2014

Utah Physicians for a Healthy Environment and Friends of Great Salt Lake, Petitioners/Appellants vs. Executive Director of the Utah Department of Environmental Quality and the Director of the Utah Division of Air Quality, in Their Official Capacity, and the Utah Department of Environmental Quality, the Utah Division of Air Quality, Respondents/Appellees.

Utah Court of Appeals

IN THE UTAH SUPREME COURT

Utah Physicians for a Healthy Environment and **FRIENDS of Great Salt Lake**, Petitioners/Appellants vs. **Executive Director of the Utah Department of Environmental Quality** and the **Director of the Utah Division of Air Quality**, in their official capacity, and the **Utah Department of Environmental Quality,** the **Utah Division of Air Quality**, Respondents/Appellees.	Appeal No. 20140344-SC Petition for Review of Agency Decisions Project No. N10123-0041 AO No. DAQE-AN101230041-13

REPLACEMENT OPENING BRIEF

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Oral Argument Requested

LIST OF PARTIES

Petitioners/Appellants:

Utah Physicians for a Health Environment
FRIENDS of Great Salt Lake

Respondents/Appellees:

Executive Director of the Utah Department of Environmental Quality
Director of the Utah Division of Air Quality
Utah Department of Environmental Quality
Utah Division of Air Quality
Holly Refining & Marketing Company – Woods Cross, LLC

Table of Contents

TABLE OF AUTHORITIES

Utah Administrative Code

JURISDICTION

Jurisdiction is provided by Utah Code Ann. §78A-4-103(2)(a)(i)(B).

ISSUES FOR REVIEW

All the issues in this matter concern whether the Executive Director of the Department of Environmental Quality (ED) erred in upholding the permitting decisions by the Director of the Utah Division of Air Quality (Director)[1] authorizing the construction of the Heavy Black Waxy Crude Processing Project (Expansion) at the Holly Marketing and Refining (Holly) Woods Cross Refinery, Davis County (Refinery) and if the ED decided correctly:

I. First Issue

Whether the Director made a defensible determination that the Expansion, which would be constructed in the Salt Lake non-attainment area for the 24-hour fine particulate matter ($PM_{2.5}$) National Ambient Air Quality Standard (NAAQS), was not a "major modification" and therefore not subject to Utah Admin. Code r.307-403.

Sub-Issue 1: If the Director's calculation of the "potential-to-emit" (PTE) $PM_{2.5}$ for a subset of the Refinery boilers and heaters based on a suspect "emission factor" 20-25 times smaller than emission rates he had previously deemed the most reliable is legally erroneous, represents an inappropriate departure from prior practice, and lacks foundation in the administrative record (Record).

[1] "Director" refers collectively to the Director of the Utah Division of Air Quality and Utah Division of Air Quality ("DAQ").

Sub-Issue 2: Whether the Director improperly authorized a credit of 2.19 tons per year (tpy) of $PM_{2.5}$ for the closure of the Propane Pit Flare (PPF) where the credit eclipsed the $PM_{2.5}$ emissions from Holly's remaining, much larger flares and from all the flares at three local refineries and when the Record contained no supporting calculations or monitoring data, but only inconsistencies.

Sub-Issue 3: Did the Director's PTE determination for fluidized catalytic cracking unit 25 (FCCU25) based on a 0.3-lb PM_{10}/1000-lb coke-burned permit limit adequately represent the maximum capacity of the unit to emit $PM_{2.5}$ although the Director did not restrict FCCU25's coke-burn rate, failed to calculated PTE based on "the most pollutant-generating" crude Holly is authorized to process, relied on data from the existing FCCU which utilizes different control technology and processes a different feedstock, and neglected to consider that the new feedstock for FCCU25 would produce more coke.

A. Standard of Review

In reviewing the legal adequacy of the Director's compliance with his permitting responsibilities, this Court will apply Utah Code Ann. §63G-4-403(4), recognizing the agency has "substantial discretion to interpret its governing statutes and rules" and upholding "factual, technical, and scientific agency determinations that are supported by substantial evidence viewed in light of the record as a whole." Utah Code Ann. §19-1-301.5(14)(c); *Murray v. Utah Labor Comm'n,* 2013 UT 38, ¶19, 308 P.3d 461 (agency finding of fact reviewed for substantial evidence). Specifically, this Court will assess whether the Director's PTE calculations and determination of the emission decreases from the PPF closure are based on an erroneous interpretation of the law, adequately supported by the Record, "contrary to [his] prior practice" and unjustified and unfair or arbitrary and capricious. Utah Code Ann. §63G-4-403(4)(d), (4)(g), (4)(h)(iii)-(iv).

The assessment of the Director's compliance with Rules 307-401 and 307-403 presents a mixed question of law and fact reviewed to determine if the "agency has erroneously...applied the law." *Provo City v. Utah Labor Com'n*, 2015 UT ¶9, 345 P.3d 1242; *id.* ¶10 ("[T]he characteristic that distinguishes a mixed question from a question of fact is the existence of an articulable legal issue."); *id.* ¶16 ("A court cannot resolve" this issue "without applying a legal definition…to the facts of the case."). As a result, the appellate court will "review the administrative body's findings of fact under the substantial evidence standard," while it will "review the law applied to these facts for correctness." *Provo City,* ¶17; *see also Utah Chapter of the Sierra Club v. Air Quality Board*, 2009 UT 76, ¶14, 226 P.3d 719 ("[M]ixed findings of fact and law, and the agency's interpretation of the operative provisions of statutory law it is empowered to administer are reviewed under an intermediate standard that considers whether the agency's determination was rational"); *id.*, ¶13 ("When reviewing an agency's interpretation of law, we review for correctness[.]").

Despite any discretion given to the Director's decision, his best available control technology (BACT) analysis must be supported by substantial evidence, *Sierra Club,* ¶13, and must further the goals of ensuring that the best control technology is adopted, *id.*, ¶45 ("[W]hile the Board has discretion to interpret its own regulations…it must do so with an eye to…ensuring that the best available control technology is adopted."), and protecting short-term ambient standards. *Sierra Club*, ¶48.

The ED's November 17, 2014 Final Order is owed no deference. The ED necessarily limited her review to the same administrative record that is before this Court, Utah Code Ann. §19-1-301.5(8)(a), to which she applied the same standard of review that this Court will apply to agency factual determinations. Utah Code Ann. §§19-1-301.5(14); 19-1-301.5(13)(b). Because this is an "on-the-record" case, there was no trial below, no witness testimony and no observation of facts "that cannot be adequately reflected in the record available to appellate courts[.]" *Adoption of Baby B.*, 2012 UT 35, ¶42, 308 P.3d 382.

Therefore, this Court is positioned to undertake an independent evaluation of the Director's permitting decision based on the administrative record and the standard of review articulated above. *See Olenhouse v. Commodity Credit Corp.,* 42 F.3d 1560, 1580 (10th Cir.1994) ("In reviewing the agency's action," on the record, "we must render an independent decision using the same standard of review applicable to the District Court. Once appealed, the District Court's decision is accorded no particular deference."). This is particularly true because the Director's decision must be reviewed on the basis he articulated at the time he made his decision and any post-hoc rationalizations for the permitting decision are unpersuasive. *Id*. 1575.

B. Preservation

This issue was preserved as follows: 1) Sub-Issue 1 (IR008584-95,[2] IR008597-98); 2) Sub-Issue 2 (IR008595-97, IR009062-63, IR009151); and, 3) Sub-Issue 3 (IR008598-601, IR009077-78, IR009081, IR009151, IR009162).

II. Second Issue

Whether, in authorizing the Expansion, the Director met his permitting obligations under Utah Admin. Code r.307-401-8.

Sub-Issue 1: If, after acknowledging that the flares would be a considerable source of air pollution, particularly of SO_2 and NO_X, during upset conditions at the Refinery, the Director complied with Utah Admin. Code r.301-401-8(1)(b)(vii), 8(1)(a) and 8(5) although he did not impose AO limits on flare emissions or otherwise ensure that the Expansion would not interfere with the maintenance or attainment of short-term NAAQS.

Sub-Issue 2: Did the Director meet the requirements of Utah Admin. Code r.301-401-8(1)(b)(vii), 8(1)(a) and 8(5) although he did not impose short-term limits on the Expansion emission units.

Sub-Issue 3: If the Director's confusing references to the applicability of Subpart Ja to the Expansion, particularly the flares, and his refusal to specify which of the particular terms and conditions of this complex provision apply to the Refinery, meet the requirements of Utah Admin. Code r.301-401-8(1)(b)(vi).

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[2] Utah Physicians attached and incorporated the Mark Hall Comments found at IR008579-602. IR009137.

Sub-Issue 4: Whether, given the evidence in the Record, with the South Flare shut down for reconstruction and all Refinery gases routed to the North Flare, the Record adequately supports the Director's contention that the apparent modification of the North Flare and increase in emissions from the unit did not trigger Subpart Ja or Utah Admin. Code r.307-401-8(1)(a).

A. Standard of Review

This Court will assess Issue 2 under the same standard of review it will apply to Issue 1, with the exception that Utah Code Ann. §63G-4-403(4)(h)(iii) is not relevant to Issue 2.

B. Preservation

This issue was preserved as follows: 1) Sub-Issue 1 and 2 (IR009078-80, IR009089-91, IR009155-57, IR009158-60); 2) Sub-Issue 3 (IR009152-54); and, 3) Sub-Issue 4 (IR009154).

DETERMINATIVE LAW

Utah Admin. Code r.307-401-8 (2012)

Utah Admin. Code r.307-403-3, 4 & 10 (2012)

STATEMENT OF THE CASE

I. Nature of the Case

Anyone living along the Wasatch Front has experienced our air pollution crisis, particularly wintertime "inversions" that settle on the Salt Lake Valley for extended periods, causing concentrations of fine particulate matter ($PM_{2.5}$) to skyrocket and giving Utah the dubious distinction of having the nation's worst air quality. We have felt our eyes and lungs burn, fretted over whether to let our children outside to play, agonized about parents and grandparents with heart problems – even taken them to the emergency room as their symptoms worsened – and watched those with asthma struggle to breathe.

Monitors quantify this public health emergency. Since 2009, the greater Salt Lake area has been formally designated as not attaining the nation's 24-hour $PM_{2.5}$ NAAQS. The Salt Lake City non-attainment area includes Salt Lake, Davis, Weber, Tooele and Box Elder counties. IR008482.[3] Because the state could not show that the area would attain the standard by 2015, the Salt Lake non-attainment area will be designated as a "**serious**" $PM_{2.5}$ non-attainment area as a matter of law by December 2015. 42 U.S.C. § 7513(b)(1), (c)(1).[4]

Our air pollution is serious. In 2013, air quality along the Wasatch Front exceeded the 24-hour $PM_{2.5}$ standard for at least 47 days – sometimes by 100%. This means that for more than a month, our community – including its most vulnerable populations, the young and the old – were subjected to levels of air pollution considerably higher than concentrations deemed unsafe and unhealthy at exposures lasting only 24 hours. *E.g.* IR009139-40.

Salt Lake County is further designated as not meeting the 24-hour PM_{10} and the SO_2 NAAQS and in recent years, air quality there has exceeded the 8-hour ozone

[3] http://www.epa.gov/pmdesignations/2006standards/final/region8.htm
[4] In the Interior West – made up of Utah ,Idaho, Montana, Colorado, New Mexico, Arizona, Nevada, Wyoming, Texas, Kansas, North Dakota, South Dakota, Nebraska and Oklahoma – only Utah (with seven counties) and Arizona (with two counties) do not meet the 24-hour $PM_{2.5}$ NAAQS. www.epa.gov/pmdesignations/2006standards/state.htm.

NAAQS, while Davis County is a "maintenance" area for ozone. IR009225; IR008482; IR008566-67; IR009140.

The health consequences of our dirty air are significant. The findings of 3,000 published research papers underscore key concepts now accepted by the medical community worldwide. First, there is no safe level of exposure to particulate pollution and no threshold below which negative health effects disappear. People literally die from exposure. For every 10 $\mu g/m^3$ increase in $PM_{2.5}$ concentrations, community mortality rates rise 14%. IR009140. Therefore, Utah Physicians estimates that 1,400 to 2,000 premature deaths occur every year in Utah from $PM_{2.5}$. IR009142.

Air pollution has the same extensive, broad-based health consequences as cigarette smoke because the signature physiologic response is the same – low-grade arterial inflammation, narrowing of blood vessels and increased propensity for clot formation, resulting in immediate increases in blood pressure, followed within hours by higher rates of heart attacks and strokes. IR009140-41.

The inflammation caused by $PM_{2.5}$ affects other organs. Particulate pollution penetrates every cell in the body, but is particularly well-documented in the brain. There, air pollution causes poor neurologic outcomes throughout the age spectrum, including loss of intelligence in children, higher rates of autism, and attention deficit disorders, as well as multiple sclerosis, Alzheimer's, and accelerated cognitive decline in the elderly. IR009142. Virtually every lung disease is caused or exacerbated, and growth of lung function during childhood can be irreversibly stunted by air pollution exposure. IR009143. Cancers, including childhood leukemia, lung, breast, prostate, cervical, brain and stomach cancer, occur at higher rates among people exposed to more air pollution, while cancer survival rates are reduced. IR009143.

The blood vessel inflammation caused by air pollution also affects the placenta, arguably representing the most significant public health impact of air pollution. Women who breathe more air pollution have higher rates of adverse pregnancy outcomes, their newborn babies showing increased birth defects, genetic damage, and a life-long disease burden that includes higher rates of metabolic disorders, reactive airway disease, cardiovascular disease, cancer, Alzheimer's and all diseases consequent to immuno-suppression. IR009143-44. The alteration of genetic material triggered by pollution can be seen within minutes, underscoring that short-term spikes in air pollution harm developing fetuses. IR009144.

At the center of Utah's Wasatch Front are five refineries, including the Holly facility. These refineries contribute to our air pollution problem by directly emitting $PM_{2.5}$, as well as the "precursor" pollutants that form fine particulate matter during our inversions – sulfur oxides (SO_X), nitrous oxides (NO_X) and volatile organic compounds (VOCs). These facilities represent a host of additional health risks. For example, when toxic substances are microscopically attached to fine particles, the health consequences are enhanced. Refinery particulate pollution is high in concentrations of attached hazardous air pollutants (HAPs) including heavy metals and polycyclic aromatic hydrocarbons (PAHs). IR009144.

Children living near petrochemical industries have higher PAH levels than adults, contributing to more DNA damage and endangering a more vulnerable population.

Industrial-based pollution is more toxic to DNA than traffic-based pollution. Rates of leukemia are doubled in populations living in the vicinity of oil refineries. Benzene, a primary component of refinery emissions, is carcinogenic and harmful to a developing fetus, causing low birth weight, delayed bone formation, bone marrow damage and low white blood cell and platelet counts. Exposure to benzene near the national standard is associated with sperm aneuploidy. Exposure to petrochemicals, specifically benzene, gasoline, and hydrogen sulfide, is significantly associated with increased frequency of spontaneous abortion. IR009144-45.

Even infinitesimal levels of exposure to PAHs, which are "endocrine disruptors," may cause "endocrine or reproductive abnormalities, particularly if exposure occurs during a critical developmental window…[L]ow doses may even exert more potent effects than higher doses." As a result, there are no safe doses for PAHs. IR009145.

In this context – a public health crisis affecting millions of Utahns – the Director issued a permit authorizing Holly to expand its facilities. At a time when the Clean Air Act requires the Director to reduce $PM_{2.5}$, NO_X, SO_2 and VOC emissions dramatically and bring the Salt Lake Valley into compliance with the NAAQS as "expeditiously as practicable," 42 U.S.C. §7513(c), he approved project increases in the refinery's annual emissions of $PM_{2.5}$ by 9.19 tons and PM_{10} by 9.54 tons, IR008566, annual emissions of the $PM_{2.5}$ and ozone precursors SO_2, NO_X and VOCs by 38, 83 and 32 tons respectively, and annual emissions of CO by 343 tons. IR008565. Annual refinery HAPs emissions will increase by 9.3 tons a year, IR002834, bringing the refinery's total yearly emissions of benzene to 1.46 tons, hexane to 5.41 tons, toluene to 1.21 tons, and xylene to 1598 pounds. IR008493.

Moreover, the Director determined that each year the refinery will release significant **uncontrolled** emissions of $PM_{2.5}$ precursors, including 240 tons of SO_2, 8 tons of NO_X and 16 tons of VOCs. IR008561. In the case of SO_2, these emissions will eclipse the relevant permit limit on the **entire** Holly facility – 110 tons of SO_2 each year, IR009245 – by more than 200%. Although these emissions threaten Utah's ability to comply with the NAAQS, the Director failed to impose emission limits or monitoring and recordkeeping requirements on the flares in order to constrain these substantial predicted "upset" emissions of SO_2, NO_X or VOCs. *E.g.* IR009245-46; IR009249-50.

As a result, at a time when the Director must find every possible emission reduction from every polluting sector, the Director has failed to undertake the analysis and review of the permit applications and the assertions they contain mandated by law and necessary to protect public health. In essence, the Director's permitting decision is not sufficiently rigorous and is not supported by the Record. The result is a permit that fails to give the citizens of Utah the legal protections to which they are entitled, does not require the control of emissions at the refinery to the extent the law demands, and fails to protect the public from air pollution.

II. Proceedings Below

Because it wanted to expand its refining capacity from 40,000 to 60,000 barrels a day (bpd) and to "accommodate…the processing" of thick and dirty heavy black and yellow waxy crudes, Holly submitted a revised Notice of Intent (NOI) to the Director in

July 2012. IR002798-3590. The Director issued an Intent to Approve (ITA) the NOI on June 5, 2013, IR008449-79, along with a Source Plan Review analyzing the proposal. IR008480-8575. Utah Physicians filed two sets of comments on the Director's plan to authorize the expansion. IR004007-44; IR009046-9173. The Director responded to these and other comments. IR009174-9222. On November 18, 2013, the Director issued an approval order (AO) to Holly, authorizing the construction of the Expansion. IR009223-54.

On December 18, 2013, pursuant to Utah Code §§19-1-301.5, Utah Physicians for a Healthy Environment and FRIENDS of Great Salt Lake (collectively "Utah Physicians") filed a Request for Agency Action (Request) seeking administrative review of the AO. ADJ009257-9373. On December 20, 2013, Utah Physicians moved for a stay of the AO. ADJ009557-96. The matter was assigned to an administrative law judge ("ALJ"), ADJ009601, who recommended denial of the stay in a March 25, 2014 proposed order, ADJ010798-820, Exhibit C, that was adopted by the ED on March 8, 2015. ADJ011035-39, Exhibit D.

On March 11, 2015, after briefing and argument, the ALJ issued another proposed order suggesting dismissal of Utah Physicians' Request. ADJ011536-648, Exhibit E. On March 31, 2015, in a two page decision, the ED adopted the proposed order. ADJ011651-53, Exhibit F. Utah Physicians timely appealed both ED orders to this Court.

III. Statement of Facts

A. NSR Permitting

"The Clean Air Act…aims to 'protect and enhance the quality of the Nation's air resources' by prescribing National Ambient Air Quality Standards (NAAQS), which state and regional authorities are required to either maintain or progress toward." *Sierra Club*, 2009 UT 76, ¶1. A key component of the Act that Congress deemed necessary to achieve and maintain the NAAQS and protect public health and the environment is the New Source Review (NSR) permitting program. Under NSR, before commencing construction or making modifications, stationary sources must obtain one or more of the following permits: a non-attainment NSR (NNSR) permit, 42 U.S.C. §§7501-15; prevention of significant deterioration (PSD) permit, *id*. §§7470-79; or a minor NSR permit. *Id.* §7410(a)(2)(C). The permits specify what air pollution control devices must be used, what emission limits must be met, and how the facility must be operated. *EPA NSR Workshop Manual* H.1.[5] Overall, permit conditions establish limits on the types and amounts of air pollution allowed, operating requirements for pollution control devices or pollution prevention activities, and monitoring and recordkeeping requirements. *Id.*

NSR serves two purposes: First, that the addition of new and modified industrial sources does not degrade air quality. *EPA NSR Factsheet* at 1, Exhibit G. In areas with unhealthy air – where NNSR applies – new emissions may not slow progress toward cleaner air, while in areas with clean air, PSD areas, new emissions may not worsen air

[5] http://www.epa.gov/nsr/ttnnsr01/gen/wkshpman.pdf, included on CD.

quality. *Id.* Second, the NSR program assures citizens that new or modified sources will be as clean as possible and advances in pollution control will be implemented as industries expand. *Id.* The NSR program accomplishes its goals by requiring sources to "obtain permits limiting air emissions before they begin construction. For that reason, NSR is commonly referred to as the 'preconstruction air permitting program.'" *Id.*

Utah's NSR permitting programs were approved by the U.S. Environmental Protection Agency (EPA) and incorporated into Utah's State Implementation Plan (SIP). EPA determined that Utah's permitting regimes complied the NNSR, PSD and minor NSR program requirements. 42 U.S.C. §7410. EPA approved and incorporated by reference into federal regulation Rule 307-401, 40 C.F.R. §52.2320(c)(28)(i)(B), and Rule 307-403, as necessary components of Utah's SIP. 40 C.F.R. §52.2320(c)(59)(i)(A). Rule 307-401 applies to all sources and all modifications, whether or not they are "major" and whether or not they are in non-attainment areas.[6] Utah Admin. Code r.307-401-3. Rule 307-403 applied to, *inter alia*, major modifications to major sources in non-attainment areas. *Id.* r.307-403-2.[7]

B. The Director's Non-Attainment NSR Determinations

Because Utah has failed to show that it will attain the 24-hour $PM_{2.5}$ NAAQS by the statutory deadline, the greater Salt Lake area – already deemed a moderate non-attainment area – will be designated a "serious" non-attainment area by December 2015.

[6] There are certain exemptions not relevant to the present matter to this requirement.
[7] "In a non-attainment area" is a simplification. NNSR requirements apply only to particular pollutants depending on which NAAQS the non-attainment area is failing to meet. *Id.* r.307-403-2(1).

42 U.S.C. §7513(b)(1), (c)(1); IR009225. This delay brings urgency to the Director's obligation to reduce emissions of air pollutants in order to achieve the $PM_{2.5}$ standard as "expeditiously as practicable." 42 U.S.C. §7513(c). To further this goal, the Clean Air Act constrains any project in a non-attainment area that constitutes a "major modification" – or that results in, *inter alia*, an increase in $PM_{2.5}$ emissions of 10 tons per year (tpy) or more. Utah Admin. Code r.307-101-2 ("major modification" is a change "that would result in a significant net emissions increase of any pollutant" and "significant" is a "net emissions increase or…potential of a source to emit" that "would equal or exceed" 10 tpy of $PM_{2.5}$); *id.* r.307-403-2(1) (r.307-403 applies to "major modifications"). Congress reasoned that no project may interfere with prompt compliance with the NAAQS or delay relief from harmful levels of air pollution to which the citizens living in a non-attainment area are entitled.

Rule 307-403 authorizes the Director to approve a major modification in a non-attainment area, "if and only if" he determines: 1) LAER (lowest achievable emission rate) has been applied, Utah Admin. Code r.307-403-3(3)(a); 2) emission offsets, "enforceable by the time a…modified source commences construction," have been secured, *id.* r.307-403-4(2) & 403-3(3)(c); and, 3) after public comment and based on an analysis of "alternative sites, sizes, production processes, and…control techniques" for the modification, that the project's benefits "significantly outweigh the environmental and social costs[.]" *Id.* r.307-403-10. Because the application of Rule 307-403 depends upon his conclusion, the Director must accurately determine, before construction commences, whether an emission increase is significant and if a project is a major modification.

Because the refinery is located in the Salt Lake $PM_{2.5}$ non-attainment area, the Director calculated the PTE $PM_{2.5}$ of the Expansion's modified and constructed units, including the FCCU25 and the NSPS boilers (Boilers#8-#11) and 11 heaters. IR002833. PTE is "the maximum capacity of a source to emit a pollutant[.]" Utah Admin. Code r.304-101-2.

The Director approximated the $PM_{2.5}$ emissions rate of Boilers#8-#11 and the 11 "non-NSPS" heaters using a constant created for inventory purposes that had never been used to predict emissions for NSR permitting. *E.g.* IR008483; IR008911-12; IR009043; IR007239-42. The inventory constant is 20 to 25 times **smaller** than the emission rate the Director applied to the other Refinery boilers and heaters, IR008549; IR008558, 20 to 25 times less than the emission rate based on the manufacture's data and guarantees, IR008502; IR002902; IR002920; IR003053, 1/20th to 1/25th of the emission rate that represents BACT and the "lowest emission rate" in the nation, IR002902-3; IR002920, and 20 to 25 times smaller than EPA's published AP-42 emission factors, the emission factor Holly used in the NOI to calculate emissions from the "NSPS" boilers and heaters. IR002847; IR003043-46; IR003048-50.

The Director authorized Holly to take "credit" for retiring the PPF. Based on a reckoning of "actual" emissions from the unit, IR008564; IR008369, the Director determined Holly could subtract 2.19 tpy $PM_{2.5}$ from the emission increases resulting from the Expansion. IR008564. 2.19 tpy is considerably greater than the annual $PM_{2.5}$

emissions from the larger North and South flares, IR002852; IR003176; IR003164, which are estimated to be zero in both upset and non-upset conditions, IR002865; IR002996; IR003029; IR003069, and is greater than the SIP-estimated $PM_{2.5}$ emissions of 1.44 tpy from all the flares at Holly, Tesoro and Big West combined. IR008153. There are no calculations or monitoring data in the Record to the support the 2.19 tpy. IR003035. The AP-42 emission factor on which Holly bases its calculation of $PM_{2.5}$ flare emissions varies from 0-274 micrograms per liter (μg/L). AP-42, 13.5-4. The Record does not indicate how the company used the variable AP-42 emission factors to calculate actual PPF emissions. IR003035. The 2.19 tpy credit is based on an unexplained increase in emissions, IR003035, that occurred after the PPF was replaced and redesigned to reduce $PM_{2.5}$ emissions. IR008564.

The Director calculated the $PM_{2.5}$ PTE for FCCU25 at 8.15 tpy, IR008367, or 97% of the Expansion's total PTE. IR008568. FCCU25 will process Utah black waxy crude, a substantial departure from the Canadian Select processed at the existing FCCU, IR007166; IR002839; IR007168, and will produce more carbon burn-off. IR008598-99; IR002937; 40 C.F.R. §60.101a; *id.* §60.104a. To assess PTE, the Director relied on an AO limit of 0.3-lb PM_{10}/1000-lb coke burned, IR009243, without restricting or accurately estimating the maximum rate of coke burn-off. IR009242-43; IR008052.

After adding and subtracting, the Director determined that the Expansion would cause an 8.35 tpy increase in $PM_{2.5}$ emissions – slightly under the significance level of 10 tpy. IR008568. Therefore he concluded the Expansion was not a major modification and not subject to Rule 307-403.

C. The Director's Minor Source NSR Permitting

The Director must comply with Rule 307-401-8 whether the Expansion is a major or minor modification. The rule, by its own terms, *see Sierra Club,* ¶13 ("We review administrative rules in the same manner as statutes, focusing first on the plain language of the rule."), applies equally to minor or major modifications. Utah Admin. Code r.307-401-3.

Under Rule 307-401-8, the Director may issue an AO only if he determines that the "degree of pollution control for emissions…is at least BACT." Utah Admin. Code r.307-401-8(1)(a); *id.* r.307-401-8(5). BACT is an "emissions limitation…based on the maximum degree of reduction for each air contaminant which…is achievable[.]" *Id.* r.307-401-2(1); *Sierra Club* ¶48. The goals of BACT emission limitations are: "(1) to achieve the lowest percent reduction, (2) to protect short-term ambient standards, and (3) to be enforceable as a practical matter." *Sierra Club,* ¶48 (*citing NSR Manual,* B.6-.9); *NSR Manual* B.56 ("BACT emission limits…must...demonstrate protection of short-term ambient standards (limits written in pounds/ hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements).").

In addition to his obligation to protect short-term NAAQS by imposing appropriate BACT emission limitations, the Director has an independent duty to ensure that emissions from any modification will not interfere with the attainment or maintenance of the NAAQS. Utah Admin. Code r.307-401-8(1)(b)(vii); *id.* r.307-401-8(5).

EPA established short-term NAAQS because spikes in air pollution of a shorter duration are as harmful to public health as long-term exposure to lower levels of pollution. Short-term NAAQS include standards prohibiting concentrations of SO_2 and NO_X, from exceeding designated levels monitored over a one-hour period. 75 Fed. Reg. 35520 (June 22, 2010); 75 Fed. Reg. 6474 (February 2, 2010). The 24-hour $PM_{2.5}$ and PM_{10} NAAQS, 78 Fed. Reg. 3086 (January 15, 2013), and the eight-hour ozone standard, 73 Fed. Reg. 16436 (March 27, 2008), also protect against high levels of these air pollutants averaged over shorter periods of time.

The Director applied BACT to various Expansion emission units, including 11 process heaters, Boiler#11, FCCU25, and the South Flare. IR008495-8518.[8] The resulting SO_2 and NO_X emission limitations are typically expressed by daily and yearly (365-day rolling) averages and **not** as hourly limits. IR009245; IR009248. The limitations on FCCU25 SO_2 and NO_X are averaged over a rolling 7-day and 365-day period. IR009242-43. The SO_2 limit on the FCCU25 scrubber is averaged on a daily and yearly basis. IR009245. The source-wide limitations on both SO_2 and NO_X are averaged daily or on a 365-day rolling basis. IR009245; IR009248. SO_2 emissions from the South and North flares are not limited by the permit, IR009186-87; IR009241-51, and only annual "non-upset" NO_X flare emissions are restricted by the AO. IR009249. NO_X emissions from the heaters and boilers are determined on a three-hour basis, but compliance is gauged by a stack test performed once in three years. IR009249-50.

[8] The Director is also required to derive and impose BACT on the North Flare.

Compliance with the PM_{10} emissions from the "NSPS" heaters and boilers are evaluated by a yearly stack test. IR009248.

The Director admits that the two Holly flares will be a significant source of air pollution. Each year, emissions from each flare due to "upsets" will amount to 120 tons of SO_2, 21 tons of CO, 4 tons of NO_X and 8 tons of VOCs. IR008561; IR002865. The Director proposed to limit flare emissions by removing exemptions for flares from the emission caps for SO_2 sources, IR008568, PM_{10} sources, IR008569, and NO_X sources. IR008569. The final AO contains "no limits on the flares." IR009186-87. The AO does not require a calculation of flare SO_2, CO, VOCs or PM_{10} emissions in order to determine whether the sources covered by emission caps are complying with the relevant emission limitations. IR009245-48. For NO_X, the AO limits only annual "non-upset" emissions by including only "non-upset" flare throughput rates in the calculation of emissions. IR009249. The AO does not limit any "upset" flare emissions for any pollutants. IR009241-51. "[F]lares are in place as control device for upset conditions." IR009186.

Holly modeled the impact of the Expansion on NAAQS, IR002993-96, and showed an increase in NO_2 concentrations equal to 95% of the one-hour NAAQS. IR00003596. Holly's modeling did not include any "upset emissions" from the flares, IR009214, did not determine maximum short-term emissions and instead used as inputs average annual emissions that masked any spikes in air pollution. IR002993-96. The Director acknowledged that the Refinery experiences significant variability in day to day emission and production levels. IR009187.

SUMMARY OF ARGUMENT

Families living along the Wasatch Front are held hostage by air pollution. During frequent wintertime inversions, they are told to stay indoors and not to exercise. They cough, get headaches and struggle to breathe. The fine particles, individually invisible but concentrated enough to block the sun, enter the body, causing inflammation and increased blood pressure, heart attacks and stroke. $PM_{2.5}$ damages lungs, retards lung function and penetrates and impairs the brain. Developing fetuses are prone to genetic damage and lifelong diseases as they are exposed to the air pollution their mothers breathe.

By 2015, the year the law promised them relief, the citizens of Utah were still trapped in unhealthy air. The State's plan to reduce emissions was not adequate and the date of compliance with the NAAQS was pushed off until 2020. In December 2015, Salt Lake, Davis, Weber, Box Elder and Tooele counties will be re-designated a "serious" non-attainment area and the State will have to develop a new plan with stricter measures to secure the necessary emission reductions. Utahns will face at least five more years of unhealthy air. In the meantime, they are entitled to all the protections the Clean Air Act provides and all the steps toward healthy air the law guarantees.

When a major source like the Refinery proposes a project that will increase emission of $PM_{2.5}$ in the Salt Lake serious nonattainment area, much is at stake – the expeditious compliance with the NAAQS and the corresponding health benefits that legal promise entails. The Director must determine if the project is a major modification and therefore if Rule 307-403 applies. The purpose of this assessment is clear. In an area already plagued by unhealthy levels of air pollution, where emissions must be reduced as expeditiously as possible, air pollution increases are not permissible.

Although an accurate calculation of projected $PM_{2.5}$ increases is fundamental to implementation of the NSR program, the Director did not make a defensible determination. First, to deem the Expansion a minor modification, the Director used an emission rate 20 to 25 times smaller than the emission rates derived from several sources the Director has deemed reliable and referenced again and again for his NSR permitting. Second, the Director approved an emission reduction for the retirement of a flare that Holly claims, without showing its monitoring data, assumptions or calculations, emitted more $PM_{2.5}$ each year than both of Holly's other, larger flares combined and more than all the flares at the Holly, Tesoro and Big West refineries put together. Third, the Director determined the PTE for FCCU25, the largest source of $PM_{2.5}$ emission increases, from a rate of 0.3-lb PM_{10}/1000-lb coke-burned, without restricting or accurately estimating the maximum hourly rate at which coke may be burned in the unit. This means that the FCCU25 PM_{10} emissions are not subject to a hard ceiling and the Director's calculation of PTE without a limit on coke-burn rate will necessarily be inaccurate.

The next line of defense safeguarding Wasatch Front air quality is Rule 307-401, which covers minor modifications. Again, the Director misapplied the law, failing to assure that the Expansion would not impede the attainment or maintenance of the NAAQS. The Director acknowledged that during upset conditions, Holly's flares would be a significant source of air pollution – for example, emitting double the Refinery-wide SO_2 emission cap – but did not restrict these emissions. The Director decided not to impose short-term limits on the Refinery to protect the short-term NAAQS, claiming that modeling showed such restrictions were unnecessary. Actually, Holly modeled neither upset flare emissions nor maximum short-term emission rates, and instead relied on average annual rates, underestimating impacts to short-term NAAQS. Still the company's analysis showed that the Expansion threatened the one-hour NO_2 NAAQS. The Director also neglected his permitting obligations by failing to clarify the application of NSPS Subpart Ja to the Expansion and refusing to specify the exact conditions of this complex rule that apply to the Refinery.

