 2003.

1
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Figure 1. 16 GCVTC Class I Areas Addressed by 40 CFR 51.309



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2 **Figure 2. Utah Class I Areas Addressed by 40 CFR 51.309.**

Five Class I Areas in the State of Utah



Utah Division of Air Quality August, 2003

3

4

1 C. LONG-TERM STRATEGY FOR THE CLEAN-AIR 2 CORRIDOR

3 1. Regulatory History and Requirements

4 One of the required tasks of the Grand Canyon Visibility Transport Commission was to
5 review whether clean-air corridors exist for the 16 GCVTC Class I areas. A clean-air
6 corridor is a geographic region that contributes clean air to the Class I areas on the days
7 with best visibility. If clean-air corridors were found to exist, the GCVTC was required
8 to recommend whether additional control strategies were needed to manage emissions
9 growth to protect visibility on the least impaired days in the Class I areas. For the
10 purpose of assessment, the GCVTC considered the average of the days representing the
11 20% best visibility conditions to be the least impaired days. EPA also used this
12 definition in defining the term in the Regional Haze Rule (40 CFR 51.308 and 51.309).

13
14 In 1995 the GCVTC Meteorology Subcommittee completed an analysis of the
15 geographical source areas contributing to least impaired days in the 16 GCVTC Class I
16 areas. The analysis, in a report entitled, *Clean-Air Corridors: A Framework for*
17 *Identifying Regions that Influence Clean Air on the Colorado Plateau*,¹¹ showed that the
18 area north and west of the Grand Canyon National Park does provide clean air to the
19 Grand Canyon area primarily due to a combination of favorable meteorological
20 conditions (rain washout and higher ventilating winds) and low emissions of pollutants
21 from the sparsely populated area. The GCVTC Public Advisory Committee (PAC)
22 reviewed the clean-air corridor analysis and emission projections and determined that, for
23 the period through 2040, emissions growth is projected to be less than the amount that
24 would degrade visibility on the least impaired days in the 16 Class I areas. Based on this
25 finding, the PAC recommended emissions growth be monitored in the future but that no
26 additional control strategies were needed in the clean-air corridor at that time. The
27 GCVTC adopted this recommendation and included it in its final report to EPA, which
28 was integrated into the Regional Haze Rule.¹²

29
30 The projections of visibility conducted by the WRAP and documented in Appendix C
31 also indicate that visibility on the 20% best and worst days will improve through 2018.

32
33 The Regional Haze Rule requires states submitting implementation plans under 40 CFR
34 51.309 to determine if there are additional areas to be considered as clean-air corridors
35 for emission tracking purposes in the GCVTC areas. The successor to the GCVTC, the
36 Western Regional Air Partnership (WRAP), completed a technical analysis to validate
37 the emissions growth projections in the clean air corridors. This analysis was included as

¹¹ Meteorology Subcommittee of the Grand Canyon Visibility Transport Commission. *Clean Air Corridors: Framework for Identifying Regions that Influence Clean Air on the Colorado Plateau*. Western Governors' Association: Denver, CO, July 1995.

¹² 64 FR 35751, July 1, 1999.

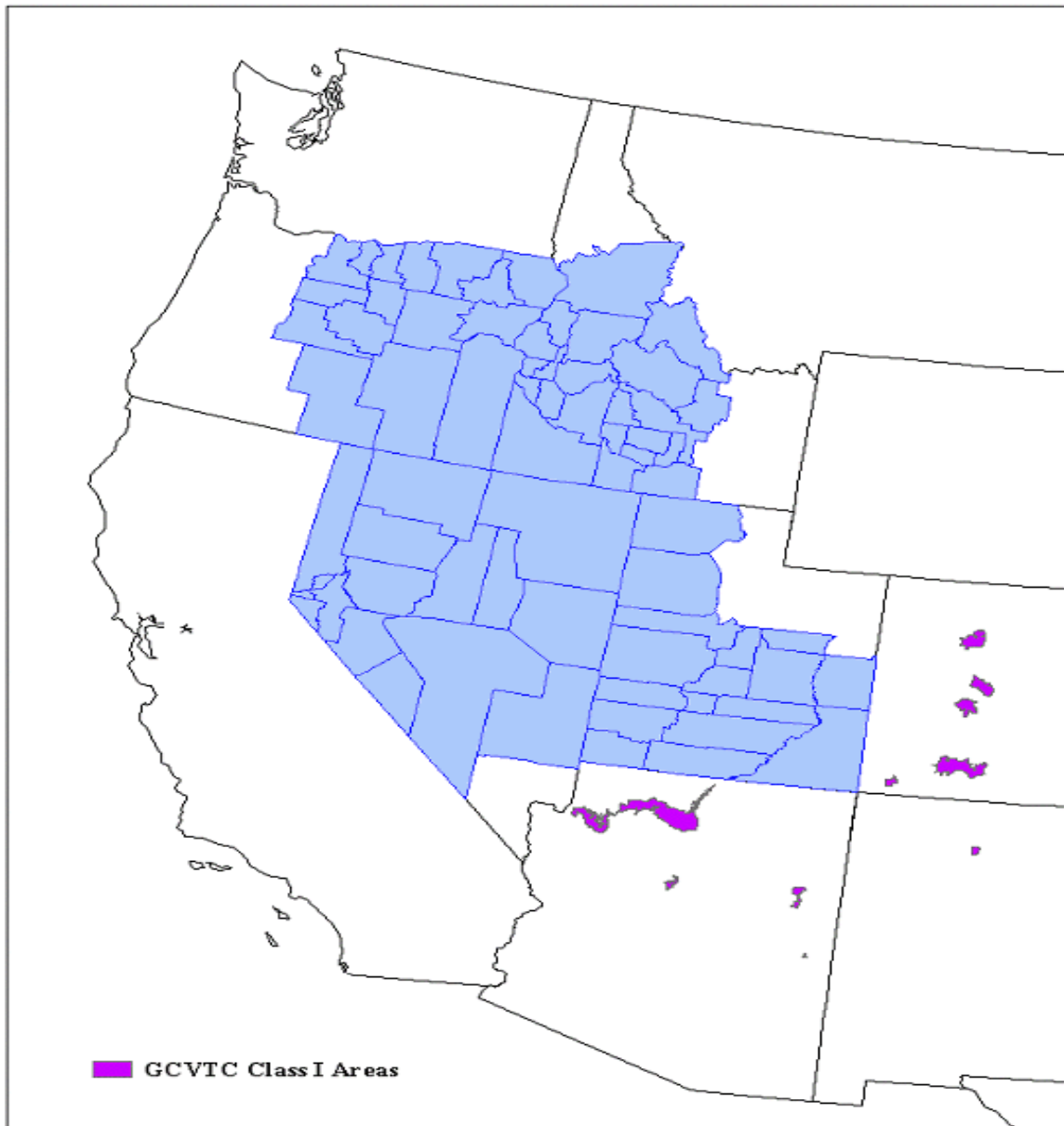
1 part of the WRAP consensus policy.¹³ A copy of this policy is contained in the Utah
2 TSD Supplement. The WRAP policy defined a clean air corridor previously identified
3 by the GCVTC Meteorology Subcommittee, and modified to recognize county level
4 emission inventory practices and an emissions tracking requirement in the clean air
5 corridor. The technical studies and findings supporting the WRAP Clean-Air Corridor
6 Policy are located in Chapter 3 of the WRAP Technical Support Document.

7 **2. Identification of the Clean-Air Corridor; Other Clean-Air**
8 **Corridors**

9 Pursuant to 40 CFR 51.309(d)(3)(i), the State of Utah concurs with the identification of
10 an existing clean-air corridor as defined in the WRAP Clean-Air Corridor Policy. The
11 boundary of the clean-air corridor is indicated on the map in Figure 3 provided below.
12 This clean-air corridor was identified using studies conducted by the Meteorological
13 Subcommittee of the GCVTC, and updated in the WRAP technical and policy analysis of
14 the area described in the WRAP Clean-Air Corridor Policy. A large portion of Utah
15 resides in the identified clean-air corridor.

¹³ *WRAP Policy on Clean Air Corridors*, adopted by Western Regional Air Partnership,
November 13, 2002.

1 **Figure 3. Map of the Clean Air Corridor in the Transport Region.**



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Source: Figure 1 from the WRAP Policy on Clean Air Corridors.

The State of Utah, pursuant to 40 CFR 51.309(d)(3)(v), has determined, based on the WRAP Clean-Air Corridor Policy and technical analysis, that no other clean-air corridors are identified at this time. The State of Utah commits to participating in a regional effort to review this determination as part of periodic plan revisions required under 40 CFR 51.309(d)(10).

1 **3. Strategy for Clean Air Corridors**

2 **a. Comprehensive emissions tracking program.**

3 Pursuant to 40 CFR 51.309(d)(3), the State of Utah commits to monitoring changes in
4 emissions inside and outside the clean-air corridor with an emissions tracking program
5 developed by the WRAP to ensure that visibility does not degrade on the least impaired
6 days in any of the 16 GCVTC Class I areas. The State of Utah commits to providing
7 statewide annual emission inventory data for use in the WRAP emissions tracking
8 program. The state of Utah is working with the WRAP to develop a comprehensive
9 emissions tracking system.¹⁴ Utah, working with the WRAP, will summarize emission
10 trends in order to identify any significant emissions growth that could lead to visibility
11 degradation in the 16 Class I areas. Included in this summary will be an assessment of
12 whether any significant emissions growth has occurred within or outside the clean-air
13 corridor, in accordance with paragraphs C.3.b and c below. The State of Utah will work
14 cooperatively with states not submitting a plan under 40 CFR 51.309 that have emissions
15 within or outside the clean-air corridor that could affect air quality in the clean-air
16 corridor, to ensure the emissions are incorporated into the tracking program through
17 inter-state consultation.
18

19 **b. Patterns of growth within the clean-air corridor.**

20 Pursuant to 40 CFR 51.309(d)(3)(ii), the State of Utah has determined, based on the
21 WRAP Clean-Air Corridor Policy and WRAP technical analysis, that current projections
22 of emissions changes inside the identified clean-air corridor will not contribute to
23 degradation of visibility on the least impaired days in the 16 Class I areas during the
24 planning period through 2018. Future emissions growth will be tracked in accordance
25 with the comprehensive emissions tracking system noted in paragraph C.3.a above. The
26 WRAP will summarize annual emission trends within the clean-air corridor and assess
27 whether any significant emission growth has occurred within the corridor as an analysis
28 tool for states.
29

30 **c. Patterns of growth outside the clean-air corridor.**

31 Pursuant to 40 CFR 309(d)(3)(iii), the State of Utah has determined, based on the WRAP
32 Clean-Air Corridor Policy and technical analysis, that current projections of emission
33 changes in areas outside the identified clean-air corridor will not contribute to
34 degradation of visibility on the least impaired days in the 16 Class I areas during the
35 planning period through 2018. The State of Utah will ensure that WRAP will track
36 emissions in areas outside the clean-air corridor and report to the State of Utah on any

¹⁴ EA Engineering, Science and Technology, Inc, for the WRAP Emissions Forum. *Emissions Forum Data Reporting, Management, and Tracking System: Draft Final Report: Needs Assessment for Evaluation and Design of an Emissions Data Reporting, Management, and Tracking System.* July, 2003. From the WRAP Web site on August 20, 2003.

1 significant changes in emission projections that may require a reassessment of this
2 determination in future SIP revisions, as required in 40 CFR 51.309(d)(10).

3
4 **d. Actions if impairment inside or outside the clean-air**
5 **corridor occurs.**

6 The State of Utah, in coordination with other transport region states and tribes, will
7 review the WRAP's annual summary of emission trends inside and outside the clean-air
8 corridor and determine if significant emissions growth as identified within the corridor in
9 accordance with paragraph C.3.b above, or was identified outside the corridor, in
10 accordance with paragraph C.3.c above. If significant emissions growth is identified, the
11 State of Utah, in coordination with other transport region states and tribes, will conduct,
12 or seek WRAP assistance in conducting, an analysis of the emissions growth on visual air
13 quality impacts on the least impaired days in any of the 16 Class I areas of the Colorado
14 Plateau. Pursuant to 40 CFR 51.309(d)(3)(iv), if this analysis finds that this growth is
15 causing visibility impairment in the 16 Class I areas, the State of Utah, in coordination
16 with other transport region states and tribes, will evaluate the need for additional
17 emission reduction measures and identify an implementation schedule for such measures,
18 if needed. The implementation of any additional emission measures shall be coordinated
19 with all appropriate transport region state and tribes, on a mutually agreed upon
20 timetable, and reported to EPA in accordance with the periodic progress reports required
21 under 40 CFR 51.309(d)(10)(i). If the WRAP regional planning process is unable to
22 perform such an analysis for the Class I areas in Utah, or come to a consensus on the
23 interpretation of such an analysis, the State of Utah will perform such studies and engage
24 in independent interstate consultation provided for under 40 CFR 51.309(d)(11).

1 **D. LONG-TERM STRATEGY FOR STATIONARY**
2 **SOURCES**

3 **1. Regulatory History and Requirements**

4 The Grand Canyon Visibility Transport Commission (GCVTC) studied the long-term
5 projected changes of emissions from stationary sources. It was found that emissions of
6 sulfur dioxide from stationary sources would decline by at least 13% between 1990 and
7 2000. Also, emissions of sulfur dioxide would continue to decline through 2040 when
8 only 30% to 50% of the 1990 emission levels would remain. This decline was due to the
9 normal turnover of source technology as older sources retire and are replaced by newer
10 and cleaner technologies.

11
12 The GCVTC decided that the most appropriate way to address emissions of sulfur
13 dioxide from stationary sources was to establish regional emission milestones and allow
14 voluntary measures to achieve the emission reductions. If the emission milestones are
15 not achieved, then a backstop market trading program would be implemented to
16 guarantee the emission reductions are achieved. The GCVTC did not have sufficient
17 time to develop the details of the emission milestones or backstop program, but
18 committed to develop it and submit it to EPA.

19
20 In the 1999 Regional Haze Rule, EPA required the states to complete the development of
21 the stationary source program for sulfur dioxide and to submit it as an Annex to the
22 GCVTC recommendations. The WRAP submitted the Annex in September, 2000.¹⁵ On
23 June 5, 2003, EPA issued the final rules related to the sulfur dioxide program for
24 stationary sources.¹⁶ These rules incorporated the materials in the Annex.

25
26 EPA's approval of the Annex was challenged, and on February 18, 2005 the DC Circuit
27 Court of Appeals vacated EPA's 2003 rules.¹⁷ The Court determined that EPA had
28 required a Best Available Retrofit Technology (BART) demonstration in the Annex that
29 was based on a methodology that had been vacated by the Court in 2002.¹⁸ On October

¹⁵ Western Regional Air Partnership. *Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and a Backstop Market Trading Program, An Annex to the Report of the Grand Canyon Visibility Transport Commission*. Denver, CO. September 29, 2000.

¹⁶ 68 FR 33764.

¹⁷ Center for Energy and Economic Development (CEED) vs. Environmental Protection Agency, February 18, 2005.

¹⁸ American Corn Growers Association vs. Environmental Protection Agency, May 24, 2002.

1 13, 2006 EPA revised the regional haze rule to establish the methodology for states to
2 develop an alternative to BART that was consistent with the Court’s decision.¹⁹

3 **2. Achievement of a 13% or Greater Reduction of Sulfur**
4 **Dioxide Emissions by 2000**

5 The GCVTC projected a 13% or greater reduction of sulfur dioxide (SO₂)
6 emissions between the years of 1990 and 2000. As shown in Table 2, regional SO₂
7 emission totals show that there was a 25% reduction in these emissions from 1990 to
8 2000.²⁰ There was a 29% decrease in SO₂ emissions during this time period from the
9 four states that developed SIPs under 40 CFR 51.309 (Arizona, New Mexico, Utah, and
10 Wyoming, excluding emissions from sources in those states that are under tribal
11 jurisdiction).

12
13
14 **Table 2. State-by-State Comparison of 1990 and 2000 Stationary Source Sulfur**
15 **Dioxide Emissions in the 9 GCVTC Transport Region States (tons per year)**

States	1990	2000
Arizona	185,398	99,133
California	52,832	38,501
Colorado	95,534	99,161
Idaho	24,652	27,763
Nevada	52,775	53,943
New Mexico	177,994	117,344
Oregon	17,705	23,362
Utah	85,567	38,521
Wyoming	136,318	124,110
Totals	828,775	621,838

16
17 **3. Strategy for Stationary Sources of Sulfur Dioxide**

18 The long-term strategy for stationary sources implements the Grand Canyon Visibility
19 Transport Commission (GCVTC) recommendation to develop regional sulfur dioxide
20 (SO₂) milestones and a backstop trading program to ensure that the milestone goals are
21 achieved. The GCVTC recommendations were further refined in an Annex to the
22 Commission report that was submitted to EPA in September 2000.

23
24 The long-term strategy for stationary sources is implemented through the following
25 documents:
26

¹⁹ 71 FR 60612

²⁰ E.H. Pechan & Associates, Inc. for the Western Governors’ Association. *Year 2000 Point Source SO₂ Emissions Analysis - 9 State Western Region Report*. Denver, CO, May 2002.

- 1 • Sulfur Dioxide Milestones and Backstop Trading Program, Part E of this plan,
2 describes the overall program and contains Utah’s commitment to implement all
3 parts of the program as outlined in the plan. The plan establishes the regional SO₂
4 milestones, emissions tracking requirements, and, if the Western Backstop SO₂
5 Trading Program (WEB Trading Program) is triggered, the plan also describes
6 how Utah will determine allocations and manage the allowance tracking system
7 that is needed to implement the program.
8
- 9 • R307-250, Western Backstop Sulfur Dioxide Trading Program, contains the
10 requirements that will apply to major industrial sources of sulfur dioxide as a
11 backstop regulatory program if the SO₂ milestones are exceeded. The rule may
12 never be implemented if the goal to meet the regional SO₂ milestones through
13 voluntary means is achieved. If the rule is implemented, it establishes the
14 procedures and compliance requirements for sources in the trading program.
15
- 16 • R307-150 requires major industrial sources of SO₂ to submit an annual emissions
17 inventory in the pre-trigger phase of the program to measure compliance with the
18 regional SO₂ milestones. If the backstop program is triggered, then these
19 requirements will eventually be replaced by more rigorous monitoring
20 requirements in R307-250.

21 **a. 2018 Milestone**

22 The 2018 milestone of 234,624 tons represents an emission reduction of approximately
23 235,000 tons of SO₂ from the 1990 baseline emissions of 469,534 tons for the four
24 participating states, and is well on the way to the GCVTC’s goal of a 50-70% reduction
25 by 2040. The 2018 regional sulfur dioxide milestone provides for greater reasonable
26 progress²¹ than would be achieved by application of best available retrofit technology
27 (BART), as required by 40 CFR 51.309(d)(4). The WRAP estimated that BART
28 reductions would total approximately 91,800 tons of SO₂ by 2018.
29

30 In modeling work conducted by the WRAP to verify the Annex analysis, it was
31 determined that, in addition to the 16 Class I areas of the Colorado Plateau, the regional
32 SO₂ milestones showed greater reasonable progress than would be achieved under BART
33 for Utah's Class I areas and for any Class I areas affected by emissions from Utah. This
34 demonstration can be found in Section 4.1.2 of the WRAP Technical Support Document
35 that was submitted to EPA as part of the 2003 regional haze SIP. In accordance with 40
36 CFR 51.309(g)(ii), no further demonstration will be needed prior to 2018 for Utah's
37 stationary sources identified in the Annex, in terms of satisfying BART for SO₂ under 40
38 CFR 51.308(e).

²¹ Demonstration that the SO₂ Milestones Provide Greater Reasonable Progress than BART

1 **b. Interim Milestones**

2 Interim milestones were set based on expected emission reductions that were already
3 planned between 2003 and 2018. These milestones show steady and continuing emission
4 reductions, with most of the emission reductions occurring by 2013.

5 **c. Triggering the Trading Program**

6 States and tribes will collect an annual SO₂ inventory. Compliance with the milestones is
7 determined by an annual comparison of the rolling 3-year average of total regional
8 emissions with the rolling 3-year average of the milestones. For 2018, total emissions
9 will be compared with the 2018 milestone. If a milestone is exceeded, the trading
10 program is activated and emission allocations are made one year later with sources
11 having five years from the year of exceedance to comply with their allocation. Sources
12 may comply by retrofitting to bring emissions below their allocation, by buying credits to
13 emit from other sources, by retiring the source, or by other means.

14 **d. Certainty that 2018 Milestone Will Be Met on Time**

15 Part E of this Plan includes a mechanism for the states and tribes to activate the trading
16 program in 2013 if available evidence indicates the 2018 milestone will not be reached.
17 In order to be in compliance with the 2018 milestone, the 2018 emissions must be less
18 than the 2018 milestone. Sources that have not controlled their emissions in accordance
19 with their allocations will be subject to financial penalties.

20 **e. Trading Program Features**

21 Details of the backstop trading program such as applicability, monitoring and reporting,
22 trading procedures, compliance requirements and penalties, are defined in R307-250.
23 Sources that reduce their emissions below their allocation will be able to sell excess
24 allowances to other sources, within certain programmatic restrictions.

25 **f. Allocations**

26 If the program is triggered, 8,500 tons of SO₂ allocations will be set aside for tribal
27 interests, acknowledging that tribal lands are largely undeveloped and that tribes would
28 not benefit from a plan based only on past emissions. There will be a new source
29 set-aside to accommodate growth within the region. Existing sources will receive a
30 "floor" allocation based on a "clean unit" emission rate. Certain renewable energy
31 sources also will be eligible to receive an allocation. The remainder of the allowances,
32 which will decline over the years, will be allocated to existing sources. If the program is
33 triggered, sources may buy and sell allowances to come into compliance.

34 **g. State and Tribal Opt-In or Opt-Out**

35 In the event that any other states or tribes choose to participate in the regional trading
36 program in the future the milestones will be adjusted through a SIP revision to reflect the
37 changes.

1 **4. Geographic Enhancement Program**

2 40 CFR 51.308(e)(2) allows states to submit a SIP, or tribes a TIP, which adopts an
3 alternative measure to regional haze BART. Geographic enhancement is a voluntary
4 approach provided in Section 308(e)(2)(v) that can be included in the plan for addressing
5 reasonably attributable visibility impairment (RAVI) for stationary sources, under the
6 provisions of 40 CFR 51.302(c). RAVI is different from regional haze in that it
7 addresses “hot spots” or situations where visibility impairment in a Class I area is
8 reasonably attributable to a single source or small group of sources in relatively close
9 proximity to the Class I area. In December 2004, the State of Utah signed a
10 Memorandum of Agreement (MOA) with the Federal Land Managers to provide sources
11 greater certainty regarding their potential risk of being certified as a RAVI source by a
12 Federal Land Manager. Sources can incorporate this information into their business
13 planning process, and use the efficiencies and reduced costs of the market to address
14 potential RAVI issues.

15 **a. Procedure for addressing Reasonably Attributable**
16 **Visibility Impairment under the Regional Haze Rule.**

17 If the National Park Service certifies impairment, the State of Utah will fulfill its
18 obligations to determine attribution and if necessary determine BART for the applicable
19 source or group of sources in accordance with Utah's SIP for visibility protection
20 submitted to EPA on April 26, 1985, and approved on May 30, 1986. Additional
21 information regarding possible technical approaches for determining attribution is
22 contained in the WESTAR report, *Recommendations for Making Attribution*
23 *Determinations in the Context of Reasonably Attributable BART.*

24 **5. Report on Assessment of NO_x/PM Strategies**

25 **a. Assessment of Need for NO_x and PM milestones.**

26 The State of Utah has evaluated the need for NO_x and PM emission control strategies, the
27 degree of visibility improvement expected, and whether such milestones are needed to
28 avoid any net increase in these pollutants. This evaluation was based on an assessment of
29 NO_x and PM stationary source emissions made by the WRAP Market Trading Forum for
30 all WRAP states, including the transport region states.²²

31
32

33 Several conclusions were reached based on the analyses.

- 34 • For the vast majority of Class I areas throughout the WRAP region, stationary
35 source NO_x and PM emissions are not a major contributor to visibility impairment

²² WRAP. *Stationary Source NO_x and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts.* Denver, CO. Presented to the WRAP Board October 15, 2003.

- 1 on the average 20% best and 20% worst days. However, on some of the worst
2 days nitrates and PM are the main components of visibility impairment.
- 3 • Stationary source NO_x emissions are projected to increase by 4% between 1996
4 and 2018. Stationary source NO_x emissions probably cause 2% - 5% of the
5 visibility impairment on the Colorado Plateau.
 - 6 • Stationary source PM emissions are projected to increase by 29% between 1996
7 and 2018. Stationary source PM emissions probably cause less than 2% of the
8 regional visibility impairment.
 - 9 • The current regional modeling does a poor job of predicting nitrate concentrations
10 in the winter when NO_x has the greatest impact on visibility impairment. The
11 modeling also does a poor job of predicting the impact of localized fugitive dust
12 impact. The WRAP is currently making significant improvements to the model
13 and to the emission inventories to address these issues.
 - 14 • There is a wide range of emission reduction techniques available to control NO_x
15 and PM emissions, and many of the technologies are cost-effective. The current
16 emission inventory does not contain enough information to determine what
17 technologies are currently in place in the West and the cost of additional controls.
 - 18 • RAVI remedies are available in cases where particular stationary sources may
19 impact particular Class I areas.

20
21 The complete report is provided in the 2003 Utah TSD Supplement.
22

23 **6. Best Available Control Technology (BART) Assessment for** 24 **NO_x and PM.**

25 **a. Regional Haze Rule BART Requirements**

26 Pursuant to 40 CFR 51.309(d)(4)(vii), certain major stationary sources are required to
27 evaluate, install, operate and maintain BART technology or an approved BART
28 alternative for NO_x and PM emissions. BART requirements can be addressed through a
29 case-by-case review under 40 CFR 51.308(e)(1) or through an alternative program under
30 40 CFR 51.308(e)(2). The State of Utah has chosen to evaluate BART for NO_x and PM
31 under the case-by-case provisions of 40 CFR 51.308(e)(1). BART for SO₂ is addressed
32 through an alternative program under 40 CFR 51.309 that is described in Part E of this
33 plan.
34

35 EPA issued guidelines for BART determinations on July 6, 2005 that are codified in
36 Appendix Y to 40 CFR Part 51. These guidelines establish a three step process.

- 37 • States identify sources which meet the definition of BART eligible
- 38 • States determine which BART eligible sources are “subject to BART”
- 39 • For each source subject to BART States identify the appropriate control
40 technology.
41

1 The determination of NO_x limits for fossil-fuel fired power plants having a total
 2 generating capacity greater than 750 megawatts must be made pursuant to the guidelines
 3 in 40 CFR 51 Appendix Y, Section E.5.²³

4 **b. BART-Eligible Sources.**

5 BART-eligible sources are those sources that fall within one of 26 specific source
 6 categories, were built during the 15-year window of time from 1962 to 1977, and have
 7 potential emissions of at least 250 tons per year of any visibility impairing air pollutant
 8 (40 CFR 51.301). Pursuant to 40 CFR 51.308 (e)(1)(i) a State is required to list all
 9 BART-eligible sources within the State.

10
 11 Two BART-eligible sources have been identified in the State of Utah: PacifiCorp’s
 12 Rocky Mountain Power plants Hunter (Units 1 and 2) and Huntington (Units 1 and 2).
 13 The sources as fossil-fuel fired steam electric plants of more than 250 million Btu per
 14 hour heat input fall into one of the 26 specific BART source categories. The plants have
 15 potential emissions greater than 250 tons per year of a visibility impairing pollutant. The
 16 plants had commenced construction within the BART time frame of August 7, 1962 to
 17 August 7, 1977.

18
 19 **Table 3. BART-Eligible Sources in Utah.**

SOURCE	UNI T ID	SERVICE DATE	GENERATING CAPACITY (MW)	BART CATEGORY	COAL TYPE	BOILER TYPE
Hunter	1	1978	488	Fossil fuel fired	Bituminous	Tangential
Hunter	2	1980	488	Fossil fuel fired	Bituminous	Tangential
Huntington	1	1977	498	Fossil fuel fired	Bituminous	Tangential
Huntington	2	1974	446	Fossil fuel fired	Bituminous	Tangential

20 Note: Hunter Unit 3 commenced construction after 1977 and is therefore not BART-
 21 eligible.

22 **c. Sources Subject to BART**

23
 24 Pursuant to 40 CFR 51.308(e)(1)(ii) the State is required to determine which BART-
 25 eligible sources are also “subject to BART.” BART-eligible sources are subject to BART
 26 if they emit any air pollutant that may reasonably be anticipated to cause or contribute to
 27 any impairment of visibility in any mandatory Class I Federal area.

28
 29 Both Rocky Mountain Power plants Hunter and Huntington were determined by the State
 30 to be subject to BART. The State utilized the technical modeling services of the WRAP
 31 Regional Modeling Center (RMC). Modeling was performed according to the RMC

²³ 40 CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 FR 39158)

1 modeling protocols²⁴. For the WRAP BART exemption screening modeling, the RMC
2 followed the EPA BART Guidelines in 40 CFR 51, Appendix Y and the applicable
3 CALMET/CALPUFF modeling guidance (e.g., IWAQM, 1998; FLAG, 2000; EPA,
4 2003c) including EPA’s March 16, 2006 memorandum: “Dispersion Coefficients for
5 Regulatory Air Quality Modeling in CALPUFF”.²⁵

6
7 The basic assumptions of the WRAP BART CALMET/CALPUFF modeling protocols
8 are as follows:

- 9 • Three years of modeling (2001, 2002 and 2003) were used.
- 10 • Visibility impacts due to emissions of SO₂, NO_x and primary PM emissions were
11 calculated
- 12 • Visibility was calculated using the Original IMPROVE equation and Annual
13 Average Natural Conditions.
- 14 • The effective range of CALPUFF modeling was set at 300km from the sources
- 15 • For pre-control modeling, maximum 24-hour average actual emissions from the
16 Acid Rain database were used in CALPUFF model.
- 17 • For post-control modeling, expected New Source Review (NSR) permitted limits
18 were used in the CALPUFF model.

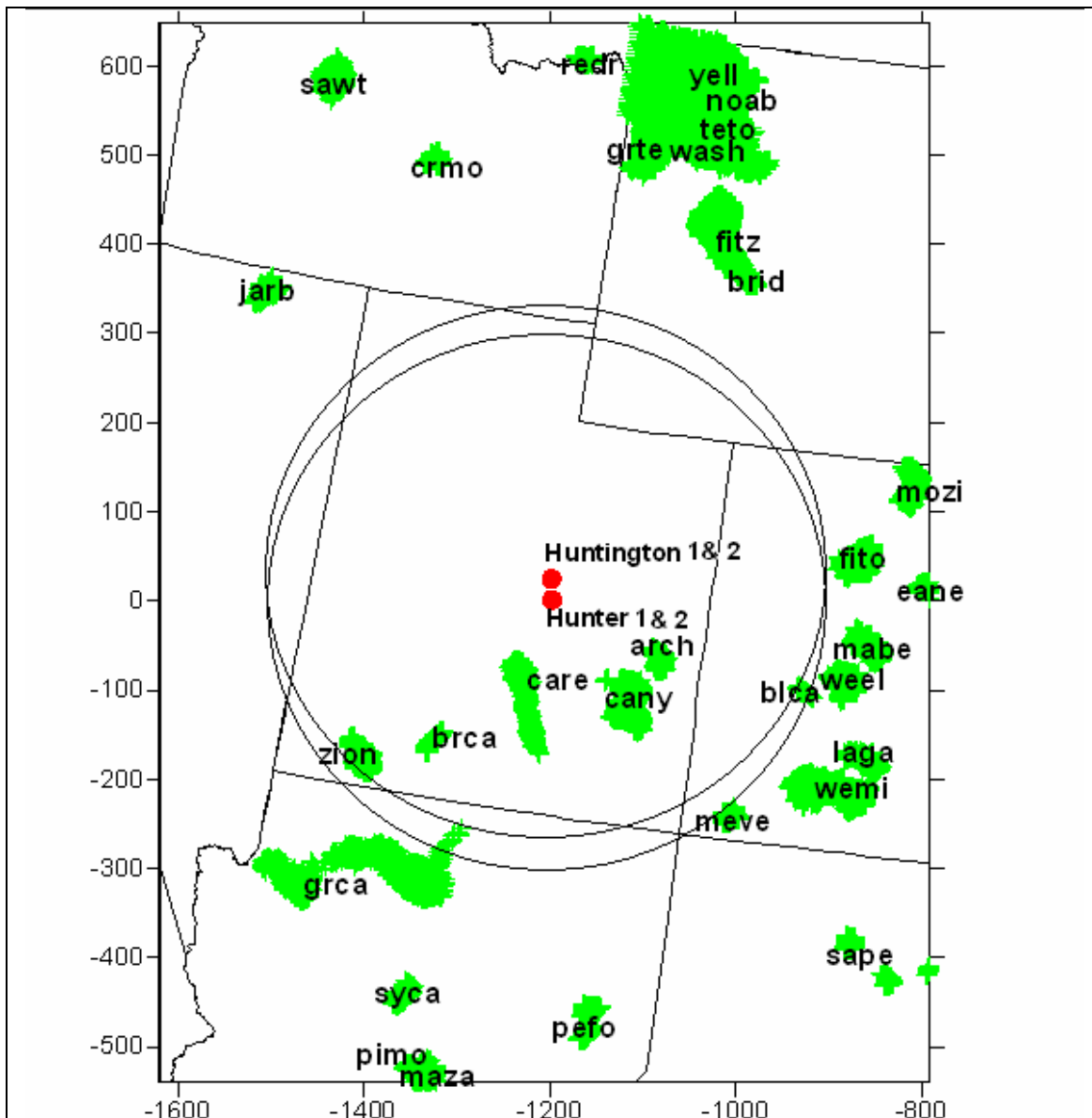
19
20 According to 40 CFR Part 51, Appendix Y, a BART-eligible source is considered to
21 “contribute” to visibility impairment in a Class I area if the modeled 98th percentile
22 change in deciviews is equal to or greater than the “contribution threshold.” The State of
23 Utah evaluated BART exemption screening modeling results at the EPA-suggested
24 contribution threshold of 0.5 deceviews within a 300 Km radius of the BART-eligible
25 sources.²⁶ Both BART-eligible sources Hunter and Huntington had a modeled impact
26 greater than the threshold level of 0.5 change in deceviews in at least one of the seven
27 Class I areas within a 300 km radius of the sources.

28

²⁴ CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the
Western United States

²⁵ Atkinson and Fox, 2006

²⁶ WRAP RMC BART Modeling for Utah Draft #5 January 9, 2007



1 **Figure 4. Relationship between Utah potential BART-eligible sources and Class I**
 2 **areas. Hunter and Huntington Units 1 and 2 modeled separately using uncontrolled**
 3 **and controlled emissions at maximum 300 km.**
 4
 5
 6

Table 4. Subject to BART Modeling

	Subject to BART Modeling - 98th Percentile 3 year average Delta Deciview							
	Capitol Reef	Canyonlands	Arches	Bryce Canyon	Zion	Grand Canyon	Black Canyon Gunnison	Mesa Verde
Hunter 1	2.145	1.892	1.643	0.543	0.458	0.585	0.599	0.532
Hunter 2	1.905	1.663	1.446	0.463	0.414	0.515	0.528	0.464
Huntington 1	1.909	1.646	1.453	0.465	0.43	0.535	0.552	0.477
Huntington 2	2.534	2.343	1.996	0.906	0.789	1.004	1.15	0.914

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d. BART Determination

3

As required under 51.308 (e)(1)(A) the determination of BART must be based on an analysis of the best system of continuous emission control technology available. In the analysis the State must take in to account five factors:

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PacifiCorp has installed, received permits to install or committed to install the following retrofit control equipment at the Hunter and Huntington fossil fuel fired electric generating units (EGU):

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Hunter Units 1 and 2:

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Huntington Units 1 and 2:

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- Conversion of existing electrostatic precipitators to pulse fabric filter bag-houses
 - The replacement of existing, first generation low-NO_x burners with Alstom TSF 2000TM low-NO_x firing system and installation of two elevations of separated overfire air.
 - Upgrade of existing flue gas conditioning system to > 90% Sulfur dioxide removal.
- Conversion of existing electrostatic precipitators to pulse fabric filter bag-houses
 - The replacement of existing, first generation low-NO_x burners with Alstom TSF 2000TM low-NO_x firing system and installation of two elevations of separated overfire air.
 - Installation of a new wet-lime, flue gas de-sulfurization system at Unit 2 (FGD).
 - Upgrade of existing flue gas conditioning system to > 90% Sulfur dioxide removal at Unit 1.

1
2 **Table 5. Emissions Rates (lb/MMBtu) for the Retrofitted Hunter and Huntington**
3 **Units**

Units Rate: lb/MMBtu	MW	Utah Permitted Rates ²⁷			Presumptive BART Limits ²⁸	
		SO ₂	NO _x	PM	SO ₂	NO _x
Hunter 1	488	0.12	0.26	0.05	0.15	0.28
Hunter 2	488	0.12	0.26	0.05	0.15	0.28
Huntington 1	498	0.12	0.26	0.05	0.15	0.28
Huntington 2	446	0.12	0.26	0.05	0.15	0.28

4
5
6
7 **Table 6. Change in Emissions (tons/yr) for Retrofitted BART Units**

Unit	Pre-Control SO ₂	Pre-Control NO _x	Pre-Control 1 PM ₁₀	Post-Control 1 SO ₂	Post-Control NO _x	Post-Control 1 PM ₁₀	Delta SO ₂	Delta NO _x	Delta PM ₁₀
Hunter 1	2741	6833	533	2239	4851	280	-502	-1981	-253
Hunter 2	2425	5922	533	2185	4734	273	-240	-1187	-260
Huntington 1	2538	5676	444	2052	4445	256	-486	-1231	-188
Huntington 2	13703	5582	443	1743	3776	218	-11960	-1806	-225
TOTALS	21,407	24,013	1,953	8,219	17,807	1,027	-13,189	-6,206	-926

8
9
10 Pursuant to 51.308(e)(1)(C)(iv) each source subject to BART is required to install and
11 operate BART no later than 5 years after approval of the implementation plan. The
12 PacifiCorp schedule for the four EGUs at Huntington and Hunter sources is as follows.
13
14

Source	Notice of Intent Submitted	Permit Issued	In Service Date
Hunter 1	June 2006	March 2008	Spring 2014
Hunter 2	June 2006	March 2008	May 2010
Huntington 1	April 2008	Fall 2008 (est.)	Spring 2010
Huntington 2	October 2004	April 2005	April 2007

15
16 EPA under the BART Rule requires coal-fired electric generating plants of greater than
17 750 MW to meet BART presumptive limits. While EPA considers presumptive limits to
18 be appropriate for all coal-fired power plants greater than 750 MW, the State may

²⁷ Utah Division of Air Quality Approval Orders: Huntington Unit 2 - AN0238012, Huntington Unit 1 - XX, Hunter Units I and 2 - XX

²⁸ 40 CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39135)

1 establish different requirements if the State can demonstrate that an alternative is justified
2 based on a consideration of the five BART factors.

3
4 “States, as a general matter, must require owners and operators of greater than
5 750 MW power plants to meet these BART emission limits... a State may
6 establish different requirements if the State can demonstrate that an alternative
7 determination is justified based on a consideration of the five statutory factors.”²⁹

8
9 “For Coal-fired EGU’s greater than 200 MW located at greater than 750 MW
10 power plants and operating without post-combustion controls (i.e. SCR or
11 SNCR), we have provided presumptive NOx limits, differentiated by boiler
12 design and type of coal burned. You may determine that an alternative control
13 level is appropriate based on careful consideration of the statutory factors.”
14 (Appendix Y Part 51 – IV (E)(5)).³⁰

15
16 EPA determined presumptive limits for SO₂ and NO_x for EGUs based on a methodology
17 equivalent~~similar~~ to that required in 50 CFR 51 Appendix Y for BART Rule. The EPA
18 determination of presumptive limits included:

- 19 • iIdentification of all potential BART-eligible EGUs (all BART-eligible
20 EGU’s were assumed to be Subject to BART);
- 21 • tTechnical analyses and industry research to determine applicable and
22 appropriate SO₂ and NO_x control options,
- 23 • eEconomic analysis to determine cost effectiveness for each potentially
24 BART-eligible EGU
- 25 • , and eEvaluation of historical emissions and forecast emission reductions
26 for each potentially BART-eligible EGU³¹.
- 27 • NOx and SO2 CALPUFF modeling of emission impacts at model Class I
28 area.

29
30 The analysis included 491 potential BART EGUs including the Hunter and
31 Huntington plants. The technical analysis conducted by EPA to determine
32 presumptive BART limits for SO₂ and NO_x is in effect a BART determination
33 analysis for 419 EGUs including the Hunter and Huntington Units.³²

34
35 Section IV (E) (5) of Appendix Y Part 51 clearly requires the implementation of
36 presumptive NOx limits for coal-fired EGU’s greater than 200 MW located at greater

²⁹ Ibid. (70 Federal Register 39131).

³⁰ 70 Federal Register 39171

³¹ Ibid. (70 Federal Register 39134)

³² “Methodology for Developing BART NO_x Presumptive Limits” EPA Clean Air Market Division June 15, 2005 HQ-OAR-2002-0076-0445 and “Technical Support Document for BART NO_x Limits for Electric Generating Units Excel Spreadsheet, Memorandum April 15, 2005 HQ-OAR-2002-0076-0369

1 than 750 MW power plants. Under Appendix Y, states are given the discretion to
 2 challenge presumptive limits through a five factor analysis, but presumptive limits were
 3 developed by EPA as a reasonable, equivalent and mandated substitution for a five factor
 4 analysis.³³

5
 6 While the State considers requirements for BART determination under 51.308(e)(1) to be
 7 satisfied by the implementation of control technology that achieves presumptive limits, a
 8 post control modeling run was conducted to assess the post-control change in visibility at
 9 seven Class I areas. The State utilized the technical modeling services of the WRAP
 10 Regional Modeling Center (RMC). Modeling was performed according to the RMC
 11 modeling protocols³⁴. Post control modeling emissions were based on New Source
 12 Review permitted emission rates (lb per MMBtu) specified in Table 5.

13
 14 The post control modeling showed a decrease in deciviews from the Subject to BART
 15 modeling for the four BART units at the seven Class I areas modeled.

16
 17 **Table 7. Post-Control BART Modeling, 98th Percentile 3-year average deciviews**

	Post-Control BART Modeling - 98th Percentile 3 year average Deciview							
	Capitol Reef	Canyonlands	Arches	Bryce Canyon	Zion	Grand Canyon	Black Canyon Gunnison	Mesa Verde
Hunter 1	0.019	0.017	0.014	0.005	0.004	0.004	0.005	0.004
Hunter 2	0.019	0.017	0.014	0.005	0.004	0.004	0.005	0.004
Huntington 1	0.015	0.012	0.009	0.004	0.004	0.004	0.004	0.004
Huntington 2	0.015	0.012	0.009	0.004	0.004	0.004	0.004	0.004

18
 19 Utah’s long-standing Prevention of Significant Deterioration (PSD) permitting program
 20 (SIP Section VII and R307-405), New Source Review permitting program (SIP Section II
 21 and R307-401) and Visibility program (SIP section XVII and R307-406) will continue to
 22 protect Class I area visibility by requiring best available control technology for new
 23 sources, and assuring that there is not a significant degradation in visibility at Class I
 24 areas due to new or modified major sources.

25

³³ CFR Part 51 Appendix Y Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39171)

³⁴ WRAP RMC BART Modeling for Utah Draft #5 January 9, 2007

1 **E. SULFUR DIOXIDE MILESTONES AND BACKSTOP**
 2 **TRADING PROGRAM**

3 **1. Milestones and Determination of Program Trigger**

4 **a. Regional Sulfur Dioxide Milestones**

5 *(1) Milestone Values.*

6 The regional sulfur dioxide (SO₂) milestones for the years 2003 through 2018 are
 7 provided in Table 8. The ~~base~~-milestones will be adjusted annually as described in
 8 paragraph E.1.a(2) of this plan.

