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IDAHO BOARD OF ENVIRONMENTAL QUALITY

THE AMALGAMATED SUGAR COMPANY LLC (Air Quality Tier II Operating Permit No. T2-2009.0105),

Petitioner,
v.

THE IDAHO DEPARTMENT OF ENVIRONMENTAL QUALITY, a Political Subdivision of the State of Idaho,

Respondent.

Docket No. _____

PETITION FOR A CONTESTED CASE PROCEEDING

The Amalgamated Sugar Company LLC ("TASCO"), by and through its representative Stoel Rives LLP, respectfully petitions the Idaho Board of Environmental Quality (the "Board") for a contested case proceeding, pursuant to Idaho Code § 39-107(5) and the Rules of Administrative Procedure before the Board of Environmental Quality, IDAPA 58.01.23, *et seq.* TASCO seeks review of conditions and requirements of Air Quality Tier II Operating Permit No. T2-2009.0105, which the Idaho Department of Environmental Quality ("IDEQ") issued on September 7, 2010 for TASCO's factory in Nampa, Idaho (the "Tier II Permit"). The Tier II

Permit, the accompanying Statement of Basis, and the Response to Public Comments are attached to this petition as exhibits.

I. INTRODUCTION

As the holder of the Tier II Permit, TASCO has legal standing to object to and seek review of the permit. TASCO's objections are described in more detail in Section III of this petition but are briefly summarized here.

TASCO is owned by Snake River Sugar Company, a grower-owned cooperative. TASCO processes sugar beets into sugar and other byproducts at three factories in Idaho, including its Nampa factory. The Nampa factory is located downwind and over 100 miles to the east/southeast of three national wilderness areas – approximately 104 miles from the Hells Canyon Wilderness (on the Idaho/Oregon border), approximately 102 miles from the Eagle Cap Wilderness (in Oregon), and approximately 109 miles from the Strawberry Mountain Wilderness (in Oregon).[1] In July 2007, IDEQ notified TASCO that emissions from the Nampa factory's Riley Boiler – which supplies steam and generates electricity for the factory – had the potential to impact visibility in those areas.

On that basis, IDEQ determined that the Riley Boiler is subject to Best Available Retrofit Technology ("BART") requirements under the Clean Air Act's Regional Haze Rule[2] and Idaho rules,[3] and that TASCO may be required to install additional emission control technology to control particulate matter ("PM"), sulfur dioxide ("SO_2"), and nitrogen oxides ("NO_x"). IDEQ requested that TASCO prepare a BART determination analysis for the Riley Boiler, which TASCO completed. IDEQ, however, largely rejected TASCO's analysis and ultimately

[1] *See* mileage log prepared by TASCO, attached as **Exhibit A** hereto.
[2] 40 C.F.R. § 51.308.
[3] IDAPA 58.01.01.668.

determined that the best control technologies for the Riley Boiler are the existing bag house for PM, a spray dry flue gas desulfurization system for SO_2, and low NO_x burners with overfire air for NO_x. The costs of the new SO_2 and NO_x controls are significant – an initial capital investment of at least $17.8 million and annual expenses of over $3 million.

On September 7, 2010, IDEQ issued the Tier II Permit, requiring the BART controls previously recommended by IDEQ. IDEQ used an unnecessarily inflexible and conservative modeling analysis in both its determination that the Riley Boiler is subject to BART and in its selection of the BART controls for SO_2 and NO_x emissions. Moreover, IDEQ failed to take into account the unique circumstances surrounding the Riley Boiler – its size, its location in relation to the protected wilderness areas, its actual contribution to visibility impacts in those areas, the significant cost of the new BART controls, and the economic realities of the Nampa facility. Instead IDEQ relied solely on modeling results to form its conclusions about the Riley Boiler. Had IDEQ given proper consideration to the totality of the circumstances, it would have reached a different conclusion, one that does not require the installation of new emission controls at such significant costs.

IDEQ's BART determinations can, in part, be traced to its rigid and uncompromising reference to Appendix Y to 40 C.F.R. Part 51 – Guidelines for BART Determinations Under the Regional Haze Rule ("Appendix Y").[4] Appendix Y was published by the U.S. Environmental Protection Agency ("EPA") as guidelines for conducting the BART analysis for large power plants. Use of the guidelines for relatively small industrial sources such as the Riley Boiler is not mandated. Despite that, IDEQ strictly followed the Appendix Y guidelines for modeling and refused TASCO's repeated requests that it exercise allowed discretion and consider a different

[4] *See* 70 Fed. Reg. 39,104, 39,157 (July 6, 2005).

approach to determine if the Riley Boiler is subject to BART and, if so, the appropriate BART controls for the boiler. IDEQ rejected TASCO's numerous requests that it perform these alternative evaluations.

IDEQ's persistent reliance on the model recommended by Appendix Y led to this petition, by which TASCO requests that the Board review and ultimately strike the Tier II Permit. There are multiple reasons that justify the Board's review of the Tier II Permit and, ultimately, its withdrawal.

For one, IDEQ's application of Appendix Y resulted in an unnecessary and flawed Tier II Permit. To establish that the Riley Boiler is subject to BART controls, following Appendix Y, IDEQ used a dispersion model known as "CALPUFF" and refused to consider a different modeling approach, specifically a receptor oriented apportionment model that takes into account actual measured impacts *at the receptor*. Results from the receptor oriented apportionment model show little visibility impact from the Riley Boiler on the Hells Canyon, Eagle Cap, or Strawberry Mountain Wilderness areas and should have raised questions for IDEQ regarding the reliability and appropriateness of the CALPUFF results, which derive from a more speculative *source* oriented approach. Yet IDEQ resisted the idea of considering other approaches. Those flaws in IDEQ's BART analysis are discussed more fully in Section III.A of this petition.

Even if IDEQ's reliance on CALPUFF is reasonable, IDEQ's determination of what BART controls are appropriate for SO_2 and NO_x emissions from the Riley Boiler is not reasonable. IDEQ failed to properly consider the five key factors required for the evaluation, including (1) the degree of improvement in visibility that may reasonably be anticipated to result from the use of the technology and (2) the costs of compliance.[5] Instead IDEQ placed

[5] 40 C.F.R. § 51.308(e)(I)(ii)(A); IDAPA 58.01.01.668.02.c.

significant weight on the model results under CALPUFF to the exclusion of a balanced assessment of all the relevant circumstances.

With respect to the degree of improvement in visibility, IDEQ failed to give appropriate weight to various circumstances known to IDEQ that would have led to a different BART result. For example, the receptor oriented apportionment evaluation conducted by TASCO demonstrated that the new controls mandated by IDEQ would result in little, if any, visibility improvements in the Hells Canyon, Eagle Cap, and Strawberry Mountain Wilderness areas. Those results conflict dramatically with the CALPUFF projections and raise questions about the reasonableness of IDEQ's selection of BART controls. In addition, IDEQ relied upon unrefined emission estimates to build the baseline for the CALPUFF model so that appropriate visibility improvements cannot be reasonably ascertained. There are also other lines of evidence known to IDEQ – such as the relative contribution of Idaho industrial sources to the emissions profile – that suggest little is to be gained by expensive controls on the Riley Boiler. Overlooking these relevant indicators, IDEQ solely and wrongly relied upon the CALPUFF model results to predict the degree of visibility improvement.

With respect to the costs of compliance, IDEQ concluded – relying on an EPA economic review – that TASCO (as a company) could afford to fund the expenditures and therefore excluded any further consideration of the costs to comply. That conclusion is not consistent with EPA's own guidance in Appendix Y. According to Appendix Y, affordability of the BART controls is not the appropriate inquiry. What is determinative is the unique economic impact of the proposed controls to the Nampa factory. IDEQ failed to properly consider the significant costs to install and operate the BART controls and the particular economic circumstances of the Nampa factory and its economic viability. That failure is particularly evident when weighing the

sizable cost of the BART controls against the uncertain visibility improvements that can be traced to those controls. IDEQ's failure to fully and appropriately consider the degree of visibility improvement reasonably anticipated and the costs of compliance are discussed more fully in Section III.B of this petition.

Finally, even if IDEQ's determination that the Riley Boiler is subject to BART and its choice of control technologies is found to be reasonable, as alternative relief TASCO seeks the revision of a number of conditions of the Tier II Permit. The requested revisions are described in Section III.C below.

II. BACKGROUND AND RELEVANT DOCUMENTS[6]

On July 19, 2007, IDEQ notified TASCO that the Riley Boiler is subject to BART and requested that TASCO submit a BART determination analysis to identify and evaluate available emission control technologies, taking into account the five factors set forth in the applicable rule and applying EPA's Appendix Y as guidance.[7] TASCO submitted a BART determination analysis to IDEQ in November 2007,[8] and supplemented the analysis in February 2009.[9]

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[6] Over the past three years, TASCO submitted detailed comments and evaluations regarding IDEQ's BART applicability and BART determination analyses. TASCO's submissions are part of the administrative record held by IDEQ and are incorporated by reference herein.

[7] Prior to July 2007, IDEQ and TASCO discussed the BART evaluation process on numerous occasions. During that time, IDEQ produced preliminary modeling reports, and TASCO expressed its concerns, particularly questioning the use of the CALPUFF model and its accuracy to predict visibility impacts in the protected wilderness areas. *See, e.g.*, April 23, 2007 letter from Dean DeLorey (TASCO) to Martin Bauer (IDEQ) re Preliminary Draft Exemption Modeling Evaluations, including attachments (referred to herein as "TASCO April 23, 2007 Comments").

[8] November 20, 2007 letter from TASCO to IDEQ re BART Determination Analysis Report, including attachments (referred to herein as "TASCO November 20, 2007 Report").

[9] February 6, 2009 letter from Kent Quinney (TASCO) to Martin Bauer (IDEQ) re BART Determination Analysis Report, including attachments (referred to herein as "TASCO February 6, 2009 Report").

TASCO's analysis challenged IDEQ's underlying determination that the Riley Boiler is subject to BART and suggested alternative feasible control technologies, considering (among other things) the reasonably anticipated degree of improvement in visibility in the Hells Canyon, Eagle Cap, and Strawberry Mountain Wilderness areas and the economic impacts of various technologies.

IDEQ, however, largely rejected TASCO's analysis and on July 17, 2009, determined that the best available SO_2 and NO_x control technologies for the Riley Boiler are spray dry flue gas desulfurization and low NO_x burners with overfire air, respectively. Over the next few months, TASCO provided IDEQ with additional information, including supplemental information on the economic impacts of IDEQ's recommended control technology choices in July 2009,[10] and supplemental information supporting TASCO's proposed alternative BART control measures in November 2009.[11] An EPA economic review dated February 12, 2010 concluded that TASCO (as a company) could afford to fund the costly expenditures, and IDEQ again rejected TASCO's analysis.

On March 26, 2010, IDEQ provided a copy of a draft Tier II Permit, proposing to implement BART for the Riley Boiler and requiring the installation of spray dry flue gas desulfurization for SO_2 controls and low NO_x burners with overfire air for NO_x controls. IDEQ also provided a supporting Statement of Basis. IDEQ issued the draft Tier II Permit for public

[10] July 21, 2009 letter from Dean DeLorey (TASCO) to Martin Bauer (IDEQ) re financial information for BART Determination Analysis, including attachments (referred to herein as "TASCO July 21, 2009 Report").

[11] November 18, 2009 letter from Joe Huff (TASCO) to Martin Bauer (IDEQ) re supplemental information for BART Determination Analysis, including attachments (referred to herein as "TASCO November 18, 2009 Report").

comment on April 19, 2010. TASCO submitted comments to IDEQ on April 6, 2010[12] and May 19, 2010,[13] asking IDEQ to strike or revise the Tier II Permit for the very reasons previously presented to IDEQ and on which TASCO now petitions for a contested case. But as with TASCO's prior submittals, IDEQ was unmoved by TASCO's comments and issued the final Tier II Permit, essentially as proposed, on September 7, 2010. The Tier II Permit is attached to this petition as **Exhibit B**. The final Statement of Basis and Response to Public Comments are attached hereto as **Exhibits C** and **D**, respectively.

III. CONTESTED CASE PETITION

A. IDEQ's Reliance On Conservative Modeling Data Resulted In An Unnecessary And Flawed Tier II Permit.

The basis for the BART controls for SO_2 and NO_x required by the Tier II Permit is fundamentally flawed because IDEQ relied solely on the CALPUFF results to the exclusion of other required and relevant factors.[14] IDEQ used the modeling approach for BART determinations detailed in Appendix Y, even though the guidelines were specifically prepared for and apply to large-scale power plants, not a smaller industrial source such as the Riley Boiler. Indeed, Appendix Y is targeted to BART determinations for sources 20 times larger than the Riley Boiler. As EPA itself recognizes and states in Appendix Y: "States must follow the

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[12] April 6, 2010 letter from Joe Huff (TASCO) to Martin Bauer (IDEQ) re Comments to Draft Tier II Permit Operating Permit, including attachments (referred to herein as "TASCO April 6, 2010 Comments").

[13] May 19, 2010 letter from TASCO to Faye Weber (IDEQ) re Public Comments to Tier II Permit Operating Permit, including attachments (referred to herein as "TASCO May 19, 2010 Comments"). The TASCO May 19, 2010 Comments are included in Appendix A to IDEQ's Response to Public Comments, attached hereto as **Exhibit D**.

[14] TASCO has submitted numerous objections to IDEQ regarding its use of Appendix Y and its determination that the Riley Boiler is subject to BART. *See, e.g.*, TASCO April 23, 2007 Comments; TASCO November 20, 2007 Report; TASCO February 6, 2009 Report; TASCO July 21, 2009 Report; TASCO November 18, 2009 Report; TASCO April 6, 2010 Comments; TASCO May 19, 2010 Comments.

guidelines in making BART determinations on a source-by-source basis for 750 megawatt (MW) power plants *but are not required to use the process in the guidelines when making BART determinations for other types of sources*." 70 Fed. Reg. at 39,158 (Appendix Y, § 1.F(1)) (emphasis added). EPA reiterates later in the guidelines:

> [Clean Air Act] Section 169A(b) requires us to issue guidelines for States to follow in establishing BART emission limitations for fossil-fuel fired power plants having a capacity in excess of 750 megawatts. This document fulfills that requirement, which is codified in 40 CFR 51.308(e)(1)(ii)(B). The guidelines establish an approach to implementing the requirements of the BART provisions of the regional haze rule; we believe that these procedures and the discussion of the requirements of the regional haze rule and the CAA should be useful to the States. *For sources other than 750 MW power plants, however, States retain the discretion to adopt approaches that differ from the guidelines.*

Id. (Appendix Y, § 1.H) (emphasis added). Thus, for the Riley Boiler, Appendix Y is guidance and IDEQ has discretion to adapt the process to achieve a reasonable result.

Precisely because the Riley Boiler is *not* a large power plant – and is located over 100 miles east/southeast of the protected wilderness areas in question and in the opposite direction of the prevailing west to east winds – TASCO asked IDEQ to exercise allowed discretion and consider a different approach to determine if the boiler is subject to BART. But over TASCO's repeated objections and expressed concerns for the anticipated outcome, and despite the language in EPA's own guidance, IDEQ chose not to adopt a different evaluative approach, thereby creating absurd and costly results for TASCO.

For example, under Appendix Y, IDEQ has discretion to exempt an individual source (or certain pollutants from the source) from a BART determination if the source "is not reasonably anticipated to cause or contribute to any visibility impairment" in a protected area. *Id.* at 39,161 (Appendix Y, § III); *see also* IDAPA 58.01.01.668.02. An exemption is warranted if the

source's contribution is less than 0.5 delta deciviews, the prescribed threshold set forth in Appendix Y and Idaho rule.[15] 70 Fed. Reg. at 39,161 (Appendix Y, § III.A(1)); IDAPA 58.01.01.668.02. Under the guidelines, to make that demonstration, IDEQ may consider "different modeling and/or emissions analysis" and "may also use other reasonable approaches for analyzing the visibility impacts of a source." 70 Fed. Reg. at 39,162 (Appendix Y, § III.A(3)). IDEQ ignored this clear discretion, instead relying upon the one-size-fits-all evaluation for large power plants outlined by Appendix Y.

With respect to modeling, Appendix Y prompts states to use the CALPUFF dispersion model. And that is the model IDEQ used to determine that the Riley Boiler is subject to BART. But no model affords the reviewer actual, precise, verifiable data. Models are tools of evaluation, prediction, and projection. They are not definitive science. Because there are so many variables and complex inputs, they can be easily manipulated and are built to overpredict impacts as compared to actual measurements. Those attributes are also true of CALPUFF, which even EPA recognizes tends to overstate actual visibility: "[T]here are other features of our recommended modeling approach that are likely to overstate the actual visibility effects of an individual source. Most important, the simplified chemistry in the model tends to magnify the actual visibility effects of that source." *Id.* at 39,121; *see also id.* at 39,123 ("Theoretically, the CALPUFF chemistry simulations, in total, may lead to model predictions that are generally overestimated at distances downwind of 200 km.").

It necessarily follows, as Appendix Y provides, that states "can use CALPUFF or *other appropriate model* to predict the visibility impacts from a single source" at a protected area. *Id.*

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[15] Deciview is a measurement of visibility impairment. *See* IDAPA 58.01.01.006.28. Deciviews are not directly measured but are calculated using many variables and assumptions. *See id.*

at 39,162 (Appendix Y, § III.A(3)) (emphasis added). Indeed, there are different modeling approaches for estimating impacts of emissions from a source such as the Riley Boiler. While CALPUFF is one type of tool, another type is *receptor* oriented apportionment modeling. CALPUFF is a *source* oriented model that uses the source's emissions to predict an impact at a particular receptor based upon complex assumptions regarding the atmospheric chemistry and the dispersion of those emissions. Receptor oriented apportionment modeling starts with the measured impacts *at the receptor* and allocates those impacts to specific sources. Thus a receptor oriented apportionment model is bound by *actual* measured impacts at the protected areas, whereas a source oriented model, like CALPUFF, is not bound by actual measurements or monitored data and, as noted, is widely known to overpredict impacts of emissions from specific sources.

To highlight the uncertainty of the CALPUFF results under the circumstances here, TASCO retained Cooper Environmental Services ("CES") to use a receptor oriented apportionment model to generate results that could be compared to the visibility impacts IDEQ predicted under CALPUFF. The receptor oriented apportionment approach showed that the Riley Boiler is *not* subject to BART (it does not cause or contribute to visibility impairment in the protected areas), in contrast to the CALPUFF results relied upon by IDEQ. The estimated deciview results using the receptor approach were all below the 0.5 delta deciview threshold for BART applicability. The disparity between the results of the receptor apportionment method and the CALPUFF model raises significant questions regarding the appropriateness of relying solely

on the CALPUFF results to impose over $17 million of new costs at the Nampa factory.[16]

There are other relevant indicators from the CES work that suggest IDEQ's over-reliance on CALPUFF is unreasonable. For instance, the receptor oriented apportionment results generated by CES suggest that the actual Riley Boiler impacts may be highest at Hells Canyon, whereas the predicted impacts using CALPUFF were highest at the Eagle Cap Wilderness, an area that is even farther to the west and much higher in elevation than Hells Canyon. In general, CES's receptor apportionment results are more logically tied to the regional geography and are more consistent with the (theoretical) down-river drainage air flow during stagnation periods that impacts the lower elevation Hells Canyon ambient monitoring site more than the higher elevation Eagle Cap monitor. Moreover, the results are bound by actual monitored impacts at the particular protected area. At a bare minimum, the CES results offer a counterpoint to the overly conservative CALPUFF results, suggesting that the latter results are an unreasonable basis on which to justify the installation of costly new emission controls on the Riley Boiler.

In sum, despite EPA's guidelines that allow IDEQ to use "different modeling and/or emissions analysis" and "other reasonable approaches for analyzing the visibility impacts of a source," IDEQ did not undertake a different analysis for TASCO during development of the BART evaluation, instead relying solely upon CALPUFF for the Tier II Permit for TASCO's Riley Boiler. IDEQ's steadfast reliance on CALPUFF resulted in an arbitrary and capricious

[16] TASCO's concerns regarding IDEQ's use of a source oriented modeling approach such as CALPUFF are warranted and well founded from recent prior experience. In 2002, in support of the Treasure Valley PM_{10} Maintenance Plan, IDEQ relied on modeling analyses for the Nampa factory and overpredicted ambient PM_{10} concentrations attributable to the factory by 20 times. Based on that modeling, IDEQ required TASCO to reduce PM_{10} emissions at a significant cost. In 2006, the Nampa factory replaced three coal-fired pulp dryers with a steam pulp dryer at a cost of approximately $20 million.

decision imposing new control requirements. *See, e.g.*, Tier II Permit Conditions 1.2, 3.2, 3.4. Therefore, TASCO respectfully requests the Board strike the Tier II Permit in its entirety.

B. IDEQ Failed To Consider The Five Factors Required By The Clean Air Act In Choosing BART Controls For SO_2 And NO_x Emissions.

Under the Clean Air Act, IDEQ must consider five factors when selecting BART controls:

(i) the costs of compliance;
(ii) the energy and nonair quality environmental impacts of compliance;
(iii) any pollution control equipment in use at the source;
(iv) the remaining useful life of the source; and
(v) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

See Clean Air Act § 169A(g)(2) (42 U.S.C. § 7491(g)(2)); *see also* 40 C.F.R. § 51.308(e)(I)(ii)(A); IDAPA 58.01.01.668.02.c. IDEQ failed to properly consider at least two of those factors – the degree of improvement in visibility which may be reasonably anticipated to result from the controls and the costs of compliance – in selecting spray dry flue gas desulfurization for SO_2 and low NO_x burners with overfire air for NO_x.

1. The Degree Of Improvement In Visibility Which May Reasonably Be Anticipated To Result From The Tier II Permit Is Minimal, If Any, And Does Not Justify The Significant Cost Of The BART Controls.

As with its determination that the Riley Boiler is subject to BART controls, IDEQ solely relied upon CALPUFF's conservative dispersion modeling to predict the degree of visibility improvements which may reasonably be anticipated from the Tier II Permit. Conversely, the receptor apportionment results indicate that little to no improvement in visibility in the Hells Canyon, Eagle Cap, or Strawberry Mountain Wilderness areas can reasonably be anticipated to result from the use of the technology required by the Tier II Permit. Those dramatically

conflicting results compel further evaluation before IDEQ imposes such significant costs on TASCO.

EPA, in fact, recommends such further evaluation. In Appendix Y, EPA describes CALPUFF as but one tool in predicting the degree of visibility improvement which may reasonably be anticipated from the Tier II Permit and in imposing BART controls, and its a mere screening tool at that:

> we also recommend that the States use CALPUFF *as a screening application in estimating the degree of visibility improvement that may reasonably be expected from controlling a single source in order to inform the BART determination.* ... [T]his estimate of visibility improvement does not by itself dictate the level of control a State would impose on a source; 'the degree of improvement in visibility which may reasonably be anticipated to result from the use of [BART]' is only one of five criteria that the State must consider together in making a BART determination. The State makes a BART determination based on the estimates available for each criterion, and as the CAA does not specify how the State should take these factors into account, the States are free to determine the weight and significance to be assigned to each factor.

70 Fed. Reg. at 39,123 (emphasis added). Indeed, other lines of evidence were known to IDEQ in the course of assessing the degree of visibility improvements that suggest it could have reached a different result.

For instance, according to IDEQ's own draft Regional Haze Plan, the largest sources of visibility constituent emissions in the federal protected areas are area sources and natural fires, not emissions from industrial sources. *See generally* Draft Idaho Regional Haze Plan, Ch. 8 (dated Aug. 31, 2010). In fact, a detailed review of the emissions and source apportionment modeling data in the draft plan shows that industrial emission sources in Idaho only account for an estimated 4% of the total visibility constituent emissions in the protected areas. *See generally id.* Emissions from the Riley Boiler can only account for an estimated fraction of that 4%.

In addition, IDEQ relies on an unrefined emissions inventory and source apportionment data in its draft Regional Haze Plan. That data results in a flawed basis on which to evaluate the degree of visibility improvements in the Hells Canyon, Eagle Cap, and Strawberry Mountain Wilderness areas. For example, emissions from a proposed and never built power plant in Jerome County remain in the state's emissions inventory. Also, IDEQ failed to coordinate with the State of Oregon to ensure proper treatment in both states' Regional Haze plans of emissions reductions achieved at TASCO's Nyssa, Oregon factory, where beet processing has been discontinued, resulting in sizable reductions in SO_2 and NO_x emissions. TASCO has urged IDEQ to make these refinements to the emissions inventory.[17] Including unrefined emission estimates inflates predicted visibility impacts and establishes an inflated baseline from which to plan visibility improvements, much less require reductions at the Riley Boiler.

In light of the relatively insignificant overall contribution of the Riley Boiler and IDEQ's unrefined emissions inventory, a reasonable reviewer would necessarily question CALPUFF's forecast of the degree of improvement in visibility which may be reasonably anticipated from the controls in the Tier II Permit. But despite the conflicting lines of evidence, IDEQ steadfastly held to the CALPUFF results to dictate the BART controls for the Riley Boiler. That approach is inconsistent with Appendix Y.

2. The Costs Of Compliance Are Significant And Could Adversely Affect Operations At The Nampa Factory.

Just as important in selecting the BART controls is the mandate to consider the costs of compliance. By overemphasizing the CALPUFF results, IDEQ improperly de-emphasized the

[17] *See, e.g.*, TASCO April 6, 2010 Comments; TASCO May 19, 2010 Comments; September 30, 2010 Letter from Dean DeLorey (TASCO) to Faye Weber (IDEQ) re Comments on Idaho's Draft Regional Haze Plan.

costs of compliance, which are significant. According to TASCO's analysis, the installation of the new SO_2 and NO_x controls will require an initial capital investment of at least $17.8 million that results in annual maintenance, operating, and financing expenses of over $3 million.[18] As one of the five factors IDEQ must consider, the costs of compliance are entitled to the same weight as the other factors, if not more. Again, EPA states in Appendix Y that "[t]he State makes a BART determination based on the estimates available for each criterion, and as the CAA does not specify how the State should take these factors into account, the States are free to determine the weight and significance to be assigned to each factor." *Id.*

Furthermore, where the costs of compliance are so extreme, Appendix Y guidance affords relief:

> There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology.... Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.

70 Fed. Reg. at 39,171 (Appendix Y, § IV.E(3)). Notably, Appendix Y does not ask if the company can *afford to fund or to obtain funding* for a given control technology. IDEQ's conclusion – which is based on EPA's economic review, not its own – was that TASCO could afford to fund BART controls. The agencies' evaluation failed to properly assess the unusual

[18] *See* TASCO February 6, 2009 Report; TASCO July 21, 2009 Report; TASCO November 18, 2009 Report; TASCO May 19, 2010 Comments. Neither EPA nor IDEQ has ever refuted TASCO's cost estimation.

economic effects as prompted by Appendix Y and is fundamentally flawed for at least three reasons.

First, EPA focused on whether TASCO as a company can afford the new SO_2 and NO_x controls, and ignored whether or not conditions at the plant – the Nampa factory – will be affected. EPA narrowly concluded that the company could obtain funding for the new controls, primarily because TASCO should have set aside funding already or could obtain funding by borrowing or by withholding payments to sugar beet growers. Yet, TASCO's financial wherewithal is not the appropriate inquiry under Appendix Y, as quoted above. The analysis must focus on the direct impact to the Nampa factory by considering "product prices," "market share," "profitability of the source," and "plant operations." As explained further below, TASCO provided documentation on just those effects. EPA and IDEQ failed to consider that information fully. EPA and IDEQ dismissed the potential effects on local economic conditions and the plant operations at the Nampa factory, instead relying upon a more general assessment of the stability and borrowing strength of TASCO. IDEQ used this deficient evaluation to justify its conclusion that the company can afford the new SO_2 and NO_X controls, thus obviating the potential relief provided by Appendix Y.

Second, EPA concluded that TASCO could spread the costs of the new controls among its growers throughout Idaho and minimize the effects of the significant upfront and continued costs on the Nampa factory. That conclusion fails to take into account the unique circumstances of the Nampa factory and its economic viability. TASCO is owned by an agricultural grower-owned cooperative. Its grower-owners decide which crops to plant based upon the greatest potential economic return they can achieve in a given crop year – whether it be from sugar beets, potatoes, or some other crop. Passing along an expenditure of $17.8 million plus an additional

$3 million per year would effectively reduce the payments growers would receive per ton of sugar beets, resulting in few growers growing sugar beets. Without question, fewer planted acres of sugar beets jeopardizes the economic viability of the Nampa factory.

TASCO has experienced similar contraction before, and submitted detailed documentation to EPA and IDEQ demonstrating the effects and supporting TASCO's renewed concerns. For example, TASCO incurred an 18.4% decline in membership one year and a decline of 13% over a seven-year period directly due to reduced returns to growers who found greater returns growing other crops. TASCO also described the conditions that led to the closure of its Nyssa factory and highlighted the 31% decline in sugar beets harvested between 2007 and 2008 – all evidence that any increase in costs passed along to the growers reduces their payments, resulting in the growers growing other crops. Thus EPA's and IDEQ's assumption that growers will continue to plant sugar beets without a reasonable return is entirely unfounded.

Third, EPA failed to consider another Appendix Y factor: "whether other competing plants in the same industry have been required to install BART controls." TASCO submitted information regarding seven of its competitors in the sugar processing industry. According to that survey, no other plant in the sugar industry in the United States is required to install BART controls. EPA refused to consider the resulting competitive disadvantage the Nampa factory would face relative to other sugar producers. Despite this circumstance being directly and expressly relevant to the economic impact test described under Appendix Y, IDEQ simply accepted EPA's inattention to this circumstance and conclusion that the company can afford the new SO_2 and NO_X controls. In doing so, IDEQ ignored the potential relief provided by Appendix Y.

In sum, IDEQ failed to fully consider the required five factors in its BART determination. Due consideration of all of these factors and relevant circumstances would lead a reasonable reviewer to a different BART determination than the one imposed by the Tier II Permit. TASCO urges the Board to strike the Tier II Permit, to order IDEQ to revise its 2009 BART determination so that the evaluation reflects a more thorough assessment of the factors established by the Clean Air Act, and to conclude that, in light of all the factors, no additional controls on the Riley Boiler are required.

C. As Alternative Relief, TASCO Seeks Review And Revision Of Certain Tier II Permit Conditions Related To The BART Controls For SO_2 And NO_x.

Should the Board decide that IDEQ's choice of BART controls for SO_2 and NO_x is not appropriate, TASCO seeks, as alternative relief, the revision of certain conditions of the Tier II Permit.

1. Conditions 1.2 and 3.2 Should Be Revised To Strike The Requirement To Install An Overfire Air System On Low NO_x Burners, Because It Is Physically Infeasible For TASCO To Install The System On The Riley Boiler.

IDEQ determined that TASCO must install low NO_x burners with overfire air to control NO_x emissions from the Riley Boiler. *See* Tier II Permit Conditions 1.2, 3.2. TASCO retained Babcock Power – the manufacturer of the Riley Boiler – to determine if an overfire air system can be installed on the boiler. Based on the results of that study, Babcock Power concluded that an overfire air system is not a feasible technology for the Riley Boiler due to physical constraints.[19] TASCO informed IDEQ of the constraints during development of the Tier II Permit and, in addition, offered documentation that a low NO_x burner without an overfire air system could still achieve an NO_x emission control efficiency of 50%.[20] Based on that

[19] *See* TASCO April 6, 2010 Comments; TASCO May 19, 2010 Comments.
[20] *See id.*

information, IDEQ modified the expected emission control efficiency and based the NO_x emission limit on achieving a 50% reduction in NO_x emissions. But while making those changes, IDEQ retained the requirement that TASCO install the overfire air system.

Because of the physical infeasibility of installing an overfire air system on the Riley Boiler, and having already incorporated an emission control efficiency for NO_x that is not dependent on the system, TASCO requests the Tier II Permit be revised to eliminate the requirement to install the overfire air system and any other corresponding permit conditions referring to such a system. *See, e.g.*, Tier II Permit Conditions 1.2, 3.2, 3.8, 3.12, 3.16.

2. Condition 3.7 Should Be Revised To Provide That The Spray Dry Flue Gas Desulfurization System Need Not Be Operated When The Riley Boiler Is Using Natural Gas.

Condition 3.7 of the Tier II Permit requires TASCO to operate the SO_2 controls (the spray dry flue gas desulfurization system) at all times the Riley Boiler is operated. To comply with the SO_2 emission limits, however, the system does not need to be operated during periods when the boiler is using natural gas as the primary fuel. TASCO informed IDEQ of this fact during development of the Tier II Permit and requested that IDEQ include language in Condition 3.7 that provides the spray dry flue gas desulfurization system "need not be operated during periods when the Riley Boiler is being fired exclusively with natural gas."[21] IDEQ failed to include that or equivalent language. TASCO requests that Condition 3.7 be revised to state that the system does not need to be operated when the boiler is using natural gas as the primary fuel.

[21] *See* TASCO April 6, 2010 Comments.

3. Condition 3.8 Should Be Revised To Provide That The Low NO_x Burner Need Not Be Operated When The Riley Boiler Is Using Natural Gas.

Condition 3.8 of the Tier II Permit also requires TASCO to operate the low NO_x burner at all times the Riley Boiler is operated. Like the SO_2 controls, the low NO_x burner does not need to be operated during periods when the boiler is using natural gas as the primary fuel. TASCO informed IDEQ of this fact,[22] and IDEQ failed to include language stating that the burner does not need to be operated when the boiler is using natural gas. TASCO requests that Condition 3.8 be revised to provide that the low NO_x burner does not need to be operated when the boiler is using natural gas as the primary fuel.

4. Condition 3.11 Should Be Revised To Allow TASCO To Continuously Monitor Either The Slurry Flow Rate Or Adiabatic Approach Temperature For The Spray Dry Flue Gas Desulfurization System.

IDEQ initially proposed that TASCO install measuring devices to continuously monitor the slurry flow rate to the spray dry flue gas desulfurization system as a method to ensure compliance with SO_2 emission limits. In comments to IDEQ, TASCO proposed that it be allowed to monitor adiabatic approach temperature because it is less expensive and more reliable than monitoring slurry feed flow.[23] IDEQ agreed and revised the condition, replacing the requirement to monitor the slurry flow rate with a requirement to monitor adiabatic approach temperature. *See* Tier II Permit Condition 3.11. TASCO, however, seeks the option of monitoring *either* the slurry flow rate *or* adiabatic approach temperature, but not both. TASCO requests that Condition 3.11 be revised to allow it the choice of monitoring the slurry flow rate *or* adiabatic approach temperature once the spray dry flue gas desulfurization system has been designed.

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[22] *See id.*
[23] *See id.*

5. Conditions 3.13 And 3.16 Should Be Revised To Strike The Requirement That TASCO Maintain And Monitor The Spray Dry Flue Gas Desulfurization Minimum Slurry Flow Rate.

Among other things, Condition 3.13 requires TASCO to maintain the operating parameters for the minimum slurry flow rate *and* adiabatic approach temperature for the spray dry flue gas desulfurization system in an Operation and Maintenance ("O&M") Manual. Condition 3.16 requires TASCO to monitor and record, during each performance test, the minimum slurry flow rate *and* adiabatic approach temperature. Maintaining, monitoring, and recording both parameters in its O&M procedures and during each performance test, are duplicative, unnecessary, and burdensome. TASCO requests that Conditions 3.13 and 3.16 be revised to allow it the choice of maintaining, monitoring, and recording the slurry flow rate *or* adiabatic approach temperature once the spray dry flue gas desulfurization system has been designed, consistent with its choice of parameters under Condition 3.11.

6. Condition 3.19 Is Unnecessary And Should Be Struck To Remove Requirements That TASCO Submit A Compliance Assurance Monitoring Plan For The BART Controls.

Condition 3.19 of the Tier II Permit requires TASCO to submit documentation for improved monitoring of the SO_2 and NO_x controls under a Compliance Assurance Monitoring ("CAM") plan. The condition is premature and unnecessary at this time. CAM requirements should be factored not into the Tier II Permit but into the Nampa factory's Tier I permit when renewed. Indeed, the time for TASCO to comply with the Tier II Permit is over five years away, giving TASCO the recognized opportunity to obtain IDEQ's approval of BART alternatives to meet the new SO_2 and NO_x emission limits. *See* Tier II Permit Condition 3.3. Moreover, at this time TASCO and IDEQ have not agreed on CAM indicators for the BART controls, and until those indicators have been identified and detailed with reference to CAM rules, a general

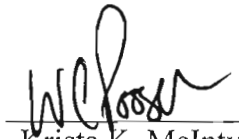
compliance statement is burdensome, unnecessary, and of no value. TASCO requests that Condition 3.19 be stricken from the permit.

IV. CONCLUSION

Based on the foregoing, TASCO petitions the Board for a contested case proceeding on the Tier II Permit and respectfully requests that the Board strike the Tier II Permit.

Submitted this 12th day of October, 2010.

STOEL RIVES



Krista K. McIntyre
W. Christopher Pooser
Attorneys for The Amalgamated Sugar Company LLC

EXHIBIT LIST

Exhibit A	Mileage Log showing distance from TASCO factories to federal wilderness areas.
Exhibit B	Air Quality Tier II Permit and Permit to Construct No. TS-2009.0105 (the "Tier II Permit") issued by IDEQ on September 7, 2010.
Exhibit C	Statement of Basis for the Tier II Permit issued by IDEQ on September 7, 2010.
Exhibit D	Response to Public Comments for the Tier II Permit issued by IDEQ on September 7, 2010. (Appendix A to the Response to Comments includes TASCO's Public Comments on the draft Tier II Permit dated May 19, 2010.)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 12th day of October, 2010, I caused to be served a true copy of the foregoing upon the following:

IDEQ Hearings Coordinator
Department of Environmental Quality
1410 North Hilton
Boise, Idaho 83706

[ ] U.S. Mail
[X] Messenger Delivered
[ ] Facsimile

Krista K. McIntyre
W. Christopher Pooser

Exhibit A

Mileage Table

Distance in Miles

Facility	Craters of the Moon	Sawtooth Wilderness	Jarbidge Wilderness	Eagle Cap Wilderness	Strawberry Mtn. Wilderness	Hells Canyon Wilderness
Twin Falls	66	91	59	221	239	209
Mini-Cassia	48	103	88	240	267	223
Nampa	148	71	132	102	109	104
Nyssa	172	89	159	79	83	84

Distance in Kilometers

Facility	Craters of the Moon	Sawtooth Wilderness	Jarbidge Wilderness	Eagle Cap Wilderness	Strawberry Mtn. Wilderness	Hells Canyon Wilderness
Twin Falls	106.4	145.6	94.6	355.7	385.0	336.3
Mini-Cassia	76.9	165.1	141.9	386.2	429.2	358.9
Nampa	238.3	114.6	213.0	164.0	175.0	166.9
Nyssa	276.3	143.7	255.7	126.8	132.8	135.7

Distances (miles) were updated on July 21, 2010.
Values are estimated using http://www.wilderness.net/mapFull.cfm to document Class 1 Area boundaries and Google Earth Pro to measure distance from facilities concrete Stacks to nearest point of Class 1 Area.

Exhibit B

Tier II Operating Permit No. T2-209.0105

Air Quality
TIER II OPERATING PERMIT

State of Idaho
Department of Environmental Quality

PERMIT No.: T2-2009.0105
FACILITY ID No.: 027-00010
AQCR: 64 **CLASS:** A **ZONE:** 11
SIC: 2063 **NAICS:** 311313
UTM COORDINATE (km): 534.5, 4828.0

1. **PERMITTEE**
The Amalgamated Sugar Company LLC – Nampa Factory

2. **PROJECT**
Tier II operating permit – required by DEQ to ensure compliance with applicable BART standards

3. **MAILING ADDRESS**	**CITY**	**STATE**	**ZIP**
P.O. Box 8787	Nampa	ID	83653-8787
4. **FACILITY CONTACT**	**TITLE**	**TELEPHONE**	
Glen Patrick	Plant Environmental Manager	(208) 468-6883	
5. **RESPONSIBLE OFFICIAL**	**TITLE**	**TELEPHONE**	
Kent Quinney	Plant Manager	(208) 466-3541	
6. **EXACT PLANT LOCATION**		**COUNTY**	
138 W. Karcher Ave., Nampa, Idaho		Canyon	

7. **GENERAL NATURE OF BUSINESS & KINDS OF PRODUCTS**
Beet sugar manufacturing

8. **PERMIT AUTHORITY**

This permit is issued according to the Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01.400 through 410, and pertains only to emissions of air contaminants regulated by the state of Idaho and to the sources specifically allowed to be operated by this permit.

Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

MORRIE LEWIS, PERMIT WRITER
DEPARTMENT OF ENVIRONMENTAL QUALITY

MIKE SIMON, STATIONARY SOURCE PROGRAM MANAGER
DEPARTMENT OF ENVIRONMENTAL QUALITY

Date Issued:	**September 7, 2010**
Date Modified/Revised:	
Date Expires:	**September 7, 2015**

MS/ML

Table of Contents

Acronyms, Units, and Chemical Nomenclature

AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
FGD	flue gas desulfurization
fpm	feet per minute
gpm	gallons per minute
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
LNB	low NO_X burner system
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
OFA	over-fired air
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration of air quality
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
TAP	toxic air pollutants
TASCO	The Amalgamated Sugar Company, LLC
T/hr	tons per hour
U.S.C.	United States Code
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1. TIER II OPERATING PERMIT SCOPE

Purpose

1.1 The purpose of this Tier II operating permit is to establish Best Available Retrofit Technology (BART) emission standards and requirements for the Riley Boiler in accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.401.03.

Regulated Sources

1.2 The following Regulated Emission Point Sources Table lists all sources of regulated emissions in this permit:

REGULATED EMISSION POINT SOURCES TABLE

Permit Section	Source Description	Emissions Controls
2 & 3	Riley Boiler (S-B3) Unit number: S-B3 Installation Date: 1969 Rated steam capacity: 250,000 lb steam/hr Maximum capacity: 350 MMBtu/hr Maximum operation: 8,760 hr/yr Fuel types: coal, natural gas	Baghouse (A-B3) Manufacturer: Envirotech Corp. Control efficiency: ≥99.0% for PM BART for PM Spray dry flue gas desulfurization system Reagent: Lime or limestone Control efficiency: 80-90% for SO_2 BART for SO_2 Low NO_X burner system with over-fired air Control efficiency: ≥50% for NO_X BART for NO_X
2 & 4	Pulp dryers (S-D1, S-D2, and S-D3)	Permanent shutdown

2. FACILITY-WIDE CONDITIONS

Obligation to Comply

2.1 Receiving a Tier II operating permit shall not relieve any owner or operator of the responsibility to comply with all applicable local, state, and federal rules and regulations, in accordance with IDAPA 58.01.01.406.

Incorporation of Federal Requirements by Reference

2.2 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein, in accordance with IDAPA 58.01.01.107. Documents include, but are not limited to:

- Protection of Visibility, 40 CFR Part 51, Subpart P, Section 308 – Best Available Retrofit Technology (BART) requirements
- Compliance Assurance Monitoring (CAM), 40 CFR Part 64

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as BART and CAM), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments.

DEQ Address

2.3 Any reporting required by this permit, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, notifications of intent to test, testing reports, or compliance certifications, shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete. Any reporting required by this permit shall be submitted to the following address:

Air Quality Permit Compliance
Department of Environmental Quality
Boise Regional Office
1445 N. Orchard
Boise, ID 83706

Phone: (208) 373-0550
Fax: (208) 373-0287

3. RILEY BOILER BART

3.1 Process Description

The Riley Boiler is fired by pulverized coal and/or natural gas, and is used to supply steam and generate electricity for processing of sugar beets into sugar and byproducts, including animal feed at the Nampa facility.

3.2 Emission Control Description

The existing baghouse (Unit No. A-B3) manufactured by Envirotech Corp. is used for the control of particulate matter (PM) emissions from the Riley Boiler.

A spray dry flue gas desulfurization (FGD) system has been required for the control of sulfur dioxide (SO_2) emissions from the Riley Boiler. In a spray dry FGD system, the flue gas is introduced into a tower and contacts an atomized spray of lime slurry, which absorbs and neutralizes the SO_2.

A low NO_X burner system (LNB) with over-fired air has been required for the control of nitrogen oxides (NO_X) emissions from the Riley Boiler. Low NO_X combustion with over-fired air utilizes fuel and air mixing optimization and staged combustion techniques to minimize thermal NO_X formation.

Compliance Dates

3.3 BART 40 CFR 51.308, Subpart P – BART Installation and Operation Due Date

The permittee shall install and operate BART or a DEQ-approved BART alternative on each source subject to BART as expeditiously as practicable, but in no event later than five (5) years after approval of the implementation plan, in accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(1)(iv).

The permittee may submit a request to obtain a DEQ-approved BART alternative and to revise this permit in accordance with IDAPA 58.01.01.404.04. DEQ will process the request in accordance with IDAPA 58.01.01.404. The request must be submitted timely such that any revisions to this permit and the corresponding revision to the Regional Haze SIP are approved prior to the BART installation and operation due date (as defined in this permit condition). Pursuant to Section 110(k)(2) of the Clean Air Act, EPA has 12 months to act on a requested SIP revision.

Emissions Limits

3.4 BART 40 CFR 51.308, Subpart P – BART and BART Alternative Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in the following Riley Boiler BART and BART Alternative Emission Limits Table, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e):

RILEY BOILER BART AND BART ALTERNATIVE EMISSION LIMITS TABLE

Source Description	PM lb/hr [a,b]	SO_2 lb/hr [a,b]	NO_X lb/hr [a,c]
Riley Boiler (S-B3)	14	115	186

(a) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.
(b) BART emission rate limit in accordance with 40 CFR 51.308(e).
(c) BART alternative emission rate limit in accordance with 40 CFR 51.308(e)(2).

3.5 CO Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in the following Riley Boiler CO Emission Limits Table, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e):

RILEY BOILER CO EMISSION LIMITS TABLE

Source Description	CO	
	lb/hr [(a)]	T/yr [(b)]
Riley Boiler (S-B3)	25.8	113

(a) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

(b) Tons per any consecutive 12-calendar month period.

Operating Requirements

3.6 BART 40 CFR 51.308, Subpart P – Baghouse Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), and at all times the Riley Boiler is fired with coal, the permittee shall operate a Baghouse (A-B3) to control PM emissions from the Riley Boiler to ensure compliance with the BART PM emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e). The baghouse need not be operated during periods when the Riley Boiler is being fired exclusively with natural gas.

3.7 BART 40 CFR 51.308, Subpart P – Spray Dry Flue Gas Desulfurization Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a spray dry flue gas desulfurization (FGD) system to control SO_2 emissions from the Riley Boiler and to ensure compliance with the BART SO_2 emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

3.8 BART 40 CFR 51.308, Subpart P – Low NO_X Burner Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a low NO_X burner system (LNB) in the Riley Boiler to reduce NO_X emissions and to ensure compliance with the BART NO_X emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

- The LNB shall have a maximum rated heat input capacity (highest heating value) of less than or equal to 350 MMBtu/hr, and shall combust only natural gas and/or coal fuel.
- If operation of the LNB with OFA in the Riley Boiler is expected to result in an emissions increase, the permittee shall submit the required preconstruction compliance demonstrations (Permit Condition 3.18).