As explained below, although the Director has discretion to carry out the Clean Air Act, the people of Utah have a right to every emission reduction the law requires. Unless and until the Director carries out his NSR obligations with the requisite rigor and basis, Utahns are not receiving the relief to which they are entitled.

ARGUMENT

I. The Director's Calculation of Increases in $PM_{2.5}$ Emissions from the Expansion Is Fatally Flawed.

Because the law requires it and because $PM_{2.5}$ air pollution from the Expansion will be added to our already seriously unhealthy air, it is critical that the increase in emissions be calculated accurately and supported by the Record. As EPA states, PTE "is of primary importance in establishing whether a…modified source is major." *EPA NSR Manual* A.4. Despite the importance of the undertaking, the Director's calculation reflects an erroneous application of the law, is not supported by the Record, is "contrary to [his] prior practice," and unjustified and unfair as well as arbitrary and capricious. Utah Code Ann. § 63G-4-403(4)(d), (4)(g), (4)(h)(iii)-(iv).

A. The Director's Departure from Prior Practice and Inconsistent Reliance on the NEI Constant is Unlawful.

Abruptly diverging from prior practice, reversing positions in the middle of permitting, embracing inconsistent methods in a single AO and deviating from a previous AO determination, the Director improperly adopted a National Emission Inventory (NEI) constant of 0.00042 lb/MMBtu – a number designed for calculating a national inventory of air pollution – to estimate $PM_{2.5}$ PTE for an arbitrary subset of Holly's boilers and heaters. *E.g.* IR008558-9; IR008419.[9] The Director's application of the NEI constant to some, but not all, heaters and boilers, represents a radical departure from the manufacturer's own specifications, EPA's AP-42 emission factors, Holly's BACT analysis and the Director's 2010 AO and BACT. The NEI constant represents an emission rate 1/20th-1/25th of the manufacture's guarantee and the standard AP-42 emission factor, is 20-25 times lower than what Holly called the "lowest emission limits" in the nation and results in an estimate of total $PM_{2.5}$ emissions 29 times smaller than NOI calculation. Therefore the Record does not support the adoption of this outlying emission rate and confirms that the resulting PTE does not reflect the maximum capacity of the heaters and boilers to emit $PM_{2.5}$.

[9] 0.43 lb $PM_{2.5}$/MMscf equals 0.00042 lb/MMBtu.

1. The Director Deviated from His Prior Practice and Arrived at an Emission Rate Out-of-Sync with Sources He Deemed Reliable.

Neither Utah, the other 49 states, nor EPA has ever used a NEI constant to calculate PTE for NSR. *E.g.* IR008911-12; IR009043; IR007239-42. The Director's own forms and guidance establish what the "NSR Section" – the Director's permitting branch – has long considered appropriate methods for calculating emissions, directing applicants to use manufacturer specifications or AP-42 emission factors.[10] DAQ NSR *Form 19, Natural Gas Boilers and Liquid Heaters* commands: "Supply calculations for all criteria pollutants[.] Use AP-42 or Manufacturers' data to complete your calculations." Exhibit H at 3; *Form 2 – Process Information* at 2 (same). DAQ's *Emission Calculation Sheets – Boiler Emissions Natural Gas* states: "Emission factors are from EPA AP-42[.] Most newer boilers have smaller emission rates, if you have manufacturer's emission rates you should use them. Please include the manufacturer's literature as a reference for why you are using different factors." Exhibit I at 2; *Boiler Emissions Fuel Oil* (same). The DAQ *AP-42 Guide* confirms: "EPA's AP-42 is the recommended source of air pollutant emission factors for both criteria and toxic emissions."[11] Similarly, the recent *Emission Estimation Protocol for Petroleum Refineries* confirms that for combustion sources, if "direct emission monitoring or site-specific emission factors are not available…default emission factors may be the only way to estimate emissions" and "emission factors in

[10] An emissions factor is supposed to be a representative value that relates the quantity of a pollutant emitted with an associated activity.

[11] www.deq.utah.gov/ProgramsServices/programs/air/emissionsinventories/ap42guide.htm

AP-42 are the recommended default emission factors, and AP-42 should be consulted to obtain the appropriate emission factors for criteria pollutants such as SO_2, NO_X, PM, and CO." IR008715; DAQ's *NOI Guid*e at i., v. & 2 (linking to "AP-42: EPA's Air Pollutant Emission factors").[12]

Consistent with this longstanding approach, the Director and Holly identified $PM_{10}/PM_{2.5}$ emission rates ranging from 0.010 lb/MMBtu to 0.0075 lb/MMBtu for the Refinery Boilers#8-11 and various process heaters based on the sources the Director's own materials deem reliable – manufacturer's data and EPA's AP-42 emission factors – and consistent with BACT and the "lowest emission rates" across the country.

The Director and Holly acknowledge that the manufacturer's guaranteed $PM_{10}/PM_{2.5}$ emission rate for Boilers#8-#11 is 0.010 lb/MMBtu. IR008502 ("[M]anufacturer's data indicates a guaranteed emission factor of 0.010 lb/MMBtu"); IR003053 ("$PM_{10}/PM_{2.5}$ emissions based on manufacturer supplied emission rate of 0.010 lb/MMBtu" for Boiler#11); IR002920 (same). Holly concludes that a 0.010 lb/MMBtu emission rate for Boiler#11 represents BACT, IR002920, an emission limitation based on "best available control technology," Utah Admin. Code r.307-401-2(1) (BACT definition), and states that 0.0075 lb/MMBtu is the "lowest [boiler] emission rate[] identified in the past four years." IR002920; IR002829 ("Emission estimates…based on

[12] "In some cases" source-specific stack tests may be used as emission factors. *NOI Guide* at 2; IR008013 (EPA AP-42 Guide stating "source-specific tests or continuous emission monitors can determine" emissions better than emission factors and giving as alternative "emissions information from equipment vendors, particularly emissions performance guarantees or actual data from similar equipment").

manufacturer data, EPA…AP-42, fuel type, and anticipated operating hours."); IR002847 (same); IR003045 (using AP-42 to calculate boiler emissions); IR003049. Holly and the Director also decide that EPA's AP-42 emission factor for natural gas boilers – 0.0075 lb/MMBtu – is the most appropriate emission rate for all the other Refinery boilers. IR008549 (applying emission rate of 7.65 lb/MMscf); IR008558.

For the process heaters, reliable sources also zero in on an emission rate –0.0075 lb/MMBtu. In the NOI, Holly calculates $PM_{10}/PM_{2.5}$ emissions from its "new" NSPS heaters using AP-42 emission factor 0.0075 lb/MMBtu.[13] *E.g.* IR003045-46; IR003048-50. Holly concludes that the $PM_{10}/PM_{2.5}$ emission factor that best represents BACT is the rate based on manufacturer data – 0.0075 lb/MMBtu. IR002902. Holly "lists the lowest emission rates identified in the past several years" for process heaters – all of which hover around 0.0075 lb/MMBtu. IR002902-3. In the NOI, Holly applies AP-42 to calculate process heaters/furnace $PM_{2.5}$ emissions. *E.g.* IR002847; IR003045-46; IR003048-50. Holly and the Director also decide that EPA's AP-42 emission factor for natural gas boilers – 0.0075 lb/MMBtu – is the most appropriate emission rate for all other Refinery heaters. IR008549; IR008558.

Finally, the Director determined in a previous permitting decision – the 2010 AO – that Boilers#9-#10 – which have been constructed – have a $PM_{10}/PM_{2.5}$ emission rate of 0.005 lb/MMBtu. IR008193 (5 lb/MMscf).[14] At the time, he also determined that this emission rate reflects BACT. Utah Admin. Code r.307-401-8(1)(a).

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[13] Sometimes expressed as 0.008 lb/MMBtu.
[14] lb/MMscf is converted to lb/MMBtu by dividing by 1020. AP-42, Table 1.4-2.

Thus, before departing from the position that manufacturer data and AP-42 were the best way to calculate PTE, the Director and Holly both concluded that a representative emission rate for the NSPS boilers and heaters, based on information long deemed reliable, was between 0.010 lb/MMBtu and 0.005 lb/MMBtu. Holly put complete confidence in manufacturer data to derive the appropriate emission rate – and backed this up with a survey of the "lowest emission rates" in the country to settle on a boiler emission rate of 0.010 lb/MMBtu and a heater rate of 0.0075 lb/MMBtu. The Director applied the emission rate of 0.005 lb/MMBtu to the existing Boilers#9-10 based on his determination of BACT. The rates from all these credible sources are similar in magnitude, further underscoring their reliability.

Then, in sudden disregard for sources he deemed most dependable, manufacturer guarantees and AP-42, and contrary to his 2010 AO determination and Holly's BACT, the Director departed from his previous position to capitulate to the 0.00042 lb/MMBtu inventory constant – a mere 4% or 1/25th of the manufacture-specified value for boilers and 5% or 1/20th of the guarantee for heaters. IR008502; IR002902; IR002920; IR003053. The inventory constant is also 20-25 times lower than what Holly deemed the "best available" and "lowest" emission rate in the U.S, IR002902-3; IR002920, and 20-25 times less than EPA's AP-42, the emission factor Holly relied on in the NOI to calculate emissions from the "NSPS" boilers and heaters, IR002847; IR003045-46; IR003048-50, and the basis for the emission rates applied to the remaining boiler and heaters. The Director also bypassed his own 2010 AO determination of BACT emission rates for Boilers#9-10 and refused to require stack testing of this existing equipment, calculating a PTE for existing boilers 8% or 1/13th of his 2010 AO determination. IR008193.

The consequences of this new math are significant. Relying on manufacturer data and BACT, the Director's $PM_{10}/PM_{2.5}$ PTE for the NSPS boilers and heaters is 19.81 tpy– alone almost twice the 10 tpy threshold that makes the Expansion a major modification. Using the NEI constant, that number is 0.69 tpy – 3.5% or 1/29th – of the total representing the rates from manufacturer's data, AP-42, BACT and the 2010 AO.

Unit	Original $PM_{10}/PM_{2.5}$ Emissions (tpy) IR002834	"New" $PM_{2.5}$ Emissions (tpy) IR008367
Boiler#11	3.91	0.16
27H1	3.25	0.18
24H1	1.97	0.11
25H1	1.48	0.08
20H3	1.38	0.08
Boilers#9-#10	7.82[15]	0.08[16]
Total	19.81	0.69

[15] IR002842.
[16] IR008410.

These numbers evidence an arbitrary departure from established practice, particularly when there is no basis in the Record to embrace an emission rate so out-of-sync with the rates derived from a host credible sources – manufacturer's data, AP-42, BACT and permit limits from other sources that reflect the lowest emission rates in the nation. While the manufacturer's data, EPA's AP-42 emission factors, Holly's BACT analysis and the 2010 AO all arrive at emission rates of a similar magnitude, the NEI constant is a complete outlier, deviating radically from the emission rates both Holly and the Director embraced at one time, and have continued to apply to the "non-NSPS" boilers and heaters. Because the so-called NSPS boilers and heaters are not necessarily "new," there is nothing to distinguish them from the non-NSPS boilers and heaters that the Director believes have an emission rate considerably higher than the NEI constant. IR008558 ("Holly Refinery and DAQ are less confident this older equipment can verify these lower NEI emission factors."). Indeed, there is nothing in the Record to explain why the $PM_{2.5}$ emission rates for one set of boilers and heaters at the refinery would be 20-25 times lower than the $PM_{2.5}$ emission rates for another set.

Thus, the Director's adoption of the NEI constant is subject to remand. The Director's action is "contrary to [his] prior practice" and he has not "justifie[d]" the departure "by giving facts and reasons that demonstrate a fair and rational basis for the inconsistency." Utah Code Ann. §63G-4-403(4)(h)(iii). The Director's unlawful reliance on future stack tests to support a calculation that must accurately reflect PTE before construction commences subverts r.307-403 and the protections it provides. Given that the NEI constant is so much smaller than the rates derived from sources the Director deems credible, he has failed to derive a legally defensible PTE that represents "the maximum capacity of a source to emit a pollutant[.]" Utah Admin. Code r.304-101-2.

2. The Director Did Not Provide a Fair or Reasonable Basis for His Inconsistency or Deviation from Prior Practice.[17]

The Director attempts to justify his abandonment of manufacturer's specifications, the 2010 AO, BACT and AP-42, but this effort fails. He contends that "NEI emission factors can be used for estimating PTE emissions as long as Holly…can demonstrate compliance with these emissions factors through stack testing[.]" IR009216; IR008558-59; IR009215-19; IR008545. However, these stack tests will not occur until well after the Expansion is complete. IR008545; IR009248. As a result, the Director subverts Rule 307-403's "preconstruction" permitting process. In particular, emission offsets must be "enforceable by the time a…modified source commences construction," Utah Admin. Code r.307-403-4(2), and the Director must analyze "alternative sites, sizes, production processes, and environmental control techniques" to determine if purported benefits of the Expansion "significantly outweigh the environmental and social costs imposed as a result of [the]…modification" *Id.* r.307-403-10. For example, the purpose of "analysis of alternatives," which considers, *inter alia*, siting the Expansion outside of the non-attainment area, and the requirement that offsets be enforceable at the commencement of construction, would be frustrated if the Director tried to comply with them after the Expansion is constructed and operating.

[17] The ED's findings are found at ADJ011622-23. Pertinent Record evidence includes England reports, IR007238-58; IR008024-44, the Director's RTC, IR009215-18, and the SPR. IR008558-59.

The Director also contends that should stack tests "indicate that the equipment cannot meet the 0.00051 lb/MMBtu for PM_{10}," Holly "would be required to either install additional control equipment to comply with this limit, or submit an application to reevaluate the project…for Major NSR applicability." IR009216; IR009215-19. This explanation lacks merit. Under r.307-403, post-construction application of "Major NSR" is too late. Holly's own BACT analysis concludes that there is no further way to reduce $PM_{2.5}$ emissions from the heaters or boilers. IR002902 ("the only control technology" – which was adopted – "is…good combustion practices and use of low sulfur…fuel"); IR002919; IR008502. Therefore there is no "additional control equipment" to install.

Finally, in determining whether the NEI constant actually represents boilers and heaters $PM_{2.5}$ emissions, the most the Director can say is "EPA believes that the current AP-42 factors for condensable emissions are too high based on some limited data from a pilot-scale dilution sampling method[.]" IR008558; IR009215-19. This lukewarm statement – which cannot overcome the vast deviation from the relevant manufacturer's data, 2010 AO, BACT and AP-42 – is not supported by the Record.

First, EPA experts did **not** advocate using NEI data as the basis for an emission factor, noting the lack of "detailed supporting information," explaining that even if the NEI numbers were more reliable, they would still have to be averaged with other data, expressing concern that the sampled population would not be representative and pointing to recent NSPS boiler standards as a better estimate of emissions. IR008911-12; IR009043 (explaining an emission factor would not be valid without an underlying test report). The Record further explains why EPA lacks faith in the NEI constants, listing the significant uncertainty associated with the "England" factors and acknowledging that the EPA had not reported any of the details that supposedly support the agency's NEI numbers, such as the statistical significance, associated uncertainty or number of tests that purport to back them up. IR007248.

Second, England, Holly's own expert and author of a report on a "dilution" sampling method that was the basis for the NEI constant, IR008911, acknowledged that his emission estimates were not ready for use, cautioning that they: 1) "should not be considered representative of all units within the same source category," 2) "should be used with considerable caution;" 3) "do not necessarily represent results from a random sample of an entire source category;" and, 4) "may best be used in conjunction with test results from other units within the same source category…to develop more robust, reliable emission factors." IR008998-99; IR009000-01; IR007248 (showing considerable uncertainty for the dilution method).[18]

Third, while the Director calls these selected boilers and heaters "new," nothing in the Record suggests that they are. IR008558. Actually, this equipment is subject to NSPS, *id.*, and therefore could be constructed or modified. 40 C.F.R. § 60.1. For example, the mothballed FCCU25 comes "from an idled New Mexico refinery," IR002821, but has been called "new" and is subject to NSPS Subpart Ja. IR002868.

Fourth, the Director's reliance on an unapproved $PM_{2.5}$ "emissions factor" based on severely limited "NEI" data violates federal and state law. *See* 42 U.S.C. §7430

[18] At IR008022-44, the author of these statements attempts to rehabilitate his study and discount his previous warnings.

(requiring EPA approval of emissions factors not established by EPA); IR008020 (because “AP-42 emission factors may have effects on most aspects of air pollution control…these factors are always made available for public review and comment before publication.”). And, unlike AP-42, they have never been vetted or subject to public notice and comment. Thus, the Director has failed to show that his departure from previous practice is reasonable and fair. Utah Code Ann. § 63G-4-403(4)(h)(iii).

B. The Director Failed to Provide a Defensible Calculation of Emission Decreases from Closure of the Propane Pit Flare.

In assessing whether the Expansion is a major modification, the Director also authorized Holly to claim a credit for closing the PPF and therefore to subtract 2.19 tpy from the Expansion’s $PM_{2.5}$ emission increases. IR008564; IR008369.[19] However, the absence of support and significant inconsistencies that surround this number mean that the Director’s reliance on the 2.19 tpy $PM_{2.5}$ credit cannot be sustained.

First, 2.19 tpy of $PM_{2.5}$ represents an enormous level of emissions coming from a hydrocarbon flaring device like the PPF, particularly in comparison to the South and North flares, which are also hydrocarbon flaring devices, IR004473, and considerably larger than the PPF. IR002852 (South Flare non-upset flow 17,000 scf/h); IR003176 (PPF 280 scf/h); IR003164 (North Flare 21,960 scf/h). Holly estimates that under both upset and non-upset conditions, PM_{10}/$PM_{2.5}$ emissions from the South and North flares are zero (0.0). IR002865; IR002996; IR003029; IR003069. The draft $PM_{2.5}$ non-attainment State Implementation Plan (SIP) calculates the “actual” 2008 $PM_{2.5}$ emissions

[19] The ED’s findings are found at ADJ011639-40.

for all Holly, Tesoro and Big West refinery flares combined as 1.44 tpy. IR008153. Therefore, the "actual" emissions from the PPF eclipse the emissions from the North and South flares and are even greater than the State's estimate of all the $PM_{2.5}$ emissions from all the flares at the three local refineries, including Holly. This casts doubt on the reliability of the 2.19 tpy $PM_{2.5}$ emission credit and the Director's claim that the credit reflects actual emissions.[20]

Second, according to the Director, the 2.19 tpy credit is accurate because Holly used AP-42 emission factors to determine "actual" $PM_{2.5}$ emissions from the PPF based on continuously monitored throughput for 2008-2009. IR008564; IR009218; ADJ011101; ADJ011204 (DAQ relied on calculations "based on monitored throughput data of propane to the flare and AP-42 emission factors."). While AP-42, 13.5, gives a vast range of emission factors, spanning from 0 to 274 μg/L depending on whether the flares are not smoking or are smoking heavily, AP-42, 13.5-4, Exhibit J, the PPF "actual" $PM_{2.5}$ emissions were the same for the years 2009 to 2011. This suggests the unlikely scenario that the PPF was smoking at a consistent yearly average, somewhere between 0-274 μg/L, for three years in a row.

Third, the AP-42 emission factors calculate soot, not $PM_{2.5}$. *Id*. Yet, nothing in the Record explains how the emission factor for soot was used to calculate $PM_{2.5}$. Without a foundation in the Record, the Director is not free to assume that all flare soot is

[20] The 2.19 tpy credit is exaggerated. Using AP-42 emission factors, Utah Physicians back-calculated the propane the PPF would have had to burn to generate 2.19 tpy $PM_{2.5}$. The answer was more than 8 million dollars' worth of propane each year, with constant flaring, visible night and day. IR008596-97.

$PM_{2.5}$. Also, AP-42 factors for flares are based on gas that is 7% propane, AP-42, 13.5-5, but the Director does not explain how "actual" emissions were derived from emission factors applied to gas that is presumably 100% propane.

Fourth, the Director claims that new PPF installed in 2009 added "air assist (to control smoke production)." IR008564; AP-42, 13.5-3 ("Soot is eliminated by adding steam or air"). He also maintains that "emission estimates" for the new PPF "compared to the flare prior to replacement did not change because reported emissions (prior to and after replacement) were based on AP-42…emission factors [and] bringing the flare into compliance did not adjust emissions." IR008564; IR007270-71; IR009182. However, according to the Record, $PM_{2.5}$ emissions from the PPF actually increased in 2009 (from 1.78 tpy in 2008), when the Consent Decree required replacement of the PPF, IR007270, and remained exactly the same – 2.6 tpy – for 2009, 2010 and 2011. IR003035. Again, it is difficult to explain how "actual" emissions based on real monitoring data and variable emission factors could remain static and the Record does not do so.

Fifth, Holly explains that under the Consent Decree it agreed to "[e]liminate the routing of continuous or intermittent, routinely-generated refinery fuel gases to" the PPF. IR004385; IR007951 (Consent Decree "requirement" for PPF to "eliminate all routinely-generated gas"), *but see* IR009182. The Consent Decree also imposes on Holly the obligation to "implement good air pollution control practices to minimize emissions from its Flaring Devices as required by 40 C.F.R. §60.11(d)." IR004384. When pressed, Holly defended the PPF's high and undocumented $PM_{2.5}$ emissions, claiming "[t]hat the propane pit flare may have been flaring continuously to equate with the…baseline is of no consequence – it is likely that given the obvious inefficiencies…the flare was flaring continuously to manage the amount of gas released from the pit." ADJ011204. Therefore, Holly admits that the claimed 2.19 tpy $PM_{2.5}$ credit likely runs afoul of the Consent Decree and federal requirement that Holly minimize emissions.

These substantial discrepancies, at a minimum, underscore that the Record must include a sound basis for the 2.19 tpy credit. But there is none. *E.g.* IR003035. Despite the importance of an accurate determination of net $PM_{2.5}$ emissions and therefore any credit attributable to the closure of the PPF, the Record is devoid of any specific emission factors, conversions, equations, calculations, assumptions or monitoring data to substantiate Holly's claimed PPF emissions. IR003035; *DAQ NOI Guide* ("Give calculations of the emission estimates…. Include equations, all relevant emission factors, and references. Explain all assumptions…made in your calculations."). Although the Director insists that the PPF $PM_{2.5}$ emissions were based on "actual throughput data," IR009218, neither he nor Holly provides those data. IR003035. As a result, for lack of foundation, the 2.19 tons of $PM_{2.5}$ credit is not supported by the Record and the Director's reliance on it to conclude the Expansion is a minor modification is invalid.

C. The Director's Estimate of the FCCU25 $PM_{2.5}$ Emissions Does Not Reflect the "Maximum Capacity of the Source to Emit" $PM_{2.5}$.

When Holly decided "to switch its crude oil feedstock source from…Select Canadian Crude to Utah Black Wax Crude (BWC)," IR007166, it proposed to bring a mothballed fluidized catalytic cracking unit (FCCU25) from New Mexico, IR002821, to process BWC in the Salt Lake non-attainment area. IR002816; IR002810. This "central" change, constituted a "revision in the planned nature of the crude oil feed to the refinery." IR002839. "Given the differences between these feedstock sources," Holly sought authorization to install new equipment and modify existing equipment so that it could now refine BWC. IR007168.

For example, because it will process BWC, FCCUC25 will not be equipped with a hydrotreater to control emissions as the BWC "heavy residual bottoms fraction" makes hydrotreatment "infeasible." IR002937. In keeping with this assessment, Universal Oil Products (UOP), world leader in FCCU technology, concluded that BWC has a relatively high tendency to produce coke in a FCCU. IR008598-99;[21] IR004250 ("Coke is a high carbon residue that is the final product of thermal decomposition in the condensation process in cracking."). Feedstock with a higher "coke-burn rate" will produce more coke in an FCCU, resulting in a proportional increase in $PM_{2.5}$ emissions. *Id.*; 40 C.F.R. §60.101a; *id.* §60.104a.

[21] The Director discounted this information, but did not endeavor to derive the degree to which BWC would produce coke in FCCU25, IR009219, while acknowledging "different feedstocks can result in slightly different emission profiles[.]" IR009194.

Because $PM_{2.5}$ emissions from FCCU25 comprise 97% of the Expansion's total PTE, an accurate calculation of the emission increases from this unit is crucial. However, the Director's calculation is legally and factually flawed. PTE must reflect "the maximum capacity of a source to emit a pollutant[.]" Utah Admin. Code r.304-101-2. A limitation on the capacity of the source to emit will be considered in a PTE calculation only if the limit is "federally" and "practically enforceable." *Id.*; *EPA NSR Manual* A.4-A.5. Where limitations are not enforceable, PTE is based on a unit's full capacity and year-round operation. *Id.* A.9; r.304-101-2.

Here, the Director relied on an AO limit of 0.3-lb PM_{10}/1000-lb coke burned, IR009243, and Holly's "engineering calculation" of a "maximum" coke-burn rate of 6200-lbs/hr, IR003047, to arrive at a PTE $PM_{2.5}$ of 8.15 tpy. IR008367. However, the 8.15 tpy does not reflect the maximum capacity of FCCU25 to emit $PM_{2.5}$ because there is no federally and practically enforceable limitation that restricts the coke-burn rate or the amount of coke/hr that Holly may burn. The AO does not put a 6200-lbs of coke-burn/hr or similar limit on FCCU25. IR009242-43. The AO does not require Holly to track the coke burned in FCCU25. IR009242-43. The AO does not even require a reality check or any verification that FCCU25 will meet the 6200-lbs/hr rate that is the basis of the PTE calculation.[22] IR009242-43. For these reasons alone, the 8.15 tpy does not meet

[22] As established above, r.307-403 does not permit verifications of PTE after construction but rather demands accurate PTE calculations before construction.

the definition of PTE. After all, nothing in the AO constrains Holly from exceeding the 6200-lb/hr coke-burn rate.[23]

Given that FCCU25 will process BWC and its heavy residual bottoms, it is almost certain that the 6200-lb/hr coke-burn rate will be surpassed. Because PTE represents the maximum capacity of a source to pollute, the Director's PTE must estimate emissions during the worst-case scenario, when the FCCU25 is emitting the maximum $PM_{2.5}$ it is capable of releasing while still complying with applicable federally and practically enforceable permit limitations. Here, where there are no restrictions on the feedstock that FCCU25 may process, PTE must be calculated for "the most pollutant-generating" crude Holly is authorized to put into the unit – the crude that will generate the most coke. As EPA instructs:

> Where raw materials or fuel vary in their pollutant-generating capacity, the most pollutant-generating substance must be used in the potential-to-emit calculations unless such materials are restricted by federally enforceable operational or usage limits. Historic usage rates alone are not sufficient to establish potential-to-emit.

NSR Manual c.2 (Appendix).

Said another way, there is nothing in the Record to suggest that the 6200-lb/hr coke-burn estimate reflects emissions from FCC25 for "the most pollutant-generating" feedstock Holly is authorized process.[24] Indeed, the Director is remiss. Although r.307-401-5(2)(a) requires Holly to describe "the nature…and quantities of raw materials" it

[23] The ED's findings are found at ADJ011610-11. Relevant to the inquiry are IR009219; IR009192; IR009208; IR008052; IR009229.

[24] By acknowledging "different feedstocks can result in slightly different emission profiles," IR009194, the Director is obligated to determine PTE for the feedstock that will generate the most $PM_{2.5}$.

proposes to process and although he cannot make a defensible permitting decision without it, the Director does not attempt to determine the impact that the "revision in the planned nature of the crude oil feed to the refinery," IR002839, "the differences between the[] feedstock sources," IR007168, will have on the PTE of FCCU25. Rather, he rejects the notion that he must determine the maximum capacity of FCCU25 to emit pollutants by considering, *inter alia*, emissions from its "most pollutant-generating" feedstock. IR009194 ("While it is true that different feedstocks can result in slightly different emission profiles, attempting to address every possible specific chemical profile would be impossible."). As a result, the PTE is legally insufficient and lacks a basis in the Record.

The Director defends his PTE by claiming that the capacity of FCCU25 – which he lists as an "annual average capacity of 8,500 bpd," IR009229, functions as a limitation on PTE. IR009192; IR009208. However, the Record makes no link between the 8,500 bpd capacity and a coke-burn rate of 6200-lb/hr. After all, the 8.15 tpy PTE is accurate only if it is based on the maximum capacity of FCCU25 to emit $PM_{2.5}$ and therefore only if FCCU25 never exceeds the 6200lb/hr coke-burn rate. And yet, the Director does not explain why the unit's annual average barrel-per-day capacity will prevent FCCU25 from exceeding the 6200-lb/hr rate. In contrast, the formula for calculating coke-burn rate is based on a host of factors that have nothing to do with capacity. 40 C.F.R §60.104a. As the UOP analysis and 40 C.F.R §60.104a show and as the Director admits, IR009194, the composition of the feedstock has a direct influence on coke-burn rate. IR008599-600. PTE must also reflect the maximum capacity of a source to emit pollutants, so reference to "annual average" is not helpful. Instead, the Director must provide the "maximum capacity" of FCCU25 and then explain how that capacity would prevent FCCU25 from exceeding the estimated 6200-lb/hr coke-burn rate.

Finally, any reliance the Director placed on Holly's "calculation supporting the coke-burn estimate," IR009219, is misplaced. First, the calculation is based on the 2013 operation of the existing FCCU4, IR008052, likely processing Select Crude and not on an estimate of FCCU25 processing "the most pollutant-generating" feedstock. Second, FCCU4 has a hydrotreater, IR008052, and FCCU25 does not. IR002937. Holly admits that "hydrotreating…lowers coke load," but makes no attempt to adjust or substantiate an adjustment to its calculation to reflect that FCCU25 has no hydrotreater. IR008052.[25] Third, a defensible PTE may not be based on "[h]istoric usage rates alone[.]" *NSR Manual* c.2. Rather, PTE must represent the maximum capacity of FCCU25 to emit $PM_{2.5}$ as it processes "the most pollutant-generating" feedstock. Because Holly's estimate of the coke-burn rate depends upon historic operations at a FCCU with a hydrotreater that was not processing the BWC that is incompatible with a hydrotreater, these past data points are not sufficient to establish potential-to-emit.

II. In Approving the Expansion, the Director Did Not Meet the Requirements of Rule 307-401-8.

Congress created the minor source NSR program to ensure that, *inter alia*, emissions from a minor modification to a major source, whether in an attainment or a non-attainment area, would not interfere with the achievement or maintenance of the

[25] Holly implies that the hydrotreater might reduce coke load by 10%, but the company lacks conviction and provides no basis for the suggestion. IR008052.

NAAQS. 42 U.S.C. §7410(a)(2)(C) (requiring a program "to provide for the enforcement of the measures…and regulation of the modification…of any stationary source…as necessary to assure that national ambient air quality standards are achieved"). As defined by the Clean Air Act and reflected in r.307-401-8, the purpose of Utah's minor source NSR is to protect the national air quality standards, including short-term NAAQS. Rule 307-401-8 also imposes BACT on minor modifications. As an extension of Utah's minor source NSR program, the resulting BACT emission limitation must further the goal of preventing a project's emissions from impeding progress toward attaining the NAAQS or threatening compliance with the standards. Thus, whether he is permitting a minor or major modification or deriving a BACT emission limit, the Director must restrict emissions and apply the measures necessary to assure that NAAQS, including the short-term standards, are achieved. 42 U.S.C. §7410(a)(2)(C).

A. While Acknowledging the Flares Are a Considerable Source of Air Pollution, Including SO_2 and NO_X, the Director Fails to Protect Short-Term NAAQS from Flare Emissions.

The two Holly flares are a significant source of air pollution. Each is predicted to release an annual total of 120 tons of SO_2, 21 tons of CO, 4 tons of NO_X and 8 tons of VOCs during various upset events. IR008561; IR002865. During these episodes, the two units have the potential to emit 240 tons of SO_2 and 8 tons of NO_X, and to overwhelm corresponding daily source-wide emission limitations imposed on the Refinery's operations. SO_2 and NO_X are $PM_{2.5}$ precursors subject to a 1-hour NAAQS. Annual upset SO_2 emissions from the flares are more than double the SO_2 PTE for the entire refinery and are twice the 110.3 tpy SO_2 emissions cap on the entire plant. IR009225;

IR009245. The yearly SO_2 emissions from the flares alone will exceed the refinery's SO_2 PTE and SO_2 emissions cap by more than 200 percent.

1. The AO Does Not Limit Flare Emissions.

The Director proposed to limit flare emissions by removing exemptions for flares from the emission caps for SO_2 sources, IR008568, PM_{10} sources, IR008569,[26] and NO_X sources. IR008569. However, he admits that the final AO contains "no limits on the flares." IR009186-87. The AO does not require a calculation of flare SO_2, CO, VOCs or PM_{10} emissions in order to determine whether the sources covered by emission caps are complying with the relevant emission limitations. IR009245-48. For NO_X, the AO puts a source-wide limit on flare emissions by calculating annual "non-upset" emissions based on "non-upset" flare throughput rates. IR009249.[27] Although "the flares are in place as control devices for upset conditions," IR009186, the AO does not limit any "upset" flare emissions for any pollutants. IR009241-51.

2. The Director Failed Rule 307-401-8 by Neglecting to Protect Short-Term NAAQS from Unregulated Flare Emissions.

The Record confirms that the AO does not restrict the vast majority of the flare emissions, including the predicted annual emissions of 240 tons of SO_2, 42 tons of CO, 8 tons of NO_X and 16 tons of VOCs the Director defines as upset emissions. IR008561; IR002865. Because they will spike during upset conditions at the Refinery, these uncontrolled emissions will have a considerable effect on short-term concentrations of

[26] IR009247-48. But upset and non-upset PM_{10} emissions from flares are estimated to be zero. IR002865; IR002996.

[27] The AO includes a 20% opacity limit on the flares. IR009241.

SO_2 and NOx, easily outstripping the daily Refinery-wide SO_2 limit of 0.31 tons, IR009245, and the daily facility-wide 2.09-ton NO_X emission limitation. IR009248.