9
 10 **Table 8. Sulfur Dioxide Emissions Milestones**

For the year	the regional sulfur dioxide milestone is	and the annual SO ₂ emissions for these years will determine whether emissions are greater than or less than the milestone
2003 ³⁵	420,637,400,636 tons SO ₂	2003
2004	420,637,400,636 tons SO ₂	Average of 2003 and 2004
2005	420,637,400,636 tons SO ₂	Average of 2003, 2004 and 2005
2006	420,637,400,636 tons SO ₂	Average of 2004, 2005 and 2006
2007	420,637,400,636 tons SO ₂	Average of 2005, 2006 and 2007
2008	378,398,365,064 tons SO ₂	Average of 2006, 2007 and 2008
2009	336,160,329,493 tons SO ₂	Average of 2007, 2008 and 2009
2010	293,921 tons SO ₂	Average of 2008, 2009 and 2010
2011	293,921 tons SO ₂	Average of 2009, 2010 and 2011
2012	293,921 tons SO ₂	Average of 2010, 2011 and 2012
2013	278,985 tons SO ₂	Average of 2011, 2012 and 2013
2014	264,050 tons SO ₂	Average of 2012, 2013 and 2014
2015	249,114 tons SO ₂	Average of 2013, 2014 and 2015
2016	249,114 tons SO ₂	Average of 2014, 2015 and 2016
2017	249,114 tons SO ₂	Average of 2015, 2016 and 2017
2018	234,624 tons SO ₂	Year 2018 only
2019 forward,	234,624 tons SO ₂	Annual; no multiyear averaging

³⁵ The 2003 through 2007 milestones have been adjusted to include only the four states that are part of the regional backstop trading program using the adjustment methodology in the 2003 Regional Haze SIP.

For the year	the regional sulfur dioxide milestone is	and the annual SO ₂ emissions for these years will determine whether emissions are greater than or less than the milestone
until replaced by an approved SIP		

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(2) *Smelter Specific Set-Aside.*

Since 1990 the existing copper smelters in the west have made significant SO₂ emission reductions. In addition, 3 of the 6 smelters that were operating in 1990 have now been permanently closed. Because of the global nature of this industry, it is not expected that any new copper smelters will be constructed between 2008 and 2018. Representative emission estimates were developed for the existing copper smelters in the 2003 SIP. These estimates have been reviewed and determined to be a good estimate of future emissions from these smelters through 2018. There is the possibility that ore from mines located near the closed smelters could be transported to the existing smelters for processing. A small smelter-specific set-aside has been created to account for this possible production increase. The smelter-specific set-aside will be determined using the calculation procedures in XX.E.1.c(4) of this Plan, and the set aside will be added to the milestone to account for capacity expansion at the remaining smelters. This set-aside will only be available for use if sulfur input and emissions from an individual copper smelter is above the baseline level listed in Table 9 in any particular year as a result of increased capacity. The increase to the milestone will be based on a smelter’s proportional increase above its baseline sulfur input. The set-aside will be recalculated every year to reflect actual operations of the remaining copper smelters. The set-aside may not be traded under the backstop trading program.

Table 9. Preliminary Smelter-Specific Set Aside

Company/Smelter	Baseline Sulfur Input	Baseline Allocation	Smelter-specific Set-aside
Asarco Hayden	235,000 tons	23,000 tons SO ₂	3,000 tons SO ₂
Kennecott Utah Copper Corporation, Smelter and Refinery	340,269 tons	1,000 tons SO ₂	100 tons SO ₂
TOTAL	575,269 tons	24,000 tons SO₂	3,100 tons SO₂

Note: The smelter baseline has decreased from 86,000 tons SO₂ in the 2003 SIP to the current value of 24,000 tons SO₂ due the permanent closure of the BHP San Manuel, Phelps Dodge Chino, and Phelps Dodge Hidalgo smelters. The Phelps Dodge Miami smelter is not included in this table because the smelter is currently operating at its permitted limit and therefore does not have a smelter-specific set-aside. Smelter emissions were 148,510 tons SO₂ in 1990.

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(3) *Other Milestone Adjustments.*

1 (a) All other milestone adjustments will require a SIP revision. Paragraph E.1.c(3)
2 of this plan outlines adjustments to be made to the emissions inventory to ensure a
3 consistent comparison to the milestones. These adjustments will be incorporated
4 into the milestones every five years as part of the periodic implementation plan
5 revisions required by 40 CFR 51.309(d)(10). Adjustments to the milestones will
6 be tracked in the annual emissions report described in paragraph E.1.c(4) of this
7 Plan.

8
9 (b) Within ninety days of adoption by the Utah Air Quality Board of the periodic
10 Implementation Plan revision incorporating adjustments based on paragraph
11 E.1.c(3) or (4) of this Plan, the State of Utah will provide notice to sources whose
12 records were used to calculate the adjustments, including the date of the SIP
13 adoption and a statement that the source needs to retain the applicable records for
14 at least five years from the date that the SIP was adopted, or ten years from the
15 date of establishing the record, whichever is longer.

16
17 (c) Opt-in Provisions for States and Tribes. The regional milestones in Table 8
18 were developed for a 4-state region: Arizona, New Mexico, Utah, and Wyoming.
19 Other western states and tribes may choose to join this backstop trading program
20 in the future. The addition of a state or tribe to the program will require a SIP/TIP
21 revision of all participating states and tribes to adjust the regional milestones, and
22 will not occur automatically. Any state or tribe that wishes to opt in to the
23 program will propose milestone adjustments to the participating states and tribes
24 using the same methodology that was used to develop the milestones in Table 8.
25 A new participant must agree to develop a SIP and backstop trading rule that is
26 consistent with those adopted by the other participating states and tribes.

27 **b. Regional Program Administration**

28 *(1) Pre-trigger tracking of regional SO₂ emissions.*

29 The executive secretary will work cooperatively with the states and tribes that are
30 participating in the SO₂ Milestones and Backstop Trading Program to ensure that an
31 emission tracking system for the regional SO₂ inventory is developed and maintained.
32 The executive secretary is responsible for all regional program administration functions
33 as described in this plan. The executive secretary will perform these functions using the
34 WRAP as the executive secretary's agent. The Western Regional Air Partnership
35 (WRAP) compiled the SO₂ emission inventories that were used during the development
36 of the Annex and subsequent SIP revisions, and the WRAP continues to refine and
37 improve the overall tracking system for regional haze. The WRAP will maintain the pre-
38 trigger emissions tracking functions described in this plan for the foreseeable future. If
39 the WRAP is no longer able to fulfill this function, then the executive secretary will
40 ensure that other arrangements are made, either through a different regional organization
41 or through a contractor, to maintain the SO₂ tracking system that is described in this plan.
42 The WRAP has no authority to make regulatory determinations. The WRAP has limited
43 authority under this plan to perform tracking and accounting functions, prepare reports,
44 and perform other administrative functions as directed by the executive secretary. The

1 executive secretary will work expeditiously to correct any problems if the WRAP fails to
2 perform any of the functions described in this plan in a timely manner.

3
4 (2) *Designation of the Tracking System Administrator.*
5 If the backstop trading program is triggered due to an exceedance of the SO₂ milestones
6 as outlined in Part E.1.c of this plan, the executive secretary will work cooperatively with
7 the other participating states and tribes to designate one Tracking System Administrator
8 (TSA). The TSA will be designated as expeditiously as possible, but no later than six
9 months after the program trigger date. In addition, before the TSA is designated, the
10 executive secretary will enter into a binding contract with the TSA that will require the
11 TSA to perform all TSA functions described in this plan. The State of Utah has sufficient
12 authority under State contract law to ensure that the functions in this plan are carried out
13 by the TSA.

14
15 (3) *Information Provided by other States and Tribes.*
16 The executive secretary will accept the emission inventory and permitting information
17 provided by the other participating states and tribes in order to determine the milestone
18 value and program trigger if such other states and tribes have provided proper
19 documentation and followed the public notification process in their federally approved
20 implementation plans.

21 **c. Determination of Program Trigger**

22 (1) The executive secretary will submit an annual emissions report to the WRAP
23 and all participating states and tribes by September 30 of each year. The report will
24 document actual sulfur dioxide emissions during the previous calendar year for all
25 sources subject to the Sulfur Dioxide Milestone Inventory requirements of R307-150.
26 The first report for calendar year 2003 ~~was will be~~ submitted ~~by September 30, in~~ 2004.
27 If the WEB Trading Program is triggered as outlined in paragraph E.1.c(10) of this plan,
28 annual reports will be prepared during the interim period for informational purposes until
29 the trading program is fully implemented. The executive secretary will prepare the
30 supporting documentation that is included with the annual emissions report as noted in
31 (2) and (3) below.

32
33 (2) The annual emissions report for Utah will include a source emissions change
34 report that contains the following information:

35
36 (a) identification of any new sources that were not contained in the previous
37 calendar year's emissions report, and an explanation of why the source is now
38 included in the program;

39
40 (b) identification of any sources that were included in the previous year's report
41 and are no longer included in the program, and an explanation of why this change
42 has occurred; and
43

1 (c) an explanation for increases or decreases of emissions at any applicable source
2 of more than twenty percent from the previous year.

3
4 (3) The annual emissions report for Utah will include the proposed emissions
5 adjustment as described in (a) and (b) to ensure a consistent comparison to the
6 milestones.

7
8 (a) Changes in flow rate measurement methods. The provisions in this subsection
9 (a) will apply only to the 2003-2007 ~~milestone-emissions~~ reports. Actual
10 emission inventories for utilities that use EPA's Reference Method 2F, 2G, or 2H
11 to measure stack flow rate will be adjusted to be comparable with the flow rate
12 assumptions that were used in 1999, the base year inventory for the Annex. The
13 adjustment may be calculated using any of the following three methods.

14
15 (i) Directly determine the difference in flow rate through a side-by-side
16 comparison of data collected with the new and old flow reference methods
17 during a relative accuracy test audit (RATA) test.

18
19 (ii) Compare the annual average heat rate using Acid Rain heat input data
20 (MMBtu) and total generation (MWHrs) as reported to the federal Energy
21 Information Administration. Under this approach, the flow adjustment
22 factor will be calculated using the following ratio:

23
24
$$\frac{\text{Heat input/MW for first full year of data using new flow rate method}}{\text{Heat input/MW for last full year of data using old flow rate method.}}$$

25
26
27 (iii) Compare the standard CFM per MW before and after the new flow
28 reference method based on CEMs data submitted in the Acid Rain
29 Program, as follows:

30
31
$$\frac{\text{SCF/Unit of Generation for first full year of data using new flow rate method}}{\text{SCF/Unit of Generation for last full year of data using old flow rate method.}}$$

32
33
34 (b) Changes in emission monitoring or calculation methods. Actual emission
35 inventories for sources that change the method of monitoring or calculating their
36 emissions will be adjusted to be comparable to the emission monitoring or
37 calculation method that was used in the base year inventory. The base year
38 inventory for the 2003-2007 ~~milestone-emissions~~ reports is 1999 for utilities and
39 1998 for all other sources. The base year inventory for the 2008 and later
40 ~~milestone-emissions~~ reports is 2006 ~~inventory~~ for all sources.

41
42 (4) The annual sulfur dioxide milestone and emissions report for Utah will
43 document any adjustments that should be made to the milestone for the previous year as
44 follows.

45
46 (a) Kennecott Utah Copper (KUC) may submit sulfur input data and SO₂
47 emissions data to the executive secretary to demonstrate that KUC qualifies for

1 the smelter-specific set-aside described in Part E.1.a(2) of this Plan. If actual
2 emissions and sulfur input are greater than the baseline level in Table 9, the
3 executive secretary will determine the milestone adjustment for KUC by
4 determining the increase in the milestone based on the proportional increase in
5 sulfur input over baseline levels. For each smelter, the adjustment will not exceed
6 the smelter-specific set-aside listed in Table 9.

7
8 (b) Changes due to enforcement actions.

9
10 (i) Adjustments due to settlements arising from enforcement actions.
11 Adjustments to the milestones will be made, as specified in subsection (iii)
12 below, if:

13
14 (A) an agreement to settle an action, arising from allegations of a
15 failure of an owner or operator of an emissions unit at a source in
16 the program to comply with applicable regulations which were in
17 effect during the base year, is reached between the parties to the
18 action;

19
20 (B) the alleged failure to comply with applicable regulations
21 affects the assumptions that were used in calculating the source's
22 base year and forecasted sulfur dioxide emissions; and

23
24 (C) the settlement includes or recommends an adjustment to the
25 milestones.

26
27 (ii) Adjustments due to administrative or judicial orders. Adjustments to
28 the milestones will be made as directed by any final administrative or
29 judicial order, as specified in (iii) below. Where the final administrative or
30 judicial order does not include a reforecast of the source's baseline, the
31 executive secretary will evaluate whether a reforecast of the source's
32 baseline emissions is appropriate.

33
34 (iii) Adjustments method and effective dates. The milestone will be
35 decreased by an appropriate amount based on a reforecast of the source's
36 decreased sulfur dioxide emissions. The adjustments will not be made to
37 the milestone until after the source has reduced its sulfur dioxide
38 emissions as required in the settlement agreement, or administrative or
39 judicial order.

40
41 (iv) Documentation of adjustments for enforcement actions. The report
42 will include the following documentation of any adjustment due to an
43 enforcement action or a settlement agreement:

1 (A) identification of each source in Utah that has reduced sulfur
2 dioxide emissions pursuant to a settlement agreement or an
3 administrative or judicial order;

4
5 (B) for each source identified, a statement indicating whether the
6 milestones were adjusted in response to the enforcement action;

7
8 (C) discussion of the rationale for the executive secretary's
9 decision to adjust or not to adjust the milestones; and

10
11 (D) if SO₂ emissions reductions over and above those reductions
12 needed for compliance with the applicable regulations were part of
13 an agreement to settle an action, a statement indicating whether
14 such reductions resulted in any adjustment to the milestones or
15 allowance allocations, and a discussion of the rationale for the
16 executive secretary's decision on any such adjustment.

17
18 (v) The State of Utah will include all accumulated milestone adjustments
19 due to enforcement actions or settlement agreements in the periodic SIP
20 revisions required under 40 CFR 51.309(d)(10).

21
22 (5) Compilation of Reports.

23
24 (a) The WRAP will compile the annual emissions reports submitted by all
25 participating states and tribes into a draft regional emission report for sulfur
26 dioxide. The WRAP will follow additional quality assurance procedures
27 developed by member states and tribes to identify possible errors in the emissions
28 data, including screening for missing or added sources, name changes, and
29 significant changes in reported emissions. Any questions or anomalies regarding
30 Utah's report will be resolved by the executive secretary prior to the submission
31 of the draft regional emission report.

32
33 (b) By December 31 of each year, the WRAP will submit the draft regional
34 emission and milestone report to the executive secretary and all participating
35 states and tribes and will post the report on the WRAP's web page. The report
36 will include the following information:

37
38 (i) actual regional sulfur dioxide emissions in tons per year;

39
40 (ii) adjustments to account for:

41
42 (A) changes in flow rate measurement methods, and

43
44 (B) changes in emission monitoring or calculation methods;

45

1 (iii) average adjusted emissions for the last three years for comparison to
2 the regional milestone, if adjustments were made;

3
4 (iv) regional milestone adjustments to account for the smelter-specific set-
5 aside; and

6
7 (v) regional milestone adjustments due to enforcement actions or
8 settlement agreements.
9

10 (6) The executive secretary will evaluate the draft regional emissions report and
11 will propose a draft determination that the sulfur dioxide milestone has either been met in
12 the region, or has been exceeded. In the event that the WRAP has not submitted a draft
13 regional emissions and milestone report to the executive secretary by the December 31
14 deadline for any year, the executive secretary will prepare the report for that year based
15 upon the annual emissions reports submitted by all participating states and tribes to the
16 WRAP for that year. The executive secretary will modify the data in these annual
17 emissions reports, or use data where such report(s) have not been submitted, based upon
18 direction received from the Environmental Protection Agency.
19

20 (7) The executive secretary will advertise availability of the draft regional
21 emissions report and will notify the public of the draft determination by publishing a
22 notice in newspapers of general circulation throughout Utah. A 30-day public comment
23 period will be established, and a public hearing will be held during the public comment
24 period. The executive secretary will also submit the draft determination to EPA for
25 review and comment concurrently.
26

27 (8) The executive secretary will consider any comments received during the
28 comment period, and will submit a copy of all comments to the WRAP and to all
29 participating states and tribes along with a response that addresses the comments.
30

31 (9) The WRAP will compile the comments and responses from all participating
32 states and tribes and prepare a draft final regional emissions report. The report will be
33 submitted to the states and tribes that are participating in the program and, if necessary,
34 the report will propose a common program trigger date.
35

36 (10) The executive secretary will review and approve the final regional emissions
37 report. The executive secretary will then submit this report to the Environmental
38 Protection Agency along with a final determination that the milestone either has been met
39 in the region, or that the milestone has been exceeded and the WEB Trading Program has
40 been triggered in Utah. This determination will be submitted to the Environmental
41 Protection Agency by the end of March, fifteen months following the milestone year. The
42 first determination ~~will be was~~ submitted ~~by March 31, in~~ 2005, for the 2003 milestone. If
43 the milestone has been exceeded, the common trigger date proposed in the regional report
44 will become the program trigger date for purposes of implementing the WEB Trading
45 Program. In the event that the program trigger date must be established by the executive

1 secretary in the absence of a regional emissions and milestone report prepared by the
2 WRAP, the program trigger date will be March 31 of the applicable year.

3
4 (11) The executive secretary will publish a notice of the final determination in
5 newspapers of general circulation throughout the state of Utah. This notice will include
6 the milestone and the final annual regional SO₂ emissions for that year. If the milestone
7 has been exceeded, the notice will specify the program trigger date and the first year that
8 WEB sources must be in compliance with the WEB Trading Program provisions as
9 outlined in R307-250-12.

10 **d. Year 2013 Assessment**

11 (1) *Initial Assessment in 2013 Periodic SIP Review.*

12
13 (a) The executive secretary will work cooperatively through the WRAP with
14 other participating states and tribes to develop a projected emission inventory for
15 SO₂ through the year 2018, using the 2010 regional inventory as a baseline. This
16 projected inventory will be included in the 2010 annual emission and milestone
17 report that will be completed in March 2012 as outlined in paragraph E.1.c of this
18 plan.

19
20 (b) The executive secretary will evaluate the projected inventory, and based upon
21 this information will make an assessment of the likelihood of meeting the regional
22 milestone for the year 2018. The executive secretary will include this assessment
23 as part of Utah's progress report that must be submitted by December 31, 2013, as
24 required by 40 CFR 51.309(d)(10).

25 26 (2) *Regional Emissions Report for 2012.*

27
28 (a) The executive secretary will prepare an SO₂ emission report for the year 2012
29 by September 30, 2013, as described in paragraph E.1.c(1) of this plan. The
30 executive secretary will include a list of all known or anticipated sources in Utah
31 that are anticipated to affect total SO₂ emissions in 2018. This may include
32 permitted sources, projects that are still in the planning stage, or projections from
33 the affected sources of anticipated emissions in 2018. The status of these projects
34 will be described to provide a better understanding of the degree of certainty that
35 individual projects will be completed by 2018.

36
37 (b) The WRAP will compile the information from all participating states and
38 tribes, prepare draft SO₂ inventory projections for the year 2018, and estimate the
39 effect of known future sources on SO₂ emissions. Projected 2018 emissions will
40 be compared to the 2018 milestone. This information will be included in the draft
41 regional emissions report for 2012 that will be submitted to the executive
42 secretary by December 31, 2013, as outlined in paragraph E.1.c(5) of this Plan.
43 The draft report will be published on the WRAP web site for a period of public
44 review and comment for not less than 30 days.

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(3) Consensus Decision.

The executive secretary commits to meet with the participating states and tribes in March 2014 to discuss any comments received on the 2018 emission projections in the draft report. The participating states and tribes will decide, through a consensus process, whether it is necessary to trigger the WEB trading program early in order to meet the SO₂ emission reduction goals in 2018.

(4) Early Trigger: Timing.

If the participating states and tribes unanimously decide in the March 2014 meeting that an early trigger of the backstop trading program is necessary, the executive secretary will trigger the WEB Trading Program and the timing of the program elements will be adjusted as follows to ensure that the WEB Trading Program is in place in 2018.

(a) The date of the consensus decision by the participating states and tribes to voluntarily trigger the WEB trading program will become the program trigger date.

(b) Allowances for 2018 will be distributed to WEB sources by January 1, 2015.

(c) The first control period will be the year 2018. WEB sources will need to demonstrate at the end of the first control period that they have enough allowances to cover their 2018 SO₂ emissions.

(5) Public Notification.

The executive secretary will publish notice of the decision in newspapers of general circulation in Utah. If applicable, the notice will include a statement that the WEB Trading Program is in effect and will specify the program trigger date.

e. Special Penalty Provisions for the 2018 Milestone

If the WEB Trading Program is triggered as outlined in paragraph E.1.c of this Plan, and the first control period will not occur until after the year 2018, a special penalty will be assessed if the 2018 milestone is exceeded.

Details of the penalty provisions for violation of the 2018 milestone can be found in R307-250-13. In general, the penalty involves an assessment of the minimum \$5,000 per ton of SO₂ emissions in excess of the WEB source’s allowance limitation. The source can resolve its excess emissions violation by agreeing to the streamlined settlement approach outlined in R307-250-13.

The amount of the minimum monetary penalty in R307-250-13 will be evaluated at each five-year SIP review, and adjusted if needed, to ensure that the penalty per ton substantially exceeds the expected cost of allowances to ensure that this remains a stringent penalty.

1 The 2018 special penalty provision will continue to be applied each year after 2018 until
2 the 2018 milestone has been achieved.

3 **2. Pre-Trigger Emissions Tracking Requirements**

4 **a. SO₂ Emission Inventory**

5 40 CFR 51.309 sets forth emissions inventory requirements for tracking compliance with
6 the SO₂ milestones. R307-150 has been revised to supplement Utah's inventory
7 requirements to satisfy the needs of this program.

8
9 (1) *Applicability.* The sulfur dioxide milestone inventory requirements of R307-
10 150 require all stationary sources with actual emissions of 100 tons per year or more of
11 SO₂ in the year 2000, or in any subsequent year, to submit an annual inventory of SO₂
12 emissions, beginning with the 2003 emission inventory. A source that meets these criteria
13 and then emits less than 100 tons per year in a later year must continue to submit an SO₂
14 inventory for tracking compliance with the regional SO₂ milestones until 2018 or until
15 the WEB Trading Program has been fully implemented and emission tracking is
16 occurring under R307-250-9, whichever is earlier.

17
18 (2) R307-150 contains enforceable requirements for WEB sources.

19
20 (a) Each source will submit an annual inventory of SO₂ emissions.

21
22 (b) Each source will use appropriate emission factors and estimating techniques
23 and document the emissions monitoring or estimation methodology used.

24
25 (c) Each source will include emissions from start up, shut down, and upset
26 conditions in the annual total inventory.

27
28 (d) Each source subject to the federal acid rain program will use methods from 40
29 CFR Part 75 to report emissions from all sources.

30
31 (e) Each source will include the rate and period of emissions, the specific
32 installation that is the source of the air pollution, composition of air contaminant,
33 type and efficiency of the air pollution control equipment and other information
34 necessary to quantify operation and emissions, and to evaluate pollution control.

35
36 (f) Each source will retain records for a minimum of 10 years from the date of
37 their creation, or if the record was the basis for an adjustment to a milestone, 5
38 years from the date of an implementation plan revision, whichever is longer.

39
40 (3) The executive secretary will quality-assure the submitted inventory data as
41 outlined in the Inventory Preparation Plan. The executive secretary will screen the
42 inventories to identify changes in emission measurement techniques that would require
43 an inventory and milestone adjustment as outlined in paragraph E.1.c(3) of this Plan.

1
2 (4) The executive secretary will retain historical emission inventory records for
3 non-utilities from 2006 that may affect milestone calculations under paragraph E.1.c(3)
4 and allocation decisions under paragraph E.3.a of this plan until the year 2018 to ensure
5 that changes in emissions monitoring techniques can be tracked.

6 **b. Development of Emission Tracking System**

7 The executive secretary will work cooperatively with the WRAP to ensure that an
8 emission tracking system for the regional SO₂ inventory is developed and maintained.

9 **c. Periodic Audit of Pre-Trigger Emission Tracking** 10 **Database**

11 (1) During the pre-trigger phase when the executive secretary is tracking
12 compliance with the regional SO₂ milestones, the executive secretary will work
13 cooperatively with the participating states and tribes to ensure that an independent audit
14 of the tracking database is conducted to make sure that the WRAP is accurately
15 compiling the regional emissions report.

16
17 (a) The first audit will occur during the year 2006 and will review data collected
18 during the first two years of the program.

19
20 (b) Subsequent audits will occur in 2011, which will cover emissions years 2005-
21 2009, and 2016, which will cover emissions years 2010-2014.

22
23 (2) The primary focus of the audit will be the process that is used to compile the
24 regional inventory from the data provided by each state and tribe, and the tracking of
25 accumulated changes during the period between SIP revisions. The audit will also review
26 the accuracy and integrity of the regional reports that are used to determine compliance
27 with the milestones. The audit will not be a full review of Utah's process for compiling
28 and reporting SO₂ emissions, but will include a broad review of Utah's inventory
29 management and quality assurance systems, including the presence and exercise of
30 systems to assure data quality and integrity.

31
32 (3) The audit will discuss the uncertainty of emissions calculations, and whether
33 this uncertainty is likely to affect the annual determination of whether the milestone is
34 exceeded. It will identify any recommended changes to emissions monitoring or
35 calculation methods or data quality assurance systems. It will also review and
36 recommend any changes to improve the administrative process of collecting the annual
37 emissions data at the state and tribal level, compiling a regional emission inventory, and
38 making the annual determination of whether the WEB Trading Program has been
39 triggered.

40
41 (4) Changes to the SO₂ Milestones and Backstop Trading Program, including any
42 changes to the milestones due to the results of these periodic audits, will be submitted to

1 EPA as a SIP revision as part of the five-year SIP review required by 40 CFR
2 51.309(d)(10).

3
4 (5) The executive secretary will advertise the availability of the draft audit report
5 by publishing a notice in newspapers of general circulation in Utah. A 30-day public
6 comment period will be established, and a hearing will be held during the public
7 comment period. The executive secretary will respond to comments and provide notice of
8 the availability of the final audit report. The executive secretary will submit the final
9 audit report to the EPA regional office.

10 **3. WEB Trading Program Requirements**

11 **a. Initial Allocation of SO₂ Allowances**

12 (1) *Draft Allocation Report.*

13
14 Within six months of the program trigger date, as outlined in paragraph E.1.c(11) of this
15 plan, the executive secretary will submit a draft allocation report to all participating states
16 and tribes and to the TSA. This report will contain the following information:

17
18 (a) A list of all WEB sources in Utah as defined in R307-250-2 that groups the
19 sources into two categories:

20
21 (i) Category 1: WEB sources that commenced operation prior to January
22 1, 2008. These sources will receive a floor allocation and will be eligible
23 for the reducible portion of the allocation.

24
25 (ii) Category 2: WEB sources that commenced operation on January 1,
26 2008 or a later date. These sources will receive a floor allocation, but will
27 not be eligible for the reducible allocation. The floor allocation for
28 Category 2 sources will be deducted from the new source set-aside.

29
30 WEB sources that have received a retired source exemption under R307-250-4(4)
31 will be included in the allocation process in the same manner as WEB sources
32 that are currently operating. However, sources that were permanently shut down
33 prior to the program trigger date are not considered WEB sources under R307-
34 250-4(1) and would therefore not be included in the allocation process.

35
36 (b) The floor allocation for all WEB sources in Utah.

37
38 (i) For non-utility category 1 WEB sources, the floor allocation will be as
39 established in the E.H. Pechan Report, “Market Trading Forum Non-
40 Utility Sector Allocation Final Report from the Allocations Working
41 Group” (November 2002). If any additional category 1 sources are
42 identified, the executive secretary will calculate a floor allocation using
43 the methodology outlined in the E.H. Pechan Report.

1
2 (ii) For utility category 1 WEB sources, the floor will be calculated by
3 first assigning a “clean unit” emission rate to each unit. The clean unit
4 emission rate will then be multiplied by an annual heat input (MMBtu)
5 that represents a realistic upper bound for the unit.
6

7 (Note: The floor level approach described above is designed to address
8 equity issues regarding the allocation process for utilities. The State of
9 Utah is participating in ongoing discussions with the other participating
10 states, tribes and regional stakeholders to ensure that all equity issues have
11 been addressed. The State of Utah will work with the other participating
12 states and tribes to ensure that the floor allocation is calculated in a
13 consistent manner for all participants. As outlined further in this
14 allocation methodology, the floor for both utilities and non-utilities is
15 limited by the utility/non-utility split in Table 10. The floor allocation
16 methodology will ensure that credits are available for early reductions and
17 renewable energy allocations. In addition, the regional number of
18 allowances allocated for each year cannot exceed the milestone for that
19 year under any circumstances.)
20

21 **Principles**

- 22
- 23 • Each unit will have enough allowances to operate as a clean source and at
24 an operating rate (capacity factor) that is a realistic upper bound for the
25 unit.
26
- 27 • There will not be significant winners and losers in this process.
28
- 29 • The focus is on a fair approach that is applied equally to all sources rather
30 than on state and tribal budgets.
31
- 32 • The allocation process will use data that reflect current conditions,
33 including current monitoring methodologies.
34

35 **Equity Issues**

- 36
- 37 • Sources that are currently burning very low sulfur coal may see changes in
38 their supply in the future. Historic actual emissions may not reflect future
39 operations.
40
- 41 • Sources that are currently operating at a low utilization may not reach full
42 capacity in the future. Assumptions about growth that are realistic on the
43 regional level may provide a windfall to some sources, and not provide
44 adequate allowances for other sources.
45

- 1 • There are some utility units in the region that are not BART-eligible and
- 2 are operating at a low level of control for SO₂. The relative responsibility
- 3 of BART-eligible vs. non-BART-eligible is a consideration in the process.
- 4
- 5 • Sources that are operating at a high level of control are already bearing the
- 6 cost of control and this affects their ability to compete in the market.
- 7
- 8 • Sources that have no SO₂ controls are facing a large expense that could
- 9 affect their ability to continue to operate.
- 10
- 11 • Emission rate disparities exist throughout the region.
- 12

13 (iii) For Category 2 WEB sources the floor allocation will be the lower of

14 the permitted SO₂ annual emissions for the WEB source, or SO₂ annual

15 emissions calculated based on a level of control equivalent to BACT and

16 assuming 100% utilization of the WEB source.

17

18 (c) A list of certified early reductions, expressed as tons of SO₂. Early reductions

19 will be calculated and certified as follows:

20

21 (i) Any WEB source that installs control technology and accepts new

22 permit emissions limits that are, for a non-utility source, below its floor as

23 established in this section, or, for a utility source, below BACT, may

24 apply for an early reduction ~~bonus allocation~~ ~~credit~~ as outlined in R307-

25 250-7(5). The ~~credit~~ ~~bonus allocation~~ will be available for reductions that

26 occur between 2008 and the program trigger year. The application must

27 show that the floor was calculated in a manner that is consistent with the

28 monitoring requirements of R307-250-9(1)(a) and the new permit must

29 contain monitoring requirements that are consistent with R307-250-

30 9(1)(a). Emission units that are monitored using the less stringent

31 monitoring requirements of R307-250-9(1)(b) are not eligible for early

32 reduction ~~bonus allocations~~ ~~credits~~. The ~~credits~~ ~~bonus allocations~~

33 accumulate from the time the new controls come on line until the program

34 trigger date and will be allocated to the WEB source over a 10 year

35 period. The use of early reduction ~~bonus allocations~~ ~~credits~~ in any control

36 period is limited to no more than five percent, systemwide, of the existing

37 available allowances, as provided in paragraph E.3.a(2)(e) of this plan.

38

39 (ii) The executive secretary will review the application and will certify

40 early reductions for each full year between 2008 and the program trigger

41 year that meet the requirements of R307-250-7(5) and this plan.

42

43 (iii) A source's certified early reductions for all years will be added

44 together to obtain the total certified early reductions for that source.

45

1 (d) A list of all renewable energy plants and sources in Utah that began operation
2 after January 1, 2008, and the MW of installed nameplate capacity for each of
3 these resources. Renewable energy credits will be granted at a rate of 2.5 tons per
4 MW, and will accumulate from the beginning of the facility's operation. Their
5 use in any control period is limited to no more than five percent, systemwide, of
6 the existing available allowances, as provided in paragraph E.3.a(2)(f) of this
7 plan.

8
9 (e) Historical SO₂ emissions data for all Category 1 sources for the purposes of
10 calculating the reducible allocation.

11
12 (i) For utilities, annual SO₂ emissions for the year 2006. Another time
13 period may be used for individual emission units, if needed, to be
14 representative of normal operating conditions.

15
16 (ii) For non-utilities, the annual SO₂ emissions for the year 2006.

17
18 (f) Changes due to settlements arising from enforcement actions or due to
19 administrative or judicial orders~~or settlement agreements as a result of~~
20 enforcement actions. The adjustment will be determined in accordance with
21 paragraph E.1.c.(4)(b)(3)(c) of this Implementation Plan. The difference between
22 the WEB source's allocations prior to enforcement and after the enforcement
23 action will be removed from the allocation pool.

24
25 (2) *Compiled Allocation Report.*

26
27 The TSA will compile the information provided by all participating states and tribes into
28 a draft regional allocation report, and will submit this draft regional report to the
29 executive secretary and all participating states and tribes for review and comment thirty
30 days after receiving the preliminary allocation reports. The draft regional allocation
31 report will include a proposed budget for each state and tribe and the proposed allocation
32 for each WEB source in Utah.

33
34 The State of Utah will work closely with the other participating states and tribes to ensure
35 that the regional allocation is distributed consistently and fairly and to address any
36 change in status that may affect this process.

37 The following methodology distributes the allowances available under the milestone in
38 the following order: tribal set-aside, new source set-aside, floor, early reduction credit,
39 renewable energy credit, reducible allocation. The allocation process is limited by the
40 number of allowances available under the milestone. It is not possible under this
41 methodology to distribute more allowances that are available under the milestone. The
42 State of Utah expects that there will be allowances available for all of the categories
43 listed above. However, if at any time in the process there are not enough allowances
44 available to fully cover a particular category, then the sources eligible for that category
45 will receive a pro-rated allowance, and the process will stop. For example, if the
46 renewable energy allocation is greater than the remaining available allowances under the

1 milestone, then each of the renewable energy sources would receive a reduced renewable
 2 energy allocation, and there would be no reducible allocation.

3
 4 (a) Table 10 shows the major categories that will be used to allocate allowances
 5 under the milestone. The methodology to calculate the available allocation for
 6 existing sources is described below. The milestone for the 4-state region is the
 7 starting point.

8
 9 NOTE: If the milestone for a particular year is adjusted due to the smelter-
 10 specific set-aside provisions in paragraph E.1.a(2) of this plan, the milestone
 11 adjustment calculated in paragraph E.1.a(2) of this Plan will be allocated to that
 12 smelter, and will be in addition to the allocations determined from the base
 13 milestone as outlined in this subsection. References to the non-utility allocation
 14 throughout the remainder of Part E will not include the potential allocation due to
 15 the smelter-specific set-aside.

16
 17 **Table 10. Utility/Non-utility Split**

	Milestone from Table 2	Tribal Set-Aside	New Source Set-aside	Remaining Allocation	Utility Portion	Non-utility portion
2008	378,398,365,06 4 tons	8,500 tons	17,000 tons	352,898,339,56 4 tons	276,263,262,92 9 tons	76,635 tons
2009	336,160,329,49 3 tons	8,500 tons	17,000 tons	310,660,303,99 3 tons	234,025,227,35 8 tons	76,635 tons
2010	293,921 tons	8,500 tons	17,000 tons	268,421 tons	191,786 tons	76,635 tons
2011	293,921 tons	8,500 tons	17,000 tons	268,421 tons	191,786 tons	76,635 tons
2012	293,921 tons	8,500 tons	17,000 tons	268,421 tons	191,786 tons	76,635 tons
2013	278,985 tons	8,500 tons	34,000 tons	236,485 tons	159,850 tons	76,635 tons
2014	264,050 tons	8,500 tons	34,000 tons	221,550 tons	144,915 tons	76,635 tons
2015	249,114 tons	8,500 tons	34,000 tons	206,614 tons	129,979 tons	76,635 tons
2016	249,114 tons	8,500 tons	34,000 tons	206,614 tons	129,979 tons	76,635 tons
2017	249,114 tons	8,500 tons	34,000 tons	206,614 tons	129,979 tons	76,635 tons
2018	234,624 tons	8,500 tons	34,000 tons	192,124 tons	116,189 tons	75,935 tons

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 20
 21
 22 (b) Subtract the floor allocation for all WEB sources in the region that
 23 were identified as Category 2 from the new source set-aside to determine

1 the available allocation for new sources that begin operation after the
2 program trigger date.

3
4 This allocation methodology treats all Category 2 sources as existing
5 sources because these sources will be operating on the program trigger
6 date. However, the allowances for all Category 2 sources are actually
7 drawn from the new source set-aside. If new source growth exceeds the
8 projections used to develop this plan, it is possible that the above
9 calculation will result in a negative number. Therefore, to address this
10 problem, Category 2 sources will be ranked based on the date the permit is
11 issued for each source. Sources will then be removed from the list of
12 Category 2 sources, starting with the most recent permit, until the new
13 source set-aside is no longer depleted. The last source on the list will
14 receive a partial allocation. The sources that were removed from the list
15 will be considered new sources as described in Part E.3.c of this plan.
16 These sources will need to purchase allowances to cover their emissions
17 because the new source set-aside for sources that begin operation after the
18 program trigger date would be calculated as zero until it is replenished in
19 the next 5-year period. The allocation process for these new sources is
20 described in Part E.3.c of this plan.

21
22
23 **Example calculation of the new source set-aside.**

24 The example uses the following assumptions:

- 25 • Emissions exceed the milestones based on an average of the years 2004-2006.
- 26 • The program trigger date is March 31, 2008.
- 27 • The first 5 years of the program are 2012-2016.
- 28 • New sources that commenced operation between January 1, 2008 and the
29 program trigger date have a total floor allocation of 600 tons.

30

	2012	2013	2014	2015	2016
Maximum Possible Set-Aside	17,000	34,000	34,000	34,000	34,000
Floor for Category 2 Sources	-600	-600	-600	-600	-600
Remaining New Source Set-aside	16,400	33,400	33,400	33,400	33,400

31
32
33 (c) The remaining allocation shown in Table 11 is available for distribution to
34 category 1 sources. The final two columns in Table 11 split this remaining
35 allocation into a utility allocation and a non-utility allocation.

36
37 (d) Subtract the floor allocations for all category 1 utility and non-utility sources
38 in the region from the utility allocation or the non-utility allocation.

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In the unlikely event that the total floor allocation for either utility or non-utility sources submitted by the participating states and tribes exceeds the total allocation available for that category, the TSA will notify the participating states and tribes of the discrepancy. The State of Utah commits to work with the participating states and tribes through a consensus process to ensure that the floor allocation has been calculated in a consistent manner for all participants and to ensure that the floor allocation does not exceed the total allocation available for that category. The total number of allowances distributed can not exceed the milestone for any given year.

(e) Calculate the early reduction bonus allocation.

(i) Divide the number of certified early reductions ~~s-credits~~ for all WEB sources in the region by ten.

(ii) Add the utility allocation for 2018 to the non-utility allocation for 2018 and then multiply this total by 0.05.

(iii) If the product of paragraph (i) is no more than the product of paragraph (ii), the product of paragraph (i) is the early reduction bonus allocation, and each source is allocated ten percent of its early reduction ~~credits~~bonus allocation.

(iv) If the product of paragraph (i) is more than the product of paragraph (ii), the early reduction bonus allocation for the region is the product of paragraph (ii). To determine a source's allocation, divide the product of paragraph (ii) by 0.10 times the total number of early reduction ~~credits~~bonus allocations and apply that ratio to the certified early reduction ~~s credits-claimed by~~for the source.

(v) Split the regional early reduction bonus allocation based on the ratio of utility to non-utility allocations in 2018 and subtract the early reduction bonus allocation from the utility and non-utility allocation totals.

(vi) The early reduction bonus allocation will be calculated in a similar manner for the second five-year allocation period under this program, and will then be discontinued for any future allocation periods.

(f) Calculate the regional renewable energy allocation.

(i) Add together the reported MW of installed nameplate capacity for renewable energy facilities reported by the participating states and tribes, and then multiply this number by 2.5.

1 (ii) Add the utility allocation for 2018 to the non-utility allocation for
2 2018 and then multiply this total by 0.05.

3
4 (iii) If the product of paragraph (i) is no more than the product of
5 paragraph (ii), the product of paragraph (i) is the renewable energy
6 allocation.

7
8 (iv) If the product of paragraph (i) is greater than or equal to the product
9 of paragraph (ii), the renewable energy allocation for the region is the
10 product of paragraph (ii). To determine a source's allocation, divide the
11 product of paragraph (ii) by the total number of renewable energy credits
12 and apply that ratio to the early reduction credits claimed by the source.

13
14 (v) Split the regional renewable energy allocation based on the ratio of
15 utility to non-utility allocations in 2018 and subtract the renewable energy
16 allocation from the utility and non-utility allocation totals.

17
18 (g) Any remaining allowances in the utility allocation or the non-utility allocation
19 after subtraction of the early reduction allocation and the renewable energy
20 allocation is considered the reducible allocation and will be assigned to Category
21 1 sources.

22
23 (i) For non-utility sources, add together the historic SO₂ emissions in
24 accordance with paragraph E.3.a(1)(e) of this plan for all Category 1 non-
25 utility sources in the region to determine an historic emission total.
26 Determine a percent contribution of SO₂ emissions for each WEB source
27 to the historic emission total. Multiply the non-utility reducible allocation
28 by the percent contribution for each WEB source to determine a reducible
29 allocation for each WEB source.

30
31 (ii) For utility sources, the reducible allocation will be distributed to
32 sources that emitted above their floor in the baseline period (~~2000~~
33 ~~through~~2006) based on their percentage of total floor emissions for
34 sources emitting above the floor times the number of reducible allowances
35 available for the first five years of the WEB Trading Program. The
36 number of allowances for any source receiving a reducible allocation will
37 not exceed a recent historic emission rate times a heat input that represents
38 a realistic upper bound for the unit.

39
40 [Note: The approach for distributing the reducible utility allocation described
41 above is designed to address equity issues regarding the allocation process for
42 utilities. The State of Utah is participating in ongoing discussions with the other
43 participating states, tribes and regional stakeholders to ensure that all equity
44 issues have been addressed. The principles and equity issues that are under
45 discussion are listed in paragraph E.3.a.(1)(b)(ii) of this plan.]
46

1 (h) Add together the floor allocation, early reduction allocation, renewable energy
2 resource allocation, and reducible allocation for each WEB source and each
3 renewable energy source to determine the proposed allocations for the first five
4 years of the WEB Trading Program.

5
6 (i) Add together the proposed allocations for all of the WEB sources in the
7 jurisdiction of each participating state and tribe to determine a draft SO₂
8 allowance budget for each state and tribe.

9
10 (3) *Public Comment Period.*

11 The executive secretary will publish notice of availability of the draft regional allocation
12 report in newspapers of general circulation throughout Utah. A 30-day public comment
13 period will be established, and a hearing will be held during the comment period. The
14 executive secretary will consider the comments, and will revise the draft report as needed
15 if the recommended changes are consistent with the allocation process outlined in this
16 plan. The executive secretary will prepare a written response that explains why each
17 comment has either been accepted or has been determined to be inconsistent with the
18 allocation process outlined in this plan.

19
20 (4) *Proposed Changes Submitted to Tracking System Administrator.*

21 The executive secretary will submit a copy of all comments received, the response to
22 those comments, and any proposed changes to the budget and source allocations to the
23 TSA within sixty days of receipt of the draft regional allocation report.

24
25 (5) *Compilation of Changes.*

26 The TSA will compile the comments, responses, and proposed changes to the report and
27 will submit a final draft regional allocation report that is consistent with the allocation
28 methodology outlined in this plan to the executive secretary within 90 days of the receipt
29 of the draft regional allocation report.