3.9 BART 40 CFR 51.308, Subpart P – Maintenance of BART Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05 and 40 CFR 51.308(e)(1)(v).

Monitoring and Recordkeeping Requirements

3.10 Baghouse Pressure Differential Monitoring

The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the pressure drop across each of the baghouses, in inches water gauge. The pressure drop shall be recorded once per day while the boilers are in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.11 Spray Dry FGD Adiabatic Approach Temperature Monitoring

The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the adiabatic approach temperature for the spray dry FGD spray tower in degrees Fahrenheit. The temperature differential shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.12 Primary and Over-Fired Air Flow Monitoring

The permittee shall install, calibrate, and maintain measuring devices to continuously monitor the primary and over-fired air flow rates into the Riley Boiler, in feet per minute. The flow rate shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

3.13 Operation and Maintenance Manuals

Within 60 days after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall develop and submit to DEQ an Operation and Maintenance (O&M) manual for review and comment at the address provided (Permit Condition 2.3). Any changes to the O&M manual shall be submitted to DEQ for review and comment within 15 days of the change.

- The O&M manual shall describe for each of the control equipment described in the Regulated Emission Point Sources Table (Permit Condition 1.2) procedures that will be followed to ensure compliance with BART emission limits (Permit Condition 3.4), CO emission limits (Permit Condition 3.5), the maintenance of BART equipment requirement (Permit Condition 3.9), the control equipment maintenance and operation general provision (General Provision 2), and the manufacturer's specifications. The O&M manual shall be a permittee developed document based upon, but independent from, the manufacturer supplied operating manual(s).
- The permittee shall operate the control equipment in accordance with the O&M manual. The procedures specified in the O&M manual are incorporated by reference into this permit and are enforceable permit conditions. The O&M manual and copies of any manufacturer's manual(s) and recommendations shall remain on site at all times and shall be made available to DEQ representatives upon request.
- At a minimum, the manufacturer's recommended values that shall be maintained for each of the following operating parameters shall be included in the manual:
  - Baghouse minimum and maximum pressure drop, in inches of water (iwg);
  - Spray dry FGD minimum slurry flow rate, in gallons per minute (gpm);
  - Spray dry FGD adiabatic approach temperature, in degrees Fahrenheit (°F) above the adiabatic saturation temperature;

- LNB minimum and maximum flow rates for both primary and over-fired airflow, in feet per minute (fpm); and
- Requirements to monitor and record the parameters listed above accordance with the frequency recommended by the manufacturer, and at a minimum each day that the Riley Boiler is operated.

Performance Testing Requirements

3.14 Initial Performance Tests

- No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3), performance tests shall be conducted on the Riley Boiler stack to demonstrate compliance with the following emission limits, in accordance with IDAPA 58.01.01.405 and IDAPA 58.01.01.157:
  - The BART PM emission limit in pounds per hour (Permit Condition 3.4);
  - The BART SO_2 emission limit in pounds per hour (Permit Condition 3.4);
  - The BART NO_X emission limit in pounds per hour (Permit Condition 3.4); and
  - The CO emission limit in pounds per hour (Permit Condition 3.5).
- Each performance test shall be conducted under the following conditions, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.405, IDAPA 58.01.01.157, and General Provision 6:
  - Emissions shall be measured while combusting coal fuel in the Riley Boiler.
  - Three separate test runs shall be conducted for each performance test.
  - Parameters shall be monitored and recorded as specified in the performance test monitoring and recordkeeping requirement (Permit Condition 3.16).

3.15 Periodic Performance Testing

Performance tests to determine PM, SO_2, NO_X, and CO emissions in pounds per hour from the Riley Boiler stack shall be conducted no less frequently than annually following the date of each required initial performance test, in accordance with IDAPA 58.01.01.405 and under the conditions required for the initial performance tests (Permit Condition 3.14), unless another testing frequency has been approved by DEQ.

3.16 Performance Test Monitoring and Recordkeeping

The permittee shall monitor and record the following during each performance test, unless otherwise approved by DEQ:

- Steam production rate of the Riley Boiler, in pounds per hour (lb steam/hr), once every 15 minutes;
- Coal feed rate to the Riley Boiler, in tons per hour (T/hr), once every 15 minutes (the coal feed rate may be determined using alternate relevant operational parameter(s) and a calculation method which has been approved by DEQ);
- Natural gas firing rate, in million standard cubic feet per hour (MMscf/hr), once every 15 minutes;
- Highest heating value and analysis results, including ash content, of the coal fired;
- Pressure drop across the baghouse during each test, in inches water gauge (iwg), once every 15 minutes;
- Spray dry FGD minimum slurry flow rate, in gallons per minute (gpm);
- Spray dry FGD adiabatic approach temperature, in degrees Fahrenheit (°F), once every 15 minutes; and

- LNB primary and over-fired air flow rates, in feet per minute (fpm), once every 15 minutes.

3.17 Performance Test Reporting

The permittee shall submit performance test reports to DEQ which include records of the monitoring required (Permit Condition 3.16) and in accordance with the performance testing general provision (General Provision 6). Performance test reports shall be submitted by the permittee to the DEQ address provided (Permit Condition 2.3).

Compliance Submittals and Notifications

3.18 Preconstruction Compliance Demonstrations

No later than 180 days prior to the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall submit information and modeling analyses demonstrating that installation and operation of BART will not cause or significantly contribute to a violation of any ambient air quality standards, in accordance with the procedures provided in IDAPA 58.01.01.200-228. This shall include the following, unless otherwise approved by DEQ:

- Demonstration of Preconstruction Compliance with Toxic Standards
- Demonstration of Preconstruction Compliance with National Ambient Air Quality Standards

3.19 CAM 40 CFR 64 and IDAPA 58.01.01.668.06.c – Documentation of Need for Improved Monitoring

No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3) and unless otherwise approved by DEQ, the permittee shall submit information to address monitoring changes in accordance with IDAPA 58.01.01.668.06.c, and in a Compliance Assurance Monitoring (CAM) plan relevant to the installation and operation of BART in accordance with the procedures in 40 CFR Part 64.

3.20 Submittal and Notification Requirements

Required compliance submittals and notifications (Permit Conditions 3.18 and 3.19) shall be submitted to the DEQ address provided (Permit Condition 2.3).

4. SOUTH PULP DRYER

Operating Requirements

4.1 BART 40 CFR 51.308, Subpart P – Shutdown of South Pulp Dryer

The permittee shall permanently shut down the South pulp dryer (S-D1).

Notification and Reporting Requirements

4.2 Pulp Dryer Shutdown Notification

Within 30 days after completing permanent shut down of the South pulp dryer (as required by Permit Condition 4.1), the permittee shall provide written notification to DEQ of the decision to permanently shut down the South pulp dryer. The notification shall include a description of the method used to ensure permanent shut down of the South pulp dryer.

5. SUMMARY OF EMISSION RATE LIMITS

The following table provides a summary of all emission rate limits required by this permit:

SUMMARY OF EMISSION RATE LIMITS

Source Description	PM	SO_2	NO_X	CO	
	lb/hr [a,c]	lb/hr [a,c]	lb/hr [a,c]	lb/hr [a]	T/yr [b]
Riley Boiler (S-B3) with BART	14	115	186	25.8	113

[a] Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.
[b] Tons per any consecutive 12-calendar month period.
[c] BART emissions rate in accordance with 40 CFR 51.308(e).

6. TIER II PERMIT TO OPERATE GENERAL PROVISIONS

General Compliance

1. The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the Rules for the Control of Air Pollution in Idaho. The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit and the Rules for the Control of Air Pollution in Idaho, and the Environmental Protection and Health Act, Idaho Code §39-101, et seq.

[Idaho Code §39-101, et seq.]

2. The permittee shall at all times (except as provided in the Rules for the Control of Air Pollution in Idaho) maintain in good working order and operate as efficiently as practicable, all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.405, 5/1/94]

3. Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules and regulations.

[IDAPA 58.01.01.406, 5/1/94]

Inspection and Entry

4. Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

   a. Enter upon the permittee's premises where an emissions source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;

   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

   c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

   d. As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

5. The permittee shall furnish DEQ written notifications as follows:

   a. A notification of the date of initiation of construction, within five working days after occurrence;

   b. A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

   c. A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date;

   d. A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and

e. A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.405, 5/1/94]

Performance Testing

6. If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

   All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

   Within 30 days following the date in which a performance test required by this permit is concluded, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

   [IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

7. The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Records of monitoring information shall include, but not be limited to the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

   [IDAPA 58.01.01.405, 5/1/94]

Excess Emissions

8. The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions due to startup, shutdown, scheduled maintenance, safety measures, upsets and breakdowns.

[IDAPA 58.01.01.130-136, 4/5/00]

Certification

9. All documents submitted to DEQ, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

10. No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

11. No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Expiration and Renewal

12. This permit shall be renewable on the expiration date, provided the permittee submits an application for renewal to the Department and continues to meet all terms and conditions contained in the permit. The expiration of this permit will not affect the operation of the stationary source of facility during the administrative procedure period associated with the permit renewal process.

[IDAPA 58.01.01.404.04, 7/1/02]

Transferability

13. This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.404.05.

[IDAPA 58.01.01.404.05, 4/11/06]

Exhibit C

Statement of Basis re Tier II Operating Permit No. T2-209.0105

State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Tier II Operating Permit No. T2-2009.0105

Final

The Amalgamated Sugar Company LLC (TASCO)

Nampa Factory

Nampa, Idaho

Facility ID No. 027-00010

September 7, 2010

Morrie Lewis

Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01.et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

Table of Contents

Acronyms, Units, and Chemical Nomenclature

AAC	acceptable ambient concentrations for non-carcinogens
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EGU	electrical generation units
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FGD	flue gas desulfurization
HAP	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
LNB	low NO_X burner system
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
OFA	over-fired air
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration
Rules	Rules for the Control of Air Pollution in Idaho
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/hr	tons per hour
T/yr	tons per year
T2	Tier II operating permit
TAP	toxic air pollutant
TASCO	The Amalgamated Sugar Company LLC
ULNB	ultra-low NO_X burner
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
Δdv	change in delta deciviews

1. FACILITY INFORMATION

1.1 Facility Description

The Amalgamated Sugar Company LLC – Nampa Factory is a beet sugar manufacturing plant.

1.2 Permitting Action and Facility Permitting History

This permit is a Tier II operating permit (T2) for this existing facility. This T2 establishes emission standards for the best available retrofit technologies (BART)[1] for the facility and associated monitoring, recordkeeping, and reporting requirements. See the current Tier I permit statement of basis for the permitting history.

2. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

2.1 Application Scope

This Tier II operating permit establishes the BART emission standards for the facility and the associated monitoring, recordkeeping, and reporting requirements, based upon the BART proposed by TASCO, and the regional haze air quality impact analysis and BART determination completed by DEQ. Specific information relevant to the control devices selected as BART may not be available at this time if the information is contingent upon the design specifications of the specified control technology; this has been noted where possible within the statement of basis.

2.2 Permitting Action Chronology

July 31, 2006	DEQ notified TASCO that each of the Nampa, Twin Falls, and Mini-Cassia facilities had a boiler considered to be BART-eligible.
December 14, 2006	DEQ notified TASCO that each facility had a boiler considered to be subject to BART based upon preliminary modeling analyses.
December 24, 2007	DEQ received a letter from TASCO including a claim of financial hardship.
August 31, 2006 – March 2008	DEQ received several communications from TASCO which provided revised emission data and supporting documentation.
August 31, 2006 – July 21, 2009	DEQ received several communications from TASCO which included concerns regarding the BART technical review. DEQ responded to concerns and provided supporting information, and informed TASCO that the option was available to submit alternate analyses.
February 23, 2007	DEQ provided revised modeling analyses to TASCO, which indicated that the Nampa facility was subject to BART and that the Twin Falls and Mini-Cassia facilities were not subject to BART.
June 17, 2007	DEQ notified TASCO that the Riley boiler was a BART-eligible source and subject to BART.
July 19, 2007	DEQ notified TASCO that the Riley boiler was determined to be subject-to-BART and provided the subject-to-BART determination (refer to Appendix C).
July 24, 2007	DEQ sent copies of the BART exemption modeling to the EPA and FLM for review.

[1] Additional information concerning the Regional Haze Rule can be found at http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_bart.cfm.

November 20, 2007	DEQ received a BART determination analysis report from TASCO for the Riley Boiler. DEQ sent a letter to TASCO requesting review of additional control technologies and requesting information supporting the claim of financial hardship and the technically infeasibility of certain control technologies.
September 16, 2008	DEQ provided TASCO the results of modeling analyses for BART alternative control strategies, and requested that TASCO provide DEQ with any BART alternatives for consideration which could achieve equivalent or better improvements.
February 9, 2009	DEQ received a revised BART determination analysis report from TASCO which included additional feasible control technologies.
March 11 – May 13, 2009	DEQ requested and received guidance from EPA concerning evaluation of the claim of financial hardship.
June 17, 2009	DEQ sent a letter to TASCO requesting financial information in order to evaluate the claim of financial hardship.
July 1, 2009	DEQ met with TASCO to discuss BART alternatives and extended the deadline for providing supporting financial information.
July 3, 2009	DEQ sent a letter to TASCO addressing questions concerning the subject-to-BART modeling analyses.
July 17, 2009	DEQ notified TASCO of the control technology selection and provided the BART determination analyses (refer to Appendix B).
July 21, 2009	DEQ received financial information from TASCO with a claim of confidentiality.
August 18, 2009	DEQ made available the draft permit and statement of basis for peer and Boise Regional Office review.
August 21, 2009	DEQ made available the draft permit and statement of basis to TASCO for facility review.
August 25, 2009	DEQ received a communication from TASCO requesting that facility review of the draft permit and statement of basis be postponed until the claim of financial hardship had been evaluated.
August 28, 2009	DEQ sent an email to TASCO approving the postponement of the facility review period for the draft permit and statement of basis.
September 10, 2009	DEQ was informed by TASCO that financial information could be released to EPA concerning the claim of confidentiality.
October 9, 2009	DEQ met with EPA and TASCO to discuss the claim of financial hardship.
November 5, 2009	DEQ met with EPA and TASCO to review the financial information submitted and to request additional information.
November 18, 2009	DEQ received supplemental BART determination information from TASCO.
February 22 – March 14, 2010	DEQ was provided a financial analysis and supporting information from EPA Region X which indicated that BART was affordable based upon the financial information provided.

March 17, 2010	DEQ notified TASCO that it had been determined that BART was affordable and provided the financial analysis and supporting information.
March 26, 2010	DEQ made available a revised draft permit and statement of basis for facility review.
April 1, 2010	DEQ sent a letter to TASCO responding to concerns identified in the BART determination letter dated November 18, 2009, and addressing financial hardship, modeling, and emissions reduction crediting concerns.
April 6, 2010	DEQ received comments from TASCO concerning the draft permit and statement of basis. Specific comments relevant to the selected BART control options were addressed as described in the permit condition section (refer to Section 4.11).
April 19 – May 19, 2010	DEQ provided a public comment period on the proposed Tier II operating permit and BART determination.
September 7, 2010	DEQ issued the final permit and statement of basis.

3. TECHNICAL ANALYSIS

3.1 Emission Unit and Control Device

Detailed discussion of the emission control devices, estimated emission reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the emission control devices required as BART follows.

A baghouse (Unit No. A-B3) manufactured by Envirotech Corp. is used for the control of particulate matter (PM) emissions from the Riley boiler.

A spray dry flue gas desulfurization (FGD) system has been required for the control of sulfur dioxide (SO_2) emissions from the Riley boiler. In a spray dry FGD system, the flue gas is introduced into a tower and contacts an atomized spray of lime slurry, which absorbs and neutralizes the SO_2.

A low NO_X burner system (LNB) with over-fired air has been required for the control of nitrogen oxides (NO_X) emissions from the Riley boiler. Low NO_X combustion with over-fired air utilizes fuel and air mixing optimization and staged combustion techniques to minimize thermal NO_X formation.

Table 3.1 SUMMARY OF BART ANALYSES & DETERMINATIONS[1]

NSR Pollutant	Step 1	Step 2	Step 3		Step 5	Step 6
	Technologies Identified	Technically Feasible? (Y/N)[2]	Control Level (lb/hr)[3]	Control Ranking	Visibility impairment (# days >0.5 Δdv)[4]	Most effective? (Y/N)[2]
PM	Wet ESP	Y	12.4	1	--[5]	N[5]
	Dry ESP	Y	12.4	1	--[5]	N[5]
	Enhanced baghouse	Y	12.4	1	--[5]	N[5]
	Existing baghouse	Y	12.4	1	--[5]	Y
SO_2	Wet FGD	Y	26	1	43	N[7]
	Spray Dry FGD	Y	104	2	51	Y
	Dry Trona FGD	Y	183	3	58	N
	Dry Lime FGD	Y	235	4	66	N
	Low sulfur coal	Y	444	5	90	N
	Base case[6]	Y	522	6	127	N
NO_X	SNCR	N[8]	--	--	--	--
	SCR	Y	37	1	40	Y
	ULNB	N[9]	--	--	--	--
	LNB/OFA	Y	131	2	56	N
	LNB	Y	187	3	69	N
	Base case[6]	Y	374	4	127	N

[1] This table summarizes each BART analysis and determination; detailed technical information can be found in Appendices B and C.

[2] "Y" = Yes; "N" = No.

[3] Estimated emission rate assuming the control efficiency provided for each technology; information on actual performance based upon specific equipment design and operating conditions was not available.

[4] Δdv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness, the Class I area showing the greatest impact from the Riley Boiler.

[5] Because the cost of the enhanced baghouse, dry ESP, and wet ESP options were determined to outweigh the improvement, BART was selected based on costs of compliance and the pollution control equipment in use (existing baghouse). Specific modeling of each PM control scenario was not analyzed.

[6] Base case provided in this table represents continuous operation of the Riley boiler and the three pulp dryers (without BART).

[7] Wet FGD was not ranked higher due to non-air quality environmental impacts of compliance related to wastewater treatment.

[8] SNCR was not considered feasible due to concerns that the flue gas would not have adequate residence time to achieve reliable control.

[9] ULNB was not considered feasible due to concerns that the boiler firebox would not be large enough to accommodate the full burner/flame management system required.

A summary of the BART analyses and determinations is provided in Table 3.1; detailed information is provided in Appendices B and C. In making the BART determination, TASCO was requested to follow the guidelines provided in Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule. Although the guidelines were required for electrical generation units, EPA has determined that they may be used for other BART source categories.

The BART analysis and determination followed the five-step process as provided in Appendix Y:

1) Identify all retrofit control technologies
2) Eliminate technically infeasible options
3) Evaluate control effectiveness of the remaining control technologies
4) Evaluate the impacts of each remaining control technology (including energy, non-air quality environmental, and cost impacts; and the remaining useful life of the source)
5) Select BART and determine the degree of visibility improvement

In accordance with IDAPA 58.01.01.668.02.c, the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the following must be taken into consideration: costs of compliance; energy and non-air quality environmental impacts of compliance; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These considerations were considered and evaluated in Steps 4 and 5 of each BART analysis (refer to Appendix B).

As provided in Table 3.1, because the existing baghouse is already in use at the facility, no improvement in visibility is expected as a result of this BART implementation.

As provided in Table 3.1, the spray dry FGD is expected to result in the reduction or elimination of 76 days of visibility impairment.

As provided in Table 3.1, the SCR system is expected to result in the reduction or elimination of 87 days of visibility impairment. The LNB with OFA combined with crediting visibility improvements related to the shutdown of three pulp dryers (BART alternative) is expected to result in the reduction or elimination of 71 days of visibility impairment.

The visibility improvements expected from the combination of the selected control options (BART controls, with or without election of the BART alternative) is expected to result in a minimum reduction or elimination of 124 days of visibility impairment (to a total of 3 days predicted of visibility impairment). Refer to Appendix B for additional information.

3.2 Emission Inventories

Detailed discussion of the emission control devices, estimated emission reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the estimated emission reductions follows.

A summary of the estimated emission reductions for the required BART and the BART alternative (crediting shutdown of the three pulp dryers) is provided in Table 3.2. SO_2, NO_X, and PM emissions were considered visibility-impairing pollutants applicable to BART review.

The BART and BART alternative will result in a net emission decrease of applicable regional haze pollutants (PM, SO_2, and NO_X). However, an increase in the emissions of other criteria pollutants (e.g., CO and VOC) and toxic air pollutants associated with the use of lime slurry may result based upon BART final design specifications. Precise estimates of these emission increases have not been determined because information is not yet available and has not been provided by the permittee.

Table 3.2 ESTIMATED INCREASE IN CONTROLLED EMISSIONS – RILEY BOILER WITH BART

Pollutants	Baseline Emissions (lb/hr)	BART Emissions (lb/hr)[a]	Net Emission Increases (lb/hr)
Regional Haze Pollutants			
PM – Riley boiler	12.4	12.4	0
PM – pulp dryers shutdown[b]	98.1		-98.1
SO_2 – Riley boiler	522	115	-407
SO_2 – pulp dryers shutdown[b]	17.8		-17.8
NO_X – Riley boiler	374	186	-188
NO_X – pulp dryers shutdown[b]	191		-191
Total	***1,215.3***	***313.4***	***-901.9***
TAP and other Criteria Pollutants			
CO – Riley boiler	10.9	25.8	14.9
VOC – Riley boiler	1.95	TBD[c]	TBD[c]
Other criteria pollutants and TAP (including lime used in spray dry FGD)	TBD[c]	TBD[c]	TBD[c]

a. Based upon the shutdown of the three pulp dryers (SD-1, SD-2, and SD-3), and the installation and operation of the existing baghouse (AB-3), spray dry FGD, and LNB with OFA control equipment as BART.
b. Based upon the estimated emission reductions attributable to shutdown of the three pulp dryers (SD-1, SD-2, and SD-3), as provided in Table 7 of the revised proposed BART determination submitted February 9, 2009.
c. To be determined (TBD); emissions of these pollutants are dependent upon BART final design specifications, and preconstruction compliance demonstrations may be required.

This Tier II operating permit (T2-2009.0105) may need to be revised based upon BART final design specifications, especially with regard to the installation of the LNB. Permit Condition 3.18 requires that the permittee provide information and modeling analyses in order to demonstrate that BART will not cause or significantly contribute to a violation of any applicable ambient air quality standards.

3.3 Ambient Air Quality Impact Analysis

Detailed discussion of the emission control devices, estimated emission reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the regional haze ambient impact analysis follows.

The Riley boiler was determined to contribute to visibility impairment (and therefore subject to BART) because the modeled 98th percentile change in deciviews (delta-deciview) was equal to or greater than the contribution threshold of 0.5 deciviews. A single source that is responsible for a one-half (0.5) deciview change or more in any mandatory Class I Federal Area is considered to "contribute" to visibility impairment in accordance with IDAPA 58.01.01.668.02.b.

As discussed in Section 3.1, the visibility improvements expected from the combination of the selected control options (with or without election of the BART alternative) is expected to result in a minimum reduction or elimination of 124 days of visibility impairment (to a total of 3 days predicted of visibility impairment). This was determined based on modeling analysis considering implementation of the existing baghouse, a spray dry flue gas desulfurization system, a dry low NO_X burner with over-fired air, and permanent shutdown of the pulp dryers). Refer to Section 3.1 for additional information.

Although regional haze modeling was completed, ambient air impact analyses for the Riley boiler have not been provided to account for any net emission increase expected to result from installation and operation of BART control equipment. A net emission increase in CO emissions may be expected to result from operation of the LNB. A net emission increase resulting from the use of lime slurry may be expected to result from the operation of the spray dry FGD system.[2]

Because ambient air impact analyses were not provided to demonstrate preconstruction compliance with National Ambient Air Quality Standards (NAAQS), applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18). The permittee is encouraged to submit any required preconstruction compliance demonstration as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable). Refer to Section 3.2 for additional information.

Similarly, because emission estimates and ambient air impact analyses were not provided to address applicability to Prevention of Significant Deterioration (PSD) requirements, applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18). In addition, an annual emission limit for CO has been included in an attempt to ensure that the significance threshold of 100 T/yr will not be exceeded, which would result in applicability to PSD review. The permittee is encouraged to submit this information as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable).

Similarly, because emission estimates and ambient air impact analyses were not provided to demonstrate preconstruction compliance with toxic standards, applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18).

4. REGULATORY REVIEW

4.1 Attainment Designation (40 CFR 81.313)

The facility is located in Canyon County, which is designated as attainment or unclassifiable for PM_{10}, $PM_{2.5}$, CO, NO_2, SO_X, and Ozone. Reference 40 CFR 81.313.

4.2 Permit to Construct (IDAPA 58.01.01.201)

This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.400-410 (refer to Section 4.3).

4.3 Tier II Operating Permit (IDAPA 58.01.01.401)

In accordance with IDAPA 58.01.01.03.b, DEQ may require or revise a Tier II operating permit for any stationary source or facility whenever DEQ determines that specific emission standards or requirements on operation or maintenance are necessary to ensure compliance with any applicable emission standard or rule. This Tier II operating permit establishes the BART emission standards applicable to the Riley boiler. Therefore this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.400-410.

[2] As provided by TASCO in the revised BART determination analysis report (02/09/09).

4.4 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The installation and operation of BART control devices are not expected to change Title V applicability or classification for the facility. Although BART control equipment is expected to reduce annual PM, SO_2, and NO_X emissions, and an enforceable CO annual emission limit (T/yr) has been established in an attempt to preclude PSD applicability, facility-wide emissions are still expected to remain above major source thresholds.

The facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because it emits or has the potential to emit regulated air pollutants in amounts greater than or equal to major facility thresholds listed in IDAPA 58.01.01.008.10.

4.5 PSD Classification (40 CFR 52.21)

The installation and operation of BART control devices is not expected to change PSD applicability or classification for the facility. BART standards establish short-term PM, SO_2, and NO_X emission limits (lb/hr); an enforceable CO annual emission limit (T/yr) has been established in an attempt to preclude PSD applicability. At the time of this permitting action, TASCO has not proposed or requested an annual increase in emissions that would be applicable to PSD review.

Emissions of CO may increase as a result of the installation of a LNB. Using the emission factors in AP-42 as a relative guide for comparison purposes, the use of a LNB could potentially double the emissions of CO, resulting in a potential increase of approximately 30 T/yr and less than the PSD significance level of 100 T/yr for CO emissions.[3]

Permit Condition 3.5 includes emission limits in tons per year and pounds per hour (based on unlimited operation at 8,760 hr/yr) in an attempt to preclude PSD applicability and to avoid exceeding the PSD significance threshold for CO.

40 CFR 52.21 .....Prevention of significant deterioration of air quality.

In accordance with §52.21(a)(2)(i), the requirements of this section apply to any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act. The Riley boiler is an existing major stationary source in an attainment area.

In accordance with §52.21(a)(2)(ii), the requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

In accordance with §52.21(b)(2)(i), major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section); and a significant net emissions increase of that pollutant from the major stationary source.

In accordance with §52.21(b)(40), a significant emissions increase means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

In accordance with §52.21(b)(23)(i), significant means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the rates listed, including 100 T/yr of carbon monoxide (CO). The LNB with OFA may

[3] Relative increase estimated based on emission estimates provided in TASCO's revised BART determination (02/09/09) and a ratio of emission factors found in AP-42 Section 1.7, Table 1.7-3 and Table 1.7-1. This estimate is provided for informational purposes only, the actual emissions increase may vary based upon LNB final design specifications and the combustion of other coal types, such as bituminous and subbituminous coal.

have the possibility of resulting in an increase in the emissions of a listed pollutant, specifically that of CO emissions.

In accordance with §52.21(b)(3)(i), net emissions increase means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero: (*a*) the increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and (*b*) any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.

In accordance with §52.21(a)(2)(iv)(*a*), a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase, and a significant net emissions increase. The project is not a major modification if it does not cause a significant emissions increase.

In accordance with §52.21(a)(2)(iv)(*c*), the actual-to-projected-actual applicability test is used as the procedure for calculating (before beginning actual construction) whether a significant emissions increase will occur for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the significant amount for that pollutant.

In accordance with §52.21(b)(48)(ii), for an existing emissions unit, baseline actual emissions means the average rate of emissions, in tons per year, of a regulated NSR pollutant, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

The average rate of emissions over 2003-2005 were provided by TASCO in the revised BART determination analysis (02/09/09). Although these emission calculations were not presented to determine PSD applicability, until additional information has been provided and in absence of data for a 10-year period, these numbers have been used for this purpose. The 24-month average annual emissions (over 2004-2005) of CO from the Riley boiler was 30.5 T/yr.

In accordance with §52.21(b)(41)(i), projected actual emissions means the maximum annual rate, in T/yr, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

In accordance with §52.21(b)(41)(ii)(*d*), in lieu of using other methods, and in absence of information unavailable at this time, the emissions unit's potential to emit has been used to determine the projected actual emissions.

In accordance with §52.21(b)(4), potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

The Riley boiler potential to emit has been limited to 113 T/yr of CO emissions in Permit Condition 3.5. As a result, the actual-to-projected-actual applicability test would result in an emissions increase of 82.5 T/yr (113 – 30.5 T/yr), which includes a significant margin of compliance to avoid exceeding the 100 T/yr significance threshold for CO.

4.6 NSPS Applicability (40 CFR 60)

Installation of a LNB for the control of NO_X may meet the definition of modification or reconstruction of the Riley boiler as defined in 40 CFR 60.14 and 60.15 (respectively); determinations of applicability have not been made at this time. The permittee is encouraged to submit information necessary to make these determinations as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable). Refer to Section 3.2 for additional information.

4.7 NESHAP Applicability (40 CFR 61)

The installation and operation of BART is not expected to change National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 61 applicability for the Riley boiler.

4.8 MACT Applicability (40 CFR 63)

The installation and operation of BART control devices is not expected to change National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 63 applicability for the Riley boiler.

4.9 CAM Applicability (40 CFR 64)

This permitting action does not address specific Compliance Assurance Monitoring (CAM) requirements relevant to the installation and operation of BART control devices. Revisions to the CAM plan may be required on or before the Title V operating permit renewal in order to address CAM requirements for each of the BART control devices implemented.

The Riley boiler has potential pre-control device emission rates equal to or greater than 100 percent of the amount required for a source to be classified as a major source (including SO_2 and NO_X emissions). Therefore, the Riley boiler and associated BART will continue to be subject to the requirements of CAM in accordance with 40 CFR 64.2(a).

New monitoring, recordkeeping, and reporting requirements associated with BART operating parameters (indicators) may need to be addressed in the CAM plan, including requirements specific to PM for the baghouse, requirements specific to SO_2 for the spray dry FGD system, and requirements specific to NO_X for over-fired air combustion techniques.

4.10 BART Applicability (40 CFR 51.308)

40 CFR 51.301 .....Definitions.

In accordance with §51.301;

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

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

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

Deciview haze index=10 $\ln_e(b_{ext}/10\ Mm{-}1)$.

Where b_{ext}=the atmospheric light extinction coefficient, expressed in inverse megameters (Mm−1).

Existing stationary facility means any of the stationary sources of air pollutants listed in 40 CFR 51.301, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. The list of 26 source categories includes fossil-fuel boilers of more than 250 MMBtu/hr heat input. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

The Riley boiler is a BART-eligible source because it was an existing stationary facility that was not in operation prior to August 7, 1962 and was in existence on August 7, 1977 (Riley boiler was installed in 1969), having the potential to emit 250 tons per year of air pollutants (PM, SO_2, NO_X, and CO). The Riley boiler is a fossil-fuel boiler with heat input of more than 250 MMBtu/hr (350 MMBtu/hr).

40 CFR 51.308 .....Regional haze program requirements.

In accordance with §51.308(a), this section establishes requirements for implementation plans, plan revisions, and periodic progress reviews to address regional haze.

Section §51.308(b) through (f) describes the administrative procedures for the implementation plan for regional haze. The plan must address regional haze in each mandatory Class I Federal area located within the state and in each mandatory Class I Federal area located outside the state which may be affected by emissions from within the state. At a minimum, the implementation plan must include reasonable progress goals, calculations of baseline and natural visibility conditions, long-term strategy for regional haze, monitoring strategy and other implementation plan requirements, Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment, requirements for comprehensive periodic revisions of implementation plans for regional haze, and requirements for periodic reports describing progress towards the reasonable progress goals.

Section §51.308(e) describes the Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment. The state must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. The purpose of IDAPA 58.01.01.668 is to implement the BART requirements in 40 CFR 51.308(e).

In accordance with §51.308(e)(1), to address the requirements for BART, the state must submit an implementation plan containing the plan elements and include documentation for all required analyses.

In accordance with §51.301, a BART-eligible source means an existing stationary facility, which includes fossil-fuel boilers of more than 250 million British thermal units per hour heat input, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year (T/yr) or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted. The Riley boiler was installed in 1969, and based on the emission estimates provided, the Riley boiler has the potential to emit more than 250 tons per year each of PM, SO_2, and NO_X emissions (refer to Section 3.1). Therefore the Riley boiler was determined to be subject to BART.

In accordance with §51.308(e)(1)(ii), each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area is subject to BART. Based on the results of the modeling analysis, the TASCO Riley Boiler impacted the Eagle Cap Wilderness, Hells Canyon National Recreation Area, and the Strawberry Mountain Wilderness. A detailed discussion follows in the regulatory review provided for IDAPA 58.01.01.668.02.

In accordance with §51.308(e)(1)(ii)(A), the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the state 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, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Because the Riley boiler has the potential to emit more than 250 T/yr each of PM, SO_2 and NO_X emissions (refer to Section 3.1), it does not qualify for the exception provided in §51.308(e)(1)(ii)(C).

In accordance with §51.308(e)(1)(iii), if the state determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results. At this time it has not been demonstrated that the imposition of an emission standard is infeasible due to technological or economic limitations. Therefore alternative standards were not considered and enforceable PM, SO_2, and NO_X emission limits and associated requirements were included in the permit.

In accordance with §51.308(e)(1)(iv), each source subject to BART shall be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision. Permit Condition 3.3 includes the requirement of this section.

In accordance with §51.308(e)(1)(v), each source subject to BART shall maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained. Permit Condition 3.12 includes the requirement of this section.

In accordance with §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. The alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such alternative measures, the state must submit an implementation plan containing the plan elements and include documentation for all required analyses.

Consideration of the shutdown of the three pulp dryers as proposed by TASCO and the associated emission reductions was provided as part of an alternative measure to the installation and operation of BART. The shutdown of the three pulp dryers (SD-1, SD-2, and SD-3) and the installation and operation of low NO_X burners with over-fired air (LNB with OFA) combined were determined to be equivalent or better in achieving the NO_X emission reductions at the facility using the SCR system BART option (refer to Appendix B).

In accordance with §51.308(e)(2)(i), a demonstration that the 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. Modeling analysis and documentation, including a list of all BART-eligible sources, an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for the Riley boiler, a determination of BART for the Riley boiler, and an analysis of the projected emission reductions achievable through the alternative measure have been provided in Appendix B.

In accordance with §51.308(e)(2)(i)(E), it has been determined by DEQ that based on the clear weight of evidence the alternative measure to BART (LNB with OFA) for the control of NO_X emissions achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

In accordance with §51.308(e)(2)(iii), all necessary emission reductions shall take place during the period of the first long-term strategy for regional haze.

In accordance with §51.308(e)(2)(iv), a demonstration that the emission reductions resulting from the alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP was provided in Appendix B.

In accordance with §51.308(e)(3), because the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, the alternative measure has been deemed by DEQ to achieve greater reasonable progress.

Permit Conditions 3.8 and 4.1 include BART alternative requirements in accordance with this section.

IDAPA 58.01.01.668.....BART REQUIREMENT FOR REGIONAL HAZE

The purpose of Section 668 is to implement the BART requirements in 40 CFR 51.308(e). The analysis and documentation specified is required for each BART-eligible source.

In accordance with IDAPA 58.01.01.668.01, analysis and documentation has been provided that DEQ has identified a list of all BART-eligible sources within the state. The Riley boiler was identified in a list of all BART-eligible sources that was provided in a letter to TASCO June 17, 2007.

In accordance with IDAPA 58.01.01.668.02, DEQ shall complete a determination of BART for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class 1 Federal Area. All such sources are subject to BART. The BART analysis and documentation demonstrating that the Riley Boiler is subject to BART was provided in a letter to TASCO on July 19, 2007, and has been provided in Appendix C.

The Riley boiler meets the definition of BART-eligible source in accordance with §51.301. SO_2, NO_X, and PM emissions were considered as the visibility-impairing pollutants applicable to BART review, and the following Class I Federal areas were included in the modeling analysis: Craters of the Moon, Eagle Cap Wilderness, Hells Canyon National Recreation Area, Jarbidge Wilderness, Sawtooth Wilderness, Selway-Bitterroot Wilderness, and Strawberry Mountain Wilderness.

In accordance with IDAPA 58.01.01.668.02.b, a single source that is responsible for a one-half (0.5) deciview change or more in any mandatory Class I Federal Area is considered to "contribute" to visibility impairment. DEQ used air dispersion modeling to determine if the 0.5 deciview threshold was exceeded by any of the BART-eligible sources in Idaho. As summarized in Table 4.1, the Riley boiler

was predicted to have contributed to a visibility impairment at the Eagle Cap Wilderness, Hells Canyon National Recreation Area, and Strawberry Mountain Wilderness mandatory Class I Federal Areas with the 98th percentile highest delta-deciview greater than 0.5 during the modeling period 2003-2005.

Table 4.1 SUMMARY OF BART ANALYSIS

Emissions Unit	Year Installed	Capacity (MMBtu/hr)	Regional Haze Pollutants	Regional Haze Pollutants Exceeding 250 T/yr	Nearest Class I Areas	Contribute to 0.5 deciview change? (Y/N)[1]
Riley boiler	1969	350	PM, SO_2, NO_X	PM, SO_2, NO_X	Eagle Cap Wilderness	Y
					Hells Canyon National Recreation Area	
					Strawberry Mountain Wilderness	
					Sawtooth Wilderness	N
					Selway-Bitterroot Wilderness	
					Jarbidge Wilderness	
					Craters of the Moon National Monument	

[1] "Y" = Yes; "N" = No.

In accordance with IDAPA 58.01.01.668.02.c, the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the following must be taken into consideration: costs of compliance; energy and non-air quality environmental impacts of compliance; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These considerations were included in Step 4 of the BART analysis (refer to Section 3.1 and Appendix B).

Because the Riley boiler has the potential to emit more than 250 T/yr each of PM, SO_2 and NO_X emissions (refer to Section 3.1), it does not qualify for the exception provided in IDAPA 58.01.01.668.02.d.

In accordance with IDAPA 58.01.01.668.03, if DEQ determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice, or operation and must provide for compliance by means which achieve equivalent results. At this time it has not been demonstrated that the imposition of emission standards for PM, SO_2, and NO_X are infeasible. Therefore alternative standards were not considered (additional discussion provided in §51.308(e)(1)(iii)).

In accordance with IDAPA 58.01.01.668.04, each source subject to BART is required to install and operate BART as expeditiously as practicable, but in no event later than five (5) years after approval of the implementation plan. Permit Condition 3.3 includes the requirement of this section.

In accordance with IDAPA 58.01.01.668.05, each source subject to BART is required to maintain the control equipment required by DEQ and establish procedures to ensure such equipment is properly operated and maintained. Permit Condition 3.9 includes the requirement of this section.

In accordance with IDAPA 58.01.01.668.06, as an alternative to the installation of BART for a source or sources, DEQ may approve a BART alternative. Permit Conditions 3.4, 3.5, 3.8, 3.12, 3.13, 3.14, 3.15, and 4.1 include requirements associated with the installation and operation of the LNB with OFA and the pulp dryers shutdown for the BART alternative.

In accordance with IDAPA 58.01.01.668.06.a, if a source proposes a BART alternative, the resultant emissions reduction and visibility impacts must be compared with those that would result from the BART options evaluated for the source. Consideration of the shutdown of the three pulp dryers as proposed by TASCO and the associated emissions reduction was provided as part of an alternative option to the installation and operation of BART. The shutdown of the three pulp dryers (SD-1, SD-2, and SD-3) and the installation and operation of low NO_X burners with over-fired air together were determined to be equivalent or better in achieving NO_X emission reductions at the facility (refer to Appendix B).

In accordance with IDAPA 58.01.01.668.06.b, the permittee proposing a BART alternative must demonstrate that this BART alternative will achieve greater reasonable progress than would be achieved through the installation and operation of BART. At this time it has not been demonstrated that the proposed shutdown of the dryers will achieve greater reasonable progress than would be achieved through the installation and operation of BART.

In accordance with IDAPA 58.01.01.668.06.c, the permittee proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation. At this time an analysis and justification of the averaging period and method of evaluating compliance with a proposed emission limitation alternative have not been provided by TASCO. A requirement documenting the need for improved monitoring has been included in Permit Condition 3.19.

In accordance with IDAPA 58.01.01.668.07, once DEQ has met the requirements for BART or BART alternative, as identified in Subsection 668.06, BART-eligible sources will be subject to the requirements of reasonable progress goals, as defined in 40 CFR 51.308(d), in the same manner as other sources.

4.11 Permit Conditions Review

This section describes the permit conditions for this initial permit. The requirements of this Tier II operating permit do not contravene any permit conditions in any applicable permits to construct and Tier I and Tier II operating permits (T1-050020, T2-050021, P-030062). The permittee must continue to comply with all applicable permits.

Permit Conditions 1.1, 1.2, 3.1, and 3.2

These permit conditions explain the purpose of this permitting action and describe the emission sources and the control equipment regulated by this permit. The information included reflects any design, equipment, and operational information presented in the BART analysis.

The permittee has documented concerns regarding the feasibility of using over-fired air on the Riley Boiler, and has estimated that a NO_X emission control efficiency of 50% could be achieved using a low-NO_X burner without over-fired air. Based upon this information, the expected control efficiency has been listed as ≥50% in the Regulated Sources Table (Permit Condition 1.2) and the BART alternative

NO_X emission limit (Permit Condition 3.4) has been based upon achieving a 50% reduction in NO_X emissions.

Permit Condition 2.1
This permit condition clarifies that compliance with all applicable local, state, and federal rules and regulations is required, in accordance with IDAPA 58.01.01.406.

Permit Condition 2.2
This permit condition incorporates applicable federal requirements into the permit by reference. The intent is that the federal requirement shall govern any conflict with a permit condition referencing a federal requirement.

Permit Condition 2.3
This permit condition provides contact information for submittal of required performance test reports, reports, applications, submittals, and other communications to DEQ.

Permit Conditions 3.3
This permit condition requires compliance with BART on and after the compliance date provided in IDAPA 58.01.01.668.04.

The permittee has requested the option to use BART alternative control strategies to achieve the BART and BART alternative emission limits (Permit Condition 3.4), which could require additional technical review and a revision to this permit. In response to this request, DEQ has included language inclusive of using either the selected BART or a DEQ-approved BART alternative within Permit Condition 3.3.

The permittee also requested the addition of clarifying language which documents that the conditions of this permit may be revised in accordance with IDAPA 58.01.01.404. Additional BART alternatives may be considered and relevant BART determinations may be revised if adequate time is allowed to meet applicable permitting and SIP deadlines.

Permit Conditions 3.4 and 3.5
This permit condition establishes emission limits for BART based on the BART analyses and determinations in accordance with IDAPA 58.01.01.401.03.

The BART PM emission limit was based upon information provided by the permittee indicating that the existing baghouse could achieve 99% control of PM emissions. The BART SO_2 emission limit was based upon the information provided by the permittee that spray dry FGD could achieve 80% control of SO_2 emissions assuming a conservative adiabatic approach temperature of 40°F to protect the baghouse. The BART alternative NO_X emission limit was based upon the use of a low-NO_X burner without consideration given to the use of over-fired air, as described below.

A limit of 113 T/yr was included to avoid exceeding the significance threshold for CO emissions, which could potentially result in a PSD major modification (refer to Section 4.5 for additional information). The CO emission limits are considered federally enforceable requirements established pursuant to 40 CFR 52.

CO emissions from the Riley boiler have previously been limited by a cap over the combined emissions from B&W No. 1 boiler (S-B1), B&W No. 2 boiler (S-B2), and the Riley boiler (S-B3) in Permit Condition 3.1 of Tier I Operating Permit No. T1-050020. Conservatively assuming that the Riley boiler could emit up to the full amount of 159.0 T/yr, a permitted limit of 113 T/yr would decrease allowable emissions for the Riley boiler. The CO hourly limit of 25.8 pounds per hour was calculated based upon the annual limit, assuming unlimited operation of the boiler at 8,760 hr/yr. This emission limit is also not expected to contravene existing Permit Condition 3.5 of Tier I Operating Permit No. T1-050020

(relevant to CO and PM_{10} emission limits), which permits operation at 120% of the average fuel rates tested.

Compliance with these emission limits is ensured by complying with performance testing (Permit Conditions 3.14 and 3.15) and monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

The permittee has documented concerns regarding the feasibility of using over-fired air on the Riley Boiler, and has estimated that a NO_X emission control efficiency of 50% could be achieved using a low-NO_X burner without over-fired air. Based upon this information, the expected control efficiency has been listed as ≥50% in the Regulated Emission Point Sources Table (Permit Condition 1.2) and the BART alternative NO_X emission limit (Permit Condition 3.4) has been based upon achieving a 50% reduction in NO_X emissions.

The permittee has requested the option to use BART alternative control strategies to achieve the BART and BART alternative emission limits (Permit Condition 3.4), which could require additional technical review and a revision to this permit. In response to this request, DEQ has included language inclusive of using either the selected BART or a DEQ-approved BART alternative within Permit Condition 3.3.

Permit Conditions 3.6, 3.7, and 3.8
These permit conditions require installation and operation of BART based on the BART determination in accordance with IDAPA 58.01.01.401.03.

Permit condition 3.8 includes the BART alternative proposed by the permittee for the control of NO_X emissions in accordance with IDAPA 58.01.01.668.06, based upon the shutdown of three pulp dryers and installation and operation of a low NO_X burner system (LNB) operating with over-fired air (in lieu of installation and operation of selective catalytic reduction system control equipment on the Riley boiler). The permittee had proposed crediting of the shutdown of the three pulp dryers as a BART alternative; however in order to achieve equivalent NO_X emission reductions, installation of a LNB with OFA has also been required as part of the BART alternative.

Because the installation of a LNB with OFA may constitute modification and/or reconstruction of the source, additional requirements may be applicable (refer to additional discussion provided in Sections 3.2, 3.3, and under Permit Condition 3.18).

Compliance with these requirements is ensured by complying with performance testing (Permit Conditions 3.14 and 3.15) and monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

The permittee has documented that the baghouse cannot be operated during periods when the boiler is using natural gas as the primary fuel. Based upon this information, operation of the baghouse has been required in Permit Condition 3.6 only when firing coal fuel in the Riley Boiler.

Permit Condition 3.9
This permit condition requires that the permittee maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

Permit Condition 3.10
This permit condition requires monitoring of pressure drop across the baghouse to ensure compliance with the BART PM emission limit (Permit Condition 3.4) and General Provision 2. This permit condition does not contravene existing Permit Condition 3.9 in Tier I Operating Permit No. T1-050020.