As a result, the Director cannot claim that he has met his obligation to protect short-term NAAQS and comply with Rule 307-401-8(1)(b)(vii). As the Director is also required to undertake BACT analysis for the flares, he has not fulfilled the added duty to derive BACT emission limitations or controls that likewise protect short-term NAAQS. Despite the magnitude of the unregulated flare emissions, there is nothing in the Record to demonstrate how the AO will protect the short-term NAAQS. Although the Record confirms that the unregulated flare emissions will be a substantial source of short-term emissions and will reach levels considerably higher than the "controlled" Refinery emissions, IR008561, IR002865, the Director did not impose AO limits or derive BACT controls that adequately resolve these "upset" emissions. IR009186-87; IR009241-51. He did not take steps to ensure that the Expansion will not interfere with the attainment or maintenance of the one-hour SO_2 and NO_X NAAQS and so violated Rule 307-401-8(1)(b)(vii). *Id.*

3. Holly's Modeling Does Not Reflect Maximum Short-Term Emission Rates.

The Director claims that Holly conducted air quality modeling demonstrating "no violation of short-term NAAQS would occur[.]" IR009187; IR009190.[28] The Director admits that Holly's modeling did not include any "upset emissions" from the flares.

[28] The ED's findings are found at ADJ011583-85. Record evidence includes IR009109-91; IR009186-87; IR009209; IR009186-87; IR001153-54; IR003591-97; IR002993-96; IR009214; IR003017.

IR009214. Translating the emission rate values for the flares from grams/second to tons/year confirms that these rates do not include predicted upset emissions. For example, the short-term and annual NO_X emission rate of 0.1675 g/s for the South Flare, IR002996; IR002999, converts to 5.82 tpy, which is the estimated non-upset annual emission rate of South Flare, IR003069, and does not include the additional upset NO_X emissions of 4.0 tpy. IR008561; IR002865. Similarly, the modeled SO_2 emission rate – 0.0030 g/s, IR002996 – translates to 0.1043 tpy, which is the estimate of the South Flare's annual SO_2 non-upset emissions, IR003069, and does not include the predicted 120 tpy of SO_2 the South Flare will release during upset conditions. IR008561; IR002865.

By omitting the considerable upset flare emissions from its "short-term" modeling, Holly failed to show that its emissions will not cause or contribute to a violation of short-term NAAQS. Modeling flare upset emissions may not be required by law. IR009214-15. The Director may not claim, however, that Holly's modeling demonstrates protection of the short-term NAAQS unless that modeling considers the impact of the significant flare emissions that he predicts will occur during upset conditions.

The ED further states that "Holly's emission modeling analysis contemplated… maximum emissions…on a lb/hr basis, thereby ensuring that any short-term spikes in emissions were accounted for…and would not cause exceedances." ADJ011584 (*citing* IR002993-96). Examination of the inputs Holly used for its short-term modeling, IR002993-96, shows that the ED is incorrect. The emission rates Holly modeled do **not** represent "maximum emissions" or "short-term spikes" at all. The inputs for Holly's short-term model represent annual PTE or annual AO emission limits in tons per year spread evenly over the approximately 31.5 million seconds there are in a year. By using these values, Holly assumes that there will be no variation in emissions and that emissions from any given unit will hold steady over every second of the year.

Comparing Holly's "PTE Emission Rates – Short-Term" model, IR002994-96, with its "PTE, NO_2 Annual Emission Rates" model, IR002997-99, provides the first evidence that Holly's short-term modeling does **not** represent maximum emission rates. In both models, for each emission "source," the inputs in the columns labeled "NO_X g/s" are identical. The two models rely on the same NO_X emission rates. There is no difference between the NO_X values used for the short-term and annual models. In reality, maximum short-term emission rates, which represent spikes in emission rates, are substantially higher than annual emissions averaged over 365 days. Holly's short-term model merely reflects annual emission rates, which smooth out any variability, and not the sharp increases in emissions that occur on a short-term basis.

The second clue is that, when converted to tons per year, the inputs for the short-term model equate to annual emission limits or estimates of annual emissions (PTE). For example, the purported short-term SO_2 emission rate for the FCCU25 and FCCU4 scrubbers – 0.5091g/s, IR002994-95 – equals 17.7 tpy, which is the AO annual emission limit on these units. IR009245. The modeled short-term SO_2 and NO_X emission rates for the South Flare, IR002996, translated to tons per year, equal the estimate of the South Flare's annual non-upset SO_2 and NO_X emissions. IR003069. This again shows that the inputs for the short-term model reflect annual emission rates held constant over the year, thereby masking any spikes in emissions. The short-term model does not represent the maximum emission rates that result from the operations of the facility over the short-term.

Thus, Holly's short-term model does not consider emission spikes or variability in emissions. As a result, the model cannot demonstrate that, despite the emission increases authorized by the AO, the short-term NAAQS will be maintained. This is particularly true because Holly's faulty modeling shows that the Expansion presents a real threat to the short-term NAAQS. Without including upset flare emissions and with modeling maximum short-term emissions, Holly concludes that 95% of the NO_2 NAAQS will be consumed as a result of the project – leaving a very small margin before the standard will be exceeded. IR003596. According to the model, the total predicted concentration of NO_2 as a result of the Expansion is 178 $\mu g/m^3$, just under the one-hour NO_2 NAAQS of 188 $\mu g/m^3$. *Id.* Modeling of either the considerable upset flare emissions or maximum short-term emissions would almost certainly confirm an impermissible violation of the NAAQS.

Nor may Holly assume that there is no variability in the emissions from any of the Refinery units or that maximum short-term emissions can be estimated by equating them to annual emissions. The Director has acknowledged that emissions from the refineries, including Holly, are highly variable, explaining that "[a]fter reviewing several years'… of operational records…for emission estimates/calculations and production levels," the Director "agreed with refinery officials that there was significant variability from day to day and from year to year. Therefore, the refineries were allowed maximum never-to-be exceeded daily limits of PM_{10}, SO_2, NO_X based on the apparent variability." IR009187.[29]

The Director's own modeling guidance also prohibits Holly from making such an assumption, stating that the basis of a modeling analysis of maximum short-term concentrations[30] must be short-term emission rates based on short-term limits specified in the AO:

> Modeled emission rates should be representative of the averaging period(s) for which impacts are being determined. The emission rate used in the modeling analyses to establish maximum short-term concentrations (24 hours or less) should be representative of the pending AO's permitted maximum allowable emission level for that time period[.][31]

IR007802; *NSR Manual* C.45 (for NAAQS compliance demonstrations, "the emissions rate for the proposed…modification must reflect the maximum allowable operating conditions as expressed by the federally enforceable emissions limit, operating level, and operating factor for each applicable pollutant and averaging time.").

Thus, the Director admits that refinery emissions are variable. He may not argue, therefore, that Holly need not model maximum short-term emission rates to determine potential exceedances of the NAAQS. His own guidance underscores that, particularly where variability exists, compliance with the one-hour NAAQS must be based on maximum one-hour emission rates determined by federally enforceable permit limits.

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[29] This statement predates the designation of the one-hour SO_2 and NO_X NAAQS.
[30] These are the concentrations that would be compared to the short-term NAAQS.
[31] The Record cannot show that Holly "routinely operates at a significantly lower emission rate." There are no federally enforceable short-term operating limits on the Refinery. Holly's modeling did not address upset emissions from the flares which indicate that the Refinery operates at a higher emission rate during these frequent upsets.

4. Rule 307-107 Does Not Regulate Upset Flare Emissions.

The Director maintains that "the flares are in place as control device for upset conditions," IR009186, and "[f]lare emissions during malfunction/upset conditions are regulated through R307-107 (ITA Condition I[].3)." IR009211; IR009186-87; IR009227 (Holly "shall comply with UAC R307-107" which addresses "breakdowns"). However, Rule 307-107 does not apply to upset emissions from the Holly flares. Therefore, the Director is mistaken to maintain that Rule 307-107 "regulates" flares or protects short-term NAAQS from upset flare emissions.

Rule 307-107, Utah's "Breakdown Rule," provides that emissions from "upsets" or "malfunctions" are not be exempt from determining compliance with AO terms and conditions. A source must report to the Director any "breakdown," including information on the quantity of emissions released as a consequence of the "incident." Utah Admin. Code r.307-101-2(1). The rule revolves around the meaning of "breakdown," which means "any malfunction…start-up [or] shutdown, which will result in…emissions in excess of those allowed by approval order or Title R307." *Id.* r.307-101-2. Under Rule 307-107, a source need only report a "breakdown" and a "breakdown" occurs only when an incident results in excess emissions or emissions in excess of the terms and conditions of an AO. *Id.*

As the Director acknowledges, at the Refinery, there are no limitations on upset flare emissions, IR009186-87, and no AO emission limits apply when the flares are operating under "upset" conditions. IR009245-50. Therefore, the Breakdown Rule will never apply to the Refinery flares because there can be no "excess emissions" and therefore no "breakdown" when the flares are operating under upset conditions. Any emissions from the flares would **not** be in excess of those allowed by the AO, because the AO allows unlimited "upset" emissions from the flares. Without excess emissions, there is no breakdown, no reporting requirement and Rule 307-107 does not apply. Because Rule 307-107 does not serve to prohibit or limit upset flare emissions, it does not "regulate" them and does not protect short-term NAAQS from upset flare emissions.

B. The Director Fails to Protect Short-Term NAAQS from Refinery Emissions.

For the same reasons that he has failed to protect short-term NAAQS from the upset flare emissions, the Director has neglected his duty to ensure that the Refinery emissions do not impede attainment or maintenance of the NAAQS. The Director has not imposed short-term emission limits on the Refinery emission limits. His oversight is particularly telling because there are no hourly source-wide short-term emission limits, which the Director deemed necessary to protect the NAAQS: "Protection of the NAAQS…is not achieved on an emission unit-by-emission unit basis…but rather on a source-by-source basis." IR009186.[32] The source-wide emission limitations on SO_2 and NO_X are expressed in tons per day and a 365-day rolling average, not with hourly averaging times. IR009245; IR009248. Combined with upset flare emissions, Refinery emissions that are not subject to short-term limits will exceed the NAAQS.

[32] Of course, many emission units make up a single source.

C. The AO is Invalid Because it Is Mired in Confusion and Conflicting Statements and Does Not Specify Applicable Subpart Ja Terms and Conditions.

New Source Performance Standard (NSPS) Subpart Ja applies to Refinery flares that have been constructed, reconstructed or modified since June 24, 2008. 40 C.F.R. §60.100a(b). Under r.307-401-8(5), the Director may not issue an AO unless and until he determines that the source will comply with, *inter alia*, the NSPS. Utah Admin. Code r.307-401-8(1)(b)(vi); r.307-210. In addition, citizens are guaranteed the right to comment on a proposed AO and have their comments addressed by the Director, r.307-401-7, and to enforce an AO's terms and conditions in court. 42 U.S.C. §7604.

Despite these decrees, it remains unclear if and how Subpart Ja applies to the Refinery and its South and North flares. For example, the Director's list of "applicable programs" does not specify that Subpart Ja applies to the flares. IR008483-89. While the Director claims that ITA section III states that NSPS Subpart Ja does pertain to both the North and South flares, IR009183,[33] that section references Subpart Ja "for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007." IR008477. The date that triggers the application of Subpart Ja for flares is June 24, 2008. 40 C.F.R. §60.100a(b).[34]

The Director also claims "the North Flare is not being modified as part of" the Expansion and so is "outside the scope of this permit action," IR009183, suggesting he

[33] There are statements in the Record suggesting that Subpart Ja applies to Refinery emission units, including the flares. *E.g.* IR008517; IR009246; IR002866-67; IR002868-69. These statement are not clear or specific and do not explain what the Director considers to be "new."

[34] *But see* IR009186-87.

has **not** made a determination whether Subpart Ja applies to this flare. The Director suggests that he will impose on each "new fuel gas combustion device" – without defining the terms – the Subpart Ja short-term 162 ppmv H_2S limit for the fuel gas, IR008572, but does not include that limit in the AO. IR009241. He instead lists a daily 60 ppmv H_2S concentration averaged over 365 days. IR009246.[35] The Director also refuses to include in the AO the particular Subpart Ja terms and conditions applicable to the refinery, disagreeing with a comment contending that he must do so. IR009212. The AO reflects this approach, for example, by failing to list the exact provisions of Subpart Ja applicable to the flares, such as the a short-term 162 ppmv H_2S limit for the fuel gas.

Particularly given the significant confusion around the applicability of the provision, the Director's decision to leave Subpart Ja terms and conditions out of the AO is untenable. Utah Physicians challenges any practitioner to decipher Subpart Ja and determine with any assurance how it applies to the Refinery and flares. The rule includes ten extensive sections, replete with equations, definitions, technical terms, cross references, options and alternatives. 40 C.F.R. §60.100a-109a. Unless the Director specifies the applicable provisions, terms and conditions in the AO, it is impossible for citizens to know – much less comment on –what the Director means if he maintains that Subpart Ja applies to the Refinery, whether he has met his r.307-401-8(5), 8(1)(b)(vi) and r. 307-210 obligations or even if Holly and the Director agree on the application of the provision to the source. The Director's approach effectively prohibits the public from

[35] The AO should include both the Subpart Ja short-term limit and this long-term limit.

exercising the Clean Air Act's citizen suit provision as it is almost impossible to enforce a permit as vague as the AO in the context of confusion that surrounds the proper application of Subpart Ja to the Refinery.

D. The Record Does Not Support the Director's Determination that the North Flare Has Not been Modified by the Expansion or Is Exempt from BACT.

The Director insists that "the North Flare is not being modified as part of" the Expansion and thus that any application of Subpart Ja to the flare is outside the present permitting process. IR009183. The Record does not support this position. Actually, Subpart Ja applies to any flare that has been modified since June 24, 2008. 40 C.F.R. § 60.100a(b). "Modification" is defined as including "any new piping…physically connected to the flare for venting or emergency relief" or an alteration "to increase the flow capacity of the flare." 40 C.F.R. § 60.100a(c). Here, the Director acknowledges that the South Flare "will be reconstructed and reconfigured as part of the heavy crude processing project." IR002825. In 2013, Holly clarified that "the decommissioned south flare will be replaced with a new flare" and "currently, all gases are routed to the north flare." IR007168. In 2008, during various shut-down events, the average flowrate to the South Flare was 40,080 scf/h, while the average flowrate of the North Flare was 21,960 scf/h. IR001261-67. To route all South Flare gases to the smaller North Flare – as the reconstruction of the South Flare had entailed – requires an alteration to increase the flow capacity of the North Flare, and likely new piping, thereby triggering Subpart Ja. 40 C.F.R. § 60.100a(c)

For the same reasons, the modification to the North Flare means that the Director must apply BACT. Utah Admin. Code r.307-401-8(1)(a). BACT is "an emissions limitation . . . based on the maximum degree of reduction for each air contaminant which would be emitted from any proposed . . . modification[.]" *Id.* r.307-401-2(1). A modification is "any planned change in a source which results in a potential increase of emission." Utah Admin. Code r.307-101-2. As a result of the Expansion, both the refinery and the North Flare will be "changed" and will experience a potential increase in emissions. IR007168; IR009225. Therefore, BACT applies to the North Flare.[36]

CONCLUSION

Based on the legal deficiencies identified above, Utah Physicians asks that the AO be revoked, vacated and remanded with instructions that the Director undertake a defensible calculation of the emission increases and decreases to determine whether the Expansion is a major modification subject to Rule 307-403. Revocation and remand is also warranted because the Director has failed to assure that the Refinery will not impede

[36] The Director's statements that the North Flare has not been modified and therefore is not subject to BACT, IR009189; IR007999; IR008516-17, are not compelling. He does not explain how the larger flare could be shut down and all its gases rerouted to the smaller flare without the North Flare undergoing a physical change or change in operations resulting in an emission increase.

attainment or maintenance of the short-term NAAQS and has not properly applied Subpart Ja to the Expansion.

Respectfully submitted this 6th day of September, 2016.

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CERTIFICATE OF COMPLIANCE

This Opening Brief contains 13,993 words and complies with the type-volume limitation of Utah R. App. P. 24(f)(1). This brief uses a proportionally spaced typeface – Times New Roman – in a 13 point font and therefore complies with the typeface requirements of Utah R. App. P. 27(b).

CERTIFICATE OF SERVICE

I certify that on September 6, 2016, I mailed two copies of this Opening Brief to each:

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Appeal No. 20140344-SC
Exhibit List

Exhibit	Exhibit Description
A.	Glossary
B.	Determinative Law
C.	Findings of Fact, Conclusions of Law, and Proposed Order Regarding Petitioners' Motion Requesting Stay of Approval Order (March 25, 2014)
D.	Order Adopting ALJ's Proposed Order and Denying Petitioners' Request for Stay (March 8, 214)
E.	Findings of Fact, Conclusions of Law, and Recommended Order on the Merits (March 11, 2015)
F.	Order Adopting Findings of Face, Conclusions of Law, and Proposed Dispositive Action
G.	EPA New Source Review Factsheet
H.	DAQ NSR Section Form 19, Natural Gas Boilers and Liquid Heaters
I.	DAQ's Emission Calculation Sheets – Boiler Emissions Natural Gas -84
J.	AP-42, 13.5 – Industrial Flares
K.	(CD Only) EPA New Source Review Workshop Manual

A

GLOSSARY OF TERMS AND ACRONYMS

AO – Approval Order

BACT – Best Available Control Technology

CO – Carbon monoxide

EPA – U.S. Environmental Protection Agency

FCCU – Fluidized Catalytic Cracking Unit

H_2S – Hydrogen Sulfide

HAPs – Hazardous Air Pollutants

ITA – Intent to Approve

NAAQS – National Ambient Air Quality Standards

NOI – Notice of Intent

NSPS – New Source Performance Standards

NSR – New Source Review

NO_2 – Nitrogen Dioxide

NO_X – Nitrous Oxides

NNSR – Non-attainment New Source Review

PAHs – Polycyclic Aromatic Hydrocarbons

PM_{10} – Coarse Particulate Matter (10 Micrometers in Diameter or Smaller)

$PM_{2.5}$ – Fine Particulate Matter (2.5 Micrometers in Diameter or Smaller)

PSD – Prevention of Significant Deterioration

PTE – Potential to Emit

SO_2 – Sulfur dioxide

SO_X – Sulfur Oxides

SPR – Source Plan Review

SSM – Startup, Shutdown and Malfunction

UAPA – Utah Administrative Procedures Act

VOCs – Volatile Organic Compounds

UNITS

bpd – barrels per day

lb/hr – pounds per hour

lb/MMBtu – pounds per million British thermal units

ppmv – parts per million by volume

scf – standard cubic feet

tpd – tons per day

tpy – tons per year

$\mu g/m^3$ – micrograms/cubic meter

B

Determinative Law

R307-401-8. Approval Order.

(1) The director will issue an approval order if the following conditions have been met:

(a) The degree of pollution control for emissions, to include fugitive emissions and fugitive dust, is at least best available control technology. When determining best available control technology for a new or modified source in an ozone nonattainment or maintenance area that will emit volatile organic compounds or nitrogen oxides, best available control technology shall be at least as stringent as any Control Technique Guidance document that has been published by EPA that is applicable to the source.

(b) The proposed installation will meet the applicable requirements of:

(i) R307-403, Permits: New and Modified Sources in Nonattainment Areas and Maintenance Areas;

(ii) R307-405, Permits: Major Sources in Attainment or Unclassified Areas (PSD);

(iii) R307-406, Visibility;

(iv) R307-410, Emissions Impact Analysis;

(v) R307-420, Permits: Ozone Offset Requirements in Davis and Salt Lake Counties;

(vi) R307-210, National Standards of Performance for New Stationary Sources;

(vii) National Primary and Secondary Ambient Air Quality Standards;

(viii) R307-214, National Emission Standards for Hazardous Air Pollutants;

(ix) R307-110, Utah State Implementation Plan; and

(x) all other provisions of R307.

(2) The approval order will require that all pollution control equipment be adequately and properly maintained.

(3) Receipt of an approval order does not relieve any owner or operator of the responsibility to comply with the provisions of R307 or the State Implementation Plan.

(4) To accommodate staged construction of a large source, the director may issue an order authorizing construction of an initial stage prior to receipt of

detailed plans for the entire proposal provided that, through a review of general plans, engineering reports and other information the proposal is determined feasible by the director under the intent of R307. Subsequent detailed plans will then be processed as prescribed in this paragraph. For staged construction projects the previous determination under R307-401-8(1) and (2) will be reviewed and modified as appropriate at the earliest reasonable time prior to commencement of construction of each independent phase of the proposed source or modification.

(5) If the director determines that a proposed stationary source, modification or relocation does not meet the conditions established in (1) above, the director will not issue an approval order.

R307-403-3. Review of Major Sources of Air Quality Impact.

Every major new source or major modification must be reviewed by the director to determine if a source will cause or contribute to a violation of the NAAQS. The determination of whether a source will cause or contribute to a violation of the NAAQS will be made by the director as of the new source's projected start-up date. He will make an analysis of the proposed new source's operation data using the best information and analytical techniques available.

****

(3) If the director finds that the emissions from a proposed source in a nonattainment area would contribute to an existing violation of a national ambient air quality standard at the time of the source's proposed start-up date, approval shall be granted if and only if:

(a) the new source meets an emission limitation which is the Lowest Achievable Emission Rate (LAER) for such source and

(b) the applicant has certified that all existing major sources in the State, owned or controlled by the owner or operator (or by any entity controlling, controlled by or under common control with such owner or operator) of the proposed source, are in compliance with all applicable rules in R307, including the Utah Implementation Plan requirements or are in compliance with an approved schedule and timetable for compliance under the Utah Implementation Plan, R307, or an enforcement order, and that the source is complying with all requirements and limitations as expeditiously as practicable.

(c) emission offsets to the extent provided in R307-403-4, 5 and 6 are sufficient such that there will be reasonable further progress toward attainment of the applicable NAAQS.

(d) the emission offsets provide a positive net air quality benefit in the affected area of nonattainment.

(e) there is an approved implementation plan in effect for the pollutant to be emitted by the proposed source.

(4) A source which is locating outside a nonattainment area or the Salt Lake City and Ogden maintenance areas for carbon monoxide and which causes the significant increments in (1) above to be exceeded in the nonattainment or maintenance area is subject to the requirements of (3) above.

R307-403-4. Offsets: General Requirements.

(1) Emission offsets must be obtained from the same source or other sources in the same nonattainment area except that the owner or operator of a source may obtain emission offsets in another nonattainment area if:

(a) the other area has an equal or higher nonattainment classification than the area in which the source is located; and

(b) emissions from such other area contribute to a violation of the national ambient air quality standard in the nonattainment area in which the source is located or which is impacted by the source.

(2) Any emission offsets shall be enforceable by the time a new or modified source commences construction, and, by the time a new or modified source commences operation, any emission offsets shall be in effect and enforceable and shall assure that the total tonnage of increased emissions of the air pollutant from the new or modified source shall be offset by an equal or greater reduction, as applicable, in the actual emissions of such air pollutant from the same or other sources in the area.

(3) Emission reductions otherwise required by the federal Clean Air Act or R307, including the State Implementation Plan shall not be creditable as emission reductions for purposes of any offset requirement. Incidental emission reductions which are not otherwise required by federal or state law shall be creditable as emission reductions if such emission reductions meet the requirements of (1) and (2) above.

(4) Sources shall be allowed to offset, by alternative or innovative means, emission increases from rocket engine and motor firing, and cleaning related to such firing, at an existing or modified major source that tests rocket engines or motors under the conditions outlined in 42 U.S.C. 7503(e) (Section 173(e)(1) through Section 173(e)(4) of the federal Clean Air Act as amended in 1990).

R307-403-10. Analysis of Alternatives.

The owner or operator of a major new source or major modification to be located in a nonattainment area or which would impact a nonattainment area must, in addition to the requirements in R307-403, submit with the notice of intent an adequate analysis of alternative sites, sizes, production processes, and environmental control techniques for such proposed source which demonstrates the benefits of the proposed source significantly outweigh the environmental and social costs imposed as a result of its location, construction, or modification. The director shall review the analysis. The analysis and the director's comments shall be subject to public comment as required by R307-401-7. The preceding shall also apply in Salt Lake and Davis Counties for new major sources or modifications which are considered major for precursors of ozone, including volatile organic compounds and nitrogen oxides.

C

**BEFORE THE EXECUTIVE DIRECTOR OF THE
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY**

In the Matter of: Approval Order No. DAQE-AN101230041-13 Holly Refining & Marketing Company – Woods Cross, LLC Heavy Crude Processing Project Project No. N10123-0041	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND PROPOSED ORDER REGARDING PETITIONERS' MOTION REQUESTING STAY OF APPROVAL ORDER** Administrative Law Judge Bret F. Randall March 25, 2014

This matter is before me pursuant to appointment by the Executive Director of the Utah Department of Environmental Quality dated January 9, 2014. The appointment charges me to conduct a permit review adjudicative proceeding in this matter in accordance with Utah Code Ann., § 19-1-301.5 and Utah Admin. Code R305-7.

Procedural Background

On November 18, 2013, the Director of the Utah Division of Air Quality ("Director") issued approval order DAQE-AN101230041-13 (Project Number N10123-0041) (the "AO" or "Permit") to Holly Refining and Marketing Company, Woods Cross LLC ("Holly"), authorizing the construction of the Heavy Black Waxy Crude Processing Project ("Expansion Project").

On December 18, 2013, Utah Physicians for a Healthy Environment and FRIENDS of Great Salt Lake (collectively "Utah Physicians") filed a Request for Agency Action seeking administrative review of the AO, pursuant to Utah Code §§ 19-1-301.5 and 63G-4-201(1)(b), (3) and Utah Admin. Code R305-7-203.

On December 24, 2013, Utah Physicians filed a motion and supporting memorandum requesting a stay of the AO, pursuant to Utah Admin. Code R305-7-217 and Utah Code Ann. § 19-1-301.5. However, because Utah Physicians had not been granted party status and no ALJ had yet been appointed to this matter, the time for responding to the motion to stay did not begin to run at that time.

On January 16, 2014, I entered an Order on Petition to Intervene, provisionally granting intervention to Utah Physicians for a Healthy Environment and Friends of Great Salt Lake (collectively, "Petitioners"). On the same date, I entered a Notice of Further Proceedings.

Petitioners filed a Corrected Motion and Memorandum Requesting Stay on January 21, 2014 ("Stay Motion"). I deemed that the date of the filing of the corrected motion for stay triggered a new response period for Respondents. The Stay Motion is the subject of the present Proposed Order.

Pursuant to the Utah Code, whenever a motion to stay is filed in a permit review adjudicative proceeding, "the administrative law judge shall: (i) consider a party's motion to stay a permit during a permit review adjudicative proceeding; and (ii) submit a proposed determination on the stay to the executive director." Section 19-1-301.5(15)(c), Utah Code Ann.

Following briefing on the Stay Motion, I granted Respondents' motion for oral argument, with oral argument being held on March 6, 2014. All parties appeared and participated in oral argument, which was of record through a court reporter.

Having heard argument on the Stay Motion, and being fully advised in the premises, and pursuant to Section 19-1-301.5(15)(c), Utah Code Ann., this tribunal enters the following proposed Findings of Fact and Conclusions of Law, and proposed determination that the Executive Director of the Utah Department of Environmental Quality ("DEQ") deny Petitioners' Stay Motion for the reasons set forth herein.

FINDINGS OF FACT

Regulatory Background

1. Air pollution is harmful to human health and to the environment. [IR at 009140-48; IR at 009139-45; IR at 009144-45; IR at 009145-47.]

2. In enacting the Utah Air Conservation Act, the Utah Legislature declared: "It is the policy of this state and the purpose of [the Utah Air Conservation Act] to achieve and maintain levels of air quality which will protect human health and safety, and to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this state, and facilitate the enjoyment of the natural attractions of this state." Section 19-2-101(2), Utah Code Ann.

3. The Utah Legislature further declared that the "purpose" of the Utah Air Conservation Act is to "(a) provide for a coordinated statewide program of air pollution prevention, abatement, and control; (b) provide for an appropriate distribution of responsibilities among the state and local units of government; (c) facilitate cooperation across jurisdictional lines in dealing with problems of air pollution not confined within single jurisdictions; and (d) provide a framework within which air quality may be protected and consideration given to the public interest at all levels of planning and development within the state." Section 19-2-101(4), Utah Code Ann.

4. Similarly, in enacting the Clean Air Act, the Congress found, among other things:

> **(2)** that the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, has resulted in mounting dangers to the public health and welfare, including

> injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation; [and]
>
> **(3)** that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments . . . .

42 U.S.C. § 7401(a).

5. Congress also stated that the "primary goal" of the Clean Air Act is to "encourage or otherwise promote reasonable Federal, State, and local governmental actions . . . for pollution prevention." 42 U.S.C. § 7401(c).

Permit Chronology

6. In May of 2012, Holly Refining & Marketing Company – Woods Cross, LLC ("Holly") submitted a notice of intent ("NOI") to DAQ requesting an approval order to expand its Woods Cross refinery and modernize certain equipment in a way that allowed Holly to process an additional 20,000 barrels per day of black wax crude from the Uintah Basin in eastern Utah ("May NOI"). [May NOI at IR000049-001108.]

7. In response to DAQ's request to provide additional information, Holly re-submitted its NOI in July of 2012 ("July NOI"). [July NOI at IR002798-003590.]

8. Following its technical and legal evaluation of the July NOI and related evidence, DAQ released for public comment an Intent to Approve ("First ITA"), dated November 28, 2012. The First ITA included a draft Approval Order. [First ITA at IR001967-001996.]

9. During the initial 60-day public comment period, DAQ received comments from Western Resource Advocates on behalf of Utah Physicians for a Healthy Environment ("UPHE") and Friends of Great Salt Lake ("Friends") [IR004007-004035], Blaine Rawson on behalf of Mark J. Hall [IR004202-004217], Alexander Sagady on behalf of UPHE [IR009046-009135],

the Environmental Protection Agency ("EPA") [IR004001-004005], and Holly [IR003757-003910].

10. In April 2013, Holly submitted a new netting analysis in a revised NOI. [Revised NOI at IR007335-007395.]

11. In addition to certain other changes, the Revised NOI estimated $PM_{2.5}$ emissions from Holly's gas-fired heaters and boilers based on the EPA's National Emission Inventory ("NEI") data. [*Id.*]

12. Following its technical and legal evaluation of the Revised NOI and related evidence, DAQ released, on June 5, 2013, for a second public comment period an Intent to Approve document ("Second ITA") and a Source Plan Review ("SPR"). [Second ITA at IR007498-007499, SPR at IR008480-008575.]

13. On July 25, 2013, DAQ received comments on the draft approval order from Western Resource Advocates on behalf UPHE [IR007842-007997], Blaine Rawson on behalf of Mark J. Hall [IR008579-008602], Alexander Sagady on behalf of Petitioners [IR009046-009135], the EPA [IR007840-007841], and Holly [IR007613-007836].

14. Following its review and evaluation of the foregoing information and comments, on November 6, 2013, DAQ requested additional information from Holly that DAQ believed was necessary in order to fully consider the pending comments and evidence. Holly responded to DAQ's request for additional information on November 7, 2013. [IR008021, IR008022-0052.]

15. After considering the supplemental information provided by Holly, on November 18, 2013, DAQ issued Holly a new approval order authorizing the construction of the Modernization Project ("Holly AO"). [Holly AO at IR009223-009254.]

16. Concurrently therewith, DAQ issued a Response to Comments Memorandum ("Response Memorandum") that addressed the comments made during the public comment periods, explained DAQ's response to those comments, and, where appropriate, described how the comments had been incorporated into the Holly AO. [Response Memorandum at IR009174-009222.]

17. On December 18, 2013, Petitioners filed their Request for Agency Action. On January 22, 2014, Petitioners filed their Amended Motion and Memorandum Requesting a Stay of the Approval Order. Oral argument was held on the Stay Motion on March 6, 2014.

DAQ's Permit Review

18. In their Stay Motion, Petitioners challenge three portions of the Holly AO: (1) the use of the NEI emission factors to estimate $PM_{2.5}$ emissions from Holly's new gas-fired heaters and boilers; (2) the calculated coke burn rate for Holly's proposed Fluid Catalytic Cracking Unit ("FCC Unit 25"), and (3) the calculated reduction of $PM_{2.5}$ emissions from the removal of Holly's existing propane pit flare. [Stay Motion, p. 15-37.]

19. DAQ determined that use of the NEI emission factors to calculate $PM_{2.5}$ emissions from the new heaters and boilers was appropriate because (1) there was substantial evidence in the record supporting the accuracy of these emission factors to estimate PM emissions from gas-fired heaters and boilers, as explained in the two reports from Glenn England [*See* Glen England Reports at IR007238-007258, IR008024-008044; *see also* Response Memorandum at IR009215-009216]; (2) DAQ had imposed a stack testing requirement in the Holly AO to verify that the emission factors were an accurate representation of actual emissions [Response Memorandum at IR008129-008131]; and (3) DAQ imposed a limit derived from the NEI factors into the final Holly AO that is binding on Holly during all operations of the Woods

Cross refinery [Holly AO, Section II.B.7.a.2 at IR009248; *see also* Response Memorandum at IR009217].

20. DAQ determined that regardless of whether there were other alternative emission factor calculations for heaters and boilers that yielded higher estimates, Holly would be subject to an enforceable PM_{10} emission limit of 0.00051 lb/MMBtu, derived from the NEI emission factors. [*See* Response Memorandum IR008130.] DAQ reasoned that any failure by Holly to comply with that emission limit would result in compliance violations, which would ensure that Holly would not contribute a significant increase of PM as a result of the expansion. [*Id.*]

21. DAQ determined that 40 C.F.R. § 60.14 did not require the use of the older AP-42 emission factors, as Petitioners argued, to calculate Holly's $PM_{2.5}$ emissions from the heaters and boilers because that regulation only applies to determining applicability of the New Source Performance Standards, "which [is] separate from the New Source Review regulations that are relevant to this permitting process." [Response Memorandum at IR008130.] Moreover "EPA guidance states that sources other than the AP-42 emission factors may be used in determining emissions for PSD/NSR emissions…including '[e]mission factors from technical literature.'" [*Id.* (second alteration in original) (quoting EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, draft dated October 1990 at A.22).]

22. With respect to the $PM_{2.5}$ emission reduction of 2.19 tons per year ("tpy") from the decommissioning of Holly's propane pit flare, which Petitioners claimed was inaccurately high, the Revised NOI reflects that Holly and DAQ calculated this emission reduction using the actual emission inventory data on file at DAQ for the years 2008 and 2009. [Revised NOI at IR007339; Response Memorandum at IR009218 ("flare emissions came from the UDAQ

inventory record for reported actual emissions from 2008-2009 based on 259 MMBtu/hr and actual throughput data").]