30 *Final Regional Allocation Report.*

31 The executive secretary will review the final regional allocation report and will determine
32 the budget for Utah and allocations for WEB sources within Utah in accordance with the
33 allocation methodology outlined in this plan within thirty days of receipt of the final draft
34 allocation report. The executive secretary will submit the budget and allocations for all
35 WEB sources in Utah to EPA, and will notify the TSA that the WEB source allocations
36 should be recorded in the allowance tracking system.

37
38 (6) *Notification.*

39 The executive secretary will notify all WEB sources within Utah of the number of
40 allowances that have been recorded in their compliance account. The notice will include
41 a warning to the WEB sources that reported annual sulfur dioxide emissions may change
42 due to the implementation of new monitoring methods as required by R307-250-9.
43 Allocations for the first five years of the program will not be adjusted to account for
44 changes due to the new monitoring method. However, allocations during the next five-
45 year distribution will be adjusted as needed to account for paper changes in emissions
46 due to changes in monitoring methodology.

1 **b. Distribution of Allowances for Future Control Periods**

2 By December 1 of the year five years after the initial allocation, the executive secretary
3 will follow the process outlined in paragraph E.3.a of this plan to distribute allowances
4 for the next five-year period. This process will continue every five years until allowances
5 have been allocated through the year 2018.

6 **c. Distribution of the New Source Allocation**

7 (1) The new source set-aside will be available for two categories of sources.
8

9 (a) A new WEB source is eligible to receive an annual floor allocation equal to
10 the lower of the annual sulfur dioxide limit in the source’s approval order, or
11 sulfur dioxide annual emissions calculated based on a level of control equivalent
12 to BACT and assuming 100% utilization of the WEB source, beginning with the
13 first full calendar year of operation and in accordance with the provisions of
14 R307-250-7(6).
15

16 (b) An existing WEB source that has increased production capacity after
17 obtaining a new approval order issued under R307-401 is eligible to receive an
18 allocation from the new source set-aside equal to:

19 (i) the permitted annual sulfur dioxide emission limit for a new unit; or
20

21 (ii) the permitted annual SO₂ emission increase for the WEB source due to
22 the replacement of an existing unit with a new unit or the modification of
23 an existing unit that increased the production capacity of the WEB source.
24

25
26 Permitted emission increases due to fuel switching or other process changes that
27 are not directly related to increased production capacity are not eligible for
28 allocations from the new source set-aside. The allocation from the new source
29 set-aside in the first year of operation will be adjusted to account for the number
30 of days that the source is operating in that first year.
31

32 **EXAMPLE.** A new unit with a nameplate capacity of 400 MW is constructed at a power
33 plant with two existing units with nameplate capacities of 400 MW and 300 MW. The
34 two existing units install SO₂ controls and reduce emissions to meet PSD requirements
35 for the construction of the new unit. In this example, the source would continue to
36 receive a floor and a reducible allocation for each of the existing units, and would also be
37 eligible to receive an allocation from the new source set-aside for the new unit. Even
38 though total SO₂ emissions will decrease at this plant due to the construction of the new
39 unit, the allowances allocated to the source will increase to reflect the increase in
40 production capacity of 400 MW of electricity. If the new unit comes on line on July 1 the
41 allocation for the first year will be reduced by 50 percent because the unit was
42 operational for half of the year.
43

1 (2) Allocations from the new source set-aside will remain constant for the
2 applicable WEB source and will be made on an annual basis by March 31 of each year
3 for the current control period. When the next five-year allocation block is distributed as
4 outlined in paragraph E.3.b of this plan, all sources with an allocation under the new
5 source set-aside will receive a five-year allocation block from the new source set-aside,
6 and will continue to receive this allocation in future five-year allocation blocks.

7
8 (3) Owners or operators of new WEB sources or modified WEB sources that meet
9 the eligibility requirements of (1) may apply for an allocation from the new source set-
10 aside by submitting a written request to the executive secretary as outlined in Subsection
11 R307-250-7(6).

12
13 (4) The executive secretary will review the application for an allocation for
14 accuracy and completeness, and will notify the source of intent to distribute allocations
15 from the regional new source set-aside pending verification that allowances are available
16 in the new source set-aside account. The executive secretary will then forward the request
17 to the TSA.

18
19 (5) The TSA will document the date that the request is received by the TSA.
20 Requests for allocation of allowances from the new source set-aside will be processed in
21 the order received. The TSA will deduct the number of allowances requested from the
22 regional new source set-aside that was established by the participating states and tribes,
23 and will then record an equal number of allowances in the source's compliance account
24 for each remaining year of the five-year period. The TSA will then send written
25 notification to the source and to the executive secretary that the allowances have been
26 recorded in the source's compliance account.

27
28 (6) If there are insufficient allowances remaining in the new source set-aside to
29 fulfill the request, the source must purchase the allowances required to demonstrate
30 compliance. Any eligible WEB source that does not receive an allocation from the new
31 source set-aside because the set-aside was depleted will be first in line to receive an
32 allocation when the new source set-aside is increased in the next five-year period as
33 outlined in Table 710 of this plan. If there is more than one such source, their allocation
34 requests will be processed in the order they were received by the TSA.

35
36 (7) A source that has received a retired source exemption and continues to receive
37 an allocation as a retired WEB source is not eligible to receive an allocation from the new
38 source set-aside.

39 **d. Regional Tribal Set-aside**

40 (1) Each year after the program is triggered for which allowances are allocated,
41 8,500 allowances will exist as a tribal set-aside.

42
43 (2) The tribal caucus of the WRAP has stated its intent to determine the means for
44 distributing the allowances among the tribes within one year after the program trigger

1 date. The executive secretary understands that there will be a process that will meet the
2 tracking and data security requirements of the allowance tracking system by which a tribe
3 will move its set-aside allowances into the trading program for the purposes of trading.
4

5 (3) The executive secretary recognizes that the tribal set-aside allowances are
6 bonus allowances for the tribes and, as such, are separate and additional to any
7 allowances included in a tribal budget or the new source set-aside as outlined in the
8 allocation report that is prepared in accordance with paragraph E.3.a(6) of this plan.

9 **e. Opt-in Sources**

10 The WRAP Market Trading Forum has recommended including provisions in this plan
11 that would allow smaller sources to opt in to the program. Opt-in sources may provide a
12 more cost-effective way to reduce overall regional SO₂ emissions, and therefore may
13 strengthen the market incentives of this program. While the benefits of allowing sources
14 to opt in to the program are important, the program must also provide safeguards to
15 ensure that the integrity of the program is not affected. For example, it would be
16 counterproductive to allow sources that were already planning to shut down to opt in to
17 the program and then sell allowances to an existing source. In this example, regional
18 emissions could slowly creep upward in a manner that is not consistent with the goals of
19 the SO₂ milestones.
20

21 The State of Utah is deferring inclusion of provisions for opt-in sources until a future SIP
22 revision to allow time to thoroughly consider how to provide the flexibility and potential
23 benefits to the market by expanding the program while also ensuring that the SO₂
24 emission reduction goals are maintained.

25 **f. WEB Emissions and Allowance Tracking System (WEB 26 EATS)**

27 The participating states and tribes will provide a centralized system for the tracking of
28 allowances and emissions. The centralized system will be referred to as the WEB
29 Emissions and Allowance Tracking System (WEB EATS or EATS). The WEB EATS
30 must provide that all necessary information regarding emissions, allowances, and
31 transactions is publicly available in a secure, centralized database. The EATS must
32 ensure that each allowance is uniquely identified, allow for frequent updates, and include
33 enforceable procedures for recording data.
34

35 The executive secretary will work cooperatively with other states and tribes participating
36 in the WEB Trading Program to design this system. The executive secretary will be
37 responsible for ensuring that all the EATS provisions are completed as described in this
38 plan.
39

40 The EATS will not exist unless the program is triggered. Prior to the implementation of
41 the WEB Trading Program, a separate emissions tracking database will be employed to
42 track the ongoing emissions of sources emitting SO₂ at amounts equal to or greater than
43 100 tons per year. The emissions tracking database, which was used to track and measure

1 SO₂ emissions against the milestones, will still exist once the WEB Trading Program is
2 triggered; however, it will become incorporated into the SO₂ Emissions and Allowance
3 Tracking System. Both the emissions tracking database and the EATS will be centralized
4 systems and data will be posted in an electronic, Web-based program and available to all
5 persons.

6
7 The participating states and tribes will contract with a common TSA to service and
8 maintain the WEB EATS. It is envisioned that the EATS will require the use of a
9 contracted consultant or database design engineer to create a secure, efficient and
10 transparent tracking system. Because the EATS will be utilized by all states and tribes
11 participating in the program, the design will require a uniform approach and level of
12 security that will satisfy regional needs and concerns as well as meet the electronic, Web-
13 based, access needs and security provisions. Due to the dynamic needs of the
14 marketplace, the EATS will require a database that will reflect the current status of
15 allowances and allowance transactions. The EATS will be operational within one year
16 after the program trigger date.

17
18 Specifications of the WEB EATS such as emissions tracking, the recording of allowance
19 transactions, account management, system integrity and transparency are outlined in the
20 Utah TSD Supplement. The specifications will be used as a guideline for developing the
21 EATS if the program is triggered. However, the overall design will be greatly affected
22 by computer software and hardware changes that will occur between the adoption of this
23 Plan and the program trigger date. The on-going experience gained from other trading
24 programs also may lead to improvements in the design of the system. The specifications
25 and related sections of R307-250 detail how a WEB source will register for the EATS
26 and how the source will, through an account representative, establish accounts, transfer
27 allowances, and track unused allowances from a previous year.

28
29 Neither the executive secretary nor the TSA will adjudicate any dispute between the
30 parties concerning the authorization of any account representative with regard to any
31 representation, action, inaction, or submission of the account representative.

32
33 As an example of how the WEB EATS will generally function, once the WEB Trading
34 Program is triggered, a WEB source will have its allowance allocation determined. At the
35 same time, the WEB source's account representative will register for the EATS under
36 R307-250-6, and a compliance account will be established under R307-250-8. Each
37 allowance will be assigned a serial number. The allowance serial number will be used by
38 the WEB EATS to track allowance allocations, transfers (R307-250-10), and deductions,
39 and to account for any unused allowances from a previous year (R307-250-11). The
40 serial number also will be assigned to each allowance recorded in a general account,
41 which is an account for allowances that are not held to meet program compliance
42 requirements. Furthermore, the EATS will track tribal allowance set-asides and new
43 source allowance set-asides not yet assigned to either a compliance or general account.

44

1 It is important to note that while this plan has provided a design for and an operational
2 understanding of the EATS, the components of the EATS will need to be examined and
3 possibly altered upon each required SIP revision.

4 **g. Allowance Transfers**

5 (1) Allowance transfers are defined as the conveyance from one account to
6 another account (compliance account or general account) of one or more allowances by
7 whatever means, including but not limited to purchase, trade, or gift in accordance with
8 the procedures established in R307-250-10. This includes the transfer of allowances for
9 the purpose of retirement. Once an allowance is retired, it is no longer available for
10 transfer to or from any account. Allowances may be purchased by any person for the
11 purpose of retirement.

12
13 (2) The TSA will have specific recording duties involving transfers. These
14 required procedures will be detailed in the service contract and will include the following
15 activities.

16 (a) Recording of Allowance Transfers.

17
18 (i) Within five business days of receiving an allowance transfer, except
19 when the transfer does not meet the requirements of R307-250-10, the
20 TSA will record an allowance transfer by moving each allowance from the
21 transferor account to the transferee account as specified by the request,
22 provided that the transfer is correctly submitted and that the transferor
23 account includes each allowance identified in the transfer.
24

25
26 (ii) Any allowance transfer that is submitted for recording following the
27 allowance transfer deadline and that includes any allowances allocated for
28 a control period prior to or the same as the control period to which the
29 allowance transfer deadline applies will not be recorded until after
30 completion of the compliance account reconciliation.
31

32 (iii) Where an allowance transfer submitted for allowance transfer
33 recording fails to meet the requirements of R307-250-10, the TSA will not
34 record the transfer.
35

36 (3) Notification of the Recording of Allowance Transfers. The TSA has specific
37 responsibilities involving the notification of the recording of any transferred allowances,
38 including the failure to record any transfer of allowances. Again, these required
39 procedures will be outlined in the service contract, but include the following.
40

41 (a) Within five business days of the recording of an allowance transfer, the TSA
42 will notify the transferor's and transferee's account representatives of both
43 accounts, and make the transfer information publicly available on the Internet.
44

1 (b) Within five business days of receipt of an allowance transfer that fails to meet
2 the requirements of R307-250-10, the TSA will notify the account representatives
3 of both accounts of the decision not to record the transfer, and the reasons for not
4 recording the transfer.

5 **h. Use of Allowances from a Previous Year**

6 (1) *Background.*

7 Unused allowances may be kept for use in future years in accordance with R307-250-11
8 and there are restrictions on the use of the allowances in accordance with R307-250-11.
9 R307-250-11 prohibits the use after the year 2017 of allowances allocated for the years
10 2003 – 2017. This provision ensures that actual emissions will be less than the 2018
11 milestone because only allowances allocated for the year 2018 could be used to show
12 compliance in that year. The provision also maintains flexibility by resetting the baseline
13 to the year 2018 and then allowing sources to once again use extra allowances to show
14 compliance in any future year. This flexibility is important for sources that have variable
15 operations because the source may build up a reserve of unused allowances for use in a
16 high production year.

17
18 The Annex explains the benefits of allowing the WEB source to use unused allowances
19 from previous years, including increased flexibility and early reduction stimulus. The risk
20 in allowing the use of allowances carried from a previous year could be an increase in
21 emissions in later years as the unused allowances are withdrawn for compliance.

22
23 Because the regional haze SIP is based on reasonable progress requirements related to the
24 remedying or prevention of any future visibility impairment, it is important to assure the
25 use of these allowances will not interfere with attainment or maintenance of any
26 reasonable progress goals. The safeguard employed here to mitigate this type of risk is
27 termed, “flow control”, and is described in paragraph (2) below.

28
29 (2) *Flow Control Provisions.*

30
31 (a) At the end of each control period, WEB sources may transfer allowances in
32 and out of their compliance account for a period of 60 days to ensure that the
33 account will contain enough allowances to cover sulfur dioxide emissions during
34 the previous year. At the end of the sixty-day transfer period, allowances will be
35 deducted from the compliance account of each WEB sources in an amount equal
36 to the sulfur dioxide emissions of that source during the control period.

37
38 (b) After the deductions have been completed, the Tracking System Administrator
39 will perform the following calculations and prepare a report according to
40 paragraph E. 3.k(1)(b) of this Plan.

41
42 (i) Determine the total number of allowances remaining in the allowance
43 tracking system that were allocated for the just completed control period
44 and all previous control periods.

1
2 (ii) If the number calculated in (i) exceeds 10 percent of the milestone for
3 the next control period, then the flow control procedures in R307-250-11
4 will be triggered for that next control period. These flow control
5 provisions will discourage the excessive use of allowances that were
6 allocated for an earlier control period without establishing an absolute
7 limit on their use. WEB sources will maintain the option to use allowances
8 allocated for an earlier control period, but will be required to use two
9 allowances for each ton of SO₂ emissions. Flow Control operates as
10 follows.

11
12 (A) The flow control ratio will be calculated by multiplying 0.1
13 times the milestone for the next control period, divided by the total
14 number of unused allowances remaining in the system.

15
16 (B) To calculate the number of prior-year allowances that can be
17 used without restriction by a source for the next control period, the
18 TSA will multiply the prior-year allowances by the flow control
19 ratio. The resulting number of allowances may be used on a one-
20 to-one ratio to show compliance with the source's allowance
21 limitation as outlined in paragraph E.3.j of this Plan.

22
23 (C) The remaining prior-year allowances may be used on a two-to-
24 one ratio to show compliance. Thus, WEB sources will maintain
25 the option to use allowances allocated for an earlier control period,
26 but will be required to use two of those allowances for each ton of
27 SO₂ emissions.

28
29 **Example:** On March 1, 2010 (the compliance transfer deadline for the 2009 control
30 period) the Tracking System Administrator deducts allowances from the compliance
31 account for each WEB source to cover 2009 SO₂ emissions from that source. After
32 completing these deductions, the TSA reports the following information:

33
34

35	Total number of allowances still in the system	=	40,000
36	for the years 2003 – 2009	=	40,000
37	2010 milestone (5-state, no smelter)	=	293,921
38	Percent of milestone	=	13.61 %

39

40 Because the number of allowances not used in previous control periods is greater than
41 10% of the milestone, flow control procedures are triggered. In the annual report required
42 in paragraph E.3.k of this Plan, the TSA will then calculate the flow control ratio for
43 2010:

44
45 $0.1 \times 2010 \text{ Milestone} \div \text{prior year allowances} = \text{flow control ratio}$
46 $0.1 \times 293,921 \div 40,000 = 0.73$

1
2 On March 1, 2011 (the compliance transfer deadline for the 2010 control period) the TSA
3 will apply the 2010 flow control ratio before deducting allowances from each WEB
4 source's compliance account

5
6

7	WEB Source A		
8	2010 Allowances	=	1,000
9	Remaining Prior Year Allowances	=	600
10	2010 Emissions	=	1,580

11 In this example, the TSA would multiply the prior year allowances by 0.73 to determine
12 the number of prior year allowances that could be used without restriction, at a one-to-
13 one ratio. This would equal 438. The remaining prior year allowances would then be used
14 at a 2:1 ratio. 284 allowances would be needed to cover the remaining 142 tons of SO₂
15 emissions. The TSA would therefore deduct a total of 1,722 allowances (1,000 + 438 +
16 284) to cover 1,580 tons of SO₂ emissions.

17
18 **i. Monitoring/Recordkeeping**

19 (1) For WEB sources subject to 40 CFR Part 75, the TSA will use data that has
20 been quality assured and finalized by the EPA. For WEB sources subject to the
21 monitoring protocol in ~~Appendix E~~Appendix B of this Plan, the executive secretary will
22 quality assure and finalize the data in accordance with these provisions for submission to
23 the TSA.

24
25 (2) The executive secretary will verify and submit the data to the emissions
26 tracking database as soon as reasonably feasible after annual emissions are reported by
27 the WEB sources. These timelines will be modified, as necessary, according to the
28 monitoring protocols.

29
30 (3) *Special Reserve Compliance Accounts.* The WEB Trading Program requires
31 most WEB sources to install continuous emission monitoring systems (CEMS) that meet
32 the monitoring, recordkeeping and reporting requirements of 40 CFR Part 75. However,
33 there are some emission units that are not physically able to install CEMS and there are
34 also emission units that do not emit enough sulfur dioxide to justify the expense of
35 installing these systems (see R307-250-9(1)(b)). The WEB Trading Program allows
36 these emission units to continue to use their pre-trigger monitoring methodology, but
37 does not allow the WEB source to transfer any allowances that were allocated to that unit
38 for use by another WEB source. The restriction on transferring these allowances is
39 needed to ensure that an emission reduction of sulfur dioxide and the corresponding
40 increase in sulfur dioxide are equal. The allowances associated with emission units that
41 continue to use their pre-trigger monitoring methodology are placed in a special reserve
42 compliance account, while allowances for other emission units are placed in a regular
43 compliance account. Allowances may not be traded out of a special reserve compliance
44 account, even for use by emission units with CEMS at the same WEB source. However,

1 the WEB source may transfer allowances into the account as needed to demonstrate
2 compliance with the WEB source's allowance limitation.

3
4 R307-250-9(b) allows WEB sources with any of the following emission units to apply to
5 establish a special reserve compliance account:

6
7 (a) any smelting operation where all of the emissions from the operation are not
8 ducted to a stack; or

9
10 (b) any flare, except to the extent such flares are used as a fuel gas combustion
11 device at a petroleum refinery; or

12
13 (c) any other type of unit without add-on sulfur dioxide control equipment, if the
14 unit belongs to one of the following source categories: cement kilns, pulp and
15 paper recovery furnaces, lime kilns, or glass manufacturing.

16
17 The emission units described in (a) and (b) cannot physically be monitored using a CEM.
18 The emission units described in (c) do not typically have add-on controls for sulfur
19 dioxide. These units, described in R307-250-9(1)(b), are expected to operate within their
20 floor-level allocation and therefore will not be affected by the market, unless they make a
21 process change and wish to sell allowances on the market. Other sources that are
22 meeting the more rigorous monitoring requirements of R307-250-9(1)(a) and emit
23 sulfur dioxide above their expected allocation will either need to purchase allowances or
24 install sulfur dioxide controls. Therefore, it is important that all emission units that
25 participate in emission trading have an accurate monitoring methodology that is
26 comparable to other sources in the program to ensure that a ton of reductions is the same
27 regardless of where the reductions originate.

28
29 The executive secretary will review the application to monitor under R307-250-9(1)(b).
30 If the emission units meet the criteria in R307-250-9(1)(b), the executive secretary will
31 determine the portion of the WEB source's allocation that is associated with the emission
32 units that will be monitored under R307-250-9(1)(b) and will require the TSA to record
33 that portion of the WEB source's allocation in the special reserve compliance account.
34 The executive secretary will use the methodology for determining allocations described
35 in paragraph E.3.a of this Plan to determine the portion of the allocation that is associated
36 with the Subsection R307-250-9(1)(b) emission units. The executive secretary will
37 notify the WEB source that the application has either been accepted or rejected, including
38 a notification of the allowances that are to be recorded in the WEB source's regular
39 compliance account and the special reserve compliance account.

40
41 If an emission unit that is monitored under R307-250-9(1)(b) is permanently retired, the
42 TSA will transfer the portion of allowances that were associated with that emission unit
43 from the WEB source's special reserve compliance account to the source's compliance
44 account. These allowances will then be available for use or sale by the WEB source.
45 The allowances will be transferred after the compliance deduction has taken place for the
46 last control period that the unit was in operation.

1 **j. Compliance and Penalties**

2 (1) *Compliance, Excess Emissions, and Penalties.*

3 When a WEB source exceeds its allowance limitation in R307-250-12, the executive
4 secretary will require the TSA to deduct allowances from the following year’s allocation
5 in an amount equal to three times the WEB source’s emissions of SO₂ in excess of its
6 allowance limitation. This deduction will be made from the WEB source’s compliance
7 account after deductions for compliance are made under R307-250-12. If sufficient
8 allowances do not exist in the compliance account for the next control period to cover
9 this amount, the executive secretary will require the TSA to deduct the required number
10 of allowances, regardless of the control period for which they were allocated, whenever
11 the allowances are recorded in the account.

12
13 Sources may also be liable for each day of violation of any other provision of the market
14 trading program.

15 (2) *Smelter Specific Set-aside.*

16 Each year, Kennecott Utah Copper (KUC) may submit data to the executive secretary
17 demonstrating that sulfur input and emissions are greater than the baseline levels listed in
18 Table 59 of this Plan. If the executive secretary determines that the criteria in paragraph
19 E.1.a(3)(d) have been met, the executive secretary will require the TSA to record
20 additional allowances in KUC's compliance account to cover the smelter specific set-
21 aside. The allowances will be recorded prior to the allowance transfer deadline to ensure
22 that KUC may use the additional allowances to demonstrate compliance with its
23 allowance limitation.
24

25 **k. Periodic Evaluation of the Trading Program**

26 (1) *Annual Report.*

27
28 (a) Beginning one year after compliance with the trading program is required, the
29 executive secretary will obtain from the TSA an annual report that contains the
30 following information:

- 31
32 (i) the level of compliance program-wide;
33
34 (ii) a summary of the use and transfer of allowances, both geographically
35 and temporally;
36
37 (iii) a source-by-source accounting of allocations compared to emissions;
38
39 (iv) a report on the use of unused allowances from a previous year, in
40 order to determine whether these emissions have or have not contributed
41 to emissions in excess of the cap; and
42

1 (v) the total number of WEB sources participating in the trading program
2 and any changes to eligible sources, such as retired sources, or sources
3 that emit more than 100 tons of SO₂ after the program trigger date.
4

5 (b) Within 2 months after the allowance transfer deadline for each control period
6 when compliance with the trading program is required, the TSA will prepare a
7 draft report that lists:
8

9 (i) the total number of allowances deducted for the control period,
10

11 (ii) the total number of allowances remaining in the Allowance Tracking
12 System allocated for that control period and any earlier control period,
13

14 (iii) a proposed determination that flow control procedures have either
15 been triggered or have not been triggered for the next control period, and
16

17 (iv) if flow control procedures have been triggered, a draft flow control
18 ratio calculated according to paragraph E.3.h(2) of this Plan.
19

20 (c) The executive secretary will evaluate the draft report, and will propose a
21 determination that flow control procedures either have been triggered or have not
22 been triggered for the next control period.
23

24 (d) The executive secretary will publish a notice of availability of the draft report
25 in newspapers of general circulation in Utah, and will hold a 30-day public
26 comment period.
27

28 (e) After the comment period the executive secretary will make a final
29 determination that the flow control procedures either have been triggered or have
30 not been triggered for the next control period. If the flow control procedures have
31 been triggered, the executive secretary will notify all WEB sources in Utah that
32 flow control procedures will be in effect during the next control period.
33

34 (2) *Five-year Evaluation.*
35

36 (a) The executive secretary will work cooperatively with other participating states
37 and tribes to conduct an audit of the WEB Trading Program no later than three
38 years following the first full year of the trading program, and at least every five
39 years thereafter. This evaluation does not replace the Plan assessments in 2008,
40 2013, and 2018. The evaluation will be conducted by an independent third party
41 and include an analysis of:
42

43 (i) whether the total actual emissions could exceed the values in Table 3 of
44 this Implementation Plan of the WEB Trading Program even though
45 sources comply with their allowances;
46

- 1 (ii) whether the program achieved the overall emission milestone it was
2 intended to reach;
- 3
- 4 (iii) the effectiveness of the compliance, enforcement and penalty
5 provisions;
- 6
- 7 (iv) a discussion of whether states and tribes have enough resources to
8 implement the WEB Trading Program;
- 9
- 10 (v) whether the trading program resulted in any unexpected beneficial
11 effects, or any unintended detrimental effects;
- 12
- 13 (vi) whether the actions taken to reduce sulfur dioxide have led to any
14 unintended increases in other pollutants;
- 15
- 16 (vii) whether there are any changes needed in emissions monitoring and
17 reporting protocols, or in the administrative procedures for program
18 administration and tracking;
- 19
- 20 (viii) the effectiveness of the provisions for interstate trading, and whether
21 there are any procedural changes needed to make the interstate nature of
22 the program more effective; and
- 23
- 24 (ix) the integrity of the emissions and allowance tracking system,
25 including whether the procedures for recording transactions are adequate,
26 whether the procedures are being followed and in a timely manner,
27 whether the information on sources' emissions are accurately recorded,
28 whether the emissions and allowance tracking system has procedures in
29 place to ensure that the transactions are valid, and whether back-up
30 systems are in place to account for problems with loss of data.

31

32 (b) The public will have an opportunity to participate in this trading program
33 evaluation.

34

35 (c) In the event that any audit results in recommendations for program revisions,
36 the State of Utah, in consultation with the WRAP, will make appropriate
37 modifications to this Plan. The State of Utah will revise this Plan if the program is
38 not meeting its emission reduction goals.

39

40 (d) The executive secretary will submit a copy of the report to the EPA regional
41 office.

42 **I. Retired Source Exemption**

43 R307-250-4(4) outlines the procedure that a WEB source must follow to receive a retired
44 source exemption. The exemption would allow the source to continue to receive an

1 allocation, but would exempt the source from monitoring and recordkeeping
2 requirements that would serve no useful function for a source that has ceased operations.
3 The executive secretary will notify the source of its obligation to apply for a retired
4 source exemption upon the cancellation or relinquishment of a permit.

5
6 To receive a retired source exemption, the source must submit a request for the
7 exemption to the executive secretary. The executive secretary will review this request,
8 and within 60 days of receipt of the request will notify the source that the retired source
9 exemption has been granted or has been rejected. If the exemption has been rejected, the
10 notification will contain an explanation of the reasons for rejecting the request.

11
12 The TSA will continue to record an allocation to a WEB source that has received a
13 retired source exemption. However, the allowances will be recorded in a general account
14 rather than a compliance account for the source. The TSA will transfer any existing
15 allowances in the retired source's compliance account or special reserve compliance
16 account into the general account for the retired source, and will close the compliance
17 accounts.

18
19 A WEB source that is permanently retired and that does not request a retired source
20 exemption will forfeit all abandoned allowances in that source's compliance account, as
21 outlined in R307-250-4(4)(e). The forfeited allowances will not be redistributed to other
22 sources, and will be permanently retired from the Allowance Tracking System, as
23 outlined in R307-250-10(3). During the next five-year allowance distribution period the
24 retired source will not receive an allocation, and the allowances that would have been
25 distributed to that source will be added to the new source set-aside.

26 **m. Integration into Permits**

27 It is expected that all WEB sources at least initially will be subject to Utah's Title V
28 permitting requirements. Under R307-415, Utah's delegated Title V permitting program,
29 the pre- and post-trigger requirements of the market trading program fall under the
30 definition of "applicable requirement," and will be incorporated into each source's Title
31 V permit according to the schedules and procedures contained in that rule. R307-250-14
32 requires that any source that for any reason and at any time is not required to have a
33 permit under R307-415 must obtain a New Source Review permit pursuant to R307-401
34 et seq. that incorporates the same requirements by submitting a Notice of Intent within 90
35 days of the program trigger. Both types of permits are enforceable both federally and by
36 citizens pursuant to Utah's SIP.

37 **4. 2013 SIP Revision; Backstop for Beginning of Second** 38 **Planning Period**

39 In addition to the requirements of 40 CFR 51.309(d)(10), the periodic SIP revision due in
40 2013 will include the following information:

- 41
42 a. Source specific allocations for all WEB sources in Utah for the year 2018; and
43

1 b. Either the provisions of a program designed to achieve reasonable progress for
2 stationary sources of SO₂ beyond 2018 or a commitment to submit a SIP
3 revision containing the provisions of such a program no later than December 31,
4 2016. The program will ensure that the requirements of 40 CFR 51.309 are
5 achieved for the first planning period, including requirements that cannot be
6 measured until after 2018, such as the determination of compliance with the 2018
7 milestone.

8
9 This 2013 SIP revision will provide certainty to sources regarding their potential liability
10 under the special penalty provisions for the year 2018 outlined in paragraph E.1e of this
11 Plan. The calculation of these allocations is delayed until 2013 to provide certainty about
12 the number of sources that will qualify as WEB sources at that time; the allocations
13 needed for new sources in the region, and the magnitude of renewable energy
14 development and early reductions that will be included in the allocation process. It is
15 difficult to estimate the impact of these factors in 2003 because circumstances may
16 change during the next 10 years.

17
18 If the 2018 milestone is not met, the starting point for the next planning period will be the
19 2018 milestones, not actual emissions in 2018.

20

1 **F. LONG-TERM STRATEGY FOR MOBILE SOURCES**

2 **1. Regulatory History and Requirements**

3 In its June 1996 Report, the GCVTC recommended EPA move forward on new national
4 vehicle emission and fuel standards to reduce emissions from mobile sources. The
5 GCVTC also recommended other regional and local strategies be considered to manage
6 mobile source emissions. One of the local strategies was to establish emission budgets
7 for those pollutants in urban areas shown to significantly contribute to visibility
8 impairment in any of the 16 GCVTC Class I areas. The budget caps were to be set at the
9 2005 emission levels.

10
11 When EPA finalized the regional haze rule in July 1999, the rule acknowledged the
12 GCVTC recommendations related to national vehicle emission and fuel standards. EPA
13 included a status of planned actions on those recommendations as of July 1999 (Preamble
14 to the regional haze rule, 64 FR 35753). EPA noted these new measures were over and
15 above those included in the regional haze rule for mobile sources that simply required a
16 cap on emissions in significantly contributing urban areas at the 2005 level. EPA also
17 indicated that emission reductions resulting from new standards adopted after the
18 regional haze rule was approved would be creditable toward reasonable progress. EPA
19 also committed to work with the states if new national standards impacted the efficacy of
20 regional or local strategies.

21
22 After the regional haze rule was finalized, EPA established new standards for on-road
23 vehicle emission and fuel standards (65 FR 6698) as well as standards for diesel vehicles
24 and diesel fuel (66 FR 5002). As a result, current mobile source emission projections
25 developed by WRAP for the GCVTC Transport Region indicate overall mobile source
26 emissions will decline continuously from 2003 through the end of the SIP planning
27 period in 2018, which is more than the level of emission reductions that EPA approved to
28 meet reasonable progress by holding mobile source emissions constant from their 2005
29 level. In addition, new standards for off-road vehicles were proposed by EPA on April
30 15, 2003, and are expected to be finalized, which will further reduce overall mobile
31 source emissions.

32
33 At the April 2003 WRAP Board meeting, the WRAP approved a recommendation for
34 EPA to modify the regional haze rule eliminating the current requirements related to
35 mobile source emission significance determination and budgets for urban areas (40 CFR
36 309(d)(5)), and replacing those requirements with a new requirement focused on tracking
37 mobile source emission reductions resulting from national standards to assure reasonable
38 progress. This action was based on the finding that emissions of all pollutants from on-
39 road and off-road mobile sources are expected to decline significantly through 2018
40 except for sulfur dioxide from non-road sources. If EPA adopts new low-sulfur standards
41 for off-road mobile sources then off-road mobile source sulfur dioxide emissions will
42 also decline continuously through 2018. The WRAP Board deliberations did not define

1 criteria for mobile source significance, leaving the determination of significance under
2 the current rule (40 CFR 51.309(d)(5)(ii)) to the states and tribes.

3
4 On July 3, 2003, EPA proposed a direct final rule (68 FR 39842) to amend the mobile
5 sources provision of the Regional Haze Rule consistent with the recommendations of the
6 WRAP. The rule was promulgated on December 22, 2003 (68 FR 71009). The revisions
7 amended 40 CFR 51.309(d)(5)(i) and eliminated the requirements under 40 CFR
8 51.309(d)(5)(ii) and (iii) for setting mobile sources emissions budgets using the lowest
9 projected level as a planning objective and performance indicator for each area. Instead,
10 the new Section 51.309(d)(5)(i) requires statewide inventories to demonstrate a
11 continuous decline in emissions of each pollutant of concern over the planning period.
12 Should mobile source emission not decline as expected, the State of Utah will review
13 control options for mobile sources and determine if additional controls are needed,
14 consistent with the criteria for reasonable progress. If the State of Utah determines that
15 additional controls are needed, Utah will prepare a revision to the implementation plan.

16
17 In addition to the revisions to Section 51.309(d)(5)(i) and the elimination of Sections
18 51.309(d)(5)(ii) and (iii), a backstop provision as outlined by the WRAP was added. The
19 new Section 51.309(d)(5)(i)(B) requires the State of Utah to assess the need for any long-
20 term strategies to address SO₂ from non-road mobile sources by no later than December
21 31, 2008. States may determine if a SIP revision is necessary to address SO₂ from
22 mobile sources by considering whether the emission reductions anticipated or achieved
23 by any Federal standards in place addressing fuel sulfur content for non-road engines are
24 sufficient to meet reasonable progress. The direct final rule also renumbered the
25 requirement to review other GCVTC mobile source strategies from (d)(5)(iv) to
26 (d)(5)(ii).

27 **2. Inventory of Current and Projected Emissions from Mobile** 28 **Sources**

29 **a. Inventory of Current and Projected Emissions from** 30 **Mobile Sources.**

31 Pursuant to 40 CFR 51.309(d)(5)(i)(A), the State of Utah, in collaboration with the
32 WRAP, assembled a comprehensive statewide inventory of mobile source emissions.
33 This emission inventory showed the year with the lowest level of emissions will be at the
34 end of the SIP planning period in 2018 instead of 2005 as anticipated by the GCVTC.
35 The substantial reduction of projected mobile source emissions from 2003 to 2018 is due
36 to the adoption of new on-road vehicle emission and fuel standards by EPA.

37
38 The values shown in Table 11 cannot be used for conformity determinations under 40
39 CFR 51 and 40 CFR 93, Subpart A. Subsection 40 CFR 93.102 states that conformity
40 applies to nonattainment and maintenance areas. The visibility provisions of 40 CFR
41 51.301 - 309 are not health-based standards resulting in nonattainment designations.

1
2

Table 11. Mobile Source Inventory for 2003 and 2018

Utah Emissions by Source Category		Sulfur Dioxide (SO _x)	Nitrogen Oxide (NO _x)	Organic Carbon <2.5 Microns (OC)	Elemental Carbon <2.5 Microns (EC)	Other Fine Mtrls <2.5 Microns (Soils etc) (OFM)	Course Material (Soils, dust) >2.5 & <10 Microns (CM)	Volatile Organic Carbon Gases (VOC)
Mobile Sources- On-Road	1996	1.4	79.6	0.6	0.3	1.4	0.1	63.0
	2018 w/309	0.1	22.2	0.1	0.1	0.3	-	19.7
	% Change	-93%	-72%	-83%	-67%	-79%	-	-69%
Mobile Sources- Non-Road	1996	10.2	52.3	1.2	0.6	2.0	0.2	27.4
	2018 w/309	17.1	38.8	1.0	0.6	1.8	0.2	20.0
	% Change	68%	-26%	-17%	-25%	-10%	0%	-27%
TOTAL MOBILE EMISSIONS IN UTAH	1996	11.6	131.9	1.8	1.1	3.4	0.3	90.4
	2018 w/309	17.2	61.0	1.1	0.7	2.1	0.2	39.7
	% Change	48%	-54%	-39%	-24%	-38%	-33%	-56%

3

b. Program to assure continuous decline in mobile source emissions.

4
5

Pursuant to 40 CFR 51.309(d)(5)(i)(A), the State of Utah commits to monitoring the emissions from mobile sources to assure a continuous decline in emissions as defined in 40 CFR 51.309(b)(6). If Utah determines that a continuous decline in emissions is not being achieved, additional control measures will be reviewed to determine if they are needed to make reasonable progress. If Utah determines such measures are needed, Utah will submit an implementation plan revision to address the identified control measures.

12

c. Backstop provision to address potential increase in non-road emissions in the event Federal standards are not finalized.

13
14
15

Pursuant to 40 CFR 51.309(d)(5)(i)(B), the State of Utah commits to provide for a SIP revision no later than December 31, 2008, containing long-term strategies necessary to reduce emission of SO₂ from non-road mobile sources consistent with the goal of reasonable progress. The need for a SIP revision will be determined by a consideration of the emission reductions achieved or anticipated to be achieved by Federal standards should those standards addressing fuel sulfur content for non-raided engines not be in place.

21

3. Other GCVTC Strategies for Mobile Sources

22

Pursuant to 40 CFR 51.309(d)(5)(ii), the State of Utah has reviewed the other mobile source recommendations contained in the GCVTC report. The results of that review are included in Part J of this implementation plan that addresses all recommendation of the GCVTC report, including mobile source recommendations.

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24
25
26

1

2 **G. LONG-TERM STRATEGY FOR FIRE PROGRAMS**

3 **1. Regulatory History and Requirements**

4 In its 1996 final report, the GCVTC recognized that past land management practices,
5 including decades of fire suppression, have led to an increase of accumulated forest fuels.
6 Thus, wildfires are becoming larger in size, unnaturally destructive, and more dangerous
7 and costly to control. Fire is a component of most natural ecosystems in the West and
8 must be a component of processes to meet land management, human health and visibility
9 objectives. The GCVTC recognized that prescribed fire and wildfire levels are projected
10 to increase significantly for decades to come, and that programs to minimize emissions
11 and visibility impacts and educate the public should be implemented.

12
13 The Regional Haze Rule (40 CFR 51.309(d)(6)) requires documentation that all federal,
14 state and private prescribed fire programs in the state evaluate and address the degree of
15 visibility impairment from smoke in their planning and application; that a statewide
16 inventory and emissions tracking system be established for volatile organic compounds,
17 nitrogen oxides, elemental and organic carbon, and fine particle emissions from fire; that
18 any administrative barriers to the use of alternatives to burning be identified and removed
19 where possible; that enhanced smoke management programs considering visibility as
20 well as health and nuisance objectives be included and that they be based on specific
21 criteria; and that annual emission goals for fire be established in cooperation with states,
22 tribes, federal land managers and private entities to minimize emissions increases from
23 fire to the maximum extent feasible.

24
25 The WRAP's effort to document and understand the incidence of fire and its effect on
26 visibility in Class I areas has been extensive and productive. WRAP modeling shows
27 that prescribed fire will continue to affect visibility. See the WRAP TSD Chapter 6 for
28 details.

29 **2. Prescribed Fire Program Evaluation**

30 Pursuant to 40 CFR 51.309(d)(6)(i), the State of Utah has evaluated all federal, state, and
31 private prescribed fire programs in the state, based on the potential to contribute to
32 visibility impairment in the 16 Class I areas of the Colorado Plateau, and how visibility
33 protection from smoke is addressed in planning and operation. The State of Utah relied
34 upon the WRAP report *Assessing Status of Incorporating Smoke Effects into Fire*
35 *Planning and Operation*³⁶ as a guide for making this evaluation. The State of Utah has
36 also evaluated whether these prescribed fire programs contain the following elements:
37 actions to minimize emissions; evaluation of smoke dispersion; alternatives to fire; public
38 notification; air quality monitoring; surveillance and enforcement; and program

³⁶ All WRAP documents cited in Part G are available in the Utah TSD Supplement.

1 evaluation. A description of the evaluation that was made in accordance with 40 CFR
2 51.309(d)(6)(i) follows.

3 **a. Wildlands Fire**

4 The Utah Smoke Management Plan (SMP), revised March 23, 2000, provides operating
5 procedures for federal and state agencies that use prescribed fire, wildfire, and wildland
6 fire on federal, state and private wildlands in Utah. The SMP includes the program
7 elements listed in 40 CFR 51.309(d)(6)(i), with the exception of alternatives to fire. In a
8 letter dated November 8, 1999, the EPA certified the Utah SMP under EPA's April 1998
9 *Interim Air Quality Policy on Wildland and Prescribed Fires (Policy)*. EPA's Policy also
10 includes the elements that are listed in 40 CFR 51.309(d)(6)(i).

11
12 In 2001, the Utah SMP requirements were codified through rulemaking and comprise
13 R307-204 of the Utah Administrative Code. R307-204 applies to all persons using
14 prescribed fire or wildland fire on land they own or manage, including federal, state, and
15 private wildlands. The Utah TSD Supplement includes copies of the Utah SMP.

16
17 Under R307-204, Land Managers are required to submit pre-burn information including
18 the location of any Class I areas within 15 miles of the burn, a map depicting the
19 potential impact of the smoke from the burn on any Class I areas, a description of fuels
20 and acres to be burned, emission reduction techniques to be applied, and monitoring of
21 smoke effects to be conducted. In addition, Land Managers are required to submit a
22 more detailed burn plan that includes, at a minimum, information on the fire prescription
23 or conditions under which a prescribed fire may be ignited.

24
25 Under R307-204, prescribed fires requiring a burn plan cannot be ignited and wildland
26 fire used for resource benefits cannot be managed before the executive secretary of the
27 Air Quality Board (AQB) approves or conditionally approves the burn request. The burn
28 approval requirement provides for the scheduling of burns to reduce impacts on visibility
29 in Class I areas.

30
31 After the burn is completed, the Land Manager is required to submit post-burn
32 information to evaluate the effectiveness of the burn and provide a record of acres treated
33 by the burn. The procedures listed above serve as an evaluation of the degree of
34 visibility impairment from smoke from prescribed fires that are conducted on federal,
35 state, and private wildlands.

36
37 Information on the types of management alternatives to fire considered by Land
38 Managers are included in programmatic or long-term management plans. These
39 programmatic plans are developed in accordance with the National Environmental Policy
40 Act (NEPA) and are reviewed by the Division of Air Quality (UDAQ) on an individual
41 basis. Typically, the Land Manager does not evaluate alternatives to fire once the
42 decision has been made to use fire and the subsequent burn plan developed.

b. Agricultural Fire

The WRAP inventory and a survey³⁷ conducted by Utah State University (USU) Extension indicate that agricultural burning is a very small portion of total emissions in Utah, and also of agricultural burning in the West. See Table 12 below. The USU survey results are included in the Utah TSD Supplement.