Permit Condition 3.11
This permit condition requires monitoring of spray dry flue gas adiabatic approach temperature to ensure compliance with the BART SO_2 emission limit (Permit Condition 3.4) and General Provision 2.

The permittee has indicated that monitoring the adiabatic approach temperature may be more reliable than monitoring the slurry feed flow rate for the spray dry FGD. Based upon this information, monitoring of adiabatic approach temperature has been required in Permit Condition 3.11 to ensure compliance with the BART SO_2 emission limit.

Permit Condition 3.12
This permit condition requires monitoring of primary and over-fired air flow rates to ensure compliance with the BART NO_X emission limit (Permit Condition 3.4) and General Provision 2.

Permit Condition 3.13
This permit condition requires the development and documentation of operation and maintenance procedures for the operation and maintenance of BART control equipment to ensure compliance with BART emission limits (Permit Condition 3.4), CO emission limits (Permit Condition 3.5), the maintenance of BART equipment requirement (Permit Condition 3.9), the control equipment maintenance and operation general provision (General Provision 2), and the manufacturer's specifications.

Permit Conditions 3.14, 3.15, 3.16, and 3.17
Permit Conditions 3.14 and 3.15 require annual performance testing of PM, SO_2, NO_X, and CO emissions from the Riley boiler to demonstrate compliance with BART emission limits (Permit Condition 3.4) and the CO emission limits (Permit Condition 3.5), in accordance with IDAPA 58.01.01.405. These permit conditions also specify conditions and require monitoring and reporting in accordance with IDAPA 58.01.01.157 and General Provision 6.

Compliance with permit conditions 3.14 and 3.15 is ensured by complying with monitoring, recordkeeping, and reporting requirements (Permit Conditions 3.16 and 3.17) and General Provision 6.

The permittee has requested the option for DEQ to approve alternate testing frequencies. In response, the option to use a DEQ-approved testing frequency has been included in Permit Condition 3.15. The permittee has also documented concerns that direct measurement of the coal feed rate is not feasible for the Riley Boiler during performance testing. In response, the option to utilize a DEQ-approved calculation method has been included in Permit Condition 3.16.

Permit Condition 3.18
This permit condition requires submittal of information and preconstruction compliance demonstrations necessary to demonstrate preconstruction compliance with applicable ambient air quality standards, in accordance with the procedures and requirements for permits to construct (IDAPA 58.01.01.200-228). Refer to additional discussion provided in Sections 3.2 and 3.3 for additional information.

In order to allow sufficient time for DEQ to review the necessary information or to process any associated permitting action (e.g., permit to construct or revision to this Tier II operating permit T2-2009.0105), a deadline of 180 days prior to the BART installation and operation due date was included in Permit Condition 3.18.

Permit Condition 3.19
This permit condition requires submittal of information necessary to address BART monitoring requirements and update CAM plan(s) as applicable to account for the installation and operation of BART, in accordance with 40 CFR 64 and IDAPA 58.01.01.668.06.c. Refer to Section 4.9 for additional discussion concerning CAM applicability.

Permit Condition 3.20
This permit condition references contact information for submittal of required reports, applications, submittals, and other communications to DEQ.

Permit Conditions 4.1 and 4.2
Permit Condition 4.1 requires permanent shutdown of the three pulp dryers to comply with the BART alternative for the control of NO_X emissions, in accordance with IDAPA 58.01.01.668.06.

Compliance with Permit Conditions 4.1 is ensured by complying with the shutdown notification requirement (Permit Condition 4.2).

5. PUBLIC COMMENT

A public comment period was made available to the public in accordance with IDAPA 58.01.01.404.01.c. During this time, comments were submitted in response to DEQ's proposed action. Refer to the chronology for public comment period dates.

A response to public comments document has been crafted by DEQ based on comments submitted during the public comment period. That document is part of the final permit package for this permitting action.

Appendix A – AIRS Information

AIRS/AFS Facility-wide Classification – Data Form

Facility Name:	The Amalgamated Sugar Company LLC (TASCO) – Nampa Factory		
Facility Location:	Nampa		
Facility ID:	027-00010	Date:	08/13/2009
Project/Permit No.:	T2-2009.0105	Completed By:	Morrie Lewis

☒ Check if there are no changes to the facility-wide classification resulting from this action. (compare to form with last permit)

☐ Yes, this facility is an SM80 source.

Identify the facility's area classification as A (attainment), N (nonattainment), or U (unclassified) for the following pollutants:

	SO2	PM10	VOC	
Area Classification:	U	A	U	DO NOT LEAVE ANY BLANK

Appendix B – BART Determinations

Department of Environmental Quality

Amalgamated Sugar Company (TASCO) Best Available Retrofit Technology Determination

July 17, 2009

Amalgamated Sugar Company (TASCO)
Best Available Retrofit Technology Determination

1.1 History of BART

The 1977 Clean Air Act (CAA) Amendments created Part C of the Act entitled Prevention of Significant Deterioration of Air Quality and includes Sections 160-169. The intent of the Prevention of Significant Deterioration (PSD) provisions is to maintain good air quality in areas that attain the national air quality standards and provide special protections for National Parks Wilderness Areas. Part C is divided into two subparts. Subpart 1 established the initial classification of Class I and Class II areas. Class I areas include: Section 162(a)

> *"(1) International Parks,*
>
> *(2) national wilderness areas which exceed 5,000 acres in size*
>
> *(3) national memorial parks which exceed 5,000 acres in size, and*
>
> *(4) national parks which exceed six thousand acres in size and which are in existence on the date of the enactment of the Clean Air Act Amendments of 1977 shall be Class I areas and may not be redesignated.*
>
> *(b) All areas in such State designated as attainment or unclassifiable which are not established as class I under subsection (a) shall be class II areas.*

The Class I areas that met this criteria and were in existence on or before 1977 became known as "mandatory class I federal areas." Although states could designate other areas as Class I areas after 1977, PSD and other portions of the Regional Haze Rule focus on those Class I areas in existence on or before 1977.

Based on the classification of an area, the amount of allowable degradation which is from new or modified air pollution sources is determined. In National Parks and other Class I areas smaller amounts of degradation known as "increment" are allowed. The PSD program under Part C, Subpart 1 primarily focuses on emission from 1977 forward and will be further discussed in the chapters on Reasonable Progress and Long Term Strategies.

Visibility is called out much stronger in Part C, Subpart 2 and set the national goal of "the prevention of any future and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution" (CAA Section 169(A). In an effort to remediate the existing impairments to visibility, the Section 169(A)(2)(A) includes "a requirement that each major stationary source which is in existence on the date of enactment of this section, but which has not been in operation for more than fifteen years as of such date, emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any such area, shall procure, install and operate, as expeditiously as practicable (and maintain thereafter) the best available retrofit technology, as determined by the state."

To carry out Congress' intent to install BART on certain emission sources, EPA promulgated the "Regional Haze Rule" [64 FR 35714 (July 1, 1999)]. These rules were challenged, and on May 24, 2002, the U.S. Court of Appeals for the District of Columbia vacated the Regional Haze Rule and remanded the BART provisions in the Rule.

Revisions to the rule were published on July 6, 2005 [70 FR 39104 (July 6, 2005)]. The BART rule can also be found under 40 CFR 51.308(e). As part of the July 6, 2005 rule revisions, EPA published Appendix Y guidance for the implementation of BART. The guidance can be found beginning at 70 FR 39156 (July 6, 2005).

In the spring of 2006, the Department of Environmental Quality (DEQ) went through a negotiated rulemaking process to develop rules for Regional Haze. During this process rules were negotiated for the implementation of BART and Reasonable Progress Goals. These rules pertaining to BART can be found at IDAPA 58.01.01.668. During the negotiated rule making process, it was recommended by industry representatives to follow EPA Appendix Y Guidance on the BART determination process but not incorporate the guidance into rule under IDAPA. A threshold of visibility impact of 0.5 deciviews in any Class I Federal Area was established through negotiated rule making as "contributing" to visibility impairment.

1.2 BART Process

The BART provision applies to "major" stationary sources. From 26 identified source categories which have the potential to emit 250 tons per year or more of any air pollutant. The CAA requires that only sources which were built or in operation during a specific 15-year time interval be subject to BART. The BART provision applies to sources that existed as of the date of the 1977 CAA amendments (that is, August 7, 1977) but which had not been in operation for more than 15 years (that is, not in operation as of August 7, 1962). The first phase of the BART process is developing a list of BART "eligible" facilities which include those major facilities from the 26 identified source categories that have a potential to emit 250 tons per year of any light impairing pollutant.

The CAA requires BART review when any source meeting the above description "emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility" in any Class I area. In most cases, the determination of whether a facility is causing or contributing to visibility impairment is done through modeling. Any BART-eligible facility with an impact of one deciview is considered "causing" visibility impairment, and in Idaho the threshold for "contributing" to impairment is 0.5 deciviews[1]. Any BART-eligible facility causing or contributing to visibility impairment is BART "subject." BART subject facilities are required to go through a process to determine what if any controls will be required.

1.2.1 BART Eligibility

The source is *BART eligible*, meaning that it falls into one of 26 sector categories, was built between 1962 and 1977, and annually emits more than 250 tons of a haze-causing pollutant. The Riley Boiler of The Amalgamated Sugar Company, LLC (TASCO) Sugar Plant in Nampa, Idaho has been determined to be BART-eligible. The Boiler is rated at 350 million BTUs per hour which meets the BART criteria as a fossil-fuel boiler of more

[1] A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions, from pristine to highly impaired. A deciview is the minimum perceptible change to the human eye.

than 250 million BTUs per hour heat input was installed in 1969, and was put into service between August 7, 1962 and August 7, 1977.

The Riley Boiler's *Potential to Emit* (PTE) exceeds 250 tons per year (tpy) for the haze-causing pollutants sulfur dioxide (SO_2, 2,770 tpy), nitrogen oxide (NO_x, 1,708 tpy) and particulate matter (PM_{10}, 55 tpy), so this emission unit is eligible for inclusion in the subject-to-BART analysis of visibility impairment in Class I areas. Following this criteria the Riley Boiler at the Nampa J.A.S.CO plant is BART eligible.

1.2.2 BART Subject

The source is *subject to BART* if it is reasonably anticipated to cause or contribute to impairment of visibility in a Class I area. According to the Guidelines for Best Available Retrofit Technology (BART) Determinations contained in 40 CFR Part 51, Appendix Y a source is considered to contribute to visibility impairment if the modeled 98th percentile change in *deciviews* (delta deciview) – a measure of visibility impairment—is equal to or greater than a contribution threshold of 0.5 deciviews. Although Appendix Y does provide for thresholds less than 0.5 deciviews and cumulative impacts, it was determined through negotiated rulemaking with industry, federal land management agencies, DEQ and the public that the "contribute" threshold for a single source would be established at 0.5 deciviews. (See IDAPA 58.01.01.668.02.e.) As suggested in Appendix Y guidance the determination was made by modeling.

DEQ used the CALPUFF air dispersion modeling system (version 6.112) to determine if the 0.5 deciview threshold is exceeded by any of the BART eligible sources in Idaho. The modeling of BART-eligible sources was performed in accordance with the *BART Modeling Protocol*[1], which was jointly developed by the states of Idaho, Washington, and Oregon, and which has undergone public review and revision. Refer to the *BART Modeling Protocol* for details on the modeling methodology used in this subject-to-BART analysis. (See Appendix A.)

The Idaho DEQ, in cooperation with Washington State of Ecology and Oregon Department of Environmental Quality, contracted with Geomatrix Consultants to develop CALMET datasets to use for the CALPUFF BART modeling. The CALMET datasets were based on Penn State and National Center of Atmospheric Research Mesoscale Model (MM5) runs performed at Washington University. There were two CALMET datasets produced: one using 12km mesh size and another using 4 km mesh size[2]. (See Appendix B.)

As part of the contract, Geomatrix Consultants ran MESTAT to quantify the quality of the MM5 files used as the meteorological dataset in CALMET—used in the CALPUFF modeling. MESTAT/TAFF pairs the MM5 forecasted data with meteorological

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[1] *Modeling Protocol for Washington, Oregon and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation.* http://www.deq.state.id.us/air/prog_issues/pollutants/bart_BART_modeling_protocol.pdf

[2] *Modeling Protocol for BART CALMET datasets, Idaho, Oregon, and Washington*, Geomatrix Consultants Inc., July 12, 2006.

observations and then performs various statistical manipulations and aggregates the results for output [4] (See Attachment C).

Subject-to-BART analysis results for the TASCO Riley Boiler, Nampa are shown in Table 1, which highlights the following two threshold values for BART:

- 8th highest value for each of the years modeled (2003-2005), representing the 98th percentile (8/365 = 0.02) cutoff for delta-deciview in the each year
- 22nd highest value for the entire period from 2003 through 2005, representing the 98th percentile (22/1095 = 0.02) cutoff for delta-deciview over three years.

The determining criterion for both values is a delta-deciview of at least 0.5 deciview.

Table 1 - Change in Visibility Compared Against 20% Best Days Natural Background

Class I Area	Change in Visibility Compared Against 20% Best Days Natural Background Conditions							
	Delta-Deciview Value larger than 0.5 from one year period						Delta-Deciview Value larger than 0.5 from 3 year period	
	2003		2004		2005		2003-2005	
	8th highest[a]	Total days[b]	8th highest	Total days	8th highest	Total days	22nd Highest[c]	Number of Days[d] (2003,2004,2005)
Craters of the Moon	0.161	2	0.224	2	0.153	0	0.190	2
Eagle Cap Wilderness, OR	0.87	20	1.355	46	1.302	46	1.325	112
Hells Canyon National Recreation Area, ID	0.772	13	1.031	27	0.9	21	0.936	61
Jarbidge Wilderness, NV	0.151	0	0.198	1	0.201	1	0.179	2
Sawtooth Wilderness, ID	0.319	2	0.296	4	0.265	0	0.271	6
Selway-Bitterroot Wilderness, ID and MT	0.186	0	0.305	1	0.264	2	0.243	3
Strawberry Mountain Wilderness, OR	0.782	12	0.639	11	1.596	31	0.943	56

a The 8th highest delta-deciview for the calendar year
b Total number of days in 1 year that exceeded 0.5 delta-deciviews
c The 22nd highest delta-deciview value for the 3-year period.
d Total number of days in the 3-year period that exceed 0.5 delta-deciviews

These findings were based on the emission rates and other facility parameters provided by TASCO at the time of the analysis[5]. Based on the analysis, the TASCO Riley Boiler

[4] *INITIAL METSTAT REPORT CALMET Fields for BART Idaho, Oregon and Washington* Geomatrix Consultants

[5] The delta deciview impact for each of the Class I areas identified in the Subject-to-BART analysis changed slightly in the final determination process due to refinements in facility parameters such as stack velocities as provided by TASCO.

impacted the following Class I areas with the 98th percentile highest delta-deciview greater than 0.5 during the modeling period 2001-2003:

- Eagle Cap Wilderness, Oregon
- Hells Canyon National Recreation Area, Idaho
- Strawberry Mountain Wilderness, Oregon

In conclusion, the CALPUFF model predicted that emissions from the Riley Boiler at the IASCO Sugar Plant, Nampa, Idaho, impacted visibility with the 98th percentile highest delta-deciview of more than 0.5 deciview on the Class I areas of Eagle Cap Wilderness, OR, Strawberry Mountain Wilderness, OR, and Hells Canyon Wilderness, ID, during the period of year 2001 to 2003.

Eagle Cap Wilderness area had the highest number of days (112 days in three years) with delta deciview value greater than 0.5. The highest one-year 8th high delta-deciview (1.596, year 2003) was found in Strawberry Mountain Wilderness.

The major contributors to visibility deterioration from the Riley Boiler at the IASCO Nampa facility are SO2 and NOx precursors of sulfate and nitrate aerosols formed in winter under conditions of low temperature and high relative humidity. The impact is greatest when a high pressure system persists in the area for three to four days or more, the atmosphere is stagnant with poor dispersion, and the pollutants transported remain relatively undiluted.

The subject to BART analysis, which followed the *BART Modeling Protocol*, and additional extensive sensitivity analysis have demonstrated that the Riley Boiler at the IASCO Nampa facility is subject to BART. IASCO was notified of the subject to BART findings by letter on July 19, 2007. (See attachment A.)

1.2.3. BART Determination

The third phase of the BART process is the determination of technically feasible control technologies. The Clean Air Act defines five factors in making a determination. They include:

- The cost of compliance
- The energy and non-air quality environmental impacts of compliance
- Any existing pollution control technology in use at the source
- The remaining useful life of the source, and
- The degree of visibility improvement which may reasonably be anticipated from the use of BART.

In making the BART determination IASCO was requested to follow Appendix Y guidance for the implementation of BART as found at 70 FR 39158 (July 6, 2005). Although this guidance was required for Electrical Generating Units (EGUs), EPA has determined there is no reason the guidance cannot be used for other BART categories. The five steps as described in Appendix Y determination process can be summarized as follows:

STEP 1 Identify all available retrofit emission control techniques (three categories):

- Pollution prevention (use of inherently lower emitting processes/practices)
- Use of add-on controls (for cases where already in place, improvement in the performance of add-on controls)
- Combination of pollution prevention and add-on controls

STEP 2 Determine technically feasible options:

- Available (commercial availability)
- Applicable (has it been used on the same or a similar source type?)

STEP 3 Evaluate technically feasible options:

- Make sure you express the degree of control using a metric that ensures an "apples to apples" comparison (emissions performance levels among options (e.g., lb/MMBtu)).
- Give appropriate treatment and consideration to control technologies that can operate over a wide range of emission performance levels (evaluate most stringent control level that the technology is capable of achieving plus other scenarios).

STEP 4 Impact analysis:

- Cost of compliance (identify emissions and design parameters, develop cost estimates):
  - Baseline emissions rate should represent a realistic depiction of anticipated annual emissions from the source. In general, for the existing sources subject to BART, you will estimate the anticipated annual emissions based upon actual emissions from a baseline period.
- Energy impacts:
  - Direct energy consumption by the control device (not indirect energy impacts).
- Non-air quality environmental impacts:
  - Solid or hazardous waste generation or discharges of pollutant water from a control device.
- Remaining useful life:
  - Can be included in the cost analysis.

STEP 5 Determine visibility impacts (improvement):

- Run the model at pre-control and post-control emission rates:
  - Pre-control emission rates = max 24-hour used in BART subject modeling.
  - Post-control emission rates = % of pre-control rate (e.g., 90% control efficiency).
  - Calculate results for each receptor as the change in deciviews compared against natural conditions.
- Determine net visibility improvement:
  - Consider frequency, magnitude, and duration components of impairment.
  - Can compare with percentages.

1.3 TASCO BART Determination

After several consultations with TASCO concerning emission rates, facility parameters and the BART process, TASCO submitted a "Best Available Retrofit Technology Determination – Riley Boiler" on November 20, 2007. After reviewing the document DEQ requested that TASCO revise the document to include some additional control technologies that were technically feasible, evaluate them using the five steps listed above and provide additional cost and financial detail. TASCO revised the document and resubmitted the information on February 6, 2009. As part of the revisions, DEQ performed the CALPUFF modeling to identify changes in visibility based on the emission estimates and facility parameters provided by TASCO for each of the technically feasible control technologies for each BART identified pollutant. The remainder of this document will review the February 6, 2009 BART determination as submitted by TASCO, comments on issues raised in the document, and provide DEQ's determination on the selection of the Best BART technologies based on the categories listed above.

1.3.1 Particulate BART Control Technology Selection

In determining the "best" BART control technology for particulate controls on the Riley Boiler, DEQ worked in conjunction with TASCO using the five steps as described in EPA Appendix Y.

STEP 1 - Identify all available retrofit emissions control techniques

In consultation with DEQ, the following particulate control technologies were identified:

- Existing baghouse
- Enhanced baghouse
- Wet Electrostatic Precipitator (Wet ESP)
- Dry Electrostatic Precipitator (Dry ESP)

STEP 2 – Determine technically feasible options

In this step, DEQ relied heavily on TASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ did review the information as provided below.

Existing Baghouse – The existing baghouse efficiently reduces PM to very low levels. Measured PM emissions are 0.036 lbs/MMBTU, well below the previously proposed industrial boiler MACT I standard of 0.07 lbs/MMBTU. Control efficiencies for baghouses are reported at 99 to 99.9%. For this analysis the control efficiency was assumed to be 99% efficient.

Enhanced Baghouse – The addition of a baghouse module may marginally improve the removal efficiency of the existing baghouse. This option would expand the number of modules from four to five resulting in reduced baghouse velocities and pressure drop. Adding another baghouse module to the Riley Boiler baghouse will be difficult and

expensive because of physical space limitations near the existing baghouse. PM control efficiency for the additional baghouse is assumed to be 99.0%.

Wet Electrostatic Precipitator - A Wet ESP consists of a series of collection surfaces in the device that removes particulate using an electrical field. The plates are continuously or intermittently cleaned using a circulating water system. Control efficiencies for Wet ESP systems are reported to be 99.0 to 99.9%. For the purposes of this evaluation, the control efficiency is assumed to be 99%.

Because of physical space limitations, the installation of the Wet ESP will require demolition and the removal of the existing baghouse and installation of the WET ESP in its place. In addition the system will produce saturated vapor conditions in the stack during some operation scenarios. A liner will be needed to be installed in the existing stack to protect the stack from corrosive conditions.

Dry Electrostatic Precipitator - A Dry ESP is very similar in operation to the Wet ESP option considered above. The particulate to be removed is charged in an electric field and attracted to a collection plate. Control efficiencies for Dry ESP system are reported at 99.0 to 99.9% efficient. For this evaluation the control efficiency is assumed to be 99.0%.

This information is summarized in Table 2, below.

Table 2. Technically Feasible Options

Pollutant	Technology	Feasibility	Reason Not Feasible
PM	Existing Baghouse	Yes	None
	Enhanced Baghouse	Yes	None
	Wet ESP	Yes	None
	Dry ESP	Yes	None

In conclusion, all particulate technologies identified are technically feasible options for the Riley Boiler .

STEP 3 - Evaluate technically feasible options

In this step, all of the technically feasible options were ranked in order of effectiveness of each control technology identified as technically feasible. Control effectiveness was based on manufacture's performance data, engineering estimates, and demonstrated effectiveness of the technology on the Riley Boiler. This data is summarized in Table 3.

Table 3 Control Technology Efficiency Evaluation

Pollutant	Control Option	BART Baseline Maximum Emission rate (lbs/hour)	BART Baseline Annual Average Emissions (tons/year)	Removal Efficiency	Expected Maximum Emission Rate (lbs/hour)	Expected Annual Emissions (tons/year)
Particulate	Existing Baghouse	12.4	54.3	99.8%	12.4	54.3
	Enhanced Baghouse	12.4	54.3	99.8%	12.4	54.3
	Dry ESP	12.4	54.3	99.8%	12.4	54.3
	Wet ESP	12.4	54.3	99.8%	12.4	54.3

Since all control technologies have the same removal efficiency no single control technology is ranked higher than the other for emissions removal.

STEP 4 – Impact analysis

The use of the existing baghouse stands out as the best BART control technology since it will not require additional costs. The existing baghouse has the added environmental benefits of not requiring additional water or electricity. The benefit of adding an additional bag house is so small the benefits are outweighed by the costs. In conclusion the best BART alternative for particulate is the existing baghouse.

STEP 5 – Determine visibility impacts/improvements

Since all control technologies have the same removal efficiency there is no merit in modeling specifically for the particulate control scenarios.

1.3.2 Sulfur Dioxide (SO_2) BART Control Technology Selection

In determining the "best" BART control technology for SO_2 controls on the Boles Boiler DEQ worked in conjunction with TASCO using the five steps as described in EPA Appendix Y.

STEP 1 – Identify all available retrofit emissions control technologies

- Low sulfur coal (LSC)
- Wet flue gas desulfurization (SO_2)
- Spray dry FGD
- Dry lime FGD
- Dry Trona injection FGD

STEP 2 – Determine technically feasible options

In this step, DEQ relied heavily on TASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ did review the information as provided below.

Low Sulfur Coal (LSC) - Currently the Nampa plant uses coal that is limited to 1% sulfur by weight to comply with the Rules for Control of Air Pollution in Idaho. The average actual percent sulfur for the baseline period is approximately 0.75%. This option will look at using 0.6% sulfur with an actual reduction of 15%.

Wet Flue Gas Desulfurization (WET FGD) – A WET FGD system typically consists of saturated absorber towers located downstream of a particulate control device. The absorbers are usually configured as a flooded tray system or spray tower. Flue gas entering the absorber reacts with slurried limestone or slaked lime to remove SO_2 at the liquid/gas surface boundary. The reaction forms insoluble products or solids that are further treated with forced oxidation to convert to gypsum which is a marketable by product. The treated flue gas passes through a mist eliminator system to remove water droplets from the flue gas stream. The flue gas leaving the absorber is saturated with water vapor and can present a visible steam plume from the stack.

Wet FGD systems offer one of the highest SO_2 removal efficiencies of the available control technologies with a removal efficiency of 95% or greater. This is also a technology which EPA is heavily invested and supports. The installation of Wet FGD will require significant modification of the facility. Key site-specific considerations are as follows:

Wet FGD results in saturated stack conditions during periods of Raley only operation (Shared stack operation during beet campaign with the B&W Boiler is not anticipated to result in saturated stack conditions). The resulting condensation formed in the stack is anticipated to have very low pH values that will require installation of a stack liner to protect the integrity of the stack. Condensed vapors will need to be neutralized. Installation of a stack liner is estimated at $2,000,000.

Since Wet FGD is a wet process, it will generate a wastewater stream. The actual wet process is expected to be contained within the Wet FGD system with a slip stream discharged for wastewater treatment.

Spray Dryer Flue Gas Desulfurization (Spray Dry FGD) - Spray Dry FGD consists of a spray dryer reactor to be located between the exhaust outlet of the boiler and upstream of a particulate removal device (usually an electrostatic precipitator or baghouse). The reactor consists of a spray dryer absorber tower and support equipment. Flue gas is introduced into a vessel and contacts an atomized spray pattern of lime slurry generated by either a set of dual fluid nozzles or a rotary atomizer. The reaction to remove SO_2 occurs on lime slurry droplets as they are evaporated from the heat of the flue gas to form a dry particle.

Because the exit temperature of the reactor must be maintained at a set temperature above the adiabatic saturation temperature of the flue gas (controlled by slurry feed rate) the product removed from the system is in dry form. The emission control efficiency of the reactor increases as the exit flue gas temperature approaches the adiabatic saturation temperature of the flue gas. The approach temperature is typically set at 30-40° F above adiabatic saturation temperature (corresponding to removal efficiencies of 90-80% respectively). Recycling fly ash into the lime slurry feed mixture may increase emission control efficiency depending on the chemical characteristics of the ash.

For the purposes of this evaluation a control efficiency of 80% will be assumed (a higher temperature 40° F was assumed to protect the baghouse)

A spray Dry FGD retrofit project will require modifications of the TASCO Nampa facility. The particulate loading to the baghouse will increase as a result of installing a spray dryer. In addition to the ash entering the reactor with flue gas, the spent lime contributes to overall particulate loading. Approximately 60% of the formed solids are predicted to drop out in the reactor while 40% will be carried to the baghouse for removal. The increase in particulate loading will likely require an additional baghouse.

Dry Lime Injection Flue Gas Desulfurization (Dry Lime FGD) - Dry Lime FGD consists of injecting pulverized lime (milled to less than 10 microns) into the flue gas upstream of the baghouse. The emission control efficiency of a Dry Lime FGD is critically dependent upon:

Particle Size - The smaller the particle size, the greater the surface area for reaction. Lime is milled to less than 10 microns using a ball mill. The smaller size of the particles is also important to avoid downstream depositing of dust in the equipment and ductwork.

Temperatures - Reaction rates increase with increased temperatures of the flue gas.

Flue Gas Mixing - Good lime particle mixing with the flue gas is important to provide uniform distribution of lime reactant in the baghouse.

The control efficiency for DLFGD is reported to vary between 45 to 55%. For the purposes of this evaluation, the control efficiency is assumed at 55%.

Dry Trona Injection Flue Gas Desulfurization (Dry Trona FGD) - Trona is a naturally occurring source of sodium carbonate that is available from mines in Wyoming. Similar to Dry Lime FGD, Dry Trona FGD consists of injecting pulverized Trona (milled to less than 10 microns) into the flue gas downstream of the existing baghouse and upstream of a new baghouse. The injection system requirements and technical characteristics are very similar to the Dry Lime FGD system discussed above.

The control efficiency for Dry Trona FGD is reported to range between 55 to 65%. For the purposes of this evaluation, the control efficiency is assumed at 65%.

This information is summarized in Table 4, below.

Table 4. Technically SO_2 Feasible Options

Pollutant	Technology	Feasibility	Reason Not Feasible
SO_2	Low Sulfur Coal	Yes	None
	Wet FGD	Yes	None
	Spray Dry FGD	Yes	None
	Dry Lime FGD	Yes	None
	Dry Trona FGD	Yes	None

STEP 3 - Evaluate technically feasible options

Based on the control efficiency rates listed above, TASCO determined the baseline maximum hourly emission rates, baseline average annual emission rate, anticipated control efficiency of emission controls, expected maximum hourly emission rate and expected annual emission rates. This data is summarized in Table 5, below.

Table 5. Technically Feasible SO_2 Options

Pollutant	Control Option	BART Baseline Maximum Emission Rate (lbs/hour)	BART Baseline Annual Average Emissions (tons/year)	Removal Efficiency	Expected Maximum Emission Rate (lbs/hour)	Expected Annual Emissions (tons/year)
SO_2	Low Sulfur Coal	522	1457	15%	444	1238
	Dry Lime FGD	522	1457	55%	235	655
	Dry Trona FGD	522	1457	65%	183	510
	Spray Dry FGD	522	1457	80%	104	291
	Wet FGD	522	1457	95%	26	73

STEP 4 - Impact analysis

TASCO did a cost evaluation for each of the control technologies reviewed. A complete cost evaluation can be found in Appendix D & E of "*Best Available Retrofit Technology (BART) Determination Analysis - 2009*. These findings were based on EPA fact sheets, engineering and performance test data, and information and discussions with equipment vendors. Table 6 summarizes those results.

Table 6 Impact Analysis for NO_x

Control Scenario	Baseline Emissions (tons/yr	Removal Efficiency (percent)	Annual Emissions Reductions (tons/yr	Total Reductions	Total Capital Costs ($ 1,000)	Total Annual Costs ($ 1,000)	Cost Effectiveness	Incremental Cost Effectiveness
Low Sulfur Coal	1,457	15%	219	219	0	$1,024	$4,685	
Dry Lime FGD	1457	55%	801	801	$1,281	$2,687	$3,355	$2,857
Dry Trona FGD	1457	65%	947	947	$1,281	$2,442	$2,579	$1,638
Spray Dry FGD	1,457	80%	1,166	1,166	$12,970	$2,521	$2,162	$360
Wet FGD	1,457	95%	1,384	1,384	$22,000	$4,034	$3,355	$6,820

After reviewing TASCO's evaluation, DEQ has concerns with the installation of Wet FGD. In reviewing TASCO's BART Determination Analysis for the Riley Boiler and specifically looking into wastewater treatment processes associated with Wet Flue Gas Desulfurization (Wet FGD), TASCO's submittal does not presents technical specifications or much detail regarding the wastewater treatment process. It's not immediately clear that the costs of the wastewater treatment process are included in the estimates presented in their submittal. However, there appear to be many vendors who provide wastewater treatment processes as part of a Wet FGS project, so it is assumed that the cost of wastewater management is contained within the cost estimates provided for the Wet FGD process itself.

There are several variables that make it very difficult to speculate about the volume of wastewater that might be produced or any constituent concentrations in wastewater from the process. The source and composition of (1) the coal fired in the boiler, and (2) the limestone used in the Wet FGS process will largely dictate the constituents and constituent concentrations in the wastewater, but there are likely to be significant concentrations of chlorides, fluorides, sulfate, arsenic, mercury, selenium, boron, cadmium, zinc, iron, aluminum, and inert fines that will require some sort of treatment prior to any discharge. Because the wastewater stream is saturated with calcium sulfate (i.e., gypsum), scaling is a major issue with operation and maintenance of process units and piping. The wastewater will also be hot, somewhat acidic, and will have high levels of total dissolved solids. There is also information available that indicates the presence of nitrates in the wastewater. Many of these constituents have primary or secondary quality standards in the *Groundwater Quality Rule*, and any proposal involving land application would almost certainly require impact assessments and/or permitting before DEQ would allow them to go forward.

It is entirely possible to design treatment units to manage and remove the majority of these constituents from the wastewater. The gypsum is a marketable product that would likely be precipitated out of solution and recovered as a commodity. The metals can also be precipitated, although many of these are regulated as hazardous wastes at relatively low concentrations (i.e., the hazardous waste program would probably want to be involved with management of these solids). There are also other processes that can be used to reduce residual levels of dissolved solids and nitrates in the final effluent, although it's important to note that more treatment generally means more cost and more oversight required. The potential volume and quality of the final, treated effluent is very difficult to speculate about without knowing more about the wastewater that will be produced by the Wet FGD process and the treatment processes that will be used to manage that wastewater.

With respect to TASCO's existing wastewater treatment system, the facility is presently treating most of its wastewater on site in an aerated lagoon and sending it to the municipal treatment plant operated by the City of Nampa during off-peak hours. To continue with this operation, a very high degree of wastewater treatment will be required, and substantial improvements to the existing treatment process will almost certainly be required. It would be expected that the city might have concerns about any potential increase in the volume of wastewater discharged to its system. This could mean that the City would need to expand its treatment system or that TASCO might look to land application to manage the new wastewater stream.

TASCO does still have a wastewater land application permit with DEQ, but the facility has only utilized land application for a very small fraction of its total wastewater load in recent years. The company land applied ~12MG in the 2005 season (6% of total WW generated), ~5MG in the 2006 season (3% of total WW generated), ~1MG in the 2007 season (1% of total WW generated), and no wastewater was land applied in the 2008 season. As a result of this reduction in land applied wastewaters, we have seen improving trends in its ground water monitoring wells. Historically, there were issues with nitrates, chlorides, and total dissolved solids concentrations in ground water around the site. While some exceedances of the associated ground water quality standards still exists, most monitoring wells have shown improving trends in ground water quality in recent years, and the DEQ Boise Regional Office is encouraging TASCO to continue to minimize wastewater land application at this time.

Although wastewater treatment processes are available to produce a high-quality effluent that could be successfully land applied under a permit from DEQ, these processes will be fairly complex and expensive, and will likely require dedicated staff to operate and maintain. **Additionally, the reduction in wastewater land application in recent years has improved historic issues with ground water quality that have generally been associated with TASCO's operation**, so any proposal to increase loading rates from a new source of wastewater would require a complete permit application that includes a ground water impact assessment showing no adverse impacts to existing ground water quality. We would issue a permit with enforceable limits and comprehensive

monitoring/reporting requirements to ensure protection of ground water quality, assuming that the application and impact assessments can be technically verified and approved

STEP 5 – Determine visibility impacts (improvements)

Since TASCO believed running the CALPUFF modeling for the various control technology scenarios would be costly, DEQ performed the CALPUFF modeling in-house and invited TASCO to have a contractor review the modeling if deemed necessary. Because each scenario can change the stack velocities and temperatures, it was important that DEQ work closely with TASCO. DEQ worked very closely with TASCO facility engineers to determine the modeling inputs for each of the scenarios.

Table 7, below, summarizes the modeling results for SO2 controls

Table 7. SO_2 Control Visibility Improvement

Eagle Cap Wilderness, OR	Change in Visibility Compared Against 20% Best Days Natural Background Conditions								
	Delta-Deciview Value larger than 0.5 from one year period						Delta-Deciview Value larger than 0.5 from 3 year period		Annual Cost ($x 1,000)
	2003		2004		2005		2003-2005		
	8th highest[a]	Total days[b]	8th highest	Total days	8th highest	Total days	22nd Highest[c]	Number of Days[d] (2003,2004,2005)	
Base Riley Boiler Plus Pulp Dryer Full Operation Scenario (wzi10469)	0.956	23	1.454	49	1.388	55	1.399	127	
Base Riley Boiler Scenario (wzi10471)	0.721	15	1.086	41	1.109	41	1.086	97	$0
SO2 Control Scenario 1 - Lower Sulfur Coal (wzi10475)	0.682	15	1.016	39	1.028	36	1.014	90	$1,024
SO2 Control Scenario 2 - Dry Lime Injection (wzi10476)	0.586	9	0.814	28	0.806	29	0.806	66	$2,687
SO2 Control Scenario 3 - Dry Trona Injection (wzi10477)	0.565	9	0.764	24	0.739	25	0.761	58	$2,422
SO2 Control Scenario 4 - Spray Dryer FGD (wzi10478)	0.527	9	0.703	22	0.707	20	0.686	51	$2,521
SO2 Control Scenario 5 - Wet FGD (wzi10479)	0.499	7	0.647	19	0.645	17	0.638	43	$4,053

Conclusion – As part of the impact analysis, non air quality environmental concerns are to be taken into consideration. Although Wet FGD has a 15% greater removal efficiency over the next closest control of Spray Dry FGD, the potential for reversing the current trend of improvements to ground water due to LASCO land applying outweigh the environmental benefits. LASCO is currently sending pretreated wastewater to the City of Nampa. There is a high likelihood that an increase in LASCO's waste stream would be greater than the city can currently handle. This would more than likely lead to LASCO requesting to increase land application of waste water. For these reasons DEQ will not be including Wet FGD in the control options even though the technology is technically feasible for improvements in air quality and visibility.

1.3.3 Nitrogen Oxides (NO_x) BART control technology selection

In determining the "best" BART control technology for NO_x controls on the Boiler, DEQ worked in conjunction with LASCO using the five steps as described in EPA Appendix Y.

STEP 1 – Identify all available retrofit emissions control techniques.

DEQ in consultation with LASCO identified the following control technologies appropriate for boilers.

- Low NO_x Burners (LNB)
- Low NO_x Burners with Over-fired Air (LNB/OFA)
- Ultra Low NO_x Burners (ULNB)
- Selective Catalytic Reduction (SCR)
- Selective Non-catalytic Reduction (SNCR)

STEP 2 – Determine technically feasible options.

In this step DEQ relied heavily on LASCO engineers to provide the technical feasibility because of plant specific requirements and their familiarity with plant operations. DEQ did review the information as provided below.

Low NO_x Burners – LNBs incorporate staged fuel or staged combustion air to control the flame temperature of the boiler. Several low NO_x burner systems are available with different levels of cost and performance capabilities. The estimates for NO_x removal range in removal efficiency from 30-60%.

According to LASCO, low NO_x burner retrofit projects are technically challenging and require significant engineering evaluations to properly size and adapt a supplied low NO_x burner system to a given boiler and burner configuration.

Low NO_x Burners with Over-Fired Air – These systems inject a portion of the combustion air downstream of the fuel burners system to lower flame temperatures and the formation of NO_x. Over fired air as a stand alone retrofit technology can be difficult to control causing combustion issues with pulverized coal boiler, including water wall

corrosion and reduced boiler efficiencies. When combined with a low NO_x burner and reasonable combustion air control, NO_x removal efficiencies can approach 65%.

Ultra Low NO_x Burners – These systems are upgraded LNB designs which involve further control and staging of combustion air and fuel. ULNB was determined not technically feasible on the Riley Boiler. The boiler's existing firebox is not large enough to accept the full burner/flame management system required by the ULNB.

Selective Catalytic Reduction – SCR systems reduce NO_x by injecting ammonia and urea into the flue gas before it passes through a catalytic grid to reduce the NO_x to N_2. This technology requires the flue gas exhaust from the Riley baghouse to be heated to 500° C before injecting ammonia or urea and passing the hot gases through the selective catalytic grid. After treatment, heat is recovered in a heat exchanger to minimize operating costs to reheat the flue gas. This technology is capable of reducing NO_x emissions by 70% to 90%. For the purposes of this evaluation a control efficiency of 90% is assumed.

Selective Non-Catalytic Reduction (SNCR) – SNCR consists of injecting ammonia or urea into boiler flue gases in a narrow temperature zone of 1550 to 1950° F. To achieve these temperatures, the injection point must be located between the Riley Boiler economizer and the air pre-heater. The process relies on good gas mixing in the narrow high temperature zone to reduce NO_x to N_2 as the flue gas moves through the ductwork. Boiler load swings can lead to temperature changes at the injection that can significantly reduce removal efficiencies. In addition, injection points can lead to "ammonia slip" or the condition where unreacted ammonia passes through downstream equipment, including the baghouse and discharges from the stack. The gas path for the Riley Boiler lacks the necessary residence time to reliably remove the NO_x. The results of upsets could lead to "ammonia slip." DEQ is concerned about the issues with ammonia emissions due to the Riley Boiler's close proximity to the City of Nampa.

This information is summarized in Table 8 below.

Table 8 Technically Feasible Options for NO_x

Pollutant	Technology	Feasibility	Reason Not Feasible
NO_x	Low NO_x Burners	Yes	None
	Low NO_x Over-Fired Air	Yes	None
	Ultra NO_x Low Burners	No	Boiler Firebox is not large enough to support the flame management system.
	Selective Catalytic Reduction	Yes	None
	Selective Non-Catalytic Reduction	No	Boiler gas path does not have adequate residence time for reliable control

STEP 3 – Evaluate technically feasible options

Based on the control efficiency rates listed above, TASCO determined the baseline maximum hourly emission rates, baseline average annual emission rate, anticipated control efficiency of emission controls, expected maximum hourly emission rate and expected annual emission rates. This data is summarized in Table 9, below.

Table 9. Impact Analysis for NO_x

Pollutant	Control Option	BART Baseline Maximum Emission Rate (lbs/hour)	BART Baseline Annual Average Emissions (tons/year)	Removal Efficiency	Expected Maximum Emission Rate (lbs/hour)	Expected Annual Emissions (tons/year)
NO_x	Low NO_x Burners	534	1042	50.0%	187	521
	LNB/OFA	534	1042	65.0%	111	364
	SCR	534	1042	90.0%	53	104

STEP 4 – Impact Analysis

TASCO did a cost evaluation for each of the control technologies reviewed. A complete cost evaluation can be found in Appendix D & E of "*Best Available Retrofit Technology (BART) Determination Analysis 2009*." These findings were based on EPA fact sheets, engineering and performance test data, and information and discussions with equipment vendors. Table 10, below, summarizes those results.

Table 10. Impact Analysis for NO_x

Control Scenario	Baseline Emissions (tons/yr)	Removal Efficiency (percent)	Annual Emissions Reductions (tons/yr)	Total Reductions	Total Capital Costs ($ 1,000)	Total Annual Costs ($ 1,000)	Cost Effectiveness	Incremental Cost Effectiveness
Low NO_x Burners	1,042	50%	521	521	$2,720	$187	$359	
Low NO_x Burners LNB/OFA	1,042	65%	677	677	$4,825	$866	$1,279	$2,411
SCR	1,042	90%	938	938	$16,202	$2,398	$2,558	$10,245

In addition to the control technologies reviewed above, TASCO has provided information relating to operational changes at the facility after the regional haze base years of 2000-2004. In 2008, TASCO installed a new pulp steam dryer system which better utilized current steam production and allowed several old pulp dryers to shut down. The pulp drying typically occurs during the fall and winter months when TASCO's emissions

show the greatest impact on the 20th worst day. The following Table 11 is a summary of the emission reductions attributed to the shutdown of the old pulp dryers.

Table 11 Pollution Reductions from Shutdown of Pulp Dryers

Pollutant	Maximum Hourly (lbs/hr)	Average Annual (tons/year)
Particulate	98.1	111
SO_2	17.8	20.6
NO_x	191	221

There are no incremental costs associated with the shutdown of the pulp dryers since they were installed in 2000. As part of the impact and visibility improvements TASCO requested that DEQ look at the visibility improvements associated with the pulp dryer shut down and determine that the reductions from the new steam dryers could be used as an alternative to BART.

STEP 5 Determine visibility impacts (improvements)

Since TASCO believed running the CALPUFF modeling for the various control technology scenarios would be costly, DEQ performed the CALPUFF modeling in house and invited TASCO to have a contractor review the modeling if deemed necessary. Because each scenario can change the stack velocities and temperatures it was important that DEQ work with TASCO. DEQ worked very closely with TASCO facility engineers to determine the modeling inputs for each of the scenarios. The modeling scenarios include the Riley Boiler with and without the shutdown of the pulp dryers to identify the visibility improvement attributed to the shutdown of the old dryers. The baseline used for the remaining control scenarios included the reductions from the pulp dryers to simulate current operating conditions. The following is a breakdown of the costs and changes to visibility at Eagle Cap Wilderness (Eagle wilderness area showing the greatest impact form the Riley Boiler) based on the NO_x controls identified as technically feasible. Similar changes occurred at the other Class I areas impacted by the Riley Boiler. (See Appendix) Table 12, below, also includes the incremental costs associated with the various NO_x control technologies. Since some of the pulp dryers were shut down to meet PM_{10} NAAQS requirements incremental costs were not included for this scenario. TASCO has found it financially advantageous to shut down additional pulp dryers for cost savings in coal usage.

Table 12. NO_x Visibility Improvements

Eagle Cap Wilderness, OR	Change in Visibility Compared Against 20% Best Days Natural Background Conditions								Change in Visibility	Incremental Cost
	Delta Deciview Value larger than 0.5 from one year period						Delta Deciview Value larger than 0.5 from 3 year period			
	2003		2004		2005		2003-2005		2003-2005	($/ton)
	8th highest[a]	Total days[b]	8th highest	Total days	8th highest	Total days	22nd Highest	Number of Days[c] (2003-2005)		
Base Riley Boiler Plus Pulp Dryer Full Operation Scenario (wzl10469)	0.956	23	1.454	49	1.488	55	1.099	127	0.000	
Base Riley Boiler Scenario (wzl10471)	0.721	15	1.086	41	1.129	43	1.088	97	0.313	$0
NO_x Control Scenario 1 - LNB (wzl10472)	0.511	11	0.822	29	0.871	29	0.816	69	0.270	$0
NO_x Control Scenario 2 LNB w/ OFA (wzl10473)	0.454	7	0.743	24	0.805	23	0.756	56	0.350	$2,431
NO_x Control Scenario 3 - SCR (wzl10474)	0.387	6	0.625	18	0.651	18	0.611	40	0.473	$10,245

Looking at changes in visibility improvements the shutdown of the pulp dryers provided more visibility improvement than LMB and is nearing the improvement of LMB with Over-Fire-Air. The largest improvement in visibility attributed to NO_x controls would come for Selective Catalytic Reduction (SCR). However, the incremental cost of $10,000 per ton for the additional 15% removal efficiency is relatively high. An option for LASCO would be taking permanent permit limits to account for the shutdown of all the pulp dryers and installing LNB with Over-Fire-Air.