23. As to the coke burn rate for Holly's proposed FCC Unit 25, which Petitioners claimed was inaccurately low, the emission calculations Holly provided to DAQ indicate that the rate was calculated based on actual emission data from the current FCC Unit 4, a larger unit than the proposed FCC Unit 25, and thus was a conservatively high estimate of expected emissions from the FCC Unit 25. [IR008052; *see also* Holly AO at IR009227-009229 (The FCC Unit 4 processes 8,880 barrels per day ("bpd") while the proposed FCC Unit 25 can only process 8,500 bpd.]

24. Regardless of the coke burn rate, DAQ concluded that the FCC Unit 25 is subject to a specific PM_{10} limit of 0.30lb/1000 lb. of coke burned, which is limited by the 8,500 bpd operating capacity, and is also subject to the overall PM_{10} emission cap of 47.5 tpy and 0.13 tons per day ("tpd") for combustion sources. [Response Memorandum at IR009219.] "If these limitations are not met, the refinery will be out of compliance until it remedies the problem with additional control equipment or redesign of the system until it meets these limits." [*Id.*]

25. DAQ rejected Petitioners' calculation of coke burn based on the Universal Oil Products yield estimates because they "provided no documents or primary data to support or detail [] which estimate, if any, was used to derive the suggested range of coke burn estimates." [Response Memorandum at IR009219.] "Based on UDAQ's technical experience and expertise," DAQ determined that "the 6200 lb/hr value is a fair and reasonable estimate of the quantity of coke burn in FCC Unit 25." [*Id.*]

Impacts of Modernization Project Construction

26. The Conrad Jenson Declaration submitted with Holly's opposition to the Stay Motion ("Jenson Declaration") is the most recent evidence of Holly's present construction schedule. In light of the procedural history recited above, the earlier construction timetable estimates are deemed to be updated by the facts as set forth in the Jenson Declaration, which are credited and treated as true for the purposes of this proposed order.

27. According to the Jenson Declaration, Holly's first phase of construction will not be fully installed and operational until the fall of 2015. [Exhibit A to Holly's Opposition to Petitioners Motion Requesting Stay of Approval Order ¶ 9.]

28. "[D]uring the construction of Phase I, there will not be any increase in emissions until completion of Phase I in the fall of 2015." [*Id.* ¶ 10.]

29. As confirmed by the parties during oral argument, this permit review adjudicative proceeding is expected to be fully briefed by July 9, 2014. [*See* Corrected Stipulated Order Regarding Response to Request for Agency Action and Subsequent Deadlines, dated February 19, 2014.] Oral argument likely will be scheduled before the end of July 2014 and a recommended order will likely be prepared for the Executive Director as soon as possible after oral argument, certainly by the end of September 2014. [*See* Stay Motion Hearing Transcript at p. 14-16.] During this time, it is undisputed that there will be no increase in emissions from the Holly refinery due to the Modernization Project, and no emissions for at least a year beyond the proposed adjudicative proceeding timeline. [Jenson Declaration ¶ 10.]

30. Holly has already incurred approximately $48,000,000 in costs for preliminary activities in preparation for construction. [*Id.* ¶ 6.]

31. Holly commenced construction on the Expansion Project after receiving the Holly AO. [*Id.* ¶ 7.]

32. The overall costs of the Modernization Project are anticipated to be approximately $700 to $800 million, with approximately $300 million allocated to Phase I and the remaining approximate $400 to $500 million allocated to Phase II. These estimated costs represent design/engineering, materials, and construction costs. [*Id.* ¶ 11.]

33. If the Holly AO is stayed and construction stopped, it is undisputed that Holly would experience significant demobilization and remobilization costs. According to the Jenson Declaration, the demobilization costs include hourly pay rates for the remaining contract workers who will need to secure construction equipment and the construction site safely during the stay period. It also includes costs of equipment storage. Remobilization costs would include similar expenses for restarting work that had been stopped. If construction is stayed, Holly's main contractor would charge a minimum of $625,000 per month for such delays. These figures do not account for lost profits or additional harm of further delay on the overall project schedule. [*Id.* ¶ 13.]

34. Delays in the Project are directly correlated with lost revenue that Holly would have generated if it were able to process the increased number of barrels of crude on schedule. For every month Holly is unable to process additional crude, it anticipates a loss of approximately $10,000,000. [*Id.* ¶ 15.]

35. During Phase I and Phase II of construction, Holly anticipates up to 500 people at any given time on site fulfilling construction jobs related to the project. [*Id.* ¶ 17.]

36. After Phase I of the Modernization Project is completed, Holly anticipates a 25% increase in permanent jobs at the Woods Cross refinery. After completion of Phase II, Holly

anticipates another 25% increase in permanent jobs. This is a 50% overall increase in permanent jobs at the refinery. [*Id.* ¶ 18.]

37. Overall, the Modernization Project will create a public benefit through job creation, increased state and local taxes, and capital infusion and investment in Davis County, as well as benefits from increased crude production within the state of Utah. These benefits will be delayed or may be lost if Holly is forced to stop construction on the Project. [*Id.* ¶ 19.]

38. The Modernization Project may also result in a number of calculated emission reductions at the Holly refinery, including a reduction in NO_x by 21.53 tpy, a reduction in SO_2 by 150.69 tpy, and a reduction in VOC by 17.02 tpy. [IR007575.] DAQ has determined that these pollutants are precursors to $PM_{2.5}$ and major contributors to wintertime inversions in the Salt Lake Valley. [Utah State Implementation Plan, § IX.A, dated December 4, 2013, § 1.6.] According to the recent Utah State Implementation Plan for $PM_{2.5}$, reductions in these pollutants would have the secondary effect of reducing wintertime $PM_{2.5}$ levels. [*Id.*]

39. Based on the evidence, these emission reductions are the result of voluntary pollution control strategies that Holly has proposed for the Modernization Project and that are incorporated in the Holly AO. [*See* SPR at IR008564, IR008568-008569; *see also* IR007335.] These reductions fall into five different categories:

a. Holly will install a new wet gas scrubber as part of the new FCC Unit 25 and will route its existing gas streams that presently are emitted after treatment in an existing sulfur recovery unit ("SRU") through that wet gas scrubber, reducing overall SO_2 emissions [*See* July NOI IR002812, 002821, 002823-002824.];

b. Holly will remove both its propane pit flare and the frozen earth propane pit storage facility, which will reduce NO_x and VOC emissions, respectively [*See* July NOI at IR002828, 003035];

c. Holly will replace four gas-driven compressor engines with electric engines, which will reduce NO_x emissions [*See* Revised NOI at IR007335];

d. Holly will add selective catalytic reduction technology to three current heaters and boilers, further reducing NO_x emissions [*See* Source Plan Review at IR008551; Holly AO at IR009248]; and

e. Holly will be subject to overall, refinery-wide emissions limitation reductions for PM_{10}, NO_x, and SO_2. [*See* Holly AO at IR009225.]

40. Based on the evidence of record, if the Holly AO is stayed or remanded, these emission control strategies will either be delayed or will not be implemented because they are approved and authorized by the Holly AO. [*See* SPR at IR008564, IR008568-008569; *see also* IR007335.]

CONCLUSIONS OF LAW

1. This is a permit review adjudicative proceeding pursuant to Utah Code § 19-1-301.5 and Utah Admin. Code R305-7.

2. The Stay Motion is governed by Section 19-1-301.5(15), Utah Code Ann., providing:

> (a) The filing of a request for agency action does not stay a permit or delay the effective date of a permit.
>
> (b) A permit may not be stayed or delayed unless a stay is granted under this Subsection (15).
>
> (c) The administrative law judge shall:

(i) consider a party's motion to stay a permit during a permit review adjudicative proceeding; and

(ii) submit a proposed determination on the stay to the executive director.

(d) The administrative law judge may not recommend to the executive director a stay of a permit, or a portion of a permit, unless:

(i) all parties agree to the stay; or

(ii) the party seeking the stay demonstrates that:

(A) the party seeking the stay will suffer irreparable harm unless the stay is issued;

(B) the threatened injury to the party seeking the stay outweighs whatever damage the proposed stay is likely to cause the party restrained or enjoined;

(C) the stay, if issued, would not be adverse to the public interest; and

(D) there is a substantial likelihood that the party seeking the stay will prevail on the merits of the underlying claim, or the case presents serious issues on the merits, which should be the subject of further adjudication.

3. In order to prevail on the Stay Motion, Petitioners must satisfy all four of the statutory elements listed above. Failure to satisfy even one element is fatal to the Stay Motion. *See Utah Med. Prods. Inc. v. Searcy*, 958 P.2d 228, 231 (Utah 1998).

4. Petitioners' burden to satisfy the four factors listed above is more stringent under Utah Code Section 19-1-301.5 than under the analogous state (or federal) procedural stay standards. Utah Code Section 19-1-301.5 represents statutory language enacted by the Utah Legislature. By contrast, the law governing interlocutory relief in state and federal courts is primarily judge-made common law, guided by procedural rules. In Utah, the rules of civil procedure do not rise to the level of statutory law but are promulgated and regulated by the Utah Supreme Court. Section 78A-3-103, Utah Code Ann. The express statutory language provides

governing stays in permit review adjudicative proceedings states that the ALJ "**<u>may not</u>**" recommend a stay of a permit "**<u>unless</u>**" the moving party establishes all four statutory elements. By contrast, Rule 65A of the *Utah Rule of Civil Procedure* begins with a neutral presumption and simply provides that a court "may issue" an injunction upon a showing of four elements. *See* Utah R. Civ. P. 65A(e) ("A restraining order or preliminary injunction may issue only upon a showing that . . . ."). This permissive language is consistent with the touchstone of interlocutory relief in state and federal courts: the broad discretion afforded state and federal judges. *See Southwest Stainless, LP v. Sappington*, 582 F.3d 1176, 1191 (10th Cir. 2009) ("The district court's discretion in [granting an injunction] is necessarily broad . . . ."); *Purkey v. Roberts*, 2012 UT App 241, ¶ 21, 285 P.3d 1242 ("Ultimately, the decision of whether to issue an injunction remains within the discretion of the trial court."). It is also worth noting that the federal courts of appeals have articulated differing versions of the discretionary, balancing tests applicable to interlocutory orders. However, these legal tests relate to a trial judge's discretion and are therefore not directly applicable here in light of the clear and unambiguous requirement in the Utah Code that the moving party prove the application of all four statutory standards.

5. Based on the foregoing and without limiting the potential discretion of the Executive Director in granting preliminary injunctive relief in permit review adjudicative proceedings, it is clear that the Utah Legislature employed mandatory language that is not found in the analogous federal and state procedural rules and case law. As a result, the state and federal cases governing stays and injunctive relief, while important to consider, also apply less stringent legal standards than the Utah Legislature has directed be applied to the Stay Motion. Analysis of the following factors is therefore undertaken in light of the more stringent statutory standard established by the Utah Legislature.

Irreparable Harm

6. Irreparable harm being the *sine qua non* of interlocutory relief, the moving party has a particularly heavy burden to prove it. *Dominion Video Satellite, Inc. v. Echostar Satellite Corp.*, 356 F.3d 1256, 1260 (10th Cir. 2004) (noting that the irreparable harm factor is the "single most important prerequisite for the issuance of a preliminary injunction") (internal quotations and citation omitted); *accord, Sys. Concepts, Inc. v. Dixon*, 669 P.2d 421, 427 (Utah 1983); *see also New York v. NRC*, 550 F.2d 745, 753 (2d Cir. 1977). Irreparable harm must be non-speculative and imminent: there must be evidence supporting a conclusion that irreparable harm will, in fact, occur if the relief is not granted. *See Direx Israel, Ltd. v. Breakthrough Medical Corp.*, 952 F.2d 802 (4th Cir. 1991).

7. In the context of a permit review adjudicative proceeding, the irreparable harm must necessarily relate to the period of time between the date of the motion for stay and the final determination on the merits. This conclusion is particularly important in the instant proceeding, where no evidentiary hearing or trial is provided. In an analogous situation, Judge Posner wrote: "When persons harmed by administrative action bring a suit for injunction in a federal district court, it is not because they want, or are entitled to, a trial." *Cronin v. United States Dep't of Agriculture*, 919 F.2d 439, 443 (7th Cir. 1990). Rather, he continued, such persons are entitled to judicial review of the agency action, applying the standard touchstones of administrative law. *Id.* After considering the legal standards that might be applied to that case, involving a Forest Service decision to allow for the cutting of timber on federal land, Judge Posner concluded: "But all this assumes that the decision whether to grant or deny the preliminary injunction is preliminary to a full hearing on the plaintiff's claim. If it is not[, then] the two stages are

collapsed into one because there will never be a fuller hearing . . . ." Id. at 445. *See also Rodriguez ex rel. Rodriguez v. DeBuono*, 175 F.3d 227, 235 (2d Cir. 1998) (noting that a petitioner must show that "the harm … [is] so imminent as to be irreparable if a court waits until the end of trial to resolve the harm."). Stated differently, "if a trial on the merits can be conducted before the injury would occur there is no need for interlocutory relief." 11A Charles Alan Wright, Arthur R. Miller & Mary Kay Kane, Federal Practice & Procedure § 2948.1, at 129 (3d ed. 2013). Such is certainly the case in these proceedings: the decision on the merits will be rendered prior to the time that the Expansion Project begins operation.

8. Petitioners have failed to carry their burden of proof that they will suffer irreparable harm if the Permit is not stayed prior to the time that the review on the merits is completed in this matter. The record supports the finding that hearing and determination on the merits in this case will be completed by the end of the summer of 2014, long before the Expansion Project is operational, being the fall of 2015 at the earliest. [Jenson Declaration ¶ 10.] If Petitioners are successful on their claims on the merits, then the proper remedy would be to remand to the Director to reconsider the Permit. In that event, the Petitioner would not have the Permit necessary to operate the Expansion Project as required by the Utah Air Conservation Act and the Clean Air Act ("CAA"). The requested injunctive relief would therefore be self-enforcing and no claimed irreparable harm could result.[1] If Petitioners' claims fail on the merits, then injunctive relief would not be warranted in any event.

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[1] This conclusion is an important consideration here because the case law cited by Petitioners supporting the Stay Motion is distinguishable from the case at bar. Here, success on the merits would itself result in a self-enforcing injunction, inasmuch as the Permit is required in order for Holly to operate the Expansion Project in the first instance. Thus, this matter is distinguishable from *Davis v. Mineta*, 302 F3d 1104 (10th Cir. 2002), where construction of the highway project in question without proper wetland fill permits under the Clean Water Act may have caused irreparable harm.

9. Petitioners have failed to carry their burden of proof that "bureaucratic momentum" will result in irreparable harm prior to the time that hearing on the merits is completed. There is no evidence to support any such conclusion. Moreover, the instant permit review adjudicative proceeding is easily distinguishable from the cases cited by Petitioners, supporting their "bureaucratic momentum" argument for irreparable harm. Here, the provisions of the CAA impose substantive requirements on Holly within the permitting process or upon a remand. *See Sierra Club v. Marsh*, 872 F.2d 497, 503 (1st Cir. 1989) (holding that where a statute substantively "*require[s]*the agency to change direction," such as the Clean Water Act at issue in *Weinberger v. Romero-Barcelo*, 456 U.S. 305 (1982), or the Alaska National Interest Lands Conservation Act in *Amoco Prod. Co. v. Village of Gambell*, 480 U.S. 531 (1987), "bureaucratic commitment to a project" does not constitute irreparable harm). Indeed, the one case to address the "bureaucratic commitment" theory in the context of the CAA permitting process expressly rejected the argument. *Sierra Club v. Larsen*, 769 F. Supp. 420 (D. Mass. 1991), *aff'd* 2 F.3d 462 (1st Cir. 1993). The National Environmental Protection Act ("NEPA") case law upon which Petitioners rely for their "bureaucratic momentum" argument is simply inapplicable in this case. *See Marsh*, 872 F.2d at 503; 15 U.S.C. § 793(c)(1) ("No action taken under the CAA shall be deemed a major federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act."). Stated differently, under the CAA, Holly is required to have, maintain, and follow a legal and valid permit in order to operate the Expansion Project. This scenario is easily distinguishable from a NEPA situation, where the law requires, and only requires, that full consideration of the environmental impacts of all applicable options be undertaken and completed *before the "federal action" can be initiated.* More specifically, the principle in *Sierra Club* that a violation of NEPA

constitutes an irreparable injury rests on NEPA's purpose to foster informed decision-making. *Sierra Club*, 872 F.2d at 500. In the context of NEPA, irreparable harm to the environment, almost by definition, occurs because uninformed decisionmakers commit themselves to a course of action that rarely can be undone given "a chain of bureaucratic commitment that will become progressively harder to undo the longer it continues." *Id.* Such considerations are not applicable here, where the substantive requirements of the CAA will continue to have prospective application.

10. Petitioners' failure to carry their burden of proof as to irreparable harm is dispositive to the Stay Motion. However, analysis of the remaining factors is warranted.

Likelihood of Success on the Merits

11. Petitioners raise three issues in their Stay Motion regarding the merits: (1) the assertion that DAQ erred in allowing the use of the NEI emission factors to calculate $PM_{2.5}$ emissions from Holly's gas-fired heaters and boilers; (2) the assertion that Holly overestimated the $PM_{2.5}$ emission reductions that will be realized through the decommissioning of the propane pit flare; and (3) the assertion that DAQ underestimated the coke burn rate from the FCC Unit 25, which Petitioners argue will result in higher $PM_{2.5}$ emissions. [Stay Motion pp. 15-37.]

12. The merits have not yet been fully briefed and argued by the parties.

13. DAQ is granted substantial discretion to interpret its governing statutes and rules. *See* Utah Code § 19-1-301.5(14)(c) (expressly "recognizing that [DAQ] has been granted substantial discretion to interpret its governing statutes and rules"). Moreover, Section 19-1-301.5 instructs that DAQ's factual, technical and scientific determinations should be upheld if they are supported by substantial evidence in the record. Utah Code § 19-1-301.5(14)(c).

14. Solely for purposes of this Recommended Order, I conclude that Petitioners have failed to carry their burden of showing that they are likely to succeed on the merits, or that the case presents serious issues on the merits, which should be the subject of further adjudication. Carrying this burden here requires a showing that DAQ abused its discretion or lacked substantial evidence to support its factual, technical and scientific determinations in connection with the Permit.

15. In reaching Conclusion No. 14, I rely in large part on the independent determination of EPA that the Permit is acceptable, notwithstanding Petitioners' objections. *See* EPA Comment Letters [IR004001-004005; IR007840-007841]. In *Alaska Dep't of Envtl. Conservation v. EPA*, 540 U.S. 461, 124 S. Ct. 983 (2004), the U.S. Supreme Court held that EPA is entitled to review the reasonableness of state permitting authorities' BACT determinations under the PSD program and has authority to issue stop construction orders if it reasonably believes that a BACT designation is erroneous or unreasonable. The CAA also provides EPA with concurrent enforcement authority that is directly applicable to the present proceeding. 42 U.S.C. §§ 7477, 7413(a)(5)(A) (describing the enforcement options available to the EPA when it finds that a state is not complying with any requirement of the CAA with respect to construction of a new source or modification of an existing source). *See* Jennifer A. Davis Foster, Note, EPA Oversight in Determining Best Available Control Technology: The Supreme Court Determines the Proper Scope of Enforcement, 69 Missouri L. Rev., Issue 4, at 1 (Fall 2004). Based on the foregoing, it is clear that if in EPA's independent judgment, any of the objections and issues Petitioners have raised on the merits were deserving of further evaluation, comment, or reconsideration, EPA had an independent duty and authority to pursue such issues. EPA declined to do so even after being given the opportunity in connection with the Permit.

16. In this permit review adjudicative proceeding, we have a somewhat unusual situation in administrative law where not one but two regulatory agencies with significant technical expertise and concurrent (and somewhat overlapping) legal jurisdiction have been involved in the procedural and substantive process that led to the issuance of the Permit. This situation provides a second layer of regulatory oversight to ensure that the applicable procedural and substantive requirements of the CAA, as adopted and enforced through the Utah Air Conservation Act in the spirit of "cooperative federalism," have been met. Solely for purposes of the Stay Motion, therefore, I conclude that EPA's independent review and acceptance of the Permit demonstrates that Petitioners do not have a substantial likelihood of success on the merits or that the case presents serious issues on the merits, which should be the subject of further adjudication

17. Petitioners' failure to carry their burden of proof as to success on the merits should, standing alone, be dispositive of the Stay Motion.

Public Interest

18. Air pollution is harmful to humans and ecological receptors. Thus, it is self-evident that the public interest is served by reduction and elimination of air pollution. Under our system, however, a source's compliance with the requirements set forth in the CAA, as implemented through the Utah Air Conservation Act and related rules and regulations, satisfies, as a matter of law, the public policy of protection of human health and the environment from exposures to air pollution.

19. Petitioners have failed to make a showing of cognizable harm that will occur during the pendency of these proceedings unless the Holly AO is stayed. As a result, they have failed to show that the public interest favors a stay.

20. To the extent that a violation of the CAA and other applicable law may have occurred in connection with the Permit, the instant proceedings will be concluded prior to the time that the Expansion Project begins operation. And in the event that Petitioners are successful on the merits, injunctive relief, in a sense, would be self-executing since a valid permit is required to operate the Expansion Project in the first instance. Hence, I find that the public interest is adequately protected by compliance with the existing permitting requirements set forth in the Utah Air Conservation Act and the CAA.

21. The record also shows that the Holly AO will result in substantial emission reductions in SO_2, NO_x, and VOCs, which are precursors to PM pollution along the Wasatch Front. The Holly AO will also lower refinery-wide emissions limits for PM10, NOx, and SO2. Staying the Holly AO will delay implementation of pollution control technologies that will result in these emission reductions, harming the public interest.

22. Finally, the public interest also extends to the economic activity, including jobs the Modernization Project design and construction will generate. This undisputed factor weighs against the Stay Motion.

23. Petitioners' failure to establish that the Stay Motion is in the public interest should be dispositive of the Stay Motion.

Balance of Harms

24. Petitioners have failed to carry their burden to show that the balance of harms tips in their favor.

25. The increased emissions about which Petitioners complain will not occur until after construction is completed in 2015, long after determination on the merits is completed. By

contrast, a stay would result in the immediate cessation of design and construction activities for the Expansion Project, resulting in the undisputed harms that are of record.

26. Finally, if Petitioners are successful on the merits, injunctive relief would be self-executing as discussed above. The balance of the harms, therefore, does not tip in Petitioners' favor.

27. Petitioners' failure to carry their burden to demonstrate that the balance of harms tips in their favor should be dispositive of the Stay Motion.

PROPOSED ORDER

Based on the forgoing, I recommend that the Executive Director deny the Stay Motion.

DATED this 25th day of March, 2014.

BRET F. RANDALL
Administrative Law Judge

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 25th day of March 2014, I served the foregoing **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDED ORDER REGARDING PETITIONERS' MOTION REQUESTING STAY OF APPROVAL ORDER** via email on the following:

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/s/ Bret F. Randall, ALJ

D

BEFORE THE EXECUTIVE DIRECTOR
OF THE UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of: **Approval Order No. DAQE-AN101230041-13** **Holly Refining & Marketing Company—Woods Cross, LLC** **Heavy Crude Processing Project** **Project Number: N10123-0041**	**ORDER ADOPTING ALJ'S PROPOSED ORDER** **and** **DENYING PETITIONERS' REQUEST FOR STAY** **Amanda Smith** **Executive Director** **Department of Environmental Quality** May 8, 2014

This matter is before me based on the Administrative Law Judge's proposed determination on a motion for stay in this matter. For the reasons set forth herein, I hereby adopt the March 25, 2014 Proposed Order regarding Petitioners' Motion Requesting Stay of Approval Order.

Findings of Fact

1. On November 18, 2013, the Director of the Utah Division of Air Quality issued Approval Order DAQE-AN101230041-13 (Project Number N10123-0041) (hereafter "AO") to Holly Refining and Marketing Company, for the construction of the Heavy Black Waxy Crude Processing Project.

2. On December 18, 2013, Petitioners Utah Physicians for a Health Environment and Friends of the Great Salt Lake (hereinafter "Utah Physicians") filed a Request for Agency Action (RFAA) seeking a review of the AO pursuant to Utah Code §§19-1-301.5 and 63G-4-201(1)(b) and Utah Admin. Code R305-7-203.

3. On January 9, 2014, I appointed Bret F. Randall as the Administrative Law Judge (ALJ) in this matter pursuant to Utah Code Ann., §19-1-301.5(5). I charged the ALJ to conduct a permit review adjudicative proceeding in accordance with Utah Code Ann., §19-1-301.5 and Utah Admin. Code R305-7.

4. On December 21, 2013, Utah Physicians filed a motion and supporting memorandum requesting a stay of the AO pending a full hearing on the merits pursuant to Utah Code Ann., §19-1-301.5(15) and Utah Admin. Code R305-7-217. Petitioners filed a Corrected Motion and Memorandum Requesting Stay on January 21, 2014.

5. Following extensive briefing on the motion to stay by the Parties, the ALJ heard oral argument on March 6, 2014. The hearing was transcribed by a court reporter.

6. On March 25, 2014, pursuant to Utah Code Ann., §19-1-301.5(15)(c), the ALJ issued proposed findings of fact (including references to the initial administrative record) conclusions of law and a proposed order recommending that the Executive Director deny the petitioners' motion to stay.

7. The ALJ's findings of fact (including references to the initial administrative record) address the: regulatory background; permit chronology; DAQ's permit review; and impacts of modernization project construction. The ALJ's conclusions of law address each of the four statutory elements required for a stay. The required statutory elements were briefed and argued by the parties at the March 6, 2014 hearing.

8. On April 8, 2014, Utah Physicians submitted comments on the ALJ's proposed order. The following memoranda were subsequently filed on April 15, 2014 in response to Utah Physicians' comments: Holly's Response to Utah Physicians' Comments on ALJ's Recommended Order Re: Petitioners' Request for a Stay of Approval Order; and the Utah

Division of Air Quality's Response to Utah Physicians' Comments on ALJ's Recommended Order Regarding Stay of Approval Order.

9. The points raised by Holly and DAQ in response to Utah Physicians' comments confirm that the comments repeat points previously briefed and argued at the time of the hearing on the stay. The ALJ has addressed each of those points in his proposed order.

Conclusions of Law

10. Whenever a motion to stay is filed in a permit review adjudicative proceeding, the ALJ shall: (i) consider a party's motion to stay a permit review adjudicative proceeding; and (ii) submit a proposed determination on the stay to the Executive Director. Utah Code Ann., §19-1-301.5(15)(c).

11. Utah Code Ann., §191-301.5(15)(d) provides that the ALJ may not recommend to the executive director a stay of a permit, or a portion of a permit, unless: (i) all parties agree to the stay; or (ii) the party seeking the stay demonstrates that:

> (A) the party seeking the stay will suffer irreparable harm unless the stay is issued;
>
> (B) the threatened injury to the party seeking the stay outweighs whatever damage the proposed stay is likely to cause the party restrained or enjoined;
>
> (C) the stay, if issued would not be adverse to the public interest; and
>
> (D) there is a substantial likelihood that the party seeking the stay will prevail on the merits of the underlying claim, or the case presents serious issues on the merits, which should be the subject of further adjudication.

The Parties did not stipulate to a stay and the Petitioners must, therefore, demonstrate compliance with all of the four statutory elements.

12. The ALJ's findings of fact and conclusions of law address each of the elements necessary for a stay and establish that based on the record then before the ALJ, the Petitioners have failed to carry their burden of proof on the statutory elements required for a stay.

Order

I have reviewed the proposed findings of fact, conclusions of law and proposed determination. I have also reviewed the comments and responses to comments submitted by the parties regarding the ALJ's proposed determination. Based on the ALJ's review and evaluation, I am persuaded that the petitioners have failed to meet the statutory elements required for a stay. I therefore adopt the ALJ's findings of fact, conclusions of law and proposed order, and I deny the Petitioners' motion for stay.

Dated this 8th day of May, 2014

Amanda Smith, Executive Director
Department of Environmental Quality
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CERTIFICATE OF SERVICE

I hereby certify that on this 8th day of May, 2014, the foregoing **ORDER ADOPTING ALJ'S PROPOSED ORDER and DENYING PETITIONERS' REQUEST FOR STAY** was served via e-mail upon the following:

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BEFORE THE EXECUTIVE DIRECTOR OF THE
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY

In the Matter of: Approval Order No. DAQE-AN101230041-13 Holly Refining & Marketing Company – Woods Cross, LLC Heavy Crude Processing Project Project No. N10123-0041	**FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDED ORDER ON THE MERITS** Administrative Law Judge Bret F. Randall March 11, 2015

This matter is before me pursuant to appointment by the Executive Director of the Utah Department of Environmental Quality dated January 9, 2014. The appointment charges me to conduct a permit review adjudicative proceeding in this matter in accordance with Utah Code Ann., § 19-1-301.5 and Utah Admin. Code R305-7. Following are my Findings of Fact,[1] Conclusions of Law, and Recommended Order on the Merits.

[1] While the Utah Code directs me to provide "findings of fact," I note that my review of this matter is in an appellate capacity. There was no trial, no witnesses were called, no testimony was heard, and no evidence was presented to me as a trier of fact. Thus, the legislature's requirement that the ALJ provide "findings of fact" and a proposed dispositive action should not be read to suggest that I have weighed evidence, except in an appellate-like role, applying the standards of review as discussed below.

TABLE OF CONTENTS

ADJ011538

INTRODUCTION

This matter came before me for oral argument on September 17, 2014 at 9:30 am. Present at the argument was Joro Walker and Rob Dubuc on behalf of Petitioners; Christian Stephens for Respondent Division of Air Quality; and Steve Christiansen, David Reymann, Cheylynn Hayman, and Megan Houdeshel for Respondent Holly. Having reviewed the briefing in this matter and heard oral argument, I propose that Petitioners' Request for Agency Action and all claims asserted therein be rejected.

PROCEDURAL BACKGROUND

1. In May of 2012, Holly Refining & Marketing Company – Woods Cross, LLC ("Holly") submitted a notice of intent ("May NOI") to the Utah Division of Environmental Quality ("UDAQ") requesting an approval order to expand its Woods Cross refinery ("Holly Refinery") and modernize certain equipment in a way that would allow Holly to process an additional 20,000 barrels per day of black wax crude from the Uintah Basin in eastern Utah ("Modernization Project"). [May NOI, IR000049-001108].

2. In July of 2012, Holly re-submitted its May NOI with revisions in response to UDAQ's request for additional information ("July NOI"). [July NOI, IR002798-003590].

3. On November 28, 2012, UDAQ released for public comment an Intent to Approve document ("First ITA") containing a draft approval order. [First ITA, IR001967-001996].

4. During the initial 60-day public comment period, UDAQ received comments from the U.S. Environmental Protection Agency ("EPA") [IR004001-004005]; Western Resource Advocates on behalf of Utah Physicians for a Healthy Environment and Friends of Great Salt Lake (collectively "Petitioners") [IR004007-004035]; Blaine Rawson on behalf of

Mark J. Hall [IR004202-004217]; Alexander Sagady on behalf of Petitioners [IR009046-009135]; and Holly [IR003757-003910].

5. In February and March of 2013, Holly provided a detailed response to EPA relating to the EPA's comments referenced above, which objected (among other things) to Holly's original netting analysis. [IR008245-008259].

6. In March 2013, Holly submitted a new netting analysis partly in response to a specific request made by UDAQ in February of 2013 and partly in response to EPA's comments referenced above [IR008198-008259].

7. In April 2013, Holly formally submitted a revised NOI ("Revised NOI") to UDAQ that also included the new netting analysis. [Revised NOI at IR007335-007395].

8. In addition to certain other changes, the Revised NOI estimated $PM_{2.5}$ emissions from Holly's gas-fired heaters and boilers based on the EPA's National Emission Inventory ("NEI") data. [*Id.*]

9. On June 5, 2013, UDAQ released for a second public comment period an Intent to Approve document ("Second ITA") and a Source Plan Review. [Second ITA, IR00008449-008479; SPR, IR008480-008575].

10. On July 25, 2013, UDAQ received comments on the draft approval order in the Second ITA from EPA ("EPA's Second Comment Letter") [IR007840-007841]; Western Resource Advocates on behalf Petitioners ("Petitioners' Second Comment Letter") [IR007842-007997]; Blaine Rawson on behalf of Mark J. Hall ("Rawson's Second Comment Letter") [IR008579-008602]; Alexander Sagady on behalf of Petitioners ("Sagady's Second Comment Letter") [IR009046-009135]; and Holly ("Holly's Second Comment Letter") [IR007613-007836].

11. On November 6, 2013, UDAQ requested additional information from Holly pertaining to certain comments raising questions about the Second ITA and Holly responded to this request for supplemental information on November 7, 2013. [IR008021, IR008022-0052].

12. On November 18, 2013, UDAQ issued a Response to Comments Memorandum ("Response to Comments Memo") addressing all of the comments made during the second public comment period, explained UDAQ's response to those comments, and, where appropriate, described how the comments had been incorporated into the Holly AO. [Response to Comments Memo, IR009174-009222].

13. UDAQ, having considered and answered all of the comments received during the public comment period, issued Holly a new approval order authorizing the construction of the Modernization Project ("Holly AO"), on November 18, 2013. [Holly AO, IR009223-009254].

14. On December 18, 2013, Petitioners filed their Request for Agency Action contesting UDAQ's issuance of the Holly AO ("RAA").

15. In January 9, 2014, the Executive Director of UDAQ appointed me as the administrative law judge ("ALJ") to conduct a permit review adjudicative proceeding in this matter in accordance with Utah Code Section 19-1-301.5 and Utah Admin. Code R305-7.

16. On January 16, 2014, I issued a Notice of Further Proceedings, in which, among other things, ordered that the party with the burden of proof on any issue would be held to a stringent marshaling requirement ("Marshaling Requirement").

17. On January 22, 2014, Petitioners filed an Amended Motion and Memorandum Requesting a Stay of the Approval Order ("Motion for Stay"). Oral argument was held on the Motion for Stay on March 6, 2014.

18. On March 25, 2014, I recommended to the Executive Director of the Department of Environmental Quality ("Executive Director") deny the Motion for Stay finding that Petitioners had not satisfied the four factors required for issuance of a stay of an environmental permit.