Table 12. Agricultural Burning Emissions Comparison

Agricultural Burning Emissions Comparison						
Numbers were obtained from the Emission Inventories Spreadsheets in the						
Technical Support Document provided by the WRAP for Section 309 SIPs.						
These spreadsheets are available at www.wrapair.org .						
		(tons per year)				
	PMC	PM _{2.5}	SO _x	NO _x	VOC	CO
Utah Agricultural Burning	12	212	10	101	216	2,327
Total Ag Burning in WRAP region	1,125	20,901	1,352	10,094	20,310	216,732
*Total Utah emissions from all sources	63,718	85,347	66,796	269,557	172,231	1,685,503
Utah Ag burning as a % of WRAP Ag Total	1.03%	1.01%	0.77%	1.00%	1.06%	1.07%
Utah Ag burning as a % of Utah Total Emissions	0.02%	0.25%	0.02%	0.04%	0.13%	0.14%
*Total Utah emissions were obtained from WRAP spreadsheets by summing Utah's county emissions and then adding total emissions due to Wild Fire, Ag Burning and Rx Fire.						

Emissions from agricultural burning are less than 0.25% of total Utah emissions and therefore do not result in significant impacts on visibility in the 16 Class I areas or on regional haze in general. Since agricultural burning emissions are minimal and half of them occur far from the Colorado Plateau, agricultural land managers are currently not subject to the Utah Enhanced Smoke Management Plan.

(1) *Decline in Agricultural Burning Since 1996.* The USU survey makes clear the decline in agricultural burning--a reduction of 48% statewide--between 1996 and 2002, and documents the reasons for the change. Only 31,999 acres were burned in 2002 out of a total of 8.7 million acres harvested. Of the total acres harvested, only about one million acres is cultivated; the majority of land is rangeland. The survey documents three reasons for the decline in agricultural burning: stubble or residue was sold rather than burned, the stubble or residue was mowed or chopped and worked back into the soil, and livestock were used to graze the stubble or residue. One reason for the change in practices is that the drought that began in 1999 has reduced the available forage for

³⁷ Utah State University Extension, in collaboration with the Utah Farm Bureau Federation. *Agricultural Burning in Utah and the Regional Haze Rule. Logan, Utah. July 2003.*

1 livestock that normally graze native vegetation, thus making straw more valuable as a
2 feed crop. However, the survey concludes that more stubble and residue was being
3 grazed by livestock or tilled into the soil or baled and sold in 2002 than in 1996.
4

5 (2) *Emission Reduction Techniques.* Of Utah's 29 counties, there are seven in
6 which no burning occurred in 1996 or 2002 and two more in which there was no burning
7 in 2002. The USU survey documents county-by-county the specific Emission Reduction
8 Techniques commonly in use. Emission reduction techniques are common practice in
9 seventeen of the counties.

10
11 (3) *Local Government Control Measures.* Finally, more than half (16,600) of the
12 acres burned are in Box Elder County in the northwestern corner of Utah, nearly 100
13 miles from any Class I area. Box Elder County has an ordinance in place to regulate
14 when, where and how much burning can take place. A copy of the ordinance is in the
15 Utah TSD Supplement.
16

17 (4) *Program Evaluation.* The State of Utah has determined that the appropriate
18 local government controls and voluntary emission reduction techniques are in place and
19 these efforts meet the requirements of 40 CFR 51.309(d)(6)(i).

20 **3. Emission Inventory and Tracking System**

21 **a. Wildlands Inventory**

22 Under R307-204, Land Managers are required to submit an emissions inventory for
23 particulate matter. A tracking system has been established to record the required
24 inventory information. Pursuant to 40 CFR 51.309(d)(6)(ii) and R307-204, the emissions
25 inventory and tracking system for fire sources has been revised within the State of Utah
26 to include volatile organic compounds, nitrogen oxides, elemental and organic carbon,
27 and fine particulate.
28

29 For consistency, the State of Utah will use the emissions tracking system developed by
30 the WRAP as defined by the WRAP *Fire Tracking System Policy*.³⁸ This policy
31 identifies a process for gathering the essential post-burn activity information necessary to
32 consistently calculate emissions for both man-made or anthropogenic and natural sources
33 of fire and uniformly assess fire impact on regional haze. This policy is the basis for
34 creating a fire emissions inventory for visibility purposes within the State of Utah, using
35 an emission calculation mechanism developed by the WRAP. In addition, fire emission
36 inventory updates will be provided in future progress reports as part of the reasonable
37 progress demonstration specified in 40 CFR 51.309(d)(10)(i). See the Utah SMP in the
38 Utah TSD Supplement for copies of the tracking forms and further information on the
39 emissions inventory and tracking system in the State of Utah.

³⁸ All WRAP documents cited in Part G are available in the Utah TSD Supplement.

1 **b. Agricultural Lands Inventory**

2 To meet the requirements of 40 CFR 51.309(d)(6)(ii), the State of Utah will work
3 collaboratively with the Utah Farm Bureau Federation and Utah State University
4 Extension to develop and implement an inventory and emissions tracking system for
5 agricultural burning. The survey conducted in 2003 by the Utah State University
6 Extension, in collaboration with the Utah Farm Bureau Federation, will be used as a
7 baseline for future emissions tracking activities. Since agricultural burning has been
8 documented in Subsection 2.b above to be a very small proportion of total emissions in
9 Utah and a very small proportion of agricultural burning in the West, the emission
10 tracking activities will be conducted on a periodic basis to determine if any significant
11 changes have been made since the 2003 survey. Results from the periodic emission
12 tracking activities will be provided in future progress reports to EPA, as part of the
13 reasonable progress demonstration specified in 40 CFR 51.309(d)(10)(i).

14 **4. Identification and Removal of Administrative Barriers**

15 During the annual meeting for establishing the Annual Emissions Goal, the UDAQ staff
16 and Land Managers for fire will assess whether administrative barriers to the use of non-
17 burning alternatives exist. If a specific administrative barrier is identified during this
18 annual meeting, UDAQ will investigate how this barrier may be removed, if feasible, and
19 will work collaboratively with the Land Managers to remove the barrier as required by 40
20 CFR 51.309(d)(6)(iii).

21
22 An evaluation of the administrative barriers to the use of the non-burning alternatives, if
23 any, will be included in the formal progress report to EPA every five years as required by
24 40 CFR 51.309(d)(10)(ii).

25
26 In addition, the State of Utah will use two documents prepared by the WRAP for this
27 effort: (1) *Nonburning Alternatives for Vegetation and Fuel Management*, and (2)
28 *Burning Management Alternatives on Agricultural Lands in the Western United States*.

29 **5. Enhanced Smoke Management Program**

30 Pursuant to 40 CFR 51.309(d)(6)(iv), all smoke management programs that operate
31 within Utah are consistent with the WRAP *Enhanced Smoke Management Programs for*
32 *Visibility Policy*. This policy calls for programs to be based on the criteria of efficiency,
33 economics, law, emission reduction opportunities, land management objectives, and
34 reduction of visibility impacts. The Enhanced Smoke Management Plan (ESMP) is found
35 in the Utah TSD Supplement.

36
37 The following is a list of the elements of the Utah ESMP and the revisions made to the
38 Utah SMP and R307-204 in order to meet the requirements of 40 CFR 51.309(d)(6)(iv).

39 **a. Actions to Minimize Fire Emissions**

40 Utah’s ESMP focuses on three general approaches that are designed to minimize
41 emissions from prescribed fire and wildland fire use for resource benefits: use of

1 emission reduction techniques, establishing emission goals, and use of existing burn
2 manager qualification programs.

3 **b. Evaluation of Smoke Dispersion**

4 Under the Utah ESMP, the Land Managers will focus on improved weather data for more
5 accurate spot weather forecasts, scheduling of prescribed fires by the executive secretary
6 of the Air Quality Board to minimize cumulative effects of smoke from fires on Class I
7 areas, burner qualification and certification programs, use of the latest modeling
8 programs to assist in the evaluation of dispersion conditions, and use of field level data
9 such as maps showing where smoke is likely to settle.

10 **c. Alternatives to Fire**

11 Under the Utah ESMP, the types of management alternatives used and the acres treated
12 on an annual basis will be tracked using Land Manager databases that are being
13 developed. Land Managers evaluate and will continue to evaluate the use of alternatives
14 to fire in programmatic or long-term management plans, and the ESMP requires Land
15 Managers to provide a summary of the management alternatives that were used in a given
16 year.

17 **d. Public Notification of Burning**

18 Under the Utah ESMP, a one-stop information center will be added to the Utah SMP
19 website to provide a list of upcoming projects as a means to notify the public about
20 prescribed fire or wildland fire projects.

21 **e. Air Quality Monitoring**

22 Under the Utah ESMP, Land Managers will monitor the effects of prescribed fire and
23 wildland fire on visibility in Class I Areas. At a minimum, visual monitoring and
24 documentation of the direction of the smoke plume will be performed. Under R307-204,
25 the executive secretary of the Air Quality Board may direct Land Managers to operate
26 real-time air quality sampling equipment on large fires that are expected to last more than
27 one day, or fires close to Class I areas. Monitoring of smoke impacts on visibility will
28 lead to improved future operations and a better understanding of smoke accumulation
29 problems and solutions. In addition, the Utah ESMP will provide a detailed description
30 of the monitoring equipment that is available and its location within the region.

31 **f. Surveillance and Enforcement**

32 The Utah ESMP builds upon the relationship that was established between the Land
33 Managers and the UDAQ for the development of the Utah SMP. A good working
34 relationship between the Land Managers and UDAQ can significantly reduce the need for
35 surveillance and enforcement. UDAQ staff conduct site inspections on prescribed fires
36 that are close to Class I areas to verify compliance with the burn plan on an as-needed
37 basis. Reports are generated when site inspections are conducted.

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g. Program Evaluation

The UDAQ staff and Land Managers will conduct an annual effectiveness review for the Utah ESMP. A formal progress report will be completed every five years as required by 40 CFR 51.309(d)(10)(ii).

h. Burn Authorization

Under R307-204, since March 2000, Land Managers have been required to submit pre-burn information including the location of any Class I areas within 15 miles of the burn, a burn plan if requested, a map depicting the potential impact of the smoke from the burn on any Class I areas, and a description of fuels and acres to be burned. Prescribed fire requiring a burn plan cannot be ignited before the executive secretary of the Air Quality Board approves or conditionally approves the burn request. See the Utah SMP in the Utah TSD Supplement for more details on the burn authorization requirements.

i. Regional Coordination

Coordination of fire projects is imperative to avoid cumulative smoke impacts in Class I areas. The Utah ESMP is designed to provide for information sharing among the Land Managers, UDAQ, and the public within Utah, as well as in neighboring states.

j. ESMP for Agricultural Burning

The State of Utah has determined that appropriate emission reduction techniques and control measures for agricultural burning are in place in the agricultural community and at the local government level. This satisfies the requirements of 40 CFR 51.309(d)(6)(iv).

6. Annual Emission Goals

Pursuant to 40 CFR 51.309(d)(6)(v), efforts will be made within the State of Utah to minimize emission increases in fire, excluding wildfire, to the maximum extent feasible, through the use of annual emission goals, in accordance with the WRAP *Annual Emission Goals for Fire Policy*. The State of Utah intends to use this policy to quantify the emission reduction techniques that are being used within the state on a project-specific basis to reduce the total amount of emissions increases being generated from areas where prescribed fire is being used. The Utah TSD Supplement describes this process in more detail.

1 **H. ASSESSMENT OF EMISSIONS FROM PAVED AND**
2 **UNPAVED ROAD DUST**

3 **1. Regulatory History and Requirements**

4 The Grand Canyon Visibility Transport Commission, in its 1996 report to EPA,³⁹
5 believed that dust emissions from paved and unpaved roads are generally near-field
6 transport issues rather than long-range transport issues, especially with respect to larger
7 coarse materials that settle out of the atmosphere before being transported long distances.
8 However, the GCVTC also recommended additional studies would be necessary to verify
9 this assumption since the state of the science the GCVTC relied upon for characterizing
10 the emissions and transport of dusts from roads was limited, and the projected growth of
11 on-road emissions could contribute to regional haze, based on the projected growth of
12 population and vehicle-miles-traveled.

13
14 The Regional Haze Rule (40 CFR 51.309(d)(7)) requires states to assess the impact of
15 dust emissions from paved and unpaved roads on regional haze in the 16 Class I areas
16 located on the Colorado Plateau in the first implementation plans due December 2003.
17 The Western Regional Air Partnership analyzed this issue, including efforts to improve
18 methods for estimating road dust emission inventories as applied to regional scale
19 modeling and characterization of the transport and deposition processes. Results of
20 WRAP modeling work have demonstrated road dust is not a significant contributor to
21 visibility impairment in the 16 Class I areas on the basis of regional transport. Due to
22 this finding, no additional road dust control strategies are needed in the current SIP.

23 **2. State of Utah Long-term Strategy for Road Dust Sources**

24 **a. Assessment of Paved and Unpaved Road Dust Emissions.**

25 Pursuant to 40 CFR 51.309(d)(7), an assessment was made by the WRAP of the impact
26 of dust emissions from paved and unpaved roads from transport region states on the 16
27 Class I areas of the Colorado Plateau. A complete description of this assessment is
28 provided in Chapter 7 of the WRAP Technical Support Document. The State of Utah, in
29 consultation with the WRAP, will track emissions and perform further assessments of
30 road dust impacts on visibility in the 16 GCVTC Class I areas in the progress updates and
31 status reports, and will submit implementation plan revisions as needed to make
32 reasonable progress in the SIP amendments due in 2008, 2013, and 2018.
33

³⁹ *Recommendations for Improving Western Vistas*, page 46.

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b. Contribution to Visibility Impairment Finding.

Pursuant to 40 CFR 51.309(d)(7) and the results of the assessment of the impact of road dust emissions described above, the State of Utah, in collaboration with other states through the WRAP, determined that road dust emissions are not a significant contributor to regional haze visibility impairment within the Colorado Plateau 16 Class I areas. Based on these findings, no emission management strategies have been identified at this time. The technical and policy foundation for this determination can be found in Chapter 7 of the WRAP TSD.

1 **I. POLLUTION PREVENTION AND RENEWABLE**
2 **ENERGY PROGRAMS**

3
4 The Public Advisory Committee of the Grand Canyon Visibility Transport Commission
5 (GCVTC) recognized the importance of pollution prevention as a way to minimize per
6 capita emissions that contribute to visibility impairment from regional haze. Thus, in
7 1996, the GCVTC recommended that one of the goals of states in the transport region
8 "should be to achieve annual additions in order that renewable energy will comprise 10%
9 of regional power needs by 2005 and 20% by 2015. Progress towards this goal should be
10 evaluated every five years, in conjunction with regular reviews of emissions reductions
11 and progress toward the national visibility goal."⁴⁰
12

13 Section 51.309 of the Regional Haze Rule outlines the information that must be
14 included in each state's first Regional Haze Implementation Plan to address visibility
15 impairment in the 16 Class I areas covered by the Commission's Report. By meeting
16 these requirements, Utah can address visibility in all of its Class I areas. Section
17 51.309(d)(8) of the Regional Haze Rule specifies the air pollution prevention
18 requirements eligible States must meet and outlines the information each State must
19 include in its Regional Haze Implementation Plan to address the use of renewable energy
20 and energy efficiency measures to reduce the emissions causing regional haze. Table 13
21 summarizes the information requirements contained in Section 51.309(d)(8).

⁴⁰ *Recommendations for Improving Western Vistas*, page 30.

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Table 13. Summary of Information Requirement for Pollution Prevention

Citation	Information Item
309(d)(8)(i)	Item 1. An initial summary of all air pollution prevention programs currently in place.
	Item 2. An inventory of all renewable energy capacity and production in use or planned as of 2002 (expressed in megawatts and megawatt-hours).
	Item 3. Total energy generation capacity and production for the state.
	Item 4. Percent of total energy generation capacity and production that is derived from renewable energy.
	Item 5. The state’s anticipated contribution toward the 10/20 goals (based on the programs and policies each state relies on to achieve its renewable goals).
309(d)(8)(ii)	Item 6. Programs providing incentives to reward efforts that go beyond compliance and/or achieve early compliance with air pollution related requirements.
309(d)(8)(iii)	Item 7. Programs to preserve and expand energy conservation efforts.
309(d)(8)(iv)	Item 8. An identification of specific areas where renewable energy has the potential to supply power where it is now lacking and where renewable energy is most cost-effective.
309(d)(8)(v)	Item 9. Projections of the short- and long-term emissions reductions, visibility improvements, cost savings, and secondary benefits associated with the renewable energy goals, energy efficiency and air pollution prevention activities.
309(d)(8)(vi)	Item 10. A description of the programs relied on to achieve the state’s contribution toward the 10/20 goals and a demonstration of the progress made toward achievement of the renewable energy goals in the years 2003, 2008, 2013, and 2018. This description must include documentation of the potential for renewable energy resources, the percentage of renewable energy associated with new power generation projects implemented or planned and the renewable energy generation capacity and production.

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The Western Regional Air Partnership (WRAP) was established in 1997 as the successor organization to the Grand Canyon Visibility Transport Commission. The WRAP was created by western states and tribes to coordinate and oversee the implementation of recommendations made by the GCVTC and to “identify regional or common air management issues, develop and implement strategies to address these issues, and formulate and advance western regional policy positions on air quality.” The WRAP develops policies, strategies and technical tools through an inclusive stakeholder-based process that includes state air agencies, the U.S. Environmental Protection Agency (EPA), tribes, federal and state land management agencies, local government, industry, utilities, environmental groups, academia and other interested parties.

1 The Air Pollution Prevention Forum (the Forum) was created in September, 1998 by the
2 WRAP’s Initiatives Oversight Committee (IOC) and charged to “recommend legislative
3 actions, economic incentives and regulatory policies states can adopt to meet the 10/20
4 renewable energy goal and increase the use of energy efficiency technologies in the
5 Grand Canyon Visibility Transport region.” Stakeholders and regulators from the State
6 of Utah were actively involved in the work of the Forum.

7
8 The objective of the Forum and its 25 members has been to provide the states and tribes
9 in the WRAP region with the policy and analytical framework needed to respond to the
10 requirements of 40 CFR 51.309(d)(8). To accomplish this purpose the Forum’s work
11 plan called for the Forum to:

- 12
- 13 • Examine barriers restricting the penetration of renewable energy, energy efficient
14 technologies, and adoption of energy efficient practices in the Transport Region;
- 15 • Identify and evaluate economic incentives, legislative actions, and regulatory
16 policies that will increase investments in renewable energy and energy efficiency,
17 including actions currently underway in the Grand Canyon Visibility Transport
18 Region; and
- 19 • Recommend market-based incentives and public policies that will support
20 increased investment in renewable energy within the Grand Canyon Visibility
21 Transport Region and improve the efficiency of the region’s energy production
22 and end-use sectors.
- 23

24 The Forum developed recommendations over a three-year period through a stakeholder-
25 based consensus process supported, in part, by nationally recognized renewable energy
26 and energy efficiency experts, including the National Renewable Energy Laboratory.
27 The Forum and workgroups held more than 11 meetings and workshops to examine
28 barriers and identify policies that would lead to increased investment in renewable energy
29 and energy efficiency in the Grand Canyon Visibility Transport Region. The Forum also
30 commissioned ICF Consulting Group to analyze the potential emissions reductions,
31 energy cost savings, and secondary environmental and economic benefits of meeting the
32 Grand Canyon Visibility Transport Commission’s 10/20 goal and implementing a suite of
33 cost-effective energy efficiency programs and policies the Forum identified as “best
34 practices” for the region.

35
36 Following the findings of the Grand Canyon Visibility Transport Commission and the
37 Air Pollution Prevention Forum, the Western Regional Air Partnership (WRAP) found
38 that energy efficiency and renewable energy can be effective tools to reduce regional
39 haze and can reduce emissions, improve visibility, reduce energy costs and provide
40 secondary environmental and economic benefits to the region. The WRAP also
41 concluded that implementing both renewable energy and energy efficiency program and
42 policy measures together will yield larger emissions benefits than either energy
43 efficiency or renewable energy measures would alone. The U.S. Environmental
44 Protection Agency made similar presumptions in promulgating Section 309(d)(8) of the
45 Regional Haze Rule.

1 The inclusion of energy efficiency and renewable energy programs in the State
2 Implementation Plan and estimated emission reductions and impacts from them does not
3 cause such programs and estimates to become mandatory and/or federally enforceable.
4 These programs are voluntary state and local programs that were never intended to be
5 federally enforceable.⁴¹ The WRAP has explicitly expressed its expectation that these
6 programs will be implemented consistent with local economic, regulatory, and political
7 conditions while protecting cultural resources and values. As such, these programs may
8 be modified, changed, expanded, redirected or eliminated and new programs may be
9 adopted and implemented without seeking approval from the federal government. The
10 projected emission reductions are estimates only. It is expected that these programs and
11 their associated emissions impacts will change over time without requiring a SIP
12 revision. Utah will, as required, report its progress toward meeting the regional 10/20
13 renewable energy goals in the periodic SIP reviews required under 40 CFR
14 51.309(d)(10).

15 **1. Description of Existing Pollution Prevention Programs in**
16 **Utah**

17 Utah’s pollution prevention programs focus on improving the efficiency of energy usage
18 by end-use consumers and increasing supplies of electrical power generated from
19 renewable sources for Utah customers. Detailed descriptions of them can be found in the
20 Utah TSD Supplement.

21 **2. Inventory of Renewable Energy Generation Capacity and**
22 **Production in 2002**

23 The State of Utah has based its inventory of existing installed renewable energy
24 generation capacity on publicly available reports published by federal government
25 agencies responsible for gathering energy information and/or licensing power plants.
26 These sources maintain reliable data on larger renewable generating plant capacity and
27 electric energy production. To supplement this information, the Utah Energy Office
28 conducted surveys to estimate the capacity and electric energy production from medium,
29 25 kW to 10 MW, and small, less than 25 kW, renewable power generation systems
30 installed within Utah that would not have been included in regularly maintained federal
31 energy databases.

32
33 The State of Utah generates a substantial amount of power from hydroelectric sources.
34 None of this hydroelectric capacity has been certified to meet the Low-Impact
35 Hydropower Institute criteria that would be necessary for hydroelectric generation to be

⁴¹ The GCVTC goal is 10 percent of generation from renewable resources in 2005 and 20 percent in 2015. With respect to the requirements of Section 309(d)(8), achieving the 10/20 goal is not mandatory or “enforceable.” This section of the rule simply establishes an “enforceable” requirement for States “to assess progress toward a goal established by the GCVTC with respect to renewable energy”. To the extent they are not able meet the goal, States are required to provide an explanation of why the goals cannot be met. See *Federal Register*, Vol. 64, No. 126, page 35754, July 1, 1999. *Regional Haze Regulations Final Rule*.

1 considered “renewable energy” under the definition endorsed by the Air Pollution
2 Prevention Forum of the WRAP. As a consequence no hydroelectric power or capacity
3 has been included in the inventory of existing Utah renewable energy generation. Some
4 existing hydroelectric plants in Utah may be certified in the future. If certified, they will
5 be included as contributors toward meeting the regional renewable energy goals in future
6 renewable energy inventories reported in the revisions to the Utah Regional Haze
7 Implementation Plan.

8
9 Total renewable power generating capacity in Utah at the end of 2002, excluding all
10 hydroelectric generation, was 42.136 Megawatts. Table 14, prepared by the Utah Energy
11 Office, summarizes renewable energy generation capacity installed within Utah by 2002.

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Table 14. Utah Renewable Electric Power Industry Capacity (Megawatts)

Year	1999	2000	2001	2002
Utility Hydro	275	275	275	275
Non-Utility Hydro	10.496	10.496		10.496
Hydro Small Survey	0.037	0.046	0.055	0.059
Total Hydroelectric*	285.533	285.542	285.551	285.555
Geo Blundell (EIA)	26.1	26.1	26.1	26.1
Geo Cove Fort	13.7	13.7	13.7	13.7
Total Geothermal	39.8	39.8	39.8	39.8
Solar/PV Small Survey	0.013	0.016	0.018	0.018
Solar/PV Medium Survey	0.220	0.220	0.220	0.220
Total Solar/PV	0.233	0.236	0.238	0.238
Wind Small Survey	0.134	0.176	0.220	0.240
Wind Medium Survey	0.033	0.258	0.258	0.258
Total Wind	0.167	0.434	0.478	0.498
MSW Landfill Gas	1.6	1.6	1.6	1.6
Wood and Wood Waste	na	na	na	na
Other Waste	na	na	na	na
Total Renewable Capacity	327.333	327.612	327.667	327.691
Total w/o Hydro	41.800	42.070	42.116	42.136

*No Utah hydroelectric sites are currently certified as low-impact hydro by the Low Impact Hydropower Institute (LIHI).

Sources: "Inventory of Electric Utility Power Plants in the U.S. 1998, 1999, and 2000"; "Inventory of Nonutility Electric Power Plants in the U.S. 1998, 1999, and 2000"; FERC "Hydroelectric Projects Under Commission License" and "Hydroelectric Projects Exempted from Licensing Requirements," NREL REPiS; Utah Energy Office Small and Large Renewable Plant Surveys.

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Table 15, prepared by the Utah Energy Office, summarizes electric energy production from renewable generation sources in Utah over the past four years. Electric energy production from renewable sources over the last four years averaged 200,995 MWh annually. In 2002, 223,664 MWh of power were generated from renewable sources located within Utah.

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Table 15. Utah Renewable Electric Power Industry Generation (Megawatt-hours)

Year	1999	2000	2001	2002
Utility and Non-Utility Hydro	1,255,142	746,125	500,203	484,357
Hydro Small Survey Generation*	107	133	159	170
Total Hydroelectric**	1,255,249	746,258	500,362	484,527
Total Geothermal	185,926	186,461	185,989	211,565
Solar/PV Small Survey Generation	23	29	32	32
Solar/PV Medium Survey Generation	385	385	385	385
Total Solar/PV	408	414	417	417
Wind Small Survey Generation	235	308	385	420
Wind Medium Survey Generation	58	452	452	452
Total Wind	293	760	837	872
MSW Landfill Gas	8,169	9,110	1,534	10,810
Wood and Wood Waste	na	na	na	na
Other Waste	na	na	na	na
Total Renewable Generation	1,450,044	943,003	689,139	708,191
Total w/o Hydro	194,796	196,745	188,778	223,664

*All medium survey hydro plants were included in EIA Utility and Non-Utility Data

**No Utah hydroelectric sites are currently certified as low-impact hydro by the Low Impact Hydropower Institute (LIHI)

Sources: EIA, Form EIA-759, "Monthly Power Plant Report"; Form EIA-867, "Annual Nonutility Power Producer Report"; Form EIA-860B, "Annual Electric Generator Report - Nonutility"; Form EIA-906 Database, "Monthly Utility Power Plant Data" and "Monthly Nonutility Power Plant Data"; and Utah Energy Office Small and Medium Renewable Plant Surveys

3 **3. Inventory of Total Utah Capacity and Production in 2002**

4 Total installed generation capacity within Utah in 2002 was 5,485 MW. Non-
5 hydroelectric renewable energy generation capacity represented 0.77 percent of the total
6 installed capacity. Table 16, prepared by the Utah Energy Office, summarizes the
7 installed generation capacity in Utah.

8

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Table 16. Utah Capacity by Source (Electric Power Annual). (Megawatts)

Year	1999	2000	2001	2002
Coal	4,705	4,781	4,781	4,781
Petroleum	54	47	47	47
Natural Gas	320	327	327	327
Petroleum/Natural Gas or Other Gas (Combined)	50	2	2	2
Hydroelectric	286	286	286	286
Other Renewable	42	42	42	42
Total	5,456	5,485	5,485	5,485
% Renewable	5.999%	5.973%	5.974%	5.975%
% Non-Hydro Renewable	0.766%	0.767%	0.768%	0.768%

3

Sources: "Inventory of Electric Utility Power Plants in the U.S. 1998, 1999, and 2000"; "Inventory of Nonutility Electric Power Plants in the U.S. 1998, 1999, and 2000"; and Utah Energy Office Estimates for Hydroelectric and Other Renewables.

4

5 **4. Percent of Total Energy Generation Capacity and Production**
6 **Derived from Renewable Energy**

7 Power plants located in Utah produced 36,496,500 MW-h on average over the past four
8 years. In 2002, Utah generators produced 36,640,000 MW-h of electric energy.
9 Renewable power contributed 0.61 percent of this total. Table 17, prepared by the Utah
10 Energy Office, summarizes electric energy production from all generation sources in
11 Utah over the past four years.

12

13 **Table 17. Utah Net Generation by Source, 1999-2002 (Thousand Megawatt-hours)**

Year	1999	2000	2001	2002
Coal	34,695	34,477	33,678	34,348
Petroleum	31	57	58	31
Natural Gas	668	1,146	1,454	763
Hydroelectric	1,255	746	500	485
Other Renewable	195	197	189	224
Total	36,844	36,623	35,879	36,640
% Renewable	3.94%	2.57%	1.92%	1.93%
% Non-Hydro Renewable	0.53%	0.54%	0.53%	0.61%

14

Sources: Form EIA-906 Database, "Monthly Utility Power Plant Data" and "Monthly Nonutility Power Plant Data"; and Utah Energy Office Small and Medium Renewable Plant Surveys.

Updated: 04/10/03

15

1 **5. Anticipated Contribution Toward Meeting the 10/20**
 2 **Renewable Energy Goals**

3 Utah has relied on the Air Pollution Prevention Forum’s guidance to interpret this
 4 provision. The Air Pollution Prevention Forum determined that the proper metric for
 5 measuring progress toward the regional goals is the amount of renewable energy Utahns
 6 bring on-line through their programs and incentives to serve indigenous loads. The Air
 7 Pollution Prevention Forum chose this metric to foster economic efficiency in the
 8 development of renewable energy within the region. The choice of this metric allows
 9 states to take credit for renewable energy generated anywhere within the interconnected
 10 grid so long as that State relies on the renewable energy facility to serve its loads, one of
 11 its renewable energy programs supports the development and/or its consumers are paying
 12 for the power output. Table 18 prepared by the Utah Energy Office summarizes Utah’s
 13 consumption of power from renewable sources compared to all generating sources over
 14 the past three years .
 15

16 **Table 18. Utah Consumption of Renewable Power; 2000-2002 (Gigawatt-hours)**

	2000	2001	2002	Average
Total Non-Hydro RE Off-Grid/Small-Scale	1.174	1.255	1.290	1.239
Blue Sky	0.673	3.799	7.810	4.094
Other Green Pricing	-	-	-	-
Non-Hydro RE Pcorp	87.533	99.900	112.439	99.957
Non-Hydro RE Non-Pcorp	34.618	33.247	29.681	32.515
Non-Hydro RE Non-Utility	9.110	1.534	10.810	7.151
Total Non-Hydro RE Consumption	133.108	139.734	162.030	144.957
Total Electricity Consumption	23,198.084	23,390.443	23,384.241	23,324.256
% Non-Hydro RE	0.57%	0.60%	0.69%	0.62%

17 Sources: Utah Small and Medium Renewable Energy Surveys; Form EIA-906 (utility and non-utility) and EIA-826
 18 Databases; Form EIA-759; Form EIA-867; Form EIA-860B; ScottishPower Environmental Performance Report
 19 2001/2002.

20 **a. States' Contributions to the Regional Renewable Energy**
 21 **Generation Goal**

22 Because only five of the nine transport region states plan to file state implementation
 23 plans under 40 CFR 51.309, it is not possible to allocate shares of the renewable energy
 24 generation goals to individual states. Even if an allocation of the goal to individual states
 25 were possible, any forecast of program performance would be uncertain. The states
 26 submitting implementation plans under Section 309 do not know if the nine-state

1 transport region will achieve the regional goals of 10 percent of electric energy
2 generation from renewable sources by 2003 and 20 percent by 2015.

3
4 Although only five states may submit plans under Section 309, efforts by other states in
5 the transport region will contribute to achieving the regional goals. In addition to the
6 efforts expected from the five states planning to address regional haze under Section 309,
7 California and Nevada are aggressively pursuing renewable resources.

8
9 Nevada has adopted a renewable portfolio standard (RPS) requiring utilities in the state
10 to obtain 15 percent of their electricity from renewable resources by 2004.

11
12 California, representing 48 percent of electricity sales in the nine-state transport region
13 during 2000, recently enacted a more aggressive RPS than its earlier standard. The
14 statutory requirements governing California's expanded RPS are contained in Senate Bill
15 1078 and Senate Bill 1038, which took effect on January 1, 2003, and are codified in
16 Public Utilities Code (PUC) sections 399.11 through 399.15, and sections 381, 383.5, and
17 445.

18
19 SB 1078 establishes an RPS program that requires retail electricity sellers, such as
20 investor-owned utilities, to increase the renewable content of their electricity deliveries
21 by one percent per year over a baseline level to be determined by the California PUC.
22 Retail sellers must meet a target of 20 percent renewable content in their electricity
23 portfolio by December 31, 2017. SB 1038 revises the structure and funding allocation
24 for the California Energy Commission's Renewable Energy Program, linking payments it
25 makes to new renewable electricity generating facilities to the RPS, with the goal of
26 increasing the amount of renewable generation in California.

27
28 The states filing plans under Section 309 will report on regional progress toward the
29 renewable energy goals for the nine-state transport region in their 2008 submittals.

30 **b. Utah's Anticipated Contribution Toward Meeting the** 31 **10/20 Renewable Energy Goals**

32 Utah has relied on the Air Pollution Prevention Forum's guidance to interpret this
33 provision. The Forum determined that the proper metric for measuring progress toward
34 the regional goals is the amount of renewable energy that Utahns bring on line through
35 their programs and incentives to serve indigenous loads. The Forum chose this metric to
36 foster economic efficiency in the development of renewable energy within the region.
37 The choice of this metric allows each state to take credit for renewable energy generated
38 anywhere within the interconnected grid so long as that state relies on the renewable
39 energy facility to serve its loads, one of its renewable energy programs supports the
40 development, and/or its consumers are paying for the power output. Table 17 prepared
41 by the Utah Energy Office summarizes Utah's consumption of power from renewable
42 sources compared to all generating sources over the past three years.

1 The Forum estimated that approximately 20 GW or 20,000 MW of new
2 renewable energy generating capacity would need to be added to the interconnected grid
3 by 2018 for the region to meet its goals of producing 10% of its power from renewable
4 sources by 2005 and 20% by 2015. Using information from the Energy Information
5 Administration and the Western Electricity Coordinating Council (WECC), the Utah
6 Energy Office estimates that Utah’s peak summer electricity demand is about 2.8% of the
7 overall WECC peak summer electricity demand. WECC includes all of the states
8 comprising the Grand Canyon Visibility Transport Region. If Utah consumers were
9 allocated a portion of the 20,000MW required to meet the regional 10/20 goals based on
10 the proportion of peak summer electricity demand they now represent, Utah would need
11 to contribute 560 MW of new renewable generation capacity toward meeting the goals.
12 Utah estimates that it will contribute about 550 MW of new renewable generating
13 capacity through its various programs to meet the regional goals by 2013. At this time,
14 there is not enough information available to reasonably estimate what additional
15 renewable generating capacity Utah will bring on line to serve indigenous loads from
16 2013 to 2018. The WRAP’s Air Pollution Prevention Forum and Utah both expect wind
17 power production to provide most of the new capacity. In addition to reporting on its
18 progress toward meeting the regional renewable energy goals, Utah will update and
19 revise its current estimate of its contribution to the goals when it makes its 2008
20 submittal.

21 **6. State of Utah Programs to Encourage Early Compliance**

22 **a. Western Backstop SO₂ Trading Program Early**
23 **Reduction Credits.**

24 As further described in Part E.3.a(1)(c) of the stationary source provisions of this plan,
25 industrial sources of SO₂ subject to the trading program which, upon verification by the
26 State, reduce emissions to levels below their floor amount prior to the program trigger
27 date shall receive additional emission allowances. Such allowances may be used by the
28 source for compliance purposes or may be sold to other parties, hence providing an
29 incentive for sources to go beyond compliance (i.e., their floor) or to achieve early
30 compliance (i.e., reductions prior to the program trigger date).
31

32 **b. Western Backstop SO₂ Trading Program Renewable**
33 **Energy Credits.**

34 As further described in Part E.3.a(1)(c) of the stationary source provisions of this plan,
35 allowances shall be provided to the owners of renewable energy facilities installed since
36 October 1, 2000. Such allowances will hold a market value and therefore provide an
37 incentive for power suppliers to invest in renewable energy facilities with zero or very
38 low air pollutant emissions.

1 **7. Summary of Utah Programs to Expand Energy Conservation**

2 Pursuant to 40 CFR 51.309(d)(8)(iii), Table 19 lists programs that are offered in Utah to
 3 preserve and expand existing energy conservation efforts. Detailed information about
 4 these programs is provided in the Utah TSD Supplement.

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Table 19. Programs to Preserve and Expand Energy Conservation Efforts

PROGRAM TYPE	INDIVIDUAL PROGRAMS
Utility Integrated Resource Planning	PacifiCorp Integrated Resource Planning – Demand Side Management
	UAMPS Integrated Resource Planning – Demand Side Management
Residential Energy Efficiency	Low-income Weatherization Program
	Residential Energy Efficiency Program
Commercial and Industrial Energy Efficiency	Commercial and Industrial Energy Efficiency Demonstration Program
	Industries of the Future Program
Schools and Public Buildings Energy Efficiency	State Buildings Energy Efficiency Program
	Schools and Public Buildings Energy Efficiency Program
	Salt Lake City Climate Action Plan Program
	Salt Lake Airport Electricity Conservation Program
Technical Assistance	Energy Education in Schools Program
	“PowerForward” Program

8

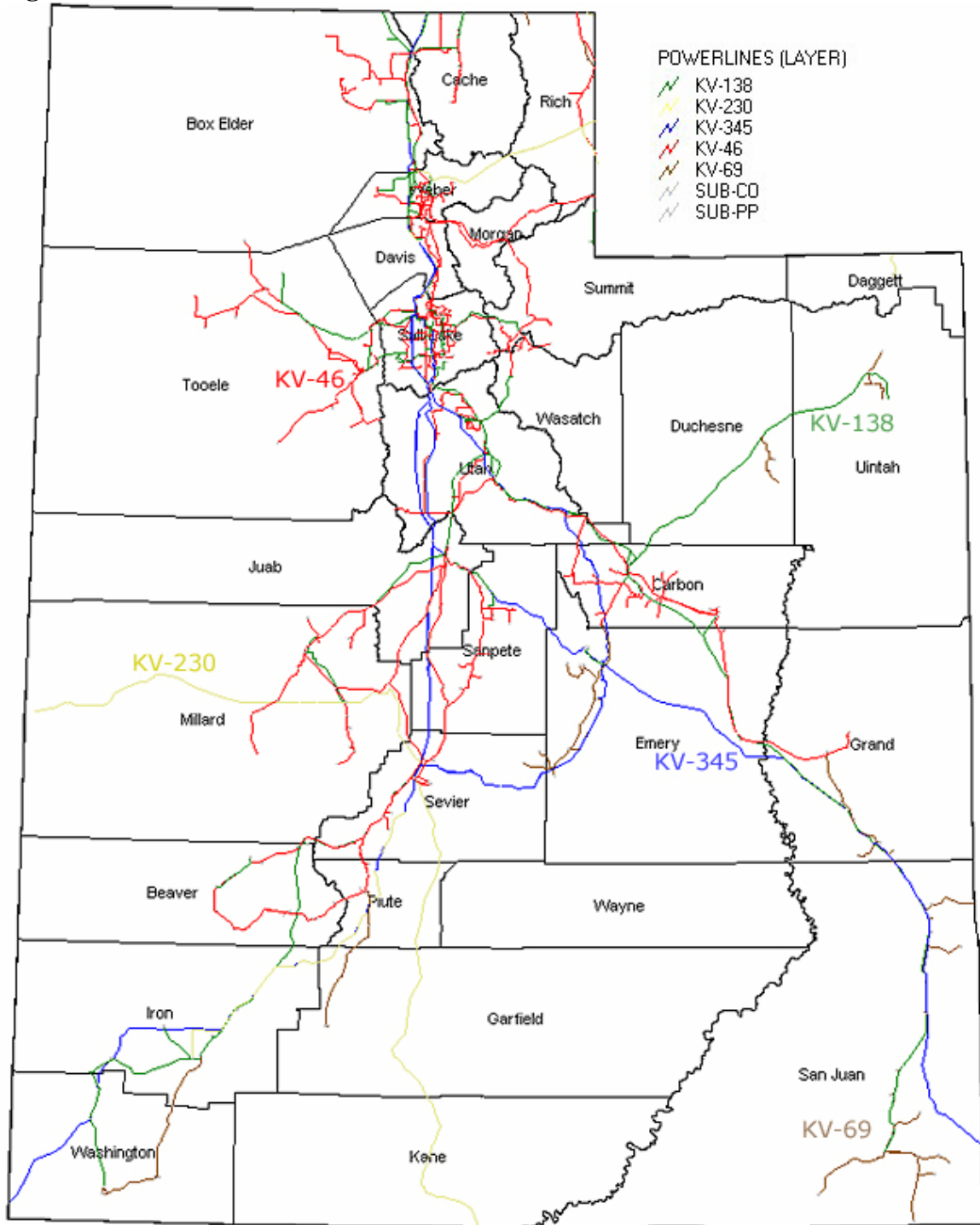
9 **8. Areas Where Power Is Lacking and Renewable Sources Can**
 10 **Supply It**

11 Supplying power from renewable sources where it is now lacking is linked fundamentally
 12 to whether or not line extensions are affordable compared to off-grid renewable power
 13 applications. Most populated areas of Utah and their associated electrical loads are being
 14 served from the interconnected transmission and distribution system. There are very
 15 limited opportunities to supply power from renewable sources to areas without existing
 16 service. Where off-grid power production is appropriate, it probably will be solar
 17 generation and will offset on-site diesel generation. In areas without electrical service,
 18 the cost-effectiveness of renewable energy generation can only be determined within the
 19 context of site-specific resource availability, the conversion technology and its capital
 20 costs, alternative power generation costs, fuel prices and volatility, proximity to grid-
 21 connected distribution lines, the cost of line extensions, and other relevant variables.
 22 Utilities’ line extension policies may also encourage or dissuade off-grid renewable
 23 power development. In general, small loads located more than 3 miles from the
 24 transmission and distribution grid have the highest potential for being served cost
 25 effectively by on-site renewable power generation. A map of Utah’s transmission system
 26 is shown below. It can be compared to the maps depicting Utah’s renewable energy

1 resource distribution (Figures 12 - 15) to get a rudimentary sense for the areas where
2 renewable power might be used to serve loads that do not have power today.

3

4 **Figure 5. Utah's Transmission and Distribution Network.**



5

1 **9. Projections of Emissions Reductions, Visibility**
2 **Improvements, Cost Savings and Secondary Benefits from**
3 **Pollution Prevention and EERE Measures**

4 **a. Regional Approach to Analyses**

5 The goal of serving 10 percent of “the regional power needs” from renewable generation
6 sources by 2005 and 20 percent by 2015 is a regional one. The goal was not apportioned
7 to the individual states comprising the Grand Canyon Visibility Transport Region.
8 Instead, each state has been required to take steps that contribute to achieving an
9 overarching regional outcome. This approach appropriately reflects the nature of the
10 western electricity grid. Load growth in one area of the western electricity system is
11 regularly met by generation additions in another, geographically separated location
12 within the interconnected western system. This fosters economic efficiency and helps to
13 keep electricity rates for retail customers low. While it may be feasible to forecast where
14 load growth is most likely to occur within the western region, it is not realistic to suggest
15 anyone can predict where and when new generation additions from renewable or any
16 other sources might come onto the interconnected system to serve it.

17
18 Because they depend largely on how the interconnected electricity system expands and
19 may be developed, the emissions reductions, visibility improvements, cost savings, and
20 secondary benefits associated with meeting the regional renewable energy goals,
21 preserving and expanding energy conservation efforts and operating pollution prevention
22 programs cannot be rationally tied prospectively to any particular state. Further, these
23 derived benefits are small. The pollution prevention recommendations of the GCVTC
24 were part of an overall strategy for reducing haze causing emissions across the entire
25 geographic region affecting the visibility at Class I areas on the Colorado plateau. All
26 benefits whether environmental or economic were intended to be accrued to the region.
27 Attempting to apportion them to individual states is not reasonable and could be
28 misleading.