1.4 Conclusion - BART Control Determination

In conclusion, TASCO has two options for NO_x controls. It can install SCR on the Riley Boiler or install LNB with Over-Fire-Air and take permit limits for shutting down all the pulp dryers. Although Wet FGD has the promise of providing greater emission reductions than Spray Dry FGD, the benefits of Wet FGD are outweighed by the possibility of requiring land application of wastewater. After reviewing the particulate controls, the current baghouse has the same reductions as other options at no additional expense. DEQ is, therefore, recommending a combination of the baghouse, Low NOx Burners with Over-Fire-Air (plus permit limits reflecting shut down of all pulp dryers), and Spray Dry FGD as the "best" of BART technologies. Below is a summary table showing the visibility improvements based upon the "best" of BART control technologies identified in this determination. It should be noted the Base Riley Boiler scenario includes the current baghouse and pulp dryer shutdown.

Table 13 Visibility Improvement - Best BART Alternatives

Eagle Cap Wilderness, Or	Change in Visibility Compared Against 20% Best Days Natural Background Conditions							
	Delta-deciview value larger than 0.5 from one year period						Delta-deciview value larger than 0.5 from 3 year period	
	2003		2004		2005		2003-2005	
	8th highest	Total days	8th highest	Total days	8th highest	Total days	22nd Highest	Number of Days (2003,2004,2005)
Base Riley Boiler Scenario (wzi16471)	0.77	17	1.086	41	1.109	41	1.080	97
Base Riley Boiler Plus Pulp Dryer Full Operation Scenario (wzi16469)	0.956	21	1.454	49	1.188	61	1.399	127
NO_x Scenario 2 + SO2 Scenario 4 (wzi16484)	0.228	1	0.319	1	0.330	1	0.319	3

Appendix C – Subject-to-BART Analyses

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1. Introduction

Under the *Regional Haze Rule* of the *Clean Air Act*, each state must set "reasonable progress goals" toward improving visibility in *Class I* areas—areas of historically clear air, such as national parks—and develop a plan to meet these goals. In December 2007, Idaho must submit a state implementation plan (SIP) to the U.S. Environmental Protection Agency (EPA), addressing how it will improve and protect visibility in its Class I areas and those Class I areas outside its borders.

1.1 BART Requirements

One strategy for addressing emissions from large, industrial sources is to implement *Best Available Retrofit Technology* (BART). A BART determination is required for any source that meets the following conditions:

- The source is *BART-eligible*, meaning that it falls into one of 26 sector categories, was built between 1962 and 1977, and annually emits more than 250 tons of a haze-causing pollutant. Common BART eligible sources may include coal-fired boilers, pulp mills, refineries, phosphate rock processing plants, and smelters. Six BART-eligible sources have been identified in Idaho.
- The source is *subject to BART* if it is reasonably anticipated to cause or contribute to impairment of visibility in a Class I area. According to the Guidelines for Best Available Retrofit Technology (BART) Determinations contained in 40 CFR Part 51, Appendix Y, a source is considered to contribute to visibility impairment if the modeled 98th percentile change in *deciviews* (delta-deciview)—a measure of visibility impairment[1]—is equal to or greater than a contribution threshold of 0.5 deciviews. This determination is made by modeling.

1.2 Determining the Subject-to-BART Status of Idaho Sources

DEQ used the CALPUFF air dispersion modeling system (version 6.112) to determine if the 0.5 deciview threshold is exceeded by any of the BART-eligible sources in Idaho. The modeling of BART-eligible sources was performed in accordance with the *BART Modeling Protocol*[2], which was jointly developed by the states of Idaho, Washington, and Oregon, and which has undergone public review and revision.

Refer to the *BART Modeling Protocol* for details on the modeling methodology used in this subject-to-BART analysis.

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[1] A deciview is a haze index derived from calculated light extinction, such that uniform changes in haziness correspond to uniform incremental changes in perception across the entire range of conditions—from pristine to highly impaired. A deciview is the minimum perceptible change to the human eye.

[2] *Modeling Protocol for Washington, Oregon and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation.* http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_BART_modeling_protocol.pdf

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2. BART Eligible Source: TASCO Riley Boiler, Nampa

The **Riley Boiler** of The Amalgamated Sugar Company, LLC (TASCO) Sugar Plant in Nampa, Idaho has been determined to be BART-eligible. Rated at 350 million BTUs per hour, the **Riley Boiler** is classified as a fossil-fuel boiler of more than 250 million BTUs per hour heat input, was installed in 1969, and was put into service between August 7, 1962 and August 7, 1977.

The **Riley Boiler's** *Potential to Emit* (PTE) exceeds 250 tons per year (tn/yr) for the haze-causing pollutants sulfur dioxide (SO_2, 2,770 tn/yr), nitrogen oxide (NO_x, 1,708 tn/yr), and particulate matter (PM, 55 tn/yr), so this emission unit is eligible for inclusion in the subject-to-BART analysis of visibility impairment in Class I areas.

2.1 Emission Rates

Maximum 24-hour emission rates for the three-year meteorological period (2003 – 2005) over which CALPUFF modeling for this emission unit was performed are shown in Table 1. Particulate matter (PM_{10}) in this table includes all particles with aerodynamic diameters less than 10 micrometers.

Table 1. Emissions rates used for subject-to-BART analysis.

Facility/Unit	Maximum 24-hour emission rate (lb/hr)		
TASCO-Nampa	SO_2	NO_x	PM_{10}*
Riley Boiler, Unit 30	632.5	390	12.61
* See note in the Table 2			

2.2 Speciation of Emissions

To simulate the visibility-impairing characteristics of particulate matter properly, particulate matter was further speciated into categories of particulate composition: *coarse particular matter* (PMC), particulate matter consisting of particles between 2.5 and 10 micrometers in diameter, and *fine particulate matter* ($PM_{2.5}$), particulate matter consisting of particles with diameters less than 2.5 micrometers. $PM_{2.5}$ is speciated further to ammonium sulfate ($(NH4)_2SO_4$),ammonium nitrate (NH_4NO_3), elemental carbon (EC), and secondary organic aerosol (SOA), and all other fine particulate matter less than 2.5 um in diameter (PMF) (see Table 2).

Particulate speciation for the coal-fired **Riley Boiler** was calculated using the Microsoft Excel workbook prepared by the National Park Service for dry bottom pulverized coal-fired boilers with fabric filtration:

http://www2.nature.nps.gov/air/Permits/ect/ectCoalFiredBoiler.cfm

PM size fractions used are as follows: Fine: mean diameter = 0.5 μm, standard deviation = 1.5 μm. Coarse: mean diameter = 5μm, standard deviation = 1.5μm.

Detailed speciated emissions, stack parameters, and location used in the analysis are presented in Table 2.

Table 2. Emission unit information, stack parameters, and speciation of emissions.

Facility Information	Facility_ID	ID-1
	Facility_Name	Amalgamated Sugar – Nampa
Emission Unit Information	Unit_ID	30
	Unit_Description	Riley Boiler
Control Information	Control_ID	41
	Control_Description	Existing Control - Ver. 3
Datum, Projection, Source Location and Base Elevation	Datum	NAD27
	Projection	UTM
	UTM_Zone	11
	Longitude_Easting (km)	534.391
	Latitude_Northing (km)	4828.031
	Base_Elevation (m)	753
Stack Parameter	Stack_Height (m)	65
	Stack_Diameter (m)	2.1
	Stack_Exit_Temperature (K)	427
	Stack_Exit_Velocity (m/s)	16
Emission Rate (lb/hr)	SO_2 (sulfur dioxide)	632.5
	SO_4 (sulfate)	6.415[a]
	NO_X (nitrogen oxides)	390
	HNO_3 (nitric acid)	0
	NO_3 (nitrate)	0[a]
	PMC (coarse particulate matter)	0.79
	PMF (fine particulate matter)	0.76[b]
	EC (elemental carbon)	0.03
	SOA (secondary organic aerosol)	2.21

a. All of sulfate particulates are assumed to be ammonium sulfate,
(NH4)2SO4 = 1.375*SO4 (Mass)
All of nitrate particulates are assumed to be ammonium nitrate
(NH4)NO3 = 1.29*NO3 (Mass)
b. The fine particulates other than SO4, NO3, EC and SOA.

3. CALPUFF Model Setup

Modeling of the BART-eligible emission unit was performed in accordance with the *BART Modeling Protocol* and implemented using a DEQ-developed interface to the CALPUFF Modeling system. The domain (the spatial extent) of the modeling analysis for the facility is shown in Figure 1.

- The blue circle represents a region of 300 kilometers (km) radius, centered at the source. In accordance with EPA guidance and the *BART Modeling Protocol*, all Class I areas within this circle were included in the analysis.
- The pink rectangle shows the resultant computational modeling domain used for the analysis. The shape of the domain is determined by the selected Class I areas plus an additional 50 km of buffer zone extending out from the furthermost extent of the Class I areas.

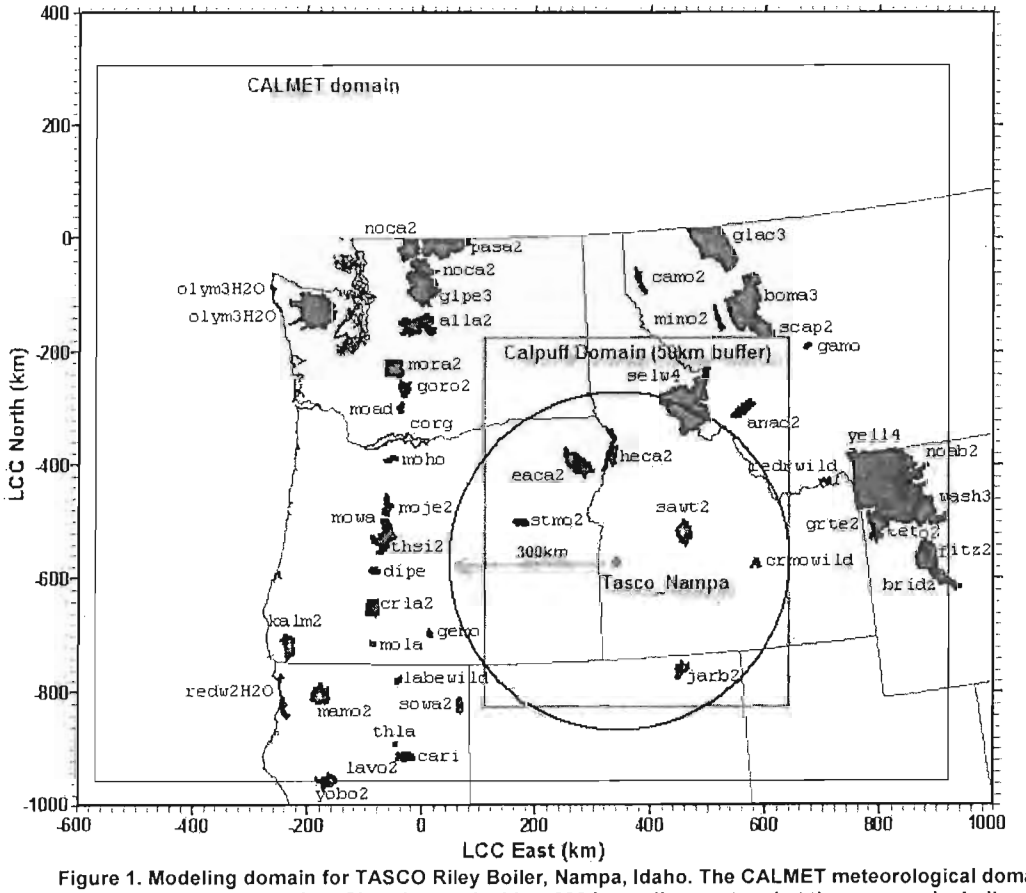

Figure 1. Modeling domain for TASCO Riley Boiler, Nampa, Idaho. The CALMET meteorological domain covers the northwest region. Class I areas inside a 300 km radius centered at the source—including those areas only partially within the circle—are included in the CALPUFF subject-to-BART modeling domain. An additional buffer distance of 50 km, extending from the outer extent of Class 1 areas near the domain boundary, was added for modeling purposes.

The meteorological inputs needed by CALPUFF for the analysis were prepared by Geomatrix, Inc. under the direction of representatives from the states of Washington, Idaho, and Oregon and using *Fifth Generation Mesoscale Meteorological Model* (MM5) data generated by the University of Washington. The result was a CALMET output file for the years 2003-2005 that covers the entire Pacific Northwest at a 4 km resolution, as shown in Figure 1.

Details of the model setup, emission data, and information about the modeled Class I areas are provided in Appendix 1.

4. Results

Subject-to-BART analysis results for the TASCO **Riley Boiler**, Nampa are shown in Table 3, which highlights the following two threshold values for BART:

- 8th highest value for each of the years modeled (2003-2005), representing the 98th percentile (8/365 = 0.02) cutoff for delta-deciview in the each year.
- 22nd highest value for the entire period from 2003 through 2005, representing the 98th percentile (22/1095 = 0.02) cutoff for delta-deciview over three years.

For both threshold values, the determining criterion is a delta-deciview of at least 0.5 deciview.

Table 3. Change in Visibility Compared Against 20% Best Days Natural Background Conditions for Class I areas within 300 km from the TASCO Riley Boiler, Nampa.

Class I Area	Change in Visibility Compared Against 20% Best Days Natural Background Conditions							
	Delta-Deciview Value larger than 0.5 from one year period						Delta-Deciview Value larger than 0.5 from 3 year period	
	2003		2004		2005		2003-2005	
	8th highest[a]	Total days[b]	8th highest	Total days	8th highest	Total days	22nd Highest[c]	Number of Days[d] (2003,2004,2005)
Craters of the Moon	0.161	2	0.224	2	0.153	0	0.196	2
Eagle Cap Wilderness, OR	0.87	20	1.355	46	1.302	46	1.325	112
Hells Canyon National Recreation Area, ID	0.772	13	1.031	27	0.9	21	0.936	61
Jarbidge Wilderness, NV	0.151	0	0.198	1	0.201	1	0.179	2
Sawtooth Wilderness, ID	0.239	2	0.294	4	0.265	0	0.271	6
Selway-Bitterroot Wilderness, ID and MT	0.186	0	0.305	1	0.264	2	0.243	3
Strawberry Mountain Wilderness, OR	0.782	12	0.639	13	1.596	31	0.943	56

a. The 8th highest delta-deciview for the calendar year.
b. Total number of days in 1 year that exceeded 0.5 delta-deciviews.
c. The 22nd highest delta-deciview value for the 3-year period.
d. Total number of days in the 3-year period that exceed 0.5 delta-deciviews.

4.1 Class I Areas Affected

Based on the analysis, the TASCO **Riley Boiler** impacted the following Class I areas with the 98th percentile highest delta-deciview greater than 0.5 during the modeling period 2003-2005:

- Eagle Cap Wilderness, Oregon
- Hells Canyon National Recreation Area, Idaho
- Strawberry Mountain Wilderness, Oregon

The 98th percentile highest values for the all Class I areas are plotted in Figure 2.

4.2 Area of Greatest Impact

The **Riley Boiler** had the greatest impact on the Strawberry Mountain Wilderness in December 2005 (1.596, the 8th highest in 2005) and the highest 22nd (1.325) on the Eagle Cap Wilderness in January, 2004. Details of the 22 highest calculated changes, ranked in order of delta-deciview (change from 20% best days natural background), for Eagle Cap for the three-year modeling period are listed in Table 4. Table 4 also shows the relative contributions to visibility degradation for each of the emission species for the BART-eligible emission unit. Sulfate and nitrate are the main contributors.

Total of 112 days with delta-deciview higher than or equal to 0.5 were predicted for Eagle Cap Wilderness, the highest in the all Class I areas, followed by 61 days in the Hells Canyon Wilderness, and 56 days in the Strawberry Mountain Wilderness, during the modeling period.

The number of impacted days in 3 years for the concerned Class I areas are plotted in Figure 4.

Table 4. The 22 highest Delta-deciview values and related modeling output data at Eagle Cap Wilderness area.

Rank	YEAR	DAY	RECEPTOR	DV(Total)	DV(BKG)	DELTA_DV	F(RH)	%_SO4	%_NO3	%_OC	%_EC	%_PMC	%_PMF
1	2003	21	753	5.052	2.466	2.586	3.77	57.66	42.18	0.14	0	0	0.01
2	2004	22	716	4.691	2.466	2.225	3.77	63.09	36.75	0.13	0	0	0.01
3	2004	335	735	4.534	2.396	2.137	3.44	44.75	54.96	0.25	0.01	0.01	0.02
4	2004	338	753	4.578	2.508	2.07	3.97	57.23	42.6	0.15	0	0	0.01
5	2005	55	716	4.318	2.337	1.982	3.16	53.95	45.83	0.19	0.01	0.01	0.02
6	2005	16	716	4.324	2.466	1.857	3.77	49.9	49.9	0.17	0.01	0	0.01
7	2004	16	753	4.314	2.466	1.848	3.77	62.51	37.34	0.13	0	0	0.01
8	2003	38	716	3.998	2.337	1.661	3.16	44.11	55.6	0.24	0.01	0.01	0.02
9	2005	33	716	3.923	2.337	1.586	3.16	56.18	43.6	0.2	0.01	0.01	0.02
10	2003	345	861	4.068	2.508	1.56	3.97	40.64	59.1	0.22	0.01	0	0.02
11	2003	318	716	3.913	2.396	1.516	3.44	44.63	55.13	0.2	0.01	0.01	0.02
12	2005	322	550	3.911	2.396	1.514	3.44	53.14	46.67	0.16	0.01	0	0.01
13	2003	18	716	3.963	2.466	1.497	3.77	57.1	42.74	0.14	0	0	0.01
14	2004	18	716	3.947	2.466	1.48	3.77	55.17	44.64	0.16	0.01	0	0.01
15	2004	13	550	3.936	2.466	1.469	3.77	52.01	47.77	0.2	0.01	0.01	0.02
16	2004	322	753	3.798	2.396	1.402	3.44	54.34	45.45	0.18	0.01	0.01	0.02
17	2005	15	716	3.861	2.466	1.395	3.77	50.72	49.1	0.15	0.01	0	0.01
18	2005	56	273	3.703	2.337	1.366	3.16	50.44	49.32	0.21	0.01	0.01	0.02
19	2003	11	550	3.826	2.466	1.36	3.77	53.84	45.96	0.17	0.01	0.01	0.01
20	2004	19	753	3.821	2.466	1.355	3.77	53.75	46.04	0.18	0.01	0	0.02
21	2005	27	716	3.805	2.466	1.339	3.77	60.71	39.17	0.1	0	0	0.01
22	2004	14	550	3.791	2.466	1.325	3.77	55.94	43.86	0.17	0.01	0.01	0.01

Day: Ordinal day of year
RECEPTOR ID: Identifier for modeled air receptor
DV(total): total deltadeciview including background and change due to the modeled emission source.
DV(BKG): Background deltadeciview.
DELTA_DV: Change in the 20% best days natural background (in deciviews) due to the modeled pollutants
F(RH): relative humidity factor, varies month by month
%_SO4: contr bution to the impact to the visibility from sulfate
%_NO3: contribution to the impact to the vis bility from nitrate
%OC: contribution to the impact to the visibility from organic carbon
%_EC: contribution to the impact to the visibility from elemental carbon
%_PMC: contribution to the impact to the visibility from coarse particulates (2.5-10µm)
%_PMF: contribution to the impact to the visibility from fine particulates (2.5µm or smaller) other than SO4, NO3, EC and OC.

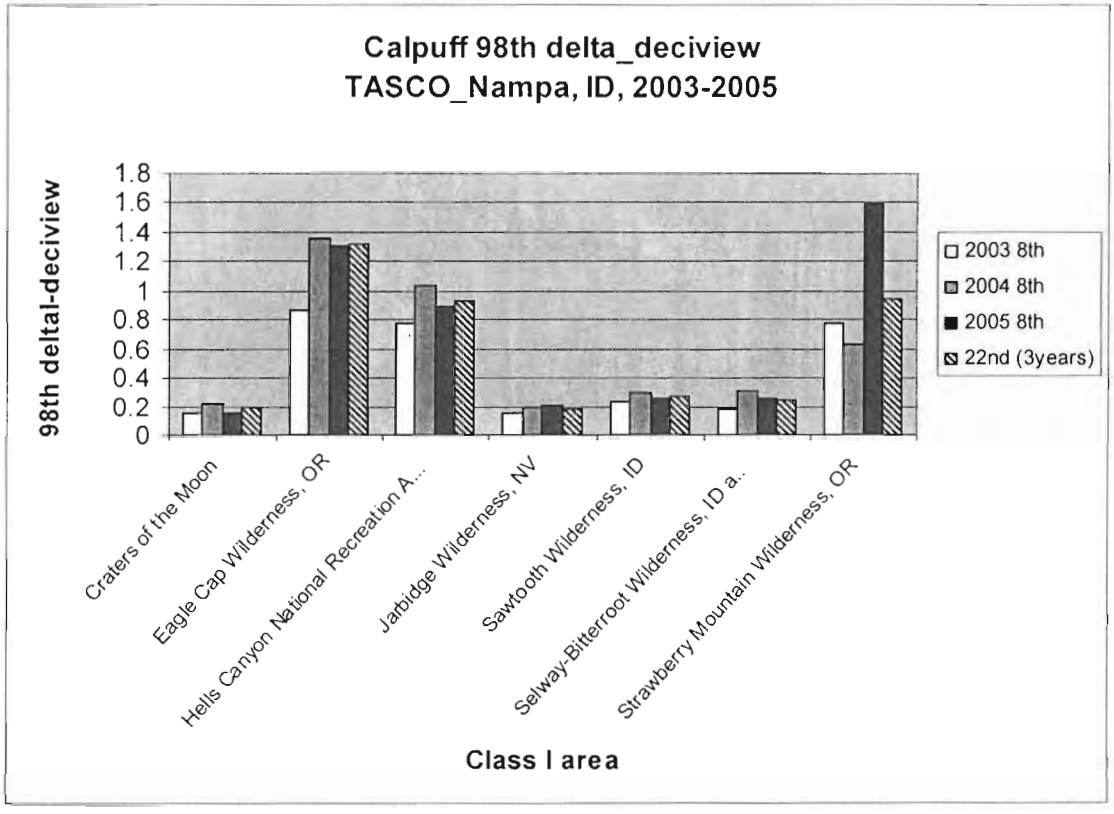

Figure 2. 98th percentile values of delta-deciview in Class I areas for TASCO Riley Boiler, Nampa, Idaho.

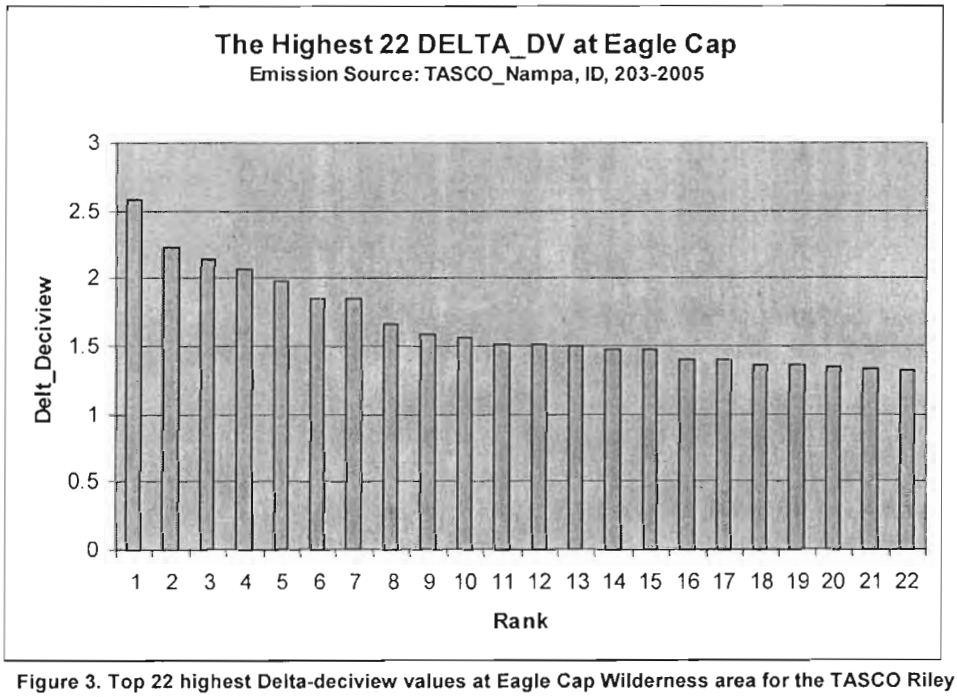

Figure 3. Top 22 highest Delta-deciview values at Eagle Cap Wilderness area for the TASCO Riley Boiler, Nampa, Idaho.

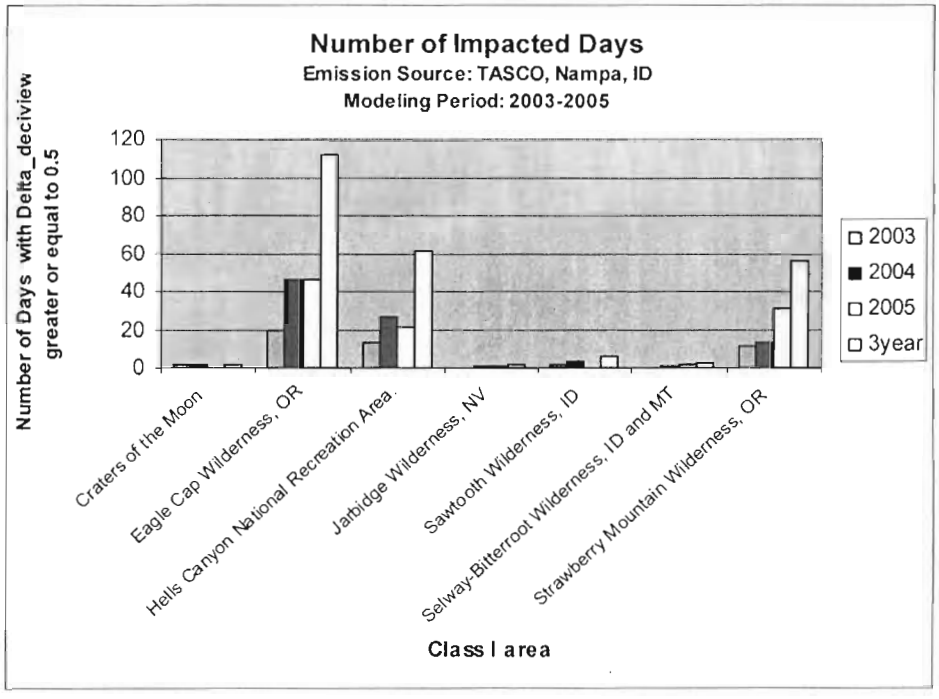

Figure 4. Number of days when the delta-deciview is greater than or equal to 0.50 in the Class I areas during the modeling period, 2003 to 2005.

4.3 Dominating Pollutants for Visibility Impact

Figure 5 shows the percentage contribution of the pollutants for the average of the highest 22 days in Eagle Cap in the modeling period from 2003 to 2005. Sulfate and nitrate are the dominating pollutants responsible for the visibility deterioration.

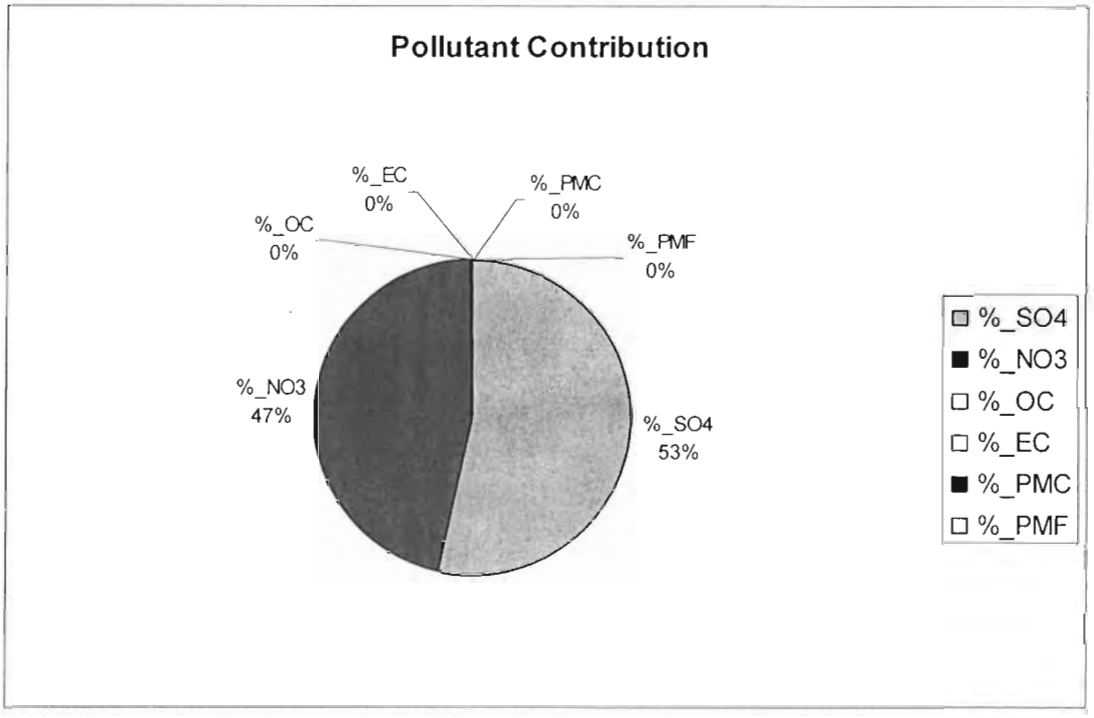

Figure 5. The pollutant contribution from the TASCO Riley Boiler, Nampa, Idaho, to visibility change at Eagle Cap Wilderness area, Oregon. The total contribution from Sulfate and Nitrate is almost 100%.

4.4 Seasonal Variation of Visibility Degradation

Figure 6 shows that the most significant impact to visibility for the Eagle Cap Wilderness occurs between November and February.

The higher impact appears to have been the result of winter meteorological conditions favorable for hygroscopic aerosol formation, as discussed in the following section. The effect is minimal in the dry, hot summertime.

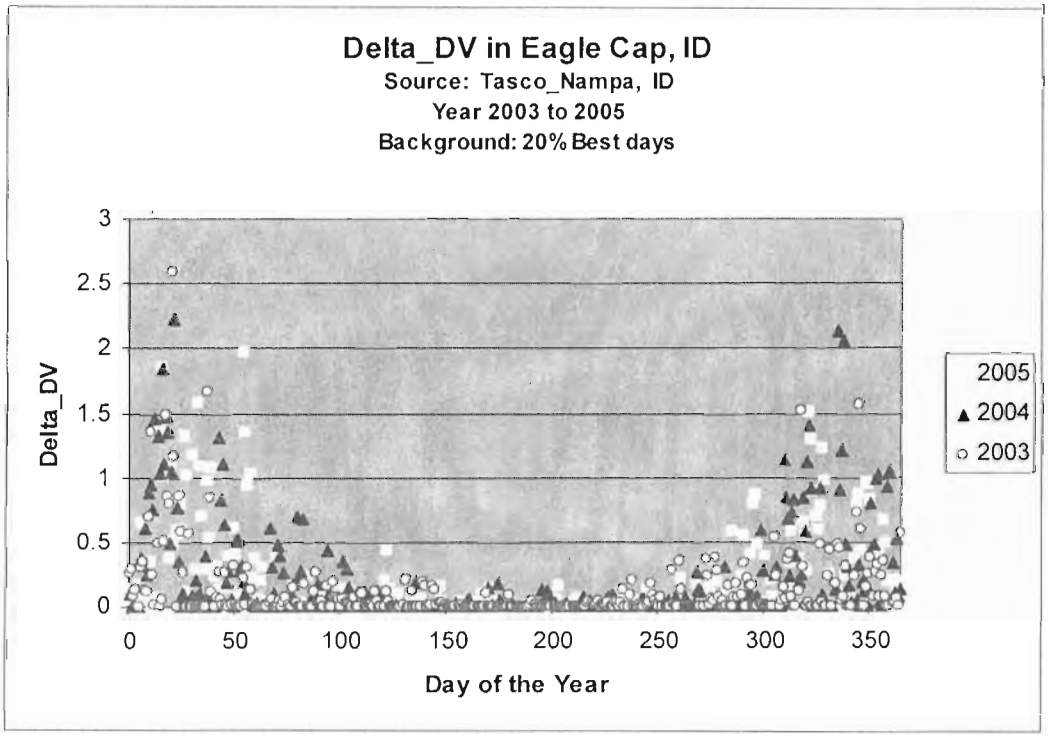

Figure 6. Seasonal impact from the TASCO Riley Boiler, Nampa, Idaho to Eagle Cap Wilderness area, Oregon, which is located about 120 km north-west from the source.

5. Meteorological and Geological Conditions

The impact to visibility in Class I areas is strongly dependent on meteorological and geological conditions. Figure 7 shows the strong stagnation conditions that occurred during the episode of January 2004. During such an episode, pollutants pool up in the valleys and slowly transport to the Class I areas with little dispersion.

Terrain (geological condition) also strongly influences impact of emission sources in Idaho's Treasure Valley area on the Class I areas. Figure 8 shows a contour map of number of impact days equal to or higher than 0.5 delta-deciview. The channeling effect of the terrain is clearly shown, indicating that Treasure Valley sources are likely to affect Class I areas to the northwest under winter conditions.

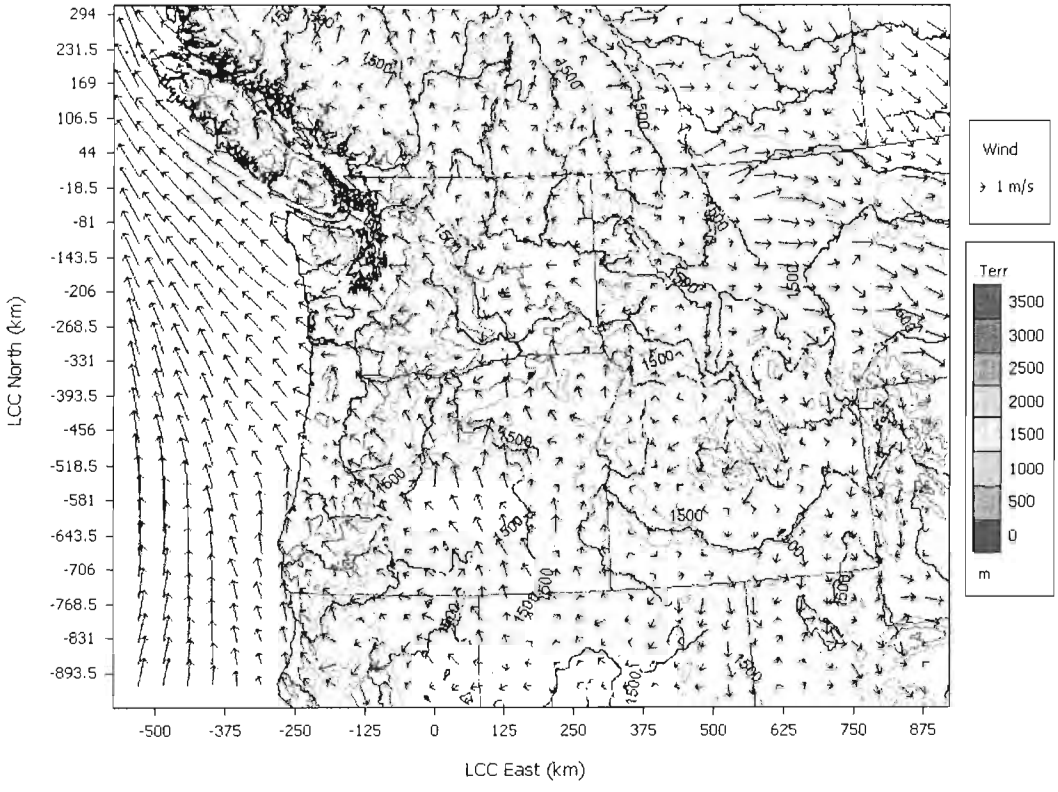

Figure 7. Wind field in the modeling domain. In January 2004, a strong stagnation system persisted in the Snake River Valley, Idaho, where the TASCO Riley Boiler is located, for more than 2 weeks. Pollutants were elevated near their sources, then were slowly dispersed and transported to the Class I areas.

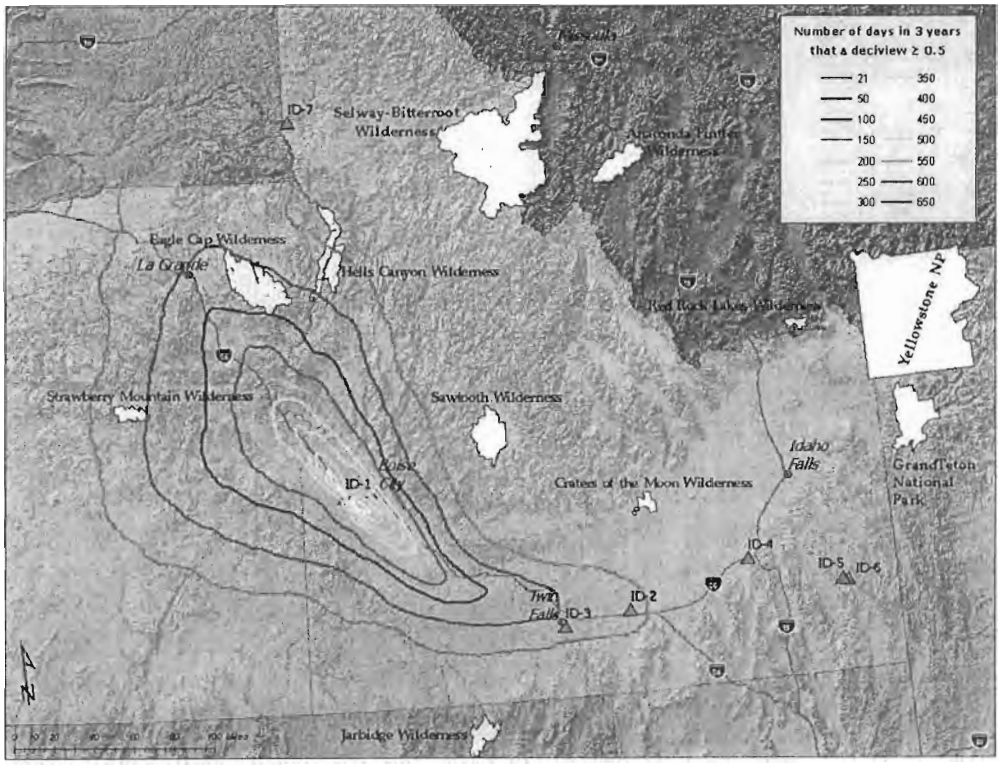

Figure 8. Wind field in the modeling domain. In January 2004, a strong stagnation system persisted in the Snake River Valley, Idaho, where the TASCO Riley Boiler is located, for more than 2 weeks. Pollutants were elevated near their sources, then were slowly dispersed and transported to the Class I areas

6. Sensitivity Analysis

DEQ performed a sensitivity analysis on the CALPUFF modeling analysis for the Riley Boiler at TASCO, Nampa. The purpose of the sensitivity analysis was to represent the least conservative parameters to show that further refinements (e.g. hourly ozone) are not likely to alter the conclusion, resulting from the *BART Modeling Protocol* analysis, that the Riley Boiler at TASCO's Nampa facility subject-to-BART. **It should be noted that this sensitivity analysis does not imply approval of these "bounding" parameters by DEQ, the EPA and Federal Land Managers.**

The parameters included in the sensitivity analysis include puff splitting, building downwash, low ozone background (10 ppb, the low end of observed vales), and the use of annual average for natural background.

The results of the sensitivity analysis are summarized in Figure 9 and Figure 10, and Table 5. The predicted impact levels based on this less conservative sensitivity analysis in the all Class I areas are lower; however, the predicted visibility deterioration in Eagle Cap Wilderness Area, Strawberry Mountain Wilderness Area, and Hells Canyon National Recreation Area is still significantly higher than the 0.5 dv threshold.

Details of the model setup used for the sensitivity analysis are provided in Appendix 2.

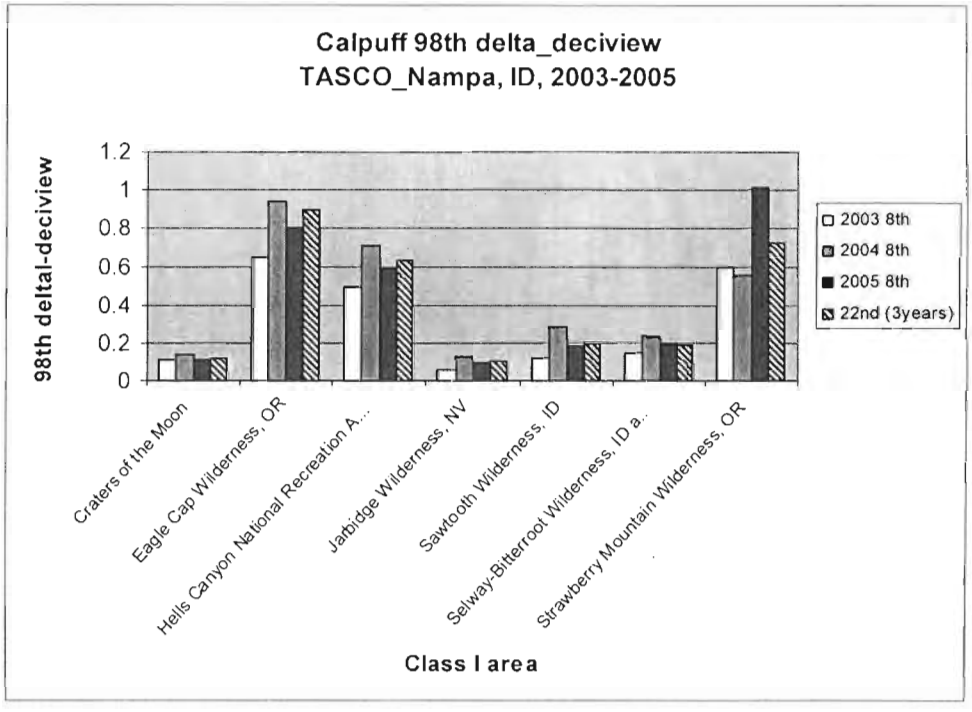

Figure 9. Analysis: 98th percentile values of delta-deciview in the Class I areas

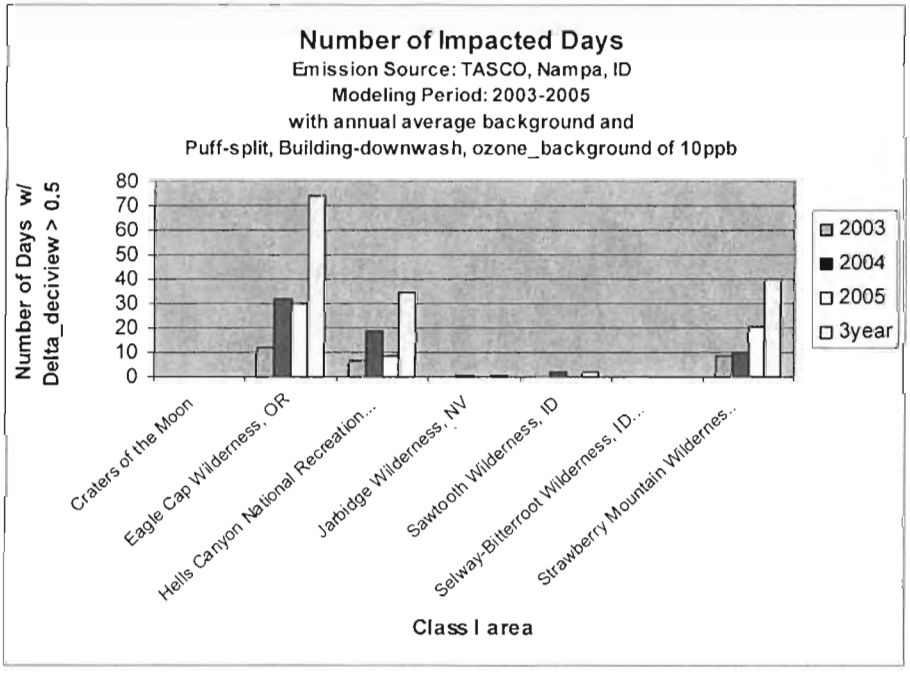

Figure 10. Sensitivity Analysis: Number of days in the Class I areas where the delta-deciview was greater than or equal to 0.5dv

Table 5. Sensitivity Analysis: Change in visibility for Class I areas within 300 km from the TASCO Riley Boiler, Nampa.

	Change in Visibility Compared Against natural background Conditions							
	Delta-Deciview Value larger than 0.5 from one year period						Delta-Deciview Value larger than 0.5 from 3 year period	
	2003		2004		2005			
Class I Area	8th highest[a]	Total days[b]	8th highest	Total days	8th highest	Total days	22nd Highest[c]	Number of Days[d] (2003,2004,2005)
Craters of the Moon	0.111	0	0.142	0	0.115	0	0.117	0
Eagle Cap Wilderness, OR	0.646	12	0.944	32	0.806	30	0.895	74
Hells Canyon National Recreation Area, ID	0.494	7	0.708	19	0.591	9	0.632	35
Jarbidge Wilderness, NV	0.064	0	0.128	1	0.097	0	0.101	1
Sawtooth Wilderness, ID	0.124	0	0.283	2	0.179	0	0.201	2
Selway-Bitterroot Wilderness, ID and MT	0.149	0	0.236	0	0.194	0	0.187	0
Strawberry Mountain Wilderness, OR	0.593	9	0.553	10	1.006	21	0.729	40

a. The 8th highest delta-deciview for the calendar year.
b. Total number of days in 1 year that exceeded 0.5 delta-deciviews.
c. The 22nd highest delta-deciview value for the 3-year period.
d. Total number of days in the 3-year period that exceed 0.5 delta-deciviews.

7. Summary and Conclusions

The CALPUFF model predicted that emissions from the **Riley Boiler** at the TASCO Sugar Plant, Nampa, Idaho, impacted visibility with the 98th percentile highest delta-deciview of more than 0.5 deciview on the Class I areas of Eagle Cap Wilderness, OR, Strawberry Mountain Wilderness, OR, and Hells Canyon Wilderness, ID, during the period of year 2003 to 2005.

Eagle Cap Wilderness area had the highest number of days (112 days in 3 years) with delta-deciview value greater than 0.5. The highest 1-year 8th high delta-deciview (1.596, year 2005) was found in Strawberry Mountain Wilderness.

The major contributors to visibility deterioration from the **Riley Boiler** of the TASCO, Nampa facility are SO_2 and NO_2, precursors of sulfate and nitrate aerosols formed in winter under conditions of low temperature and high relative humidity. The impact is greatest when a high-pressure system persists in the area for 3 to 4 days or more, the atmosphere is stagnant with poor dispersion, and the pollutants transported remain relatively undiluted.

The subject-to-BART analysis, which followed the *BART Modeling Protocol,* and additional extensive sensitivity analysis have demonstrated that the **Riley Boiler** of the TASCO, Nampa facility is subject to BART.