19. On May 8, 2014, the Executive Director of the Department of Environmental Quality adopted my proposed order and denied the Motion for Stay.

20. Prior to briefing the merits, Holly and UDAQ submitted Motions to Dismiss certain issues in Petitioners' RAA.

21. On April 2, 2014, I denied without prejudice the Motions to Dismiss, finding at that time that "preservation issues would be most efficiently addressed in connection with briefing on the merits," which would afford a reviewing court "a more complete record for appellate review." [Order on Motions to Dismiss at 6-7].

22. On April 16, 2014, the Petitioners filed a Motion for Clarification Regarding Notice of Further Proceedings, in which they asked me to clarify the Marshaling Requirement imposed by the Notice of Further Proceedings.

23. On April 17, 2014, I issued an Order Clarifying the Marshaling Requirement ("Clarification Order") reiterating that the Petitioners bear the burden to marshal all of the evidence in the administrative record, both supportive of and contrary to their claims.

24. On September 12, 2014, I issued a subsequent Order regarding the Marshaling Requirement, clarifying further the Petitioners' burden of proof in light of the Utah Supreme Court decision in State v. Nielsen, 2014 UT 10, 326 P.3d 645. In that Order, I explained that Petitioners were required to marshal all of the evidence in the administrative record to carry their burden of proof on any particular issue.

25. On September 17, 2014, after receiving briefs on the merits from all the parties, I heard oral argument to hear the merits of Petitioners' RAA, as required by the Utah Code. After reviewing and considering all of the facts and arguments presented in the briefing and at oral argument and pursuant to Utah Code Section 19-1-301.5(12)(c), I hereby submit to the Executive Director the following Proposed Findings of Fact, Conclusions of Law, and Proposed Order Regarding the Merits.

LAW APPLICABLE TO THIS ADJUDICATION

I. Standard of Review

1. This permit review adjudicative proceeding is governed by Utah Code Section 19-1-301.5, which requires the presiding ALJ to "conduct a permit review adjudicative proceeding based only on the administrative record and not as a trial de novo." Utah Code § 19-1-301.5(8)(a). Unlike many other administrative proceedings involving an ALJ, in a permit review adjudicative proceeding it is clear that the Utah Legislature intended to limit the ALJ's authority to a review of UDAQ's decision, thereby placing the ALJ in an appellate-like review role. There is to be no trial. There will be no witnesses, no examination or cross examination, and no findings of fact where disputed testimony is weighed and where witness credibility is at issue, as often occurs in other administrative adjudicative proceedings. Rather, all of the weighing of the evidence has already occurred at the UDAQ level.

2. UDAQ prepared a written response to public comments in connection with the issuance of the Holly AO. [IR009174-9222]. The ALJ must "review…the director's determination, based on the record," culminating in a proposed dispositive action that includes findings of fact, conclusions of law, and a recommended order. Utah Code § 19-1-301.5(12)(b)-(c). Because these proceedings are, by definition, limited to the issues raised during the public

comment period, UDAQ's written response to public comments plays a central role in evaluating whether UDAQ's conclusions satisfy applicable legal requirements.

3. Petitioners have the burden of proof to demonstrate that the Director's determination to issue the Holly AO was in error. [Clarification Order at 4 ("Petitioners acknowledge that they have the burden of proof in this proceeding.")]; s*ee also* Taylor v. Pub. Serv. Comm'n, 2005 UT App 121, *1 (unpublished) ("In the typical challenge to agency action, the party challenging the action carries the burden of demonstrating its impropriety." (internal quotations omitted)).

4. The Director's determination can include factual findings, interpretations of law, and mixed determinations of law and facts.

5. To carry their burden of proof with respect to their challenge of factual findings, the Petitioners must demonstrate that UDAQ's findings of fact are not supported by substantial evidence; otherwise, the ALJ must "uphold all factual technical, and scientific agency determinations that are supported by substantial evidence taken from the record as a whole." Utah Code § 19-1-301.5(13)(b).[2] Under Utah case law relevant to this proceeding, the ALJ's review on questions of fact is limited to determining if UDAQ's factual findings "were reasonable and rational," while giving "great deference" to UDAQ's factual findings and not "reweighing" the evidence. Utah Chapter of the Sierra Club v. Bd. of Oil, Gas & Mining, 2012

[2] While subsection (13)(b) expressly applies directly to the Executive Director's review, the standard of review that the ALJ is to apply to the record is not expressly stated in the Utah Code. Under a fair reading of the statute, it is clear that the ALJ is to apply the same standard as the Executive Director is required to apply. This conclusion is based on a reading of the permit review adjudicative proceeding statute as a whole. In the first instance, the ALJ's express duty and authority is to undertake a permit review adjudicatory proceeding and not a trial *de novo* on the merits, resulting in a recommended ruling for the Executive Director. In other words, the role of the ALJ is to "stand in the shoes" of the Executive Director and provide her with a recommended ruling on the merits. Thus, the ALJ is to apply the same standard of review to the administrative record as the Executive Director is required to apply. Utah Code Ann. § 19-1- 301.5.

UT 73, ¶ 11, 38 P.3d 291 (hereinafter Sierra Club v. BOGM) (internal quotation marks omitted).[3] While reviewing an agency's determination for substantial evidence, the ALJ should "state the facts and all legitimate inferences drawn therefrom in the light most favorable to the agency's findings." *Id.* ¶ 12.

6. With respect to legal interpretations, the ALJ should grant "substantial discretion" to UDAQ in its interpretation of its governing statutes and rules. *See* Utah Code § 19-1-301.5(14)(c)(i). In this case, the governing statutes and rules include the Clean Air Act, the Utah Air Conservation Act, and the applicable regulations under these statutes. UDAQ's legal interpretation of these statutes and rules may be overturned only if Petitioners show that such interpretation is a "clearly erroneous interpretation or application of the law." *See, e.g.,* Sierra Club v. BOGM, 2012 UT 73, ¶ 10; *see also* Assoc. Gen. Contractors v. Bd. of Oil, Gas & Mining, 2001 UT 112, ¶ 18, 38 P.3d 291 (an agency's "interpretation of the operative provisions of the statutory law it is empowered to administer" must be given deference).

7. By contrast, UDAQ's general interpretations of the law, including constitutional questions, jurisdiction, and statutes unrelated to the agency, are granted little or no deference and are simply reviewed for correctness. *Sierra Club*, 2012 UT 73, ¶ 9; *see also* Sevier Citizens v. Dept. of Envt. Quality, 2014 UT App 257, ¶ 6 (where the statute under review was procedural, and where issue was interpretation of the statute itself that granted agency interpretive discretion, the court applied a traditional approach to standard of review and imposed a correctness standard

[3] Section 19-1-301.5, however, also vests the ALJ with the authority to supplement the administrative record. Utah Code Ann. § 19-1-301.5(8)(c)(iv) (providing that the ALJ "may supplement the record with technical or factual information."). Based on these statutory provisions, if the ALJ determines that UDAQ has not addressed an issue or UDAQ's response to an issue is inadequate, the ALJ may request additional technical or factual information from the parties as opposed to recommending a remand of the AOs.

to the question of whether the failure to file a petition to intervene strips the agency of jurisdiction under Utah Code Section 19-1-301.5(7)).

8. Finally, when the agency has been granted discretion to interpret the statute or regulation at issue, mixed questions of law and fact are reviewed under an abuse of discretion standard. *See* Murray v. Utah Labor Comm'n, 2013 UT 38, ¶ 39, 308 P.3d 461. Here, Section 19-1-301.5(14)(c)(i) expressly grants UDAQ "substantial discretion to interpret its governing statutes and rules." Agency decisions on mixed questions of law and fact must be upheld under this discretion standard if they are "rationally based" and set aside only "if they are imposed arbitrarily and capriciously or are beyond the tolerable limits of reason." Assoc. Gen. Contractors, 2001 UT 112, ¶ 18 (internal quotation marks omitted).

II. Petitioners' Burden of Proof

1. Petitioners, as the parties challenging UDAQ's decision to issue the Holly AO, carry the burden of demonstrating UDAQ's determinations were not supported by substantial evidence, were erroneous, or were an abuse of discretion. *See* Sierra Club v. BOGM, 2012 UT 73, ¶ 31; Associated Gen. Contractors, 2001 UT 112, ¶ 34; *Taylor*, 2005 UT App 121, *1 (Utah Ct. App 1993) (unpublished).

2. A party with the burden of proof must "fully identify, analyze, and cite its legal arguments" and "provide meaningful legal analysis" but may not "dump the burden of argument and research" on the reviewing authority. W. Jordan City v. Goodman, 2006 UT 27, ¶ 29, 135 P.3d 874 (internal quotation marks omitted); *see also* Kennon v. Air Quality Bd., 2009 UT 77, ¶ 29, 270 P.3d 417 (declining to review a petitioner's challenge to an AO where the petitioners failed to adequately brief a claim). Moreover, a party's briefing is inadequate where the briefing "merely contains bald citations to authority without development of that

authority and reasoned analysis based on that authority." Allen v. Friel, 2008 UT 56, ¶ 9, 194 P.3d 903 (internal quotation marks omitted); State v. Lamb, 2013 UT App 5, ¶ 11, 294 P.3d 639.

III. Petitioners' Duty to Marshal All Relevant Evidence

1. This tribunal's statutory jurisdiction under Utah Code Section 19-1-301.5 requires this tribunal to conduct this proceeding based only on the administrative record and to uphold "all factual, technical, and scientific agency determinations that are supported by substantial evidence viewed in light of the record as a whole." Utah Code § 19-1-301.5(14)(c) (emphasis added). Accordingly, there will never be a "trial" on the merits. Rather, UDAQ undertook the adjudication of Holly's NOIs after receiving and considering, among other things, public comments.

2. All of the evidentiary information upon which the Director could have relied is contained in the formal administrative record as defined by Utah Code Section 19-1-301.5(8)(b). For every issue raised in public comments, the Director provided a detailed written response, which also forms part of the administrative record. Utah Code Ann. § 19-1-301.5(8)(b).

3. The Director's detailed response to comments provides a specific record as to how the Director considered and resolved each public comment and also, in some instances, refers to and provides citation to other evidence in the administrative record upon which the Director has relied in reaching any given conclusion. Thus, while there is no trial on the merits, the Director's response to public comments provides a rather detailed "roadmap" as to the factual and legal basis for the Director's decision to issue the Holly AO.

4. Because Petitioners have the burden of persuasion in this proceeding, the only way they can possibly carry that burden of proof it to convince the ALJ (or, by extension, the Executive Director, the Utah Court of Appeals, or the Utah Supreme Court) that any disputed factual, technical, or scientific agency determination is not supported by substantial evidence taken from the administrative record *as a whole*. By extension, therefore, they must marshal *all* of the evidence relevant to each claim they assert. *See, e.g.,* Nielsen, 2014 UT 10, ¶ 42. In short, the Marshaling Requirement forms an inherent part of Petitioners' burden of proof in this proceeding. Indeed, the Utah Supreme Court recently clarified that "a party who fails to identify and deal with supportive evidence will never persuade an appellate court to reverse under the deferential standard of review that applies to such issues." Nielsen, 2014 UT 10, ¶ 40 (emphasis added).

5. In their briefing on the merits and at oral argument, Petitioners raised a number of objections to the Marshaling Requirement. These objections lack merit.[4] The Marshaling Requirement was properly imposed, either as an inherent part of Petitioners' burden of proof or, in the alternative, pursuant to the ALJ's statutory grant of authority to manage all non-dispositive aspects of these proceedings.

6. The Utah Legislature has granted the ALJ the jurisdiction to "take any action in a permit review adjudicative proceeding that is not a dispositive action." Utah Code § 19-1-301.5(9)(f). Although the Marshaling Requirement is not specifically adopted in the Utah Code or Utah Administrative Code as applied to these proceedings and Rule 24(a)(9) does not expressly apply here, an ALJ has the authorization to manage this proceeding in the most efficient

[4] The fact that Holly was able to marshal record evidence, point by point, in the manner that I had requested of Petitioners, provides further support for the conclusion that Petitioners' arguments against the Marshaling Requirement lack merit and should be rejected.

and effective way appropriate under the circumstances of this case.[5] All of the policy reasons underlying Rule 24(a)(9) of the Rules of Appellate Procedure apply with full force to a permit review adjudicative proceeding.

7. In an analogous situation, the Utah Court of Appeals declined to undertake an independent review of a large record. Wright v. Westside Nursery, 787 P.2d 508, 512 n.2 (Utah App. 1990). There, the court noted that Rule 24(a)(9) was intended precisely "to spare appellate courts such an onerous burden." *Id.* Hence, the court continued, "[a]bsent exceptional circumstances, our review of the record is limited to those specific portions of the record which have been drawn to our attention by the parties and which are relevant to the legal questions before us." *Id.* The court noted that Rule 24(a)(9) was intended precisely "to spare appellate courts such an onerous burden." Hence, the court continued, "[a]bsent exceptional circumstances, our review of the record is limited to those specific portions of the record which have been drawn to our attention by the parties and which are relevant to the legal questions properly before us." Id. I have applied this same standard to my review of the administrative record in this proceeding, for the same reasons as stated by the Utah Court of Appeals. If this rule were not applied to the administrative record in a permit review adjudicative proceeding, an appellant on future appeal could potentially argue that the administrative law judge overlooked or failed to consider, under his or her independent review of the record, certain evidence of record even though that evidence was not specifically drawn

[5] It is undisputed that should Petitioners appeal any issue arising from this proceeding to the Utah Court of Appeals, Rule 24(a)(9) would apply to their briefs on appeal. Because the administrative law judge and the Executive Director are called upon to apply the same standard of review to the agency determinations as the Utah Court of Appeals, it stands to reason that the marshaling requirement should also apply at the ALJ and Executive Director levels of review. Moreover, Petitioners have been on notice of this procedural requirement from the outset of this proceeding and did not appeal the ALJ's Order Clarifying the Marshaling Requirement to the Executive Director. They cannot therefore show undue burden or prejudice.

to the attention of the administrative law judge. I find and conclude that the types of "exceptional circumstances" that may warrant deviation from this rule, as stated in *Wright*, do not apply to the present proceedings.[6]

8. This conclusion finds further support in Utah case law in the cases cited below, subject to the clarification that in these cases, the potential for a procedural default upon failure to marshal the record is not an appropriate result, as held in State v. Nielsen*, supra.* However, to the extent that Utah case law regarding the burden of proof and marshaling does not deal with the procedural default issue rejected in State v. Nelson, it is still good law and should be considered as being relevant here. *See, e.g.,* Simmons Media Group, LLC v. Waykar, LLC, 2014 UT App 145, ¶¶ 46, 763 Utah Adv. Rep. 32 (dismissing a claim where the appellant "does not identify and deal with the supportive evidence" (internal quotation marks omitted)); Nebeker v. Summit County, 2014 UT App 137, ¶ 46, 762 Utah Adv. Rep. 25 ("To prevail on such a challenge, the County must acknowledge the evidence that supports the findings and demonstrate 'a basis for overcoming the healthy dose of deference owed to factual findings'" (quoting Nielsen, 2014 UT 10 ¶¶ 41-42); Wachocki v. Luna, 2014 UT 139, ¶ 11, n. 6, 330 P.3d 717 (holding that because appellants failed to marshal the evidence, appellants did not carry their burden on appeal); W. Jordan City, 2006 UT 27, ¶ 29; Heinecke v. Dep't of Commerce, 810 P.2d 459, 464 (Utah Ct. App. 1991) (holding that parties fail to meet their burden to marshal the evidence when they leave "it to the court to sort out what evidence

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[6] There is simply nothing in the Utah Code to suggest that the administrative law judge in a permit review adjudicative proceeding has an independent duty to comb through the entire Administrative Record to identify all relevant facts in support of a disputed factual, technical, and scientific agency determination, particularly where, as here, Petitioners are represented by experienced and competent legal counsel. To be sure, a more generous standard of briefing may apply to a permit review adjudicative proceeding where parties appear *pro se*. Because no *pro se* parties are involved in the instant proceeding, I will not speculate as to the potential applicability of the Marshaling Requirement in cases where parties are not represented by legal counsel.

actually supported the finding" and instead argued their "own position without regard for the evidence supporting the…findings").

9. The duty to carry the burden of proof through marshaling must fall to Petitioners in this permit review adjudicative proceeding, because as a matter of longstanding administrative law, the party challenging any factual finding underlying an agency's determination is required to marshal "all" evidence supporting the agency's determination. Sierra Club v. BOGM, 2012 UT 73, ¶ 12; *see also* Kennon, 2009 UT 77, ¶ 27 ("When challenging factual findings, a party is obligated to marshal 'all record evidence that supports the challenged finding.'" (quoting Utah R. App. P. 24(a)(9))); First Nat'l Bank of Boston v. County Bd. of Equalization of Salt Lake County, 799 P.2d 1163, 1165 (Utah 1990) (In an appeal of an agency action, "the party challenging the finding…must marshal all of the evidence supporting the finding .").

10. The duty to marshal the evidence in administrative appeals also applies to parties challenging an agency's determination on mixed questions of fact and law. Peterson Hunting v. Labor Comm'n, 2012 UT App 14, ¶ 15, 269 P.3d 998; *see also* United Park City Mines Co. v. Stichting Mayflower Mountain Fonds, 2006 UT 35, ¶ 25, 140 P.3d 1200 ("Even where the defendants purport to challenge only the legal ruling, as here, if a determination of the correctness of a court's application of a legal standard is extremely fact-sensitive, the [appellants] also have a duty to marshal the evidence." (internal quotation marks omitted)).

> A party obligated to marshal the evidence must do so for each claim that the marshaling mandate applies. *Sierra Club 2012*, 2012 UT 73, ¶ 30 & n.3 (holding that Petitioners failed to marshal one claim while determining that the same Petitioners marshaled another claim). At its core, the marshaling requirement demands that a party "marshal all of the evidence supporting the findings and show that despite the supporting facts, the…findings are not support by substantial evidence." *Id.* ¶ 30. To do so, the party may not "'simply attack [the agency's] credibility.'"

Associated Gen. Contractors, 2001 UT 112, ¶ 34 (quoting Brewer v. Denver & Rio Grande W. R.R., 2001 UT 77, ¶ 36, 31 P.3d 557).

11. In light of the Marshaling Requirement, the ALJ has ordered that Petitioners were not subject to a page limitation in their briefing on the merits. Rather, the only requirement has been that the briefing be of reasonable length. Thus, Petitioners have been afforded every opportunity to carry their burden of proof in this proceeding to convince the ALJ that any disputed factual, technical, or scientific agency determination is ***not*** supported by substantial evidence taken from the administrative record as a whole. In order to meet that burden of proof, it will be necessary for Petitioners to bring to the tribunal's attention ***all*** evidence from the administrative record that relates to any such disputed issue.

IV. Preservation Standard

1. Pursuant to Utah Code Section 19-1-301.5(10), "[a] person who files a request for agency action has the burden of demonstrating that an issue or argument raised in the request for agency action has been preserved." Lacking such demonstration, the ALJ "shall dismiss, with prejudice, any issue or argument in a request for agency action that has not been preserved." *Id.*

2. An issue or argument has been preserved for appeal if (a) the person raised it during the public comment period and it was supported with sufficient information or documentation to enable the director to fully consider the substance and significance of the issue, Utah Code § 19-1-301.5(4)(a)-(b); or (b) the issue was not reasonably ascertainable during the public comment period, *id.* § 19-1-301.5(6)(c).

3. The failure to raise reasonably ascertainable issues or arguments relating to the proposed permit during the public comment period deprives UDAQ from considering all

possible issues prior to any issuance of an approval order and results in less effective agency process.

4. The demonstration that each issue has been properly preserved must be found in the Petitioners' RAA at the outset of the case. *See id.*; *see also* Utah Admin. Code R305-7-203(3)(h) (mandating that an RAA provide a showing on preservation).

5. The failure to raise issues in the RAA frustrates the goals of the permit review adjudicative process by failing to place the respondents on notice of the specific claims. Such failure prevents UDAQ and Holly from assessing whether it should have supplemented the record in response to newly presented claims in the RAA. Moreover, by not raising issues in the RAA and waiting to reveal claims until the briefing, Petitioners prevented Holly from assessing the full risks of proceeding with construction under an AO subject to a permit challenge.

6. Any claims not preserved in accordance with the statutory standard set forth above will be dismissed.

7. Petitioners raised concerns in their RAA and then again in their Reply Brief about whether due process had been satisfied where Holly submitted additional information to UDAQ after the close of the public comment period and Petitioners were not given a second opportunity to submit comments on this additional material.

8. First, Petitioners have waived this claim by not briefing it in their opening brief. Petitioners may not raise claims in their RAA and then wait to address such claims until their Reply brief. *See e.g.,* Coleman ex rel. Schefski v. Stevens, 2000 UT 98, ¶ 9, 17 P.3d 1122 (refusing to consider matters raised for the first time in the reply brief).

9. Even if Petitioners' claims regarding procedural due process were not waived and had merit, which is unclear in light of the fact that Petitioners do not adequately brief this issue,

fail to cite any case law, or quote from the due process clause of the Utah or United States Constitution, it is clear that Petitioners were afforded an opportunity to supplement the record and raise issues in the RAA relating to any new information submitted after the close of the public comment period.

10. Petitioners were on notice that additional information had been submitted, as it was referenced multiple times in the response to comments document UDAQ issued in conjunction with the final Holly AO. Petitioners also had access to UDAQ's permitting file after the Holly AO was issued before the deadline for filing their RAA.

11. Moreover, this tribunal has allowed arguments that were not reasonably ascertainable to be raised in the RAA, for the first time, in accordance with Utah Code Section 19-1-301.5(6)(c)(ii), and allowed the parties to supplement the record via motion in accordance with Section 19-1-301.5(8)(c). This tribunal has also waived any page limits to allow the parties the opportunity to fully develop any claims that arose either during the public comment period, or after.

12. Petitioners are incorrect that their due process rights have been implicated in this case.[7] Any claims or issues that were reasonably ascertainable during the public comment period must have been raised in Petitioners' comments. Any claims that were not reasonably ascertainable during the public comment period could be included for the first time in the Petitioners' RAA but may not appear for the first time in Petitioners' briefing on the merits. Petitioners have failed to demonstrate how, in light of this tribunal's treatment of the claims in accordance with 19-1-301.5, any procedural due process rights have been violated.

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[7] To the extent Petitioners claim that permit review adjudication statute and rules violate the due process protections of the Utah and United States Constitutions, such claims are beyond the jurisdiction of the ALJ to decide in this permit review proceeding. *See e.g.,* Nebeker v. Utah State Tax Comm'n, 2001 UT 74, ¶ 23, 34 P.3d 180.

V. Scope of Proceedings; Regulatory Background; and EPA Role

1. The evidence Petitioners presented in this matter stands for the self-evident, general proposition that air pollution is harmful to human health and to the environment. [IR at 009140-48; IR at 009139-45; IR at 009144-45; IR at 009145-47.] On that point, there is no disagreement.

2. In enacting the Utah Air Conservation Act, the Utah Legislature declared: "It is the policy of this state and the purpose of [the Utah Air Conservation Act] to achieve and maintain levels of air quality which will protect human health and safety, and to the greatest degree practicable, prevent injury to plant and animal life and property, foster the comfort and convenience of the people, promote the economic and social development of this state, and facilitate the enjoyment of the natural attractions of this state." Section 19-2-101(2), Utah Code Ann.

3. The Utah Legislature further declared that the "purpose" of the Utah Air Conservation Act is to "(a) provide for a coordinated statewide program of air pollution prevention, abatement, and control; (b) provide for an appropriate distribution of responsibilities among the state and local units of government; (c) facilitate cooperation across jurisdictional lines in dealing with problems of air pollution not confined within single jurisdictions; and (d) provide a framework within which air quality may be protected and consideration given to the public interest at all levels of planning and development within the state." Section 19-2-101(4), Utah Code Ann.

4. Similarly, in enacting the Clean Air Act, the Congress found, among other things:

> **(2)** that the growth in the amount and complexity of air pollution brought about by urbanization, industrial development, and the increasing use of motor vehicles, has resulted in mounting dangers to the public health and welfare, including

> injury to agricultural crops and livestock, damage to and the deterioration of property, and hazards to air and ground transportation; [and]
>
> **(3)** that air pollution prevention (that is, the reduction or elimination, through any measures, of the amount of pollutants produced or created at the source) and air pollution control at its source is the primary responsibility of States and local governments . . . .

42 U.S.C. § 7401(a).

5. Congress also stated that the "primary goal" of the Clean Air Act is to "encourage or otherwise promote reasonable Federal, State, and local governmental actions . . . for pollution prevention." 42 U.S.C. § 7401(c).

6. In these proceedings, I am charged to conduct a permit review adjudicative proceeding in this matter in accordance with Utah Code Ann., § 19-1-301.5 and Utah Admin. Code R305-7.

7. As a matter of law, any source's compliance with the permitting requirements set forth in the Clean Air Act and the Utah Air Conservation Act satisfies the public policy of protecting the public and the environment from the harms of air pollution.

8. The question before me in these proceedings is not whether air pollution is harmful but rather whether the Holly AO is in compliance with applicable laws, rules, and regulations. Based on the evidence in this record, the unavoidable conclusion is that the Holly AO is in compliance with the law, all as explained in more detail below.

9. The conclusions reached in these proposed Findings and Fact and Conclusions of Law, to the effect that the Holly AO is in compliance with all applicable laws, rules, and regulations, notwithstanding Petitioners' objections, find additional support in the EPA's independent review of the Holly AO and that agency's conclusion that the Holly AO may be issued. *See* EPA Comment Letters [IR004001-004005; IR007840-007841]. In *Alaska Dep't of*

Envtl. Conservation v. EPA, 540 U.S. 461, 124 S. Ct. 983 (2004), the U.S. Supreme Court held that EPA is entitled to review the reasonableness of state permitting authorities' BACT determinations under the PSD program and has authority to issue stop construction orders if it reasonably believes that a BACT designation is erroneous or unreasonable. The CAA also provides EPA with concurrent enforcement authority that is directly applicable to the present proceeding. 42 U.S.C. §§ 7477, 7413(a)(5)(A) (describing the enforcement options available to the EPA when it finds that a state is not complying with any requirement of the CAA with respect to construction of a new source or modification of an existing source). *See* Jennifer A. Davis Foster, Note, EPA Oversight in Determining Best Available Control Technology: The Supreme Court Determines the Proper Scope of Enforcement, 69 Missouri L. Rev., Issue 4, at 1 (Fall 2004). Based on the foregoing, it is clear that if in EPA's independent judgment, any of the objections and issues Petitioners have briefed on the merits were meritorious, EPA had an independent duty and authority to pursue such issues. EPA declined to do so even after being given the opportunity in connection with the Holly AO.

10. In this permit review adjudicative proceeding, we have a somewhat unusual situation in administrative law where not one but two regulatory agencies with significant technical expertise and concurrent (and somewhat overlapping) legal jurisdiction have been involved in the procedural and substantive process that led to the issuance of the Permit. This situation provides a second layer of regulatory oversight to ensure that the applicable procedural and substantive requirements of the Clean Air Act, as adopted and enforced through the Utah Air Conservation Act in the spirit of "cooperative federalism," have been met.

FINDINGS OF FACT AND CONCLUSIONS OF LAW FOR CLAIMS PETITIONERS FAILED TO BRIEF ON THE MERITS

1. Petitioners' RAA contains a number of claims that Petitioners did not raise in their briefing on the merits. Those claims are listed in a Table of Waived Claims attached hereto as **Appendix A**, incorporated herein by this reference.

2. Both Holly and UDAQ pointed out in their briefing and at oral argument that Petitioners failed to brief these claims and therefore waived such claims. Petitioners did not rebut this argument and at oral argument conceded that this tribunal need not address claims they did not brief.

3. Because Petitioners failed to brief these claims, they should be dismissed with prejudice on two separate and independent grounds: (a) waiver; and (b) failure to carry Petitioners' burden of proof. *See, e.g.*, See Sierra Club v. BOGM, 2012 UT 73, ¶ 31; Kennon, 2009 UT 77, ¶ 29; *W. Jordan City*, 2006 UT 27, ¶ 29; Anderson v. Kriser, 2009 UT App 319, *2 n.3 ("[A]rguments not raised in an appellant's initial brief are waived."); Brown v. Glover, 2000 UT 89, ¶ 23, 16 P.3d 540 ("Generally, issues raised by an appellant in the reply brief that were not presented in the opening brief are considered waived and will not be considered by the appellate court.").

FINDINGS OF FACT AND CONCLUSIONS OF LAW FOR CLAIMS PETITIONERS BRIEFED ON THE MERITS

Petitioners' remaining claims can be grouped into eleven independent claims, each of which will be addressed below. Before addressing the specific claims, I would like to make the following general findings of fact relating to the regulatory context, inasmuch as the general aim of many of Petitioners' comments go to the issue of the harms caused by air pollution.

I. UDAQ Is Properly Regulating the Holly Refining Flares as Required by Subpart Ja.

Petitioners' first specific argument on the merits goes to the interplay between the regulation of the Holly flares, as required by law, and the Holly AO at issue in this matter. Petitioners argue that the Holly AO is invalid because UDAQ did not "properly regulate" the refining flares by explicitly listing and explaining every applicable provision of the regulation governing the flares (New Source Performance Standards ("NSPS"), 40 C.F.R. Part 60, Subpart Ja ("Subpart Ja"). [Petitioners' Opening Brief at 4-12.] More specifically, Petitioners argue that "the Director has failed to specify in the AO – or elsewhere – the exact conditions of Subpart Ja that apply to the Holly Refining Flares and has failed to impose these conditions on the facility. Without particular AO terms and conditions that reflect the relevant Supbart Ja standards on the flares, the Heavy Crude Project will not meet the requirements of Utah Admin Code R307-401-8(1)(b)(vi), Rule 307-401-8(1)(a) and Rule R307-401-8(5)." [Petitioners' Opening Brief at 4-5.] For the reasons set forth below, this argument should be rejected.

A. Findings of Fact

1. Holly's NOI acknowledges that Subpart Ja applies to the refinery generally and to the flares specifically. [*See* IR002866-87, Holly's July 2012 NOI ("The following Subparts are applicable to the proposed project…Subpart Ja – Standards of Performance for Petroleum Refineries"); IR002868-69 ("The provisions of [40 C.F.R. Part 60 Subpart Ja] apply to the new FCCU and fuel gas combustion devices, including flares and process heaters.");[8] IR002962

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[8] When Holly submitted its NOI, Subpart Ja included all flares in its definition of "fuel gas combustion device." *See* 40 C.F.R. § 60.101a (2012). However, during Holly's permit review process, the regulation was revised to separate fuel gas combustion devices from flares. 40 C.F.R. § 60.101a (2013). Despite this change in the regulations, in Holly's NOI and the Source Plan Review, flares were grouped together with other fuel gas combustion devices and subject to the same emission requirements. *See* IR005871-72.

(“Because the flare is located at a petroleum refinery, the flare must comply with the requirements and limitations presented in 40 C.F.R. Part 60 Subpart Ja.”)].

2. Holly’s NOI also incorporated emission limits derived from Subpart Ja for combustion devices. [IR002868-69, Holly’s July 2012 NOI (“Holly will comply with the following emission limitations…Holly shall not burn in any new fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a three-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.”).]

3. UDAQ independently recognized in the Source Plan Review that Subpart Ja applies to the Holly Refinery and that Holly is subject to the emission limitations contained in Subpart Ja. [IR008571-8572, Source Plan Review (“40 CFR 60 Subpart Ja: The provisions of this subpart apply to the new FCCU and fuel gas combustion devices, including flares and process heaters. Holly Refinery will comply with the following emission limitations…Holly Refinery shall not burn in any new fuel gas combustion device any fuel gas that contains H_2S in excess of 162 ppmv determined hourly on a three-hour rolling average basis and H_2S in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.”).] UDAQ also made clear that Subpart Ja applies to the flares in its Response to Comments Memo. [IR009183, Response to Comments Memo (“NSPS Subpart Ja applies to the Woods Cross refinery generally and to both the North and South Flares.”)].

4. UDAQ determined that Holly is required to comply with Subpart Ja whether or not such emission limits were contained in the Holly AO. [*See* IR009183, Response to Comments Memo (“Regardless of whether the requirements [of NSPS] are in the AO, Holly Refinery must comply with all applicable subparts…Holly Refinery is not in violation of any

federal limits."); IR009252, Holly AO (listing Subpart Ja in Section III, "Applicable Federal Requirements").]

5. The EPA made no comments regarding issues with the applicability or enforcement of Subpart Ja as to the Holly Refinery generally or as to the AO specifically. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. Findings and Conclusions on Preservation

6. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR007858-7860, Petitioners' Second Comment Letter.]

C. Findings and Conclusions on Burden of Proof

7. Petitioners assert that this issue is purely a question of law—whether UDAQ is required to explicitly outline and explain every applicable provision of Subpart Ja in the Holly AO. Petitioners concede that Subpart Ja applies to Holly's flares and other combustion sources, but argue that the AO is deficient because each applicable provision is not explained in detail in the Holly AO.

8. The question of whether Utah law requires applicable NSPS provisions to be listed in approval orders is a question of law that the agency has been given discretion to interpret and so shall be reviewed under a clearly erroneous standard. Whether UDAQ correctly applied a particular NSPS provision and whether Holly is in compliance with NSPS are mixed questions of law and fact that are reviewed for reasonableness and whether there is substantial evidence in the record to support the determinations. Whether Holly is in compliance with subpart Ja is a question that is specifically handled by DAQ's enforcement section and therefore beyond the scope of these proceedings.

9. In their briefing, Petitioners failed to reference any of the specific evidence in Holly's NOI in which Holly recognized it was subject to Subpart Ja.

10. Additionally, Petitioners' reference to other evidence in the record is relegated to footnotes and lacks any description of the document being referenced.

11. Because Petitioners have omitted multiple pieces of evidence from their analysis that show Subpart Ja does apply to the Holly Refinery, they have failed to meet their burden of proof on this issue for the reasons described in more detail above.

D. Conclusions of Law on the Merits

12. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' arguments should fail on the merits for the independent reasons discussed below.