29
30 The WRAP analyzed the emissions reductions, cost savings, and secondary benefits the
31 Transport Region, all nine states and the tribal lands within them, could expect from
32 implementing the pollution prevention recommendations of the Grand Canyon Visibility
33 Transport Commission. The analysis focused on stationary sources, including electricity
34 generation and industrial steam production plants and refineries, smelters and other
35 facilities that emit SO₂ from processing. The assessment assumed every state would
36 participate to implement the pollution prevention recommendations. Five of the
37 Transport Region states are preparing Regional Haze Implementation Plans under
38 Section 309. Two others, California and Nevada, have adopted aggressive sets of
39 policies including Renewable Portfolio Standards and System Benefits Charges to
40 promote the development of new renewable power plants before 2018. Because these
41 states are all taking steps to achieve the regional 10/20 goal and represent an
42 overwhelming portion of the load within the Transport Region, the assumptions used by
43 WRAP to model emission reductions, cost savings, and secondary benefits should be

1 representative. Utah has relied on their analysis⁴² to prepare this section of the Utah
2 Regional Haze Implementation Plan. Additional modeling using different or state-
3 specific assumptions seems unlikely to yield any significant, substantive improvement
4 over the projections the WRAP has developed.

5 **b. Projections of Emissions Reductions, Visibility**
6 **Improvements, Cost Savings and Secondary Benefits**
7 **from Pollution Prevention and EERE Measures**

8 *(1) Modeling Method and Assumptions.*

9 The Air Pollution Prevention Forum of the WRAP developed a three-phase analytical
10 framework to assess the potential emissions reductions, cost savings and secondary
11 regional economic impacts of implementing the 10/20 goals and preserving and
12 expanding energy conservation efforts within the Transport region. These included: (1)
13 assumptions and scenario development, (2) modeling of the electric, steam and process
14 source sectors, and (3) modeling of the secondary regional economic impacts.

15
16 The Air Pollution Prevention Forum developed two types of scenarios to examine the
17 emissions reductions, cost savings and secondary regional economic impacts of meeting
18 the 10/20 goals and preserving and expanding energy conservation efforts. The first was
19 a Business-As-Usual scenario that characterized how the future might unfold with the
20 proposed, “backstop,” regional SO₂ trading program but without any policy measures
21 designed to achieve the 10/20 goals or enhance energy efficiency. The second set of
22 scenarios reflected a future with the regional SO₂ trading program and policy drivers
23 designed to meet the 10/20 goals or preserve and expand energy conservation efforts, or
24 both. Assessments of emissions reductions, cost savings and secondary regional
25 economic impacts were estimated by analyzing the differences between the policy
26 scenarios compared to the Business-As-Usual scenario.

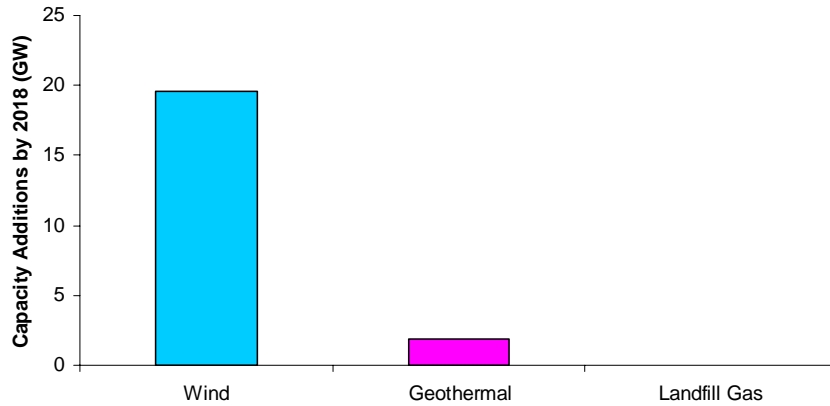
27
28 *(2) Forecast Power Supply Changes.*

29 Achieving the 10/20 goals and implementing the Air Pollution Prevention Forum energy
30 efficiency recommendations will stimulate significant renewable energy capacity
31 additions, 20,000 MW by 2018. Figure 6 summarizes the growth in renewable energy
32 capacity spawned by meeting the 10/20 goals. Figure 7 contrasts the generation mix in
33 2018 between the Business-As-Usual and 10/20 goal policy scenario.

⁴² Prepared for the Western Regional Air Partnership Air Pollution Prevention Forum. *Economic Assessment of Implementing the 10/20 Goals and Energy Efficiency Recommendations*. Draft Report of October, 2002;

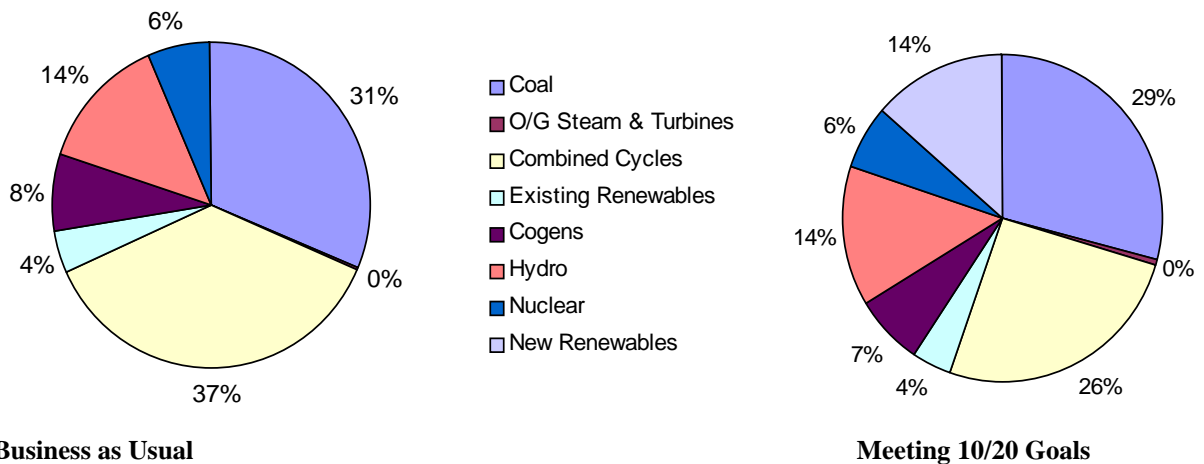
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Figure 6. Forecast Renewable Energy Capacity Additions to Meet 10/20 Goals.



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Figure 7. Generation Mix in 2018: Business-As-Usual and Meeting 10/20 Goals.



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Business as Usual

Meeting 10/20 Goals

9 As illustrated in Figures 6 and 7, wind power dominates the growth in new renewable
10 energy generation capacity and the increased use of renewable energy displaces new gas-
11 fired generation. While these results illustrate only the impact from meeting the 10/20
12 renewable generation goal, similar impacts occur with increased energy efficiency. The
13 key point illustrated by the projected change in the mix of generation capacity from
14 meeting the 10/20 goal and preserving and expanding energy conservation efforts is that
15 new renewable power generation and energy conservation compete against new
16 conventional capacity additions without significantly affecting existing electricity
17 generating sources.

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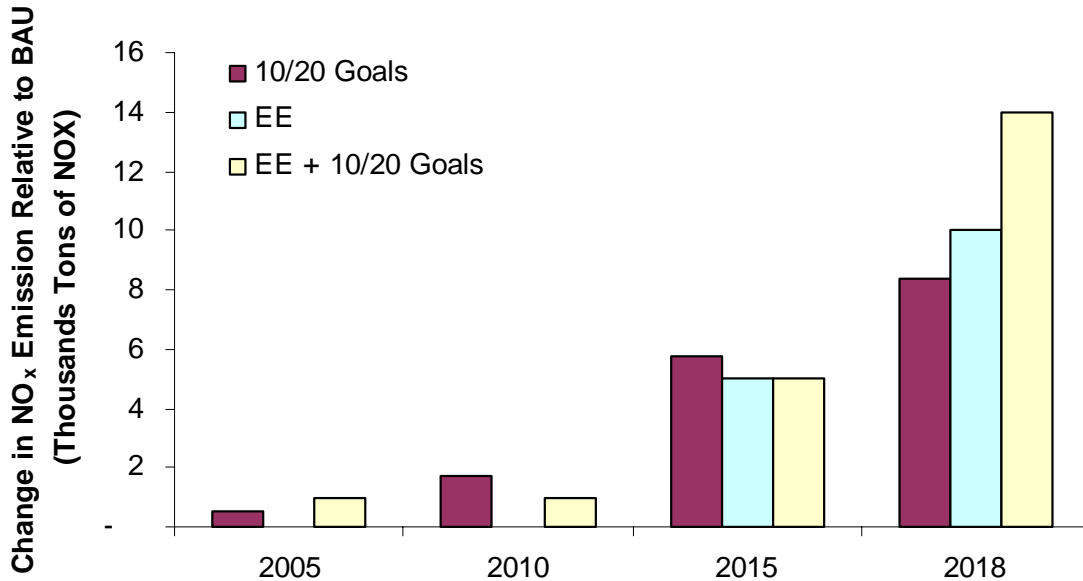
(3) Emissions Reductions.

20 The analyses completed by the WRAP indicate that meeting the 10/20 renewable energy
21 goal and implementing the recommendations developed by the Air Pollution Prevention
22 Forum as “best practices” to preserve and expand energy conservation can serve as cost-

1 effective air pollution prevention strategies because they provide emissions reductions at
2 modest costs or with some savings.

3
4 The fact that renewable energy capacity additions and energy efficiency are likely to
5 compete against generation from new gas-fired facilities affects the projected emissions
6 reductions from meeting the 10/20 renewable energy goal and implementing more
7 aggressive energy efficiency programs. As illustrated in Figure 8, the WRAP estimates
8 the potential reduction in NO_x emissions from meeting the 10/20 renewable energy goal
9 and preserving and expanding energy conservation efforts will likely be between 8,000
10 tons and 14,000 tons, 1 percent to 2 percent relative to Business-As-Usual. In Figure 8,
11 the bar labeled “10/20 goals” represents NO_x emissions reductions from a scenario in
12 which the 10/20 goal is met, the one marked “EE” represents NO_x emissions reductions
13 from a scenario in which the Air Pollution Prevention Forum energy efficiency
14 recommendations are implemented and the one labeled “EE + 10/20 goals” represents
15 NO_x emissions reductions from the policy scenario in which both the 10/20 goal and the
16 energy efficiency recommendations have been fully accomplished.

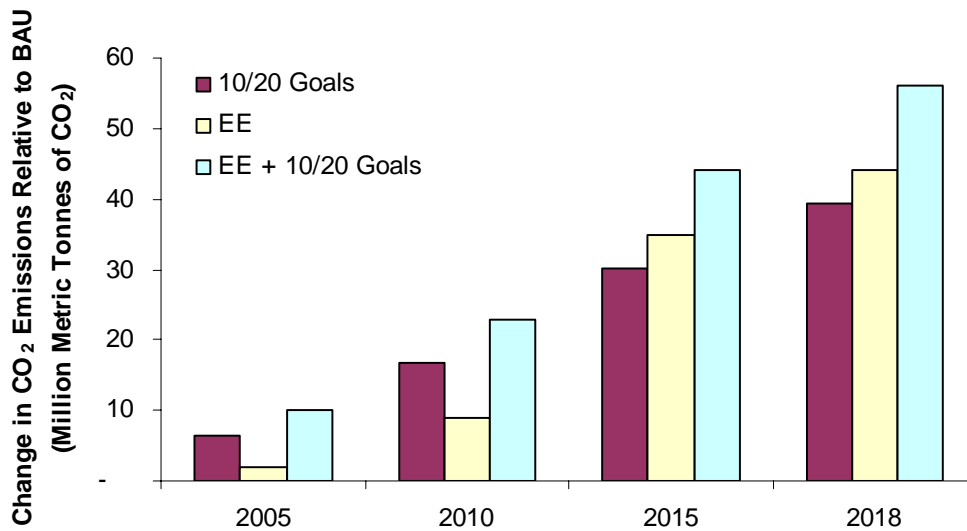
17
18 **Figure 8. Potential NO_x Emissions Reductions from Meeting the 10/20 Goal and**
19 **Implementing Energy Efficiency Recommendations.**



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3 Achieving the 10/20 renewable energy goal and pursuing energy efficiency aggressively
4 also leads to reductions in CO₂ emissions through the displacement of new fossil fuel
5 generation. As illustrated in Figure 9, CO₂ emissions reductions in 2018 from meeting
6 the 10/20 goal and preserving and expanding energy conservation efforts have been
7 projected to range between 40 million and 55 million metric tonnes, 10 percent to 14
8 percent relative to Business-As-Usual.

9
10
11 **Figure 9. Potential CO₂ Emission Reductions From Meeting the 10/20 Goal and EE.**



12
13 The WRAP modeling suggests accomplishing the 10/20 renewable energy goal and
14 preserving and expanding energy conservation efforts do not reduce SO₂ emissions
15 because the regional SO₂ trading program proposed under the Annex is the controlling
16 factor in reducing SO₂ emissions. Since the trading program creates a monetary value for
17 emissions reductions, any potential for emissions reductions is fully offset by increases in
18 SO₂ emissions from sources affected by the trading program. In other words, SO₂
19 emissions in 2013 and 2018 will reflect the emissions caps specified by the Annex.
20 However, meeting the 10/20 renewable energy goal and preserving and expanding energy
21 conservation efforts could decrease the cost of the SO₂ trading program by as much as \$7
22 million in 2018, about 10 percent of its projected cost,⁴³ and could displace 1,200 MW to
23 1,700 MW of new scrubber capacity by 2018.

24
25 (4) *Visibility Improvements.*

26 Projections of visibility improvements for the 16 Class I areas on the Colorado Plateau
27 are provided in Table 25 found in Part K. These projections include the combined effects
28 of all measures in this SIP, including air pollution prevention programs. Although

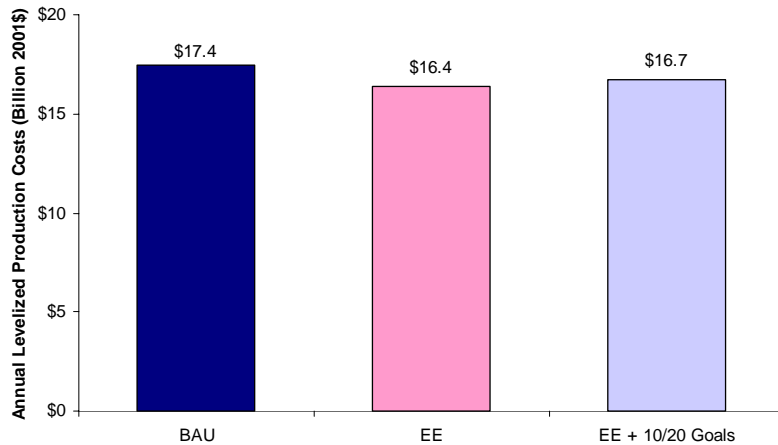
⁴³ *Economic Assessment of Implementing the 10/20 Goals and Energy Efficiency Recommendations*, page 36.

1 emission reductions and visibility improvements from air pollution prevention programs
2 are expected at some level, they were not explicitly calculated because the resolution of
3 the regional air quality modeling system is not currently sufficient to show any
4 significant visibility changes resulting from the marginal nitrogen oxide emission
5 reductions described above for air pollution prevention programs.

6
7 (5) *Cost Savings and Secondary Regional Economic Impacts.*

8 Achieving the 10/20 renewable energy goal and implementing the Air Pollution
9 Prevention Forum efficiency recommendations could be done for a modest production
10 cost increase or with some financial savings. In particular, preserving and expanding
11 energy conservation efforts could yield net, levelized annual production costs⁴⁴ savings
12 of \$750 million to \$1 billion, 4 percent to 7 percent relative to Business-As-Use. These
13 net savings reflect the cost of implementing the energy efficiency recommendations, the
14 avoided investment costs for transmission and distribution system upgrades, and the
15 reductions in electricity and steam production costs resulting from lower electricity
16 demand. Figure 10 compares the production costs estimated for Business-As-Usual and
17 those resulting from taking recommended steps to preserve and expand energy
18 conservation efforts across the transport region.

19
20 **Figure 10. Annual Levelized Production Costs for Business-As-Usual and**
21 **Efficiency.**

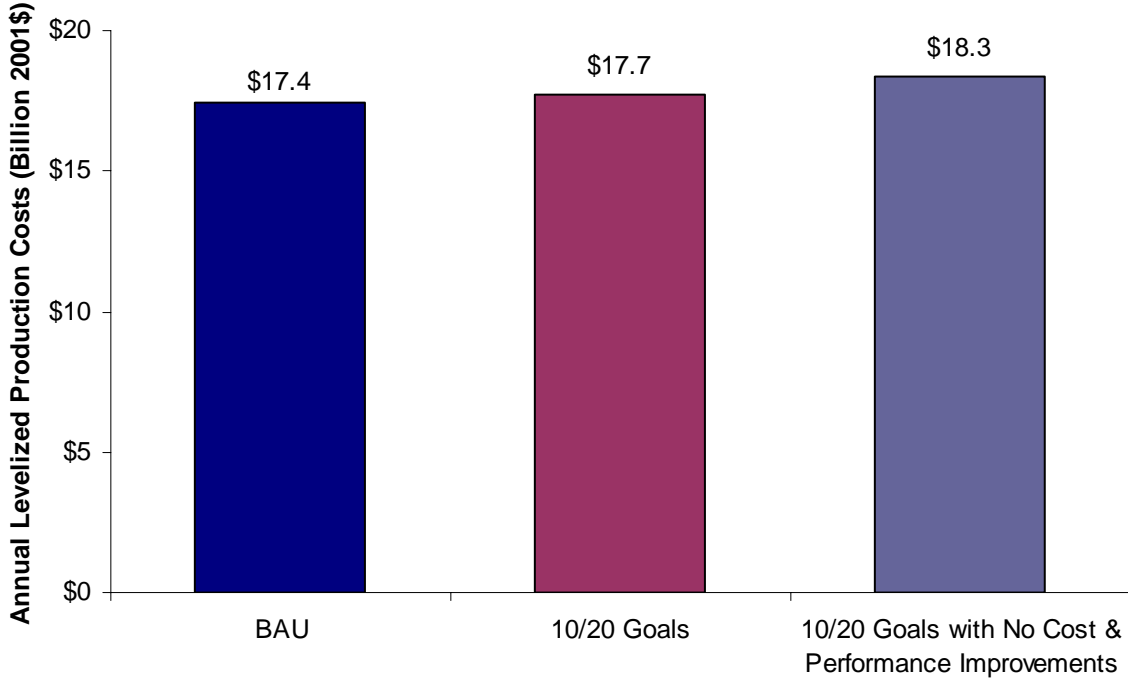


22 Accomplishing the 10/20 renewable energy goal by itself will increase annual levelized
23 production costs modestly. Electricity production costs could rise between \$300 million
24 and \$900 million, 2 percent to 5 percent compared to Business-As-Usual. This increase
25 is largely driven by the capital investments in new renewable energy generation capacity
26 and is offset by production cost savings from displaced fossil fuel generation. Figure 11
27 compares the annual levelized production costs associated with Business-As-Usual and
28

⁴⁴ Annual levelized production costs reflect the capital, fuel and operation and maintenance expenditures associated with the production of electricity and industrial steam levelized over the years 2005 – 2022. These modeled production costs do not include the sunk costs (capital cost or carrying charges) of existing units.

1 meeting the 10/20 renewable energy goal with and without cost and performance
 2 improvements that may occur over the planning period.

3
 4 **Figure 11. Annual Levelized Production Costs for BAU and Meeting the 10/20**
 5 **Goal.**



6
 7
 8 Achieving the 10/20 renewable energy goal and preserving and expanding energy
 9 conservation efforts has little or no impact on the regional economy. Most of the
 10 estimated regional impacts are less than one half of one percent. Table 20 summarizes
 11 the annual average secondary region economic impacts from meeting the 10/20
 12 renewable energy goal and pursuing energy efficiency improvements more aggressively.

13
 14 **Table 20. Annual Average (2005-2020) Changes for Key Economic Indicators**

	Employment		Gross Regional Product		Personal Disposable Income	
	(Persons)	(% Change)	(Million 2001\$)	(% Change)	(Million 2001\$)	(% Change)
10/20 Goals	627	0.00%	-312	-0.01%	73	0.00%
Energy Efficiency (EE)	8,415	0.02%	450	0.02%	776	0.04%
10/20 Goals + EE	4,097	0.01%	-58	0.00%	547	0.03%

15
 16
 17 The regional economic analysis suggests that meeting the 10/20 renewable energy goal
 18 and preserving and expanding energy conservation efforts may, on average, lead to an
 19 increase in economic activity. Over time, there may be small increases in regional
 20 economic activity in the early years and a small decline in later years from air pollution
 21 prevention programs. The impacts from 2005 to 2015 are largely the result of
 22 investments made in new renewable energy generation that increase labor demand and
 23 have secondary impacts on output and income. Following the investment and
 24 construction boom, the region could see some decline in employment, gross regional
 25 product and personal disposable income.

1
2 In general, accomplishing the 10/20 renewable energy goal probably will lead to small
3 increases in employment and personal income along with a small decline in gross
4 regional product. Preserving and expanding energy conservation efforts within the
5 Transport Region results in small increases in employment, personal disposable income
6 and gross regional product. This is sparked by new energy conservation investments.

7 **10. Utah Programs to Meet the Regional Renewable Energy** 8 **Goals**

9 **a. Summary of Utah Programs**

10 Following the findings of the Grand Canyon Visibility Transport Commission and the
11 Air Pollution Prevention Forum, the Western Regional Air Partnership (WRAP) found
12 that energy efficiency and renewable energy can be effective tools to reduce regional
13 haze and can reduce emissions, improve visibility, reduce energy costs and provide
14 secondary environmental and economic benefits to the region. The WRAP also
15 concluded that implementing both renewable energy and energy efficiency program and
16 policy measures together will yield larger emissions benefits than either energy
17 efficiency or renewable energy measures alone would yield. The U.S. Environmental
18 Protection Agency made similar presumptions in promulgating Section 309(d)(8) of the
19 Regional Haze Rule.

20
21 The inclusion of energy efficiency and renewable energy programs in the State
22 Implementation Plan and estimated emission reductions and impacts from them does not
23 cause such programs and estimates to become mandatory and/or federally enforceable.
24 These programs are voluntary state and local programs that were never intended to be
25 federally enforceable.⁴⁵ The WRAP has explicitly expressed its expectation that these
26 programs will be implemented consistent with local economic, regulatory, and political
27 conditions while protecting cultural resources and values. These programs may be
28 modified, changed, expanded, redirected or eliminated and new programs may be
29 adopted and implemented without seeking approval from the federal government. The
30 projected emission reductions are estimates only. It is expected that these programs and
31 their associated emissions impacts will change over time without requiring a SIP
32 revision. Utah will, as required, report its progress toward meeting the regional 10/20
33 renewable energy goals in the periodic SIP reviews required under 40 CFR
34 51.309(d)(10).
35

⁴⁵ The GCVTC goal is 10 percent of generation from renewable resources in 2005 and 20 percent in 2015. With respect to the requirements of Section 309(d)(8), achieving the 10/20 goal is not mandatory or “enforceable.” This section of the rule simply establishes an “enforceable” requirement for states “to assess progress toward a goal established by the GCVTC with respect to renewable energy.” To the extent they are not able meet the goal, states are required to provide an explanation of why the goals cannot be met. See 64 FR 35754, July 1, 1999. *Regional Haze Regulations Final Rule*.

Pursuant to 40 CFR 51.309(d)(8)(vi), Table 21 lists the programs that the State of Utah will employ to make its contribution toward meeting the regional renewable energy goals of supplying 10 percent of its power needs from renewable sources by 2005 and 20 percent by 2015.

Table 21. Utah Renewable Energy Program Descriptions

PROGRAM TYPE	INDIVIDUAL PROGRAMS
Utility Integrated Resource Planning	PacifiCorp Integrated Resource Planning – Renewable Additions
	UAMPS Integrated Resource Planning
Net Metering	Utah Net Metering Program
Green Pricing	PacifiCorp Blue Sky Marketing Program
Financial Incentives	Renewable Energy Systems Tax Credit Program
Government Endorsed Green Power Purchases	Supplemental Environmental Project Program
	Salt Lake City Climate Action Plan Program
Technical Assistance	Million Solar Roofs Partnership Program

b. Potential for Renewable Energy Resources

(1) *Renewable energy potential and areas where renewable energy can supply power.*

The renewable energy resource potential in Utah and its geographic distribution across the state have been characterized succinctly in the *Renewable Energy Atlas of the West*.⁴⁶ The Atlas was assembled using best available renewable energy resource maps and data. Data and map sources have been scrupulously documented. The Atlas was used as a source for preparing this section. The existing data and maps are useful to policymakers as a tool for planning. They serve their intended function within the context of the Utah Regional Haze Implementation Plan.

The potential to generate power from renewable energy sources reported in this section is based on the total estimated availability of each type of renewable energy source within Utah. The power production potential for each type of renewable resource is an estimate of what could be developed, not an estimate of what will be developed during any future period of time. The estimates are presented to document that Utah has sufficient renewable energy resource potential to meet the regional goals of generating 10% of its power from renewable resources by 2005 and 20% by 2015. In fact, Utah has the potential to generate much more than would be required to simply meet the regional

⁴⁶ Land and Water Fund of the Rockies, Northwest Sustainable Energy for Economic Development, and GreenInfo Network with support from the Hewlett Foundation and the Energy Foundation. *Renewable Energy Atlas of the West: A Guide to the Region’s Resource Potential*. Available at www.energyatlas.org.

1 goals. During the periodic SIP reviews required under 40 CFR 51.309(d)(10), an update
2 of information required under 40 CFR 51.309(d)(8) will be incorporated into the Utah
3 Regional Haze Implementation Plan revisions.

4
5 (a) Solar energy potential and distribution. The potential to generate power from
6 incident solar radiation in Utah is estimated to be 69,000,000 MWh/yr. Most of
7 this potential is located in the southern and southwestern portions of Utah.
8 Assuming that the systems used to transform Utah's solar energy potential to
9 power operate at a 20 percent capacity factor⁴⁷, there is potential to install
10 approximately 39,400 MW of solar power capacity in Utah. Presently, solar
11 power production costs significantly more than other means for generating power.
12 As a consequence, the vast majority of Utah's solar power potential is not
13 economical to develop for utility system electricity sales at this time. Figure 12
14 characterizes the distribution and relative potential of the solar energy resource in
15 Utah.

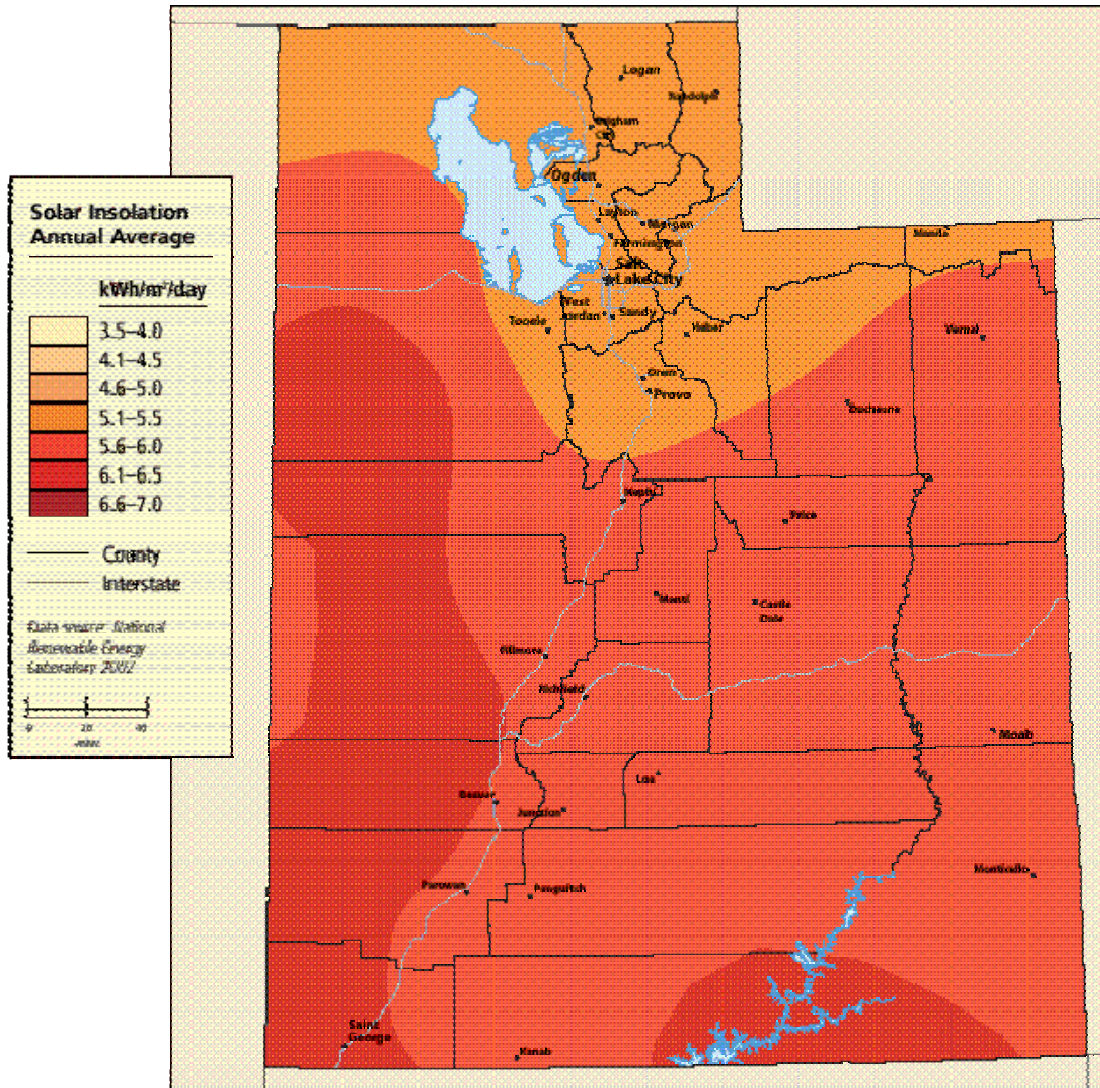
⁴⁷ "Capacity factor" is a value used to express the average percentage of full power production capacity achieved or expected over a given period of time. For example, a generating facility that operates at an average of 60% of its normal full capacity over a measured period has a capacity factor of 0.6 for that period. A capacity factor can apply to an individual generating unit or any collection of generating units. In mathematical terms this can be expressed as:

$$\frac{\text{Installed renewable capacity}}{\text{capacity for the renewable source}} \times \text{capacity factor} = \text{renewable power production}$$

Since the availability of many renewable energy sources varies throughout the day and from day to day, renewable power generators operate at only a portion of their full power production capacity. The capacity factors used in this section to convert the potential power production in Utah from each type of renewable energy source to an estimate of the potential installed renewable energy capacity for each type of renewable resource were developed by the Utah Energy Office based on their experience and information reported in professional papers. It was done to permit readers to more easily compare Utah's existing installed capacity and power production with the installed capacity and power production that might be possible in the future from Utah's renewable energy resources.

1

2 **Figure 12. Solar Energy Potential in Utah.**

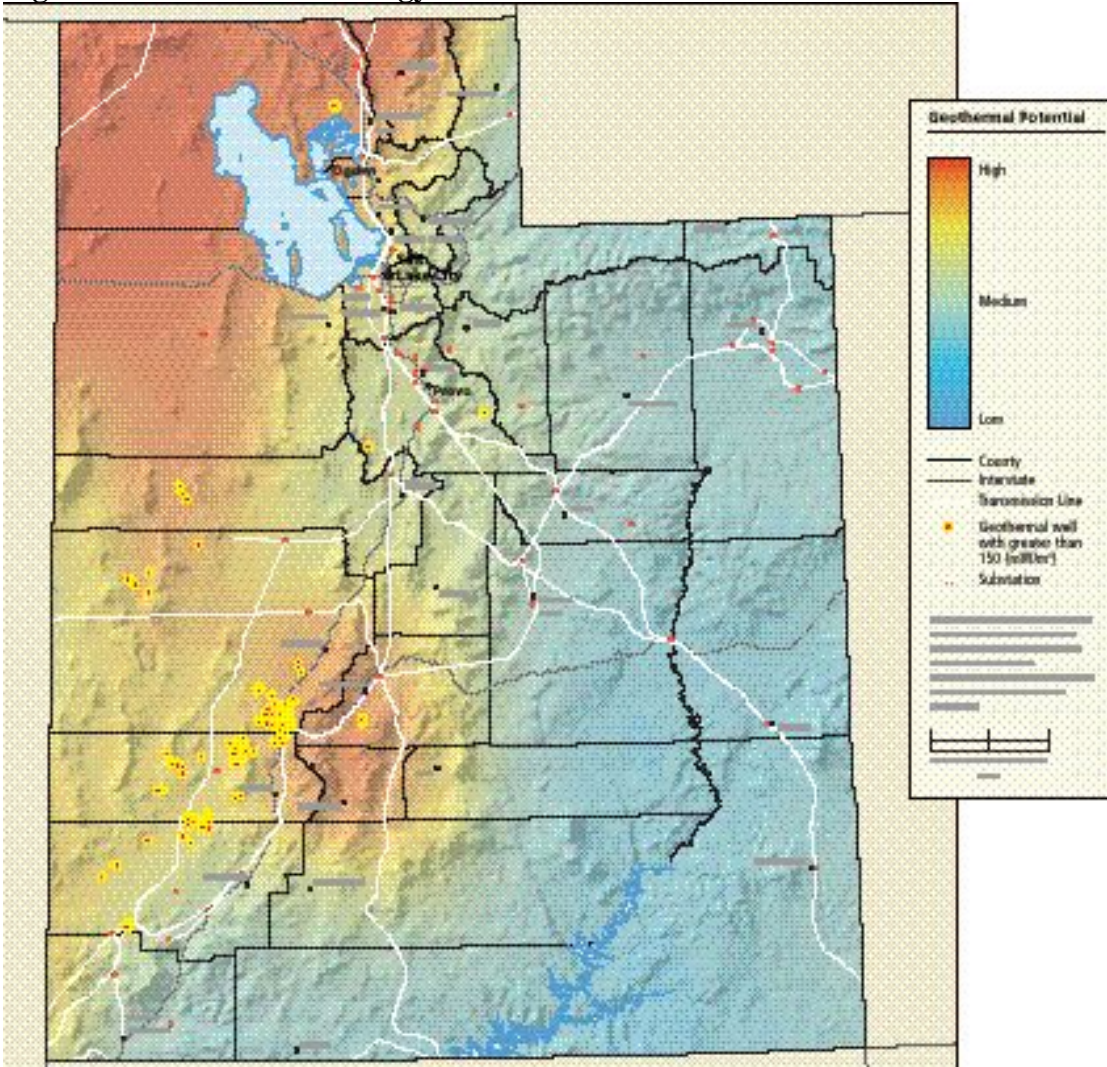


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(b) Geothermal energy potential and distribution. Utah is one of the few states to have developed geothermal power plants, 39.8 MW of generation capacity. Utah has substantial, additional, undeveloped geothermal power production potential. The potential to generate power from geothermal sources in Utah is estimated to be 9,000,000 MWh/yr. Assuming that systems used to transform Utah's geothermal energy potential to power operate at a 60 percent capacity factor, there is potential to install approximately 1,700 MW of geothermal generating capacity in Utah. Figure 13 characterizes the distribution and relative potential for producing electricity from geothermal sources in Utah.

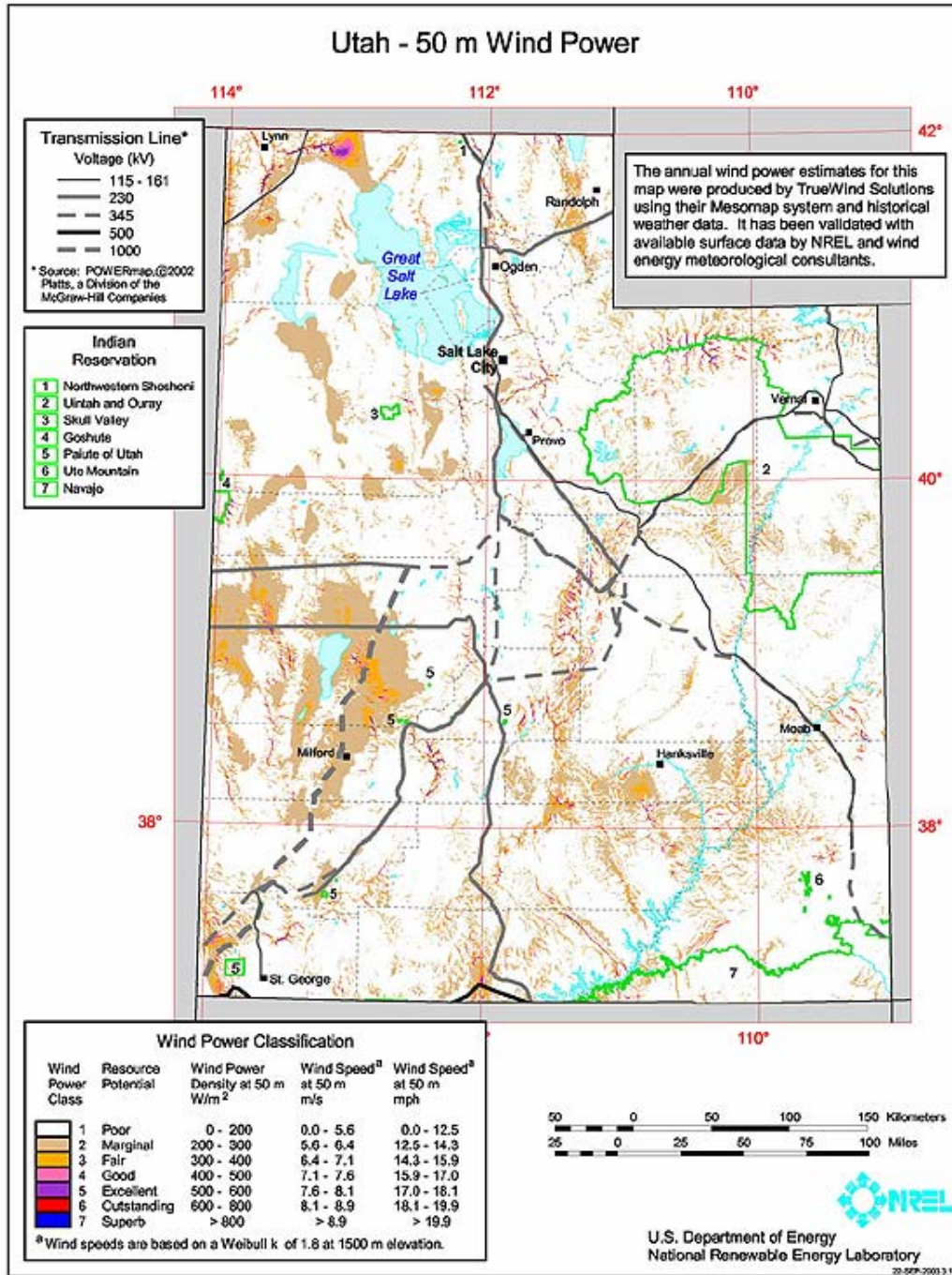
Figure 13. Geothermal Energy Potential in Utah.



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1 (c) Wind energy potential and distribution. Some areas of Utah have excellent
2 wind energy resources that may be suitable for utility-scale development. The
3 potential to generate power from wind in Utah is estimated to be 23,000,000
4 MWh/yr. Figure 7 roughly characterizes the distribution and relative potential of
5 the wind energy resource in Utah. The most recent map and estimate of the
6 developable wind resource potential in Utah has been prepared by the Utah
7 Energy Office and the National Renewable Energy Laboratory, and is included
8 below as Figure 14. Assuming that systems used to transform Utah's wind energy
9 potential to power operate at a 32 percent capacity factor, there is potential to
10 install approximately 8,200 MW of wind generating capacity in Utah. Most of
11 the wind energy potential in Utah comes from areas with lower power production
12 capability. Wind power developers generally want to build only in the windiest
13 areas to assure their competitiveness in electricity markets. As a consequence,
14 only a fraction of Utah's overall wind potential will be attractive for wind
15 development in the near term.

1 Figure 14. Wind Energy Potential in Utah.

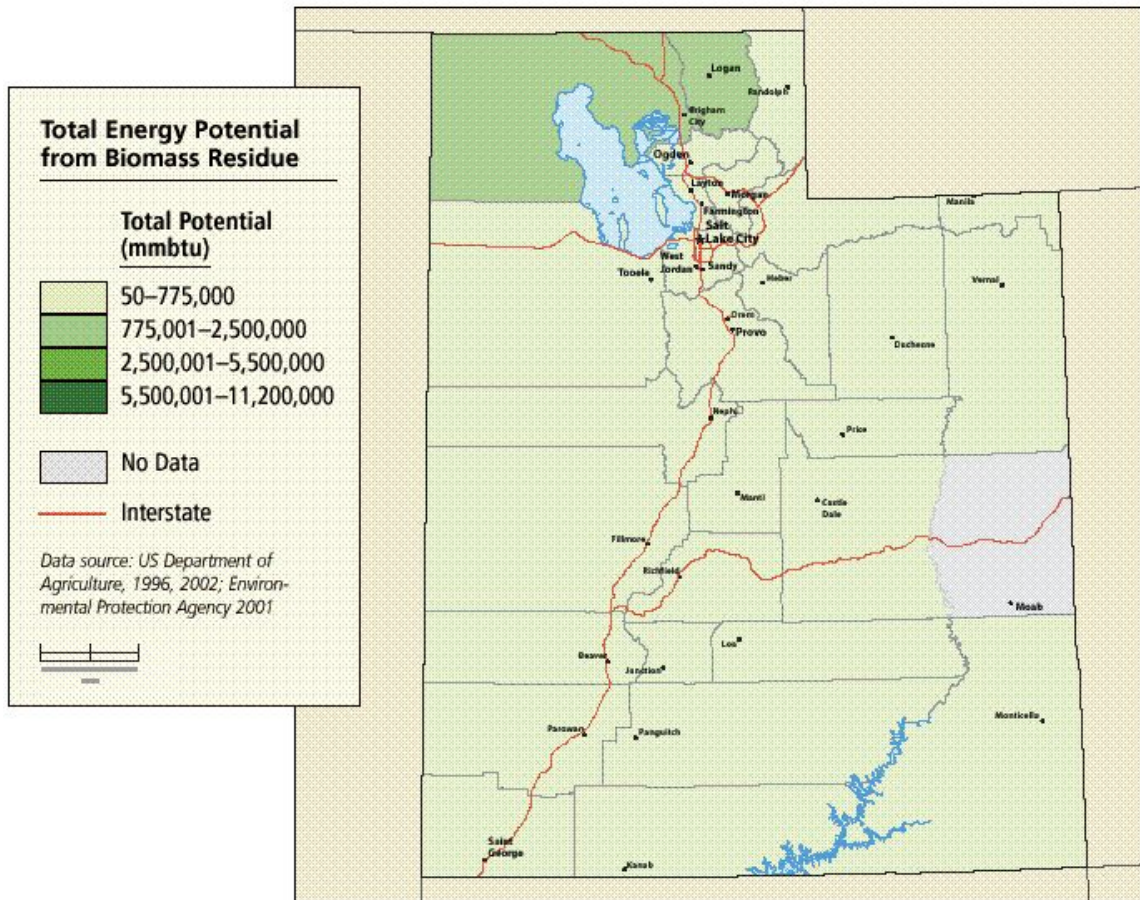


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(d) Biomass energy potential and distribution. The potential to generate power from landfill gas and plant and animal wastes in Utah is estimated to be 1,000,000 MWh/yr. Most of this potential is located in the northern and northwestern portions of Utah. Assuming that systems used to transform Utah's biomass energy potential to power operate at an 80% capacity factor, there is potential to install approximately 140 MW of biomass generating capacity in Utah. Figure 15 characterizes the distribution and relative potential for generating power from biomass in Utah.