Appendix 1: CALPUFF Modeling Setup for TASCO Riley Boiler, Nampa, Idaho

Scenario Summary

Scenario Information

Scenario Name:	wzl10444
Title:	ID-1 4km Existing Control version 3; 2004 through 2005 corrected
Scenario Description:	ID-1; 4km; partical size distribution(0.5/1.5 for fine, 5/1.5 for coarse); model source elevation; Existing Control version 3 (Control_ID = 41); 2004 through 2005 corrected

Species Group Information

Species Group ID:	1
Number of Species:	9
Species Names:	SO2, SO4, NOX, HNO3, NO3, PMC, PMF, EC, SOA

Calpuff Working Directory

Working Directory:	Y:\airmodel\calpuff\runs\bart\wzl10444

Domain Projection and Datum

Projection:	Lambert Conic Conformal	
Origin of Projection:	Latitude: 49	Longitude: -121
Matching Latitudes:	Latitude 1: 30	Latitude 2: 60
Offset(km):	XEasting: 0	YNorthing: 0
Datum:	NWS	

Calmet Domain

Domain Name and Short Name:	bart_4km	bar_4km
Grid Origin(km):	X: -572	Y: -956
Grid Spacing(km):	4	
NX and NY:	NX: 373	NY: 316

Sources

Number of Sources:	1
Source_Elevation_Option:	Model

Source 1

Source Category

Category:	Point

Facility Information

Facility ID:	ID-1
Facility Name:	Amalgamated Sugar - Nampa

Unit Information

Unit ID:	30
Unit Description:	Riley Boiler

Control Strategy Applied

Control ID:	41
Control Description:	Existing Control - Ver. 3

Source Location and Base Elevation

Datum:	NAD27
Projection:	UTM
UTM Zone:	11
Easting (km):	534.391
Northing (km):	4828.031
Base Elevation (m):	753

Source Location under Domain Projection and Datum

XEasting (km):	344.051
YNorthing (km):	-569.801

Model Source Base Elevation In Calmet Domain

bar_4km (m):	759.705
bar_12km (m):	764.555

Stack Parameters

Height (m):	65
Diameter (m):	2.1
Exit Temperature (K):	427
Exit Velocity (m/s):	16

Emission Rate (Unit: lb/hr)

SO2 (lb/hr):	632.50000
SO4 (lb/hr):	6.41455
NOX (lb/hr):	390.00000
HNO3 (lb/hr):	0.00000
NO3 (lb/hr):	0.00000
PMC (lb/hr):	0.79000
PMF (lb/hr):	0.76000
EC (lb/hr):	0.03000
SOA (lb/hr):	2.21000

Emission Rate (Unit: g/s)

SO2 (g/s):	79.69366
SO4 (g/s):	0.80822
NOX (g/s):	49.13917
HNO3 (g/s):	0.00000
NO3 (g/s):	0.00000
PMC (g/s):	0.09954
PMF (g/s):	0.09576
EC (g/s):	0.00378
SOA (g/s):	0.27846

Class I Areas

Searching Radius (km):	300km
Number of Class I Areas:	7

ID:	crmowild
Name:	Craters of the Moon NM - Wilderness
State:	ID
# Total Receptors:	271
# Receptors In Calmet Domain:	271

Position In Receptor List:	1 - 271
ID:	eaca2
Name:	Eagle Cap Wilderness
State:	OR
# Total Receptors:	596
# Receptors In Calmet Domain:	596
Position In Receptor List:	272 - 867
ID:	heca2
Name:	Hells Canyon Wilderness
State:	ID
# Total Receptors:	353
# Receptors In Calmet Domain:	353
Position In Receptor List:	868 - 1220
ID:	jarb2
Name:	Jarbidge Wilderness
State:	NV
# Total Receptors:	174
# Receptors In Calmet Domain:	174
Position In Receptor List:	1221 - 1394
ID:	sawt2
Name:	Sawtooth Wilderness
State:	ID
# Total Receptors:	353
# Receptors In Calmet Domain:	353
Position In Receptor List:	1395 - 1747
ID:	selw4
Name:	Selway-Bitterroot Wilderness
State:	ID
# Total Receptors:	575
# Receptors In Calmet Domain:	575
Position In Receptor List:	1748 - 2322
ID:	stmo2
Name:	Strawberry Mountain Wilderness
State:	OR
# Total Receptors:	114
# Receptors In Calmet Domain:	114
Position In Receptor List:	2323 - 2436

Computational Domain

Minimum Buffer (km):	50
Beginning Column:	171
Ending Column:	304
Beginning Row:	33
Ending Row	195

Calpuff Run Period Definition

Base Time Zone:	8 (Pacific Standard)
Calpuff Beginning Time:	01/01/2003 00:00:00
Calpuff Ending Time:	01/01/2006 00:00:00
Calpuff Time Step(Second):	3600

Appendix 2: Sensitivity Analysis: CALPUFF Modeling Setup for TASCO Riley Boiler, Nampa, Idaho

Scenario Summary

Scenario Information

Scenario Name:	wzI10445
Title:	ID-1 4km Existing Control version 3; 2004 through 2005 corrected
Scenario Description:	ID-1; 4km; partical size distribution(0.5/1.5 for fine, 5/1.5 for coarse); model source elevation; Existing Control version 3 (Control_ID = 41); 2004 through 2005 corrected; O3 = 10ppb; Puff splitting on with nsplit=2; building downwash (assume stack name is SPB3 in bpip input file)

Species Group Information

Species Group ID:	1
Number of Species:	9
Species Names:	SO2, SO4, NOX, HNO3, NO3, PMC, PMF, EC, SOA

Calpuff Working Directory

Working Directory:	Y:\airmodel\calpuff\runs\bart\wzI10445

Domain Projection and Datum

Projection:	Lambert Conic Conformal	
Origin of Projection:	Latitude: 49	Longitude: -121
Matching Latitudes:	Latitude 1: 30	Latitude 2: 60
Offset(km):	XEasting: 0	YNorthing: 0
Datum:	NWS	

Calmet Domain

Domain Name and Short Name:	bart_4km	bar_4km
Grid Origin(km):	X: -572	Y: -956
Grid Spacing(km):	4	
NX and NY:	NX: 373	NY: 316

Sources

Number of Sources:	1
Source_Elevation_Option:	Model

Source 1

Source Category

Category:	Point

Facility Information

Facility ID:	ID-1
Facility Name:	Amalgamated Sugar - Nampa

Unit Information

Unit ID:	30
Unit Description:	Riley Boiler

Control Strategy Applied
Control ID: 41
Control Description: Existing Control - Ver. 3

Source Location and Base Elevation
Datum: NAD27
Projection: UTM
UTM Zone: 11
Easting (km): 534.391
Northing (km): 4828.031
Base Elevation (m): 753

Source Location under Domain Projection and Datum
XEasting (km): 344.051
YNorthing (km): -569.801

Model Source Base Elevation In Calmet Domain
bar_4km (m): 759.705
bar_12km (m): 764.555

Stack Parameters
Height (m): 65
Diameter (m): 2.1
Exit Temperature (K): 427
Exit Velocity (m/s): 16

Emission Rate (Unit: lb/hr)
SO2 (lb/hr): 632.50000
SO4 (lb/hr): 6.41455
NOX (lb/hr): 390.00000
HNO3 (lb/hr): 0.00000
NO3 (lb/hr): 0.00000
PMC (lb/hr): 0.79000
PMF (lb/hr): 0.76000
EC (lb/hr): 0.03000
SOA (lb/hr): 2.21000

Emission Rate (Unit: g/s)
SO2 (g/s): 79.69366
SO4 (g/s): 0.80822
NOX (g/s): 49.13917
HNO3 (g/s): 0.00000
NO3 (g/s): 0.00000
PMC (g/s): 0.09954
PMF (g/s): 0.09576
EC (g/s): 0.00378
SOA (g/s): 0.27846

Class I Areas
Searching Radius (km): 300km
Number of Class I Areas: 7

ID: crmowild
Name: Craters of the Moon NM - Wilderness
State: ID
Total Receptors: 271
Receptors In Calmet Domain: 271
Position In Receptor List: 1 - 271

```
ID:                              eaca2
Name:                            Eagle Cap Wilderness
State:                           OR
# Total Receptors:               596
# Receptors In Calmet Domain:    596
Position In Receptor List:       272 - 867

ID:                              heca2
Name:                            Hells Canyon Wilderness
State:                           ID
# Total Receptors:               353
# Receptors In Calmet Domain:    353
Position In Receptor List:       868 - 1220

ID:                              jarb2
Name:                            Jarbidge Wilderness
State:                           NV
# Total Receptors:               174
# Receptors In Calmet Domain:    174
Position In Receptor List:       1221 - 1394

ID:                              sawt2
Name:                            Sawtooth Wilderness
State:                           ID
# Total Receptors:               353
# Receptors In Calmet Domain:    353
Position In Receptor List:       1395 - 1747

ID:                              selw4
Name:                            Selway-Bitterroot Wilderness
State:                           ID
# Total Receptors:               575
# Receptors In Calmet Domain:    575
Position In Receptor List:       1748 - 2322

ID:                              stmo2
Name:                            Strawberry Mountain Wilderness
State:                           OR
# Total Receptors:               114
# Receptors In Calmet Domain:    114
Position In Receptor List:             2323 - 2436

Computational Domain
Minimum Buffer (km):             50
Beginning Column:                171
Ending Column:                   304
Beginning Row:                   33
Ending Row                       195

Calpuff Run Period Definition
Base Time Zone:                  8 (Pacific Standard)
Calpuff Beginning Time:          01/01/2003 00:00:00
Calpuff Ending Time:             01/01/2006 00:00:00
Calpuff Time Step(Second):       3600
```

Appendix D – Executive Summary Excerpt from Affordability Analysis

Executive Summary excerpt

from: An Affordability Analysis of The Amalgamated Sugar Company LLC's Affordability Claim with respect to the Best Available Retrofit Technology (BART) for the Riley Boiler at the Nampa, Idaho facility

February 12, 2010

prepared by
Elliot Rosenberg
Senior Economist
U.S. EPA - Region 10

assisted by
Lloyd Oatis
(SEE) Financial Analyst
U.S. EPA - Region 10

Steve Body
Senior Planning Engineer
U.S. EPA - Region 10

EXECUTIVE SUMMARY

NOTE: THIS SUMMARY IS WRITTEN FOR PUBLIC VIEWING AND DOES NOT INCLUDE CONFIDENTIAL BUSINESS INFORMATION (CBI). THE FULL REPORT DOES CONTAIN CBI AND IS SUBJECT TO NON-DISCLOSURE REQUIREMENTS AT 40 CFR PART 2.

As a result of the Riley Boiler at The Amalgamated Sugar Company LLC (TASCO) Nampa, Idaho facility being identified as a Best Available Retrofit Technology (BART) source by the Idaho Department of Environmental Quality (DEQ), and DEQ's modeling input modeling which indicated the Riley boiler exceeded the BART exemption threshold of 0.5 deciview (dv) at any one Federal Class I area, TASCO conducted a site specific BART Determination Analysis for the Riley Boiler (TASCO 2008) according to EPA Guidelines (EPA Appendix Y).

The BART determination derived from this Determination Analysis has an estimated capital cost of $1.8 million, and estimated annual operation and maintenance (O&M) cost of $1.4 million. TASCO and the State of Idaho have agreed on the BART control technology and specified emission limitations, and these are based on the BART related costs. This BART determination consists of a fabric house bag particulate matter control which is already in place and operating, a low NO_x burner with overfire air, and flue gas desulfurization for SO_2. In accordance with federal BART requirements, the BART controls must be installed and operating by approximately April 30, 2013.

In TASCO's cover letter to its BART Determination Analysis, the company mentions that the above cited BART related costs would affect the long-term economic viability of the Nampa facility and TASCO as a whole, and that affordability is a critical element of the BART determination (TASCO 2008). In support of this claim and ongoing economic viability, TASCO submitted the company pro forma financial information to the BART Determination Analysis. Subsequently, TASCO provided additional clarifying and substantial additional information regarding its claim directly to DEQ and EPA.

In determining BART the EPA Guidelines indicate the State may take into consideration the economic effects of imposing the use of a particular technology. In the selection process the State may also consider any of the economic effects that are determined to have a severe impact on the plant's or the company's operations. DEQ decided to consider TASCO's affordability claim, but does not have the technical capability conduct a thorough affordability analysis. The EPA does have this analytical capability and conducted this affordability analysis. A copy was provided to DEQ.

The purpose of the affordability analysis was to determine the validity of TASCO's affordability claim, i.e. that the company cannot afford the control technology specified in the BART determination. The analysis took into consideration

- The estimated capital and O&M costs of the BART determination;
  compliance with BART emission limits required no later than approximately April 30, 2016;
  TASCO's continuing viability, i.e., the company's ability to continue as a going concern;
- The reasons provided by TASCO to support its affordability claim;
  The information provided by TASCO and obtained from other sources;
  BART related costs are considered to be a cost of doing business, and are not an investment with an expected financial return;
- The TASCO/Snake River Sugar Company (SRSC) owner/operator, management and financial relationships;
  TASCO's financial related commitments; and that
  BART related regulatory events [i.e., DEQ issuing a permit, followed by EPA approval of Idaho's Regional Haze State Implementation Plan (SIP), or in lieu of a SIP the issuance of a Federal Implementation Plan (FIP) by EPA] will occur subsequent to the completion of the BART Determination Analysis

Throughout this BART determination process, it appears that without the issuance of a permit and/or an approved SIP, TASCO's approach to the BART costs has been that the company has no financial or legal obligation to actually address these costs, and that all available funds are already committed for contractual reasons or as part of internal business decisions. A consequence of this approach has been that since about mid-2007, when TASCO was first made aware of the forthcoming BART obligation, the company has made no attempt to actively fund the prospective BART costs. It appears that TASCO does not intend to address the prospect of actually funding the BART costs until a permit is issued, and even then BART funding could depend on certain subsequent events. At the time of issuing a permit there will then exist a legal (regulatory) requirement that has to be met by TASCO and would require the company to make a financial related response. TASCO had to be aware that a decision not to proactively address BART costs prior to the issuance of a permit could make funding the BART related costs difficult.

A review of the company's past and current financial condition through September 30, 2009, which was supported by additional relevant information, indicates that overall the company is in relatively sound financial health. Its annual revenues have remained relatively consistent, the company has been able to meet all of its financial obligations including significant contractually obligated annual cash distributions to its owners, and has maintained regular repayments of its loans.

Taking into consideration TASCO's recent and current operating and financial condition, including annual cash distributions; its known current and future financial obligations and restrictions; how the company has decided to address funding the BART costs until now; the company's most recent audit related issues, the TASCO-SRSC relationship issues; the stipulated time period - defined by when the company becomes obligated to comply with the forthcoming issuance of a permit by DEQ, estimated to be no later than approximately June 2010, and ends with the BART emissions limit compliance date of

Exhibit D

Response to Public Comments re Tier II Operating
Permit No. T2-209.0105

Response to Public Comments

Final

The Amalgamated Sugar Company LLC
Nampa Factory
Nampa, Idaho
Facility ID No. 027-00010
Permit to Construct No. T2-2009.0105

September 7, 2010
Morrie Lewis
Permit Writer

BACKGROUND

As deemed appropriate by the Director, the Idaho Department of Environmental Quality (DEQ) provided for public comment on the proposed permit from April 19, 2010 through May 19, 2010 in accordance with IDAPA 58.01.01.404.01.c. During this period, comments were submitted in response to DEQ's proposed action. Each comment and DEQ's response is provided in the following section. Comments with a common theme have been grouped together and responded to as one comment. All comments submitted in response to DEQ's proposed action are included in the appendix to this document.

PUBLIC COMMENTS AND RESPONSES

Public comments regarding the technical and regulatory analyses and the air quality aspects of the proposed permit are summarized below. Questions, comments, and/or suggestions received during the comment period that did not relate to the air quality aspects of the permit application, the Department's technical analyses, or the proposed permit have not been addressed. For reference purposes, a copy of the Rules for the Control of Air Pollution in Idaho can be found at:

http://adm.idaho.gov/adminrules/rules/idapa58/0101.pdf.

Comment 1: **I believe it would be better if IDEQ shared some evidence, understandable to laymen, to substantiate its claims that TASCO is a major contributor to haze in the areas cited, especially since the prevailing winds usually blow in the opposite direction. What measures are available and what are the costs financially and environmentally to the company and to the community?**

Response: The subject-to-Best Available Retrofit Technology (BART) modeling analyses indicated that the Amalgamated Sugar Company's (TASCO) Riley boiler has caused a significant contribution (as defined by federal rules), but not as a "major contributor", to haze at the Eagle Cap, Strawberry Mountain, and Hells Canyon Class I areas. The modeling analyses predicted elevated haze impacts on days when elevated impacts were measured in these areas, when upper level transport winds were flowing from the Nampa area toward these Class I areas. Such conditions are frequently observed during wintertime stagnant air periods, when the most severe impacts occur.

In the modeling analyses, DEQ utilized modeling approaches which have been used nationwide and developed by several federal agencies, including the EPA, National Park Service, and U.S. Forest Service. The analyses used appropriate inputs developed jointly by modeling experts at the Idaho DEQ, EPA Region 10, Washington Department of Ecology, and Oregon DEQ. The modeling system used has undergone extensive testing by its developer and the EPA, and is identified in Appendix W to 40 CFR Part 51, the Guideline on Air Quality Modeling, as the recommended model for long-range transport based on validation studies in which it was compared to measured values.

The determination of BART takes into account environmental and financial impacts in steps three through five of the five-step process outlined in Section 3.1 of the Statement of Basis, in which the control effectiveness, financial impacts, and environmental impacts are evaluated for the feasible control technologies. The costs of compliance, energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology must all be taken into consideration in steps four and five of the process, in accordance with IDAPA 58.01.01.668.02.c. DEQ has evaluated these impacts and has summarized the results of each BART analysis and determination in Table 3.1 of the Statement of Basis ("Summary of BART Analyses and Determinations"). Detailed

information on these impacts can be found in Appendix B ("BART Determinations") and Appendix C ("Subject-to-BART Analyses") to the Statement of Basis.

Comment 2: **Why are the NO_X emission limits specified in the permit not consistent with the NO_X emission rates used in the BART analysis for the selected control technology?**

Response: Due to concerns related to the implementation of the selected BART, and in order to allow a margin for compliance with the corresponding BART NO_X emission limit, an effective NO_X control removal efficiency of 50% was used to establish the NO_X emission rate limit of 186 lb/hr (Permit Condition 3.4) for the Riley boiler.

Concerns related to the implementation of LNB with over-fired air suggest that a 65% NO_X control removal efficiency may not be achieved in practice for one or more of the following reasons:

- Based upon a review of reference literature and as reported in the "BART Determination Analysis Report" dated February 6, 2009, the target 65% NO_X control removal efficiency was approaching the high end of the range of what has been achieved in practice for LNB with over-fired air in coal-fired boiler retrofit applications. Actual NO_X emissions performance will be dependent upon the final LNB and boiler design configurations, which are not yet available.
- TASCO has documented concerns regarding the feasibility of using over-fired air on the Riley boiler based on the results of a feasibility study completed by Babcock Power, Inc.[1]

Comment 3: **Please clarify the averaging period of the emission limits associated with the Riley boiler. If these differ from the 30-day rolling average used in the BART presumptive limits, please explain.**

Response: An averaging period was not specified for any of the BART and BART alternative emission limits, since annual performance testing has been required to demonstrate ongoing compliance with each of the BART emission limits. (As required by Permit Condition 3.14, three test runs with a minimum time per run of 20 minutes are required for each performance test, resulting in an effective averaging time of 20 minutes or greater during each performance test.)

Although this permitting action does not address Compliance Assurance Monitoring (CAM) requirements relevant to the installation and operation of BART control devices, it is expected that the Riley boiler will continue to be subject to the requirements of CAM in accordance with 40 CFR 64.2(a) and that new monitoring, recordkeeping, and reporting requirements associated with BART control device operating parameters (indicators) will be considered in a future permitting action based upon a CAM plan submitted by TASCO. Refer to Section 4.9 of the Statement of Basis for additional discussion concerning CAM applicability.

Continuous emission monitoring to ensure compliance with the BART SO_2 and NO_X emission limits has not been required at this time for the new BART control devices (spray dry flue gas desulfurization system and LNB with over-fired air), based on the assumption that these control devices will be in operation at all times the Riley boiler is in operation (as required in Permit Conditions 3.7 and 3.8, respectively). Alternate operating scenarios have not been considered or evaluated as part of this permitting action.

Continuous emission monitoring to ensure compliance with the PM BART emission limit has not been required at this time for the existing baghouse, since established monitoring and recordkeeping requirements have been considered sufficient for ensuring compliance with the existing boiler operating scenarios. The existing baghouse is currently operated when firing coal fuel in the Riley boiler, and cannot be operated during periods when the boiler is using natural gas

[1] Feasibility Study BART – Riley Power & Proposed Revisions to the Draft BART Tier II Operating Permit and Statement of Basis, Attachment 1 to Public Comments on Tier II Operating Permit, TASCO, April 6, 2010.

as the primary fuel (Permit Condition 3.6).[1] Refer to Tier I Operating Permit No. T1-050020[2] for additional monitoring and recordkeeping requirements applicable to the existing baghouse; including visible emissions, pressure drop, operations and maintenance, PM performance testing, fuel feed rates, and hours of operation requirements.

Comment 4: **What is the total number of pulp dryers? Which dryers were shut down to meet the PM_{10} National Ambient Air Quality Standards (NAAQS)? Which dryers are being proposed to be shut down as part of the Alternative to BART NO_X control scenario?**

Response: The Center pulp dryer (S-D2) and the North pulp dryer (S-D3) were required as part of a compliance schedule to be shut down before September 30, 2007 and replaced with a single steam dryer system, in accordance with Permit Condition 13.8 in Tier II Operating Permit No. T2-050021.[3]

The remaining permitted coal-fired pulp dryer, the South pulp dryer (S-D1), is required to be shut down as a result of this permitting action in accordance with Permit Conditions 4.1 and 4.2.[4] These permit conditions have been updated to clarify that only the South pulp dryer is affected by this permitting action.

Comment 5: **In the proposed Tier II permit document, there are several references to the size of the boiler as 350,000 MMBtu/hr. In fact, the boiler is 350 MMBtu/hr.**

Response: Typographical corrections have been made in the permit to the Regulated Emission Point Sources Table (Permit Condition 1.2) and the dry low NO_X burner control equipment requirement (Permit Condition 3.8).

Comment 6: **Why was the Riley boiler not exempted from the need to perform a BART determination? Why has DEQ not considered refined receptor apportionment results in addition to DEQ's dispersion modeling results? Why won't DEQ reconsider the degree of improvement in visibility which may reasonably be anticipated to result from the use of the proposed BART?**

Response: DEQ is not reconsidering model selection at this time. Model selection, modeling protocol information, and modeling analyses results were provided to TASCO in the BART modeling protocol notification letter dated July 31, 2006 and in the subject-to-BART notification letter dated December 14, 2006, and the opportunity was provided for TASCO to perform refined modeling analyses at that time.

As described in these notification letters and in Section 1.2 of Appendix C ("Subject-to-BART Analyses") to the Statement of Basis, DEQ performed the BART exemption and BART determination modeling in accordance with the *BART Modeling Protocol*,[5] which was jointly developed by the states of Idaho, Washington, and Oregon, and which has undergone public review and revision.

In addition, the source apportionment analysis submitted in the comments to DEQ utilized a flawed statistical treatment that neither DEQ, nor the EPA, nor the Federal Land Managers could approve.

Comment 7: **Why was the EPA's affordability analysis not considered as fundamentally flawed?**

Response: DEQ is not reconsidering the results of the affordability analysis at this time. DEQ has relied upon the results of the affordability analysis conducted by EPA, which was provided to TASCO in the affordability notification letter dated March 17, 2010. The Statement of Basis has been updated to include an executive summary from this affordability analysis in Appendix D.

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[2] Tier I Operating Permit No. T1-050020, final, revised May 23, 2006.

[3] Tier II Operating Permit No. T2-050021, final, revised March 8, 2006.

[4] Tier II Operating Permit No. T2-2009.0105, final, issued September 7, 2010.

[5] Modeling Protocol for Washington, Oregon and Idaho: Protocol for the Application of the CALPUFF Modeling System Pursuant to the Best Available Retrofit Technology (BART) Regulation, draft, May 22, 2006.

APPENDIX A

PUBLIC COMMENTS RECEIVED

Name: Crystal Sverdsten
Email Address: lilcntry_lilnot@yahoo.com
Affiliation: Resident
Sent: Monday, April 19, 2010 4:09 PM
To: Faye Weber
Subject: Public Comment

I believe it would be better if IDEQ shared some evidence, understandable to laymen, to substantiate it's claims that TASCO is a major contributor to haze in the areas cited, especially since the prevailing winds usually blow in the opposite direction. What measures are available and what are the costs, financially and environmentally to the company and the community?

Name: Bryce Cook
Email Address: dukkhnter@hotmail.com
Affiliation: None
Sent: Tuesday, April 20, 2010 12:29 PM
To: Faye Weber
Subject: Public Comment

There is no way this is affecting those recreation areas.

Please stop regulating industry out of town. Unemployment is bad enough in Canyon County.

I am in no way affiliated with Algamated Sugar. I am just a long time Nampa resident who is sick of seeing regulation kill business in this area.

USDA United States Department of Agriculture | Forest Service | Intermountain Region | 324 25th Street Ogden, UT 84401 801-625-5605

File Code: 2580
Date: May 14, 2010

Ms. Faye Weber
Idaho DEQ, Air Program
1410 North Hilton
Boise, ID 83706-1255

Dear Ms. Weber:

Thank you for the opportunity to provide comments on the Best Available Retrofit Technology (BART) analysis for The Amalgamated Sugar Company (TASCO) – Nampa facility. Cooperative efforts, such as these, ensure that together we will continue to make progress toward the Clean Air Act's goal of natural visibility conditions at our Class I wilderness areas and parks.

In general, the USDA Forest Service is supportive of the BART Determination and Tier II Permit established for TASCO Nampa facility. We appreciate the efforts of Idaho DEQ staff and the staff at TASCO in preparing the BART analysis and determination documents. After reading through the BART determination documents, proposed Tier II operating permit and Statement of Basis we offer the following comments:

- The NO_x emission limits specified in the permit are not consistent with the NO_x emission rate used in the BART analysis for the selected control technology. The BART determination for "Low NO_x Boilers with Over Fire Air" was based upon a control efficiency of 65 percent resulting in a NO_x emission rate of 131 lbs/hr[1]. However, the permit limit assumes a control efficiency of 50 percent, resulting in a NO_x emission limit of 186 lbs/hr[2]. While it is common for States to set a permit level slightly below the most stringent level of control so as to allow some flexibility for compliance, this must be balanced against reducing emissions sufficiently to accomplish goals. As such, it seems the 50 percent control efficiency is too lenient, and that a control efficiency closer to that used in the BART analysis seems more appropriate.

- Please clarify the averaging period of the emission limits associated with the Riley boiler. If these differ from the 30-day rolling average used in the BART presumptive limits, please explain.

[1] Table 9, Page 20 of TASCO BART Determination (July 17, 2009).
[2] Regulated Sources Table, Page 4 and Riley Boiler BART and BART Alternative Emission Limits Table, Proposed Tier II Operating Permit (April 19, 2010).

- Page 21 of the BART Determination document (July, 2009) states that "some of the pulp dryers were shut down to meet P_{M10} NAAQS requirements..." Please clarify the following. What is the total number of pulp dryers? Which dryers were shut down to meet the PM_{10} NAAQS? Which dryers are being proposed to be shut down at part of the Alternative to BART NO_x control scenario?

- In the proposed Tier II permit document, there are several references to the size of the boiler as 350,000 MMBtu/hr. In fact, the boiler is 350 MMBtu/hr.

We appreciate your consideration of our comments. Please contact Jeff Sorkin, Air Quality Specialist, Natural Resources Staff, at (303) 275-5759 if you have questions.

Sincerely,

/s/ William P. Levere
WILLIAM P. LEVERE
Director, Natural Resources

cc: Jeff A Sorkin
Rick Graw
Scott A Copeland

THE AMALGAMATED SUGAR COMPANY LLC

1951 S. SATURN WAY, SUITE 100 • BOISE, ID 83709
PHONE (208) 383-6500 • FAX (208) 383-6684

May 19, 2010

Faye Weber
Air Quality Division
DEQ State Office
1410 N. Hilton
Boise, ID 83706
Email: *faye.weber@deq.idaho.gov*

Re: Public Comments on Tier II Operating Permit
The Amalgamated Sugar Company LLC—Nampa Factory
Facility ID No. 027-00010

Dear Ms. Weber:

The Amalgamated Sugar Company LLC (TASCO) submits these comments on a Tier II operating permit proposed by the Department of Environmental Quality (DEQ) to be included in Idaho's Plan for Implementing Section 308 of the Regional Haze Rule. The Tier II operating permit proposes to require Best Available Retrofit Technology (BART) for the Riley boiler operated by TASCO at its Nampa, Idaho factory. As proposed the Tier II operating permit would require TASCO to install approximately $18,000,000 of pollution control equipment.

TASCO presents additional information to support the following conclusions: (1) the Riley boiler is exempt from the need to perform a BART determination, (2) DEQ has discretion to consider refined receptor apportionment results in addition to DEQ's dispersion modeling results, (3) even if a BART determination is performed, it is appropriate to reconsider the degree of improvement in visibility which may reasonably be anticipated to result from the use of the proposed BART; and (4) EPA's affordability analysis is fundamentally flawed.

TASCO previously submitted detailed evaluations regarding both DEQ's BART applicability and BART determination analyses that DEQ failed to consider or ignored, and that resulted in the proposed Tier II permit requirements. Therefore, TASCO's public comments include comments presented with this letter, previous submissions to DEQ and the Environmental Protection Agency (EPA) that are referred to in footnotes and are currently in DEQ's file, and the proposed permit and Statement of Basis marked up to reflect specific edits.

TASCO urges DEQ to defer issuance of the Tier II operating permit until the receptor apportionment analysis prepared by Cooper Environmental Services, LLC and summarized in these comments can be meaningfully evaluated in support of an exemption from BART for the Riley Boiler, and until corresponding revisions to Idaho's Plan for Implementing Section 308 of the Regional Haze Rule are accomplished. TASCO remains willing to assist DEQ in this work to ensure a timely and sufficient plan is submitted to EPA.

Sincerely,

Dean C. DeLorey

Dean C. DeLorey
Director of Environmental Affairs

Cc: G.O. – Joe Huff, John McCreedy, Bob Braun
Nampa – Kent Quinney, Glen Patrick

TASCO's Comments on the Proposed Tier II Operating Permit[1]

TASCO presents additional information for DEQ to consider to support the following conclusions: (1) the Riley boiler was exempt from the need to perform a BART determination, (2) DEQ has discretion to consider refined receptor apportionment results in addition to DEQ's dispersion modeling results, (3) even if a BART determination is performed, it is appropriate to reconsider the degree of improvement in visibility which may reasonably be anticipated to result from the use of the proposed BART; and (4) EPA's affordability analysis is fundamentally flawed.

States are required to develop a regional haze program.[2] BART is only one element prescribed by EPA.[3] Little direction was given in EPA's rules for preparing the BART section of the State's regional haze program. A single EPA guidance document adopted in 2005 mandated a process for fossil fuel fired power plants greater than 750 megawatts in generating capacity (referred to as "Appendix Y").[4] The language of Appendix Y reinforces EPA's requirement that States use that process for BART determinations for power plants, and it provides that States "are not required to use the process in the guidelines when making BART determinations for other types of sources."[5] DEQ nonetheless followed the process presented in Appendix Y for the applicability analysis of TASCO's small industrial source, resulting in an unreasonable and very expensive BART determination for the Riley boiler. TASCO presents a complementary approach that is consistent with the discretion afforded under Appendix Y.

Additional Information for Consideration

TASCO is the only company in the sugar or food processing industry that is expected to commit significant economic resources to address regional haze in the entire U.S. The Riley Boiler at TASCO's Nampa, Idaho factory is one of only two stationary sources in Idaho subject to BART. Under the proposed Tier II operating permit TASCO will be required to spend $18,000,000 in attempt to improve visibility in protected areas located over 100 miles from the factory. In addition to the information submitted previously by TASCO to IDEQ and incorporated here for review during this public comment process, TASCO provides new information for the agencies

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[1] References throughout these comments are made to TASCO and DEQ documents currently contained in DEQ's files. Those documents are not resubmitted with these public comments, but are incorporated by reference to prompt formal response from DEQ and EPA.

[2] 40 CFR 51.308

[3] 40 CFR 51.308(e)

[4] 40 CFR 51.308(e)(1)(ii)(B); 40 CFR Part 51, Appendix Y

[5] Appendix Y, Section I.*F*(1)

to consider in support of a revised BART applicability analysis and a revised BART determination. This information also supports a revised Tier II operating permit.[6]

Analysis using a refined receptor apportionment approach reveals that TASCO's Riley boiler could have been exempted from the need to perform a BART determination.

Under Appendix Y, DEQ has discretion to exempt an individual source or certain pollutants from a source from the need to make a BART determination, if the source "is not reasonably anticipated to cause or contribute to any visibility impairment" in a protected area.[7] DEQ can support an exemption if it demonstrates that the contribution of the Riley boiler is less than a prescribed threshold set forth in Appendix Y (0.5 delta deciviews). To make that demonstration, DEQ may consider modeling, emissions analysis, or other reasonable approaches for analyzing the visibility impacts of a source.[8] Appendix Y also allows States to use EPA's recommended dispersion model (CALPUFF) or "other appropriate model to predict the visibility impacts from a single source at a Class I area."[9]

Different approaches exist for estimating impacts of emissions from stationary sources including various source oriented dispersion models, like CALPUFF, that predict a source's impact at a receptor based on the source emissions and dispersive influences of wind fields; and receptor oriented approaches that start with measured receptor concentrations and allocate measured concentrations to source categories based on source profiles. Dispersion models, like CALPUFF, are not bound by any actual measured impacts at the Class I areas and can readily over predict impacts from specific sources. Another reasonable approach to ascertaining the impacts of the Riley boiler is the receptor oriented apportionment approach that takes into account measured impacts at the Class I areas and allocates impacts to specific sources.

DEQ utilized the CALPUFF dispersion model recommended by EPA to predict visibility impacts at the relevant Class I areas attributable to TASCO's Riley boiler. DEQ solely relied upon conservative dispersion modeling results to conclude that emissions from the Riley boiler contribute to impaired visibility only during winter time periods in Hells Canyon, Strawberry Mountain Wilderness, and Eagle Cap Wilderness. CALPUFF dispersion modeling has numerous recognized limitations that prompt comparison of that model's results to other analysis. TASCO

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[6] See, Attachment 1 – TASCO mark up of proposed Tier II operating permit reflecting changes consistent with these narrative comments; and letter to Glen Patrick from Riley Power dated May 4, 2010 regarding infeasibility of overfired air.

[7] Appendix Y, Section III

[8] Appendix Y, Section III.*A*.(3)

[9] Appendix Y, Section III.*A*(3)

previously provided detailed comments to DEQ regarding the complexities and inadequacies of the CALPUFF mathematical model to predict visibility impacts and urged DEQ to reconsider its results. DEQ declined to compare its CALPUFF modeling outcomes with other relevant information in completing its BART analyses.

In response to the proposed Tier II operating permit, therefore, TASCO retained Cooper Environmental Services LLC (CES) to use a receptor oriented apportionment approach to compare impacts predicted under this method with the CALPUFF results.[10] The receptor oriented apportionment approach utilized by CES considered measured impacts recorded at receptors in the Class I areas and apportionment data referenced by DEQ in its draft regional haze plan. The approach is similar to the receptor modeling approach used in development of DEQ's Treasure Valley PM_{10} Maintenance Plan in 2002.

According to CES, comparing the results of a dispersion model with receptor oriented apportionment outcomes to evaluate the visibility impacts from the Riley boiler leads to a more supportable conclusion than simply relying upon dispersion modeling alone. CES has utilized this complementary approach before to refine dispersion modeling results that are inherently not bound by actual measurements or monitored data. The source apportionment work of CES clearly shows that the Riley boiler is not subject to BART, in contrast to the CALPUFF results that indicate the source is subject to BART.

Preliminary receptor apportionment results prepared by CES reveal that TASCO's Riley boiler could have been exempted from the need to perform a BART determination.[11] The highest delta deciview day identified using the receptor modeling approach was 0.4 delta deciview. The 98th percentile delta deciview results using this approach ranged from 0.06 to 0.15 – all substantially below the 0.5 delta deciview threshold for BART applicability. Overall the delta deciview results using receptor apportionment methods are substantially smaller than those predicted by the CALPUFF model. The differences range from about 3 to 30 times less using the receptor approach.

The receptor oriented apportionment results also indicate that the actual Riley boiler impacts may be highest at Hells Canyon, whereas the predicted impacts using CALPUFF were highest at Eagle Cap Wilderness. These receptor apportionment results are more consistent with a conceptual model of down river drainage air flow influenced by low inversions that impact the

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[10] See, Attachment 2 – qualifications of Dr. John Cooper, President, Cooper Environmental Services, LLC

[11] See, Attachment 3 – "Report for The Amalgamated Sugar Company: Riley Boiler Impacts on Visibility in Select Class I Areas," prepared by Cooper Environmental Services LLC for TASCO on May 19, 2010

lower elevation Hells Canyon ambient monitoring site more than the higher elevation Eagle Cap monitor.

Based upon these findings by CES, TASCO urges DEQ to reevaluate its 2007 BART applicability analysis and to exempt the Riley boiler from the need to make a BART determination. Such an outcome reflects a reasonable complementary modeling approach to predicting visibility impacts and is consistent with the discretion afforded States under Appendix Y.

Analysis using a refined receptor apportionment approach reveals that installation of controls on the TASCO's Riley boiler is not likely to result in any measurable visibility improvement.

If after close consideration of the CES work, DEQ fails to revise its 2007 BART applicability evaluation to exempt the Riley boiler from the need to perform a BART determination, then reexamination of DEQ's 2009 BART determination is appropriate.[12] To establish BART controls, DEQ was required to consider five prescribed criteria, including "the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[13] DEQ solely relied upon CALPUFF's conservative dispersion modeling projections to determine the degree of visibility improvement which may reasonably be anticipated from the $18,000,000 expenditure at the Nampa factory. Under Appendix Y, however, States may consider the impact of each particular pollutant and States may consider modeling, emissions analysis, or other reasonable approaches for analyzing the visibility impacts of a source.[14]

The receptor oriented apportionment work of CES (using actual measurements from representative site monitors), confirms that the Riley boiler impacts predicted by CALPUFF are not reasonable estimates when compared to receptor measurements and, therefore, cannot be relied upon to establish the degree of improvement that can reasonably be anticipated from the installation of BART on the Riley boiler. The receptor apportionment suggests little to no improvement in visibility can reasonably be anticipated to result from the use of the technology proposed in the Tier II operating permit.

Based upon these findings by CES, TASCO urges DEQ to revise its 2009 BART determination and to conclude that no additional controls on the Riley boiler are required. Such an outcome reflects a complementary modeling evaluation of the reasonably anticipated visibility improvements and is consistent with the discretion afforded States under Appendix Y.

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[12] July 17, 2009 letter from Martin Bauer to Glen Patrick, including "TASCO Best Available Retrofit Technology Determination"

[13] 40 CFR 51.308(e)(1)(ii)(A); IDAPA 58.01.01.668.02(c)

[14] Appendix Y, Section III.*A*.(3)

EPA's affordability analysis was fundamentally flawed and failed to recognize that no other sources in the industry are required to install BART controls.

Also relevant to the assessment of the degree of visibility improvement for the Riley boiler is an assessment of "affordability."[15] Appendix Y states:

> There may be unusual circumstances that justify taking into consideration the conditions of the plant and the economic effects of requiring the use of a given control technology. These effects would include effects on product prices, the market share, and profitability of the source. Where there are such unusual circumstances that are judged to affect plant operations, you may take into consideration the conditions of the plant and the economic effects of requiring the use of a control technology. Where these effects are judged to have a severe impact on plant operations you may consider them in the selection process, but you may wish to provide an economic analysis that demonstrates, in sufficient detail for public review, the specific economic effects, parameters, and reasoning....Any analysis may also consider whether other competing plants in the same industry have been required to install BART controls if this information is available.[16]

As early as November 2007, TASCO alerted DEQ to the unusual circumstances related to the affordability of BART controls for the Nampa factory and TASCO repeated its concerns to DEQ in 2009.[17] Throughout 2009 TASCO responded to requests for additional financial information from DEQ and EPA. On February 12, 2010, EPA finalized its affordability analysis stating that "TASCO can afford to fund the BART."[18] In TASCO's comments on the preliminary draft Tier II operating permit submitted in April 2010, TASCO disagreed with EPA's conclusion and observed that EPA's analysis was flawed in several fundamental ways. Neither DEQ nor EPA responded. Since the conditions of the proposed Tier II operating permit that require expenditure of $18,000,000 for pollution control equipment are subject to an affordability test, TASCO's earlier

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[15] 40 CFR 51.308(e)(1)(ii)(A); IDAPA 58.01.01.668.02 (c)(i)

[16] Appendix Y, Section IV.*E*.(3)

[17] November 20, 2007 letter from TASCO to DEQ; and February 6, 2009 letter from TASCO to DEQ

[18] February 12, 2010 document "An Affordability Analysis of [TASCO], LLC's Affordability Claim with respect to the BART for the Riley Boiler at the Nampa, Idaho facility." TASCO received a copy of EPA's analysis from DEQ on March 23, 2010

comments are incorporated into this submittal and TASCO presents additional comments on EPA's analysis. TASCO requests a response from both DEQ and EPA.

First, EPA centers its review on whether TASCO can "fund" the expenditure.[19] EPA observed in its analysis, for example, that TASCO failed to be proactive and set aside funding for BART. EPA commented that TASCO should have been aware that "a decision not to proactively address BART costs prior to the issuance of a permit could make funding the BART related costs difficult."[20] EPA's logic means that anytime a company becomes aware of a potential compliance obligation, the company should start reserving funds -- even before it is determined if compliance is required. Such an approach is not supported by generally accepted accounting principles, as confirmed by the comments of TASCO's auditors in the EPA report.

Moreover, whether or not TASCO can obtain or set aside funding is not the focus of the affordability test, as quoted above from Appendix Y. Fundamental to the review are the effects such an expenditure would have on "profitability", "market share", "plant operations" and position relative to "competing plants." The appropriate test is not whether TASCO is able to fund the cost, but whether unusual circumstances that affect plant operations prompt consideration of the conditions of the plant and the economic effects of requiring the use of a control technology.[21]

Next, to the extent the economic effects described in the Appendix Y language were considered at all by EPA, the analysts considered the overall effects to TASCO and its related entities. The direct effects on TASCO's Nampa plant operations were underestimated or ignored by EPA. Materials submitted by TASCO and referred to in EPA's analysis discussed particular circumstances and plant conditions ripe for consideration; however, EPA dismissed the affects of local realities on specific plant operations at Nampa and instead relied upon a more general assessment of the stability and business structure of TASCO to justify its conclusion.

EPA further observed that TASCO can spread the BART control costs among growers throughout Idaho and thus ameliorate the effects of the expenditure on the Nampa plant operations. This observation reflected a flawed notion that by spreading the costs among more growers the adverse economic effects to Nampa's growers disappear. Not true. Growers decide which crops to plant based upon the greatest potential economic return to the grower. Payments to growers throughout Idaho that are reduced to fund installation and operation of

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[19] See, footnote 18 -- for example page 1, 3, and Table 1

[20] See, footnote 18 -- page 2

[21] Applying EPA's funding logic to the residential mortgage crisis, EPA's analysts might conclude that if a buyer could obtain or fund a sub-prime mortgage, then the underlying asset was affordable. Current events demonstrate that access to funds does not equal affordability.

BART controls at the Nampa plant will result in decreased acreage planted with sugarbeets throughout Idaho. Under EPA's cost spreading approach the adverse impacts will also be spread beyond the Nampa plant to the whole of Idaho's sugarbeet industry.

TASCO described for EPA the specific impact on the Nampa factory of a reduced number of growers who plant sugarbeets in the surrounding area, and the potential for a reduced number of planted sugarbeets if the cost of BART control technology is passed on to growers through decreased payments. In its analysis, however, EPA assumed that growers will continue to plant sugarbeets without a reasonable return relative to alternative crops.

TASCO highlighted a severe decline (18.4% decline in one year and a decline of 13% over a 7 year period) in membership due to decreased returns to growers, yet EPA minimized the impact that a reduced supply of raw materials would have on the Nampa factory. EPA dismissed the one year decline in membership by stating that "This most recent decline was obviously not a result of any BART related costs passed on to the growers."[22] EPA's reaction missed the point and overlooked the reality that any increase in costs passed along to the growers reduces the payment to growers who plant sugarbeets. Decreased payments result in growers' interest in higher priced crop production and fewer planted acres of sugarbeets. Fewer planted acres of sugarbeets jeopardize the viability of the Nampa plant.

EPA further ignored that this trend is actually happening. TASCO described the closure of TASCO's Nyssa factory as evidence of the vulnerability and actual impact to plant operations from diminished sugarbeet acreage. TASCO also highlighted the 31% decline in sugarbeet harvest between 2007 and 2008.[23] EPA downplayed these plant specific impacts, however, and emphasized other information to conclude that TASCO is economically stable. These unusual circumstances certainly impact the viability of the Nampa plant.

Third, EPA placed "substantial weight" in the statements of TASCO's auditors.[24] EPA concludes that a "reasonable inference that can be drawn from the lack of any mention of the BART issues as they may affect the company's ongoing viability in the auditor's report is that the auditor did not consider the BART issues would have a material adverse impact on the company's ability to continue as a going concern."[25] Interpreting the auditor's report in this manner is flawed and inconsistent with auditing practice. Auditors rely upon professional judgment and the information available at the time of the statements to determine if review by a governmental agency should be addressed in the financial statements. At the time of the auditor's evaluation

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[22] See, footnote 18 -- page 25

[23] The 2008 beet crop was the smallest crop in over 25 years.

[24] See, footnote 18 -- pages 32-38

[25] See, footnote 18 -- page 36

in 2009, TASCO's auditor had insufficient information about the ultimate outcome of the BART review and any future obligation. The auditor was aware of the BART process, but there was no legal obligation to incur BART costs. "[S]ince the company did not yet have any legal obligation that required it to address the BART costs - and there are no financial standards obligation to do so" the auditor's financial report did not address the impacts.[26] EPA conveniently relied upon the auditor's silence to support their conclusion.

Finally, EPA failed to consider whether other competing plants in the same industry are required to install BART controls. TASCO contacted seven other companies, TASCO's competitors in the sugar processing industry.[27] As far as TASCO knows, no other plant in the sugar industry in the U.S. is required to install BART controls.[28] That information including contact information for each company was requested by EPA and provided by TASCO. EPA completely ignored this facet of the affordability test, however. The cost of BART controls will saddle the Nampa plant with a competitive disadvantage relative to other producers in the U.S. and that unusual circumstance is relevant to the affordability test.

TASCO requests reconsideration of EPA's affordability analysis. TASCO urges EPA to address the unusual circumstances that directly affect the Nampa plant operations and determine that the proposed expense is not affordable under the test outlined in Appendix Y.