13. Subpart Ja is one of many NSPS the EPA has promulgated for particular types of new or modified sources that EPA has determined are major emitters of criteria air pollutants, such as petroleum refineries. *See generally* 42 U.S.C. § 7411, Standards of Performance for New Stationary Sources (granting the administrator of EPA the authority to regulate certain sources). The applicability of a particular NSPS to a particular source is often specifically outlined in the text of the regulation applicable to that source category. *See e.g.,* 40 C.F.R. § 60.100a (defining modification for purposes of Subpart Ja applicability). The applicability of NSPS is evaluated separately from other Clean Air Act regulations such as the Prevention of Significant Deterioration Program ("PSD"), which is implemented through individual pre-construction permits like the Holly AO. *See generally* 42 U.S.C. §§ 7475, 7503 (setting forth the pre-construction permitting requirements).

14. Unlike the PSD program, the NSPS regulations apply to a source whether or not that source is undergoing a modification requiring pre-construction approval. *See, e.g.*, 40 C.F.R. § 60.1(a) (defining NSPS applicability); *id.* § 60.2 (defining when "construction" or "modification" takes places for purposes of NSPS applicability); Envt'l Defense v. Duke Energy Corp., 549 U.S. 561, 577-78 (2007) (recognizing the distinction between the NSPS and PSD regulations). Therefore, NSPS compliance and/or applicability determinations are not dependent upon inclusion of the NSPS regulation's language in the pre-construction permit. Compliance or non-compliance with NSPS is entirely separate from the PSD permitting process.

15. The oversight of Holly's compliance with Subpart Ja is a matter for UDAQ's enforcement section. This is true regardless of whether the provisions of Subpart Ja are in the permit or not. [IR009183, Response to Comments Memo ("Regardless of whether the requirements [of NSPS] are in the AO, Holly Refinery must comply with all applicable subparts…Holly Refinery is not in violation of any federal limits.").]

16. If Holly were in violation of Subpart Ja, contrary to UDAQ's determination, the Clean Air Act provides Petitioners with a separate remedy in the form of a citizen suit under Section 304 of the Clean Air Act. *See* 42 U.S.C. § 7604(a) (Clean Air Act citizen suit provision). Challenging compliance with Subpart Ja in this permit review proceeding is therefore misplaced.

17. Petitioners also are incorrect in their assertion that R307-415 of the Utah Administrative Code requires all federally-applicable NSPS requirements to be included in the Holly AO. The regulations Petitioners cite apply only to Title V operating permits—not approval orders. The Title V operating permit regulations are independent of the approval order

pre-construction permit regulations. *Compare* Utah Admin. Code R307-415 (Title V operating permit regulations), *with id.* R307-401 (pre-construction approval order permit regulations).

18. The purpose of Title V is to consolidate all applicable federal and state regulatory requirements into one permit. *See* 40 C.F.R. § 71.1(b) ("All sources subject to the operating permit requirements of title V and this part shall have a permit to operate that assures compliance by the source with all applicable requirements."). Thus, there is no legal requirement to include all applicable NSPS regulations in an approval order.

19. Accordingly, Petitioners' arguments that the applicable provisions of Subpart Ja must be included in the Holly AO fail on the merits and should be dismissed.

II. <u>The North Flare is Subject to Subpart Ja.</u>

1. The Petitioners next contend that the Director erred in reversing his position regarding the applicability of Subpart Ja to the North Flare. [Petitoners' Opening Brief at 12-15.] For the reasons stated below, this argument should be rejected.

A. <u>Findings of Fact</u>

2. The Director determined that Holly must comply with all applicable subparts of the NSPS regulations and that Holly was not in violation of any federal limits. [IR009183, Response to Comments Memo ("Regardless of whether the requirements [of NSPS] are in the AO, Holly Refinery must comply with all applicable subparts…Holly Refinery is not in violation of any federal limits.").]

3. The Director determined that the North Flare was not being modified as part of this project and therefore was outside the scope of the permitting action. [IR009183, Response to Comments Memo ("The North Flare is not being modified as part of the project proposed by

Holly Refinery in its NOI, so it is outside the scope of this permit action. NSPS Subpart Ja applies to the Woods Cross refinery generally and to both the North and South Flares.").]

4. According to undisputed evidence in the record, Holly's North Flare was subject to and in compliance with Subpart J and A of the NSPS regulations. [IR007999, Email Correspondence between Eric Benson and Camron Harry ("Holly's North Flare was applicable and compliant with 40 CFR 60 Subpart A & J upon startup.").]

5. A consent decree entered in 2008 between Holly and EPA required that Holly bring the North Flare into compliance with applicable NSPS standards. [*See* IR004800-4801, Consent Decree (requiring flaring devices to become NSPS compliant).]

6. As of December 2008, Holly reported to the EPA that its North Flare was in compliance with NSPS. [*See* IR007946, IR007951, Semi-Annual Progress Report to EPA and UDAQ re Consent Decree (reporting that "Performance tests for both North and South Flares [were] conducted December 10, 2008" and "[the] North Flare [was] subject to NSPS as of date of [Consent Decree] entry, eliminate all routinely-generated gas" and compliance status was "Complete.…[N]o routinely-generated gas sent to the flare.").]

7. In connection with its independent review of the entire Holly AO, the EPA made no comments about the North Flare or Subpart Ja, compliance with the Consent Decree, or any of the other related issues raised by Petitioners here. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. Findings and Conclusions on Preservation

8. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR007858, IR007864, Petitioners' Second Comment Letter.]

C. Findings and Conclusions on Burden of Proof

9. Petitioners' argument that the Director reversed his position relative to the North Flare is a question of fact and the Petitioners bear the burden to demonstrate that the Director's decision is not supported by substantial evidence in the record and was an abuse of discretion.

10. Petitioners, in their briefing, failed to marshal all of the evidence that supported the Director's ultimate conclusion that Subpart Ja applied to the North Flare and that Holly was in compliance with this Subpart. By contrast, Holly did marshal all of the evidence in its briefing.

11. Nothing in the record supports the assertion that the Director changed his mind about the applicability of Subpart Ja. From the beginning of the project, all parties agreed that this NSPS provision applied to the Holly Refinery.

12. Accordingly, Petitioners failed to satisfy their burden of proof for this claim.

D. Conclusions of Law on the Merits

13. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

14. The legislative intent of a permit review adjudicative process is to allow for an evolving understanding of a project before any final decisions are made. The Director may, at the beginning of a project, take a position in light of the information in the record at the time but later reverse that position based on additional information presented during the public comment period or otherwise, such as information provided by the source upon request. The question that must be answered in this permit review adjudication proceeding is whether the Director's final decision to issue the Holly AO is supported by substantial evidence in the record. This question

remains the same whether or not the Director may have changed his mind during the permitting process. In fact, the entire point of the permitting process as defined by the Utah Legislature is to allow for well-informed administrative decisionmaking. To the extent that the Director may have reached a different view on any given point suggests that the process is working as intended.

15. In this case, the Petitioners do not present any evidence that there was a reversal of position with respect to the applicability of Subpart Ja to the North Flare. To the contrary, all of the evidence in the record supports the position that the Director ultimately took, which was that Subpart Ja applied to the North Flare.

16. Petitioners argue that the North Flare was modified when all gases from the South Flare were routed to the North Flare and this modification triggered NSPS Subpart Ja applicability. [Petitioners' Opening Brief at 13.]

17. Regardless of whether the North Flare was modified, the record evidence demonstrates that Holly and the Director agreed that Subpart Ja applied for this project. [IR009183; IR009183; IR004800-4801; IR007946, IR007951.] Therefore, any evidence that a modification may have occurred on the North Flare would only be superfluous, not contradictory.

18. The EPA raised no procedural or substantive comments regarding with UDAQ's handling of Subpart Ja. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

19. The substantial weight of the evidence supports the Director's ultimate determination that Subpart Ja applies to Holly's North Flare and Petitioners' arguments that the Director contradicted himself should be dismissed with prejudice.

III. A BACT Analysis Was Not Required for the North Flare.

1. Petitioners argue that UDAQ erred in failing to perform or require a BACT analysis for the North Flare. [Petitioners' Opening Brief at 15-16]. For the reasons set forth below, this argument should be rejected.

A. Findings of Fact

2. Holly did not propose any physical modification of the North Flare as part of the project approved in the Holly AO. [IR009183, Response to Comments Memo ("The North Flare is not being modified as part of the project proposed by Holly Refinery in its NOI, so it is outside the scope of this permit action. NSPS Subpart Ja applies to the Woods Cross refinery generally and to both the North and South Flares."); IR009189, Response to Comments Memo ("Because neither the North Flare nor the SRU will undergo any physical change or experience an increase in emissions as a result of Holly Refinery's proposed project, the 'emission units' are not subject to the BACT analysis requirements in the PSD rules.").]

3. UDAQ did not anticipate any increase in overall flare emissions as a result of the project. [IR008561, Source Plan Review ("there is no reason to assume that upset condition emissions will be any greater after the project is complete than before the project.").]

4. The North Flare is already subject to and in compliance with NSPS requirements. [IR009183, Response to Comments Memo ("NSPS Subpart Ja applies to the Woods Cross refinery generally and to both the North and South Flares.").]

5. UDAQ determined that BACT for flares was compliance with Subpart Ja. [IR008516-17, Source Plan Review ("The only technically feasible control options for emissions of all pollutants from flares are: (1) equipment design specifications and good combustion work

practices…; and (2) flare gas recovery systems…DAQ NSR recommends compliance with the requirements of 40 CFR 60 Subpart Ja as BACT.").]

6. According to the record, prior to the authorization of this project, all of the flare gases were being routed to the North Flare. [IR08200, Holly's first revised netting analysis ("currently all gases are routed to the north flare").]

7. The EPA raised no procedural or substantive comments regarding UDAQ's analysis regarding BACT for the North Flare. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. <u>Findings and Conclusions on Preservation</u>

8. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR007858, IR007864, Petitioners' Second Comment Letter.]

C. <u>Findings and Conclusions on Burden of Proof</u>

9. Petitioners' claim that UDAQ erred in failing to perform a BACT analysis on the North Flare is a mixed question of law and fact. There is also a dispute regarding the correct interpretation of the regulations that trigger BACT, which is a question of law reviewed under a clearly erroneous standard. The application of that law to the facts in this case triggers the mixed question standard of review in which the ALJ reviews the Director's determination for reasonableness.

10. Petitioners failed to marshal all of the evidence related to their claim.

11. Specifically, Petitioners failed to cite UDAQ's finding that BACT for flares is compliance with Subpart Ja and that the North Flare is already subject to NSPS requirements.

12. Accordingly, Petitioners failed to satisfy their burden of proof on this claim and it can be dismissed on this basis.

D. <u>Conclusions of Law on the Merits</u>

13. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

14. In the briefing on this issue, Petitioners erroneously conflate the same definition of modification they cite in their NSPS arguments. However, a "modification" that triggers a BACT analysis is different than what is required to trigger NSPS applicability. *See, e.g., Envt'l Defense v. Duke Energy Corp.*, 549 U.S. 561, 577 (2007) ("The 1980 PSD regulations on 'modification' simply cannot be taken to track the Agency's regulatory definition under the NSPS.").

15. A modification for purposes of BACT applicability occurs when a person "intend[s] to make <u>modifications</u> or relocate an existing <u>installation</u> which will or might reasonably be expected to increase the amount or change the effect of, or the character of, air contaminants discharged." Utah Admin. Code R307-401-3(1)(a) (emphasis added). An "installation" is defined as "a discrete process with identifiable emissions which may be part of a larger industrial plant" and a "modification" is defined as "any planned change in a source which results in a potential increase of emission." *Id.* R307-100-2.

16. Accordingly, for there to be a "modification" triggering BACT applicability, there must be (1) a planned change in an emissions unit that (2) is reasonably expected to increase the amount or character of the emissions. The federal regulations contain similar requirements. *See* 40 C.F.R. § 52.21(j)(3) (BACT is required on units that experience a net emissions increase "as a

result of a physical change or change in the method of operation in the unit."); 71 Fed. Reg. 54,235, 54,240 (Sept. 14, 2006) ("We further note that our current rules do not require BACT or LAER at unchanged units …."); Letter from Robert B. Miller, Chief of the Permits and Grants Section of the EPA to Lloyd Eagan, Director of the Bureau of Air Management in Wisconsin (Feb. 8, 2000) ("[W]here an emissions unit has not undergone a physical or operational change, BACT does not apply.").

17. Here, UDAQ specifically found that Holly was not proposing any changes to its North Flare as part of the project. A shift of emissions from one flare to the other does not result in increased emissions, only *redistributed* emissions. In its NSPS regulations, the EPA discussed the analogous situation of two interconnected flares, stating "that interconnections between flares will not alter the cumulative amount of gas being flared (i.e., interconnecting two flares does not result in an emissions increase relative to the two single flares prior to interconnection)…. Considering this, we agree that the interconnection of two flares does not necessarily result in a modification of the flare and we have specifically excluded flare interconnections from the modification provisions…. [W]e agree that connections that do not increase the emissions from the flare should not trigger a modification…." 77 Fed. Reg. 56,422, 56,438 (Sept. 12, 2012). Petitioners' argument is not the law.

18. Moreover, to the extent Petitioners are arguing that the re-route of gases to the North Flare constitutes a change in operation, such a change occurred well before Holly initiated the current black wax crude project. This is evidenced by the language Petitioners themselves quote which reflects that "***currently*** all gases are routed to the north flare." [IR08200, Holly's first revised netting analysis (emphasis added).]

19. Without a change in operation or an increase in emissions for the North Flare, Petitioners' argument (that a "modification" of the North Flare was part of this project triggering a BACT analysis for the North Flare) is not supported by the record and should be rejected.

20. Even if Petitioners could demonstrate by substantial evidence that Holly proposed to modify the North Flare, conducting a BACT analysis on the North Flare would be superfluous because the North Flare is already subject to Subpart Ja, which itself constitutes BACT for Holly's flares. [*See* IR008516-17, Source Plan Review ("The only technically feasible control options for emissions of all pollutants from flares are: (1) equipment design specifications and good combustion work practices…; and (2) flare gas recovery systems…DAQ NSR recommends compliance with the requirements of 40 CFR 60 Subpart Ja as BACT."); *see also* IR009183, Response to Comments Memo ("NSPS Subpart Ja applies to the Woods Cross refinery generally and to both the North and South Flares.").] Petitioners' argument fails for this independent reason as well.

21. Finally, the record suggests that Petitioners' argument is ultimately moot because Holly is required by the recently-adopted $PM_{2.5}$ SIP to install flare gas recovery technology at the Refinery,[9] which Petitioners do not contest is the most stringent pollution control device currently available for flares.[10] [*See* IR008516, Source Plan Review (referring to flare gas recover as "the top control technology").] This requirement is binding on Holly regardless of whether it is explicitly stated in the Holly AO. As such, even if Petitioners' argument were

[9] The Utah $PM_{2.5}$ SIP requires "all major source petroleum refineries in or affecting a designated $PM_{2.5}$ non-attainment area within the State shall install and operate a flare gas recovery system." *See* Utah $PM_{2.5}$ SIP, Section IX, Part H, p. 43.

[10] Flare gas recovery is a system that captures gases that would otherwise be combusted in the flare and redirects those gases as fuel sources for other refinery operations. This reduces the emissions associated with flaring and is an economic use of excess fuel gas.

correct, there is no need for a remand regarding control technology on the North Flare because there are no additional pollution controls that could be required of Holly.

22. Accordingly, Petitioners have failed to demonstrate with substantial evidence in the record as a whole that UDAQ erred in not performing a BACT analysis on the North Flare and this claim should be dismissed with prejudice on the merits.

IV. Emissions From Holly's Flares Were Properly Calculated and Are Regulated in Accordance With the Unavoidable Breakdown Rule.

1. Petitioners next argue that the emissions from the flares have not been properly calculated and that UDAQ has not been appropriately regulating the flares in accordance with the Unavoidable Breakdown Rule ("UBR"). [Petitioners' Opening Brief at 16-22.] For the reasons stated below, this argument should be rejected.

A. Findings of Fact

2. In the Holly AO, UDAQ imposed a number of emission limits that included emissions from the flares, thereby limiting the routine emissions from the flares. [*See* IR009225, Holly AO ("Previous exclusions from the AO emission caps will be removed therefore the AO emission caps will be source wide caps."); IR009240, Holly AO ("PM_{10} Combustion Emissions Cap Sources…Flares."); IR009247, Holly AO ("PM_{10} emissions from all combustion sources shall not exceed 47.5 tons per rolling 12-month period or 0.13 tpd."); IR009245, Holly AO ("The emission of SO_2 into the atmosphere from all sources (excluding routine turnaround maintenance emissions) shall not exceed 110.3 tons per rolling 12-month period or 0.31 tons per day."); IR009245, Holly AO ("Emissions of SO_2 shall be limited as follows…All other sources 0.21 (tpd) 74.9 (tpy)."); IR009245, Holly AO ("For all the above listed emission points a CEM shall be used to determine compliance as outlined in II.B.3.e."); IR009247-48, Holly AO ("Total 24-hour PM_{10} emissions for the sources shall be calculated by adding the daily results of the above

PM_{10} emissions equations for natural gas, plant gas, and fuel oil combustion. Results shall be tabulated for every day, and records shall be kept."); IR008568, Source Plan Review (discussion of inclusion of flares into SO_2 and PM emission caps).]

3. In response to Petitioners' comments that the emission estimates for the flares were inaccurate because they did not include upset emissions, UDAQ explained that Holly's emissions were capped and any exceedance due to an upset would constitute an exceedance of the cap. [IR009187, Response to Comments Memo ("The commenter is correct that there are no limits on the flares. This is because the flares are in place as control device[s] for upset conditions. However Holly Refinery does have to comply with the requirements of 40 CFR 60 Subpart Ja. The Commenter is incorrect that 'upset' conditions are not addressed…'the refineries were allowed maximum never-to-be exceeded daily limits of PM_{10}, SO_2, NO_x based on the apparent variability. Emissions were capped at these maximum levels from the sources that could have their emissions metered by fuel metering/and calculations and from the other sources that would be stack tested every 1-3 years.'" (quoting Utah SIP § IX.A.6.c.(2) (1991)).]

4. The assumption in determining the PTE for the flares was that upset emissions would be zero because they are not part of normal refinery operation. [IR002852, July 2012 NOI ("PM_{10} and $PM_{2.5}$ emissions for the Woods cross refinery flares were assumed to be zero."); *see also* IR002857, July 2012 NOI ("Startup, shutdown, malfunction events were considered to be zero.").]

5. According to the evidence in the record, the PTE for the flares was calculated based on the purge gas flowing through the flare and planned startups and shutdowns, but did not include calculations for upset emissions. [IR003175-76, July 2012 NOI (recognizing emissions from the flares of SO_2 were estimated based on the assumption of 1700 scfh non-upset

throughput to the flare. This is the "purge gas" amount that must run to the flare to keep it from backdrafting); IR009196, Response to Comments ("startup and shutdown emissions were included in the analysis"); IR008560-8561, Source Plan Review ("to be conservative and representative of potential increases in emissions from SU and SD, UDAQ and Holly Refinery have agreed to include these emissions in Step 1 of the PSD and NNSR applicability analysis"); IR008522, Source Plan Review ("To ensure proper flare operation, Holly Refinery will install flow meters and gas combustion monitors on the flare gas line."); IR009211 ("The combustion of flue gas through the pilot flame is accounted for in the emission calculations.").]

6. According to the record, upset emissions from flares are unpredictable and uncontrollable because the flare is the safety valve for excess refinery gases generated in a period of malfunction. [IR008516, Source Plan Review ("The flare system at Holly Refinery provides for the safe disposal of hydrocarbon gases which are vented automatically from process units through pressure relief valves, control valves or are manually vented."); IR008561, Source Plan Review ("Section 3.6 of the July 2012 NOI lists upset conditions for both the North and South Flares. These upset conditions (malfunctions) do not include normal process flow combustion at the flares and there is no reason to assume that upset condition emissions will be any greater after the project is complete than before the project. Although these emissions have not been included in the netting analysis, they are noted below for reference.").]

7. The Holly AO does not contain exceptions for emissions due to malfunctions at the refinery; such excess emissions are subject to the UBR. [IR009196, Response to Comments Memo ("All limits of the permit apply at all times, which include periods of startup, shutdown and malfunction. The ITA contains no exclusion for these events."); IR009211 ("Flare

emissions during malfunction/upset conditions are regulated through R307-107 (ITA Condition II.3).”).]

8. In connection with its independent review of the Holly AO, the EPA raised no procedural or substantive comments regarding with UDAQ’s regulation of the Refinery Flares, including the UBR. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. Findings and Conclusions on Preservation

9. Petitioners have partially preserved this argument in accordance with Section 19-1-301.5(4). In their comments, Petitioners challenged the calculation of the PTE for the flares but said nothing about misapplication or noncompliance with the UBR. [*See* IR009056-9057, Sagady second comment letter.]

10. Petitioners could have reasonably ascertained this issue as the UBR was specifically referenced in the ITA. [*See* IR008453.]

11. The argument that the issue is preserved because UDAQ referenced the UBR in the Response to Comments Memo is misplaced. In the responses, UDAQ simply referenced the UBR in response to an entirely unrelated comment. [*See* IR009210-9211, Response to Comments Memo (referring to R307-107 in response to the comment that “nothing provided by the applicant’s final revised notice of intent justifies the claimed 98% control efficiency claimed for VOC, HAP and CO Destruction efficiency from Applicant’s open air flares”).]

12. UDAQ’s unrelated response does not save Petitioners from the requirement to raise their issues and arguments in a way that gives UDAQ notice of the substance of the issue.

13. To the extent Petitioners argue that the UBR has been violated by Holly or is not being enforced by UDAQ, the argument is beyond the scope of what was raised during the

comment period and is unpreserved pursuant to Utah Code Section 19-1-301.5(4). Accordingly, it should be dismissed.

C. <u>Findings and Conclusions on Burden of Proof</u>

14. The claims Petitioners assert (both preserved and unpreserved) regarding the PTE for the flares constitute mixed questions of law and fact. The questions of law involve the interpretation of the UBR and the regulations and guidance relating to how PTE for flares should be calculated—specifically, whether upset emissions must be included in such calculations. The application of those laws to the facts of this case and the calculations performed by Holly create a mixed question. Accordingly, a reasonableness standard of review shall apply.

15. Petitioners have failed to meet their burden of proof for this claim because they failed in their briefing to marshal all of the relevant evidence from the record.

16. Petitioners ignore multiple pieces of evidence that explain how Holly calculated the PTE for the flares in accordance with applicable guidance and the UBR.

17. Having failed to meet their burden of proof, Petitioners' claim should be dismissed on this basis.

D. <u>Conclusions of Law on the Merits</u>

18. Even if Petitioners had properly preserved all of their arguments regarding the PTE calculations of the flare emissions, and even had carried their burden of proof (or to the extent marshaling is not properly applied to this claim (being a question of law)), Petitioners' claims fail on the merits for the independent reasons discussed below.

i. <u>UBR Application</u>

19. Petitioners claim that the UBR requires emission limits on sources of malfunction emissions. Nothing in the plain language of the UBR requires numeric limits on malfunction

emissions. Nor is there any other authority in support of requiring such a limit as part of the UBR. To the extent that Petitioners' arguments constitute a request for rulemaking, they must be rejected in these permit review proceedings.[11]

20. In any event, such limits are impossible for malfunction emissions because such emissions are, by their very nature, unpredictable and uncontrollable. [*See* IR008516.]

21. The UBR simply sets forth criteria that must be met in the event of excess malfunction emissions to allow UDAQ the enforcement discretion to forgo monetary penalties. *See* Utah Admin. Code R307-107-1 to -3.

22. Stated differently, the UBR assumes that malfunction emissions are violations of an applicable approval order but affords to UDAQ enforcement discretion regarding the imposition of fines and penalties if a source is otherwise in compliance with the other requirements of the rule, including monitoring and good combustion practices. Utah Admin. Code R307-107-1 to -3 (requiring reporting of breakdown emissions and giving UDAQ enforcement discretion).

23. The limit in the Holly AO for malfunction emissions from the flare is zero tpy, which is accounted for in the overall SO_2 and PM emission caps. [*See* IR002857, July 2012 NOI ("Startup, shutdown, malfunction events were considered to be zero.").] Any violation of those limits due to an upset or malfunction subjects Holly to the enforcement discretion of UDAQ under the UBR.

[11] Petitioners may not advocate for a rulemaking change in a permit review adjudicative proceeding. [*See* In the Matter of: South Davis Sewer District, Order (*Remand to ALJ with Directions on Determining Whether There is a Basis to Grant Friends Standing to Intervene*), March 29, 2011, p. 11 ("a permitting proceeding is not the appropriate forum in which to advance adoption of new rules or challenge existing ones").] Such a request is only proper in a rulemaking proceeding under Utah Code Section 63G-3-101 *et seq.*

24. Any enforcement action by UDAQ, however, would be an independent proceeding separate from this adjudication and not a valid basis to remand the AO.

ii. <u>Flare PTE</u>

25. Petitioners challenge the PTE calculations of SO_2 and PM from the flares by arguing that the PTE inappropriately excluded upset and malfunction emissions. This argument fails for three reasons.

26. First, the law does not require the inclusion of upset emissions in a PTE calculation for flares because such upset emissions are not considered part of normal operation. *See Sierra Club v. Wyoming Dep't of Envtl. Quality*, 251 P.3d 310, 314 (Wyo. 2011) (holding that "hypothesizing the worst possible emissions from the worst possible operation is the wrong way to calculate potential to emit…PTE includes only emissions that occur during normal operations" thus "cold start" emissions and "malfunctions" were properly excluded from the plant's PTE); *see also Alabama Power Co. v. Costle*, 636 F.2d 323 (D.C. Cir. 1979); *United States v. Louisiana-Pacific Corp.*, 682 F. Supp. 1141, 1158 (D. Colo. 1988) ("[P]otential to emit does not refer to the maximum emissions that can be generated by a source hypothesizing the worst conceivable operation. Rather, the concept contemplates the maximum emissions that can be generated while operating the source as it is intended to be operated and as it is normally operated.").

27. Holly excluded malfunction emissions from its PTE calculations for the flares and, instead, calculated emissions based on the "average non-upset throughput to [the] flare" and appropriate emissions factors. [*See* IR 003175.]

28. Second, Petitioners' arguments challenging the PTE calculations for the flares also fail because federally enforceable permit conditions in the Holly AO limit malfunction emissions to zero tons per year from the flares.

29. PTE is defined as:

> 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*.

40 C.F.R. § 52.21(b)(4) (emphasis added); Utah Admin. Code R307-101-2 (same definition).

30. Holly assumed a limit of zero tpy for malfunction emissions, which it factored into its emissions totals for the SO_2 and PM_{10} emission caps in the Holly AO. [*See* IR002857, July 2012 NOI ("Startup, shutdown, malfunction events were considered to be zero.").] The SO_2 and PM_{10} emission caps, which include emissions from all combustion sources including flares, are federally enforceable operational limitations. [*See* IR009245, Holly AO (Section II.B.6.a, "The emission of SO_2 into the atmosphere from all sources (excluding routine turnaround maintenance sessions) shall not exceed 110.3 tons per rolling 12-month period or 0.31 tons per day."); *see also* IR009247, Holly AO (Section II.B.7.a "PM_{10} emissions from all combustion sources shall not exceed 47.5 tons per rolling 12-month period.").]

31. If Holly exceeds its emission caps due to an upset or malfunction, Holly will be in violation of its permit and subject to enforcement by UDAQ. [*See* IR009196, Response to Comments Memo ("All limits of the permit apply at all times, which include periods of startup, shutdown and malfunction.").] The UBR was put in place to deal with these very kinds of emissions.

32. Finally, the 240 tpy that Petitioners contend will be emitted every year as a result of upset emissions was a conservative estimate of what malfunctions could be—not what they actually are. [*See* IR003780.]

33. In fact, the emission calculation documentation in the record demonstrates that actual recorded historic malfunction emissions from the flare averaged only 34 tpy of SO_2 from both flares combined.[12] [*Id.*]

34. An addition of 34 tpy of SO_2 from the flares, even if such emissions were required for purposes of calculating PTE, would not have changed the conclusions of the netting analysis or made this project major for SO_2 given that the netting analysis demonstrated a 150.69 tpy overall emission reduction in SO_2. [*See* IR007574-7575.]

35. For all of these independent reasons, Petitioners' arguments regarding the PTE for the flares fail on the merits and should be dismissed.

iii. Reporting Requirements for the Flares

36. Petitioners' final argument relating to the flares is that the Holly AO lacks limits or enforceable reporting requirements for its flares. The substantial weight of record evidence shows that this contention is unfounded.

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[12] The prediction for malfunction emissions utilized three standard deviations of the average actual malfunction emissions to come up with the 120 ton per flare figure. [*See* IR003780] The actual total of SO_2 emitted from the North and South Flares *combined* was:

12.7 tons of SO_2 in 2009
25.5 tons of SO_2 in 2008
91.0 tons of SO_2 in 2007
19.7 tons of SO_2 in 2006
20.8 tons of SO_2 in 2005

Id. Accordingly, contrary to Petitioners' contention that 240 tons of SO_2 from the flares will be emitted on a yearly basis, the highest emissions in any one given year was only 91 tons and the lowest was 12.7 tpy.

37. Holly is required to perform continuous emissions monitoring ("CEM") of SO_2 emissions on all sources of SO_2, including flares. [IR009245, Holly AO, ("For all the above listed emission points a CEM shall be used to determine compliance as outlined in II.B.3.e.").]

38. Holly also is required to install "flow meters and gas combustion monitors" on the South Flare gas line "to monitor flare combustion efficiency" [IR009251, Holly AO]; and Holly is required to calculate PM emissions from all PM sources based on the amount of fuel combusted, the totals of which are then added into Holly's emission cap for PM and reported to the state. [IR009245-47, Holly AO.]

39. Finally, Subpart Ja—applicable to all Holly Flares—contains requirements for monitoring and recordkeeping. *See* 40 C.F.R. § 60.107a(a)(2) (requiring owners or operators of flares to install a continuous monitoring device to measure H2S in the fuel gases going to the flare); *see also* 40 C.F.R. § 60.108a (record keeping and reporting requirements).

40. These multiple record keeping and reporting requirements all apply to Holly's flares. Accordingly, Petitioners arguments regarding the flares all fail and should be dismissed with prejudice on the merits.

V. <u>The Record Demonstrates That Holly's Emissions Will Not Cause or Contribute to an Exceedance of the NAAQS.</u>

1. Petitioners next argue, at some length, that the Holly AO is insufficient to protect the short term National Ambient Air Quality Standards ("NAAQS") because it does not contain short term emission limits on all of Holly's emission sources. [Petitioners' Opening Brief at 22-34.] For the reasons stated below, this argument should be rejected.

A. <u>Findings of Fact</u>

2. UDAQ determined that its regulations did not require short term emission limits when there was no risk of exceedance of the NAAQS. [IR009186, Response to Comments

Memo ("Where it is clear that a source would not cause or contribute to a NAAQS violation, there is no free-standing regulation requiring short-term emissions limits.").]

3. Based on modeling information provided by Holly and reviewed by UDAQ's modeling staff, UDAQ determined there was no risk of any exceedance of the NAAQS from Holly's proposed project. [IR009190-91, Response to Comments Memo ("Holly Refinery's October 9, 2012 memo…was based on a request by UDAQ for Holly Refinery to submit an initial impact analysis based on the July 2012 NOI. This analysis showed no impact on the NAAQS CO, PM_{10}, NO_2, or SO_2."); IR009209, Response to Comments Memo ("This modeling analysis demonstrates that the predicted 1-hour SO_2, concentrations would be 50.4 $\mu g/m^3$, much lower than the NAAQS of 195 $\mu g/m^3$").]

4. Holly submitted its plans for modeling to UDAQ and those plans were approved by UDAQ's modeling staff. [IR00031-48, Modeling Protocol (prepared by MSI setting forth the plan for the modeling); IR001153-54, Letter from UDAQ to Holly (approving of the Modeling Protocol submitted for emissions impact modeling); IR003591-97, Tom Orth Memo (analyzing Holly's modeling and agreeing with results).]

5. Holly's emission modeling analysis contemplated the maximum emissions that Holly could generate on a lb/hr basis, thereby ensuring that any short-term spikes in emissions were accounted for in the modeling and would not cause exceedances. [IR002993-96, July 2012 NOI (explaining that emissions input for the modeling were measured in lb/hr); IR009209, Response to Comments Memo ("This modeling analysis demonstrates that the predicted 1-hour SO_2, concentrations would be 50.4 $\mu g/m^3$, much lower than the NAAQS of 195 $\mu g/m^3$").]

6. Malfunction emissions were not considered in the modeling analysis because federal and state guidance exclude malfunction emissions from the modeling protocols.

[IR009214, Response to Comments Memo (explaining the application of Appendix W and that malfunction emissions need not be included in modeling).]

7. The results of Holly's modeling efforts clearly demonstrated there would be no exceedance of the NAAQS, including short-term NAAQS. [IR003017, July 2012 NOI (Table 6-15) (demonstrating no exceedance of NAAQS).]

8. UDAQ determined that Holly's permit application was complete in an email sent on July 19, 2014. [*See* IR003767, email from Camron Harry to Eric Benson, dated July 19, 2012 ("I am notifying you that I have now determined Holly Refinery's NOI is administratively complete.").]

9. In connection with its independent review of the Holly AO, EPA submitted two separate comment letters to UDAQ but did not raise any comments regarding short-term NAAQS protection or otherwise exercise EPA's broad oversight or enforcement discretion over the final Holly AO for any real or perceived failure to protect the short-term NAAQS. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. <u>Findings and Conclusions on Preservation</u>

10. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR007861-7863, Petitioners' Second Comment Letter.]

C. <u>Findings and Conclusions on Burden of Proof</u>

11. Petitioners have not satisfied their burden of proof for this argument because they have failed to marshal all of the evidence that demonstrates the NAAQS will not be exceeded.

12. While Petitioners cite some of UDAQ's reasoning in the response to comments, they failed to marshal the actual modeling evidence showing that short term emissions were

calculated on a lb/hr basis. This evidence supports UDAQ's determination that the short-term NAAQS were being protected regardless of whether there are short term emission limits in the Holly AO.

13. Having failed to provide any contradictory evidence in the record, Petitioners cannot satisfy their burden of proof and their claims regarding the NAAQS fail.

D. Conclusions of Law on the Merits

14. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

i. Short-Term Emission Limits Are Not Required for Minor Modifications

15. Petitioners contend that short-term emission limits are always required to ensure protection of the short-term NAAQS. However, the one-hour NO_2 and SO_2 guidance documents Petitioners rely upon for this contention, [Petitioners' Opening Br. at 23-24], by their terms apply only to "major" modifications. *See* Memorandum from Anne Marie Wood, Air Quality Policy Division, to EPA Regional Directors, General Guidance for Implementing the 1-hour SO2 National Ambient Air Quality Standard in Prevention of Significant Deterioration Permits, at 6 (Aug. 23, 2010) ("We are issuing the following guidance to explain and clarify the procedures that may be followed by applicants for *Prevention of Significant Deterioration Permits*." (emphasis added)).