Figure 15. Biomass Energy Potential in Utah.



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(e) Landfill gas energy potential. The estimated power production potential from landfill gas in Utah that is embedded in the biomass map and energy production projections was derived from the Environmental Protection Agency Landfill Methane Outreach Program database (2001). The detailed landfill gas database for Utah is presented in Table 22.

1 **Table 22. Utah Land-fill Gas Resources**

Project ID #	Landfill ID #	LMOP Territory	Landfill Name	Landfill City	Landfill County	Landfill State	WIP (tons)	Year Landfill Opened	Landfill Closure Year	Landfill Owner	Project Status	Project Developer	Utilization Type (Direct-Use vs Electricity)	Specific Utilization Type	Capacity (MW)	LFG Flow to Project (mmscfd)	Emission Reductions (MMTCO2E)
1619	1542	3	Salt Lake Valley LF	Salt Lake	Salt Lake	UT	6,700,000	1982	2020	Salt Lake Valley Solid Waste Management Council	Construction	DTE Energy	Direct	Boiler			0.242
1604	1527	3	City of Logan Sanitary Landfill	Logan	Cache	UT	1,400,000	1961	2016	City of Logan	Potential		Electricity				
1630	1553	3	Beaver County LF	Beaver	Beaver	UT	107,648	1968	2014	Beaver City	Unknown		Direct				
1625	1548	3	Blanding LF	Blanding	San Juan	UT	50,780	1956	1995	Blanding City	Unknown		Direct				
1617	1540	3	Bountiful City Sanitary LF	West Bountiful	Davis	UT	2,171,531	1960	2058	City of Bountiful	Unknown		Direct				
1598	1521	3	Brigham City LF	Brigham	Box Elder	UT	693,000	1960	1995	Box Elder County	Unknown		Direct				
1606	1529	3	Callao LF		Juab	UT		1970			Unknown		Direct				
1621	1544	3	Carbon County LF	Price	Carbon	UT	280,000	1956	1995	Carbon County	Unknown		Direct				
1626	1549	3	City of Monticello LF	Monticello	San Juan	UT	36,000	1960	1995	Max Dalton	Unknown		Direct				
1618	1541	3	Davis County Solid Waste Management SSD LF	Layton	Davis	UT	1,840,150	1959	2022	Wasatch Energy Systems	Unknown		Direct				
1642	1565	3	Duchesne County LF	Duchesne	Duchesne	UT		1984	2044	Duchesne & Wasatch Counties	Unknown		Direct				
180128	2074	3	ECDC	East Carbon		UT					Unknown						
1622	1545	3	Emery County LF	Castledale	Emery	UT	212,184	1983	2024	Emery County	Unknown		Direct				
1609	1532	3	Eskdale LF		Millard	UT					Unknown		Direct				
1631	1554	3	Garfield County/John's Valley LF	Garfield	Garfield	UT	16,200	1992	2044	Garfield County	Unknown		Direct				
1632	1555	3	Garfield County/Ticaboo LF	Garfield	Garfield	UT	8,852	1993	2014	Garfield County	Unknown		Direct				
1610	1533	3	Garrison LF	Garrison	Millard	UT	660	1986	2094	Millard County	Unknown		Direct				
1624	1547	3	Grand County LF	Moab	Grand	UT	76,300	1960	2004	Grand County	Unknown		Direct				
1623	1546	3	Green River LF	Green River	Emery	UT	79,205	1965	1995	Green River City	Unknown		Direct				
1599	1522	3	Grouse Creek LF	Grouse Creek	Box Elder	UT	1,760	1980	1995	Box Elder County	Unknown		Direct				
1633	1556	3	Iron County/ Armstrong Pit LF	Cedar	Iron	UT	44,962	1993	2014	Iron County	Unknown		Direct				
1635	1558	3	Kane County/Glendale LF	Glendale	Kane	UT	6,560	1988	2094	Western Kane County SSD# 1	Unknown		Direct				
1634	1557	3	Kane County/Kanab LF	Kanab	Kane	UT	39,680	1981	2044	Western Kane County SSD# 1	Unknown		Direct				
1641	1564	3	Manila City LF	Manila	Daggett	UT	32,120	1974	1995	Manila City/Daggett County	Unknown		Direct				
1611	1534	3	Millard County LF	Delta	Millard	UT	67,650	1986	2034	Millard County	Unknown		Direct				
1607	1530	3	Nephi LF	Nephi	Juab	UT	18,300	1987	2044	Nephi City	Unknown		Direct				

Table 22. (Continued) Utah Land-fill Gas Resources

Project ID #	Landfill ID #	LMOP Territory	Landfill Name	Landfill City	Landfill County	Landfill State	WIP (tons)	Year Landfill Opened	Landfill Closure Year	Landfill Owner	Project Status	Project Developer	Utilization Type (Direct-Use vs Electricity)	Specific Utilization Type	Capacity (MW)	LFG Flow to Project (mmscfd)	Emission Reductions (MMTCO2E)
1645	1568	3	North Utah County Special Service District LF		Utah	UT	1,707,965	1964	1993		Unknown		Direct				
1600	1523	3	Park Valley LF	Park Valley	Box Elder	UT	2,400	1980	1995	Box Elder County	Unknown		Direct				
1608	1531	3	Partoun LF		Juab	UT					Unknown		Direct				
1614	1537	3	Payson City LF	Payson	Utah	UT	616,029	1950	2014	Payson City Corporation	Unknown		Direct				
1646	1569	3	Provo LF	Provo	Utah	UT	1,131,000	1963	1991	City of Provo	Unknown		Direct				
1605	1528	3	Rich County LF	Laketown	Rich	UT	40,688	1981	2030	Rich County	Unknown		Direct				
1627	1550	3	San Juan County/Bluff LF	Bluff	San Juan	UT	1,600	1980	1995	San Juan County	Unknown		Direct				
1628	1551	3	San Juan County/Halls Crossing LF	Halls Crossing	San Juan	UT	9,464	1970	1995	San Juan County	Unknown		Direct				
1629	1552	3	San Juan County/Mexican Hat LF	Mexican Hat	San Juan	UT	1,600	1980	1995	San Juan County	Unknown		Direct				
1612	1535	3	Sanpete SLF Coop	Spring City	Sanpete	UT	108,396	1989	2066	Sanpete SLF Coop	Unknown		Direct				
1615	1538	3	Santaquin County LF	Santaquin	Utah	UT	262,080	1900	1995	Santaquin City	Unknown		Direct				
1613	1536	3	Sevier County/Sage Flat LF	Glenwood	Sevier	UT	70,200	1993	2024	Sevier County	Unknown		Direct				
1601	1524	3	Snowville LF	Snowville	Box Elder	UT	8,100	1970		Snowville Town	Unknown		Direct				
1616	1539	3	South Utah County SSD/Bayview LF	Utah	Utah	UT	1,100,000	1991	2094	South Utah Valley Solid Waste District	Unknown		Direct				
1637	1560	3	Summit County/Three Mile Canyon LF	Wanship	Summit	UT	358,896	1986	2026	Summit County	Unknown		Direct				
1638	1561	3	Tooele Army Depot LF #1	Tooele	Tooele	UT			1995	Commander Tead	Unknown		Direct				
1639	1562	3	Tooele Army Depot LF #2	Tooele	Tooele	UT			1995	Commander Tead	Unknown		Direct				
1620	1543	3	Transjordan LF	South Jordan	Salt Lake	UT	8,622,936	1955	2021	Trans-Jordan Cities	Unknown		Direct				
1602	1525	3	Tremonton LF	Tremonton	Box Elder	UT	184,600	1970	1995	Box Elder County	Unknown		Direct				
1643	1566	3	Uintah County/Vernal City LF	Vernal	Uintah	UT	2,773,000	1950	2008	Uintah County and Vernal City	Unknown		Direct				
1636	1559	3	Washington County Solid Waste SSD #1 LF	Washington	Washington	UT	1,292,000	1978	2067	Washington County	Unknown		Direct				
1644	1567	3	Weber County LF	Ogden	Weber	UT	3,500,000	1966	1996	Weber County	Unknown		Direct			0.8	
1640	1563	3	Wendover City LF	Wendover	Tooele	UT	118,260	1970	1996	Wendover City	Unknown		Direct				
1603	1526	3	Yost LF	Yost	Box Elder	UT	800	1980	1995	Box Elder County	Unknown		Direct				

1 **J. OTHER GCVTC RECOMMENDATIONS**

2 **1. Regulatory History and Requirements**

3 The recommendations of the GCVTC are presented throughout the June 1996 final report with
4 varying degrees of specificity. Not all are included in the Regional Haze Rule. However, some of
5 the recommendations were intended as a menu of options, with no expectation that any geographic
6 area would implement all of them. The GCVTC pointed out in its final report that:

7
8 “Some of the Commission's recommendations ask the EPA to take specific actions
9 or institute particular **programs**, in cooperation with the tribes, states and federal
10 agencies as implementing bodies. Other recommendations provide a range of
11 potential policy or strategy **options for consideration** by the EPA and implementing
12 entities. As the EPA develops policies and takes actions based on this report, this
13 distinction between "actions" and "options" should be maintained with diligence.
14 That is, recommendations intended as policy options should not become mandated
15 actions or regulatory programs.” [BOLD emphasis in original.]⁴⁸

16 **2. Other State of Utah Long-term Strategy Components**

17 **a. Evaluation of Additional Grand Canyon Visibility Transport** 18 **Commission Recommendations.**

19 Pursuant to 40 CFR 51.309(d)(9), Utah has evaluated the “additional” recommendations of the
20 Grand Canyon Visibility Transport Commission to determine if any of these recommendations can
21 be practicably included in this implementation plan. Utah reviewed the GCVTC's 1996 report,
22 *Recommendations for Improving Western Vistas*, to identify those recommendations that were not
23 incorporated into Section 309 of the Regional Haze Rule.

24 **b. Implementation of Additional Recommendations.**

25 Based on the evaluation made by the State of Utah, no additional measures have been identified as
26 being practicable or necessary to demonstrate reasonable progress. *Report to the Environmental*
27 *Protection Agency and the Public to Satisfy the Requirements of 40 CFR 51.309(d)(9)* includes a
28 complete list of all additional recommendations and their status.⁴⁹ This report is to be reviewed
29 and updated if necessary in 2008, 2013, and 2018.

⁴⁸ *Recommendations for Improving Western Vistas*, page i.

⁴⁹ Utah Division of Air Quality. *Report to the Environmental Protection Agency and the Public to Satisfy the Requirements of 40 CFR 51.309(d)(9)*. Salt Lake City, Utah. December, 2003.

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K. PROJECTION OF VISIBILITY IMPROVEMENT ANTICIPATED FROM LONG-TERM STRATEGY

The Western Regional Air Partnership performed extensive analysis and modeling in order to determine the impact of the regional haze program on visibility at the 16 Class I areas on the Colorado Plateau. This work was performed by several contractors under the direction of various technical and policy forums of the WRAP.

This work began with development of a comprehensive inventory of emissions throughout the region for all categories of sources. In addition, econometric models and new technology profiles were used to project changes in those emissions over time that are expected from implementation of current requirements under the CAA. The WRAP also estimated emission changes resulting from the programs contained in the long-term strategy for regional haze under 40 CFR 51.309.

The emission inventories and projections were used by the WRAP Regional Modeling Center to estimate aerosol concentrations and visibility at each of the 16 Class I areas. WRAP also developed estimates of aerosol concentrations and visibility for the non-GCVTC Class I areas. The WRAP Regional Modeling Center used the Community Multi-scale air Quality (CMAQ) model to estimate aerosol concentrations from the emission inventories and projections.

Emission inventories and modeling results are generated from the technical work conducted by the WRAP, which evaluated the visibility improvements resulting from the application of the regional haze control strategies and programs. The WRAP developed a Technical Support Document (TSD) that contains detailed descriptions of the emissions inventory and projection methods as well as the air quality modeling techniques and results. The following sections contain an overview of the projected changes in emissions and visibility resulting from the implementation of the Regional Haze Rule.

1. Effect on Emissions of Long-term Strategy Components

a. Inventory Methodology and Scope

The base WRAP emission inventories used for assessment of visibility included the following pollutants:

- Volatile Organic Compounds (VOCs);
- Oxides of Nitrogen (NO_x);
- Carbon Monoxide (CO);
- Sulfur Dioxide (SO₂);
- Particulate Matter smaller than 10 microns (PM₁₀);
- Particulate Matter smaller than 2.5 microns (PM_{2.5}); and
- Ammonia (NH₃).

For visibility modeling, the PM_{2.5} emissions inventory was broken into components, or species, representing the key visibility impairing species of interest. This breakdown is necessary since each

1 component has a different effect on visibility. These PM_{2.5} species are organic carbon particles
2 (OC), elemental carbon particles (EC), and other fine particles such as soils and dusts. The factors
3 used to allocate PM_{2.5} into its components are based on source specific speciation factors. In
4 addition, the coarse material (CM) fraction of PM₁₀ (i.e., PM₁₀ minus PM_{2.5}) was also computed,
5 since coarse particulate matter has a different effect on visibility than fine particulate matter.
6

7 The geographic domain for the inventory included the 22 states west of the Mississippi River, and
8 portions of Mexico and Canada. A detailed base year emission inventory was developed for 1996
9 and included emissions from all of the following categories of sources:

- 11 • Area Sources;
- 12 • Stationary Point Sources;
- 13 • Mobile Sources (both on-road and non-road);
- 14 • Road Dust (from both paved and unpaved road surfaces);
- 15 • Fire Emissions (agricultural burning, prescribed fire, and wild fire); and
- 16 • Biogenic Sources.

17
18 In support of the WRAP Regional Haze air quality modeling efforts after 2003, the WRAP
19 Regional Modeling Center (RMC) developed annual emissions inventories for the 2002 actual
20 emissions base case, a planning case to represent the 2000-04 regional haze baseline period using
21 averages for key emissions categories, and a 2018 base case of projected emissions determined
22 using factors known at the end of 2005 and 2007 with a final update in 2008. Each of these
23 inventories has undergone a number of revisions throughout the development process with input
24 from UDAQ staff, to arrive at the final versions used for air quality modeling. The WRAP emission
25 inventories developed by the RMC include:

- 26 • The 2002 base case emissions scenario is referred to as “2002 Base Case” or “Base02”. The
27 purpose of the Base02 inventory is to represent the actual conditions in calendar year 2002
28 with respect to ambient air quality and the associated sources of criteria and particulate
29 matter air pollutants. The Base02 emissions inventories are used to validate the air quality
30 model and associated databases by demonstrating acceptable model performance with
31 respect to replicating observed particulate matter air quality.
- 32 • The 2000-04 baseline period planning case emission scenarios are referred to as the
33 “Plan02” series. The purpose of the Plan02 inventories is to represent baseline emission
34 patterns based on average, or “typical”, conditions. This inventory series (cases Plan02 a, b,
35 c) was developed in sequence to diagnose inventory problems and true up the
36 representativeness and accuracy of the emissions for planning purposes. This inventory
37 provides a basis for comparison with the future year 2018 projected emissions.
- 38 • Three 2018 future-year emission scenarios were developed. These emission inventories are
39 used to represent conditions in 2018 with respect to sources of criteria and particulate matter
40 air pollutants, taking into consideration growth and controls. Modeling results based on this
41 emission inventory are used to define the future year ambient air quality and visibility
42 metrics.

- Base Case (base18b) is a modeling case with estimated emissions growth plus all controls “on the books” as of December 2004 without BART or the Section 309 SO₂ milestone reductions.
- Preliminary Reasonable Progress Case (PRP18) is the modeling case with a refined emissions growth estimate plus all emission controls “on the books” as of May 2007, including presumptive limits or known SO₂ BART controls on electric generating units (EGU).
- Final Reasonable Progress Case (FRP18) is a future modeling case with a refined emissions growth estimate plus all emission controls “on the books” as of May 2007, including all BART controls in the WRAP region and limits defined in the Section 309 SO₂ milestone “better than BART” program.” The RMC anticipated that FRP 18 modeling will be complete by the third quarter of 2008.

UDAQ staff reviewed the Utah emission inventory for consistency and provided feedback to WRAP on areas of the inventory that should be improved in the future. UDAQ staff concluded that the 1996 and 2002 inventories were adequate for regional haze modeling given the uncertainties in any emission inventory process. UDAQ staff also reviewed the 2018 emission growth and projection factors used to develop the 2018 inventory and found the projection to be within the range expected from long range economic projections.

b. Projected Changes in Emissions for Utah and the GCVTC Region

The changes in overall emissions for the State of Utah are summarized in Table 23. As shown, emissions of sulfur dioxide are expected to decrease by 33% by 2018 from the 1996 levels. This reduction is due primarily to the long-term strategy for stationary sources of sulfur dioxide described in Part E that will generate a 48% reduction in emissions from stationary sources in the four states that are participating in the Western Regional Milestones and Backstop Trading Program by 2018 from a 1990 baseline. Also, emissions of oxides of nitrogen and particulate matter (PM_{2.5}) in the state are expected to decline by 36% and 38%, respectively, due to the implementation of new federal engine standards and fuel standards described in Part F and BART controls for NO_x and PM_{2.5} described in Part D. The emission inventories for VOC and coarse particulate matter (CM) are also shown, but it is difficult to compare the 1996 and 2018 inventories for these pollutants due to significant changes in the methodology for estimating emissions from dust, fire, and oil and gas production. Therefore a percent change is not shown for those pollutants.

Table 23. Summary of the Change in Emissions from 1996-2018 for Utah Sources

(Thousands of Tons per Year)(Plan 02d – PRP 18a)					
		NO _x	SO ₂	PM _{2.5} *	
1996	172	270	67	85	64
2002	186	227	54	53	98
2018	233	172	45	53	110
% Change (1996-2018)		-36%	-33%	-38%	

*PM_{2.5} includes organic carbon, elemental carbon, and fine soils/dusts.

1 Table 24 shows similar emission reductions for the nine-state GCVTC region, except that
 2 regionally, sulfur dioxide emissions will be reduced by 53% by 2018 from 1996 levels. The reason
 3 Utah's reduction of sulfur dioxide is smaller than that in the nine states is that the level of pollution
 4 controls on facilities in Utah was generally better than that in several other states. Emissions of
 5 NO_x and PM will decrease in the region by 57% and 31% respectively. The detailed county-level
 6 emission inventories for the entire WRAP region are included in the 2003 and 2008 WRAP TSDs.

7
8
9

Table 24. Changes in Emissions from 1996 - 2018 for 9 GCVTC States

	(Thousands of tons per year)(Plan 02d – PRP 18a)				
	VOC	NO _x	SO ₂	PM _{2.5} *	CM
1996	3,325	3,952	1,063	1,197	1,171
2002	2,449	2,241	675	832	1,886
2018	2,760	1,683	503	832	2,104
% Change (1996-2018)	-17%	-57%	-53%	-31%	80%

10 *PM_{2.5} includes organic carbon, elemental carbon, and fine soils/dusts.

11
12
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14

The emission reductions in Utah occur throughout the state and will therefore benefit all Class I areas outside of Utah that might be impacted by emissions from Utah.

- 15 • Northern Utah. The urban area in northern Utah that may impact Class I areas in Idaho, Nevada and Wyoming will have a significant reduction in NO_x emissions from mobile sources as described in Section XX.F of this plan. Mobile (on-road and non-road) NO_x emissions in the four main urban counties (Weber, Davis, Salt Lake, and Utah) are projected to decrease by 42,000 tons/yr or 61% between 2002 and 2018. Mobile sources dominate the NO_x emission inventory in Utah's urban area. Class I areas that have some days when nitrates are a significant contributor to visibility impairment, such as Craters of the Moon National Park, will benefit from the NO_x emission reductions during those episodes.
- 24 • Central and Southern Utah. As described in Section XX.D.6 of this plan, two BART-eligible plants in central Utah are projected to decrease SO₂ emissions by 13,200 tons and NO_x emissions by 6,200 tons between 2002 and 2018. Central and Southern Utah are sparsely populated and the inventory is dominated by point sources. The exception is Washington County that is becoming more urban due to the growth of St. George and the inventory is therefore dominated by mobile source emissions. In Washington County, NO_x emissions from mobile sources (on-road and non-road) are projected to decrease by 2,300 tons or 57% between 2002 and 2018. These emission reductions will benefit Class I areas in southern Colorado, New Mexico and Arizona that may be affected by emissions from Utah.
- 34 • Eastern Utah. Oil and Gas emissions dominate the inventory in eastern Utah and are increasing between 2002 and 2018. Approximately 90% of current emissions from oil and gas occur on land that is under the jurisdiction of the Ute Indian Tribe of the Uintah Ouray Reservation and is therefore not covered by Utah's SIP. The inventory compiled by the WRAP does not currently separate out these emissions that are not under Utah's jurisdiction. These emissions may affect Class I areas in Northeastern Colorado and the

1 State of Utah expects that this impact will be addressed in the TIP or FIP that is developed
2 for the Ute Tribe.

3 **2. Projected Changes in Visual Air Quality**

4 **a. Applicable Class I Areas**

5 This projection of visibility improvement covers the 16 Class I areas of the Colorado Plateau, as
6 defined in 40 CFR 51.309(b)(1).

7 **b. Projected Visibility Improvement**

8 Pursuant to 40 CFR 51.309(d)(2), Table 25 indicates the projected visibility improvement for each
9 of the 16 Class I Areas on the Colorado Plateau. The table below compares the monitored 2000-04
10 baseline visibility conditions in deciviews⁵⁰ for the 20% Best and 20% Worst days to the projected
11 visibility improvement resulting from the 2018 Base Case (Base 18b) and 2018 Preliminary
12 Reasonable Progress (PRP18) modeling scenarios completed to date.

13
14 When SO₂ and NO_x controls for all BART sources have been adopted in the WRAP region, and the
15 §309 states re-adopt the SO₂ milestone program, a 2018 Final Reasonable Progress (FRP18)
16 modeling scenario will then be analyzed.

17
18 All 16 Colorado Plateau Class I areas show a projected visibility improvement for 2018 using the
19 monthly averages on the 20% Worst average visibility days, and no degradation on the 20% Best
20 average visibility days for each monitoring site. The monthly average method for projecting
21 visibility improvement is an allowed variation of EPA guidance.⁵¹ The monthly averaging method
22 was chosen because it was the shortest averaging period for making the future visibility projections,
23 while avoiding the use of the EPA specific days method that only assesses improvements on the
24 Worst and Best days observed during one year (2002) of the 2000-04 baseline monitoring period.

25
26 The visibility improvement observed in the 16 Colorado Plateau Class I areas is not as significant as
27 might be expected considering the large emission reductions that are projected to occur in the
28 region. This is because the 20% worst days are dominated by wildfire emissions that temporarily
29 overwhelm all other sources in the region. International emissions and dust storms can also be a
30 major factor on the 20% worst days. These emission sources are not controllable and therefore little
31 improvement is seen during these episodes. The metric required by the regional haze rule focuses
32 on the 20% worst days; thus the visibility benefits on those days when fires and other
33 uncontrollable sources are not dominating the inventory are not as apparent. It is perhaps more
34 revealing to focus on the improvements that will occur on the 20% best days when visibility is
35 already excellent. Visibility is expected to improve on the best days at most of the Colorado
36 Plateau Class I areas (including all five Class I areas in Utah). The emission reductions from

⁵⁰ Deciview means a measurement of visibility impairment. Its method of calculation is defined in 40 CFR 51.301, and is reprinted in Appendix A. Lower deciview numbers indicate better visibility, while higher numbers indicate more impaired visibility.

⁵¹ WRAP Technical Analysis Forum, *Technical Recommendations on Monitoring Metrics for Regional Haze Planning*, 3/23/2007

- 1 stationary sources, mobile sources and controllable fire emissions will provide a benefit every day
- 2 of the year even though that benefit may not be as obvious when fires are burning in the region.

1 **Table 25. Projected Visibility Improvement**

		Visibility Impairment in Deciviews*							
		20% Worst Visibility Days				20% Best Visibility Days			
		<u>2000-04 Regional Haze Rule Baseline Monitoring Data</u>	<u>Projected Visibility (Monthly Average Method)</u>			<u>2000-04 Regional Haze Rule Baseline Monitoring Data</u>	<u>Projected Visibility (Monthly Average Method)</u>		
<u>2018 Base Case (Base18b)</u>	<u>2018 Preliminary Reasonable Progress Case (PRP18)</u>		<u>2018 Final Reasonable Progress Case (FRP18)</u>	<u>2018 Base Case (Base18b)</u>	<u>2018 Preliminary Reasonable Progress Case (PRP18)</u>		<u>2018 Final Reasonable Progress Case (FRP18)</u>		
Colorado Plateau Class I areas under §309(d)(2)	State								
Grand Canyon National Park	AZ	11.7	11.4	11.3		2.2	2.2	2.1	
Mount Baldy Wilderness	AZ	11.9	11.5	11.4		3.0	2.9	2.8	
Petrified Forest National Park	AZ	13.2	12.9	12.9		5.0	4.9	4.8	
Sycamore Canyon Wilderness	AZ	15.3	15.1	15.1		5.6	5.6	5.6	
Black Canyon of the Gunnison National Park Wilderness	CO	10.3	10.1	9.9		3.1	2.9	2.9	
Flat Tops Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
Maroon Bells Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
Mesa Verde National Park	CO	13.0	12.8	12.6		4.3	4.1	4.0	
Weminuche Wilderness	CO	10.3	10.1	9.9		3.1	2.9	2.9	
West Elk Wilderness	CO	9.6	9.2	9.0		0.7	0.6	0.5	
San Pedro Parks Wilderness	NM	10.2	10.0	9.8		1.5	1.3	1.2	
Arches National Park	UT	11.2	11.0	10.9		3.8	3.6	3.5	
Bryce Canyon National Park	UT	11.6	11.3	11.2		2.8	2.7	2.6	
Canyonlands National Park	UT	11.2	11.0	10.9		3.8	3.6	3.5	
Capitol Reef National Park	UT	10.9	10.6	10.5		4.1	4.0	3.9	
Zion National Park	UT	13.2	13.0	13.0		5.0	4.7	4.7	

2 * Data are from: <http://vista.cira.colostate.edu/TSS/Results/HazePlanning.aspx> --> Modeling --> Visibility Projections

1 **L. PERIODIC IMPLEMENTATION PLAN REVISIONS**

2 **1. Periodic Progress Reports for Demonstrating Reasonable**
3 **Progress.**

4 Pursuant to 40 CFR 51.309(d)(10)(i), the State of Utah shall submit to EPA, as a SIP
5 revision, periodic progress reports for the years 2013 and 2018 for the purpose of
6 demonstrating reasonable progress in Class I areas within Utah, and Class I areas outside
7 Utah that are affected by emissions from Utah. This demonstration may be conducted by
8 the WRAP, with assistance from Utah, and shall address the elements listed under 40
9 CFR 51.309(d)(10)(i)(A) through (G), as summarized below:

- 10
- 11 • Implementation status of 2003 SIP measures;
 - 12 • Summary of emissions reductions;
 - 13 • Assessment of most/least impaired days;
 - 14 • Analysis of emission reductions by pollutant;
 - 15 • Significant changes in anthropogenic emissions;
 - 16 • Assessment of 2003 SIP sufficiency; and
 - 17 • Assessment of visibility monitoring strategy.

18 **2. Actions To Be Taken Concurrent with Periodic Progress**
19 **Reports.**

20 Pursuant to 40 CFR 51.309(d)(10)(ii), the State of Utah shall take one of the following
21 actions based upon information contained in each periodic progress report:

- 22
- 23 • Provide a negative declaration statement to EPA saying that no implementation
24 plan revision is needed if reasonable progress is being made, in accordance with
25 section L.1 above;
 - 26
 - 27 • If the state finds that the implementation plan is inadequate to ensure reasonable
28 progress due to emissions from outside the state, Utah shall notify EPA and the
29 other contributing state(s), and initiate efforts through a regional planning process
30 to address the emissions in question. The State of Utah shall identify in the next
31 progress report the outcome of this regional planning effort, including any
32 additional strategies that were developed to address the plan's deficiencies;
 - 33
 - 34 • If the state finds that the implementation plan is inadequate to ensure reasonable
35 progress due to emissions from another country, Utah shall notify EPA and
36 provide information on the impairment being caused by these emissions; or
 - 37
 - 38 • If the state finds that the implementation plan is inadequate to ensure reasonable
39 progress due to emissions from within Utah, Utah shall develop additional

1 strategies to address the plan deficiencies and revise the implementation plan no
2 later than one year from the date that the progress report was due.

1 **M. STATE PLANNING/INTERSTATE COORDINATION**
2 **AND TRIBAL IMPLEMENTATION**

3 **1. Participation in Regional Planning and Coordination**

4 Pursuant to 40 CFR 51.309(d)(11), the State of Utah has participated in regional planning
5 and coordination with other states in developing its emission reduction strategies under
6 40 CFR 51.309, related to protecting the 16 Class I areas of the Colorado Plateau. This
7 participation was through the Western Regional Air Partnership (WRAP). Appendix D
8 of this implementation plans illustrates the interstate planning and coordination programs
9 developed by WRAP and the State of Utah’s participation in regional planning and
10 interstate coordination.
11

12 **2. Applicability to Tribal Lands**

13 Pursuant to 40 CFR 51.309(d)(12), and in accordance with the Tribal Authority Rule, the
14 Tribe whose lands are surrounded by the State of Utah has the option to develop a
15 regional haze TIP for its lands to assure reasonable progress in the 16 Class I areas of the
16 Colorado Plateau. As such, no provision of this chapter of the implementation plan shall
17 be construed as being applicable to tribal lands.
18

19 **3. Interstate Coordination**

20
21 Pursuant to 40 CFR 51.308(d)(3)(i), the State of Utah has participated in regional
22 planning and coordination with other states in developing management strategies for
23 emissions from within the State that would contribute to visibility impairment in a
24 mandatory Class I Federal area outside of the State. The 16 Class I areas of the Colorado
25 Plateau are excluded from the consultation provisions of 51.308 given the reasonable
26 progress and visibility improvement requirements under Section 309. Consultation
27 participation was conducted through the Western Regional Air Partnership (WRAP). A
28 more detailed description of the goals, objectives, management, and decision-making
29 structure of the WRAP has been included in Appendix D. The following WRAP forums
30 have provided consultation opportunities between states on emission management
31 strategies:
32

- 33 • Economic Analysis Forum
- 34 • Stationary Sources Forum
- 35 • Emissions Forum
- 36 • Technical Analysis Forum
- 37 • Fire Emissions Forum
- 38 • Sources In and Near Class I Areas Forum
- 39 • Air Pollution Prevention Forum

- 1 • Mobile Sources Forum
- 2 • Dust Emissions Forum

3

4 Opportunities for consultation on emission strategies provided through the WRAP are
5 documented in more detail in Appendix D.

6

7 Changes in visibility impairing emissions from sources in the State of Utah are projected
8 to show significant decreases by 2018 from 1996 levels. Based on WRAP modeling
9 projections and current emission inventories, oxides of nitrogen (NO_x), sulfur dioxide
10 (SO₂), and particulate matter (PM_{2.5}) are expected to decrease in Utah 36%, 33% and
11 38% respectively. These reductions are due primarily to the long-term strategy
12 developed in conjunction with western states through the WRAP. Decreases in SO₂ for
13 stationary sources are described in Part E. Emission reductions of NO_x and PM_{2.5} are due
14 to the implementation of new federal engine standards and fuel standards described in
15 Part F and BART controls for NO_x and PM_{2.5} described in Part D.

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Utah State Implementation Plan

Section XX

Regional Haze

APPENDICES

**Addressing Regional Haze Visibility Protection for the Mandatory
Federal Class I Areas Required Under 40 CFR 51.309**

Complete Document Available On-line at
[http://www.airquality.utah.gov/SIP/Regionalhazesip/
regionalhaze.htm](http://www.airquality.utah.gov/SIP/Regionalhazesip/regionalhaze.htm)

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1 **A. DEFINITIONS**

2 **Applicable Definitions from 40 CFR 51.301, in effect on July 1, 2007**

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

4
5 ***Best Available Retrofit Technology (BART)*** means an emission limitation based on the
6 degree of reduction achievable through the application of the best system of continuous
7 emission reduction for each pollutant, which is emitted by an existing stationary facility.
8 The emission limitation must be established, on a case-by-case basis, taking into
9 consideration the technology available, the costs of compliance, the energy and non-air
10 quality environmental impacts of compliance, any pollution control equipment in use or
11 in existence at the source, the remaining useful life of the source, and the degree of
12 improvement in visibility which may reasonably be anticipated to result from the use of
13 such technology.

14
15 ***Deciview*** means a measurement of visibility impairment. A deciview is a haze index
16 derived from calculated light extinction, such that uniform changes in haziness
17 correspond to uniform incremental changes in perception across the entire range of
18 conditions, from pristine to highly impaired. The deciview haze index is calculated based
19 on the following equation (for the purposes of calculating deciview, the atmospheric light
20 extinction coefficient must be calculated from aerosol measurements):

21
22 Deciview haze index = $10^{-1} \ln_e (b_{\text{ext}}/10 \text{ Mm}^{-1})$.

23 Where b_{ext} = the atmospheric light extinction coefficient, expressed in inverse
24 megameters (Mm^{-1}).

25
26 ***Existing stationary facility*** means any of the following stationary sources of air
27 pollutants, including any reconstructed source, which was not in operation prior to
28 August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit
29 250 tons per year or more of any air pollutant. In determining potential to emit, fugitive
30 emissions, to the extent quantifiable, must be counted.

- 31
32 Fossil-fuel fired steam electric plants of more than 250 million British thermal units per
33 hour heat input,
34 Coal cleaning plants (thermal dryers),
35 Kraft pulp mills,
36 Portland cement plants,
37 Primary zinc smelters,
38 Iron and steel mill plants,
39 Primary aluminum ore reduction plants,
40 Primary copper smelters,
41 Municipal incinerators capable of charging more than 250 tons of refuse per day,
42 Hydrofluoric, sulfuric, and nitric acid plants,
43 Petroleum refineries,

1 Lime plants,
2 Phosphate rock processing plants,
3 Coke oven batteries,
4 Sulfur recovery plants,
5 Carbon black plants (furnace process),
6 Primary lead smelters,
7 Fuel conversion plants,
8 Sintering plants,
9 Secondary metal production facilities,
10 Chemical process plants,
11 Fossil-fuel boilers of more than 250 million British thermal units per hour heat input,
12 Petroleum storage and transfer facilities with a capacity exceeding 300,000 barrels,
13 Taconite ore processing facilities,
14 Glass fiber processing plants, and
15 Charcoal production facilities.

16
17 ***Federal Class I area*** means any Federal land that is classified or reclassified Class I.

18
19 ***Federal Land Manager*** means the Secretary of the department with authority over the
20 Federal Class I area (or the Secretary's designee) or, with respect to Roosevelt-
21 Campobello International Park, the Chairman of the Roosevelt-Campobello International
22 Park Commission.

23
24 ***Federally enforceable*** means all limitations and conditions which are enforceable by the
25 Administrator under the Clean Air Act including those requirements developed pursuant
26 to parts 60 and 61 of this title, requirements within any applicable State Implementation
27 Plan, and any permit requirements established pursuant to Sec. 52.21 of this chapter or
28 under regulations approved pursuant to part 51, 52, or 60 of this title.

29
30 ***Geographic enhancement for the purpose of §51.308*** means a method, procedure, or
31 process to allow a broad regional strategy, such as an emission trading program designed
32 to achieve greater reasonable progress than BART for regional haze, to accommodate
33 BART for reasonably attributable impairment.

34
35 ***Implementation plan*** means, for the purposes of this part, any State Implementation
36 Plan, Federal Implementation Plan, or Tribal Implementation Plan.

37
38 ***Indian tribe or tribe*** means any Indian tribe, band, nation, or other organized group or
39 community, including any Alaska Native village, which is federally recognized as
40 eligible for the special programs and services provided by the United States to Indians
41 because of their status as Indians.

42
43 ***In existence*** means that the owner or operator has obtained all necessary preconstruction
44 approvals or permits required by Federal, State, or local air pollution emissions and air
45 quality laws or regulations and either has (1) begun, or caused to begin, a continuous
46 program of physical on-site construction of the facility or (2) entered into binding

1 agreements or contractual obligations, which cannot be cancelled or modified without
2 substantial loss to the owner or operator, to undertake a program of construction of the
3 facility to be completed in a reasonable time.

4
5 **Least impaired days** means the average visibility impairment (measured in deciviews) for
6 the twenty percent of monitored days in a calendar year with the lowest amount of
7 visibility impairment.

8
9 **Major stationary source and major modification** mean major stationary source and
10 major modification, respectively, as defined in Sec. 51.166.

11
12 **Mandatory Class I Federal Area** means any area identified in part 81, subpart D of this
13 title.

14
15 **Most impaired days** means the average visibility impairment (measured in deciviews) for
16 the twenty percent of monitored days in a calendar year with the highest amount of
17 visibility impairment.

18
19 **Natural conditions** includes naturally occurring phenomena that reduce visibility as
20 measured in terms of light extinction, visual range, contrast, or coloration.

21
22 **Potential to emit** means the maximum capacity of a stationary source to emit a pollutant
23 under its physical and operational design. Any physical or operational limitation on the
24 capacity of the source to emit a pollutant including air pollution control equipment and
25 restrictions on hours of operation or on the type or amount of material combusted, stored,
26 or processed, shall be treated as part of its design if the limitation or the effect it would
27 have on emissions is federally enforceable. Secondary emissions do not count in
28 determining the potential to emit of a stationary source.

29
30 **Reasonably attributable** means attributable by visual observation or any other technique
31 the State deems appropriate.

32
33 **Reasonably attributable visibility impairment** means visibility impairment that is caused
34 by the emission of air pollutants from one, or a small number of sources.

35
36 **Regional haze** means visibility impairment that is caused by the emission of air
37 pollutants from numerous sources located over a wide geographic area. Such sources
38 include, but are not limited to, major and minor stationary sources, mobile sources, and
39 area sources.

40
41 **State** means ``State" as defined in section 302(d) of the CAA.

42
43 **Stationary Source** means any building, structure, facility, or installation, which emits or
44 may emit any air pollutant.

45

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

4 **Applicable Definitions from 40 CFR 51.309, in effect on July 1, 2003**

5 **16 Class I areas** means the following mandatory Class I Federal areas on the Colorado
6 Plateau: Grand Canyon National Park, Sycamore Canyon Wilderness, Petrified Forest
7 National Park, Mount Baldy Wilderness, San Pedro Parks Wilderness, Mesa Verde
8 National Park, Weminuche Wilderness, Black Canyon of the Gunnison Wilderness, West
9 Elk Wilderness, Maroon Bells Wilderness, Flat Tops Wilderness, Arches National Park,
10 Canyonlands National Park, Capital Reef National Park, Bryce Canyon National Park,
11 and Zion National Park.

12
13 **Transport Region State** means one of the States that is included within the Transport
14 Region addressed by the Grand Canyon Visibility Transport Commission (Arizona,
15 California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming).

16
17 **Commission Report** means the report of the Grand Canyon Visibility Transport
18 Commission entitled "Recommendations for Improving Western Vistas," dated June 10,
19 1996.

20
21 **Fire** means wildfire, wildland fire (including prescribed natural fire), prescribed fire, and
22 agricultural burning conducted and occurring on Federal, State, and private wildlands and
23 farmlands.

24
25 **Milestone** means the maximum level of annual regional sulfur dioxide emissions for a
26 given year, assessed annually, through the year 2018, consistent with paragraph (d)(4) of
27 this section.

28
29 **Continuous decline in total mobile source emissions** means that the projected level of
30 emissions from mobile sources of each listed pollutant in 2008, 2013, and 2018, are less
31 than the projected level of emissions from mobile sources of each listed pollutant for the
32 previous period (i.e., 2008 less than 2003; 2013 less than 2008; and 2018 less than 2013).

33
34
35
36 **Base Year** means the year for which data for a source included within the program were
37 used by the WRAP to calculate emissions as a starting point for development of the
38 milestone required by paragraph (d)(4)(i) of this section.

39 **Definitions for the Fire Program**

40 **Agricultural Fuel or Agricultural Burning** means any fire ignited by management
41 actions to meet specific objectives (i.e., managed to achieve resource benefits) on
42 agricultural land.

1 **Alternatives to Fire** means non-burning techniques that replace fire and that are used to
2 achieve a particular land management objective, including but not limited to reduction of
3 fuel loading, manipulation of fuels, enhancement of wildlife habitat, and ecosystem
4 restructuring.

5
6 **Emission Reduction Techniques** means techniques for controlling emissions from
7 prescribed fires to minimize the amount of emission output per unit or acre burned.

8
9 **Fire** means wildfire, wildland fire(including prescribed natural fire), prescribed fire, and
10 agricultural burning conducted and occurring on federal, state and private wildlands and
11 farmlands.

12
13 **Land Manager** means any federal, state, local, or private entity that owns, administers,
14 directs, oversees or controls the use of public or private land, including the application of
15 fire to the land.

16
17 **Prescribed fire or prescribed burn** means any fire ignited by management actions to
18 meet specific objectives, such as achieving resource benefits.

19
20 **Wildfire** means any unwanted, non-structural fire.

21
22 **Wildland** means an area in which development is essentially non-existent, except for
23 pipelines, power lines, roads, railroads, or other transportation or conveyance facilities.

24
25 **Wildland Fire** means all types of fire occurring in the wildland, except for fire on
26 agricultural land.

27
28 **Wildland Fire Used for Resource Benefits** means naturally ignited wildland fire that is
29 managed to accomplish specific prestated resource management objectives in predefined
30 geographic areas.

31 **Definitions for the Western Emission Backstop Trading Program**

32 **Account Certificate of Representation** means the completed and signed submission
33 required to designate an Account Representative for a **Western Emission Backstop**
34 **(WEB)** source or an Account Representative for a general account.

35
36 **Account Representative** means the individual who is authorized through an Account
37 Certificate of Representation to represent owners and operators of the WEB source with
38 regard to matters under the WEB Trading Program or, for a general account, who is
39 authorized through an Account Certificate of Representation to represent the persons
40 having an ownership interest in allowances in the general account with regard to matters
41 concerning the general account.