Incorporation of Documents as Public Comments

Through the course of the four years of work with DEQ, TASCO was repeatedly advised by representatives of DEQ that the agency was unable to provide thorough and complete responses to the company's substantive concerns because the agency did not have time. Although DEQ and TASCO met many times ostensibly to discuss and to respond to the company's questions, no substantive technical analysis was completed by DEQ and no meaningful discussion occurred in response to TASCO's important questions.[29] Most recently, DEQ informed TASCO that the agency did not have time to respond to TASCO's detailed comments on the preliminary draft Tier II operating permit,[30] but that the company could

[26] See, footnote 18 -- page 38

[27] American Crystal Sugar Company, Southern Minnesota Beet Sugar Coop, Sidney Sugars, Inc., Michigan Sugar Company, Minn-Dak Farmers Cooperative, Western Sugar Cooperative, and Roberts Sugar Ltd.

[28] Furthermore, TASCO is not aware of any facility in the food industry sector that is subject to BART.

[29] See, for example, April 1, 2010 letter from Martin Bauer to Joe Huff

[30] See, April 6, 2010 letter from Joe Huff to Martin Bauer and Morrie Lewis

resubmit the comments during this formal public comment period. Therefore, TASCO incorporates all of its previously submitted materials into these public comments (specifically, all of the materials referenced in the footnotes to these public comments), so that DEQ and EPA can formally respond. It is appropriate to renew the request for substantive responses to TASCO's earlier comments, now, in the course of formal public review of the Tier II operating permit since the permit is based upon the underlying work of DEQ.

Conclusion.

Since 2007 when DEQ concluded that the Riley boiler at the Nampa location was subject to BART TASCO submitted several detailed evaluations to DEQ raising questions about the reasonableness of agency's conclusions for the Nampa factory.[31] In particular, TASCO expressed concern about the agency's reliance upon conservative dispersion modeling as the sole basis for its BART applicability determination for this relatively small industrial source.[32]

TASCO's concerns were well founded based upon experience. In support of the Treasure Valley PM_{10} Maintenance Plan published in 2002 DEQ relied upon PM_{10} modeling analyses for the Nampa facility and over predicted ambient PM_{10} concentrations attributable to the plant. DEQ modeled a predicted value of 354 $\mu g/m^3$ then added an estimated background concentration of 90 $\mu g/m^3$ for an estimated impact of 444 $\mu g/m^3$ from the Nampa facility. This value was above the applicable National Ambient Air Quality Standard of 150 $\mu g/m^3$ and DEQ required TASCO to reduce emissions at a significant cost.[33] In 2004 and 2005 actual PM_{10} concentrations measured by a DEQ approved monitor located at the Nampa facility fence line averaged only 22 ug/m^3 -- twenty times less than the value predicted by modeling – and proving the model to be grossly inaccurate. Notably, monitored PM_{10} concentrations did not materially change after the installation of the pulp steam dryer and shutdown of the rotary pulp drum dryers. Fortunately, the pulp stream dryer significantly reduces fuel consumption at the plant and has earnings associated with that capital expenditure. The proposed BART controls will not have any earnings benefit, and will increase future operating costs.

As a result, the Riley boiler BART analyses cannot reasonably be based upon CALPUFF dispersion modeling alone. TASCO urges DEQ to reconsider its conclusions in light of the additional information prepared by CES. TASCO further urges DEQ to defer issuance of the Tier

[31] See, July 19, 2007 letter from Martin Bauer to Glen Patrick, including "Subject to BART Analysis for the TASCO Riley boiler, Nampa, Idaho"; July 21, 2009 letter from Dean Delorey to Martin Bauer; and November 18, 2009 letter from Joe Huff to Martin Bauer

[32] See, footnote 17

[33] In 2006, the Nampa facility completed the $16.9 million steam pulp dryer project which replaced three coal-fired pulp dryers.

II operating permit until the receptor modeling analysis presented by CES can be meaningfully evaluated in support of an exemption from BART for the Riley Boiler, and until corresponding revisions to Idaho's Plan for Implementing Section 308 of the Regional Haze Rule are accomplished. TASCO remains willing to assist DEQ in this work to ensure a timely and sufficient plan is submitted to EPA.

ATTACHMENT 1

FEASIBILITY STUDY BART – RILEY POWER
&
PROPOSED REVISIONS TO THE
DRAFT BART TIER II OPERATING PERMIT AND
STATEMENT OF BASIS

THE AMALGAMATED SUGAR COMPANY LLC
NAMPA FACILITY

RILEYPower
A Babcock Power Inc. Company

May 4, 2010

Glen Patrick
The Amalgamated Sugar Co
138 W. Karcher Road
Nampa, ID 83687

Subject: **Feasibility Study to Determine Best Suited Combustion Technology to meet BART**
TASCO Purchase Order #65276
Nampa Sugar Mill – RPI Contract #100477

Dear Glen:

Riley Power Incorporated (RPI) recently completed a study evaluating the feasibility of installing low NOx burner upgrades on the Amalgamated Sugar Company (TASCO) Nampa Riley Boiler. For this feasibility study, RPI evaluated installation of a new Low NOx combustion system, which includes a new Low NOx coal burners and Overfire Air system. A technical summary of the RPI engineering report is provided below, discussing the required modifications to the Riley Boiler that will achieve at least a 50% NOx reduction.

In order to install an overfire air (OFA) system, RPI's engineering standards define the minimum OFA air residence time of approximately 0.7 sec between the elevation of the proposed overfire air system and the nose arch of the furnace. For TASCO Nampa Facility, the boiler residence time, or the residence time between the top burner elevation to the nose arch of the furnace, is only 0.83 seconds before installation of the OFA system. This indicates that installation of an OFA system between the top burner elevation and the nose arch will produce an OFA residence time much less than the minimum required residence time of 0.7 sec. Furthermore a mechanical review of the existing burner configuration was conducted, which determined that the vertical distance between the top burner elevation and the furnace nose arch is not sufficient in terms of physical space for installing the OFA System needed to achieve the greatest NOx reduction without significant modification to both the burner configuration and boiler pressure parts. Therefore, installation of a new OFA system would be ineffective for reducing NOx and not recommended.

In addition to the OFA system, both CCV® Single Register Burners (SRB) and CCV® Dual Air Zone (DAZ) burners were reviewed for this particular application. Both burner systems are considered state-of-the-art and therefore capable of significant NOx reduction without the use of overfire air. The CCV® DAZ is the most recent generation of burner which offers better air flow

MAILING ADDRESS
Post Office Box 15040
Worcester, MA 01615-0040

SHIPPING ADDRESS
5 Neponset Street
Worcester, MA 01606

TELEPHONE. (508) 852-7100
FAX (508) 852-7548
www.babcockpower.com

control and flame stabilization and improved NOx reduction. RPI has concluded that both burner systems are capable of achieving at least a 50% reduction of NOx for the TASCO Riley boiler. Note that for both the CCV® SRB and CCV® DAZ burner, significant modification of existing burner windbox is required to accommodate the new burner geometry and increased weight of the burners. Modification of the surrounding coal pipes, coal pipe supports and deck elevations adjacent to the burner windbox will also be required.

Thank you again for including Riley. We look forward to continued success working with TASCO on this most important project.

Larry Begin
Assistant Project Manager
Riley Power Inc.
508-854-4034 F: 508-853-3944
M: 508-688-2367

Air Quality
TIER II OPERATING PERMIT

State of Idaho
Department of Environmental Quality

PERMIT No.: T2-2009.0105
FACILITY ID No.: 027-00010
AQCR: 64 CLASS: A ZONE: 11
SIC: 2063 NAICS: 311313
UTM COORDINATE (km): 534.5, 4828.0

1. PERMITTEE
The Amalgamated Sugar Company LLC – Nampa Factory

2. PROJECT
Tier II operating permit – required by DEQ to ensure compliance with applicable BART standards

3. MAILING ADDRESS	CITY	STATE	ZIP
P.O. Box 8787	Nampa	ID	83653-8787
4. FACILITY CONTACT	TITLE	TELEPHONE	
Glen Patrick	Plant Environmental Manager	(208) 468-6883	
5. RESPONSIBLE OFFICIAL	TITLE	TELEPHONE	
Kent Quinney	Plant Manager	(208) 466-3541	
6. EXACT PLANT LOCATION		COUNTY	
138 W. Karcher Ave., Nampa, Idaho		Canyon	

7. GENERAL NATURE OF BUSINESS & KINDS OF PRODUCTS
Beet sugar manufacturing

8. PERMIT AUTHORITY

This permit is issued according to the Rules for the Control of Air Pollution in Idaho, IDAPA 58.01.01.400 through 410, and pertains only to emissions of air contaminants regulated by the state of Idaho and to the sources specifically allowed to be operated by this permit.

Changes in design, equipment or operations may be considered a modification. Modifications are subject to DEQ review in accordance with IDAPA 58.01.01.200 through 228 of the Rules for the Control of Air Pollution in Idaho.

MORRIE LEWIS, PERMIT WRITER
DEPARTMENT OF ENVIRONMENTAL QUALITY

MIKE SIMON, STATIONARY SOURCE PROGRAM MANAGER
DEPARTMENT OF ENVIRONMENTAL QUALITY

Date Issued:	PROPOSED
Date Modified/Revised:	
Date Expires:	PROPOSED

MS/ML

Table of Contents

Acronyms, Units, and Chemical Nomenclature

AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
~~DLN~~	~~dry low NO_x~~
EPA	U.S. Environmental Protection Agency
~~FGD~~	~~flue gas desulfurization~~
fpm	feet per minute
gph	gallons per hour
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
iwg	inches of water gauge
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NO_2	nitrogen dioxide
NO_X	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
~~OFA~~	~~over-fired air~~
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration of air quality
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
TAP	toxic air pollutants
TASCO	The Amalgamated Sugar Company, LLC
T/hr	tons per hour
U.S.C.	United States Code
UTM	Universal Transverse Mercator
VOC	volatile organic compounds

1. TIER II OPERATING PERMIT SCOPE

Purpose

1.1 The purpose of this Tier II operating permit is to establish Best Available Retrofit Technology (BART) emission standards and requirements for the Riley Boiler in accordance with 40 CFR 51.308(e) and IDAPA 58.01.01.401.03.

Regulated Sources

1.2 Table 1, ~~The following~~ Regulated Sources, ~~Table~~ lists all sources of regulated emissions in this permit:

Table 1. **REGULATED SOURCES** ~~TABLE~~

Permit Section	Source Description	Emissions Controls
2 & 3	Riley Boiler (S-B2) Unit number: S-B3 Installation Date: 1969 Rated steam capacity: 250,000 lb steam/hr Maximum capacity: 350,000 MMBtu/hr Maximum operation: 8,760 hr/yr Fuel types: coal, natural gas	Baghouse (A-B3) Manufacturer: Envirotech Corp. Control efficiency: ≥99.0% for PM BART for PM ~~Spray-dry-line gas desulfurization system~~ ~~Reagent: Lime or limestone~~ ~~Control efficiency: 80-90% for SO_2~~ ~~BART for SO_2~~ ~~Dry low NO_X burner with over-fired air~~ Control efficiency: ≥50% for NO_X BART for NO_X
2 & 4	Pulp dryers (S-D1, S-D2, and S-D3)	Permanent shutdown

2. FACILITY-WIDE CONDITIONS

Obligation to Comply

2.1 Receiving a Tier II operating permit shall not relieve any owner or operator of the responsibility to comply with all applicable local, state, and federal rules and regulations, in accordance with IDAPA 58.01.01.406.

Incorporation of Federal Requirements by Reference

2.2 Unless expressly provided otherwise, any reference in this permit to any document identified in IDAPA 58.01.01.107.03 shall constitute the full incorporation into this permit of that document for the purposes of the reference, including any notes and appendices therein, in accordance with IDAPA 58.01.01.107. Documents include, but are not limited to:

- Protection of Visibility, 40 CFR Part 51, Subpart P, Section 308 – Best Available Retrofit Technology (BART) requirements
- Compliance Assurance Monitoring (CAM), 40 CFR Part 64

For permit conditions referencing or cited in accordance with any document incorporated by reference (including permit conditions identified as BART and CAM), should there be any conflict between the requirements of the permit condition and the requirements of the document, the requirements of the document shall govern, including any amendments.

DEQ Address

2.3 Any reporting required by this permit, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, notifications of intent to test, testing reports, or compliance certifications, shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete. Any reporting required by this permit shall be submitted to the following address:

Air Quality Permit Compliance
Department of Environmental Quality
Boise Regional Office
1445 N. Orchard
Boise, ID 83706

Phone: (208) 373-0550
Fax: (208) 373-0287

3. RILEY BOILER BART

3.1 Process Description

The Riley Boiler is fired by pulverized coal and/or natural gas, and is used to supply steam and generate electricity for processing of sugar beets into sugar and byproducts, including animal feed products at the Nampa facility.

3.2 Emission Control Description

The existingA baghouse (Unit No. A-B3) manufactured by Envirotech Corp. is used for the control of particulate matter (PM) emissions from the Riley Boiler[A1].

~~A spray dry flue gas desulfurization (FGD) system has been required for the control of sulfur dioxide (SO_2) emissions from the Riley Boiler. In a spray dry FGD system, the flue gas is introduced into a tower reactor and contacts an atomized spray of lime slurry, which absorbs and neutralizes the SO_2.~~

A ~~dry~~ low NO_x ~~(DLN) Burner combustor with over-fired air~~(LNB) has been required for the control of nitrogen oxides (NO_x) emissions from the Riley Boiler. ~~Dry low-NO_x (DLN) combustion with over-fired air Low-NOX Burners~~LNB utilizes fuel and air mixing optimization and staged combustion techniques to minimize thermal NO_x formation.

Compliance Dates

3.3 BART 40 CFR 51.308, Subpart P – BART Installation and Operation Due Date

The permittee shall install and operate BART or a DEQ-approved BART alternative on each source subject to BART as expeditiously as practicable, but in no event later than five (5) years after approval of the implementation plan, in accordance with IDAPA 58.01.01.668.04 and 40 CFR 51.308(e)(3)(iv).

Emissions Limits

3.4 BART 40 CFR 51.308, Subpart P – BART and BART Alternative Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in ~~the following~~ Table 2, Riley Boiler BART and BART Alternative Emission Limits ~~Table~~, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e):

Table 2 RILEY BOILER BART AND BART ALTERNATIVE EMISSION LIMITS TABLE

Source Description	PM	~~SO_2~~	NO_x
	lb/hr [a,c]	~~lb/hr~~ [a,c]	lb/hr [a,d]
Riley Boiler (S-B3)	14	~~115~~	186

[a] Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

[b] Tons per any consecutive 12-calendar month period[A2].

[c] BART emissions rate in accordance with 40 CFR 51.308(e).

[d] BART alternative emissions rate in accordance with 40 CFR 51.308(e)(2).

3.5 CO Emission Limits

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the emissions from the Riley Boiler stack shall not exceed any corresponding emission rate limit listed in Table 3 ~~the following~~ Riley Boiler CO Emission Limits Table, in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

Table 3. RILEY BOILER CO EMISSION LIMITS TABLE

Source Description	CO	
	lb/hr [a]	T/yr [b]
Riley Boiler (S-B3)	25.8	113

[a] Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

[b] Tons per any consecutive 12-calendar month

Operating Requirements

3.6 BART 40 CFR 51.308, Subpart P – Baghouse Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), and at all times the Riley Boiler is fired with coal, the permittee shall operate a Baghouse (A-B3) to control PM emissions from the Riley Boiler to ensure compliance with the BART PM emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e). The baghouse need not be operated during periods when the Riley Boiler is being fired exclusively with natural gas[A3].

~~3.7 BART 40 CFR 51.308, Subpart P – Spray Dry Flue Gas Desulfurization Control Equipment~~

~~On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a spray dry flue gas desulfurization (FGD) system to control SO_2 emissions from the Riley Boiler and to ensure compliance with the BART SO_2 emission limit (Permit Condition 3.11), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).~~

~~3.8~~3.7 BART 40 CFR 51.308, Subpart P – Dry Low NO_X Burners Control Equipment

On and after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall operate at all times the Riley Boiler is operated, a ~~dry Low NO_X (DLN) burner~~ LNB in the Riley Boiler to reduce NO_X emissions and to ensure compliance with the BART NO_X emission limit (Permit Condition 3.4), in accordance with IDAPA 58.01.01.401.03 and 40 CFR 51.308(e).

- The ~~DLN burner~~ LNB shall have a maximum rated heat input capacity (highest heating value) of less than or equal to 350,000 MMBtu/hr, and shall combust only natural gas and/or coal fuel.
- If operation of the ~~DLN burner with OFA~~ LNB in the Riley Boiler is expected to result in an emissions increase, the permittee shall submit the required preconstruction compliance demonstrations (Permit Condition 3.16~~3.16~~3.18).

~~3.9~~3.8 BART 40 CFR 51.308, Subpart P – Maintenance of BART Equipment

On and after the BART installation and operation due date in Permit Condition 3.3, the permittee shall maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05 and 40 CFR 51.308(e)(1)(v).

Monitoring and Recordkeeping Requirements

~~3.10~~3.9 Baghouse Pressure Differential Monitoring

The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the pressure drop across each of the baghouses, in inches water gauge. The pressure drop shall be recorded once per day while the boilers are in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision ~~7~~7(A4).

~~3.11Spray Dry FGD Adiabatic Approach Temperature Monitoring~~

~~The permittee shall install, calibrate, and maintain measuring device(s) to continuously monitor the adiabatic approach temperature for the spray dry FGD spray tower in degrees Fahrenheit. The temperature differential shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.~~

~~3.12~~3.10 Primary ~~and Over-Fired~~ Air Flow Monitoring

The permittee shall install, calibrate, and maintain measuring devices to continuously monitor the primary ~~and over-fired~~ air flow rates into the Riley Boiler, in feet per minute. The flow rate shall be recorded once per day while the Riley Boiler is in operation. In the event a measuring device becomes inoperable, it shall be repaired or replaced as soon as practicable. The records shall be maintained in accordance with General Provision 7.

~~3.13~~3.11 Operation and Maintenance Manuals

Within 60 days after the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall develop and submit to DEQ an Operation and Maintenance (O&M) manual for review and comment at the address provided (Permit Condition 2.3). Any changes to the O&M manual shall be submitted to DEQ for review and comment within 15 days of the change.

- The O&M manual shall describe for each of the control equipment described in the Regulated Sources Table (Permit Condition 1.2) procedures that will be followed to ensure compliance with BART emission limits (Permit Condition 3.4), CO emission limits (Permit Condition 3.5), the maintenance of BART equipment requirement (Permit Condition ~~3.8~~3.8.9), the control equipment maintenance and operation general provision (General Provision 2), and the manufacturer's specifications. The O&M manual shall be a permittee developed document based upon, but independent from, the manufacturer supplied operating manual(s).
- The permittee shall operate the control equipment in accordance with the O&M manual. The procedures specified in the O&M manual are incorporated by reference into this permit and are enforceable permit conditions. The O&M manual and copies of any manufacturer's manual(s) and recommendations shall remain on site at all times and shall be made available to DEQ representatives upon request.
- At a minimum, the manufacturer's recommended values that shall be maintained for each of the following operating parameters shall be included in the manual:
  - Baghouse minimum and maximum pressure drop, in inches of water (~~in~~iwg as);
  - ~~Spray dry FGD minimum slurry flow rate, in gallons per hour (gph);~~
  - ~~DLN burner~~ NB minimum and maximum flow rates for ~~both~~ primary ~~and over fired~~ airflow, in feet per minute (fpm);

- Requirements to monitor and record the parameters listed above accordance with the frequency recommended by the manufacturer, and at a minimum each day that the Riley Boiler is operated.

Performance Testing Requirements

~~3.14~~3.13.12 Initial Performance Tests

- No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3), performance tests shall be conducted on the Riley Boiler stack to demonstrate compliance with the following emission limits, in accordance with IDAPA 58.01.01.405 and IDAPA 58.01.01.157:
  - The BART PM emission limit in pounds per hour (Permit Condition 3.4);[A6]
  - ~~The BART SO_2 emission limit in pounds per hour (Permit Condition 3.4);~~
  - The BART NO_X emission limit in pounds per hour (Permit Condition 3.4); and
  - The CO emission limit in pounds per hour (Permit Condition 3.5).
- Each performance test shall be conducted under the following conditions, unless otherwise approved by DEQ, in accordance with IDAPA 58.01.01.405, IDAPA 58.01.01.157, and General Provision 6:
  - Emissions shall be measured while combusting coal fuel in the Riley Boiler.
  - Three separate test runs shall be conducted for each performance test. The minimum time per run shall be ~~20~~ 60 minutes.
  - Parameters shall be monitored and recorded as specified in the performance test monitoring and recordkeeping requirement (Permit Condition 3.~~14~~13.~~14~~16).

~~3.15~~3.13.13 Periodic Performance Testing

Performance tests to determine PM, ~~SO_2~~, NO_X, and CO emissions in pounds per hour from the Riley Boiler stack shall be conducted no less frequently than annually following the date of each required initial performance test, in accordance with IDAPA 58.01.01.405 and under the conditions required for the initial performance tests (Permit Condition 3.~~12~~13.~~12~~14), unless another testing frequency has been approved by DEQ.

~~3.16~~3.13.14 Performance Test Monitoring and Recordkeeping

The permittee shall monitor and record the following during each performance test, unless otherwise approved by DEQ:

- Steam production rate of the Riley Boiler, in pounds per hour (lb steam/hr), once every 15 minutes;
- Coal feed rate to the Riley Boiler, in tons per hour (T/hr), once every 15 minutes (the coal feed rate may be determined using alternate relevant operational parameter(s) and a calculation method which has been approved by DEQ);
- Natural gas firing rate, in million standard cubic feet per hour (MMscf/hr), once every 15 minutes;
- Highest heating value and analysis results, including ash content, of the coal fired;
- Pressure drop across the baghouse during each test, in inches water gauge (iwg), once every 15 minutes;
- ~~Spray dry FGD adiabatic approach temperature, in degrees Fahrenheit (°F), once every 15 minutes; and~~
- ~~DLN burner~~] NB primary ~~and over fired~~ air flow rates, in feet per minute (fpm), once every 15 minutes.

~~3.173.15~~ Performance Test Reporting

The permittee shall submit performance test reports to DEQ which include records of the monitoring required (Permit Condition ~~3.143.143.16~~) and in accordance with the performance testing general provision (General Provision 6). Performance test reports shall be submitted by the permittee to the DEQ address provided (Permit Condition 2.3).

Compliance Submittals and Notifications

~~3.183.16~~ Preconstruction Compliance Demonstrations

No later than 180 days prior to the BART installation and operation due date (as defined in Permit Condition 3.3), the permittee shall submit information and modeling analyses demonstrating that installation and operation of BART will not cause or significantly contribute to a violation of any ambient air quality standards, in accordance with the procedures provided in IDAPA 58.01.01.200-228. This shall include the following, unless otherwise approved by DEQ:

- Demonstration of Preconstruction Compliance with applicable ~~H~~toxicsoxic air pollutant emission rules~~Standards~~
- Demonstration of Preconstruction Compliance with National Ambient Air Quality Standards[NAAQS]

~~3.19CAM 40 CFR 64 and IDAPA 58.01.01.668.06.c Documentation of Need for Improved Monitoring~~

~~No later than 90 days after the BART installation and operation due date (as defined in Permit Condition 3.3) and unless otherwise approved by DEQ, the permittee shall submit information to address monitoring changes in accordance with IDAPA 58.01.01.668.06.c, and in a Compliance Assurance Monitoring (CAM) plan relevant to the installation and operation of BART in accordance with the procedures in 40 CFR Part 64.~~

~~3.203.17~~ Submittal and Notification Requirements

Required compliance submittals and notifications (Permit Conditions ~~3.163.163.18~~ and ~~3.193.193.19~~) shall be submitted to the DEQ address provided (Permit Condition 2.3).

4. PULP DRYERS

Operating Requirements

4.1 BART 40 CFR 51.308, Subpart P – Shutdown of Coal-Fired (as)Pulp Dryers Shutdown

The permittee shall permanently shut down the Souththree coal-fired pulp dryers (aq)(S-D1, S-D2, and S-D3).

Notification and Reporting Requirements

4.2 Pulp Dryers Shutdown Notification

Within 30 days after completing permanent shut down of the Souththree coal-fired pulp dryers (as required by Permit Condition 4.1), the permittee shall provide written notification to DEQ of the decision to permanently shut down the South coal-fired pulp dryers. The notification shall include a description of the method used to ensure permanent shut down of the pulp dryers.

5. SUMMARY OF EMISSION RATE LIMITS

The following table 4 provides a summary of all emission rate limits required by this permit:

Table 4. SUMMARY OF EMISSION RATE LIMITS

Source Description	PM	~~SO_2~~	NO_X	CO	
	lb/hr [a,c]	~~lb/hr~~ [a,c]	lb/hr [a,c]	lb/hr [a]	T/yr [b]
Riley Boiler (S-B3) with BART	14	~~115~~	186	25 8	113

(a) Pounds per hour, as determined by a test method prescribed by IDAPA 58.01.01.157, EPA reference method, or DEQ approved alternative.

(b) Tons per any consecutive 12-calendar month period

(c) BART emissions rate in accordance with 40 CFR 51 308(e).

6. TIER II PERMIT TO OPERATE GENERAL PROVISIONS

General Compliance

1. The permittee has a continuing duty to comply with all terms and conditions of this permit. All emissions authorized herein shall be consistent with the terms and conditions of this permit and the Rules for the Control of Air Pollution in Idaho. The emissions of any pollutant in excess of the limitations specified herein, or noncompliance with any other condition or limitation contained in this permit, shall constitute a violation of this permit and the Rules for the Control of Air Pollution in Idaho, and the Environmental Protection and Health Act, Idaho Code §39-101, et seq.

[Idaho Code §39-101, et seq.]

2. The permittee shall at all times (except as provided in the Rules for the Control of Air Pollution in Idaho) maintain in good working order and operate as efficiently as practicable, all treatment or control facilities or systems installed or used to achieve compliance with the terms and conditions of this permit and other applicable Idaho laws for the control of air pollution.

[IDAPA 58.01.01.405, 5/1/94]

3. Nothing in this permit is intended to relieve or exempt the permittee from the responsibility to comply with all applicable local, state, or federal statutes, rules and regulations.

[IDAPA 58.01.01.406, 5/1/94]

Inspection and Entry

4. Upon presentation of credentials, the permittee shall allow DEQ or an authorized representative of DEQ to do the following:

   a. Enter upon the permittee's premises where an emissions source is located or emissions related activity is conducted, or where records are kept under conditions of this permit;

   b. Have access to and copy, at reasonable times, any records that are kept under the conditions of this permit;

   c. Inspect at reasonable times any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit; and

   d. As authorized by the Idaho Environmental Protection and Health Act, sample or monitor, at reasonable times, substances or parameters for the purpose of determining or ensuring compliance with this permit or applicable requirements.

[Idaho Code §39-108]

Construction and Operation Notification

5. The permittee shall furnish DEQ written notifications as follows:

   a. A notification of the date of initiation of construction, within five working days after occurrence;

   b. A notification of the date of any suspension of construction, if such suspension lasts for one year or more;

   c. A notification of the anticipated date of initial start-up of the stationary source or facility not more than sixty days or less than thirty days prior to such date;

   d. A notification of the actual date of initial start-up of the stationary source or facility within fifteen days after such date; and

   e. A notification of the initial date of achieving the maximum production rate, within five working days after occurrence - production rate and date.

[IDAPA 58.01.01.405, 5/1/94]

Performance Testing

6. If performance testing (air emissions source test) is required by this permit, the permittee shall provide notice of intent to test to DEQ at least 15 days prior to the scheduled test date or shorter time period as approved by DEQ. DEQ may, at its option, have an observer present at any emissions tests conducted on a source. DEQ requests that such testing not be performed on weekends or state holidays.

   All performance testing shall be conducted in accordance with the procedures in IDAPA 58.01.01.157. Without prior DEQ approval, any alternative testing is conducted solely at the permittee's risk. If the permittee fails to obtain prior written approval by DEQ for any testing deviations, DEQ may determine that the testing does not satisfy the testing requirements. Therefore, at least 30 days prior to conducting any performance test, the permittee is encouraged to submit a performance test protocol to DEQ for approval. The written protocol shall include a description of the test method(s) to be used, an explanation of any or unusual circumstances regarding the proposed test, and the proposed test schedule for conducting and reporting the test.

   Within 30 days following the date in which a performance test required by this permit is concluded, or an alternate deadline approved by DEQ, the permittee shall submit to DEQ a performance test report. The written report shall include a description of the process, identification of the test method(s) used, equipment used, all process operating data collected during the test period, and test results, as well as raw test data and associated documentation, including any approved test protocol.

   [IDAPA 58.01.01.157, 4/5/00]

Monitoring and Recordkeeping

7. The permittee shall maintain sufficient records to ensure compliance with all of the terms and conditions of this permit. Records of monitoring information shall include, but not be limited to the following: (a) the date, place, and times of sampling or measurements; (b) the date analyses were performed; (c) the company or entity that performed the analyses; (d) the analytical techniques or methods used; (e) the results of such analyses; and (f) the operating conditions existing at the time of sampling or measurement. All monitoring records and support information shall be retained for a period of at least five years from the date of the monitoring sample, measurement, report, or application. Supporting information includes, but is not limited to, all calibration and maintenance records and all original strip-chart recordings for continuous monitoring instrumentation and copies of all reports required by this permit. All records required to be maintained by this permit shall be made available in either hard copy or electronic format to DEQ representatives upon request.

   [IDAPA 58.01.01.405, 5/1/94]

Excess Emissions

8. The permittee shall comply with the procedures and requirements of IDAPA 58.01.01.130-136 for excess emissions due to startup, shutdown, scheduled maintenance, safety measures, upsets and breakdowns.

[IDAPA 58.01.01.130-136, 4/5/00]

Certification

9. All documents submitted to DEQ, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

[IDAPA 58.01.01.123, 5/1/94]

False Statements

10. No person shall knowingly make any false statement, representation, or certification in any form, notice, or report required under this permit, or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.125, 3/23/98]

Tampering

11. No person shall knowingly render inaccurate any monitoring device or method required under this permit or any applicable rule or order in force pursuant thereto.

[IDAPA 58.01.01.126, 3/23/98]

Expiration and Renewal

12. This permit shall be renewable on the expiration date, provided the permittee submits an application for renewal to the Department and continues to meet all terms and conditions contained in the permit. The expiration of this permit will not affect the operation of the stationary source of facility during the administrative procedure period associated with the permit renewal process.

[IDAPA 58.01.01.404.04, 7/1/02]

Transferability

13. This permit is transferable in accordance with procedures listed in IDAPA 58.01.01.404.05.

[IDAPA 58.01.01.404.05, 4/11/06]

State of Idaho
Department of Environmental Quality
Air Quality Division

AIR QUALITY PERMIT
STATEMENT OF BASIS

Tier II Operating Permit No. T2-2009.0105

Public Comment

The Amalgamated Sugar Company LLC (TASCO)

Nampa Factory

Nampa, Idaho

Facility ID No. 027-00010

April 16, 2010

Morrie Lewis

Permit Writer

The purpose of this Statement of Basis is to satisfy the requirements of IDAPA 58.01.01 et seq, Rules for the Control of Air Pollution in Idaho, for issuing air permits.

Table of Contents

Acronyms, Units, and Chemical Nomenclature

AAC	acceptable ambient concentrations for non-carcinogens
AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
BART	Best Available Retrofit Technologies
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
DLN	dry low-NO_x
EGU	electrical generation units
EPA	U.S. Environmental Protection Agency
ESP	electrostatic precipitator
FGD	flue gas desulfurization
HAP	hazardous air pollutants
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
km	kilometers
lb/hr	pounds per hour
lb steam/hr	pounds of steam output per hour
LNB	low NO_x burner
MACT	Maximum Achievable Control Technology
MMBtu/hr	million British thermal units per hour
MMscf/hr	million standard cubic feet per hour
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industry Classification System
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	operations and maintenance
OFA	over-fired air
PM	particulate matter
$PM_{2.5}$	particulate matter with an aerodynamic diameter less than or equal to a nominal 2.5 micrometers
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
PSD	prevention of significant deterioration
Rules	Rules for the Control of Air Pollution in Idaho
SCR	selective catalytic reduction
SIC	Standard Industrial Classification
SIP	State Implementation Plan
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/hr	tons per hour
T/yr	tons per year
T2	Tier II operating permit
TAP	toxic air pollutant
TASCO	The Amalgamated Sugar Company LLC
ULNB	ultra-low NO_x burner
UTM	Universal Transverse Mercator
VOC	volatile organic compounds
Δdv	change in delta deciviews

1. FACILITY INFORMATION

1.1 Facility Description

The Amalgamated Sugar Company LLC – Nampa Factory is a beet sugar manufacturing plant.

1.2 Permitting Action and Facility Permitting History

This permit is a Tier II operating permit (T2) for this existing facility. This T2 establishes the best available retrofit technologies' (BART) emissions standards[1] for the facility and associated monitoring, recordkeeping, and reporting requirements. See the current Tier I permit statement of basis for the permitting history.

2. APPLICATION SCOPE AND APPLICATION CHRONOLOGY

2.1 Application Scope

This Tier II operating permit establishes the BART emissions standards for the facility and the associated monitoring, recordkeeping, and reporting requirements, based upon the BART proposed by TASCO, and the regional haze air quality impact analysis and BART determination completed by DEQ. Specific information relevant to the control devices selected as BART may not be available at this time if the information is contingent upon the design specifications of the specified control technology; this has been noted where possible within the statement of basis.

2.2 Permitting Action Chronology

July 31, 2006	DEQ notified TASCO that each of the Nampa, Twin Falls, and Mini-Cassia facilities had a boiler considered to be BART-eligible.
December 14, 2006	DEQ notified TASCO that each facility had a boiler considered to be subject to BART based upon preliminary modeling analyses.
December 24, 2007	DEQ received a letter from TASCO including a claim of financial hardship.
August 31, 2006 – March 2008	DEQ received several communications from TASCO which provided revised emission data and supporting documentation.
August 31, 2006 – July 21, 2009	DEQ received several communications from TASCO which included concerns regarding the BART technical review. DEQ responded to concerns and provided supporting information, and informed TASCO that the option was available to submit alternate analyses.
February 23, 2007	DEQ provided revised modeling analyses to TASCO, which indicated that the Nampa facility was subject to BART and that the Twin Falls and Mini-Cassia facilities were not subject to BART.
June 17, 2007	DEQ notified TASCO that the Riley boiler was a BART-eligible source and subject to BART.
July 19, 2007	DEQ notified TASCO that the Riley boiler was determined to be subject-to-BART and provided the subject-to-BART determination (refer to Appendix C).
July 24, 2007	DEQ sent copies of the BART exemption modeling to the EPA and FLM for review.

[1] Additional information concerning the Regional Haze Rule can be found at http://www.deq.idaho.gov/air/prog_issues/pollutants/haze_bart.cfm.

November 20, 2007	DEQ received a BART determination analysis report from TASCO for the Riley Boiler. DEQ sent a letter to TASCO requesting review of additional control technologies and requesting information supporting the claim of financial hardship and the technically infeasibility of certain control technologies.
September 16, 2008	DEQ provided TASCO the results of modeling analyses for BART alternative control strategies, and requested that TASCO provide DEQ with any BART alternatives for consideration which could achieve equivalent or better improvements.
February 9, 2009	DEQ received a revised BART determination analysis report from TASCO which included additional feasible control technologies.
March 11 – May 13, 2009	DEQ requested and received guidance from EPA concerning evaluation of the claim of financial hardship.
June 17, 2009	DEQ sent a letter to TASCO requesting financial information in order to evaluate the claim of financial hardship.
July 1, 2009	DEQ met with TASCO to discuss BART alternatives and extended the deadline for providing supporting financial information.
July 3, 2009	DEQ sent a letter to TASCO addressing questions concerning the subject-to-BART modeling analyses.
July 17, 2009	DEQ notified TASCO of the control technology selection and provided the BART determination analyses (refer to Appendix B).
July 21, 2009	DEQ received financial information from TASCO with a claim of confidentiality.
August 18, 2009	DEQ made available the draft permit and statement of basis for peer and Boise Regional Office review.
August 21, 2009	DEQ made available the draft permit and statement of basis to TASCO for facility review.
August 25, 2009	DEQ received a communication from TASCO requesting that facility review of the draft permit and statement of basis be postponed until the claim of financial hardship had been evaluated.
August 28, 2009	DEQ sent an email to TASCO approving the postponement of the facility review period for the draft permit and statement of basis.
September 10, 2009	DEQ was informed by TASCO that financial information could be released to EPA concerning the claim of confidentiality.
October 9, 2009	DEQ met with EPA and TASCO to discuss the claim of financial hardship.
November 5, 2009	DEQ met with EPA and TASCO to review the financial information submitted and to request additional information.
November 18, 2009	DEQ received supplemental BART determination information from TASCO.
February 22 – March 14, 2010	DEQ was provided a financial analysis and supporting information from EPA Region X which indicated that BART was affordable based upon the financial information provided.

March 17, 2009	DEQ notified TASCO that it had been determined that BART was affordable and provided the financial analysis and supporting information.
March 26, 2010	DEQ made available a revised draft permit and statement of basis for facility review.
April 1, 2010	DEQ sent a letter to TASCO responding to concerns identified in the BART determination letter dated November 18, 2009, and addressing financial hardship, modeling, and emissions reduction crediting concerns.
April 6, 2010	DEQ received comments from TASCO concerning the draft permit and statement of basis. Specific comments relevant to the selected BART control options were addressed as described in the permit condition section (refer to Section 4.11).
April 2010	DEQ provided a public comment period on the proposed Tier II operating permit and BART determination.

3. TECHNICAL ANALYSIS

3.1 Emission Unit and Control Device

Detailed discussion of the emissions control devices, estimated emissions reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the emissions control devices required as BART follows.

A baghouse (Unit No. A-B3) manufactured by Envirotech Corp. is used for the control of particulate matter (PM) emissions from the Riley boiler.

~~A spray dry flue gas desulfurization (FGD) system has been required for the control of sulfur dioxide (SO_2) emissions from the Riley boiler. In a spray dry FGD system, the flue gas is introduced into a tower and contacts an atomized spray of lime slurry, which absorbs and neutralizes the SO_2.~~

A ~~dry low NO_x (DLN) combustor~~low-NO_x burner (LNB) with ~~over-fired air~~ has been required for the control of nitrogen oxides (NO_x) emissions from the Riley boiler. LNB~~Dry low NO_x (DLN)~~ combustion ~~with over-fired air~~ utilizes fuel and air mixing optimization and staged combustion techniques to minimize formation of thermal NO_x ~~formation~~.

Need to clarify that LNB is required for firing coal. There has never been any discussion or evaluation of LNB for natural gas.

Table 3.1 SUMMARY OF BART ANALYSIS & DETERMINATION[1][A1]

NSR Pollutant	Step 1	Step 2	Step 3		Step 4	Step 5
	Technologies Identified	Technically Feasible? (Y/N)[2]	Control Level (lb/hr)[3]	Control Ranking	Visibility impairment (# days >0.5 Δdv)[4]	Most effective? (Y/N)[2]
PM	Wet ESP	Y	12.4	1	--[5]	N[5]
	Dry ESP	Y	12.4	1	--[5]	N[5]
	Enhanced baghouse	Y	12.4	1	--[5]	N[5]
	Existing baghouse	Y	12.4	1	--[5]	Y
SO_2	Wet FGD	Y	26	1	43	N[7]
	Spray Dry FGD	Y	104	2	51	Y
	Dry Trona FGD	Y	183	3	58	N
	Dry Lime FGD	Y	235	4	66	N
	Low sulfur coal	Y	444	5	90	N
	Base case[6]	Y	522	6	127	N
NO_X	SNCR	N[8]	--	--	--	--
	SCR	Y	37	1	40	Y
	ULNB	N[9]	--	--	--	--
	LNB/OFA	~~Y~~N[10]	131	2	56	N
	LNB	Y	187	3	69	N
	Base case[6]	Y	374	4	127	N

1 This table summarizes each BART analysis and determination; detailed technical information can be found in Appendices B and C.

2 "Y" = Yes; "N" = No.

3 Estimated emissions rate assuming the control efficiency provided for each technology; information on actual performance based upon specific equipment design and operating conditions was not available.

4 Adv = delta deciviews; result is based on changes to visibility at the Eagle Cap Wilderness, the Class I area showing the greatest impact from the Riley Boiler.

5 Because the cost of the enhanced baghouse, dry ESP, and wet ESP options were determined to outweigh the improvement, BART was selected based on costs of compliance and the pollution control equipment in use (existing baghouse). Specific modeling of each PM control scenario was not analyzed.

6 Base case provided in this table represents continuous operation of the Riley boiler and the three coal-fired pulp dryers (without BART).

7 Wet FGD was not ranked higher due to non-air quality environmental impacts of compliance related to wastewater treatment.

8 SNCR was not considered feasible due to concerns that the flue gas would not have adequate residence time to achieve reliable control.

9 ULNB was not considered feasible due to concerns that the boiler firebox would not be large enough to accommodate the full burner/flame management system required.

10 An evaluation by the boiler manufacturer has confirmed that modification to accommodate over-fire air is not feasible.

A summary of the BART analysis and determination is provided in Table 3.1~~Table 3-1~~, detailed information is provided in Appendices B and C. In making the BART determination, TASCO was requested to follow the guidelines provided in Appendix Y to Part 51—Guidelines for BART Determinations Under the Regional Haze Rule. Although the state is required to follow the guidelines to make BART determinations ~~were required~~ for 750 megawatt power plants, the state is not required to use the guidelines for making BART determinations for other types of source~~electrical generation units, EPA has determined that they may be used for other BART source categories.~~ Despite petitions from TASCO requesting flexibility, DEQ declined to exercise discretion in applying the guidelines to

the Riley BART determination analysis. In this regard TASCO also requested DEQ to factor visibility improvements that resulted from the permanent shut down of all combustion units when TASCO closed the Nyssa, Oregon factory. Although combustion emissions from Nyssa were released into the same airshed, DEQ declined to exercise regulatory discretion.

The BART analysis and determination followed the five-step process as provided in Appendix Y

1) Identify all retrofit control technologies
2) Eliminate technically infeasible options
3) Evaluate control effectiveness of the remaining control technologies
4) Evaluate impacts of each remaining control technology
5) Select BART

In accordance with IDAPA 58.01.01.668.02.c, the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the following must be taken into consideration: costs of compliance; energy and non-air quality environmental impacts of compliance; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These considerations were considered and evaluated in Step 4 of the BART analysis (refer to Appendix B).

As provided in Table 3.1~~Table 3-1~~, because the existing baghouse is already in use at the facility, no improvement in visibility is expected as a result of this BART implementation.

As provided in Table 3.1~~Table 3-1~~, the spray dry FGD is expected to result in the reduction or elimination of 76 days of visibility impairment. However, TASCO has submitted documentation that FGD is cost prohibitive, so DEQ has determined that FGD is not required under the BART.

As provided in Table 3.1~~Table 3-1~~, the SCR system is expected to result in the reduction or elimination of 87 days of visibility impairment. Furthermore, since ~~T~~the next best option, the DLN burner with OFA (BART alternative[A2]) is infeasible. The next best alternative, LNB is expected to result in the reduction or elimination of 58~~71~~ days of visibility impairment.

In addition to maintaining the existing baghouse and installing the LNB on the Riley Boiler TASCO has requested acknowledgement of visibility improvements related to shut down of the coal-fired dryers. The dryer shutdown is expected to result in the reduction or elimination of 30 days of visibility impairment.

The visibility improvements expected from the combination of the selected control options (BART controls, with or without election of the BART alternative[A3]) is expected to result in a minimum reduction or elimination of ~~(30+58)~~124 days of visibility impairment (to a total of 693 days predicted of visibility impairment). Refer to Appendix B for additional information.

3.2 Emissions Inventory

Detailed discussion of the emissions control devices, estimated emissions reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the estimated emissions reductions follows.

A summary of the estimated emissions reductions for the required BART and the BART alternative (curtailing shutdown of the three coal-fired pulp dryers) is provided in Table 3.2~~Table 3-2~~. SO_2, NO_x, and PM emissions were considered visibility-impairing pollutants applicable to BART review.

Both BART and the BART alternative will result in a net emissions decrease for the applicable regional haze pollutants (PM, SO_2, and NO_x). However, an increase in the emissions of other criteria pollutants (e.g., CO and VOC) ~~and toxic air pollutants associated with the use of lime slurry~~ may result based upon BART final design specifications. Precise estimates of these emissions increases have not been determined because information is not yet available and has not been provided by the permittee.

Table 3.2 ESTIMATED INCREASE IN CONTROLLED EMISSIONS – RILEY BOILER WITH BART

Pollutants	Baseline Emissions (lb/hr)	BART Emissions (lb/hr)[a]	Net Emissions Increase (lb/hr)
Regional Haze Pollutants			
PM – Riley boiler	12.4	12.4	0
PM – pulp dryers shutdown[b]	98.1		-98.1
SO_2 – Riley boiler	522	~~522~~115	~~0~~-407
SO_2 – pulp dryers shutdown[b]	17.8		-17.8
NO_X – Riley boiler	374	186	-188
NO_X – pulp dryers shutdown[b]	191		-191
Total	*1,215.3*	~~313.4~~720.4	~~-901.9~~-494.9
TAP and other Criteria Pollutants			
CO – Riley boiler	10.9	25.8	14.9
VOC – Riley boiler	1.95	TBD[c]	TBD[c]
~~Other criteria pollutants and TAP (including lime used in spray dry FGD)~~	~~TBD~~[c]	~~TBD~~[c]	~~TBD~~[c]

a. Based upon the shutdown of the three coal-fired pulp dryers (SD-1, SD-2, and SD-3), and the installation and operation of the existing baghouse (AB-3), ~~spray dry FGD~~, and LNB with OFA control equipment as BART

b. Based upon the estimated emissions reductions attributable to shutdown of the three coal-fired pulp dryers (SD-1, SD-2, and SD-3), as provided in Table 7 of the revised proposed BART determination submitted February 9, 2009

c. To be determined (TBD); emissions of these pollutants are dependent upon BART final design specifications, and preconstruction compliance demonstrations may be required.

This Tier II operating permit (T2-2009.0105~~T2-2009-0105~~) may need to be revised based upon BART final design specifications, especially with regard to the installation of the ~~LNB burner~~. Permit Condition 3.18 requires that the permittee provide information and modeling analyses in order to demonstrate that BART will not cause or significantly contribute to a violation of any applicable ambient air quality standards.

3.3 Ambient Air Quality Impact Analysis

Detailed discussion of the emissions control devices, estimated emissions reductions, and regional haze air quality impact analysis associated with the BART determination have been included in Appendices B and C. A general description of the regional haze ambient impact analysis follows.

The Riley boiler was determined to contribute to visibility impairment (and therefore subject to BART) because the modeled 98th percentile change in deciviews (delta-deciview) was equal to or greater than the contribution threshold of 0.5 deciviews. A single source that is responsible for a one-half (0.5) deciview change or more in any mandatory Class I Federal Area is considered to "contribute" to visibility impairment in accordance with IDAPA 58.01.01.668.02.b.