16. Moreover, the guidance expressly states that it does not bind state permitting authorities. *See* Memorandum from Stephen D. Page, Office of Air Quality Planning and Standards, to Regional Air Division Directors, at 2 (Aug. 23, 2010) ("This guidance does not bind state and local governments and permit applicants as a matter of law.").

17. According to UDEQ's analysis, Holly's proposed project fell into the "major" category for CO and GHG emissions, not for NO_x, SO_2, or PM. [IR009186, Response to Comments Memo.]

18. Whether a modification is "major" is determined on a pollutant-by-pollutant basis:

> Applicability of the major NSR program must be determined in advance of construction and is pollutant-specific. In cases involving existing sources, this requires a pollutant-by-pollutant determination of the emissions change, if any, that will result from the physical or operational change …. Once a modification is determined to be major, the PSD requirements apply only to those specific pollutants for which there would be a significant net emissions increase.

67 Fed. Reg. 80,186, 80,188 & n. 5 (Dec. 31, 2002). Because the project is not major for NO_x, SO_2, or PM, the Director, as a matter of law, was not required to adhere to federal guidance or impose short-term emissions limits for these pollutants.[13]

[13] Petitioners claim that the Utah Supreme Court has "held that BACT emission limits must protect short term NAAQS," citing *Sierra Club v. Air Quality Board*, 2009 UT 76, 226 P.3d 719. [Petitioners' Opening Br. at 23-27.] Petitioners incorrectly interpret the Court's holding. In that case, the court simply observed in dicta "the EPA has described the goals of BACT emission limitations in three-parts: (1) to achieve the lowest percent reduction, (2) to protect short-term ambient standards, and (3) to be enforceable as a practical matter." *Id.* at 734. The court never evaluated or held this was a correct interpretation of the relevant regulations. Moreover, the fact that a goal of BACT is to protect the short-term NAAQS does not mean that short-term limits must invariably be imposed as part of a BACT determination regardless of whether the project involves a major modification or poses any actual risk of an exceedance. EPA guidance indicates that while any BACT emissions limits are to be considered in determining whether the source will cause or contribute to a NAAQS violation, the BACT requirement is not an independent basis for imposing additional short-term emissions limits. *See* Memorandum from Anne Marie Wood, Acting Director Air Quality Policy Division to Regional Air Division Directors, at 7 (Aug. 23, 2010) ("Once a level of control is determined by the PSD applicant via the Best Available Control Technology (BACT) top-down process, the applicant must model the proposed source's emissions at the BACT emissions rate(s) to demonstrate that those emissions will not cause or contribute to a violation of any NAAQS or PSD increment.").

19. Petitioners' reliance on *In re: Mississippi Lime*, PSD Appeal No. 11-01 (Aug. 9, 2011) as an alternate basis for the requirement for imposition of short-term emission limits in the Holly AO is also misplaced. The decision is inapplicable for two reasons.

20. First, in *Mississippi Lime*, the permit applicant proposed to construct a facility that, unlike Holly's proposed expansion, would emit SO_2 and NO_x in quantities well above the significance thresholds so as to render the proposed facility subject to the PSD requirements for those pollutants. *See* IEPA, Project Summary at 4 (2010) (noting that "Mississippi Lime's proposed lime manufacturing plant is subject to PSD for emissions of SO_2, NO_x and CO because the potential emissions of the plant are more than 100 tons/year"), *available at* http://www.epa.state.il.us/public-notices/2010/mississippi-lime-pdr/project-summary.pdf; *see also Mississippi Lime*, slip op. at 1 (noting that Mississippi Lime sought to construct a new lime manufacturing plant).

21. Second, as the Director explained in his response to comments—which Petitioners do not contest—in *Mississippi Lime*, the permit was remanded to the state permitting authority "not simply because it failed to establish a limit, but because IEPA failed to provide 'a coherent, well-reasoned explanation of the decision' not to impose such a limit." [IR009186, Response to Comments Memo.]

22. By contrast, UDAQ has a well-reasoned explanation for why it did not impose the short-term limits requested by Petitioners—the modeling demonstrated there would be no exceedance of the short-term NAAQS. [IR003017, July 2012 NOI (Table 6-15) (demonstrating no exceedance of NAAQS).]

23. Accordingly, Petitioners' argument that short-term limits were required in the Holly AO fails on the merits and should be rejected.

ii. ***Holly's Modeling Constitutes Substantial Evidence That the NAAQS Will Be Protected***

24. Although UDAQ and Holly were not required to conduct modeling to demonstrate compliance with the NAAQS because Holly proposed only a minor modification for NO_x, SO_2, and PM, *see* 40 C.F.R. § 52.21(a)(2)(ii) ("The requirements of paragraphs (j) through (r) of this section apply to … the major modification of any existing major stationary source."),[14] in an effort to be thorough, Holly conducted the modeling anyway.

25. Before conducting any modeling, Meteorological Solutions Inc. ("MSI"), Holly's technical consultant, developed a modeling protocol setting forth the procedure that MSI would use to demonstrate that there were would be no exceedance of the NAAQS, including the short term NAAQS. This protocol was sent to the modeling staff at UDAQ, who approved of the protocol. [*See* IR00031-48, Modeling Protocol; IR001153; IR003593, Orth Modeling Memo ("The applicant had an approved modeling protocol for using AERMOD in PSD modeling protocols.").] MSI used the PTE calculations of all SO_2 and NO_x emission sources at the refinery for input into the model for the short-term modeling. [*See* IR000038 ("Maximum hourly potential to emit (PTE) emissions for existing and proposed sources will be input to the model."); IR000041 (same).]

26. PTE is defined as "the maximum capacity of a stationary source to emit a pollutant under its physical and operational design," taking into account enforceable emissions limits. 40 C.F.R. §§ 52.21(b)(4), 51.165(a)(1)(iii), 51.166(b)(4). Using the maximum capacity of each unit, MSI determined the total emissions the refinery could generate in one hour of operation measured in terms of lbs/hr. [*See* IR002993-96, July 2012 NOI.] Because PTE is

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[14] *See also* Utah Admin. Code R307-403-3 ("Every…major modification must be reviewed by the director to determine if a source will cause or contribute to a violation of the NAAQS.")

based on maximum capacity, this calculation represented the maximum emissions that could be produced at the refinery in a one-hour period. These values were used in the model and, once the background concentrations were combined with the PTE emissions, the modeling results showed that there would be no exceedance of the NAAQS, including the short-term NAAQS. [*See* IR003017, July 2012 NOI (Table 6-15); IR003596, Tom Orth Memo (Table 3); *see also* IR009209 ("This modeling analysis demonstrates that the predicted 1-hour SO2, concentrations would be 50.4 $\mu g/m^3$, much lower than the NAAQS of 195 $\mu g/m^3$…Accordingly there is no need to impose 1 or 24-hour SO_2 limits to protect the SO_2 NAAQS.").]

27. UDAQ's Orth Memorandum specifically found that "the proposed project's impacts, when combined with other industrial sources and ambient background, would comply with federal standards," including the one-hour NO_x and SO_2 NAAQS. In light of all of this record evidence, it was reasonable for UDAQ not to include any additional short-term emission limits in the Holly AO.

28. Petitioners do not dispute that the modeling results showed no exceedance of the NAAQS. Instead Petitioners challenge the modeling itself. These challenges do not undermine UDAQ's approval of and reliance on the modeling analysis, particularly given the deference that UDAQ is due with respect to technical issues such as air quality modeling: "[Q]uestions pertaining to the appropriate pollutant emissions rates and other inputs to air quality models raise scientific and technical concerns that generally are best left to the specialized expertise and reasoned judgment of the permitting authority." *In re: N. Mich. Univ. Ripley Heating Plant*, PSD Appeal No. 08-02, at 53 (EAB Feb. 18, 2009).

29. First, Petitioners argue that DAQ's Orth Memorandum is unreliable because it states that "[t]his report outlines the methodology used in the dispersion modeling analysis of

emissions of criteria and HAP proposed in the NOI and the subsequent modeling results. It makes no determination with respect to compliance with the NAAQS or UDAQ – Toxic Screening Levels for HAPs or compliance thereof." [IR003591-92, Tom Orth Memo.] However, that language simply indicates that the Orth Memorandum, by itself, did not constitute a determination as to compliance with the NAAQS, as illustrated by the fact that the memorandum made only a "recommendation" as to what further steps to take. [IR003597, Tom Orth Memo.] It does not mean that the Director may not consider the Orth Memorandum in determining compliance with the NAAQS and whether short-term limits are required, as the Director did in the Response to Comments Memorandum. [*See* IR009190-91, IR009209, Response to Comments Memo.]

30. Second, Petitioners assert that the modeling analysis cannot be used because the modeling must be "based on short term limits specified in the AO," and may not "merely estimate short term emission rates." [Petitioners' Opening Br. at 29-31.] However, the modeling done here was based on the *maximum* possible hourly emissions level based on the *maximum* capacity of each emissions unit as explained above, not an estimate of average short-term emission rates. [*See* IR002993-96, July 2012 NOI.] UDAQ acted within its discretion when it relied upon this modeling analysis.

31. Third, Petitioners argue that the modeling is inadequate to demonstrate compliance with the short-term NAAQS because the modeling does not include upset emissions from the flares. [Petitioners' Opening Br. at 31-33.] In support of this argument, Petitioners rely on 40 C.F.R. § 51, Appendix W, for the proposition that such emissions must be modeled. Petitioners are incorrect. As UDAQ specifically explained in rejecting Petitioner's argument:

> The commenter references 40 CFR 51 Appendix W, Section 8.1.2(a) as reference that malfunction/upset emissions should be included in the modeling analysis.

> However, the commenter neglected to include the following footnote from that same section: "Malfunctions which may result in excess emissions are not considered to be a normal operating condition. They generally should not be considered in determining allowable emissions. However, if the excess emissions are the result of poor maintenance, careless operation, or other preventable conditions, it may be necessary to consider them in determining source impact."

[IR009214, Response to Comments Memo (quoting 40 C.F.R. pt. 51, App'x W, § II.B.7.a.1.2(a) n.a).] UDAQ's explanation has not been rebutted by Petitioners.

32. UDAQ's interpretation of Appendix W is supported by a 2011 EPA guidance document providing additional clarification of the modeling requirements under Appendix W. *See* Memorandum from Tyler Fox, Leader Air Quality Modeling Group to Regional Air Division Directors, *Additional Clarification Regarding Application of Appendix W Modeling Guidance for the 1-hour NO2 National Ambient Air Quality Standard* (Mar. 1, 2011). There, EPA stated that modeling for compliance with the 1-hour NAAQS should only

> address emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations based on existing modeling guidelines, which provide sufficient discretion for reviewing authorities to not include intermittent emissions from emergency generators or startup/shutdown operations from compliance demonstrations for the 1-hour NO_2 standard under appropriate circumstances.

Id. at 2.[15]

33. In an attempt to fit within the language of Appendix W, Petitioners contend that Holly's malfunction emissions must be the result of poor maintenance, careless operation, or

[15] EPA further clarified that "we are concerned that assuming continuous operations for intermittent emissions would effectively impose an additional level of stringency beyond that intended by the level of the standard itself. As a result, we feel that it would be inappropriate to implement the 1-hour NO_2 standard in such a manner and recommend that compliance demonstrations for the 1-hour NO_2 NAAQS be based on emission scenarios that can logically be assumed to be relatively continuous or which occur frequently enough to contribute significantly to the annual distribution of daily maximum 1-hour concentrations." *Id* at 9. The same logic applies to the 1-hour SO_2 standard.

other preventable conditions, and therefore should have been included in the modeling analysis. Petitioners argue that because EPA's NSPS regulations relating to flares require a root cause analysis where a flare emits more than 500 pounds of SO_2 in a 24-hour period, emissions over that level are necessarily the result of poor maintenance, careless operation, or other preventable conditions. [Petitioners' Opening Br. at 33.] However, Petitioners cite no authority suggesting that the separate requirement to conduct a root cause analysis contained in the NSPS regulations somehow amounts to a determination that as a matter of law all upsets emitting more than 500 pounds of SO_2 are necessarily caused by preventable conditions for purposes of Appendix W. Petitioners cite no reason to conclude that, just because an investigation into the cause of all emission events over a certain size is required, all such emission events are necessarily caused by preventable conditions. Indeed, EPA recognizes that "the probability of successfully identifying a means to avoid future emissions from each root cause analysis performed is certainly less than 100 percent," 72 Fed. Reg. 27,178, 27,197 (May 14, 2007), indicating that far from all emissions that trigger a root cause analysis would be caused by preventable conditions. [Petitioners' Opening Br. at 32-33.] Petitioners' argument finds no support in the record. The record evidence is to the contrary, recognizing that

> if SO_2 modeling would have been required, then the malfunction emissions for SO_2 would not have been included because they do not represent normal, controlled operations. The 120 tpy of SO_2 from the flares due to malfunctions, as documented in the SPR Reviewer Note 5 (pp81-82), are based on Holly Refinery's historical data and do not predict future malfunctions. Nor do they result from poor maintenance or careless operation of the flare.

[IR009214-15, Response to Comments Memo.]

34. In light of UDAQ's technical conclusion, it was well within UDAQ's discretion to determine that the malfunction emissions should not be included in the modeling analysis.

iii. ***Holly Was Not Required to Model for $PM_{2.5}$***

35. Petitioners raise one final challenge to Holly's modeling. Specifically, Petitioners argue the modeling did not address the revision of the annual $PM_{2.5}$ NAAQS that took place in January 2013. This argument does not relate to any purported need for short-term emissions limits but rather is a separate attack on the modeling analysis.

36. For the same reasons as stated above, Holly's modification was not determined to be "major" for $PM_{2.5}$ and therefore Holly was not required to do any modeling for PM regardless of whether the NAAQS were amended. *See* 40 C.F.R. § 52.21(k)-(m); *see also* Utah Admin. Code R307-410-4.

37. Additionally, Holly's application fell within the grandfathering provision of the revised $PM_{2.5}$ NAAQS and so did not need to be updated to address the revised NAAQS. In finalizing the $PM_{2.5}$ NAAQS, EPA explained:

> To facilitate timely implementation of the PSD requirements resulting from the revised NAAQS, which would otherwise become applicable to all PSD permit applications upon the effective date of this final PM NAAQS rule, the EPA is finalizing a grandfathering provision for pending permit applications. This final rule incorporates revisions to the PSD regulations that provide for grandfathering of PSD permit applications that have been determined to be complete on or before December 14, 2012 or for which public notice of a draft permit or preliminary determination has been published as of the effective date of today's revised $PM_{2.5}$ NAAQS. Accordingly, for projects eligible under the grandfathering provision, sources must meet the requirements associated with the prior primary annual $PM_{2.5}$ NAAQS rather than the revised primary annual $PM_{2.5}$ NAAQS.

78 Fed. Reg. 3,086, 3,249 (Jan. 15, 2013).

38. Holly's application was determined to be administratively complete on July 19, 2012, long before the $PM_{2.5}$ NAAQS modeling requirements became effective. [*See* IR003767, email from Camron Harry to Eric Benson, dated July 19, 2012 ("I am notifying you that I have

now determined Holly Refinery's NOI is administratively complete.").] Therefore, no additional modeling was required.

39. In short, none of Petitioners' challenges to the modeling analysis itself succeed. Petitioners have failed to provide any evidence that would undermine the significant evidence in the record demonstrating there would not be an exceedance of the NAAQS. The modeling analysis demonstrated that Holly's project would not cause or contribute to any NAAQS violation, including the short-term NAAQS. EPA raised no comments about any of the foregoing issues in connection with its independent technical and legal review of the Holly AO. Therefore Petitioners' arguments fail on the merits and should be dismissed.

VI. Holly and the Director Properly Calculated PM Emissions from the FCC Units.

1. Petitioners next argue that the Director erred in failing to require Holly to count condensable emissions in determining compliance with the emission limits on the FCC Units. [Petitioners' Opening Brief at 34-36.] For the reasons stated below, this argument should be rejected.

A. Findings of Fact

2. UDAQ determined that condensable particle emissions would not be counted for compliance with FCC Unit limits, but would be included in inventory calculations. [IR009243, Holly AO ("The condensable particle emissions shall not be used for compliance demonstration, but shall be used for inventory purposes.").]

3. The Utah PM_{10} SIP, approved by EPA in 1994 (64 Fed. Reg. 68031 (July 8, 1994)), excluded condensable PM emissions from compliance demonstration with the PM_{10} emission caps in the SIP. [IR007826, PM_{10} SIP (attached as Exhibit L to Holly's Comment

Letter, ("The back half condensibles are required for inventory purposes and shall be determined using the method specified by the Executive Secretary.").]

4. UDAQ recognized that the language in the PM_{10} SIP controlled for purposes of drafting the Holly AO and excluded condensable emissions from all compliance limits for all PM_{10} SIP cap sources—including the FCC Unit 25. [IR008569, Source Plan Review ("Holly Refinery is listed in the PM_{10} SIP. That document established several emission limitations, one of which is a cap on PM_{10} emissions. At the time the SIP was written the cap on PM_{10} emissions was established using only the filterable PM_{10} emissions captured during stack testing. This limitation was then included in the AO (and subsequent revisions) issued to Holly Refinery. UDAQ has since agreed that all future particulate (PM_{10} and $PM_{2.5}$) limitations at all sources will also include the condensable fraction of particulate emissions (such as those found in the back half of a particulate sampling train or by reference test method 202). However, any limitation which is derived directly from the PM_{10} SIP cannot be altered without similarly altering the SIP. Therefore, those limitations on SIP-listed sources will continue to retain the original 'filterable emissions only' language, with the condensable emissions being used only for inventory purposes. Such is the case with Holly Refinery's PM_{10} cap emission limit. It is the intent of the Division to update these types of conditions once new SIP limitations are established in the $PM_{2.5}$ SIP.").]

5. UDAQ specifically determined that it would not set $PM_{2.5}$ limits on the new FCC Unit 25 because source wide limits of $PM_{2.5}$ were being set for Holly in the new $PM_{2.5}$ SIP that was being developed at the time UDAQ issued the Holly AO. [IR009183, Response to Comments Memo ("UDAQ has not set a condensable limit on the FCC Unit 25 in this permitting action because UDAQ is currently developing a SIP for $PM_{2.5}$. In this SIP, the contribution of

Holly Refinery to the valley airshed will be part of that evaluation and condensable limitations will be addressed."); IR009206, Response to Comments Memo ("$PM_{2.5}$ condensable emissions will be addressed in the $PM_{2.5}$ SIP.").]

6. In connection with its independent review of the Holly AO, the EPA submitted two separate comment letters to UDAQ but did not raise any comments regarding condensable emissions in determining compliance with the PM emission limits on the FCC Units or otherwise exercise EPA's broad oversight or enforcement discretion over the final Holly AO for any real or perceived failure regarding the same. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. <u>Findings and Conclusions on Preservation</u>

7. During the public comment period, Petitioners' comments were limited to challenging the PTE calculations for the new FCC Unit 25 and whether such calculations properly included condensable emissions. [*See* IR007857, WRA Second Comment Letter ("Holly's Permit Application Underestimates the Increase in PM Emissions from the new FCCU").]

8. Petitioners' challenge to the FCC Unit 25 emission limit and the exclusion of condensables was never raised in the comments notwithstanding the fact that this issue was reasonably ascertainable as the limit was included in the ITA. [*See* IR008469, ITA ("Condensable particle emissions shall not be used for compliance demonstration, but shall be used for inventory purposes").]

9. Petitioners also appear to argue in their Opening Brief that the BACT analysis for the FCC Unit 25 was invalid because it did not address condensables. Petitioners failed to raise this argument during the comment period and therefore it was not preserved.

10. Because, Petitioners failed to preserve both of these arguments as required by Utah Code Section 19-1-301.5(4), they should be dismissed.

C. <u>Findings and Conclusions on Burden of Proof</u>

11. Even if Petitioners had preserved their claims, Petitioners have failed to meet their burden of proof.

12. Whether condensable emissions are required to be included for purposes of compliance with emission limits is a question of law. Because this question of law is one with which UDAQ has been charged to administer, the ALJ must apply a clearly erroneous standard of review.

13. Petitioners do not acknowledge the requirements of the PM_{10} SIP. Although this is not an instance where marshaling is required, Petitioners' disregard of the PM_{10} SIP requirements is fatal to their claim that condensable emissions must be included for compliance with the FCC Unit's limits.

14. Petitioners have failed to point to any valid legal basis that undermines UDAQ's conclusion that the PM_{10} SIP does not require condensables to be included for compliance with the PM emission limits in the Holly AO.

D. <u>Conclusions of Law on the Merits</u>

15. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

16. The PM_{10} SIP imposes a cap on all PM_{10} sources at the Holly refinery including the new FCC Unit 25 but does not require condensable PM emissions to be calculated for compliance with that cap. [IR007826, PM_{10} SIP (attached as Exhibit L to Holly's Comment

Letter ("The back half condensibles are required for inventory purposes and shall be determined using the method specified by the Executive Secretary."); IR009243, Holly AO ("The condensable particle emissions shall not be used for compliance demonstration, but shall be used for inventory purposes."); IR008569, Source Plan Review (recognizing the PM_{10} SIP cap).]

17. At the time the Holly AO was being considered, the PM_{10} SIP was the only applicable PM SIP and any provisions in the Holly AO that conflicted with that SIP would have required a SIP amendment. [*See* IR008569, Source Plan Review ("any limitation which is derived directly from the PM_{10} SIP cannot be altered without similarly altering the SIP"); IR007826; Attachment L to Holly's second comment letter (excerpt from PM_{10} SIP stating "[t]he back half condensibles are required for inventory purposes…[t]he PM_{10} captured in the front half…shall be considered for compliance purposes").]

18. Although the recently adopted $PM_{2.5}$ SIP now requires condensable PM emissions to be calculated for compliance purposes, such a requirement was not in place prior to the issuance of the Holly AO. Utah law is clear that permits are only required to incorporate regulatory requirements that exist at the time of permit issuance. [*See, e.g.,* In the Matter of Petroleum Processing Plant Emery Refining, LLC, Order Returning Recommended Order Re Motions to Stay to Administrative Law Judge for Further Action, April 8, 2014 ("Emery Order") at 4 (limiting ALJ's review to the record before her and prohibiting consideration of a separate NOI that could be granted or denied sometime in the future.).]

19. Petitioners' references to Federal Register notices and guidance requiring PM condensable emissions for compliance purposes are misplaced because such requirements had not yet become binding on Holly. *See* 73 Fed. Reg. 28321, 28334 (May 16, 2008) (describing a

transition period for incorporation of condensable requirements into state implementation plans but only requiring such inclusion on major NSR projects).

20. If EPA believed UDAQ erred in its handling of condensables in the Holly AO, it had the jurisdiction and obligation to raise that issue in connection with its independent review of the Holly AO. EPA declined to do so. [*See* IR007840-7841, EPA comment letter (raising no issues about permit limits or the inclusion of condensables for compliance purposes).]

21. Petitioners also appear to argue that the BACT analysis for the new FCC Unit 25 is invalid because it does not account for condensable emissions. This argument fails not only because Petitioners did not preserve it during the comment period but also because any emission control technology that reduces filterable emissions will necessarily control for condensable emissions, both being post-control components of Holly's emission sources. Petitioners do not present any evidence that an alternative emission control technology would more effectively control condensable emissions beyond that which Holly is already required to install.

22. All of Petitioners' arguments regarding UDAQ's treatment of condensable PM emissions in the Holly AO fail on the merits and should be dismissed with prejudice.

VII. Holly Properly Calculated and Included in its Netting Analysis VOC Emissions Reductions From its Cooling Towers.

1. Petitioners next argue that Holly improperly claimed a 39.28 tpy VOC emission reduction from its cooling towers in the netting analysis it submitted to UDAQ. [Petitioners' Opening Brief at 36-41.] For the reasons set forth below, this argument should be rejected.

A. Findings of Fact

2. In 2009, Holly implemented a voluntary monitoring program in which it identified leaks in its cooling tower operation and fixed those leaks, thereby reducing emissions of VOCs from its cooling towers. [IR009203, Response to Comments Memo ("The reduction in

VOC emissions reported in Holly Refinery's NOI was a result of a voluntary monitoring program of the cooling towers that identified leaks from the towers that Holly Refinery fixed, thereby reducing its VOC emissions.").]

3. This monitoring program was made mandatory in the Holly AO on a going forward basis to ensure that the emission reductions Holly experienced by fixing its equipment remained at the reduced level. [IR007236, email from Mike Astin (environmental manager for Holly) to Camron Harry (permit writer for UDAQ), dated March 26, 2013 ("For the cooling towers, we monitor the cooling water return lines monthly for volatile organics using the Texas El Paso method. If any leaks are identified, we use screening methods to identify the leaking heat exchanger and repair it."); IR009230; Holly AO (requiring that "all cooling towers implement the Modified El Paso Method."); IR009244, Holly AO (requiring repair of any leaks detected "as soon as practicable, but no later than 45 days after identifying the leak…[v]erification of the repair shall be done through additional testing").]

4. Prior to implementing the leak detection and monitoring program, Holly utilized an "uncontrolled" emission factor to calculate emissions from its cooling towers. [IR009203, Response to Comments Memo ("Prior to using the Modified El Paso Method, the AP-42 VOC 'uncontrolled' emissions were the basis for refineries to report cooling tower VOC emissions.").]

5. After implementation of the monitoring program made mandatory by the Holly AO, Holly utilized a "controlled" emission factor to calculate emissions from its cooling towers. [IR008558, Source Plan Review ("VOC emissions from cooling towers 4 through 8 were previously estimated using the uncontrolled emission factor listed in AP-42 Section 5.1 of 6 lb/10^6 gal cooling water. In 2009, Holly Refinery began a voluntary daily monitoring program to detect VOC leaks into cooling water and to eliminate those leaks. In 2012, the monitoring

method was replaced with monthly monitoring using the Texas El Paso method. With continued use of regular monitoring, it is proposed to utilize the 'controlled' emission factor of 0.7 lb/10^6 gallons cooling water in AP-42 Section 5.1. This method will also be implemented for cooling towers 10 and 11.").]

6. It is the difference between the calculations with the "uncontrolled" and "controlled" emission factor that makes up the emission reduction that Holly included in its netting analysis. [*Id.*]

7. In connection with its independent review of the Holly AO, EPA submitted two separate comment letters to UDAQ. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.] While the Second Comment Letter requested more information regarding "the basis for the estimate of emissions reduced by converting from gas fired to electric motors for the compressors" [IR007840], the EPA raised no concerns about the netting issues raised by Petitioners here. Moreover, EPA's request for supplemental information on this issue was satisfied in UDAQ's response to comments.

B. <u>Findings and Conclusions on Preservation</u>

8. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR004214-4216, Mark Hall First Comment Letter.]

C. <u>Findings and Conclusions on Burden of Proof</u>

9. Petitioners' claim that Holly incorrectly included a VOC emission reduction from its cooling towers is a mixed question of law and fact. The correct interpretation of the regulations governing when a source can utilize an emission reduction in a netting analysis is a

question of law. However, the application of those regulations to the facts in this case presents a mixed question to which the ALJ must apply a reasonableness standard of review.

10. Because this is a mixed question of law and fact, Petitioners had the burden to marshal the relevant factual evidence that pertained to this claim.

11. Petitioners failed to meet this burden by failing to reference the requirements in the Holly AO that make monitoring and leak repairs for the cooling towers enforceable permit conditions. This evidence undermines Petitioners' argument that the cooling tower emission reductions are not enforceable or creditable.

12. Having failed to marshal this and other relevant evidence, Petitioners cannot satisfy their burden to prove that UDAQ acted unreasonably in accepting Holly's netting analysis.

D. <u>Conclusions of Law on the Merits</u>

13. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

14. Petitioners challenge the creditability and enforceability of the VOC emission reduction from the cooling towers because they claim it resulted from a voluntary monitoring program and therefore was unenforceable. *See* 40 C.F.R. § 52.21(b)(3) (requiring decreases in actual emissions be creditable and enforceable in order to be included in a netting analysis); [*see also* Petitioners' Opening Br. at 36-37]. Petitioners also claim that Holly was precluded from including the emission reduction in its netting analysis because the State of Utah arguably relied upon the emission reduction for demonstration of attainment of the $PM_{2.5}$ SIP. [*Id.*] Both arguments fail on the merits.

i. Creditability of the VOC emission reduction

15. The UDAQ reasonably found that Holly's VOC emission reduction to be creditable because it resulted from a physical change to refinery equipment and will be maintained through an enforceable permit condition in the Holly AO. [*See* IR009230; Holly AO (requiring that "all cooling towers implement the Modified El Paso Method."); IR009244, Holly AO (requiring repair of any leaks detected "as soon as practicable, but no later than 45 days after identifying the leak…[v]erification of the repair shall be done through additional testing").]

16. Under applicable law, an emission reduction is creditable if "(a) the old level of actual emissions exceeds the new level of actual emissions; (b) it is enforceable as a practical matter; [and] (c) it has approximately the same qualitative significance for public health and welfare as that attributed to the increase from the particular change." 40 C.F.R. § 52.21(vi)(a)-(c). The VOC emission reduction Holly claimed satisfies each of these three requirements.

17. First, Holly's VOC cooling tower emissions were higher prior to Holly's physical repairs to the cooling towers. [*See* IR009203, Response to Comments Memo ("The reduction in VOC emissions reported in Holly Refinery's NOI was a result of a voluntary monitoring program of the cooling towers that identified leaks from the towers ***that Holly Refinery fixed***, thereby reducing its VOC emissions.") (emphasis added); *see also* IR007236, email from Mike Astin (environmental manager for Holly) to Camron Harry (permit writer for UDAQ), dated March 26, 2013 ("For the cooling towers, we monitor the cooling water return lines monthly for volatile organics using the Texas El Paso method. If any leaks are identified, we use screening methods to identify the leaking heat exchanger and repair it.").]

18. Petitioners argue that these emissions are merely estimated from emission factors and do not represent actual emission reductions, and therefore are not credible. Contrary to

Petitioners' arguments, however, the applicable regulations contemplate the calculation of emissions through emission factors. *See* 40 C.F.R. § 52.21(b)(21)(i) (providing that emissions "shall be calculated"). The EPA-drafted preamble to the relevant regulation explains that emission factors may be used in calculating "actual emissions." 67 Fed. Reg. 80,186, 80,195 (Dec. 31, 2002) ("When you calculate the baseline actual emissions for an existing emissions unit…you may select any consecutive 24 months of source operation within the past 10 years. Using the relevant source records for that 24-month period, including such information as the utilization rate of the equipment, fuels and raw materials used in the operation of the equipment, *and applicable emission factors*, you must be able to calculate an average annual emissions rate, in tpy, for each pollutant emitted by the emissions unit that is modified, or is affected by the modification." (emphasis added)).

19. I find that a "calculation" of emissions from cooling towers would necessarily be an estimate based on operating hours, production rates, and types of materials. Holly's VOC calculation was based on these same factors. [*See* IR008558, Source Plan Review (noting that Holly used the 'controlled' emission factor of 0.7 lb/10^6 gallons cooling water as described in AP-42 Section 5.1)]; *See also* AP-42 5.1 Petroleum Refining emission calculation descriptions, available at http://www.epa.gov/ttnchie1/ap42/ch05/final/c05s01.pdf (including in the emission calculation for cooling tower emissions the cooling water rate and refinery feed rate).]

20. Prior to Holly's voluntary monitoring program and physical changes to its cooling towers to reduce and eliminate VOC leaks, Holly utilized the "uncontrolled" AP-42 emission factor to calculate the VOC emissions from the cooling towers. [*See* IR009203, Response to Comments Memo ("Prior to using the Modified El Paso Method, the AP-42 VOC 'uncontrolled' emissions were the basis for refineries to report cooling tower VOC emissions.").]

21. After the units were repaired, Holly used the AP-42 "controlled" emission factor which resulted in a calculated emission reduction. [IR008558, Source Plan Review ("VOC emissions from cooling towers 4 through 8 were previously estimated using the uncontrolled emission factor listed in AP-42 Section 5.1 of 6 lb/10^6 gal cooling water. In 2009, Holly Refinery began a voluntary daily monitoring program to detect VOC leaks into cooling water and to eliminate those leaks. In 2012, the monitoring method was replaced with monthly monitoring using the Texas El Paso method. With continued use of regular monitoring, it is proposed to utilize the 'controlled' emission factor of 0.7 lb/10^6 gallons cooling water in AP-42 Section 5.1. This method will also be implemented for cooling towers 10 and 11.").]

22. Where actual emissions are not easily measured—such as VOC emissions leaking from cooling towers—calculation estimates can provide reliable information to satisfy 40 C.F.R. § 52.21(vi)(a)-(c). *See* 74 Fed. Reg. 55,670 55,679 (Oct. 28, 2009) (noting that certain historical inventory data based on the AP-42 factors and "the AP–42 emission factors are the best available data by which to estimate cooling tower emissions").

23. Second, the VOC emission reduction from the cooling towers is enforceable because it was the result of a physical change to the refinery equipment, which must be monitored and maintained under the terms of the HollyAO. [IR009224, Holly AO (condition II.B.4.a *Id.*; *see also* 40 C.F.R. § 52.21(b)(3)(vi)(b) (reduction is creditable if it is enforceable "at and after the time that actual construction on the particular change begins").]

24. Holly is required, pursuant to the terms of the Holly AO, to continue monitoring for leaks from the cooling towers and must fix any discovered leaks in order to maintain the lower VOC emission levels from the cooling towers. [*See* IR009230; Holly AO (requiring that "all cooling towers implement the Modified El Paso Method."); IR009244, Holly AO (requiring

repair of any leaks detected "as soon as practicable, but no later than 45 days after identifying the leak…[v]erification of the repair shall be done through additional testing").] Any failure to do so subjects Holly to enforcement action by UDAQ—making these requirements, and the associated emission reduction, enforceable.

25. Third, Holly has satisfied the qualitative significance requirement that Petitioners claim has been violated. EPA's NSR Manual states that "[c]urrent EPA policy ***is to assume that an emissions decrease will have approximately the same qualitative significance*** for public health and welfare as that attributed to an increase" unless the state has reason to believe otherwise. [Petitioners' Reply Brief at 34 (emphasis added) (quoting EPA NSR Workshop Manual, 1990, A-38-39).]