42
43 **Act** means the Clean Air Act, as amended, 42 U.S.C. 7401, *et seq.*
44

1 **Actual Emissions** means total annual SO₂ emissions as reported to the executive
2 secretary in accordance with the requirements R307-250-9 or R307-150, as applicable.
3

4 **Allocate** means to assign allowances to a WEB source in accordance with sections
5 XX.E.3.a. through XX.E.3.e of this plan.
6

7 **Allowance** means the limited authorization under the WEB Trading Program to emit one
8 ton of SO₂ during a specified control period or any control period thereafter subject to the
9 terms and conditions for use of unused allowances as established by R307-250.
10

11 **Allowance limitation** means the tonnage of SO₂ emissions authorized by the allowances
12 available for compliance deduction for a WEB source for a control period under R307-
13 250-12(1) on the allowance transfer deadline for that control period.
14

15 **Allowance Tracking System** means the system where allowances under the WEB
16 Trading Program are recorded, held, transferred and deducted.
17

18 **Allowance Tracking System account** means an account in the Allowance Tracking
19 System established for purposes of recording, holding, transferring, and deducting
20 allowances.
21

22 **Compliance account** means an account established in the Allowance Tracking System
23 under R307-250-8(1) for the purpose of recording allowances that a WEB source might
24 hold to demonstrate compliance with its allowance limitation.
25

26 **Control period** means the period beginning January 1 of each year and ending on
27 December 31 of the same year, inclusive.
28

29 **Emissions tracking database** means the central database where SO₂ emissions for WEB
30 sources as recorded and reported in accordance with R307-250 are tracked to determine
31 compliance with allowance limitations.
32

33 **Emission Unit** means any part of a stationary source, which emits or has the potential to
34 emit any pollutant subject to regulation under the Clean Air Act.
35

36 **EPA Administrator** means the Administrator of the United States Environmental
37 Protection Agency or the Administrator's duly authorized representative.
38

39 **Existing source** means a stationary source that commenced operation before the Program
40 Trigger Date.
41

42 **Floor allocation** means the amount of allowances set by the executive secretary in
43 accordance with this Plan that represents the minimum necessary for a source to operate
44 under stringent control assumptions.
45

1 **General account** means an account established in the Allowance Tracking System under
2 R307-250-8 for the purpose of recording allowances held by a person that are not to be
3 used to show compliance with an allowance limitation.
4

5 **Milestone** means the maximum level of stationary source regional sulfur dioxide
6 emissions for each year from 2003 to 2018, established according to the procedures in
7 section XX.E.1 of this plan.
8

9 **New WEB Source** means a WEB source that commenced operation on or after the
10 Program Trigger Date.
11

12 **New Source Set-aside** means a pool of allowances that are available for allocation to new
13 WEB sources and modified WEB sources that have increased capacity in accordance
14 with the provisions of Section E.3.c of this plan.
15

16 **Opt-in** means to choose to participate in the WEB Trading Program by following the
17 procedures in R307-250-4(4) and to comply with the terms and conditions of the R307-
18 250.
19

20 **Program Trigger Date** means the date that the executive secretary determines that the
21 WEB Trading Program has been triggered in accordance with the provisions of section
22 XX.E.1.b of this plan.
23

24 **Reducible allocation** means the amount of allowances set by the executive secretary in
25 accordance with section XX.E.3.a(2)(i) of this plan that represents, for each source,
26 emissions in excess of the floor allocation that shall be reduced over time as the regional
27 milestone is decreased.
28

29 **Renewable Energy Facility** means a facility that generates electricity by non-nuclear and
30 non-fossil technologies that results in low or no air emissions. The term includes
31 electricity generated by wind energy technologies; solar photovoltaic and solar thermal
32 technologies; geothermal technologies; technologies based on landfill gas and biomass
33 sources, and new low-impact hydropower that meets the Low-Impact Hydropower
34 Institute criteria. Biomass includes agricultural, food and wood wastes. For the purposes
35 of this Plan, a renewable energy facility does not include pumped storage or biomass
36 from municipal solid waste, black liquor, or treated wood.
37

38 **Retired source** means a WEB source that has received a retired source exemption as
39 provided in R307-250-4(5).
40

41 **Special Reserve Compliance Account** means an account established in the allowance
42 tracking system under R307-250-8(1) for the purpose of recording allowances that a
43 WEB source might hold to demonstrate compliance with its allowance limitation for
44 emission units that are monitored for sulfur dioxide in accordance with 250-9(1)(b).
45

1 **Stationary source** means any building, structure, facility or installation that emits or may
2 emit any air pollutant subject to regulation under the Clean Air Act.

3
4 **Ton** means 2000 pounds and, for any control period, any fraction of a ton equaling 1000
5 pounds or more shall be treated as one ton and any fraction of a ton equaling less than
6 1000 pounds shall be treated as zero tons.

7
8 **Tracking System Administrator** means the person designated by the executive secretary
9 as the administrator of the WEB Allowance Tracking System and the emission tracking
10 database.

11
12 **Tribal Set-Aside** means an 8,500-ton SO₂ WEB allowance allocated to tribes on an
13 annual basis. The tribes will decide how to distribute the allowances in the set-aside
14 among tribes in the region. The set-side is intended to ensure equitable treatment for
15 tribal economies and to prevent barriers to economic development.

16
17 **Trigger** refers to the activation of the WEB Trading Program for SO₂ in accordance with
18 section XX.E.1 of this plan.

19
20 **WEB source** means a stationary source that meets the applicability requirements of
21 R307-250-4

22
23 **WEB Trading Program** refers to the Western Backstop (WEB) Trading Program Rule,
24 R307-250, that shall be triggered as a backstop in accordance the provisions in section
25 XX.E.1 of this plan to ensure that regional SO₂ emissions are reduced.

26
27 **Western Regional Air Partnership (WRAP)** means the collaborative effort of tribal
28 governments, state governments, and federal agencies to promote and monitor
29 implementation of recommendations from the Grand Canyon Visibility Transport
30 Commission authorized under Section 169B(f) of the Clean Air Act, and to address other
31 common Western regional air quality issues.

1 **B. WEB MODEL RULE MONITORING PROTOCOLS**

2
3
4 **Protocol WEB-1: SO₂ Monitoring of Fuel Gas Combustion Devices**

5
6 1. Applicability

- 7
8 (a) The provisions of this protocol are applicable to fuel gas combustion
9 devices at petroleum refineries.
10
11 (b) Fuel gas combustion devices include boilers, process heaters, and flares
12 used to burn fuel gas generated at a petroleum refinery.
13
14 (c) Fuel gas means any gas which is generated and combusted at a petroleum
15 refinery. Fuel gas does not include (1) natural gas, unless combined with
16 other gases generated at a petroleum refinery, (2) gases generated by a
17 catalytic cracking unit catalyst regenerator, (3) gases generated by fluid
18 coking burners, (4) gases combusted to produce sulfur or sulfuric acid, or
19 (5) process upset gases generated due to startup, shutdown, or
20 malfunctions.
21

22 2. Monitoring Requirements

- 23
24 (a) Except as provided in paragraphs (b) and (c) of this Section 2, fuel gas
25 combustion devices shall use a continuous fuel gas monitoring system
26 (CFGMS) to determine the total sulfur content (reported as H₂S) of the
27 fuel gas mixture prior to combustion, and continuous fuel flow meters to
28 determine the amount of fuel gas burned.
29
30 (1) Fuel gas combustion devices having a common source of fuel gas
31 may be monitored for sulfur content at one location, if monitoring
32 at that location is representative of the sulfur content of the fuel
33 gas being burned in any fuel gas combustion device.
34
35 (2) The CFGMS shall meet the performance requirements in
36 Performance Specification 2 in Appendix B to 40 CFR Part 60, and
37 the following:
38
39 (i) Continuously monitor and record the concentration by
40 volume of total sulfur compounds in the gaseous fuel
41 reported as ppmv H₂S.
42

- 1 (ii) Have the span value set so that the majority of readings fall
- 2 between 10 and 95% of the range.
- 3
- 4 (iii) Record negative values of zero drift.
- 5
- 6 (iv) Calibration drift shall be 5.0% of the span, for initial
- 7 certification and daily calibration error tests.
- 8
- 9 (v) Methods 15A, 16, or approved alternatives for total sulfur,
- 10 are the reference methods for the relative accuracy test. The
- 11 relative accuracy test shall include a bias test in accordance
- 12 with paragraph 4.(c) of this section.
- 13

- 14 (3) All continuous fuel flow meters shall comply with the provisions of
- 15 section 2.1.5 of Appendix D to 40 CFR Part 75.
- 16
- 17 (4) The hourly mass SO₂ emissions rate for all the fuel gas combustion
- 18 devices monitored by this approach shall be calculated using the
- 19 following equation:
- 20

$$E_t = (C_s)(Q_t)(K)$$

21 where:

- 22 E_t = Total SO₂ emissions in lb/hr from applicable
- 23 fuel gas combustion devices
- 24 C_s = Sulfur content of the fuel gas as H₂S(ppmv)
- 25 Q_t = Fuel gas flow rate to the applicable fuel gas
- 26 combustion devices (scf/hr)
- 27 $K = 1.660 \times 10^{-7}$ (lb/scf)/ppmv
- 28
- 29

30 (b) In place of a CFGMS in paragraph (a) of this Section 2, fuel gas

31 combustion devices having a common source of fuel gas may be monitored

32 with an SO₂ CEMS, a flow CEMS, and (if necessary) a moisture

33 monitoring system at only one location, if the CEMS monitoring at that

34 location is representative of the SO₂ emission rate (lb SO₂/scf fuel gas

35 burned) of all applicable fuel gas combustion devices. Continuous fuel

36 flow meters shall be used in accordance with paragraph (a), and the fuel

37 gas combustion device monitored by a CEMS shall have separate fuel

38 metering.

- 39
- 40 (1) Each CEMS for SO₂, flow, and (if applicable) moisture, shall
- 41 comply with the operating requirements, performance
- 42 specifications, and quality assurance requirements of 40 CFR Part
- 43 75.
- 44

1 (2) All continuous fuel flow meters shall comply with the provisions of
2 section 2.1.5 of Appendix D to 40 CFR Part 75.

3
4 (3) The SO₂ hourly mass emissions rate for all the fuel gas combustion
5 devices monitored by this approach shall be determined by the ratio
6 of the amount of fuel gas burned by the CEMS-monitored fuel gas
7 combustion device to the total fuel gas burned by all applicable fuel
8 gas combustion devices using the following equation:
9

10
$$E_t = (E_m)(Q_t)/(Q_m)$$

11
12 where: E_t = Total SO₂ emissions in lb/hr from applicable
13 fuel gas combustion devices
14 E_m = SO₂ emissions in lb/hr from the CEMS-monitored fuel
15 gas combustion device, calculated using Equation F-1 or (if
16 applicable) F-2 in Appendix F to 40 CFR Part 75
17 Q_t = Fuel gas flow rate (scf/hr) to the applicable fuel
18 gas combustion devices
19 Q_m = Fuel gas flow rate (scf/hr) to the CEMS-monitored
20 fuel gas combustion device
21

22 (c) In place of a CFGMS in paragraph (a) of this section, fuel gas combustion
23 devices having a common source of fuel gas may be monitored with an SO₂ -
24 diluent CEMS at only one location, if the CEMS monitoring at that location is
25 representative of the SO₂ emission rate (lb SO₂/mmBtu) of all applicable fuel gas
26 combustion devices. If this option is selected, the owner or operator shall conduct
27 fuel gas sampling and analysis for gross calorific value (GCV), and shall use
28 continuous fuel flow metering in accordance with paragraph (a) of this Section 2,
29 with separate fuel metering for the CEMS-monitored fuel gas combustion device.
30

31 (1) Each SO₂-diluent CEMS shall comply with the applicable
32 provisions for SO₂ monitors and diluent monitors in 40 CFR Part
33 75, and shall use the procedures in section 3 of Appendix F to Part
34 75 for determining SO₂ emission rate (lb/mmBtu) by substituting
35 the term SO₂ for NO_x in that section, and using a K factor of
36 1.660×10^{-7} (lb/scf)/ppmv instead of the NO_x K factor.

37 (2) All continuous fuel flow meters and fuel gas sampling and analysis
38 for GCV to determine the heat input rate from the fuel gas shall
39 comply with the applicable provisions in sections 2.1.5 and 2.3.4 of
40 Appendix D to 40 CFR Part 75.
41

42 (3) The SO₂ hourly mass emissions rate for all the fuel gas combustion
43 devices monitored by this approach shall be calculated by using the
44 following equation:

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$$E_t = (E_m) (Q_t)(GCV)/10^6$$

where:

E_t = Total hourly SO₂ mass emissions in lb/hr from the applicable fuel gas combustion devices

E_m = SO₂ emission rate in lb/mmBtu from the CEMS - monitored fuel gas combustion device

Q_t = Fuel gas flow rate (scf/hr) to the applicable fuel gas combustion devices

GCV = Fuel Gross Calorific Value (Btu/scf)

10^6 = Conversion from Btu to million Btu

(d) Calculate total SO₂ mass emissions for each calendar quarter and each calendar year based on the emissions in lb/hr and Equations F-3 and F-4 in Appendix F to 40 CFR Part 75, Appendix F.

3. Certification/Recertification Requirements

All monitoring systems are subject to initial certification and recertification testing as follows:

- (a) The owner or operator shall comply with the initial testing and calibration requirements in Performance Specification 2 in Appendix B to 40 CFR Part 60 and paragraph 2 (a)(2) of this section for each CFGMS.
- (b) Each CEMS for SO₂ and flow or each SO₂-diluent CEMS shall comply with the testing and calibration requirements specified in 40 CFR Part 75, section 75.20 and Appendices A and B, except that each SO₂-diluent CEMS shall meet the relative accuracy requirements for a NO_x-diluent CEMS (lb/mmBtu).
- (c) A continuous fuel flow meter shall comply with the certification and quality-assurance requirements in sections 2.1.5 and 2.1.6 to Appendix D to 40 CFR Part 75.

4. Quality Assurance/Quality Control Requirements

- (a) A quality assurance/quality control (QA/QC) plan shall be developed and implemented for each CEMS for SO₂ and flow or the SO₂-diluent CEMS in compliance with sections 1, 1.1, and 1.2 of Appendix B to Part 75.

- 1 (b) A QA/QC plan shall be developed and implemented for each continuous
2 fuel flow meter and fuel sampling and analysis in compliance with sections
3 1, 1.1, and 1.3 of Appendix B to 40 CFR Part 75.
4
- 5 (c) A QA/QC plan shall be developed and implemented for each CFGMS in
6 compliance with sections 1 and 1.1 of Appendix B to 40 CFR Part 75, and
7 the following:
8
- 9 (i) Perform a daily calibration error test of each CFGMS at two gas
10 concentrations, one low level and one high level. Calculate the
11 calibration error as described in Appendix A to 40 CFR Part 75.
12 An out of control period occurs whenever the error is greater than
13 5.0% of the span value.
14
- 15 (ii) In addition to the daily calibration error test, an additional
16 calibration error test shall be performed whenever a daily
17 calibration error test is failed, whenever a monitoring system is
18 returned to service following repairs or corrective actions that may
19 affect the monitor measurements, or after making manual
20 calibration adjustments.
21
- 22 (iii) Perform a linearity test once every operating quarter. Calculate the
23 linearity as described in Appendix A to 40 CFR Part 75. An out of
24 control period occurs whenever the linearity error is greater than
25 5.0 percent of a reference value, and the absolute value of the
26 difference between average monitor response values and a
27 reference value is greater than 5.0 ppm.
28
- 29 (iv) Perform a relative accuracy test audit once every four operating
30 quarters. Calculate the relative accuracy as described in Appendix
31 A to 40 CFR Part 75. An out of control period occurs whenever
32 the relative accuracy is greater than 20.0% of the mean value of the
33 reference method measurements.
34
- 35 (v) Using the results of the relative accuracy test audit, conduct a bias
36 test in accordance with Appendix A to 40 CFR Part 75, and
37 calculate and apply a bias adjustment factor if required.
38

39 5. Missing Data Procedures

- 40
- 41 (a) For any period in which valid data are not being recorded by an SO₂
42 CEMS or flow CEMS specified in this section, missing or invalid data
43 shall be replaced with substitute data in accordance with the requirements
44 in Subpart D of 40 CFR Part 75.

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- (b) For any period in which valid data are not being recorded by an SO₂-diluent CEMS specified in this section, missing or invalid data shall be replaced with substitute data on a rate basis (lb/mmBtu) in accordance with the requirements for SO₂ monitors in Subpart D of 40 CFR Part 75.
- (c) For any period in which valid data are not being recorded by a continuous fuel flow meter or for fuel gas GCV sampling and analysis specified in this section, missing or invalid data shall be replaced with substitute data in accordance with missing data requirements in Appendix D to 40 CFR Part 75.
- (d) For any period in which valid data are not being recorded by the CFGMS specified in this section, hourly missing or invalid data shall be replaced with substitute data in accordance with the missing data requirements for units performing hourly gaseous fuel sulfur sampling in section 2.4 of Appendix D to 40 CFR Part 75.

6. Monitoring Plan and Reporting Requirements

In addition to the general monitoring plan and reporting requirements of Section I of this Rule, the owner or operator shall meet the following additional requirements:

- (a) The monitoring plan shall identify each group of units that are monitored by a single monitoring system under this Protocol WEB-1, and the plan shall designate an identifier for the group of units for emissions reporting purposes. For purpose of submitting emissions reports, no apportionment of emissions to the individual units within the group is required.
- (b) If the provisions of paragraphs 2.(b) or (c) are used, provide documentation and an explanation to demonstrate that the SO₂ emission rate from the monitored unit is representative of the rate from non-monitored units.

1 **Protocol WEB-2: Predictive Flow Monitoring Systems for Kilns with Positive**
2 **Pressure Fabric Filter**

3
4 1. Applicability

5
6 The provisions of this protocol are applicable to cement kilns or lime kilns that (1)
7 are controlled by a positive pressure fabric filter, (2) combust only a single fuel,
8 no fuel blends, and (3) have operating conditions upstream of the fabric filter that
9 the WEB source documents would reasonably prevent reliable flow monitor
10 measurements. This protocol does not modify the SO₂ monitoring requirements in
11 section I of this Rule.
12

13 2. Monitoring Requirements

14
15 (a) A cement or lime kiln with a positive pressure fabric filter shall use a
16 predictive flow monitoring system (PFMS) to determine the hourly kiln exhaust
17 gas flow.
18

19 (b) A PFMS is the total equipment necessary for the determination of exhaust gas
20 flow using process or control device operating parameter measurements and a
21 conversion equation, a graph, or computer program to produce results in cubic
22 feet per hour.
23

24 (c) The PFMS shall meet the following performance specifications:

25
26 (1) Sensors readings and conversion of sensor data to flow in cubic feet
27 per hour must be automated.
28

29 (2) The PFMS must allow for the automatic or manual determination of
30 failed monitors. At a minimum a daily determination must be performed.
31

32 (3) The PFMS shall have provisions to check the calibration error of each
33 parameter that is individually measured. The owner or operator shall
34 propose appropriate performance specifications in the initial monitoring
35 plan for all parameters used in the PFMS comparable to the degree of
36 accuracy required for other monitoring systems used to comply with this
37 Rule. The parameters shall be tested at two levels, low: 0 to 20% of full
38 scale, and high: 50 to 100% of full scale. The reference value need not be
39 certified.
40

41 (4) The relative accuracy of the PFMS must be $\leq 10.0\%$ of the reference
42 method average value, and include a bias test in accordance with
43 paragraph 4(c) of this section.

1 3. Certification Requirements

2
3 The PFMS is subject to initial certification testing as follows:

4
5 (a) Demonstrate the ability of the PFMS to identify automatically or manually a
6 failed monitor.

7
8 (b) Provide evidence of calibration testing of all monitoring equipment. Any
9 tests conducted within the previous 12 months of operation that are consistent
10 with the QA/QC plan for the PFMS are acceptable for initial certification
11 purposes.

12
13 (c) Perform an initial relative accuracy test over the normal range of operating
14 conditions of the kiln. Using the results of the relative accuracy test audit,
15 conduct a bias test in accordance with Appendix A to 40 CFR Part 75, and
16 calculate and apply a bias adjustment factor if required.

17
18 4. Quality Assurance/Quality Control Requirements

19
20 A QA/QC plan shall be developed and implemented for each PFMS in
21 compliance with sections 1 and 1.1 of Appendix B of 40 CFR Part 75, and the
22 following:

23
24 (a) Perform a daily monitor failure check.

25
26 (b) Perform calibration tests of all monitors for each parameter included in the
27 PFMS. At a minimum, calibrations shall be conducted prior to each relative
28 accuracy test audit.

29
30 (c) Perform a relative accuracy test audit and accompanying bias test once every
31 four operating quarters. Calculate the relative accuracy (and bias adjustment
32 factor) as described in Appendix A to 40 CFR Part 75. An out of control period
33 occurs whenever the flow relative accuracy is greater than 10.0% of the mean
34 value of the reference method.

35
36 5. Missing Data

37
38 For any period in which valid data are not being recorded by the PFMS specified
39 in this section, hourly missing or invalid data shall be replaced with substitute
40 data in accordance with the flow monitor missing data requirements for non-load
41 based units in Subpart D of 40 CFR Part 75.

42
43 6. Monitoring Plan Requirements

44
45 In addition to the general monitoring plan requirements of Section I of this Rule,
46 the owner or operator shall meet the following additional requirements:

1
2
3
4
5
6
7
8
9
10

(a) The monitoring plan shall document the reasons why stack flow measurements upstream of the fabric filter are unlikely to provide reliable flow measurements over time.

(b) The initial monitoring plan shall explain the relationship of the proposed parameters and stack flow, and discuss other parameters considered and the reasons for not using those parameters in the PFMS. The [state or tribe] may require that the subsequent monitoring plan include additional explanation and documentation for the reasonableness of the proposed PFMS.

1 C. PROJECTION OF VISIBILITY IMPROVEMENT

2 A. Modeling Scenarios

3
4 Improvement in visibility for the 16 Colorado Plateau Class I areas was modeled
5 for two scenarios, the results of which are shown in Tables 22 and 23 in Part K of this
6 SIP.

7 8 *Control Strategies*

9
10 The WRAP modeled two control scenarios for 2018, with and without optimal
11 smoke management. The results are found in the WRAP TSD. Scenario 1 is designed to
12 assess the effect of the Grand Canyon Visibility Transport Commission (GCVTC)
13 recommended control strategies, comparing the 1996 modeled base case to the visibility
14 improvement resulting from the implementation of the following GCVTC strategies: the
15 sulfur dioxide Annex Milestones, the regional pollution prevention program,
16 maintenance of existing base smoke management programs, and accounting for the 2018
17 base case emissions (known and adopted federal, tribal, state, and local control programs
18 in the contiguous WRAP region). Visibility changes resulting from regional
19 implementation of state pollution prevention programs were modeled by the Regional
20 Modeling Center, as part of the other Section 309 control strategies. Visibility changes
21 resulting from implementation of pollution prevention programs by individual states or
22 tribes were not modeled. Emissions changes from state or tribal pollution prevention
23 programs, and the resulting visibility changes are small, based on the regional pollution
24 prevention emissions analysis, but are accounted for in the regional modeling.

25
26 Scenario 2 is designed to assess the effect of the implementation of enhanced smoke
27 management programs, as reflected in the WRAP Fire Emissions Joint Forum's 2018
28 optimal smoke management inventory. Enhanced smoke management programs were
29 recommended by GCVTC and are required in Section 309(d)(6) of the Regional Haze
30 Rule. This scenario uses the emissions inventories from Scenario 1, except the optimal
31 smoke management inventory was substituted for fire emissions. Thus, the results for
32 Scenario 2 are a comparison of visibility changes resulting from emission reductions
33 between the 2018 baseline smoke management and 2018 optimal smoke management fire
34 inventories.

35 36 *Modeling results projecting visibility improvement in 2018*

37
38 Visibility at the 16 Class I areas on the Colorado Plateau was estimated for the 2018
39 Scenario 1 and Scenario 2 control strategies. Tables 22 and 23 display the improvements
40 in visibility from the 2018 base case (i.e., without the strategies included in this Plan) to
41 the 2018 controlled case with all the strategies included in this Plan. In all cases,
42 visibility is expected to be better with this Plan than without it.

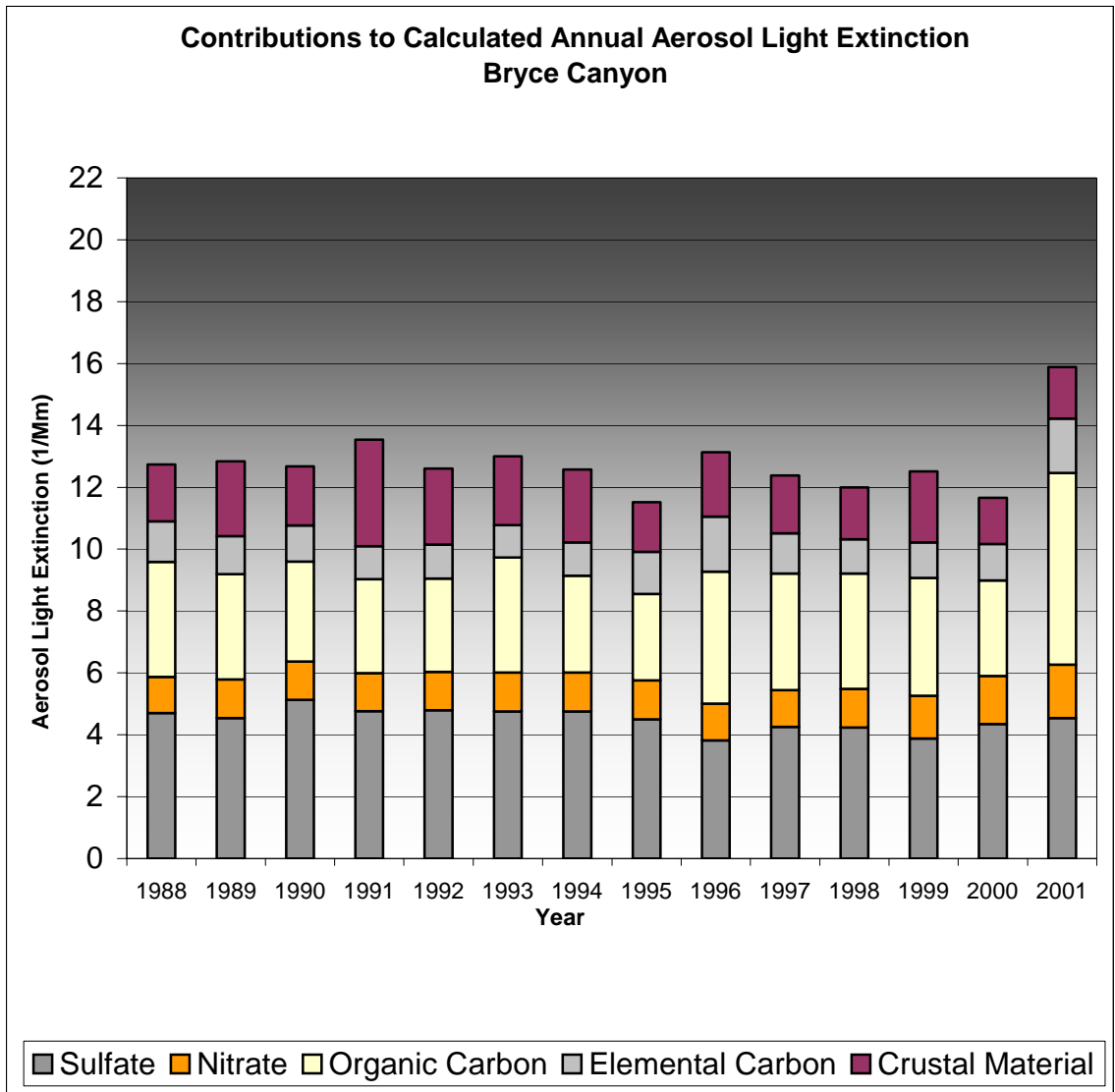
1 Visibility estimates for Scenarios 1 and 2 are found in the WRAP Technical Support
2 Document, Chapter 2. A comparison of the visibility estimates for 2018 Scenarios 1 and
3 2 at the 16 Class I areas on the Colorado Plateau for the worst 20% and best 20% days
4 reveals that 2018 Scenario 2 always estimated improved visibility as compared to 2018
5 Scenario 1. That is, the optimal smoke management programs produces visibility
6 improvements over the base smoke management programs across all 16 Class I areas for
7 both the worst 20% and best 20% days.

8 **Visibility Measurements over the Years**

9 The National Park Service conducted visibility monitoring at Utah's parks for many
10 years, but the data is not comparable because improvements in equipment have been
11 made. The only modern data available for a lengthy period is from Bryce and
12 Canyonlands since 1988. IMROVE monitors were installed at Zion and Capitol Reef in
13 2001, though the Zion monitor was moved to a more appropriate site in the spring of
14 2003. There is too little data available from those monitors to draw any conclusions
15 about trends in visibility or the sources of visibility impairment.

16
17 Displayed below are charts summarizing more than a decade of data from IMPROVE
18 monitors at Bryce and Canyonlands National Parks. Projections of visibility for 2018
19 have been added.

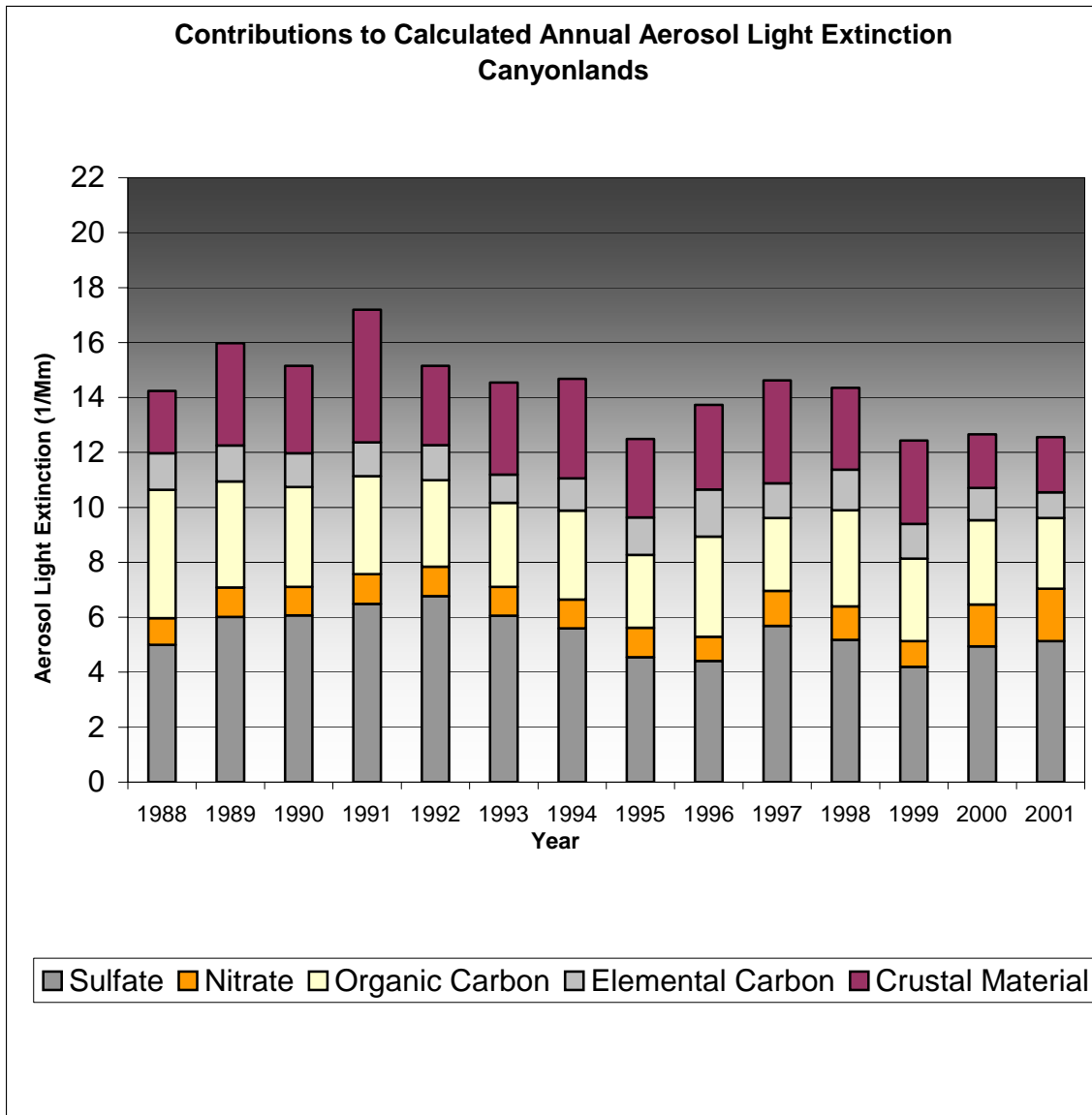
1 **Figure1 Appendix. Contributions to Light Extinction at Bryce Canyon**
 2



3 Sources: 1988-2001 data from IMPROVE Web site.
 4

5
 6 The only trend apparent in this chart is the small decline in sulfates over the period.
 7 Larger amounts of organic and elemental carbon in 1996 and 2001 are probably
 8 attributable to fires.

1 **Figure 2 Appendix. Contributions to Light Extinction at Canyonlands**
 2



3
 4 Sources: 1988-2001 data from IMPROVE Web site.

5
 6 Again, the chart shows a decline in sulfates over the period and a possible small increase
 7 in nitrates.

D. WRAP INTERSTATE AND REGIONAL PLANNING ACTIVITIES

A. Overview of Western Regional Air Partnership

The Western Regional Air Partnership (WRAP) is the regional planning organization for the development of regional haze State Implementation Plans (SIPs) in the west. The following overview was drawn from a fact sheet prepared by the WRAP and can be found at www.wrapair.org.

What is the Western Regional Air Partnership--the WRAP?

The WRAP is a voluntary organization of western states, tribes and federal agencies. It was formed in 1997 as the successor to the Grand Canyon Visibility Transport Commission, which made over 70 recommendations in June 1996 for improving visibility in 16 national parks and wilderness areas on the Colorado Plateau. The Partnership promotes, supports and monitors the implementation of those recommendations throughout the West. The WRAP is also implementing regional planning processes to improve visibility in all Western Class I areas by providing the technical and policy tools needed by states and tribes to implement the federal regional haze rule. The WRAP is administered jointly by the Western Governors' Association (WGA) and the National Tribal Environmental Council (NTEC).

The WRAP recognizes that residents have the most to gain from improved visibility and that many solutions are best implemented at the local, state, tribal or regional level with public participation.

Who belongs to the WRAP?

The WRAP is made up of western states, tribes and federal agencies. The states are Alaska, Arizona, California, Colorado, Idaho, Montana, New Mexico, North Dakota, Oregon, South Dakota, Utah, Washington, and Wyoming. Tribal board members include Campo Band of Kumeyaay Indians, Confederated Salish and Kootenai Tribes, Cortina Indian Rancheria, Hopi Tribe, Hualapai Nation of the Grand Canyon, Native Village of Shungnak, Nez Perce Tribe, Northern Cheyenne Tribe, Pueblo of Acoma, Pueblo of San Felipe, and Shoshone-Bannock Tribes of Fort Hall. Representatives of other tribes participate on WRAP forums and committees. Participation is encouraged throughout the Western states and tribes. Federal participants are the Department of the Interior (National Park Service and Fish & Wildlife Service,) the Department of Agriculture (Forest Service), and the Environmental Protection Agency.

How does the WRAP make decisions?

The WRAP's committees and forums seek consensus among the governmental partners and stakeholders including large and small businesses, academia, environmental groups and other public interest representatives. Scientific findings and policy options are presented to policy makers and the public for appropriate discussion and response. The

1 WRAP is committed to bringing together all those who may contribute to or be affected
2 by poor air quality. Findings and policy options go before the WRAP Board.

3 **How is the WRAP funded and Who does the work?**

4 The Western Governors' Association in Denver and the National Tribal Environmental
5 Council in Albuquerque receive funding from the U.S. EPA to administer and support the
6 WRAP and its committees and forums. The majority of the work is done by individuals
7 serving on the WRAP committees and forums, with assistance from staff and outside
8 contractors. Work plans are prepared by the WRAP forums and work products are
9 reviewed by the forums and the co-directors. The WRAP recognizes the great
10 contribution from organizations and individuals who contribute often un-reimbursed time
11 and effort to committee and forum work.

12 **How can individuals and organizations be involved in the WRAP's** 13 **work and decisions?**

14 The WRAP's success depends on the participation of concerned and informed
15 participants who devote time and energy to this endeavor. Committees and forums are
16 continuously accepting applications for a number of appointments. See our Web site,
17 www.wrapair.org if you are interested in getting involved.

18

19 **B. WRAP Committees and Forums**

20 The following overview of the current WRAP committees and forums was drawn
21 from a fact sheets prepared by the WRAP and can be found at www.wrapair.org.

22

23 **Initiatives Oversight Committee**

24 The Initiatives Oversight Committee is responsible for establishing and overseeing the
25 work of forums that develop policies and programs to improve and protect our air quality.
26 IOC forums are:

27

28 **The Air Pollution Prevention Forum** (AP2)

29 The Air Pollution Prevention Forum is tasked with developing energy
30 conservation initiatives and programs to expand the use of renewable energy
31 sources. They are working to find, and encourage use of, energy sources that
32 minimize air pollution.

33

34 **The Economic Analysis Forum** (EAF)

35 This Forum assists with studies to evaluate the economic effects of air quality
36 programs being developed by the WRAP to diminish haze throughout the West.

37

38 **Sources In and Near Class 1 Areas Forum** (Class 1)

39 This Forum is looking at pollution sources in and near federally mandated Class 1

1 areas to determine their impact on visibility in those areas. The group also will
2 address mitigation and outreach options.

3
4 **The Mobile Sources Forum** (MSF)

5 This Forum addresses the impact of motor vehicles and other mobile sources of
6 pollution. For example, the Forum developed a plan presented to the WRAP,
7 suggesting a revision of U.S. Environmental Protection Agency rules regarding
8 the production of low-sulfur fuel by small refineries. The Forum also
9 recommended reforms for off-road emissions and diesel fuel.

10
11 **Technical Oversight Committee** (TOC)

12 The Technical Oversight Committee's tasks are to identify and manage technical issues
13 and to establish and oversee the work of forums and work groups that are developing and
14 analyzing, scientific information related to air quality planning in the West.

15 TOC forums and work groups include:

16
17 **The Air Quality Modeling Forum** (AQMF)

18 This Forum identifies, evaluates the performance of, and applies mathematical air
19 quality models, which can be used to quantify the benefits of various air quality
20 programs for reducing haze in the western United States.

21
22 **The Ambient Monitoring and Reporting Forum** (AMRF)

23 This Forum oversees the collection, use, and reporting of ambient air quality and
24 meteorological monitoring data as needed to further the WRAP's overall goals.

25
26 **The Emissions Forum** (EF)

27 This Forum is developing the first comprehensive inventory of haze-causing air
28 emissions in the West, including a comprehensive emissions tracking and
29 forecasting system. The forum also monitors trends in actual emissions and
30 forecasts emissions reductions anticipated from current regulations and alternative
31 control strategies.

32
33 **Attribution of Haze Work Group** (AoH)

34 This Work Group is preparing guidance for states and tribes regarding both the
35 types of pollution emitters and the regions in which pollutants contribute to
36 visibility impairment in national parks and other Class 1 wilderness areas. Three
37 state and three tribal representatives form the work group along with all members
38 of the Technical Oversight Committee and one representative each from the
39 Initiatives Oversight Committee, the technical and joint forums and the Tribal
40 Data Development Work Group.

41
42 **The Tribal Data Development Work Group** (TDDWG)

43 This Work Group is identifying gaps in air quality data for tribal lands and
44 working with tribes to collect that data. While some tribes have adequate staff and

1 equipment for such an undertaking, many lack the manpower and technical
2 resources to accomplish the work on their own. This Work Group is providing
3 help by both enhancing the tribes' ability to collect the necessary data and
4 establishing an organized way to standardize and catalogue the information for
5 subsequent analysis.
6

7 **Joint Technical and Policy Forums**

8 Joint Forums address both technical issues and policy. Both the TOC and the IOC have
9 oversight.

11 **The Dust Emissions Joint Forum** (DEJF)

12 This Forum is seeking first to improve the methods for estimating dust emissions
13 and their inputs in air quality models. The Forum also is examining the extent of
14 dust impacts and strategies to reduce dust emissions.

16 **The Fire Emissions Joint Forum** (FEJF)

17 The Grand Canyon Commission confirmed that forest fires contribute
18 significantly to visibility problems and that the use of prescribed fire is expected
19 to increase as a forest management tool. The Fire Emissions Joint Forum is
20 developing measures to reduce the effects of prescribed fires and is examining
21 emissions from all kinds of fire, whether ignited naturally or by humans. The
22 Forum is considering public health and nuisance effects as well as visibility
23 impacts. It will develop a tracking system for fire emissions and management
24 techniques to minimize emissions. This Forum is working to coordinate with and
25 gain the full cooperation of federal, tribal, state, and local agencies as well as
26 private landowners, forest managers, and the agriculture community.

28 **The Stationary Sources Joint Forum** (SSJF)

29 The Stationary Sources Joint Forum, formerly the [Market Trading Forum](#),
30 developed the details of an emissions trading program to achieve cost-effective
31 reductions from industrial sources of sulfur dioxide. The Forum first set emission
32 milestones for sulfur dioxide between now and 2018 and then designed a trading
33 program to be triggered if these emission targets are exceeded. The Forum is now
34 examining other industrial source emissions, such as oxides of nitrogen and
35 particulate matter, and is assisting WRAP members in compliance with the
36 stationary source provisions of the regional haze rule.
37

38 **Other Committees/Forums**

39

40 **Air Managers' Committee** (AMC)

41 This Committee provides a venue for tribal and state air managers to deal with
42 regulatory issues they face related to the WRAP process. The group, joined by air
43 managers from the U.S. Environmental Protection Agency and federal land

1 management agencies, also aids communication linkages between the air
2 managers and the other technical and policy forums.

3 4 Communications Committee

5 The Communications Committee facilitates the exchange of information among
6 the WRAP Committees and Forums. The Committee also is charged with
7 developing materials to help the general public understand the WRAP process and
8 participate in its decision-making. A primary means of communication is through
9 this Web site.

10 11 Planning Group

12 This group helps to provide coordination among the IOC, TOC, Air Managers
13 Committee, and Communications Committee, whose co-chairs sit on the group.
14 Among its duties are: administrative oversight and budget coordination as well as
15 coordination to prevent duplication among forums.

16
17 *All of the above groups are formally recognized by the WRAP. Additional ad-hoc, task-
18 specific work groups may be formed within a forum or a committee to work on shorter-
19 term assignments.
20

21 **C. Utah's Participation in the Regional Process**

22
23 Utah has been an active participant in interstate coordination and planning
24 initiatives to address visibility impairment and regional haze. The following is a brief
25 summary of the committees and forums where Utah was an active member, and in many
26 cases was co-chair of the committee or forum. Further information regarding the
27 hundreds of meetings and conference calls that have occurred over the last 10 years can
28 be found on the WRAP webpage at www.wrapair.org.

29
30 1991 – 1996 Grand Canyon Visibility Transport Commission

31
32 1997 – 2003 Western Regional Air Partnership, Annex and 2003 SIP Development

- 33
34 1. WRAP Co-Chair
35 2. Initiatives Oversight Committee Co-Chair
36 3. Market Trading Forum Co-Chair
37 4. Pollution Prevention Forum Co-Chair
38 5. Air Managers Committee member
39 6. Communications Committee member
40 7. Dust Emissions Joint Forum member
41 8. Emissions Forum member
42 9. Fire Emissions Joint Forum member
43 10. Air Monitoring and Reporting Forum member
44 11. Air Quality Modeling Forum member

12. Utah provided data and reviewed materials prepared by the remaining WRAP forums and workgroups where Utah did not have direct representation and used those materials in Utah's 2003 SIP.

2004 – 2008 Western Regional Air Partnership, 2008 SIP Development

1. 309 Coordinating Committee member
2. Air Managers Committee member
3. Implementation Work Group member
4. Stationary Sources Joint Forum member
5. Technical Analysis Forum member
6. Attribution of Haze Work Group member
7. Utah provided data and reviewed materials prepared by the remaining WRAP forums and workgroups where Utah did not have direct representation, and provided significant technical expertise during the development of the Technical Support System and regional modeling.

The State of Utah was a team member in the development of or has used the following WRAP work products in the 2008 update to Utah's implementation plan:

1. Western Backstop SO₂ trading Program Model Rule
2. Technical Support System Website
3. Regional Modeling Center
4. VIEWS Website
5. Causes of Haze Website
6. IWG work products
7. GIS Landuse Database
8. Ao Phase II Project
9. Enhanced Smoke Management Programs
10. Fire Tracking Systems
11. Oil/Gas Area Source Emissions/Controls
12. EGU NO_x Controls
13. Stationary/Area Source Data Pivot Tables
14. Stationary/Area Source Emission Projections
15. General BART Information
16. Identifying BART-Eligible Sources

The extensive collaboration and consultation that has occurred through the WRAP provided a regional view of a regional problem that could not have been addressed by one state independently.

~~April 23, 2008~~ July 19, 2008

Demonstration That the SO₂ Milestones Provide Greater Reasonable Progress Than BART

A. Background

In 1996 the Grand Canyon Visibility Transport Commission (GCVTC) submitted recommendations to EPA to improve visibility in the 16 Class I areas on the Colorado Plateau. The GCVTC concluded that a broad-based approach that addressed multiple pollutants and source categories was necessary to reduce regional haze. The report recommended a series of strategies to address stationary sources, mobile sources, fire, pollution prevention, fugitive dust, and clean air corridors.

On July 1, 1999 the Environmental Protection Agency (EPA) published regulations to address regional haze visibility impairment. The regulations required States to address Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment, and allowed nine western states to develop plans that were based on the GCVTC recommendations for stationary sources in lieu of BART.