As discussed in Section 3.1, the visibility improvements expected from the combination of the selected control options (BART controls, with or without election of the BART alternative) is expected to result in a minimum reduction or elimination of [124 days of visibility impairment (to a total of 3 days [A4]predicted of visibility impairment). This was determined based on modeling analysis considering implementation of the existing baghouse, ~~and a spray dry flue gas desulfurization system, a dry~~ low NO_X burner ~~with over-fired air~~ on the Riley Boiler and permanent shutdown of the coal-fired pulp dryers).

Refer to Section 3.1 for additional information.

Although regional haze modeling was completed, ambient air impact analyses for the Riley boiler have not been provided to account for any net emissions increase resulting from installation and operation of BART control equipment. A net emissions increase in CO emissions may be anticipated to result from installation and operation of the LNB burner. ~~A net emissions increase resulting from the use of lime slurry may be anticipated to result from the installation and operation of the spray dry FGD system.~~[2]

Because ambient air impact analyses were not provided to demonstrate preconstruction compliance with National Ambient Air Quality Standards (NAAQS), applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18). The permittee is encouraged to submit any required preconstruction compliance demonstration as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable). Refer to Section 3.2 for additional information.

Similarly, because emissions estimates and ambient air impact analyses were not provided to address applicability to Prevention of Significant Deterioration (PSD) requirements, applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18). In addition, an annual emission limit for CO has been included in an attempt to ensure that the significance threshold of 100 T/yr will not be exceeded, which would result in applicability to PSD review. The permittee is encouraged to submit this information as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable).

Similarly, because emissions estimates and ambient air impact analyses were not provided to demonstrate preconstruction compliance with toxic standards, applicable preconstruction compliance demonstrations have been required to be submitted to DEQ prior to construction (Permit Condition 3.18).

4. REGULATORY REVIEW

4.1 Attainment Designation (40 CFR 81.313)

The facility is located in Canyon County which is designated as attainment or unclassifiable for PM_{10}, $PM_{2.5}$, CO, NO_2, SO_X, and Ozone. Reference 40 CFR 81.313.

4.2 Permit to Construct (IDAPA 58.01.01.201)

This permitting action was processed in accordance with the procedures of IDAPA 58.01.01.400-410 (refer to Section 4.3).

4.3 Tier II Operating Permit (IDAPA 58.01.01.401)

In accordance with IDAPA 58.01.01.03.b, DEQ may require or revise a Tier II operating permit for any stationary source or facility whenever DEQ determines that specific emission standards or requirements on operation or maintenance are necessary to ensure compliance with any applicable emission standard or rule. This Tier II operating permit establishes the BART emissions standards applicable to the Riley boiler. Therefore this permitting action was processed in accordance with the procedures of IDAPA 58.01.01.400-410.

4.4 Title V Classification (IDAPA 58.01.01.300, 40 CFR Part 70)

The installation and operation of BART control devices are not expected to change Title V applicability or classification for the facility. Although BART control equipment is expected to reduce annual PM,

[2] As provided by IASCO in the revised BART determination analysis report (02/05/09).

SO_2, and NO_x emissions, and an enforceable CO annual emission limit (T/yr) has been established in an attempt to preclude PSD applicability, facility-wide emissions are still expected to remain above major source thresholds

The facility is classified as a major facility as defined in IDAPA 58.01.01.008.10, because it emits or has the potential to emit regulated air pollutants in amounts greater than or equal to major facility thresholds listed in IDAPA 58.01.01.008.10

4.5 PSD Classification (40 CFR 52.21)

The installation and operation of BART control devices is not expected to change PSD applicability or classification for the facility. BART standards establish short-term PM, SO_2, and NO_x emission limits (lb/hr); an enforceable CO annual emission limit (T/yr) has been established in an attempt to preclude PSD applicability. At the time of this permitting action, TASCO has not proposed or requested an annual increase in emissions that would be applicable to PSD review.

Emissions of CO may increase as a result of the installation of a LNB~~DLN burner~~. Using the emission factors in AP-42 as a relative guide for comparison purposes, the use of a LNB~~DLN burner~~ could potentially double the emissions of CO, resulting in an anticipated increase of approximately 30 T/yr and less than the PSD significance level of 100 T/yr for CO emissions.[3]

Permit Condition 3.5 includes emission limits in tons per year and pounds per hour (based on unlimited operation at 8,760 hr/yr) in an attempt to preclude PSD applicability and to avoid exceeding the PSD significance threshold for CO.

40 CFR 52.21 ... . Prevention of significant deterioration of air quality.

In accordance with §52.21(a)(2)(i), the requirements of this section apply to any project at an existing major stationary source in an area designated as attainment or unclassifiable under sections 107(d)(1)(A)(ii) or (iii) of the Act. The Riley boiler is an existing major stationary source in an attainment area.

In accordance with §52.21(a)(2)(ii), the requirements of paragraphs (j) through (r) of this section apply to the construction of any new major stationary source or the major modification of any existing major stationary source, except as this section otherwise provides.

In accordance with §52.21(b)(2)(i), major modification means any physical change in or change in the method of operation of a major stationary source that would result in: a significant emissions increase (as defined in paragraph (b)(40) of this section) of a regulated NSR pollutant (as defined in paragraph (b)(50) of this section), and a significant net emissions increase of that pollutant from the major stationary source.

In accordance with §52.21(b)(40), a significant emissions increase means, for a regulated NSR pollutant, an increase in emissions that is significant (as defined in paragraph (b)(23) of this section) for that pollutant.

In accordance with §52.21(b)(23)(i), significant means, in reference to a net emissions increase or the potential of a source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the rates listed, including 100 T/yr of carbon monoxide (CO). The ~~DLN burner with OFA~~ LNB may have the possibility of resulting in an increase in the emissions of a listed pollutant, specifically that of CO emissions.

[3] Relative increase estimated based on emissions estimates provided in TASCO's revised BART determination (02/09/09) and a ratio of emission factors found in AP-42 Section 1.7, Table 1.7-1 and Table 1.7-1. This estimate is provided for informational purposes only, the actual emissions increase may vary based upon ~~DLN burner~~ LNB final design specifications and the combustion of other coal types, such as bituminous and subbituminous coal.

In accordance with §52.21(b)(3)(i), net emissions increase means, with respect to any regulated NSR pollutant emitted by a major stationary source, the amount by which the sum of the following exceeds zero: (*a*) the increase in emissions from a particular physical change or change in the method of operation at a stationary source as calculated pursuant to paragraph (a)(2)(iv) of this section; and (*b*) any other increases and decreases in actual emissions at the major stationary source that are contemporaneous with the particular change and are otherwise creditable.

In accordance with §52.21(a)(2)(iv)(*a*), a project is a major modification for a regulated NSR pollutant if it causes two types of emissions increases—a significant emissions increase, and a significant net emissions increase. The project is not a major modification if it does not cause a significant emissions increase.

In accordance with §52.21(a)(2)(iv)(*c*), the actual-to-projected-actual applicability test is used as the procedure for calculating (before beginning actual construction) whether a significant emissions increase will occur for projects that only involve existing emissions units. A significant emissions increase of a regulated NSR pollutant is projected to occur if the sum of the difference between the projected actual emissions and the baseline actual emissions equals or exceeds the significant amount for that pollutant.

In accordance with §52.21(b)(48)(ii), for an existing emissions unit, baseline actual emissions means the average rate of emissions, in tons per year, of a regulated NSR pollutant, at which the emissions unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 10-year period immediately preceding either the date the owner or operator begins actual construction of the project, whichever is earlier, except that the 10-year period shall not include any period earlier than November 15, 1990.

The average rate of emissions over 2003-2005 were provided by TASCO in the revised BART determination analysis (02/09/09). Although these emissions calculations were not presented to determine PSD applicability, until additional information has been provided and in absence of data for a 10-year period, these numbers have been used for this purpose. The 24-month average annual emissions (over 2004-2005) of CO from the Riley boiler was 30.5 T/yr.

In accordance with §52.21(b)(41)(i), projected actual emissions means the maximum annual rate, in T/yr, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project, or in any one of the 10 years following that date, if the project involves increasing the emissions unit's design capacity or its potential to emit that regulated NSR pollutant and full utilization of the unit would result in a significant emissions increase or a significant net emissions increase at the major stationary source.

In accordance with §52.21(b)(41)(ii)(*d*), in lieu of using other methods, and in absence of information unavailable at this time, the emissions unit's potential to emit has been used to determine the projected actual emissions.

In accordance with §52.21(b)(4), potential to emit means the maximum capacity of a stationary source to emit a pollutant under its physical and operational design. Any physical or operational limitation on the capacity of the source to emit a pollutant, including air pollution control equipment and restrictions on hours of operation or on the type or amount of material combusted, stored, or processed, shall be treated as part of its design if the limitation or the effect it would have on emissions is federally enforceable. Secondary emissions do not count in determining the potential to emit of a stationary source.

The Riley boiler potential to emit has been limited to 113 T/yr of CO emissions in Permit Condition 3.5. As a result, the actual-to-projected-actual applicability test would result in an emissions increase of 82.5

T/yr (113 – 30.5 T/yr), which includes a significant margin of compliance to avoid exceeding the 100 T/yr significance threshold for CO.

4.6 NSPS Applicability (40 CFR 60)

Installation of a ~~DI-N-burner~~ LNB for the control of NO_x may meet the definition of modification or reconstruction of the Riley boiler as defined in 40 CFR 60.14 and 60.15 (respectively); determinations of applicability have not been made at this time. The permittee is encouraged to submit information necessary to make these determinations as soon as practicable to allow adequate time for DEQ to review, and to process any associated permitting actions (if applicable). Refer to Section 3.2 for additional information.

4.7 NESHAP Applicability (40 CFR 61)

The installation and operation of BART is not expected to change National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 61 applicability for the Riley boiler.

4.8 MACT Applicability (40 CFR 63)

The installation and operation of BART control devices is not expected to change National Emission Standards for Hazardous Air Pollutants (NESHAP) Part 63 applicability for the Riley boiler.

4.9 CAM Applicability (40 CFR 64)

This permitting action does not address specific Compliance Assurance Monitoring (CAM) requirements relevant to the installation and operation of BART control devices. Revisions to the CAM plan may be required on or before the Title V operating permit renewal in order to address CAM requirements for each of the BART control devices implemented.

The Riley boiler has potential pre-control device emissions rates equal to or greater than 100 percent of the amount required for a source to be classified as a major source (including SO_2 and NO_x emissions). Therefore, the Riley boiler and associated BART will continue to be subject to the requirements of CAM in accordance with 40 CFR 64.2(a).

New monitoring, recordkeeping, and reporting requirements associated with BART operating parameters (indicators) may need to be addressed in the CAM plan, including requirements specific to PM for the baghouse~~, requirements specific to SO_2 for the spray dry FGD system,~~ and requirements specific to NO_x LNB for ~~over-fired air~~ combustion techniques.

4.10 BART Applicability (40 CFR 51.308)

40 CFR 51.301 ..... Definitions.

In accordance with §51.301.

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

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

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

Deciview haze index=10 $\ln_e(b_{ext}/10\ Mm^{-1})$.

Where b_{ext} =the atmospheric light extinction coefficient, expressed in inverse megameters (Mm^{-1}).

Existing stationary facility means any of the stationary sources of air pollutants listed in 40 CFR 51.301, including any reconstructed source, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year or more of any air pollutant. The list of 26 source categories includes fossil-fuel boilers of more than 250 MMBtu/hr heat input. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted.

The Riley boiler is a BART-eligible source because it was an existing stationary facility that was not in operation prior to August 7, 1962 and was in existence on August 7, 1977 (Riley boiler was installed in 1969), having the potential to emit 250 tons per year of air pollutants (PM, SO_2, NO_x, and CO). The Riley boiler is a fossil-fuel boiler with heat input of 350 MMBtu/hr which exceeds ~~more than the~~ 250 MMBtu/hr heat input threshold for source categories identified in the CAA~~(350 MMBtu/hr)~~.

40 CFR 51.308 ..... Regional haze program requirements

In accordance with §51.308(a), this section establishes requirements for implementation plans, plan revisions, and periodic progress reviews to address regional haze.

Section §51.308(b) through (f) describes the administrative procedures for the implementation plan for regional haze. The plan must address regional haze in each mandatory Class I Federal area located within the state and in each mandatory Class I Federal area located outside the state which may be affected by emissions from within the state. At a minimum, the implementation plan must include reasonable progress goals, calculations of baseline and natural visibility conditions, long-term strategy for regional haze, monitoring strategy and other implementation plan requirements, Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment, requirements for comprehensive periodic revisions of implementation plans for regional haze, and requirements for periodic reports describing progress towards the reasonable progress goals.

Section §51.308(e) describes the Best Available Retrofit Technology (BART) requirements for regional haze visibility impairment. The state must submit an implementation plan containing emission limitations representing BART and schedules for compliance with BART for each BART-eligible source that may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area. The purpose of IDAPA 58.01.01.668 is to implement the BART

requirements in 40 CFR 51.308(e).

In accordance with §51.308(e)(1), to address the requirements for BART, the state must submit an implementation plan containing the plan elements and include documentation for all required analyses.

In accordance with §51.301, a BART-eligible source means an existing stationary facility, which includes fossil-fuel boilers of more than 250 million British thermal units per hour heat input, which was not in operation prior to August 7, 1962, and was in existence on August 7, 1977, and has the potential to emit 250 tons per year (T/yr) or more of any air pollutant. In determining potential to emit, fugitive emissions, to the extent quantifiable, must be counted. The Riley boiler was installed in 1969, and based on the emissions estimates provided, the Riley boiler has the potential to emit more than 250 tons per year each of PM, SO_2, and NO_X emissions (refer to Section 3.1). Therefore the Riley boiler was determined to be subject to BART.

In accordance with §51.308(e)(1)(ii), each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal area is subject to BART. Based on the results of the modeling analysis, the TASCO Riley Boiler impacted the Eagle Cap Wilderness, Hells Canyon National Recreation Area, and the Strawberry Mountain Wilderness. A detailed discussion follows in the regulatory review provided for IDAPA 58.01.01.668.02.

In accordance with §51.308(e)(1)(ii)(A), the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the state 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, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology.

Because the Riley boiler has the potential to emit more than 250 T/yr each of PM, SO_2 and NO_X emissions (refer to Section 3.1), it does not qualify for the exception provided in §51.308(e)(1)(ii)(C).

In accordance with §51.308(e)(1)(iii), if the state determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice or operation, and must provide for compliance by means which achieve equivalent results. At this time it has not been demonstrated that the imposition of an emission standard is infeasible due to technological or economic limitations. Therefore alternative standards were not considered and enforceable PM, SO_2, and NO_X emission limits and associated requirements were included in the permit.[A5]

In accordance with §51.308(e)(1)(iv), each source subject to BART shall be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision. Permit Condition 3.3 includes the requirement of this section.

In accordance with §51.308(e)(1)(v), each source subject to BART shall maintain the control equipment required by this subpart and establish procedures to ensure such equipment is properly operated and maintained. Permit Condition 3.12 includes the requirement of this section.

In accordance with §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. The alternative measure must achieve greater reasonable progress than would be achieved through the installation and operation of BART. For all such alternative measures, the state must submit an implementation plan containing the plan elements and include documentation for all required analyses.

Consideration of the optional shutdown of the three coal-fired pulp dryers as proposed by TASCO and the associated emissions reduction was provided as part of an alternative measure to the installation and operation of BART. The shutdown of the three coal-fired pulp dryers (SD-1, SD-2, and SD-3) and the installation and operation of ~~low-NO_x burners with over-fired air (~~LNB ~~with OFA)~~ combined were determined to be equivalent or better in achieving the NO_x emissions reductions at the facility using the SCR BART option (refer to Appendix B).

In accordance with §51.308(e)(2)(i), a demonstration that the 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. Modeling analysis and documentation, including a list of all BART-eligible sources, an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for the Riley boiler, a determination of BART for the Riley boiler, and an analysis of the projected emissions reductions achievable through the alternative measure have been provided in Appendix B.

In accordance with §51.308(e)(2)(i)(E), it has been determined by DEQ that based on the clear weight of evidence the alternative measure to BART (LNB ~~with OFA~~) for the control of NO_x emissions achieves greater reasonable progress than would be achieved through the installation and operation of BART at the covered sources.

In accordance with §51.308(e)(2)(iii), all necessary emission reductions shall take place during the period of the first long-term strategy for regional haze.

In accordance with §51.308(e)(2)(iv), a demonstration that the emission reductions resulting from the alternative measure will be surplus to those reductions resulting from measures adopted to meet requirements of the CAA as of the baseline date of the SIP was provided in Appendix B.

In accordance with §51.308(e)(3), because the distribution of emissions is not substantially different than under BART, and the alternative measure results in greater emission reductions, the alternative measure has been deemed by DEQ to achieve greater reasonable progress.

Permit Conditions 3.8 and 4.1 include BART alternative requirements in accordance with this section.

IDAPA 58.01.01.668 ..... BART REQUIREMENT FOR REGIONAL HAZE

The purpose of Section 668 is to implement the BART requirements in 40 CFR 51.308(e). The analysis and documentation specified is required for each BART-eligible source.

In accordance with IDAPA 58.01.01.668.01, analysis and documentation has been provided that DEQ has identified a list of all BART-eligible sources within the state. The Riley boiler was identified in a list of all BART-eligible sources that was provided in a letter to TASCO June 13, 2007.

In accordance with IDAPA 58.01.01.668.02, DEQ shall complete a determination of BART for each BART-eligible source in the state that emits any air pollutant which may reasonably be anticipated to cause or contribute to any impairment of visibility in any mandatory Class I Federal Area. All such sources are subject to BART. The BART analysis and documentation demonstrating that the Riley Boiler is subject to BART was provided in a letter to TASCO on July 19, 2007, and has been provided in Appendix C§.

The Riley boiler meets the definition of BART-eligible source in accordance with §51.301. SO_2, NO_x, and PM emissions were considered as the visibility-impairing pollutants applicable to BART review, and the following Class I Federal areas were included in the modeling analysis: Craters of the Moon, Eagle Cap Wilderness, Hells Canyon National Recreation Area, Jarbidge Wilderness, Sawtooth Wilderness, Selway-Bitterroot Wilderness, and Strawberry Mountain Wilderness.

In accordance with IDAPA 58.01.01.668.02.b, a single source that is responsible for a one-half (0.5) deciview change or more in any mandatory Class I Federal Area is considered to "contribute" to visibility impairment. DEQ used air dispersion modeling to determine if the 0.5 deciview threshold was exceeded by any of the BART-eligible sources in Idaho. As summarized in Table 4.1 ~~Table 4.1~~, the

Riley boiler was predicted to have contributed to a visibility impairment at the Eagle Cap Wilderness, Hells Canyon National Recreation Area, and Strawberry Mountain Wilderness mandatory Class I Federal Areas with the 98th percentile highest delta-deciview greater than 0.5 during the modeling period 2003-2005.

Table 4.1 SUMMARY OF BART ANALYSIS

Emissions Unit	Year Installed	Capacity (MMBtu/hr)	Regional Haze Pollutants	Regional Haze Pollutants Exceeding 250 T/yr	Nearest Class I Areas	Contribute to 0.5 deciview change? (Y/N)[1]
Riley boiler	1969	350,000	PM, SO_2, NO_X	PM, SO_2, NO_X	Eagle Cap Wilderness	Y
					Hells Canyon National Recreation Area	
					Strawberry Mountain Wilderness	
					Sawtooth Wilderness	N
					Selway-Bitterroot Wilderness	
					Jarbidge Wilderness	
					Craters of the Moon National Monument	

[1] "Y" = Yes; "N" = No.

In accordance with IDAPA 58.01.01.668.02.c, the determination of BART must be based on an analysis of the best system of continuous emission control technology available and associated emission reductions achievable for each BART-eligible source that is subject to BART within the state. In this analysis, the following must be taken into consideration: costs of compliance; energy and non-air quality environmental impacts of compliance; any pollution control equipment in use at the source; the remaining useful life of the source; and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology. These considerations were included in Step 4 of the BART analysis (refer to Section 3.1 and Appendix B).

Because the Riley boiler has the potential to emit more than 250 T/yr each of PM, SO_2 and NO_X emissions (refer to Section 3.1), it does not qualify for the exception provided in IDAPA 58.01.01.668.02.d.

In accordance with IDAPA 58.01.01.668.03, if DEQ determines in establishing BART that technological or economic limitations on the applicability of measurement methodology to a particular source would make the imposition of an emission standard infeasible, it may instead prescribe a design, equipment, work practice, or other operational standard, or combination thereof, to require the application of BART. Such standard, to the degree possible, is to set forth the emission reduction to be achieved by implementation of such design, equipment, work practice, or operation and must provide for compliance by means which achieve equivalent results. At this time it has not been demonstrated that the imposition of emission standards for PM, SO_2, and NO_X are infeasible. Therefore alternative standards were not considered (additional discussion provided in §51.308(e)(1)(iii)).[A6]

In accordance with IDAPA 58.01.01.668.04, each source subject to BART is required to install and operate BART as expeditiously as practicable, but in no event later than five (5) years after approval of the implementation plan. Permit Condition 3.3 includes the requirement of this section.

In accordance with IDAPA 58.01.01.668.05, each source subject to BART is required to maintain the control equipment required by DEQ and establish procedures to ensure such equipment is properly operated and maintained. Permit Condition 3.9 includes the requirement of this section.

In accordance with IDAPA 58.01.01.668.06, as an alternative to the installation of BART for a source or sources, DEQ may approve a BART alternative. Permit Conditions 3.4, 3.5, 3.8, 3.12, 3.13, 3.14, 3.15, and 4.1 include requirements associated with the installation and operation of the LNB ~~with OFA~~ and the coal-fired pulp dryers shutdown for the BART alternative.

In accordance with IDAPA 58.01.01.668.06.a, if a source proposes a BART alternative, the resultant emissions reduction and visibility impacts must be compared with those that would result from the BART options evaluated for the source. Consideration of the shutdown of the three coal-fired pulp dryers as proposed by TASCO and the associated emissions reduction was provided as part of an alternative option to the installation and operation of BART. The shutdown of the three coal-fired pulp dryers (SD-1, SD-2, and SD-3) and the installation and operation of low NO_x burners ~~with over-fired air~~ together were determined to be equivalent or better in achieving NO_x emissions reductions at the facility (refer to Appendix B).

In accordance with IDAPA 58.01.01.668.06.b, the permittee proposing a BART alternative must demonstrate that this BART alternative will achieve greater reasonable progress than would be achieved through the installation and operation of BART. At this time it has not been demonstrated that the proposed shutdown of the dryers will achieve greater reasonable progress than would be achieved through the installation and operation of BART.

In accordance with IDAPA 58.01.01.668.06.c, the permittee proposing a BART alternative shall include in the BART analysis an analysis and justification of the averaging period and method of evaluating compliance with the proposed emission limitation. At this time an analysis and justification of the averaging period and method of evaluating compliance with a proposed emission limitation alternative have not been provided by TASCO. A requirement documenting the need for improved monitoring has been included in Permit Condition 3.19.

In accordance with IDAPA 58.01.01.668.07, once DEQ has met the requirements for BART or BART alternative, as identified in Subsection 668.06, BART eligible sources will be subject to the requirements of reasonable progress goals, as defined in 40 CFR 51.308(d), in the same manner as other sources.

4.11 Permit Conditions Review

This section describes the permit conditions for this initial permit. The requirements of this Tier II operating permit do not contravene any permit conditions in any applicable permits to construct and Tier I and Tier II operating permits (T1-050020, T2-050021, P-0300621. The permittee must continue to comply with all applicable permits.

Permit Conditions 1.1, 1.2, 3.1, and 3.2

These permit conditions explain the purpose of this permitting action and describe the emission sources and the control equipment regulated by this permit. The information included reflects any design, equipment, and operational information presented in the BART analysis.

The permittee has documented concerns regarding the feasibility of using over-fired air on the Riley Boiler, and has estimated that a NO_x emission control efficiency of 50% could be achieved using a low-NO_x burner without over-fired air. Based upon this information, the expected control efficiency has been listed as ≥50% in the Regulated Sources Table (Permit Condition 1.2) and the BART alternative

NO_x emission limit (Permit Condition 3.4) has been based upon achieving a 50% reduction in NO_x emissions[A7].

Permit Condition 2.1
This permit condition clarifies that compliance with all applicable local, state, and federal rules and regulations is required, in accordance with IDAPA 58.01.01.406

Permit Condition 2.2
This permit condition incorporates applicable federal requirements into the permit by reference. The intent is that the federal requirement shall govern any conflict with a permit condition referencing a federal requirement.

Permit Condition 2.3
This permit condition provides contact information for submittal of required performance test reports, reports, applications, submittals, and other communications to DEQ.

Permit Conditions 3.3
This permit condition requires compliance with BART on and after the compliance date provided in IDAPA 58.01.01.668.04.

The permittee has requested the option to use BART alternative control strategies to achieve the BART and BART alternative emission limits (Permit Condition 3.4), which could require additional technical review and a revision to this permit. In response to this request, DEQ has included language inclusive of using either the selected BART or a DEQ-approved BART alternative within Permit Conditions 3.3 and 3.4.

Permit Conditions 3.4 and 3.5
This permit condition establishes emission limits for BART based on the BART analyses and determinations in accordance with IDAPA 58.01.01.401.03.

The BART PM emission limit was based upon information provided by the permittee indicating that the existing baghouse could achieve 99% control of PM emissions. ~~The BART SO_2 emission limit was based upon the information provided by the permittee that spray dry FGD could achieve 80% control of SO_2 emission, assuming a conservative adiabatic approach temperature of 40°F to protect the baghouse.~~ The BART alternative NO_x emission limit was based upon the use of a low-NO_x burner without consideration given to the use of over-fired air, as described below.

A limit of 113 T/yr was included to avoid exceeding the significance threshold for CO emissions, which could potentially result in a PSD major modification (refer to Section 4.5 for additional information). The CO emission limits are considered federally enforceable requirements established pursuant to 40 CFR 52

CO emissions from the Riley boiler have previously been limited by a cap over the combined emissions from B&W No. 1 boiler (S-B1), B&W No. 2 boiler (S-B2), and the Riley boiler (S-B3) in Permit Condition 3.1 of Tier I Operating Permit No. T1-050020. Conservatively assuming that the Riley boiler could emit up to the full amount of 159.0 T/yr, a permitted limit of 113 T/yr would decrease allowable emissions for the Riley boiler. The CO hourly limit of 25.8 pounds per hour was calculated based upon the annual limit, assuming unlimited operation of the boiler at 8,760 hr/yr. This emission limit is also not expected to contravene existing Permit Condition 3.5 of Tier I Operating Permit No. T1-050020 (relevant to CO and PM_{10} emission limits), which permits operation at 120% of the average fuel rates tested.

Compliance with these emission limits is ensured by complying with performance testing (Permit Conditions 3.14 and 3.15) and monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

The permittee has documented concerns regarding the feasibility of using over-fired air on the Riley Boiler, and has estimated that a NO_X emission control efficiency of 50% could be achieved using a low NO_X burner without over-fired air. Based upon this information, the expected control efficiency has been listed as ≥50% in the Regulated Sources Table (Permit Condition 1.2) and the BART alternative NO_X emission limit (Permit Condition 3.4) has been based upon achieving a 50% reduction in NO_X emissions.

The permittee has requested the option to use BART alternative control strategies to achieve the BART and BART alternative emission limits (Permit Condition 3.4), which could require additional technical review and a revision to this permit. In response to this request, DEQ has included language inclusive of using either the selected BART or a DEQ-approved BART alternative within Permit Conditions 3.3 and 3.4.

Permit Conditions 3.6, 3.7, and 3.8

These permit conditions require installation and operation of BART based on the BART determination in accordance with IDAPA 58.01.01.401.03.

Permit condition 3.8 includes the BART alternative proposed by the permittee for the control of NO_X emissions in accordance with IDAPA 58.01.01.668.06, based upon voluntary shutdown of three coal-fired pulp dryers and installation and operation of ~~a dry~~ low NO_X burner ~~operating with over-fired air~~ (in lieu of installation and operation of selective catalytic reduction system control equipment on the Riley boiler). The permittee had proposed crediting of the shutdown of the three coal-fired pulp dryers as a BART alternative; however in order to achieve equivalent NO_X emissions reductions, installation of LNB ~~DLN with OFA~~ has also been required as part of the BART alternative.

Because the installation of a LNB ~~DLN burner with OFA~~ may constitute modification and/or reconstruction of the source, additional requirements may be applicable (refer to additional discussion provided in Sections 3.2, 3.3, and under Permit Condition 3.18).

Compliance with these requirements is ensured by complying with performance testing (Permit Conditions 3.14 and 3.15) and monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

The permittee has documented that the baghouse cannot be operated during periods when the boiler is using natural gas as the primary fuel. Based upon this information, operation of the baghouse has been required in Permit Condition 3.6 only when firing coal fuel in the Riley Boiler.(A8)

Permit Condition 3.9

This permit condition requires that the permittee maintain the control equipment required and establish procedures to ensure such equipment is properly operated and maintained, in accordance with IDAPA 58.01.01.668.05.

Compliance with this requirement is ensured by complying with monitoring and recordkeeping requirements (Permit Conditions 3.10 through 3.13).

Permit Condition 3.10

This permit condition requires monitoring of pressure drop across the baghouse to ensure compliance with the BART PM emission limit (Permit Condition 3.4) and General Provision 2. This permit condition does not contravene existing Permit Condition 3.9 in Tier I Operating Permit No. T1-050020.

~~Permit Condition 3.11~~

~~This permit condition requires monitoring of spray dry flue gas adiabatic approach temperature to ensure compliance with the BART SO_2 emission limit (Permit Condition 3.4) and General Provision 2.~~

~~The permittee has indicated that monitoring the adiabatic approach temperature may be more reliable than monitoring the slurry feed flow rate for the spray dry FGD. Based upon this information, monitoring of adiabatic approach temperature has been required in Permit Condition 3.11 to ensure compliance with the BART SO_2 emission limit.~~

Permit Condition 3.12

This permit condition requires monitoring of primary and ~~over fired~~ air flow rates to ensure compliance with the BART NO_x emission limit (Permit Condition 3.4) and General Provision 2.

Permit Condition 3.13

This permit condition requires the development and documentation of operation and maintenance procedures for the operation and maintenance of BART control equipment to ensure compliance with BART emission limits (Permit Condition 3.4), CO emission limits (Permit Condition 3.5), the maintenance of BART equipment requirement (Permit Condition 3.9), the control equipment maintenance and operation general provision (General Provision 2), and the manufacturer's specifications.

Permit Conditions 3.14, 3.15, 3.16, and 3.17

Permit Conditions 3.14 and 3.15 require annual performance testing of PM, ~~SO_2~~, NO_x, and CO emissions from the Riley boiler to demonstrate compliance with BART emission limits (Permit Condition 3.4) and the CO emission limits (Permit Condition 3.5), in accordance with IDAPA 58.01.01.405. These permit conditions also specify conditions and require monitoring and reporting in accordance with IDAPA 58.01.01.157 and General Provision 6.

Compliance with permit conditions 3.14 and 3.15 is ensured by complying with monitoring, recordkeeping, and reporting requirements (Permit Conditions 3.16 and 3.17) and General Provision 6.

The permittee has requested the option for DEQ to approve alternate testing frequencies. In response, the option to use a DEQ-approved testing frequency has been included in Permit Condition 3.15. The permittee has also documented concerns that direct measurement of the coal feed rate is not feasible for the Riley Boiler during performance testing. In response, the option to utilize a DEQ-approved calculation method has been included in Permit Condition 3.16.

Permit Condition 3.18

This permit condition requires submittal of information and preconstruction compliance demonstrations necessary to demonstrate preconstruction compliance with applicable ambient air quality standards, in accordance with the procedures and requirements for permits to construct (IDAPA 58.01.01.200-228). Refer to additional discussion provided in Sections 3.2 and 3.3 for additional information.

In order to allow sufficient time for DEQ to review the necessary information or to process any associated permitting action (e.g., permit to construct or revision to this Tier II operating permit T2-2009.0105~~T2-2009.0105~~), a deadline of 180 days prior to the BART installation and operation due date was included in Permit Condition 3.18.

Permit Condition 3.19

This permit condition requires submittal of information necessary to address BART monitoring requirements and update CAM plan(s) as applicable to account for the installation and operation of

BART, in accordance with 40 CFR 64 and IDAPA 58.01.01.668.06.c. Refer to Section 4.9 for additional discussion concerning CAM applicability.

Permit Condition 3.20
This permit condition references contact information for submittal of required reports, applications, submittals, and other communications to DEQ.

Permit Conditions 4.1 and 4.2
Permit Condition 4.1 requires permanent shutdown of the three coal-fired pulp dryers to comply with the BART alternative for the control of NO_X emissions, in accordance with IDAPA 58.01.01.668.06.

Compliance with Permit Conditions 4.1 is ensured by complying with the shutdown notification requirement (Permit Condition 4.2).

ATTACHMENT 2

QUALIFICATIONS OF DR. JOHN COOPER

CES
Cooper Environmental Services

John A. Cooper

Biographical Summary

Dr. Cooper is currently President of Cooper Environmental Services LLC in Portland, Oregon. He received his Doctorate in Nuclear Chemistry from the University of California, Berkeley in 1966 and a Bachelors degree in Chemistry from Humboldt State College in 1962.

Dr. Cooper has been actively involved in the development and application of environmental measurement methods and research related to the origin, transport and fate of environmental pollutants for the past 44 years since receiving his doctorate. He has published extensively in such areas as:

- Aerosol Source Characterization
- Receptor Modeling
- Residential Wood Combustion
- X-ray Fluorescence Analysis
- Neutron Activation Analysis
- Environmental Radionuclide Analysis
- Gamma Ray Spectroscopy
- Environmental Effects on Nuclear Decay Constants

Much of his contemporary research over the past decade has focused on source apportionment and the development of methods for speciating mercury emissions, developing continuous emissions monitoring methods for hazardous elements, and dilution sampling methods for $PM_{2.5}$ and receptor modeling source profiles. More recently, the technology Dr. Cooper has developed for multi-metal continuous emissions monitoring has been approved by the EPA for emissions compliance demonstration and he is currently extending the application of this technology to fence line monitoring and ambient air toxic metals monitoring at the pico gram per cubic meter concentration levels.

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JOHN A. COOPER, Ph.D.
President
Cooper Environmental Services LLC

PROFILE

- Dr. Cooper has been actively involved for the past 44 years in the development of environmental measurement methods and research related to the origin, transport, and fate of organic, radioactive, and elemental pollutants.
- Development of size-specific source profiles for CMB modeling.
- Development of source characterization sampling and analysis methods.
- Evaluation of State Implementation Plans, control strategies and aerosol chemistry.
- Management of multi-disciplinary source apportionment projects.
- Research into the development of ambient and source aerosol sampling methods specifically for receptor modeling and air toxic applications.
- Direction of large environmental analysis programs involving the analysis of environmental samples by x-ray fluorescence, neutron activation, ion chromatography, organic and elemental carbon, b_{abs}, etc.
- Development of environmental analysis instruments and methods using atomic and nuclear procedures.

EDUCATIONAL BACKGROUND

Ph.D., Nuclear Chemistry, University of California, Berkeley, CA, 1966
B.S., Chemistry, Humboldt State College, Arcata, CA, 1962

CAREER CHRONOLOGY

- President, Cooper Environmental Services LLC, Portland, Oregon (1996 to present)
- Vice President/Principal Consulting Scientist, TRC Environmental -Tigard, Oregon (2/94 to 1996)
- Director of Air Quality Technology, Chester Environmental - Tigard, Oregon (1992 to 1994)
- President, Keystone/NEA - Tigard, Oregon (1991 to 1992)
- President, NEA, Inc. - Tigard, Oregon (1977 to 1991)
- Professor Environmental Sciences, Oregon Graduate Institute - Beaverton, Oregon (1976-1984)
- Director of Applications Laboratories, ORTEC, Inc. - Oak Ridge, Tennessee (1974 to 1976)
- Senior Research Scientist, Battelle Northwest - Richland, Washington (1966 to 1974)

SELECTED EXPERIENCE AND PUBLICATIONS

SOURCE CHARACTERIZATION

Dr. Cooper has directed the development of plume simulating dilution stack samplers over the past twelve years, which has resulted in TRC's current plume-simulating dilution sampler for particulate, gaseous and hazardous species using evaporated liquid nitrogen as diluent.

Recently completed a coal-fired power plant emissions characterization study funded by EPRI.

Recently completed a source composition profile library for the South Coast Air Basin.

Developed special dilution sampling equipment to collect vehicle tailpipe emissions for particles simultaneously with the measurement of gases emissions.

Directed a tunnel aerosol characterization study in which semi-metallic brakes were first recognized as a significant source of metallic emissions from on-road motor vehicles.

Directed a study to measure the chemical composition of tire and brake wear products.

Directed numerous receptor modeling studies in which fifty-one stack emissions were characterized by TRC's dilution techniques, fifty-seven process fugitive emission categories were characterized, twenty vehicle exhaust profiles were measured, and over five hundred bulk dust samples were characterized.

Selected Publications

Cooper, J.A., "Recent Advances in Sampling and Analysis of Coal-Fired Power Plant Emissions for Air Toxic Compounds", Fuel Processing Technology, 39 (1994), 251-258.

Cooper, J.A., et.al., "PM_{10} Source Composition Library for the South Coast Air Basin", July 1987.

Jackson, J.O., B.S. Smith, J.A. Cooper, et al., "Dilution/Aging Systems for Plume Fly Ash Inhalation Studies", Electric Power Research Institute, 1987.

Sousa, J.A., J.M. Daisy, J.E. Houck and J.A. Cooper, "The Mutagenic Activity of Particulate Organic Matter Collected with a Dilution Sampler at Coal-Fired Power Plants", J. Air Pollution Control Assoc., December 1987, Volume 37, No. 12.

Olmez, I., A.E. Sheffield, G.E. Gordon, J.A. Cooper, et al., "Composition of Particles from Selected Sources in Philadelphia for Receptor Modeling Applications", submitted J. Air Pollution Control Assoc., 1987.

Houck, J.E., J.A. Cooper and E.R. Larson, "Dilution Sampling for Chemical Receptor Source Fingerprinting", in Proceedings of Air Pollution Control Association, New Orleans, June 1982.

Droppo, J.G., D.W. Glover, O.B. Abbey, C.W. Spicer, and J.A. Cooper, "Measurement of Dry Deposition of Fossil Fuel Plant Pollutants," U.S. EPA-60014-76-056, Nov. 1976.

Eatough, D.J., R.J. Arthur, N.L. Eatough, M.W. Hill, N.F. Mangelson, B.E. Richter, L.D. Hasen, and J.A. Cooper, "Rapid Conversion of SO_2(g) to Sulfate in a Fog Bank", Environ. Sci. Technol., 1984, 18, 855-859.

Sverdrup, G.M., J.C. Chuang, L. Slivon, A.R. McFarland, J.A. Cooper, R.W. Garber and B.S. Smith, "Comparison of Chemical Composition of Fly Ash Particles Collected in the Plume and Stack of a Coal-Fired Power Plant.", Managing Hazardous Air Pollutants State of the Art, EPRI ISBN 0-87371-866-6, 1993.

RECEPTOR MODELING

Program manager and principal investigator for the Portland Aerosol Characterization Study.

Project director for more than 100 airshed source apportionment studies in the U.S., Canada, and Brazil.

Has taught eighteen short courses on receptor modeling in the U.S., Canada, and Brazil.

Co-author of EPA's first source profile library.

Co-author of EPA's demonstration of dispersion and receptor model reconciliation

Developed first source profile library for California's South Coast Air Basin.

Directed source apportionment studies of numerous copper and lead smelter throughout the western U.S.

Evaluated the applicability of receptor modeling to PM_{10} SIP development for Hunton and Williams (Edison Institute).

Was first to use carbon-14 counting methods to assess the impact of vegetative burning and wood smoke on urban particulate levels.

Selected Publications

Cooper, J.A. and E. Peake, "Source Apportionment Studies Near Crossfield, Alberta," in Acidic Deposition: Sulphur and Nitrogen Oxides, ed. A.H. Legge and S.V. Krupa, Chelsea, Michigan: Lewis Publishers, pp. 347-380, 1990.

Olmez, I., A.E. Sheffield, G.E. Gordon, J.E. Houck, J.A. Cooper, T.G. Dzubay and R.L. Bennett, "Compositions of Particles from Selected Sources in Philadelphia for Receptor Modeling Applications", J. Air Pollution Control Assoc., 38, p. 11, 1988.

Ryan, W.R., C.R. Badgett-West, D.R. Holtz and T.A. Peters, "Reconciliation of Receptor and Dispersion Modeling Impacts of PM_{10} in Hayden, Arizona", in Trans. Air & Waste Manag. Assoc. Int. Spec. Conf. on PM-10: Implementation of Standards, San Francisco, CA, Feb. 1988, p. 419.

Gray, H.A., B. Landry, C.S. Liu, R.C. Henry, J.A. Cooper and J.R. Sherman, "Receptor Modeling for PM_{10} Source Apportionment in the South Coast Air Basin of California", in Trans. Air and Waste Manag. Assoc. Int. Spec. Conf. on PM-10: Implementation of Standards, San Francisco, CA, Feb. 1988, p. 399.

Cooper, J.A., J. Sherman, E. Miller, D. Redline, L. Valdovinos and W. Pollard, "CMB Source Apportionment of PM_{10} Downwind of an Oil- Fired Power Plant in Chula Vista, California", in Trans. Air and Waste Manag. Assoc. Int. Spec. Conf. on PM-10: Implementation of Standards, San Francisco, CA, Feb. 1988, p. 430.

Cooper, J.A., D.C. Redline, J.R. Sherman, L.M. Valdovinos and W.L. Pollard, "Evaluating Resolvability of Crustal Sources in Eagle River, Alaska Using Singular Value Diagnostics", in Trans. Air and Waste Manag. Assoc. Int. Spec. Conf. on PM-10: Implementation of Standards, San Francisco, CA, Feb. 1988, p. 495.

Shah, J.J, J.G. Watson, J.A. Cooper and J.J. Huntzicker, "Aerosol Chemical Composition and Light Scattering in Portland, Oregon: The Role of Carbon", Atmos. Environ., 18, pp. 235-240, 1984.

Watson, J.G., J.A. Cooper, and J.J. Huntzicker, "The Effective Variance Weighting for Least Squares Calculations Applied to the Mass Balance Receptor Model", Atmos. Environ., 18, p. 1347, 1984.

Currie, L.A., J.A. Cooper, et al., "Interlaboratory Comparison of Source Apportionment Procedures: Results for Simulated Data Sets", Atmos. Environ., 18, p. 1517, 1984.

Miller, E.A., J.A. Cooper, et al., "Cubatao Aerosol Source Apportionment Study", in Proceedings of APCA Specialty Conf. on Receptor Models, Williamsburg, Virginia, March, 1984.

Mangelson, N.F., R.T. DeCesar, S.M. Fields and J.A. Cooper, "Effect of Sampling Duration on Aerosol Source Apportionment by the Chemical Mass Balance Method", in Proceedings of APCA Specialty Conf. on Receptor Models, Williamsburg, Virginia, March, 1984.

Currie, L.A., R.W. Gerlach, C.W. Lewis, W.D. Balfour, J.A. Cooper, et al., "Interlaboratory Comparison of Source Apportionment Procedures: Results for Simulated Data Sets", Atmos. Environ., 18, 1555, 1984.

Gordon, G.E., W.R. Pierson, J.M. Daisey, P.J. Gioy, J.A. Cooper, J.G. Watson and G.R. Cass, "Considerations for Design of Source Apportionment Studies", Atmos. Environ., 18, 1555, 1984.

Dzubay, T.G., R.K. Stevens, W.D. Balfour, H.J. Williamson, J.A. Cooper, et.al., "Interlaboratory Comparison of Receptor Model Results for Houston Aerosol", Atmos. Environ., 18, 1555, 1984.

Core, J.E., J.A. Cooper, P.L. Hanrahan and W.M. Cox, "Particulate Dispersion Model Evaluation: A New Approach Using Receptor Models", J. Air Pollution Control Assoc., 32, 1132, 1982.

Core, J.E. and J.A. Cooper, "Current and Projected Air Quality Impacts of Residential Wood Combustion in the Pacific Northwest", Proceedings of PNWIS Air Poll. Control Assoc., 1982.

Cooper, J.A., "Chemical and Physical Methods of Apportioning the Contributions of Emissions from Residential Solid Fuels to Reductions in Air Quality", in Residential Solid Fuels: Environmental Impacts and Solutions, ed. J.A. Cooper and D. Malek, Oregon Graduate Center, Beaverton, OR, 1982.

DeCesar, R.T., and J.A. Cooper, "Evaluation of Multivariate and Chemical Mass Balance Approaches to Aerosol Source Apportionment, Using Synthetic Data and an Expanded PACS Data Set", in Proceedings of APCA Specialty Meeting. Recent Developments and Applications of Source-Receptor Modeling, Danvers, MA, October 18-20, 1982.

Cooper, J.A., "Receptor Model Source Apportionment of Lead in Three Airsheds with Lead Smelters", in Proceedings of APCA Specialty Meeting, Receptor Models Applied to Contemporary Pollution Problems", Danvers, MA, p. 34, October 1982.

Cooper, J.A., "Receptor Model Approaches to Aerosol Source Apportionment of Acid Rain Precursors", in Proceedings of APCA Specialty Meeting, Atmospheric Deposition, Detroit, MI, November 7-10, 1982.

Cooper, J.A., J.E. Core, R.T. DeCesar and J.E. Houck, "Fundamental Principles of the Receptor Model and Its Application to Particulate and Gaseous Species Source Apportionment", NEA report, April 2, 1982.

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Currie, L.A., G.A. Klouda and J.A. Cooper, "Mini-Radiocarbon Measurements, Chemical Selectivity and Impact of Man on Environmental Pollution and Climate", Radiocarbon, 22, 349, 1980.

Cooper, J.A. and J.G. Watson, Jr., "Receptor Oriented Methods of Air Particulate Source Apportionment", Air Pollution Control Assoc. Journal, 30, 1116, 1980.

Houck, J.E. and J.A. Cooper, "Meteorological Regime Frequency Categorization", NEA report, September 1980.

Cooper, J.A., J.G. Watson, J.J. Huntzicker, et.al., "Summary of the Portland Aerosol Characterization Study (PACS)", in Proceedings of the 1979 Annual Air Pollution Control Association Meeting, Cincinnati, OH, 1979.

RESIDENTIAL WOOD COMBUSTION IMPACTS

Made the first direct ambient measurement of the impact of residential wood combustion on urban air quality using carbon-14.

Organized first International Conference on Residential Solid Fuels and Their Impact on the Environment.

Conducted numerous receptor modeling studies focusing on the impact of wood smoke.

Selected Publications

Cooper, J.A. and D. Malek, Residential Solid Fuels: Environmental Impacts and Solutions, book published by Oregon Graduate Center, Beaverton, Oregon, 1982.

Cooper, J.A., "Chemical and Physical Methods of Apportioning the Contributions of Emissions from Residential Solid Fuels to Reductions in Air Quality", in Residential Solid Fuels: Environmental Impacts and Solutions, ed. J.A. Cooper and D. Malek, Oregon Graduate Center, Beaverton, Oregon, 1982.

DeCesar, R.T. and J.A. Cooper, "The Quantitative Impact of Residential Wood Combustion and Other Vegetative Burning Sources on Air Quality in Medford, Oregon", ibid., 551.

Cooper, J.A., L.A. Currie and G.A. Klouda, "Assessment of Contemporary Carbon Combustion Source Contributions to Urban Air Particulate Levels Using Carbon-14 Measurements", Envir. Sci. Techn., 15, 1045, 1981.

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Cooper, J.A., "Environmental Impact of Residential Wood Combustion Emissions and Its Implications", J. Air Pollution Control Assoc., 30, 855, 1980.

X-RAY FLUORESCENCE ANALYSIS

In 1970, Dr. Cooper designed and built an x-ray fluorescence (XRF) analyzer for the analysis of air filters.

In 1973, published first evaluation of x-ray technique applied to environmental samples.

Organized first NSF workshop on the use of x-ray methods for aerosol analysis in 1973.

Organized the first and second XRF aerosol analysis interlaboratory comparisons.

Director of ORTEC, Inc. x-ray applications laboratory.

Taught courses on atomic and nuclear methods of environmental analysis.

Directed the analysis of over 50,000 air filters by XRF over the past ten years.

Selected Publications

Cooper, J.A., "Interpretation of Energy-Dispersive X-Ray Spectra", American Laboratory, 8, 35, 1976.

Cooper, J.A., "Determination of Sulfur, Ash, and Trace Element Content of Coal, Coke, and Fly Ash Using Multielement Tube-Excited X-Ray Fluorescence Analysis", in Proceedings of the ERDA Symposium on Applications of X- and Gamma-Ray Sources, Ann Arbor, MI, May 1976.

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Cooper, J.A., B.D. Wheeler and D.M. Bartell, "Rapid, Multielement Analysis of Portland Cement, Raw Mix, and Raw Materials", Cement Technology, February 1976.

Cooper, J.A. and D.B. Schlafke, "Faster, Lower Cost Assays with New Fluorescence Instruments", Skillings Mining Review, January 31, 1976.

Cooper, J.A., H.L. Nielson, N.A. Wogman and R.W. Perkins, "Feasibility Study of In Situ Sediment Analysis by X-Ray Fluorescence", Nuclear Technology, 26, 224, 1975.

Camp, D.C., J.A. Cooper and J.R. Rhodes, "X-Ray Fluorescence Analysis -- Results of a First Round Intercomparison Study", X-Ray Spectrometry, 3, 47, 1974.

Cooper, J.A., "Review of a Workshop on X-Ray Fluorescence Analysis of Aerosols", Pacific Northwest Laboratory Report No. BNWL-SA-4690, June 1973.

Cooper, J.A., "Comparative Analysis of the Applicability of Particle and Photon Excited X-Ray Fluorescence Analysis to Trace Element Measurements of Environmental and Biological Samples", Nuclear Instruments and Methods, 109, 525, 1973.

NEUTRON ACTIVATION ANALYSIS

Developed anti-coincidence gamma-ray spectrometric method for neutron activation analysis.

Directed the analysis of both ambient and source samples.

Selected Publications

Tanner, T.M., J.A. Young and J.A. Cooper, "Multielement Analysis of St. Louis Aerosols by Nondestructive Techniques", Chemosphere, 5, 211, 1974.

Rancitelli, L.A., J.A. Cooper and R.W. Perkins, "Multielement Characterization of Atmospheric Aerosols by Instrumental Neutron Activation Analysis and X-Ray Fluorescence Analysis", in Proceedings of the Symposium on Nuclear Techniques in Comparative Studies of Food and Environmental Contamination, Finland, IAEA, August 1973.

Wogman, N.A., R.W. Perkins, H.G. Rieck and J.A. Cooper, "In Situ Neutron Activation", Patent No. 3,723,727, 1973.

Cooper, J.A. and R.W. Perkins, "A Versatile Ge(Li) - Na(Ti) Coincidence-Anticoincidence Gamma-Ray Spectrometer for Environmental and Biological Problems", Nucl. Instr. and Methods, 99, 1, 1972.

Cooper, J.A., "Analytical Applications of Gamma-Gamma Coincidence Techniques with Ge(Li) Detectors", Anal. Chem., 43, 838, 1971.

Perkins, R.W., L.A. Rancitelli and J.A. Cooper, "Laboratory and Environmental Mineral Analysis Using a Californium-252 Neutron Source", Nucl. Appl. and Tech., 9, 861, 1970.

Cooper, J.A., L.A. Rancitelli and R.W. Perkins, "An Anticoincidence Shielded Ge(Li) Gamma-Ray Spectrometer and Its Radioanalytical Chemistry Problems", J. Radioanalyt. Chem., 6, 147, 1970.

Haller, W.A., L.A. Rancitelli, R. Libby and J.A. Cooper, "The Instrumental Determination of Trace Elements in Plant Tissue by Neutron Activation Analysis", in Proceedings of the 1968 International Conference on Modern Trends in Activation Analysis.

Rancitelli, L.A., J.A. Cooper and R.W. Perkins, "The Multielement Analysis of Biological Material by Neutron Activation and Direct Instrumental Techniques, BNWL-SA-2010", in Proceedings of the 1968 International Conference on Modern trends in Activation Analysis.

Haller, W.A., L.A. Rancitelli and J.A. Cooper, "The Instrumental Determination of Trace Elements in Plant Tissue by Neutron Activation Analysis and Ge(Li) Gamma-Ray Spectrometry, BNWL-SA-1634", J. Agricultural and Food Chemistry, 16, 1036, 1968.

ENVIRONMENTAL RADIONUCLIDE ANALYSIS

Selected Publications

Cooper, J.A., P.O. Jackson, J.C. Langford, M.R. Petersen and B.O. Stuart, "Characteristics of Attached Radon-222 Daughters Under Both Laboratory and Field Conditions with Particular Emphasis Upon Underground Uranium Mine Environments", Pacific Northwest Laboratories Report No. BN-SA-299, December 22, 1973; also proceedings of Radiation Hazards in Mining Conference, Golden, CO, October, 1981.

Rancitelli, L.A., J.A. Cooper and R.W. Perkins, "Multielement Characterization of Atmospheric Aerosols by Instrumental Neutron Activation Analysis and X-Ray Fluorescence Analysis", in Proceedings of the Symposium on Nuclear Techniques in Comparative Studies of Food and Environmental Contamination, Finland, IAEA, August 1973.

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Wogman, N.A., R.W. Perkins, H.G. Rieck and J.A. Cooper, "In Situ Neutron Activation", Patent No. 3,723,727, 1973.

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Cooper, J.A. and R.W. Perkins, "An Anticoincidence Shielded Dual Ge(Li) Gamma-Ray Spectrometer for Low Level and Gamma-Gamma Coincidence Counting", Nucl. Instr. and Methods, 94, 29, 1971.

Cooper, J.A., "Figure of Merit Measurements for Ge(Li) Detectors", Nucl. Instr. and Methods, 94, 289, 1971.

Cooper, J.A., "Analytical Applications of Gamma-Gamma Coincidence Techniques with Ge(Li) Detectors", Anal. Chem., 43, 838, 1981.

Brodzinski, R.L., L.A. Rancitelli, J.A. Cooper and N.A. Wogman, "High Energy Proton Spallation of Iron", Phys. Rev. C., 4, 1257, 1971.

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ATTACHMENT 3

"THE AMALGAMATED SUGAR'S RILEY BOILER IMPACTS ON VISIBILITY IN CLASS I AREAS"

PREPARED BY
COOPER ENVIRONMENTAL SERVICES
FOR
THE AMALGAMATED SUGAR COMPANY LLC
ON MAY 19, 2010

REPORT FOR THE AMALGAMATED SUGAR COMPANY: RILEY BOILER IMPACT ON VISIBILITY IN SELECT CLASS I AREAS

Submitted by

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May 19, 2010

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1.0 INTRODUCTION

Cooper Environmental Services LLC (CES) was retained by Stoel Rives LLP to compare the results of CALPUFF modeling performed by the Idaho Department of Environmental Quality (DEQ) with receptor oriented source apportionment results developed by CES. The objective of these efforts was to obtain the most probable estimate of the actual (not predicted) impact of emissions from the Riley Boiler on visibility at select Class I areas on the same days modeled by the DEQ.

This report has been prepared by CES staff and Dr. John A. Cooper, President of CES.

DEQ defined the years 2003 to 2005 as its baseline for calculating visibility impairment impacts. DEQ found that during this period the Riley Boiler operated by The Amalgamated Sugar Company (TASCO) in Nampa, Idaho impacted visibility with the 98th percentile highest delta-deciview of more than 0.5 deciview on the Class I areas of Eagle Cap Wilderness, OR, Strawberry Mountain Wilderness, OR and Hells Canyon Wilderness, ID. DEQ's results and supporting information were provided in its report "Subject-to-Bart Analysis, For the TASCO Riley Boiler, Nampa, Idaho, July 2007" (BART Analysis) and its draft "Plan for Implementing Section 308 (40 CFR 51.308) of the Regional Haze Rule" (Plan).

CES reviewed these two reports as well as others as indicated below and in the reference section, performed receptor oriented apportionment calculations similar to those performed by DEQ (Section 9 of its draft Plan), and revealed that the most probable 98th percentile highest delta-deciview impact of the Riley Boiler on visibility in the above three Class I areas is substantially less than 0.5 deciview.

The following sections provide the details of our review and supporting data.

2.0 BACKGROUND

General meteorology. DEQ determined the maximum impacts of the Riley Boiler on these Class I areas occur in the winter during extended periods of air stagnation in the months from November through February. Meteorology during these winter air stagnation episodes is a major contributor to the poor visibility in these Class I areas. The meteorological factors responsible for these winter pollution episodes typical of the Northwest are both meteorologically and topographically-defined. These air stagnation periods generally begin with the passage of a cold-air low-pressure system with a snowfall of a few inches. After such a storm leaves, a surface high-pressure system begins to build into the area. The first clear night after frontal passage can cause a nocturnal cooling and surface based inversion, which inhibits ventilation of near ground level emitted pollutants. As the surface high pressure intensifies, visibility decreases rapidly, fogs can form further exacerbating conditions, and PM_{10} values rise. Extended stagnation conditions are established if surface high pressure is reinforced by a strong high-pressure ridge aloft. This can create additional stable subsiding layers of inversion above ground. If the upper level high-pressure ridge covers the western states, the stagnation conditions will usually persist from seven to ten days.

Wind speeds during a stagnation episode are light and variable, and are influenced by local topographic circulation patterns. For example, DEQ identified the seventh ranked day, January 16th, 2004 that had 21 hourly average wind speeds of less than or equal to 1 mile per hour with wind

directions ranging all over the compass. The winds throughout the Northwest can also be dependent on the time of day and the heating and cooling of the surrounding geography. This daily wind pattern can be fairly constant from one day to the next during a pollution episode. In the early morning, winds are flowing down the mountain slopes and canyons towards lower elevations in a valley airshed. During midmorning, the mountain slopes and canyon walls absorb solar radiation, heat up and cause a reversal of airflow from down-slope/canyon to up-slope/canyon. As dusk approaches, the mountain slopes begin to cool and the airflow once again reverses to a down-slope/canyon flow. During this transition period, areas in the valley can experience near calm conditions and lowering inversion heights, which can coincide with evening rush hour and peak vehicle emissions. Superimposed on this flow is a general drainage flow of dense air along river valley floors towards lowest elevations.

CALPUFF model. Measured meteorological conditions during the days considered in the BART Analysis are generally consistent with this meteorological conceptual model. Under these daytime conditions, for example, wind is blowing emissions from sources such as the Riley Boiler towards surrounding mountains and up slopes and canyons, contributing to an increase in dispersion and dilution of emissions.

DEQ ran a dispersion model (CALPUFF) to estimate Riley Boiler visibility impacts during these winter pollution episodes. CALPUFF is a deterministic model where the impact at a monitoring site due to emissions from a specific source like the Riley Boiler is predicted based on complex dispersion and transformation sub-models. The dispersion term takes into account dilution effects of wind along with other meteorological and topography factors, while the transformation term accounts for chemical reactions that can take place during transport of emissions from the source to a monitoring site. These terms are extremely complex and the results are generally questionable when applied to low wind speed conditions (less than or equal to about 1 mile per hour) typical of these Northwest episode days.

In addition, there is rarely enough meteorological data to accurately define the wind fields along a plumes path, further adding to the modeling difficulty and uncertainty in the results. As such, the EPA on occasions has disallowed the use of results from this type of model in developing state implementation plans. (Dickstein, 1990) In addition, these dispersion models are conservative (designed to predict maximum impacts) and are not bound by reality. As such, it is not uncommon for specific day predicted impacts to differ from measured impacts by factors of two or more.

Alternative approach. Receptor models, on the other hand, are based on apportioning receptor measured concentrations and fractional source composition profiles. As such, the apportionment results are bound by reality (measured concentrations) and uncertainties in results are typically in the range of 10 to 30% of the source contribution estimate for a specific source category. Receptor models are probabilistic models that statistically calculate the most probable combination of sources responsible for species (sulfate and nitrate) measured at an ambient monitoring site. Using chemical fingerprints representing emissions from possible sources, a linear regression analysis is typically used to determine the most probable combination of source profiles that can best explain the ambient chemistry. Although this modeling approach is not typically used to apportion sources of secondary species, it has been used in some cases to resolve impacts of secondary species from specific sources as CES did in Boise (Cooper and Johnsen, 2002).

3.0 APPROACH

The approach used by CES to estimate the most probable impacts by the Riley Boiler emissions was a receptor oriented approach similar to that used by Cooper and Johnsen in Boise in 2002 for the Treasure Valley PM_{10} Maintenance Plan, and similar to that used by DEQ to apportion sulfate (ammonium sulfate) and nitrate (ammonium nitrate) as described in Section 9 of its Plan.

The starting point of our approach was the species concentration ($\mu g/m^3$ of sulfate or nitrate) measured at the receptor for the Class I area. CES assumed that the measured concentration is the sum of the background contribution and the contribution of local sources, and that all local sources or source categories contributed something to the local source contribution at the receptor. CES also assumed a boundary condition that the sum of the contributions by all local sources and the background cannot exceed the measured concentrations.

The resulting sulfate and nitrate source contribution estimates (SCE) associated with the Riley Boiler were then used to calculate the extinction caused by the Riley Boiler sulfate and nitrate, which were then used along with the background extinction to calculate the delta deciview impact from the Riley Boiler emissions. The following is an outline of the steps used to apportion the sulfate and nitrate:

1. Assume the average "Worst 20% Visibility Days" apportionment was the same for each individual modeled day. For example, according to DEQ's Plan (page 100) WRAP (Western Regional Air Partnership, AK, AZ, CA, CO, ID, MT, NM, ND, OR, SD, UT, WA and WY) contributions were responsible for 33% of the measured sulfate at Hells Canyon and 12.4% of the WRAP contribution was from Idaho point sources; i.e. on average during the 20% worst visibility days, and Idaho point sources contributed 4.1% (12.4% of 33%) of the measured sulfate.

2. CES assumed half of Idaho's point source contribution to receptor measured sulfate came from the Riley Boiler. This was based on DEQ's point source emission inventory for the three years modeled by DEQ, changes in the emissions in 2005, and the location of the major point sources of sulfate.

3. Sulfate emissions from the Riley Boiler represent 66% of the total Nampa plant sulfate emissions. Based on these three steps, the Riley Boiler emissions on the worst 20% visibility days contributed 1.4% (66% of half of 4.1%) of the measured sulfate.

4. After calculating the sulfate contribution from the Riley Boiler according to the above three steps, the Riley Boiler nitrate contribution was calculated on the basis of the Riley Boiler emission inventory sulfate and nitrate ratio and the relatively conservative assumption that this ratio holds at the receptor.

The results from these calculations are presented and discussed in the following section.

4.0 RESULTS AND DISCUSSION

The results of our receptor oriented apportionment calculations are summarized in Tables 1 – 3 for the three Class I areas identified by DEQ as impacted from the Riley Boiler. The four columns on the left identify the CALPUFF and receptor ranking along with the day and date. The middle two columns list the Riley Boiler apportioned sulfate and nitrate. The four columns on the right list the Riley Boiler contributions to visibility impairment (delta deciviews) as calculated using our receptor oriented approach. This approach used DEQ's Plan apportionment data as projected by DEQ using CALPUFF. It needs to be noted that CES did not locate receptor data for all of the days modeled by DEQ. On these days, the closest (in time) day with the highest sulfate concentration were selected for comparison. These non-modeled days are highlighted in the following three tables.

The maximum delta deciview due to the Riley Boiler predicted by the CALPUFF model was 2.6 deciviews for January 21, 2003 at Eagle Cap, which corresponds to the 9th **lowest** measured sulfate concentration of the 22 highest predicted impact days. The second highest CALPUFF predicted Riley Boiler impact day corresponds to the 4th **lowest** measured sulfate day.

By comparison, the highest delta deciview day identified with the receptor approach was associated with the day with the highest measured sulfate and the Riley Boiler contributed only 0.4 delta deciview. The receptor oriented 98th percentile delta deciviews ranged from 0.06 to 0.15 and are substantially below the 0.5 delta deciview threshold for subject to BART determination.

The receptor total delta deciview results are substantially smaller than those predicted by the CALPUFF model. In general, the differences range from about 3 to 30 fold. The receptor approach also indicates that the actual Riley Boiler impacts were highest at Hells Canyon, whereas the CALPUFF predicted impacts were highest at receptors in Eagle Cap. The receptor impacts are more consistent with the conceptual model of down river drainage flow of polluted air influenced by low inversions impacting the lower elevation Hells Canyon monitoring site (2050 ft elevation) more than the higher elevation (4000 to 6000 ft) Eagle Cap receptors. (See the above Section 2 discussion of typical meteorological conditions leading to high winter haze conditions.)

Table 1. Estimates of Riley Boiler Contributions to Visibility Impairment

Eagle Cap wilderness area

				Riley Boiler Conc. contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model date	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
20%[a]				0.00334	0.00605				
1	13	21	1/21/2003	0.0025	0.0016	0.02511478	0.0166	0.042	2.586
2	19	22	1/22/2004	0.0013	0.0009	0.013477666	0.0089	0.022	2.225
3	16	335	12/1/2004	0.0023	0.0015	0.024062318	0.0159	0.040	2.137
4	8	338	12/4/2004	0.0034	0.0022	0.035361455	0.0234	0.059	2.07
5	17	55	2/24/2005	0.0020	0.0013	0.017756488	0.0117	0.029	1.982
6	1	16	1/16/2005	0.0082	0.0054	0.08208542	0.0543	0.136	1.857
7	21	16	1/16/2004	0.0008	0.0005	0.008580787	0.0057	0.014	1.848
8	15	38	2/7/2003	0.0028	0.0018	0.024902061	0.0164	0.041	1.661
9	10	33	2/2/2005	0.0034	0.0022	0.029936955	0.0198	0.050	1.586
10	22	345	12/11/2003	0.0006	0.0004	0.006107014	0.0040	0.010	1.56
11	11	318	11/14/2003	0.0029	0.0019	0.028514514	0.0188	0.047	1.516
12	12	322	11/18/2005	0.0027	0.0018	0.026464417	0.0175	0.044	1.514
13	20	18	1/18/2003	0.0012	0.0008	0.012447989	0.0082	0.021	1.497
14	3	18	1/18/2004	0.0066	0.0044	0.066558923	0.0440	0.110	1.48
15	5	13	1/13/2004	0.0054	0.0036	0.054277131	0.0359	0.090	1.469
16	9	322	11/18/2004	0.0033	0.0022	0.032660282	0.0216	0.054	1.402
17	2	15	1/15/2005	0.0082	0.0054	0.08208542	0.0543	0.136	1.395
18	18	56	2/25/2005	0.0020	0.0013	0.017756488	0.0117	0.029	1.366
19	14	11	1/11/2003	0.0025	0.0016	0.024975803	0.0165	0.041	1.36
20	4	19	1/19/2004	0.0066	0.0044	0.066558923	0.0440	0.110	1.355
21	7	27	1/27/2005	0.0037	0.0025	0.037690197	0.0249	0.062	1.339
22	6	14	1/14/2004	0.0054	0.0036	0.054277131	0.0359	0.090	1.325

Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Eagle Cap.

* values based on Figures 9-81 & 9-83 assuming nitrates and sulfates are ammonium

b. 308 Imp. - Plan for Implementing Section 308 (40CFR51.308) of the Regional Haze Rule

* 308 Imp. Data is based on IMPROVE monitoring sites STAR1 (Starkey, OR) and state distribution data.

* 308 Imp. Data assumes the emission distribution for 2003, 2004 & 2005 is the same as 2002.

* 308 Imp. Data assumes 50% of the Idaho point sources comes from TASCO's Nampa, ID site.

* Distribution data came from Figures 9-81 & 9-83

c. Ratio of ammonium sulfate to ammonium nitrate was obtained from "Subject-to-BART Analysis, for Tasco Riley Boiler, Nampa Idaho" 2007, and personal comm. w/ Amalgamated sugars

Gray - Days when the receptor & model dates don't match. (the closest receptor date is paired to the model)

Table 2. Estimates of Riley Boiler Contributions to Visibility Impairment

Hells Canyon wilderness area

				Riley Boiler Conc. Contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
20%[a]				0.0138	0.0102				
1	17	21	1/21/2003	0.0052	0.0035	0.046	0.0301	0.076	2.194
2	6	338	12/5/2004	0.0157	0.0104	0.139	0.0921	0.230	1.862
3	21	22	1/22/2004	0.0032	0.0021	0.028	0.0186	0.047	1.609
4	2	16	1/16/2004	0.0274	0.0181	0.236	0.1563	0.389	1.514
5	10	345	12/11/2003	0.0080	0.0053	0.071	0.0472	0.118	1.404
6	19	55	2/24/2005	0.0052	0.0034	0.038	0.0252	0.063	1.369
7	7	335	12/2/2004	0.0103	0.0068	0.092	0.0610	0.153	1.301
8	16	310	11/5/2004	0.0058	0.0039	0.046	0.0307	0.077	1.298
9	3	322	11/18/2004	0.0213	0.0140	0.168	0.1114	0.278	1.115
10	1	19	1/19/2004	0.0279	0.0184	0.240	0.1590	0.395	1.079
11	20	56	2/25/2005	0.0052	0.0034	0.038	0.0252	0.063	1.064
12	18	18	1/18/2003	0.0045	0.0030	0.039	0.0259	0.065	1.059
13	12	318	11/14/2003	0.0085	0.0056	0.068	0.0447	0.112	1.043
14	11	43	2/12/2004	0.0094	0.0062	0.069	0.0454	0.114	1.031
15	9	328	11/24/2005	0.0112	0.0074	0.089	0.0586	0.147	1.027
16	5	15	1/16/2005	0.0186	0.0123	0.160	0.1062	0.265	1.02
17	4	321	11/17/2004	0.0213	0.0140	0.168	0.1114	0.278	1.003
18	14	322	11/18/2005	0.0060	0.0040	0.048	0.0316	0.079	0.973
19	13	327	11/23/2004	0.0075	0.0050	0.060	0.0396	0.099	0.973
20	15	323	11/19/2005	0.0060	0.0040	0.048	0.0316	0.079	0.972
21	22	21	1/22/2004	0.0032	0.0021	0.028	0.0186	0.047	0.954
22	8	337	12/4/2004	0.0103	0.0068	0.091	0.0605	0.151	0.936

Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Hells Canyon.

* values based on Figures 9-17 & 9-19 assuming nitrates & sulfates are ammonium

b. 308 - Plan for implementing Section 308 (40CFR 51.308) of the Regional Haze Rule

* 308 Data is based on IMPROVE monitoring site, HECA1 (Hells Canyon), and state distribution data.

* 308 Data assumes the emission distribution for 2003, 2004 & 2005 is the same as 2002.

* 308 Data assumes 50% of the Idaho point sources comes from TASCO's Nampa, ID site.

* Distribution data came from Figures 9-17 & 9-19

c. Ratio of ammonium sulfate to ammonium nitrate was obtained from "Subject-to-BART Analysis, for Tasco Riley Boiler, Nampa Idaho" 2007, and personal comm. w/ Amalgamated sugars

Grey - Days when the receptor & model dates don't match, (the closest receptor data is paired to the model)

Table 3. Estimates of Riley Boiler Contributions to Visibility Impairment

Strawberry Mountain wilderness area

				Riley Boiler Conc. Contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model date	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
20%[a]				0.00334	0.00605				
1	5	351	12/17/2005	0.0056	0.0037	0.059	0.0384	0.097	2.367
2	15	323	11/19/2005	0.0026	0.0017	0.026	0.0171	0.043	1.996
3	22	18	1/18/2003	0.0012	0.0008	0.012	0.0081	0.020	1.982
4	6	350	12/16/2005	0.0055	0.0037	0.058	0.0380	0.096	1.932
5	8	325	11/21/2005	0.0042	0.0028	0.041	0.0271	0.068	1.872
6	3	345	12/11/2005	0.0059	0.0039	0.062	0.0406	0.102	1.702
7	9	326	11/22/2005	0.0042	0.0028	0.041	0.0271	0.068	1.632
8	16	322	11/18/2005	0.0026	0.0017	0.026	0.0171	0.043	1.626
9	14	344	12/10/2005	0.0032	0.0021	0.034	0.0221	0.056	1.596
10	4	310	11/6/2003	0.0060	0.0039	0.059	0.0386	0.097	1.475
11	17	21	1/21/2003	0.0025	0.0016	0.025	0.0163	0.041	1.312
12	7	349	12/15/2005	0.0055	0.0037	0.058	0.0380	0.096	1.245
13	11	313	11/9/2004	0.0038	0.0025	0.038	0.0248	0.063	1.22
14	12	312	11/8/2004	0.0038	0.0025	0.038	0.0248	0.063	1.219
15	10	324	11/20/2005	0.0042	0.0028	0.041	0.0271	0.068	1.209
16	21	22	1/22/2004	0.0013	0.0009	0.013	0.0087	0.022	1.188
17	1	24	1/24/2005	0.0078	0.0051	0.078	0.0513	0.129	1.126
18	19	9	1/9/2003	0.0024	0.0016	0.025	0.0161	0.041	1.104
19	2	25	1/25/2005	0.0078	0.0051	0.078	0.0513	0.129	1.101
20	20	10	1/10/2003	0.0024	0.0016	0.025	0.0161	0.041	1.03
21	13	21	1/21/2005	0.0035	0.0023	0.035	0.0230	0.058	0.95
22	18	11	1/11/2003	0.0025	0.0016	0.025	0.0162	0.041	0.943

Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Strawberry Mountain.

* values based on Figures 9-81 & 9-83 assuming nitrates and sulfates are ammonium

b. 308 - Plan for Implementing Section 308 (40CFR 51.308) of the Regional Haze Rule

* 308 Data is based on IMPROVE monitoring sites STAR1 (Starkey, OR) and state distribution data.

* 308 Data assumes the emission distribution for 2003, 2004 & 2005 is the same as 2002.

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* Distribution data came from Figures 9-81 & 9-83

c. Ratio of ammonium sulfate to ammonium nitrate was obtained from "Subject-to-BART Analysis, for Tasco Riley Boiler, Nampa Idaho" 2007, and personal comm. w/ Amalgamated sugars

Grey - Days when the receptor & model dates don't match. (the closest receptor date is paired to the model)

5.0 CONCLUSION

The actual impact of the Riley Boiler emissions on visibility at the three Class I areas modeled by DEQ do not exceed the 98th percentile BART limit of 0.5 delta deciviews. As such, the Riley Boiler should not be subject to BART controls.

6.0 REFERENCES

Dickstein, Il L. 1990. Letter to F. Burnell Cordner, Director of Utah Bureau of Air Quality, Reference 8AT-AP. October 15, 1990 EPA 50575.

Cooper, J. A. and B. E. Johnsen, Task 3. "Compare Samples to Source Profiles, Receptor Modeling for the PM10 Maintenance SIP, Development of the Northern Ada County PM10 Maintenance Plan," Final Report from Environ International Corporation to Idaho DEQ, February 27, 2002.

ATTACHMENT 3

"THE AMALGAMATED SUGAR'S RILEY BOILER IMPACTS ON VISIBILITY IN CLASS I AREAS"

PREPARED BY
COOPER ENVIRONMENTAL SERVICES
FOR
THE AMALGAMATED SUGAR COMPANY LLC
ON MAY 19, 2010

REPORT FOR THE AMALGAMATED SUGAR COMPANY: RILEY BOILER IMPACT ON VISIBILITY IN SELECT CLASS I AREAS

Submitted by

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J. Cooper, D. Barth and T. Pittenger
10180 SW Nimbus Ave. Suite J6
Portland, OR 97223

May 19, 2010

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1.0 INTRODUCTION

Cooper Environmental Services LLC (CES) was retained by Stoel Rives LLP to compare the results of CALPUFF modeling performed by the Idaho Department of Environmental Quality (DEQ) with receptor oriented source apportionment results developed by CES. The objective of these efforts was to obtain the most probable estimate of the actual (not predicted) impact of emissions from the Riley Boiler on visibility at select Class I areas on the same days modeled by the DEQ.

This report has been prepared by CES staff and Dr. John A. Cooper, President of CES.

DEQ defined the years 2003 to 2005 as its baseline for calculating visibility impairment impacts. DEQ found that during this period the Riley Boiler operated by The Amalgamated Sugar Company (TASCO) in Nampa, Idaho impacted visibility with the 98th percentile highest delta-deciview of more than 0.5 deciview on the Class I areas of Eagle Cap Wilderness, OR, Strawberry Mountain Wilderness, OR and Hells Canyon Wilderness, ID. DEQ's results and supporting information were provided in its report "Subject-to-Bart Analysis, For the TASCO Riley Boiler, Nampa, Idaho, July 2007" (BART Analysis) and its draft "Plan for Implementing Section 308 (40 CFR 51.308) of the Regional Haze Rule" (Plan).

CES reviewed these two reports as well as others as indicated below and in the reference section, performed receptor oriented apportionment calculations similar to those performed by DEQ (Section 9 of its draft Plan), and revealed that the most probable 98th percentile highest delta-deciview impact of the Riley Boiler on visibility in the above three Class I areas is substantially less than 0.5 deciview.

The following sections provide the details of our review and supporting data.

2.0 BACKGROUND

General meteorology. DEQ determined the maximum impacts of the Riley Boiler on these Class I areas occur in the winter during extended periods of air stagnation in the months from November through February. Meteorology during these winter air stagnation episodes is a major contributor to the poor visibility in these Class I areas. The meteorological factors responsible for these winter pollution episodes typical of the Northwest are both meteorologically and topographically-defined. These air stagnation periods generally begin with the passage of a cold-air low-pressure system with a snowfall of a few inches. After such a storm leaves, a surface high-pressure system begins to build into the area. The first clear night after frontal passage can cause a nocturnal cooling and surface based inversion, which inhibits ventilation of near ground level emitted pollutants. As the surface high pressure intensifies, visibility decreases rapidly, fogs can form further exacerbating conditions, and PM_{10} values rise. Extended stagnation conditions are established if surface high pressure is reinforced by a strong high-pressure ridge aloft. This can create additional stable subsiding layers of inversion above ground. If the upper level high-pressure ridge covers the western states, the stagnation conditions will usually persist from seven to ten days.

Wind speeds during a stagnation episode are light and variable, and are influenced by local topographic circulation patterns. For example, DEQ identified the seventh ranked day, January 16th, 2004 that had 21 hourly average wind speeds of less than or equal to 1 mile per hour with wind

directions ranging all over the compass. The winds throughout the Northwest can also be dependent on the time of day and the heating and cooling of the surrounding geography. This daily wind pattern can be fairly constant from one day to the next during a pollution episode. In the early morning, winds are flowing down the mountain slopes and canyons towards lower elevations in a valley airshed. During midmorning, the mountain slopes and canyon walls absorb solar radiation, heat up and cause a reversal of airflow from down-slope/canyon to up-slope/canyon. As dusk approaches, the mountain slopes begin to cool and the airflow once again reverses to a down-slope/canyon flow. During this transition period, areas in the valley can experience near calm conditions and lowering inversion heights, which can coincide with evening rush hour and peak vehicle emissions. Superimposed on this flow is a general drainage flow of dense air along river valley floors towards lowest elevations.

CALPUFF model. Measured meteorological conditions during the days considered in the BART Analysis are generally consistent with this meteorological conceptual model. Under these daytime conditions, for example, wind is blowing emissions from sources such as the Riley Boiler towards surrounding mountains and up slopes and canyons, contributing to an increase in dispersion and dilution of emissions.

DEQ ran a dispersion model (CALPUFF) to estimate Riley Boiler visibility impacts during these winter pollution episodes. CALPUFF is a deterministic model where the impact at a monitoring site due to emissions from a specific source like the Riley Boiler is predicted based on complex dispersion and transformation sub-models. The dispersion term takes into account dilution effects of wind along with other meteorological and topography factors, while the transformation term accounts for chemical reactions that can take place during transport of emissions from the source to a monitoring site. These terms are extremely complex and the results are generally questionable when applied to low wind speed conditions (less than or equal to about 1 mile per hour) typical of these Northwest episode days.

In addition, there is rarely enough meteorological data to accurately define the wind fields along a plumes path, further adding to the modeling difficulty and uncertainty in the results. As such, the EPA on occasions has disallowed the use of results from this type of model in developing state implementation plans. (Dickstein, 1990) In addition, these dispersion models are conservative (designed to predict maximum impacts) and are not bound by reality. As such, it is not uncommon for specific day predicted impacts to differ from measured impacts by factors of two or more.

Alternative approach. Receptor models, on the other hand, are based on apportioning receptor measured concentrations and fractional source composition profiles. As such, the apportionment results are bound by reality (measured concentrations) and uncertainties in results are typically in the range of 10 to 30% of the source contribution estimate for a specific source category. Receptor models are probabilistic models that statistically calculate the most probable combination of sources responsible for species (sulfate and nitrate) measured at an ambient monitoring site. Using chemical fingerprints representing emissions from possible sources, a linear regression analysis is typically used to determine the most probable combination of source profiles that can best explain the ambient chemistry. Although this modeling approach is not typically used to apportion sources of secondary species, it has been used in some cases to resolve impacts of secondary species from specific sources as CES did in Boise (Cooper and Johnsen, 2002).

3.0 APPROACH

The approach used by CES to estimate the most probable impacts by the Riley Boiler emissions was a receptor oriented approach similar to that used by Cooper and Johnsen in Boise in 2002 for the Treasure Valley PM_{10} Maintenance Plan, and similar to that used by DEQ to apportion sulfate (ammonium sulfate) and nitrate (ammonium nitrate) as described in Section 9 of its Plan.

The starting point of our approach was the species concentration ($\mu g/m^3$ of sulfate or nitrate) measured at the receptor for the Class I area. CES assumed that the measured concentration is the sum of the background contribution and the contribution of local sources, and that all local sources or source categories contributed something to the local source contribution at the receptor. CES also assumed a boundary condition that the sum of the contributions by all local sources and the background cannot exceed the measured concentrations.

The resulting sulfate and nitrate source contribution estimates (SCE) associated with the Riley Boiler were then used to calculate the extinction caused by the Riley Boiler sulfate and nitrate, which were then used along with the background extinction to calculate the delta deciview impact from the Riley Boiler emissions. The following is an outline of the steps used to apportion the sulfate and nitrate:

1. Assume the average "Worst 20% Visibility Days" apportionment was the same for each individual modeled day. For example, according to DEQ's Plan (page 100) WRAP (Western Regional Air Partnership, AK, AZ, CA, CO, ID, MT, NM, ND, OR, SD, UT, WA and WY) contributions were responsible for 33% of the measured sulfate at Hells Canyon and 12.4% of the WRAP contribution was from Idaho point sources; i.e. on average during the 20% worst visibility days, and Idaho point sources contributed 4.1% (12.4% of 33%) of the measured sulfate.

2. CES assumed half of Idaho's point source contribution to receptor measured sulfate came from the Riley Boiler. This was based on DEQ's point source emission inventory for the three years modeled by DEQ, changes in the emissions in 2005, and the location of the major point sources of sulfate.

3. Sulfate emissions from the Riley Boiler represent 66% of the total Nampa plant sulfate emissions. Based on these three steps, the Riley Boiler emissions on the worst 20% visibility days contributed 1.4% (66% of half of 4.1%) of the measured sulfate.

4. After calculating the sulfate contribution from the Riley Boiler according to the above three steps, the Riley Boiler nitrate contribution was calculated on the basis of the Riley Boiler emission inventory sulfate and nitrate ratio and the relatively conservative assumption that this ratio holds at the receptor.

The results from these calculations are presented and discussed in the following section.

4.0 RESULTS AND DISCUSSION

The results of our receptor oriented apportionment calculations are summarized in Tables 1 – 3 for the three Class I areas identified by DEQ as impacted from the Riley Boiler. The four columns on the left identify the CALPUFF and receptor ranking along with the day and date. The middle two columns list the Riley Boiler apportioned sulfate and nitrate. The four columns on the right list the Riley Boiler contributions to visibility impairment (delta deciviews) as calculated using our receptor oriented approach. This approach used DEQ's Plan apportionment data as projected by DEQ using CALPUFF. It needs to be noted that CES did not locate receptor data for all of the days modeled by DEQ. On these days, the closest (in time) day with the highest sulfate concentration were selected for comparison. These non-modeled days are highlighted in the following three tables.

The maximum delta deciview due to the Riley Boiler predicted by the CALPUFF model was 2.6 deciviews for January 21, 2003 at Eagle Cap, which corresponds to the 9th **lowest** measured sulfate concentration of the 22 highest predicted impact days. The second highest CALPUFF predicted Riley Boiler impact day corresponds to the 4th **lowest** measured sulfate day.

By comparison, the highest delta deciview day identified with the receptor approach was associated with the day with the highest measured sulfate and the Riley Boiler contributed only 0.4 delta deciview. The receptor oriented 98th percentile delta deciviews ranged from 0.06 to 0.15 and are substantially below the 0.5 delta deciview threshold for subject to BART determination.

The receptor total delta deciview results are substantially smaller than those predicted by the CALPUFF model. In general, the differences range from about 3 to 30 fold. The receptor approach also indicates that the actual Riley Boiler impacts were highest at Hells Canyon, whereas the CALPUFF predicted impacts were highest at receptors in Eagle Cap. The receptor impacts are more consistent with the conceptual model of down river drainage flow of polluted air influenced by low inversions impacting the lower elevation Hells Canyon monitoring site (2050 ft elevation) more than the higher elevation (4000 to 6000 ft) Eagle Cap receptors. (See the above Section 2 discussion of typical meteorological conditions leading to high winter haze conditions.)

Table 1. Estimates of Riley Boiler Contributions to Visibility Impairment

Eagle Cap wilderness area

				Riley Boiler Conc. contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model date	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
20%[a]				0.00334	0.00605				
1	13	21	1/21/2003	0.0025	0.0016	0.02511478	0.0166	0.042	2.586
2	19	22	1/22/2004	0.0013	0.0009	0.013477666	0.0089	0.022	2.225
3	16	335	12/1/2004	0.0023	0.0015	0.024062318	0.0159	0.040	2.137
4	8	338	12/4/2004	0.0034	0.0022	0.035361455	0.0234	0.059	2.07
5	17	55	2/24/2005	0.0020	0.0013	0.017756488	0.0117	0.029	1.982
6	1	16	1/16/2005	0.0082	0.0054	0.08208542	0.0543	0.136	1.857
7	21	16	1/16/2004	0.0008	0.0006	0.008580787	0.0057	0.014	1.848
8	15	38	2/7/2003	0.0028	0.0018	0.024902061	0.0164	0.041	1.661
9	10	33	2/2/2005	0.0034	0.0022	0.029936955	0.0198	0.050	1.586
10	22	345	12/11/2003	0.0006	0.0004	0.006107014	0.0040	0.010	1.56
11	11	318	11/14/2003	0.0029	0.0019	0.028514514	0.0188	0.047	1.516
12	12	322	11/18/2005	0.0027	0.0018	0.026464417	0.0175	0.044	1.514
13	20	18	1/18/2003	0.0012	0.0008	0.012447989	0.0082	0.021	1.497
14	3	18	1/18/2004	0.0066	0.0044	0.066558923	0.0440	0.110	1.48
15	5	13	1/13/2004	0.0054	0.0036	0.054277131	0.0359	0.090	1.469
16	9	322	11/18/2004	0.0033	0.0022	0.032660282	0.0216	0.054	1.402
17	2	15	1/15/2005	0.0082	0.0054	0.08208542	0.0543	0.136	1.395
18	18	56	2/25/2005	0.0020	0.0013	0.017756488	0.0117	0.029	1.366
19	14	11	1/11/2003	0.0025	0.0016	0.024975803	0.0165	0.041	1.36
20	4	19	1/19/2004	0.0066	0.0044	0.066558923	0.0440	0.110	1.355
21	7	27	1/27/2005	0.0037	0.0025	0.037690197	0.0249	0.062	1.339
22	6	14	1/14/2004	0.0054	0.0036	0.054277131	0.0359	0.090	1.325

Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Eagle Cap.

* values based on Figures 9-81 & 9-83 assuming nitrates and sulfates are ammonium

b. 308 Imp. - Plan for Implementing Section 308 (40CFR 51.308) of the Regional Haze Rule

* 308 Imp. Data is based on IMPROVE monitoring sites STAR1 (Starkey, OR) and state distribution data.

* 308 Imp. Data assumes the emission distribution for 2003, 2004 & 2005 is the same as 2002.

* 308 Imp. Data assumes 50% of the Idaho point sources comes from TASCO's Nampa, ID site.

* Distribution data came from Figures 9-81 & 9-83

c. Ratio of ammonium sulfate to ammonium nitrate was obtained from "Subject-to-BART Analysis, for Tasco Riley Boiler, Nampa Idaho" 2007, and personal comm. w/ Amalgamated sugars

Grey - Days when the receptor & model dates don't match. (the closest receptor date is paired to the model)

Table 2. Estimates of Riley Boiler Contributions to Visibility Impairment

Hells Canyon wilderness area

				Riley Boiler Conc. Contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
20%[a]				0.0138	0.0102				
1	17	21	1/21/2003	0.0052	0.0035	0.046	0.0301	0.076	2.194
2	6	338	12/5/2004	0.0157	0.0104	0.139	0.0921	0.230	1.862
3	21	22	1/22/2004	0.0032	0.0021	0.028	0.0186	0.047	1.609
4	2	16	1/16/2004	0.0274	0.0181	0.236	0.1563	0.389	1.514
5	10	345	12/11/2003	0.0080	0.0053	0.071	0.0472	0.118	1.404
6	19	55	2/24/2005	0.0052	0.0034	0.038	0.0252	0.063	1.369
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Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Hells Canyon.

* values based on Figures 9-17 & 9-19 assuming nitrates & sulfates are ammonium

b. 308 - Plan for Implementing Section 308 (40CFR 51.308) of the Regional Haze Rule

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Table 3. Estimates of Riley Boiler Contributions to Visibility Impairment

Strawberry Mountain wilderness area

				Riley Boiler Conc. Contribution (ug/m^3)		Riley boiler Contribution to visibility (Δ DV)			
CALPUFF Rank	Receptor Rank	Day	CALPUFF model date	Receptor/308 $(NH_4)_2SO4$[b]	Receptor/308 NH_4NO_3[c]	Receptor/308 $(NH4)_2SO_4$	Receptor/308 NH_4NO_3	Receptor/308 Total	CALPUFF
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4	6	350	12/16/2005	0.0055	0.0037	0.058	0.0380	0.096	1.932
5	8	325	11/21/2005	0.0042	0.0028	0.041	0.0271	0.068	1.872
6	3	345	12/11/2005	0.0059	0.0039	0.062	0.0406	0.102	1.702
7	9	326	11/22/2005	0.0042	0.0028	0.041	0.0271	0.068	1.632
8	16	322	11/18/2005	0.0026	0.0017	0.026	0.0171	0.043	1.626
9	14	344	12/10/2005	0.0032	0.0021	0.034	0.0221	0.056	1.595
10	4	310	11/6/2003	0.0060	0.0039	0.059	0.0386	0.097	1.475
11	17	21	1/21/2003	0.0025	0.0016	0.025	0.0163	0.041	1.312
12	7	349	12/15/2005	0.0055	0.0037	0.058	0.0380	0.096	1.245
13	11	313	11/9/2004	0.0038	0.0025	0.038	0.0248	0.063	1.22
14	12	312	11/8/2004	0.0038	0.0025	0.038	0.0248	0.063	1.219
15	10	324	11/20/2005	0.0042	0.0028	0.041	0.0271	0.068	1.209
16	21	22	1/22/2004	0.0013	0.0009	0.013	0.0087	0.022	1.188
17	1	24	1/24/2005	0.0078	0.0051	0.078	0.0513	0.129	1.126
18	19	9	1/9/2003	0.0024	0.0016	0.025	0.0161	0.041	1.104
19	2	25	1/25/2005	0.0078	0.0051	0.078	0.0513	0.129	1.101
20	20	10	1/10/2003	0.0024	0.0016	0.025	0.0161	0.041	1.03
21	13	21	1/21/2005	0.0035	0.0023	0.035	0.0230	0.058	0.95
22	18	11	1/11/2003	0.0025	0.0016	0.025	0.0162	0.041	0.943

Notes & assumptions:

a. Idaho point source contribution of sulfate & nitrate on worst 20% visibility days in Strawberry Mountain.

* values based on figures 9-81 & 9-83 assuming nitrates and sulfates are ammonium

b. 308 - Plan for Implementing Section 308 (40CFR 51.308) of the Regional Haze Rule

* 308 Data is based on IMPROVE monitoring sites STAR1 (Starkey, OR) and state distribution data.

* 308 Data assumes the emission distribution for 2003, 2004 & 2005 is the same as 2002.

* 308 Data assumes 50% of the Idaho point sources comes from TASCO's Nampa, ID site.

* Distribution data came from figures 9-81 & 9-83

c. Ratio of ammonium sulfate to ammonium nitrate was obtained from "Subject-to-BART Analysis, for Tasco Riley Boiler, Nampa Idaho" 2007, and personal comm. w/ Amalgamated sugars

Grey - Days when the receptor & model dates don't match. (the closest receptor date is paired to the model)

5.0 CONCLUSION

The actual impact of the Riley Boiler emissions on visibility at the three Class I areas modeled by DEQ do not exceed the 98th percentile BART limit of 0.5 delta deciviews. As such, the Riley Boiler should not be subject to BART controls.

6.0 REFERENCES

Dickstein, Il L. 1990. Letter to F. Burnell Cordner, Director of Utah Bureau of Air Quality, Reference 8AT-AP. October 15, 1990 EPA 50575.

Cooper, J. A. and B. E. Johnsen, Task 3. "Compare Samples to Source Profiles, Receptor Modeling for the PM10 Maintenance SIP, Development of the Northern Ada County PM10 Maintenance Plan," Final Report from Environ International Corporation to Idaho DEQ, February 27, 2002.