In 2000, the Western Regional Air Partnership (WRAP) submitted an Annex to the GCVTC recommendations that provided more details regarding the regional SO₂ milestones and Backstop Trading Program that had been recommended in the GCVTC Report, and included a demonstration that the milestones achieved greater reasonable progress than would have been achieved by the application of BART in the region. The Annex was approved by EPA in 2003, but this approval was later vacated by the DC Circuit Court of Appeals in 2005 due to problems with the methodology that was required in the Regional Haze Rule for demonstrating greater reasonable progress than BART.¹

On July 6, 2005 EPA revised the Regional Haze Rule in response to the judicial challenges to the BART requirements. On October 13, 2006 EPA published additional revisions to address alternatives to source-specific BART determinations.

Five western states (Arizona, New Mexico, Oregon, Utah, and Wyoming) had submitted State Implementation Plans (SIPs) in 2003 under 40 CFR §51.309. Four of those states (Arizona, New Mexico, Utah, and Wyoming) have updated their SIPs to include new milestones that are based on more recent emission inventories as well as the revised BART requirements in the Regional Haze Rule. The fifth state, Oregon, is no longer participating in the program. This demonstration shows that the SO₂ milestones will achieve greater reasonable progress than would have been achieved from the installation and operation of BART at all sources subject to

¹ *Center for Energy and Economic Development v. EPA*, February 18, 2005; *American Corn Growers Association v. EPA*, May 24, 2002.

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BART in the participating states in accordance with the revised Regional Haze Rule.

B. RH Rule Requirements

40 CFR 51.309(d)(4) states, “The milestones must be shown to provide for greater reasonable progress than would be achieved by application of BART pursuant to §51.308(e)(2).”

40 CFR 51.308(e)

...

(2) A State may opt to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain BART. Such an emissions trading program or other alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such emission trading programs or other alternative measures, the State must submit an implementation plan containing the following plan elements and include documentation for all required analyses:

(i) A demonstration that the emissions trading program or other alternative measure will achieve greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART in the State and covered by the alternative program. This demonstration must be based on the following:

(A) A list of all BART-eligible sources within the State.

(B) A list of all BART-eligible sources and all BART source categories covered by the alternative program. The State is not required to include every BART source category or every BART-eligible source within a BART source category in an alternative program, but each BART-eligible source in the State must be subject to the requirements of the alternative program, have a federally enforceable emission limitation determined by the State and approved by EPA as meeting BART in accordance with section 302(c) or paragraph (e)(1) of this section, or otherwise addressed under paragraphs (e)(1) or (e)(4) of this section.

(C) An analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each source within the State subject to BART and covered by the alternative program. This analysis must be conducted by making a determination of BART for each source subject to BART and covered by the alternative program as provided for in paragraph (e)(1) of this section, unless the emissions trading program or other alternative measure has been designed to meet a requirement other than BART (such as the core requirement to have a long-term strategy to achieve the reasonable progress goals established by States). In this case, the State may determine the best system of continuous emission control technology and associated emission reductions for similar types of sources within a source category based on both source-specific and category-wide information, as appropriate.

(D) An analysis of the projected emissions reductions achievable through the trading program or other alternative measure.

(E) A determination under paragraph (e)(3) of this section or otherwise based on the clear weight of evidence that the trading program or other alternative measure achieves greater

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reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

C. Identification of BART-Eligible Sources and Sources Subject to BART

Establishing BART emission limitations under 51.308(e)(1) is a three-step process (70 FR 39106):

- States identify sources which meet the definition of BART eligible.
- States determine which BART-eligible sources are “subject to BART.”
- For each source subject to BART the State identifies the appropriate control technology.

1. BART-Eligible Sources

Pursuant to 40 CFR 51.308(e)(2)(i), States submitting §309 SIPs are required to list all BART-eligible sources covered by the alternative program. BART-eligible sources are identified as those sources that fall within one of 26 specific source categories, were built between 1962 and 1977, and have potential emissions of at least 250 tons per year of any visibility impairing air pollutant (40 CFR 51.301). The BART-eligible sources identified by the four Section 309 States are shown in Table 1.

2. Subject to BART Determination

Pursuant to 40 CFR 51.308(e)(2)(i)(B) and (e)(1)(ii), States are required to determine which BART-eligible sources are “subject to BART.” BART-eligible sources are subject to BART if they emit any air pollutant that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. Section 309 States have conducted individual source modeling to determine if a BART-eligible source causes or contributes to visibility impairment.

Three of the §309 States (Arizona, New Mexico, and Utah) utilized the technical modeling services of the WRAP Regional Modeling Center (RMC). Modeling was performed according to the RMC modeling protocols (CALMET/CALPUFF Protocol for BART Exemption Screening Analysis for Class I Areas in the Western United States). For the WRAP BART exemption screening modeling, the RMC followed the EPA BART Guidelines (EPA, 2005) and the applicable CALMET/CALPUFF modeling guidance (e.g., IWAQM, 1998; FLAG, 2000; EPA, 2003c) including EPA’s March 16, 2006 memorandum: “Dispersion Coefficients for Regulatory Air Quality Modeling in CALPUFF” (Atkinson and Fox, 2006).

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The basic assumptions of the WRAP BART CALMET/CALPUFF modeling protocols are as follows.

- Three years (2001, 2002 and 2003) were modeled.
- Visibility impacts due to emissions of SO₂, NO_x and primary PM emissions were calculated.
- Visibility was calculated using the original IMPROVE equation and “Annual Average Natural Conditions.”
- The effective range of CALPUFF modeling was set at 300 km from the sources.
- According to 40 CFR part 51, Appendix Y (EPA BART Guidelines; EPA, 2005), a BART-eligible source is considered to “contribute” to visibility impairment in a Class I area if the modeled 98th percentile change in deciviews is equal to or greater than the “contribution threshold.”
- The threshold for visibility impact, for a single source, was a 0.5 deciview change or more to “contribute” to visibility impairment. This threshold is consistent with the EPA BART Guidelines (EPA 2005) that state, “As a general matter, any threshold that you use for determining whether a source ‘contributes’ to visibility impairment should not be higher than 0.5 deciviews.” This threshold is also consistent with long-standing visibility modeling practices. States have the discretion to set a lower threshold, but the four participating states have not determined that a lower threshold is needed or justified.

The State of Wyoming performed modeling in-house that was also based on EPA BART Guidelines and the applicable CALMET/CALPUFF guidelines. The basic assumptions were the same as used in the RMC modeling with the following exception: meteorological data for 1995, 1996, and 2001 that were prepared for a previous modeling analysis were used for the southwest Wyoming modeling domain. Wyoming’s *BART Air Modeling Protocol*, September 2006, is posted at <http://deq.state.wy.us/aqd/BART.asp>.

Table 1. Subject to BART Status for 309 BART-Eligible Sources

State	Plant Name	Unit	BART Eligible	Subject to BART	Modeling Entity	BART Category
AZ	Abitibi Consolidated Sales Corp – Snowflake Pulp Mill	Power Boiler 2	Y	Y	WRAP	22
AZ	Apache Nitrogen Products Nitric Acid Plant	AOPs 3-4	Y	N	WRAP	10
AZ	Arizona Electric Power Coop – Apache Power Plant	Units 1-3	Y	Y	WRAP	01
AZ	Arizona Portland Cement Company	Kiln 4	Y	Y	WRAP	04
AZ	Arizona Public Service – Cholla Power Plant	Units 2-4	Y	Y	WRAP	01
AZ	Arizona Public Service – West Phoenix Power Plant	CC 1-3	Y	Y	WRAP	01
AZ	Chemical Lime Company – Douglas Lime Plant	Kilns 4-5	Y	N	WRAP	12
AZ	Chemical Lime Company – Nelson	Kilns 1-2	Y	Y	WRAP	12

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	Lime Plant					
AZ	Kennecott (ASARCO) – Hayden Copper Smelter	Converters 1-5, Anode Furnaces 1-3	Y	Y	WRAP	08
AZ	Phelps Dodge Corporation – Morenci Plant	Gas Turbines 1-2, Gas Boilers 1-2, Boiler 4	Y	N	WRAP	22
AZ	Phelps Dodge Miami Copper Smelter	Hoboken Converters 1-5, Remelt Furnace, Shaft Furnace	Y	Y	WRAP	08
AZ	Salt River Project – Coronado Power Plant	Units 1-2	Y	Y	WRAP	01
AZ	Salt River Project – Santan Power Plant	Units 1-4	Y	N	WRAP	01
NM	Amoco Empire Abo	SRU Only	Y	N	WRAP	15
NM	SWPS Cunningham Station (Xcel Energy)	One Unit	Y	N	WRAP	01
NM	Duke Energy Artesia Gas Plant	SRU Only	Y	N	WRAP	15
NM	Duke Energy Linam Ranch Gas Plant	SRU Only	Y	N	WRAP	15
NM	Dynegy Saunders	SRU Only	Y	N	WRAP	15
NM	Giant Refining San Juan Refinery	Unit #1 FCCP ESP Stack	Y	N	WRAP	11
NM	Giant Refining, Ciniza Refinery	4 B&W CO boiler	Y	N	WRAP	11
NM	SWPS Maddox Station (Xcel Energy)	One Unit	Y	N	WRAP	01
NM	Marathon Indian Basin Gas Plant	SRU Only	Y	N	WRAP	15
NM	PNM, San Juan	Units 1-4	Y	Y	WRAP	01
NM	Rio Grande Station	One Unit	Y	N	WRAP	01
NM	Western Gas Resources San Juan River Gas Plant	SRU Only	Y	N	WRAP	15
UT	PACIFICORP – Hunter Power Plant	Units 1-2	Y	Y	WRAP	01
UT	PACIFICORP – Huntington Power Plant	Units 1-2	Y	Y	WRAP	01
WY	BASIN ELECTRIC POWER COOP – LARAMIE RIVER	Units 1-3	Y	Y	WY DEQ	01
WY	BLACK HILLS POWER & LIGHT – NEIL SIMPSON 1	Unit 1	Y	N	WY DEQ	01
WY	Dyno Nobel (formerly Coastal Chemical)	9 Units	Y	N	WY DEQ	10
WY	FMC CORP – GREEN RIVER SODA ASH PLANT	3 Units	Y	Y	WY DEQ	22
WY	FMC WYOMING CORP – GRANGER SODA ASH PLANT	2 Units	Y	N	WY DEQ	22
WY	GENERAL CHEMICAL – GREEN RIVER SODA ASH PLANT	2 Units	Y	Y	WY DEQ	22
WY	P4 PRODUCTION – ROCK SPRINGS COKING PLANT	1 Unit	Y	N	WY DEQ	22
WY	PACIFICORP – DAVE JOHNSTON	Units 1-3	Y	Y	WY DEQ	01
WY	PACIFICORP – JIM BRIDGER	Units 1-4	Y	Y	WY DEQ	01
WY	PACIFICORP – NAUGHTON	Units 1-3	Y	Y	WY DEQ	01
WY	PACIFICORP – WYODAK	Unit 1 (335 MW)	Y	Y	WY DEQ	01
WY	SINCLAIR OIL CORP – SINCLAIR	16 units	Y	N	WY DEQ	11

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	REFINERY					
WY	SINCLAIR REFINERY – CASPER	1 unit	Y	N	WY DEQ	11

D. BART Control Technology

Emission estimates for 2018, assuming the application of BART for SO₂ on all subject-to-BART sources in the four states, were prepared and are compiled in a spreadsheet named “2008-04_18 four state EGU & Other SO₂ rates V26.xls” (see technical support documentation). The 2018 estimates for these sources are estimates of actual emissions and therefore reflect greater emission reductions than would be enforceable in a case-by-case BART permit. The methodology that was used to estimate these emission reductions is described below.

1. Case-by-Case BART Estimates Were Completed for a Number of Sources

Utah: PacifiCorp initiated pollution control projects at the Huntington and Hunter Power Plants to reduce SO₂, NO_x, PM and mercury. Upgraded controls were installed on Huntington Unit 2 in 2007, a permit authorizing the project at the Hunter Power Plant is expected to be issued in December 2007, and the permit for Huntington Unit 1 is expected to be issued in 2008. The State of Utah evaluated the proposed projects, and determined that they exceeded the presumptive BART levels for SO₂ in EPA’s BART guidelines. Therefore, the permitted emission rates (or expected permitted rates) were used to estimate actual emissions in 2018.

Wyoming: Wyoming Air Quality Division, Standards and Regulations, Chapter 6, Section 9, required each source subject to BART to submit a BART permit application to the Division. The applications were required to include a proposal and justification for BART emission limits and control technology that reflect the BART guidelines established in 40 CFR part 51, Appendix Y. The emission rates contained in those applications for utilities smaller than 750 MW and non-utilities were used to estimate 2018 emissions for the affected sources in Wyoming for the purpose of establishing the regional milestone. Emission rates from utilities greater than 750 MW were assumed to be at the presumptive BART level as described below.

2. Copper Smelters

Arizona DEQ notified two copper smelters (Asarco Hayden and Phelps Dodge Miami) that the facilities were potentially subject to BART and required these sources to either submit a BART analysis or a demonstration that the source was not subject to BART. Arizona has not yet completed its review of the analyses submitted by these sources. Therefore, the previous determination that had been made during the development of the Annex is used as a placeholder until a final determination can be made.

As described in the Annex, the smelters in Arizona were not considered BART-eligible for SO₂ emissions because the smelters installed acid plants to meet the requirements of Arizona’s SO₂

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SIP during the 15-year BART window. This was determined to be consistent with 40 CFR part 51, Appendix Y, Section II.A.2, subsection 2 that states, “Sources are not BART-eligible if the only change at the plant during the relevant time period was the addition of pollution controls.” The Annex also concluded that copper smelters in the region were already operating at a BART level of control for SO₂. This placeholder will be re-evaluated when Arizona completes its review of the analyses that were submitted by the smelters, if there are significant changes.

3. Presumptive BART Levels

All other utilities that were determined to be subject to BART were assumed to be operating at the presumptive emission rate established in 40 CFR part 51, Appendix Y (0.15 lb/MMBtu). Actual emissions at this presumptive emission rate were estimated for 2018.

4. Other Sources

There are several other small non-utility sources that are potentially subject to BART. The total emissions from these sources are negligible (1%) when compared to the regional total and are therefore not considered in this analysis.

The analysis described above represents the best efforts of the four participating states to estimate actual emissions reductions that would occur due to BART. The total estimated emission reductions from all subject-to-BART sources is 91,760 tons SO₂. If a simpler methodology is used where all electric generating units that are subject to BART (including plants below 750 MW and units that are already achieving greater than 50% control of SO₂) are assumed to be operating at the presumptive minimum emission rate of 0.15 lbs/MMBtu, the estimated emission reductions from all subject to BART sources is almost the same, 91,872 tons SO₂. The analysis in this document is based on the more detailed approach, but the same result would be achieved by using a presumptive minimum BART approach.

E. Baseline Inventory for 2018

The Stationary Sources Joint Forum of the WRAP coordinated the development of a baseline inventory for 2018 that was used to update the SO₂ milestones for the 4-state region. The inventory was estimated as described below.

1. Electric Generating Units (EGUs)

The methodology for projecting existing EGUs into the future involves the following steps:

- a) the electricity production (MWs) for each individual unit at a plant was determined from the Energy Information Administration [EIA] (data available for 2002-05).
- b) the electricity generation design maximum capacity (MWs) was determined for each individual unit from EIA data.
- c) an operating Capacity Factor was determined by dividing the year-specific production

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- by the design maximum capacity of each individual plant unit.
- d) all individual units were assumed to be operating at 85% capacity in 2018 (unless they were already operating above this level in 2002).
- e) the Growth Ratio necessary to achieve 85% capacity was determined by dividing 0.85 by the Capacity Factor for each individual plant unit (averaged over four years).
- f) a Current Year Emission Factor (lb SO₂/MMBtu) was calculated for the latest year of available EIA data (2006), using the actual reported emissions (tons SO₂) for each individual plant unit divided by the actual reported annual heat generation (MMBtu).
- g) the 2018 Emission Factor was assumed to be the same as the current emission factor, except for a few sources that had submitted a source-specific emission rate.
- h) the 2018 Emission Rate (tons SO₂) was calculated by multiplying current year emissions by the ratio of the 2018 to current year Emission Factors.
- i) the Adjusted 2018 Emission Rate (tons SO₂) was “grown” to 85% capacity by multiplying the 2018 Emission Rate by the Growth Ratio from Step 5 (emissions from units already operating at or higher than the 85% capacity in the 2002 data year, were not grown, but accepted at face value).

2. Permitted/Future EGUs

The Methodology for projecting emissions from Permitted/Future EGUs is described in the ERG’s June 18, 2007 Technical Memorandum, *WRAP 2018 Preliminary Reasonable Progress Emissions Inventory – Final*. The memorandum is posted at <http://www.wrapair.org/forums/ssjf/documents/eictts/projections.html>.

The emission projections were not calculated to capture an amount of anticipated renewable energy that would arise from a state’s renewable energy portfolio standard. The Renewable Portfolio Standard (RPS) is a policy that promotes renewable energy in a way that is compatible with the competitive electricity markets. A state’s RPS does not have a direct relationship to emissions within the four participating §309 states because the RPS could be met by renewable resources outside of the state. For the actual impact of a portfolio standard on reasonable progress for states that have an RPS, please see the Pollution Prevention chapter of the SIP.

3. Non-EGUs

The Methodology for projecting emissions from “Other Industrial Sources” is described in E.H. Pechan’s October 2006 Report, *2018 SO₂ Emissions Evaluation for Non-Utility Sources – Final*. The report is posted online at <http://www.wrapair.org/forums/ssjf/documents/eictts/projections.html>.

- a) The SO₂ emissions for 19 Natural Gas Processing Plants were updated by Environ in April 2007, with additional research into future O&G Operations. The September 2007 Final Report with results of that update is posted at <http://www.wrapair.org/forums/ssjf/documents/eictts/oilgas.html>.

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- b) The 2005 SO₂ Milestone Report had some sources which were not picked up in the Pechan Report. In those cases, the 2005 emissions were used as a placeholder for the 2018 emission values.
- c) The projections do not specifically break out emissions from existing sources vs. new sources. For purposes of establishing a new source set-aside, current (2006 for most sources, and 2007 for two copper smelters in AZ) emissions were assumed to be the baseline emissions for existing sources, and the projected increase in emissions between 2005 and 2018 is attributed to new source growth.

Table 2. 2018 Baseline

	Projected 2018 SO ₂ Emissions Baseline
Utility	207,249
Non-Utility	76,635
New Source Growth	34,000
Total 2018 Baseline	317,884

F. Calculation of Milestone for Alternative Program

The SO₂ milestones are based on the GCVTC recommendations that were designed to remedy existing and prevent future visibility impairment in the 16 Class I areas on the Colorado Plateau. When EPA adopted the Regional Haze Rule in 1999, Section 309 of the rule was included that incorporates the GCVTC's recommendations and determines that the strategies developed by the GCVTC meet reasonable progress for the first planning period. An analysis of BART was included as an additional requirement, but at its heart the SO₂ milestones are designed to achieve reasonable progress by reducing SO₂ emissions by 50% - 70% from 1990 emissions by 2040. All sources that are subject to BART for SO₂ are included in the program as required by 40 CFR 51.308(e)(2)(i)(B) because the program applies to all sources with actual emissions of 100 tons of SO₂ per year. The following calculation methodology was used to support the additional BART requirement in the establishment of the 2018 milestone.

The 2018 milestone was derived from the 2018 baseline. First, the estimated actual emission reduction from all sources that are subject to BART in the participating states (see section D of this analysis) was subtracted from the baseline. Then, an operational headroom and uncertainty factor was added to the baseline.

1. Operational Headroom and Uncertainty

a) Recognition of Early Reductions

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The GCVTC agreements and recommendations contain two tenets that have uniquely informed the establishment of operational headroom and uncertainty under the market trading program. First, the Commission recommended that the market trading program “contain specific provisions to encourage and reward early emission reductions, including reductions achieved before 2000.”² The GCVTC committed to achieve a 13% reduction in SO₂ emissions from stationary sources by the year 2000. The GCVTC also recognized that there was a good possibility that actual emission reductions would be greater than this 13% goal. A general plan was derived to give some early reductions credit to the region and some to the environment. The emission reductions that were greater than 13% were to be split, with ½ going to the environment (through the establishment of milestones) and the other ½ providing headroom.³

Sulfur dioxide emissions decreased by 25% in the 9-state GCVTC between 1990 and 2000, while SO₂ emissions in the four participating §309 states decreased 29% in that same time period. Emissions decreased an additional 10% between 2000 and 2005.⁴

b) Allocation to Tribes

Second, the Commission recommended allocations to tribes that are of practical benefit.⁵ This recognized the concern that “tribes, by and large, have not contributed to the visibility problem in the region” and that “[t]ribal economies are much less developed than those of states, and tribes must have the opportunity to progress to reach some degree of parity with states in this regard.”⁶ The tribes specifically recommended that if an emission trading strategy is adopted to achieve SO₂ reductions from stationary sources that allocations be based on considerations of equity rather than historical emissions:

Credits should not be based on historical emissions, but should be based on equitable factors, including the need to preserve opportunities for economic development on tribal lands. In general, these lands are currently lacking in economic bases and have not contributed to the visibility problems.⁷

² *Recommendations for Improving Western Vistas* at 33 (June 1996) (emphasis added).

³ *Id.* at 34.

⁴ *WRAP 2005 Regional Emissions and Milestone Report*, March 29, 2007. Emissions calculations from Oregon are included in this report but are not included in the calculated emission reductions for the participating states.

⁵ *Recommendations for Improving Western Vistas* (June 1996). at 35.

⁶ *Id.* at 66-67.

⁷ *Id.* at 71.

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Accordingly, the Backstop Trading Program contains an 8,500 allocation to tribes.

These two considerations – to reward emission reductions occurring between 1990 and 2000, and to provide an equitable allocation to the tribes – originate from the GCVTC recommendations. They reflect distinct policy concerns of the Commission that are unique to the program under Section 309 of the Regional Haze Rule incorporating the Commission’s recommendations.

c) Uncertainty

In addition, because the baseline emissions inventory is a projection of actual emissions, uncertainty exists in the projection method including, for example, fluctuations in weather and changing economic conditions.

There are inherent uncertainties in the inventory calculation that need to be recognized.

- Inherent measurement uncertainties. CEMs are calibrated daily to a relative accuracy of 20% using calibration gases. Fluctuations in measurements can occur due to the measurement techniques that are not indicative of actual changes in emissions. Pluses and minuses will cancel out to a certain degree, but some consideration of these fluctuations is needed.
- Projections. Projections of future “actual” emissions are based on the best information available, but are inherently uncertain. This uncertainty increases further out in time. Growth rates may be underestimated, impacts of new technologies or regulatory requirements may have unexpected effects, etc.

The participating §309 States recognize that there are some competing uncertainties that the future “actual” emissions may be over-predicted. However, in light of the Commission’s specific recommendation to reward early reductions occurring between 1990 and 2000, the participating §309 States specifically set aside 8,500 tons in 2018 to account for the allocation described above for tribes as well as the uncertainty in the calculation and projection of actual emissions. The 8,500 tons represents 2.7% of the projected 2018 baseline SO₂ emissions (309,438 tons) encompassed within the trading program.

The participating §309 States also believe the likelihood exists that the full complement of emissions set aside for uncertainty and headroom will not be utilized. All sources in the region operate below their allowable emissions to ensure that they are in compliance with emission limits. The regional milestones are comparable to allowable emissions because an exceedance of the milestone will trigger regulatory consequences. Individual sources will be tracking their emissions, as well as the overall regional emissions, and the possibility of avoiding a regulatory program will provide a powerful incentive for sources to keep

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emissions below the cap. This will also provide a disincentive for keeping regional emissions close to the cap, because that will increase the risk that an unexpected event (such as increased production from one sector) will trigger the regulatory program. The incentive to operate below the cap should be especially powerful in 2018 when individual sources will face penalties if the cap is exceeded and a source has emitted SO₂ in excess of its allowances.

2. 2018 SO₂ Milestone Calculation

2018 Baseline	317,884
Estimated BART Reductions	-91,760
Uncertainty/Headroom	+ 8,500
Total	234,624

FG. Other Considerations

There are a number of other considerations that must be taken into account in the overall determination as to whether or not the 2018 milestone developed by the participating §309 States achieves greater reasonable progress than would have resulted from the installation and operation of BART at all sources subject to BART.

1. Remedy and Prevention

When Congress established the visibility program in 1977 it declared as a national goal “the prevention of any future, and the remedying of any existing” anthropogenic visibility impairment in mandatory Class I Federal areas.⁸ BART is an emission limitation established at a specific source and is designed as a remedy to impairment at specific mandatory Class I areas. By contrast, the SO₂ milestones developed by the participating §309 States serve the dual purpose of remedying existing impairment and preventing future impairment by requiring regional SO₂ emissions reductions and capping emissions for stationary sources. Future impairment is prevented by capping emissions growth from sources not eligible under the BART requirements, from sources subject to BART that are expected to significantly increase utilization, and from entirely new sources in the region.

2. Additional Sources Included

The SO₂ milestones developed by the participating §309 States will include all stationary sources with emissions higher than 100 tons/year of SO₂. The participating §309 States designed this program as part of an overall strategy to address all sources of visibility impairing pollutants,

⁸ CAA § 169A(a)(1).

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rather than focusing on a subset of stationary sources.

		2005
	Number of Sources	Emissions
Subject to BART	19	190,797
Other Stationary Sources	76	84,967

The inclusion of all major SO₂ sources in the program is necessary to create a viable trading program, and also serves a broader purpose to ensure that growth in emissions from sources that are not subject to BART does not undermine the progress that has been achieved. BART applied on a case-by-case basis would not affect these sources, and there would be no limitation on their future operations under their existing permit conditions. Because the milestones will cap these sources at actual emissions (which are less than current allowable emissions), the overall effect of their inclusion is to provide greater reasonable progress than would have been achieved if only sources that are subject to BART were included in the program.

3. Cap on New Source Growth

The milestones developed by the participating §309 States will cap the growth of SO₂ emissions in the west. These milestones include estimates for growth, but then lock these estimates in as an enforceable emission cap. The milestone approach is consistent with the statutory goal of preventing any future visibility impairment that results from man-made air pollution. The entire region is experiencing rapid growth which could erode the progress that has been achieved in the last two decades towards improving visibility. BART applied on a case-by-case basis would have no impact on future growth, and in the long run would not achieve the regional emission reductions that are guaranteed by the program.

4. Actual vs. Allowable Emissions

The baseline emission projections and assumed reductions due to the assumption of BART-level emission rates on all sources subject to BART are all based on actual emissions, using 2006 as the baseline. The use of actual emissions has an effect in several ways. If the BART process was applied on a case-by-case basis to individual sources, emission limitations would be established based on the maximum level of operation of the unit. The “allowable emissions” are typically higher than actual emissions, because sources do not always run under full load conditions, over the full year’s available time. In addition, the allowable emissions would account for variations in the sulfur content of fuel and alternative operating scenarios. The difference between actual emissions and allowable emissions is particularly large when a source is permitted to burn two different fuel types, such as oil and natural gas, or when the source is part of a cyclical industry where production varies from year to year due to the changing demand for their product.

The emission projections used in the development of the SO₂ milestones allows for some increase in capacity for the electric utility industry which will partially address this difference between actual and allowable emissions. Even in this case, the utilities are assumed to operate at

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an average of 85% of nameplate capacity, even though they are permitted to operate at 100% capacity.

In addition to the cap on growth of actual emissions, the difference between an emission projection for future years and a regional emission cap must also be considered. The milestones will act as a regulatory trigger that will be converted into an enforceable emission cap if the milestones are not met. This essentially creates a regional “allowable” emission level. When sources are managing their operations they have a large incentive to maintain headroom under any enforceable limit to ensure that they stay in compliance. This process is expected to happen on a voluntary basis prior to the program trigger, and will be strengthened if the milestones become enforceable emission caps. The net effect is that compliance with the milestones should lead to actual emissions that are below the milestone. The difference between actual emissions and allowable emissions is commonly referred to as headroom.

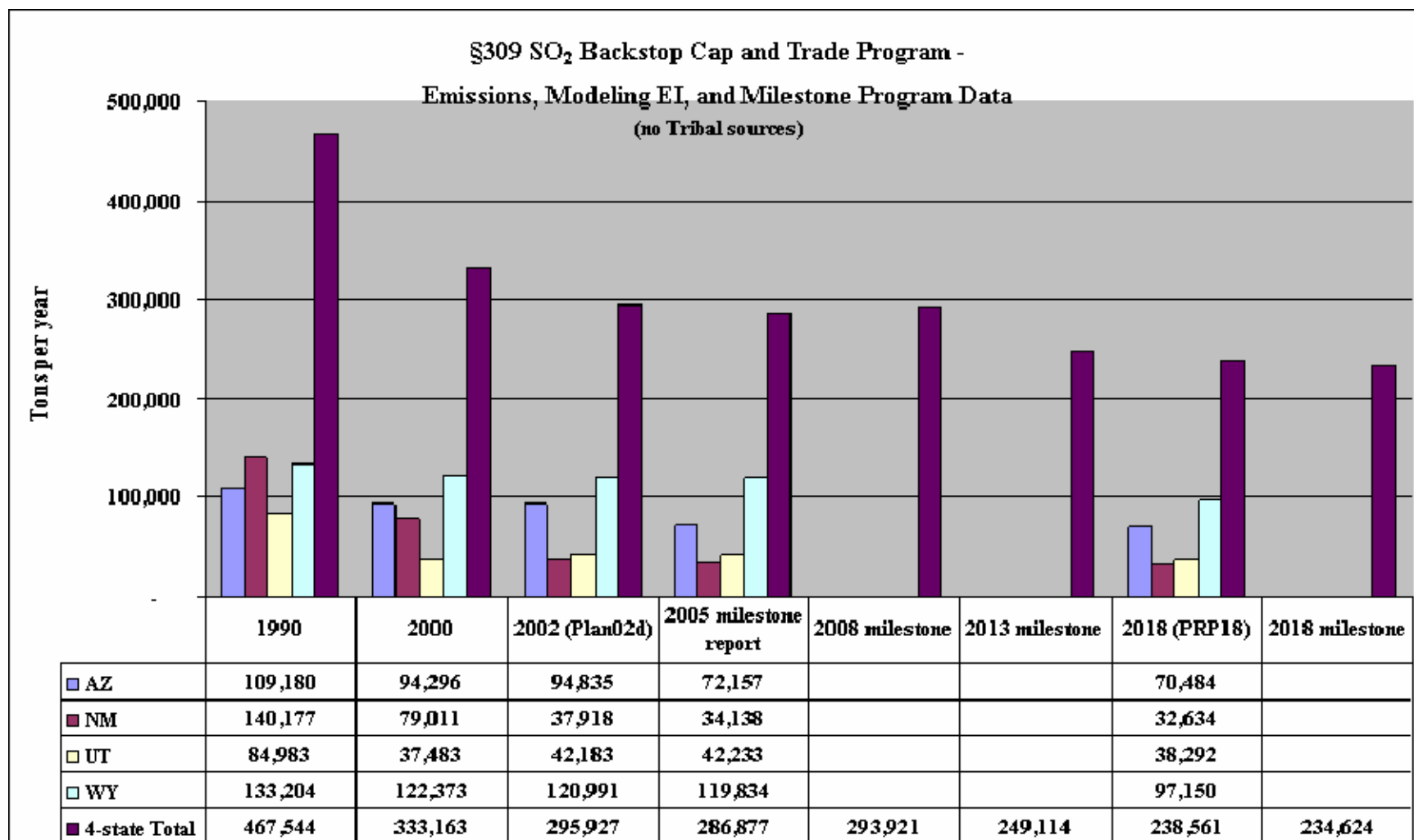
5. Mass-Based Cap vs. Rate-Based Emission Limits for BART

Emission limitations for stationary sources (including BART limits) are typically expressed as emission rates (lbs/hour or lbs/MMBtu), while the SO₂ milestones are expressed as total mass during a given year (tons/year). One effect of this difference is that rate-based limits can lead to higher emissions when production is increased or when higher sulfur fuel is used, as explained in the discussion of actual vs. allowable emissions above. Another difference is that mass-based limits will include excess emissions that may occur due to malfunctions or during the start-up or shut-down of emission units. A good example of this difference is the requirement in the Acid Rain Program that emissions must be assumed to be the highest value recorded from the past year during the time period that continuous emission monitors are not functioning on a stack. These higher emissions are calculated as part of the overall tons/year, and must be accounted for under the mass-based cap for the Acid Rain Program.

6. 1990 as a Baseline for Section 309 Regional Haze Plans

The Regional Haze Rule recognized the significant work that had been completed by the Grand Canyon Commission, and Section 309 of the rule was therefore designed to incorporate the Commission recommendations. A key element of this section of the rule is the use of 1990 as a baseline for measuring progress. There have been significant emission reductions in the west since 1990, and this improvement needs to be considered when measuring the overall effects of the Commission’s strategies. The Commission established a goal of a 13% reduction from 1990 emissions. The actual emission reductions in the region were 25%. Figure 1 shows the emission reductions from 1990 baseline emissions in the participating §309 States that will have been achieved by 2018. This 51% reduction is well on the way to the GCVTC goal of reducing SO₂ emissions by 50% - 70% by the year 2040.

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7. Commission Strategies are a Total Package

The GCVTC recommendations go well beyond stationary sources, and include strategies to address mobile sources, prescribed fire, pollution prevention, and emissions in and near mandatory Class I areas. The stationary source strategies need to be viewed as part of this overall package. Visibility impairment in the west is caused by multiple sources and pollutants, and a narrow focus on stationary sources may not achieve the same results as a broad-based program.

H. Comparison of Trading vs. Command and Control BART Requirements

During the development of the Annex, the WRAP conducted modeling to determine whether the distribution of emissions under the Backstop Trading Program would differ substantially from the distribution of emissions assuming installation of BART or would disproportionately impact any Class I area due to a geographic concentration of emissions. The results of this modeling are included in Tables 2 and 3 of Attachment C to the Annex⁹. Attachment C, Section G concludes, “The results of this analysis showed that the maximum difference between the two scenarios at any of the Class I areas was only 0.1 deciviews.¹⁰”

⁹ Voluntary Emissions Reduction Program for Major Industrial Sources of Sulfur Dioxide in Nine Western States and A Backstop Market Trading Program, an Annex to the Report of the Grand Canyon Visibility Transport Commission (September 2000) at C-15 and 16.

¹⁰ Id. at C-21.

district in the prior year compared to the state total of completed IB credits.

(2) The remaining 50 percent allocation shall be distributed equally to schools where students scored a grade of 4 or higher on IB exams, resulting in a fixed amount of dollars per exam passed.

D. All candidate IB and approved IB schools shall be equally eligible for funding.

R277-710-6. Annual Reporting and Other Student Instruction Issues.

A. The Board shall develop uniform deadlines, forms, and fiscal and pupil accounting procedures for the IB Program.

B. School districts/charter schools participating in the IB Program shall provide the USOE with end-of-year expenditure reports itemized by the categories requested by the USOE.

C. School districts/charter schools participating in the IB Program shall provide for parental permission for students to participate in IB classes.

D. This rule shall apply to IB programs operating and approved as of the 2008-09 school year, and continue thereafter.

KEY: international baccalaureate

Date of Enactment or Last Substantive Amendment: 2008

Authorizing, and Implemented or Interpreted Law: Art X Sec 3; 53A-17a-120; 53A-1-402(1)(c); 53A-1-401(3)

**Environmental Quality, Air Quality
R307-110-28
Regional Haze**

NOTICE OF PROPOSED RULE

(Amendment)

DAR FILE NO.: 31557

FILED: 06/13/2008, 12:43

RULE ANALYSIS

PURPOSE OF THE RULE OR REASON FOR THE CHANGE: When the Environmental Protection Agency (EPA) adopted the Regional Haze Rule at 40 CFR 51.309 in 1999, it incorporated the recommendations of the Grand Canyon Visibility Transport Commission (GCVTC). EPA required the Western Regional Air Partnership (WRAP), a regional planning organization that was established to address regional haze, to complete the development of regional milestones and a backstop trading program for stationary sources that emit sulfur dioxide and to submit it as an Annex to the GCVTC recommendations. The WRAP submitted the Annex in September 2000. On June 5, 2003, EPA approved the Annex and incorporated the stationary source provisions into the Regional Haze Rule. In December 2003 the Air Quality Board adopted Section XX of the State Implementation Plan (SIP) to address regional haze.

This plan was based on the GCVTC recommendations and the Annex. EPA's approval of the Annex was challenged, and on February 18, 2005, the DC Circuit Court of Appeals vacated EPA's 2003 rules (Center for Energy and Economic Development (CEED) vs. Environmental Protection Agency, February 18, 2005). The Court determined that EPA had

required a Best Available Retrofit Technology (BART) demonstration in the Annex that was based on a methodology that had been vacated by the Court in 2002 (American Corn Growers Association vs. Environmental Protection Agency, May 24, 2002). On October 13, 2006, EPA revised the regional haze rule to establish the methodology for states to develop an alternative to BART that was consistent with the Court's decision. This rule change revises the SO₂ milestones and backstop trading program to meet the 2006 revisions to the Regional Haze Rule.

SUMMARY OF THE RULE OR CHANGE: Utah has been working cooperatively with the States of Arizona, New Mexico, and Wyoming to revise the SO₂ milestones and backstop trading program to meet the 2006 revisions to the Regional Haze Rule. The SO₂ milestones that are included in Part E of the Regional Haze SIP are based on the provisions in the 2006 Regional Haze Rule. The changes to the SO₂ milestones led to the following additional changes in Part E of the Regional Haze SIP that describes the milestones and backstop trading program: 1) the SO₂ milestones in the 2003 SIP were designed to automatically adjust as states or tribes opted in to the regional trading program. There are four states that are currently planning to participate in the program, and therefore, the milestones have now been changed to a fixed number rather than a formula. If a state or tribe decides to opt in to the program at a future date, then the milestones would need to be changed through a SIP revision; 2) when the 2003 SIP was adopted there were two copper smelters that had temporarily suspended operations. Provisions were included in the SIP to adjust the milestones if either of the smelters resumed operation. Since that time, both smelters as well as one additional copper smelter have been permanently closed.

The provisions to adjust the milestone are no longer needed and have been removed from the SIP. A small set-aside is still included to account for production shifts from the closed smelters to the remaining smelters in the region; 3) the 2003 SIP included a set-aside of 20,000 allowances that would be distributed to tribes if the backstop trading program was ever implemented. This amount had been based on the expectation that nine states might participate in the program. Because only four states are now participating, the amount has been decreased proportionately to 8,500 allowances. In addition to the preceding changes to Part E, revisions to Section D of Utah's Regional Haze SIP were made to address the BART requirements for two sources in Utah: PacifiCorp Hunter Power Plant (Units 1 and 2) and PacifiCorp Huntington Power Plant (Units 1 and 2). PacifiCorp has recently received approval orders to implement pollution control projects at Hunter Power Plant (Units 1 and 2) to address a number of air quality issues including mercury, regional haze, and ozone. When these projects were evaluated, the Utah Division of Air Quality (UDAQ) determined that the pollution control projects satisfied the BART requirements for NO_x and particulate matter in the Regional Haze Guidance. The pollution control project has already been completed for Huntington Unit 2, and will be completed for Huntington Unit 1 by 2010. These projects will collectively reduce NO_x emissions by 6,200 tons/yr and PM₁₀ emissions by 925 tons per year. In addition, a number of clarifications

and corrections were made to the SIP that were identified by EPA during their review of the 2003 SIP.

STATE STATUTORY OR CONSTITUTIONAL AUTHORIZATION FOR THIS RULE: Subsection 19-2-104(3)(e)

THIS RULE OR CHANGE INCORPORATES BY REFERENCE THE FOLLOWING MATERIAL: State Implementation Plan Section XX, Regional Haze, 2008

ANTICIPATED COST OR SAVINGS TO:

- ❖ **THE STATE BUDGET:** No cost or savings are anticipated with this rule change. No new requirements were created with this rule change that impact state budget.
- ❖ **LOCAL GOVERNMENTS:** No cost or savings are anticipated with this rule change. No new requirements were created with this rule change that impact local government.
- ❖ **SMALL BUSINESSES AND PERSONS OTHER THAN BUSINESSES:** Small Business: No cost or savings are anticipated with this rule change. No new requirements were created with this rule change that impacted small businesses. Other Persons: The only affected entity is PacifiCorp. at Hunter Units 1 and 2 and Huntington Units 1 and 2. UDAQ has estimated the total compliance cost for these 4 units to be \$414,000,000 per unit. However this cost includes other upgrades that are not required by this rule. It is impossible to itemize the actual cost for the required upgrades mentioned in this rule change. There are no other affected persons.

COMPLIANCE COSTS FOR AFFECTED PERSONS: The only affected entity is PacifiCorp. at Hunter Units 1 and 2 and Huntington Units 1 and 2. UDAQ has estimated the average compliance cost for these 4 units to be \$103,500,000 per unit. However this cost included other includes other upgrades that are not required by this rule. It is impossible to itemize the actual cost for the required upgrades mentioned in this rule change. There are no other affected persons.

COMMENTS BY THE DEPARTMENT HEAD ON THE FISCAL IMPACT THE RULE MAY HAVE ON BUSINESSES: Aside from PacifiCorp.'s required upgrades on Hunter Units 1 and 2 and Huntington Units 1 and 2, no other costs are anticipated for business in Utah. Rick W. Sprott, Executive Director

THE FULL TEXT OF THIS RULE MAY BE INSPECTED, DURING REGULAR BUSINESS HOURS, AT:

ENVIRONMENTAL QUALITY
AIR QUALITY
150 N 1950 W
SALT LAKE CITY UT 84116-3085, or
at the Division of Administrative Rules.

DIRECT QUESTIONS REGARDING THIS RULE TO:
Kimberly Kreykes at the above address, by phone at 801-536-4042, by FAX at 801-536-4099, or by Internet E-mail at kkreykes@utah.gov

INTERESTED PERSONS MAY PRESENT THEIR VIEWS ON THIS RULE BY SUBMITTING WRITTEN COMMENTS TO THE ADDRESS ABOVE NO LATER THAN 5:00 PM on 07/31/2008

INTERESTED PERSONS MAY ATTEND A PUBLIC HEARING REGARDING THIS RULE: 7/17/2008 at 2:00 PM, DEQ Bldg, 168 N 1950 W, Room 201, Salt Lake City, UT.

THIS RULE MAY BECOME EFFECTIVE ON: 08/07/2008

AUTHORIZED BY: Bryce Bird, Planning Branch Manager

R307. Environmental Quality, Air Quality.

R307-110. General Requirements: State Implementation Plan.

R307-110-28. Regional Haze.

The Utah State Implementation Plan, Section XX, Regional Haze, as most recently amended by the Utah Air Quality Board on [May 5, 2004]2008, pursuant to Section 19-2-104, is hereby incorporated by reference and made a part of these rules.

KEY: air pollution, PM10, PM2.5, ozone

Date of Enactment or Last Substantive Amendment: [May 2, 2007]2008

Notice of Continuation: March 15, 2007

Authorizing, and Implemented or Interpreted Law: 19-2-104(3)(e)

**Environmental Quality, Air Quality
R307-150-4
Sulfur Dioxide Milestone Inventory
Requirements**

**NOTICE OF PROPOSED RULE
(Amendment)**

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RULE ANALYSIS

PURPOSE OF THE RULE OR REASON FOR THE CHANGE: Utah's 2003 Regional Haze State Implementation Plan (SIP) contained sulfur dioxide (SO₂) milestones that were based in part on 1999 SO₂ emissions from power plants that were reported to the federal acid rain program. In the middle of 1999, EPA changed the flow rate methodology that could be used to measure emissions for the acid rain program and in some cases the new flow rates could lead to a significant change in reported emissions. To ensure that real emission changes were being measured, Rule R307-150 required power plants that were using the new flow rate methodology to adjust their emissions back to the old methodology for purposes of comparing regional SO₂ emissions to the regional SO₂ milestone. Due to proposed changes in the Regional Haze SIP, this adjustment is no longer needed.

SUMMARY OF THE RULE OR CHANGE: The modification to Rule R307-150 removes requirements for power plants that were using the new flow rate methodology to adjust their emissions back to the old methodology for purposes of comparing regional SO₂ emissions to the regional SO₂ milestone. In addition, sources that make changes to their measurement