26. Holly's modeling demonstrates that there will be no violation of any NAAQS or PSD increments and overall, VOC emissions will be reduced. [*See* IR002980-3021, Holly's NOI, section 6.0; *see also* IR003591-3597, Tom Orth Memorandum; IR007575, UDAQ information sheet (indicating a -17.02 overall VOC emission decrease from the project).]

27. Consequently, UDAQ had no reason to believe that the qualitative presumption would not be met in this case, and Petitioners have not identified any contrary evidence. *See, e.g., In re Inter-Power of N.Y., Inc.*, No. 92-8, 5 E.A.D. 130, 153-54 (EAB Mar. 16, 2014) (rejecting the argument that EPA should have conducted a health assessment to demonstrate that the qualitative significance of emissions was approximately the same, and holding that the burden was on the petitioner to "document[] that [the source's] fuel change has increased its heavy metals emissions or created any health concerns. Accordingly, [petitioner] has not pointed to any record evidence" that indicates that this provision was not satisfied). Holly's inclusion of the VOC emission reductions from the cooling towers therefore was proper.

28. Petitioners also argue that the 52.95 tpy VOC emission baseline referenced in the July 2012 NOI is inflated and, therefore, the emission reduction of 39.28 tons of VOC is inflated. Petitioners overlook that the emission spreadsheet they cite indicates that if 52.95 tpy was the VOC baseline, the associated emission reduction would have been 48.08 tons—not 39.28. [IR003059, July 2012 NOI.] Holly had two different baseline calculations for VOC emissions because at different points in the application process it used different baseline years for its netting calculations. [*Compare* IR003059, July 2012 NOI, *with* IR007300, Revised NOI.] In its Revised NOI, Holly used 44.15 tpy as a baseline for VOC emissions, which resulted in the reduction of 39.28 tons of VOC. [IR007300.] Had it used the higher baseline, the emission reduction would have also been higher, which means Holly's netted VOC reduction is conservatively low. All of these baseline totals are derived from emission inventory reports that Holly submitted to DAQ, and they were all calculated with AP-42 emission factors. [IR003059, July 2012 NOI (citing "VOC Baseline 2008-2009" inventory years; IR007300, Revised NOI (citing "VOC baseline 2008-2009" inventory years").]

ii. <u>Holly Was Not Required to Adjust Downward its Baseline VOC Emission Calculations</u>

29. Petitioners also challenge the VOC emission reduction on the basis that Holly should have adjusted downward its baseline VOC emission calculations because the El Paso monitoring method is required by a Maximum Achievable Control Technology ("MACT") requirement under a National Emission Standard for Hazardous Air Pollutants and has been relied upon by UDAQ as a Reasonably Available Control Technology ("RACT") requirement in the $PM_{2.5}$ SIP to demonstrate attainment.

30. Any requirements that are otherwise required to be imposed as MACT standards under section 112 of the Clean Air Act that result in emission reductions can still be used for

netting purposes unless the state has specifically relied upon the emission reduction in demonstrating attainment of a NAAQS in a SIP. *See* 40 CFR § 52.21(b)(48)(ii)(b) & (c) ("[I]f an emission limitation is part of a maximum achievable control technology standard…, the baseline actual emissions need only be adjusted if the State has taken credit for such emissions reductions in an attainment demonstration or maintenance plan."); *see also* Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, to Bob Hannesschlager, Acting Director, Multimedia Planning and Permitting Division, Region VI (Nov. 12, 1997) ("Since the MACT program is not designed to limit criteria or other pollutants regulated by NSR programs of parts C and D of title I of the Act, EPA's policy is that actual emissions reductions of hazardous or other air pollutants that result from complying with MACT regulations codified at 40 CFR part 63 may be considered 'surplus' for purposes of NSR netting and are not precluded from NSR netting as long as the reductions are otherwise creditable under NSR.").

31. Petitioners argue that UDAQ relied upon the MACT standard of the Texas El Paso Method in the $PM_{2.5}$ SIP to demonstrate compliance. However, that assertion is misplaced because the $PM_{2.5}$ SIP had not been formally adopted at the time UDAQ issued the Holly AO. Petitioners overlook that the regulation upon which they rely for this assertion provides only that emissions must be adjusted downward where such emissions "would have exceeded an emissions limitation with which the major stationary source must ***currently comply***," with "currently comply" referring to the time of permit issuance. 40 C.F.R. § 52.21(b)(48)(ii)(c) (emphasis added).

32. That Holly may have been on notice that the El Paso Method might subsequently be required as a RACT standard is irrelevant in this analysis and Petitioners cite no authority holding otherwise.

33. Accordingly, UDAQ acted reasonably in accepting Holly's netting analysis with the VOC emission reductions included therein. Petitioners' claims to the contrary should be dismissed with prejudice on the merits.

VIII. The FCC Unit 25's PTE Was Accurate and its Emission Limits Are Adequate.

1. Petitioners challenge the accuracy of Holly's PTE calculations for the FCC Unit 25, arguing that the Holly AO is insufficient because it does not impose specific PM emission limits on the unit. [Petitioners' Opening Brief at 41-46.] For the reasons stated below, this argument should be rejected.

A. Findings of Fact

2. The emissions from the FCC Unit 25 are limited by the maximum capacity of the unit of 8500 barrels per day ("bpd"). [IR002811, July 2012 NOI ("A Fluid Catalytic Cracking Unit (FCCU) with a capacity of processing 8500 barrels per day will be constructed along with a 45 MMBtu/hr feed heater. Emissions from the FCCU will be controlled by a wet gas scrubber."); IR002820, July 2012 NOI ("A Fluid Catalytic Cracking Unit (FCCU) from an idled New Mexico refinery will be relocated to the Woods Cross Refinery. This unit is capable of processing 8500 barrels of gas oil per day and is similar in size to the existing FCCU."); IR003078, July 2012 NOI ("FCC Capacity Limit based on Equipment Specifications 8500 bbls/day."); IR003160, July 2012 NOI ("New FCCU…Capacity…8500 bbpd."); IR008491, Source Plan Review ("To process the additional bottom cut from the new crude unit (Unit 24), an additional Fluid Catalytic Cracking Unit ('FCCU Unit 25') with a capacity of processing 8500 barrels per day will be constructed."); IR009227, Holly AO ("Unit 4: Fluid Catalytic Cracking Unit (FCCU) 8,880 bpd annual average capacity"); IR009229, Holly AO ("Unit 25: FCCU 8,500

bpd annual average capacity"); IR009192, Response to Comments Memo (explanation for why the FCC Unit 25 emissions are limited by the operational capacity of the unit).]

3. The information relating to the capacity of the FCC Unit 25 contained in Holly's NOI was certified as accurate by the Plant Manager, Mike Wright. [IR007836, certification signature page (Mike Wright certified that the information provided for the approval order was accurate and complete.).]

4. UDAQ determined that a coke burn rate of 6200 lb/hr was reasonable based on the data Holly provided. [IR009219, Response to Comments Memo ("Based on UDAQ's technical expertise and experience," UDAQ determined that "the 6200 lb/hr value is a fair and reasonable estimate of the quantity of coke burn in FCC Unit 25."); IR008052, November 7, 2013 letter (Holly's emission calculations for PTE of the FCC Unit 25).]

5. UDAQ also determined that Holly was subject to a PM emission cap that included the FCC Unit 25, and that any exceedance of the PTE calculated for the unit would subject Holly to enforcement for exceedance of the emission cap. [IR009208, Response to Comments Memo ("regardless of maximum throughput rates, the emissions are limited at the values established in ITA"); IR009219, Response to Comments Memo (explanation for why the PTE for the FCC Unit #25 was correct because the unit is subject to the PM emission cap and any exceedance of that cap would be a violation).]

6. In connection with its independent review of the Holly AO, the EPA submitted two separate comment letters to UDAQ but did not raise any comments regarding UDAQ's PTE calculations for any FCCU or otherwise exercise EPA's broad oversight or enforcement discretion over the final Holly AO for any real or perceived failure regarding the same. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. Findings and Conclusions on Preservation

7. In their public comments, Petitioners only challenged the accuracy of the PTE calculations for Holly's FCC Unit 25. Specifically, Petitioners argued there was insufficient evidence to support the 6200 lbs/hr coke burn rate calculation, and that as a result, additional limits were needed for the unit. [*See* IR008598-8599, Mark Hall Second Comment Letter.]

8. In response to this comment, UDAQ requested that Holly provide additional documentation and calculations to support the 6200 lb/hr coke burn rate. [IR008021.]

9. Holly responded by providing the calculations it used to determine the coke burn rate. [IR8022-8023; IR008052.]

10. Petitioners argued differently in their Motion for Stay, that the 6200 lb/hr figure would not effectively limit PM emissions because emissions would increase if more coke was burned.

11. In Petitioners' briefing on the merits, Petitioners challenge for the first time the accuracy of the maximum capacity of the FCC Unit 25, claiming that there was no evidence in the record to support the 8500 bpd figure.

12. This maximum capacity was expressly stated in multiple places in the NOI and ITA. Any concern with the accuracy of the number was therefore reasonably ascertainable during the public comment period. [IR002811, July 2012 NOI ("A Fluid Catalytic Cracking Unit (FCCU) with a capacity of processing 8500 barrels per day"); IR008491, Source Plan Review ("To process the additional bottom cut from the new crude unit (Unit 24), an additional Fluid Catalytic Cracking Unit ('FCCU Unit 25') with a capacity of processing 8500 barrels per day will be constructed.").]

13. Accordingly, the only issue that has been adequately preserved by Petitioners is their challenge to the 6200 lb/hr coke burn rate and their assertion that additional limits are required for the FCC Unit 25. Their most recent challenge to the accuracy of the 8500 bpd capacity limit on the FCC Unit 25 has not been preserved in accordance with Utah Code Section 19-1-301.5(4) and should be dismissed for the reasons described above.

C. <u>Findings and Conclusion on Burden of Proof</u>

14. Even if Petitioners had preserved their challenge to the accuracy of the 8500 bpd capacity limit on the FCC Unit 25, Petitioners have failed to satisfy their burden of proof.

15. Whether the PTE emission calculations for the FCC Unit 25 are supported in the record is a highly technical factual issue that requires this tribunal to give deference to UDAQ in its review of the issue. Petitioners must demonstrate that UDAQ lacked substantial evidence in the record to support its decision that the PTE was calculated correctly.

16. Accordingly, Petitioners carry a heavy burden of proof to marshal the evidence relating to this issue to allow this tribunal to adequately evaluate and weigh the evidence relating to the claims at issue.

17. Petitioners have failed to meet their burden here by ignoring the relevant evidence in Holly's NOI explaining how Holly calculated the emissions that would be generated by the FCC Unit 25. Petitioners also provide no evidence contradicting Holly's certification that all of the numbers contained in the NOI were accurate.

18. DAQ invited commenters, including Petitioners here, during the public comment period to provide technical evidence of alternate coke burn rates that commenters argued would be more appropriate. Neither Petitioners nor other commenters responded to DAQ's request. [IR009219, Response to Comments Memo ("The commenter makes general reference to the

'UOP yield estimates' and 'other more generic publications,' but provided no documents or primary data to support or detail to which estimate, if any, was used to derive the suggested range of coke burn estimates. Based on UDAQ's technical experience and expertise, the 6200 lb/hr value is a fair and reasonable estimate of the quantity of coke burn in FCC Unit 25. The commenter has not provided any specific technical information to UDAQ that would suggest a higher value is more appropriate.")

19. Failing to carry their burden of proof on this highly technical issue, Petitioners' claims fail.

D. Conclusions of Law on the Merits

20. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

21. The question of whether Holly and UDAQ correctly calculated the potential emissions for the FCC Unit 25 is a highly technical issue that requires this tribunal and any reviewing court to give deference to the agency because the agency, in its technical expertise, is in the best position to evaluate these issues.

22. Holly based its conclusion that the new FCC Unit 25 would burn coke at a rate of 6200 lb/hr on empirical data it obtained from the FCC Unit 4 that was in current operation at the refinery. [IR008052.] UDAQ requested and reviewed Holly's calculation information and was satisfied that it justified the coke burn rate. [IR009219, Response to Comments Memo ("Based on UDAQ's technical expertise and experience," UDAQ determined that "the 6200 lb/hr value is a fair and reasonable estimate of the quantity of coke burn in FCC Unit 25."); IR008052, November 7, 2013 letter (Holly's emission calculations for PTE of the FCC Unit 25).]

23. The 6200 lb/hr figure was a conservative estimate. The original calculations showed a rate of 5653.964 lb/hr, and the FCC Unit 4 is a larger unit than the new FCC Unit 25. [IR008052; *see also* Holly AO at IR009227-009229 (The FCC Unit 4 processes 8,880 barrels per day ("bpd") while the proposed FCC Unit 25 can only process 8,500 bpd).]

24. Petitioners are incorrect in their assumption that because the rate is not included as a limit in the Holly AO that Holly will exceed the PM limit of 0.30lb/1000 lbs of coke burned. The FCC Unit 25 emissions will not exceed the PTE because there is a finite capacity limit on the FCC Unit 25 that acts as a physical limitation on the amount of PM that can be emitted.

25. Even were this not the case, the refinery is limited to an overall PM_{10} emission cap of 47.5 tpy and 0.13 tpd for combustion sources. [*See* IR009219, Response to Comments Memo.] "If these limitations are not met, the refinery will be out of compliance until it remedies the problem with additional control equipment or redesign of the system until it meets these limits." [*Id.*]

26. Petitioners have failed to point to any evidence in the record that undermines the reasonableness of UDAQ's reliance on the calculations Holly provided.

27. Petitioners' only challenge to the PM cap that limits emissions from the FCC Unit 25 is the contention that EPA generally disfavors source wide cap limits. This assertion is without merit.

28. In the PM_{10} SIP that EPA approved, UDAQ specifically noted that due to the significant variability of emission sources at a refinery, emission caps are appropriate. [*See* IR07768, PM_{10} SIP language attached to Holly Comment letter as Exhibit I, (because "there was significant variability from day to day and from year to year…the refineries were allowed maximum never-to-be exceeded daily limits of PM_{10}, SO_2, NO_x based on the apparent

variability").] This is true even though EPA generally disfavors source wide caps. In this case, EPA recognized an exception to the general approach in approving such caps in the PM_{10} SIP.

29. In light of the highly technical nature of this issue, UDAQ must be afforded the greatest degree of deference in its conclusions regarding the evidence in the record supporting the FCC Unit 25's PTE calculations. *See* Utah Code § 19-1-301.5(14). Lacking any evidence that would undermine UDAQ's conclusions,[16] Petitioners' challenge to the PM emission calculations fail.

IX. <u>Holly is in Compliance with Title V.</u>

1. Petitioners next argue that the Holly AO may not be issued if Holly is not in compliance with Title V of the Clean Air Act. Petitioners make three distinct arguments related to this claim: (1) Holly's Title V application is not complete because the AO and Source Plan review lack certain Title V requirements; (2) Holly has not adequately supplemented its Title V application; and (3) not all applicable parts of Subpart Ja are included in the Holly AO in violation of Title V regulations. [Petitioners' Opening Brief at 46-51.] For the reasons stated below, these arguments should be rejected.

[16] For the first time in their Reply Brief, Petitioners appear to suggest that that the Holly AO is purportedly deficient because the Director's use of PM_{10} modeling as a surrogate for $PM_{2.5}$ modeling was invalid. Specifically, Petitioners assert that the FCC Unit 25 must contain a separate $PM_{2.5}$ limit to ensure its emissions will not contribute to a NAAQS violation. [Petitioners' Reply Brief at 42.] Even were it permissible to raise a new argument in a Reply Brief, Petitioners never raised any concerns about this alleged surrogate policy in their comment letters; thus the issue is not preserved. Moreover, Holly is now subject to a source wide emission cap in the $PM_{2.5}$ SIP that will limit its $PM_{2.5}$ emissions. [Utah $PM_{2.5}$ SIP, January 8, 2014, p. 21 (setting a source wide $PM_{2.5}$ limit of 47.6 tons per rolling 12-month period).] UDAQ was reasonable in determining that its regulation of Holly's $PM_{2.5}$ sources in the $PM_{2.5}$ SIP would limit Holly's emissions and that a separate limit in the Holly AO was unnecessary.

A. Findings of Fact

2. Holly's predecessor-in-interest received a letter from UDAQ in 1995 that stated Holly's operating permit application was administratively complete, which provides Holly with an application shield from Title V enforcement action. [IR007725, Letter from UDAQ to the Phillips 66 Company, Holly's predecessor in interest (stating that "the Operating Permit application for Phillips Refinery (application #47) has been reviewed and determined to be complete in accordance with Utah Administrative Code (UAC) R307-15-5(1)(b)," that "the above site is shielded from enforcement action for operating without a permit until a permit is issued," and that additional information would be requested if needed).]

3. UDAQ recognized that Holly had a Title V application shield letter in its response to Petitioners' comments regarding Title V. [IR009175, Response to Comments Memo (Holly submitted at UDAQ's request "a July 29, 1995 letter from UDAQ indicating that a complete Title V Permit application had been received [and it] has been included in the record."); IR009184, Response to Comments Memo ("In any event…Holly Refinery is operating under an application shield…[t]he Title V application is currently pending.").]

4. UDAQ also recognized that Petitioners pointed to no statute or regulation that would preclude Holly from receiving an approval order without first obtaining a final Title V permit. [IR009184, Response to Comments Memo ("UDAQ does agree that Holly Refinery is a major source and is thus bound by R307-415, but the commenter has not referenced regulations that prevent a major source without a Title V permit from obtaining an AO, nor is UDAQ aware of such a regulation.").]

5. UDAQ determined that Holly was still subject to all applicable federal regulations regardless of whether Holly was in receipt of a final Title V permit. [IR008571, Source Plan

Review ("Title V of the Clean Air Act of 1990 applies to Holly Refinery as a major source. The absence of a Title V permit does not negate the requirements of Holly Refinery, it is still subject to all AO conditions and federal regulations that would be included in the Title V permit.").]

6. In connection with its independent review of the Holly AO, the EPA submitted two separate comment letters to UDAQ but did not raise any comments regarding non-compliance with Title V or otherwise exercise EPA's broad oversight or enforcement discretion over the final Holly AO for any real or perceived failure regarding the same. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.]

B. <u>Findings and Conclusions on Preservation</u>

7. Petitioners did raise a Title V issue during the comment period that focused on the allegation that Holly was illegally operating without a Title V permit. [*See* IR007860-7861, Petitioners' Second Comment Letter ("Holly Refinery is illegally operating and will continue to do so until it receives a valid Title V permit.").]

8. However, this is a much different claim than what Petitioners advocate in their briefing on the merits—that somehow Holly's approval order and supporting documentation turned into a Title V application that is insufficient, leaving Holly in violation of Title V of the Clean Air Act.

9. This new argument was also not raised by Petitioners in their RAA even though the source plan review signature page they rely upon in the briefing was available for Petitioners to review. [*See* IR007834-7835 (attached to Holly's Second Comment Letter).]

10. The relief requested in the RAA was simply that the Director must issue a Title V permit for Holly prior to authorizing the expansion project—not that Holly's Title V application was incomplete or insufficient. [*See* RAA at 38.]

11. To the extent Petitioners' arguments extend beyond their initial contention that Holly is allegedly illegally operating without a valid Title V permit, such arguments have not been adequately preserved and should be dismissed on this basis.

C. Findings and Conclusions on Burden of Proof

12. The question of whether Holly is in compliance with Title V and whether UDAQ properly interpreted the Title V statute and rules to allow UDAQ to issue the Holly AO presents a mixed question of law and fact. The questions regarding interpretation of the Title V rules and regulations are questions of law. The application of that law to this specific case presents a mixed question of fact and law that must be reviewed under a reasonableness standard.

13. Petitioners are required to marshal all of the relevant evidence on this issue to allow this tribunal to adequately evaluate whether there is substantial evidence in the record to support UDAQ's decision to issue the Holly AO.

14. Petitioners have failed to satisfy their burden of proof for this claim. In fact, Petitioners' fail to reference the only piece of record evidence related to Title V compliance: UDAQ's letter to Holly's predecessor expressly stating that the refinery ***is in compliance*** with Title V. [*See* IR007725.]

15. Petitioners also fail to identify any final determination on Holly's pending Title V application that would restrict UDAQ's ability to issue Holly its approval order.

16. Lacking this evidence, Petitioners cannot satisfy their burden of proof and their claims regarding Title V must fail.

D. Conclusions of Law on the Merits

17. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

18. Petitioners argue that before the Director may issue Holly an approval order, he must purportedly determine whether Holly is in compliance with Title V. *See* Utah Admin. Code R307-401-8(1)(b)(x) (an approval order may only be issued if "the proposed installation will meet the applicable requirements of…all other provisions of R307"); [*see also* Petitioners' Opening Br. at 47].

19. Petitioners assert that Holly is in violation of Title V because its Title V application is not complete and it has violated its duty to supplement its application "as necessary to address any requirements that become applicable to the source." Utah Admin. Code R307-415-5b. In support of this assertion, Petitioners rely on the fact that, as part of Holly's approval order application, Holly signed an optional signature page allowing the information in the Source Plan Review to be included in Holly's pending operating permit application. [*See* IR007836, SPR signature page.] Because this signature page signifies that the AO application is an update to Holly's Title V application but lacks certain Title V requirements, Petitioners argue that Holly's Title V application is legally deficient.

20. Petitioners similarly argue that by omitting the Subpart Ja requirements in the Holly AO, Holly also has violated the application requirements under Title V. On these bases, Petitioners assert that UDAQ may not issue an approval order to Holly while it is in violation of the Title V permit application requirements.

21. These arguments fail for four reasons.

22. First, any arguments related to Title V compliance or the sufficiency of Holly's Title V application is outside of this tribunal's jurisdiction. The Executive Director of DEQ has made clear that an ALJ's jurisdiction is limited to the administrative record before him or her and the particular permit under review. [*See* Emery Order (limiting ALJ's jurisdiction to the record before her and prohibiting consideration of an NOI application that could be granted or denied at some point in the future.).] Any other permits or applications for permits that Holly may have submitted—all of which involve separate administrative records—are beyond the scope of these proceedings. *Id.* More important, Petitioners do not point to any final Title V permit decision that could be reviewed by this tribunal even if it had jurisdiction to do so.

23. Second, even if I had jurisdiction, it is clear from this record that Petitioners have not presented any evidence or authority that renders invalid the application shield letter issued to Holly's predecessor-in-interest. [*See* IR007725.] This shield remains in place until the permitting authority takes action on the entire Title V permit application, which it appears has not yet occurred. *See* 42 U.S.C. § 7661c(d) ("if a part 70 source submits a timely and complete application for permit issuance (including for renewal), the source's failure to have a part 70 permit is not a violation of this part until the permitting authority takes final action on the permit application"); *see also* 40 C.F.R. § 70.7(b) (same); *see also* Utah Admin. Code. R307-415-5a(3)(e) (same). This means every approval order that Holly has received is an update to its Title V permit application. The Holly AO is no exception and does not independently give rise to a cause of action under Title V's separate rules or regulations.

24. Third, even if I had jurisdiction, this argument fails as a matter of law: Nothing in the Title V statute or applicable regulations contains any time period for supplementation of the Title V application. *See* Utah Admin. Code R307-415-5b. That Holly continues to provide

information to EPA and UDAQ regarding NSPS compliance (which is a Title V requirement) effectively evidences that Holly's Title V permit application is being updated on an ongoing basis. [*See* IR004138-59, Exhibit 7 to Petitioners' first comment letter (containing a compliance report, sent to the EPA and UDAQ, including compliance demonstration for NSPS requirements).] Thus, Petitioners' reliance on the signature page as evidence of an incomplete Title V application is without merit.

25. Fourth, even if I had jurisdiction, Petitioners' argument that UDAQ's failure to recite the entire Subpart Ja regulation in the Holly AO violates Title V is incorrect. [Petitioners' Br. at 10-11.] As previously explained, UDAQ is not required to recite the entire 43-page Subpart Ja regulation in the Holly AO. In any event, the record demonstrates that Subpart Ja ***does apply*** and that Holly is in compliance with all federal requirements. [*See* IR007725.]

26. For all of these reasons, Petitioners' claims regarding Title V fail on the merits and should be dismissed with prejudice.

X. The Record Supports the Use of the NEI Emission Factors in Holly's Emission Calculations.

1. Petitioners next argue that the Director erred when he authorized the use of the NEI emission factors to calculate PM emissions from certain of Holly's heaters and boilers. [Petitioners' Opening Brief at 51-58.] For the reasons discussed below, this argument should be rejected.

A. Findings of Fact

2. Holly submitted to UDAQ two independent expert reports explaining why the NEI emission factors were more accurate and better predictors of emissions than the AP-42 emission factors—namely, because of the newer dilution testing methodology that was used to develop the NEI emission factors. [IR007238-58, First Glen England Report ("England I")

(explaining why the NEI emission factors more accurately predict $PM_{2.5}$ emissions from gas fired heaters and boilers); IR008024-44, Second Glen England Report ("England II") (same).]

3. Because the NEI emission factors were untested at the Holly refinery, UDAQ imposed stack testing requirements to verify the accuracy of the emission factor calculations. [IR009215-16, Response to Comments Memo (explaining that UDAQ imposed stack testing requirements to verify the accuracy of the NEI emission factors, reviewed the Glen England Reports and maintained the original conclusion that use of the NEI emission factors was appropriate); IR009217, Response to Comments Memo (explaining that Holly was subject to a stringent emission limit for its heaters and boilers that matched the NEI emission factor calculations and that Holly is subject to stack testing requirements to verify compliance).]

4. UDAQ also imposed an emission limit of 0.00051 lb/MMBtu in Section II.B.7.a.2 of the Holly AO. [IR009248, Holly AO.]

5. UDAQ only imposed this limit on Holly's NSPS heaters and boilers. [IR008558-59, Source Plan Review (explaining use of NEI emission factors for NSPS sources); IR009218, Response to Comments Memo (explaining use of NEI emission factors for NSPS sources).]

6. Presumably at the request of Mark Hall, a commenter on the draft Holly AO, EPA staff members sent emails to an undisclosed Gmail account discussing the accuracy of the NEI emission factors and the ability of EPA to approve new emission factors generally. [IR008911-8922; IR009043.] Neither the attachments to these emails nor the complete emails were included with the comments. [*Id.*]

B. <u>Findings and Conclusions on Preservation</u>

7. Petitioners preserved some aspects of their argument regarding their challenge to the NEI emission factors in accordance with 19-1-301.5(4) by raising the issue during the public comment period. [*See* IR008584-8595, Mark Hall Second Comment Letter.]

8. Petitioners did not, however, preserve the argument that § 7430 of the Clean Air Act precluded the use of the NEI emission factors.

9. Section 7430 of the Clean Air Act was not cited anywhere in the comments submitted during the public comment period but was reasonably ascertainable because it was codified in the U.S. Code during the public comment period.

10. Petitioners did not raise this substantive argument until their briefing on their request for a stay in this proceeding.

11. Accordingly, any arguments relating to § 7430 of the Clean Air Act are unpreserved and should be dismissed.

12. In their Reply Brief, Petitioners, argued for the first time that the § 7430 claim was made in response to additional information submitted to UDAQ after the close of the public comment period and was therefore not barred by the preservation rules found in Utah Code Section 19-1-301.5(4). Petitioners asserted than any prohibition to their ability to address information submitted after the close of the public comment period would be a violation of their due process rights.

13. Petitioners' due process argument relating to their ability to assert the § 7430 claim was not briefed until the Reply. Issues raised for the first time in a reply brief are rejected in appellate contexts. *See e.g., Coleman ex rel. Schefski v. Stevens*, 2000 UT 98, ¶ 9, 17 P.3d 1122 (refusing to consider matters raised for the first time in the reply brief). Accordingly, this

tribunal will not entertain Petitioners' due process arguments briefed for the first time in their Reply Brief.

14. Additionally, even if such an argument were properly before this tribunal, the only information Holly submitted after the close of the public comment period relating to the NEI emission factors was the second Glen England Report, in which Mr. England expanded on his prior report (submitted before the public comment period) explaining why the NEI emission factors were the most representative factor for determining emissions from Holly's new heaters and boilers. [*See* IR008024-44.]

15. Petitioners' § 7430 argument is not directed at this second Glen England report and does not address any of the technical findings contained therein. Instead, as Petitioners admit, the § 7430 argument is purely a legal argument relating to whether UDAQ could use emission factors other than the AP-42 factors, officially approved by EPA.

16. Therefore, in light of the fact that the § 7430 argument has nothing to do with the Glen England Report and is a purely legal argument that was reasonably ascertainable during the public comment period, the claim has not been adequately preserved, and no due process rights have been infringed.

C. <u>Findings and Conclusions on Burden of Proof</u>

17. Even if Petitioners' claims had all been adequately preserved, they have failed to meet their burden of proof.

18. Petitioners' claim that UDAQ erred in relying on the NEI emission factors to calculate the PTE for Holly's NSPS heaters and boilers presents a mixed question of law and fact. Whether UDAQ is legally authorized to use an emission factor other than AP-42 is a question of law and UDAQ has been given discretion to interpret this law, requiring the

application of a clearly erroneous standard of review. The question of whether UDAQ was reasonable in accepting the NEI emission factor data is a highly technical mixed question of law and fact that is reviewed for reasonableness.

19. Although Petitioners reference, in a footnote, the Glen England Reports, they do not analyze any of the information contained in those reports. Instead, Petitioners focus on a paper that Glen England published in 2004, which discusses generally the NEI emission factors as well as several emails from EPA staff discussing the adequacy of the NEI emission factors.

20. Petitioners also focus their argument on the assertion that UDAQ is prohibited by Section 7430 of the Clean Air Act from using any emission factors not specifically approved by EPA.

21. Petitioners have failed to adequately marshal all of the relevant evidence for this highly complicated issue. Accordingly, they have not satisfied their burden of proof to challenge Holly's use of and UDAQ's acceptance of the NEI emission factors.

D. <u>Conclusions of Law on the Merits</u>

22. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

23. Petitioners advance multiple arguments as to why the use of the NEI emission factors to calculate emissions from Holly's heater and boilers was improper. Each of these arguments fails for the reasons discussed in detail below.

i. ***<u>There is No Legal Requirement that UDAQ use AP-42 Emission Factors</u>***

24. Petitioners argue that the law mandates UDAQ use AP-42 emission factors to calculate PM emissions from Holly's NSPS heaters and boilers. This argument fails for three reasons.

25. First, nothing in Utah's minor source permitting regulations and nothing in the federal PSD/NSR regulations requires the use of AP-42 emission factors. In fact, those regulations do not mention the AP-42 factors at all.

26. While EPA has identified the AP-42 factors as one method of estimating potential emissions under the PSD/NSR program, the AP-42 factors are not the only authorized method. EPA also has sanctioned numerous other methods, including "emissions from technical literature." [EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, draft dated October 1990 ("EPA Puzzlebook"). The NEI emission factors are "emissions from technical literature" that Holly used to calculate potential $PM_{2.5}$ emissions from its gas fired heaters and boilers.

27. Moreover, the AP-42 factors themselves caution that they are not to be mechanically applied, but may be superseded by more specific or appropriate technical information. As EPA has advised:

> Before simply applying AP-42 emission factors to predict emissions from new or proposed sources, or to make other source-specific emission assessments, the user should review the latest literature and technology to be aware of circumstances that might cause such sources to exhibit emission characteristics different from those of other, typical existing sources. Care should be taken to assure that the subject source type and design, controls, and raw material input are those of the source(s) analyzed to produce the emission factor. This fact should be considered, as well as the age of the information and the user's knowledge of technology advances.

EPA, *Introduction to AP-42*, 4 (Jan. 1995), available at www.epa.gov/ttnchie1/ap42/c00s00.pdf. In this fashion, EPA delegates to the relevant permitting authority discretion to determine how to calculate emission rates.

28. Second, Petitioners' argument that the NSPS regulations mandate the use of AP-42 is also misplaced because the NSPS program is entirely separate from the PSD program and regulations from one program cannot dictate action in the other. *See, e.g, Envtl. Defense v. Duke Energy Corp.*, 549 U.S. 561, 577 (2007) (recognizing the definitions of "modification" under the PSD and NSPS programs are distinct and the "PSD regulations on 'modification' simply cannot be taken to track the Agency's regulatory definition under the NSPS").

29. Finally, Petitioners' argument that 42 U.S.C. § 7430 prohibits the use of the NEI emission factors because EPA has not specifically approved such factors also fails.

30. The plain language of this statute contradicts Petitioners' argument because Section 7430 applies only to emission factors used "to estimate the quantity of emissions of *carbon monoxide, volatile organic compounds, and oxides of nitrogen* from sources of such air pollutions."[17] 42 U.S.C. § 7430 (emphasis added). The statute says nothing about the use of emission factors to estimate the quantity of $PM_{2.5}$ and PM_{10}—the only emissions for which Holly used NEI factors to estimate emissions from its heaters and boilers.

31. In any event, Section 7430 does not dictate that UDAQ use any specific emission factors in a permitting proceeding, but requires EPA to update emission factors, saying nothing

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[17] Consistent with the plain language of the statute, EPA has repeatedly explained that this provision applies only to "the emission factors used to estimate emissions of volatile organic compounds (VOC), carbon monoxide (CO), and oxides of nitrogen (NO_x) from area and mobile sources," not to emission factors for $PM_{2.5}$ and PM_{10}. 67 Fed. Reg. 56289 (Sept. 3, 2002); 62 Fed. Reg. 45802 (Aug. 29, 1997).

about when such factors must be used. UDAQ retains discretion to decide which emission factors are appropriate, in its expert technical opinion.

32. As EPA has explained in evaluating the use of emission factors generated under Section 7430:

> These procedures are *not* a means for individual facilities to obtain EPA approval of a site-specific emission factor or to determine the appropriateness of applying a published EPA factor to a specific facility. *EPA does not approve site-specific factors or judge the appropriateness of its factors for specific facilities. The responsibility for such decisions continues to be that of the State or local regulating authority*, as well as the facility operators themselves.
>
> EPA's published emission factors are intended to provide an affordable method of estimating emissions where no better data are available. They are best used to characterize the total emissions loading of a large geographic area containing many individual facilities. Therefore, these factors attempt to represent a typical or average facility or process in a given industry. *EPA recognizes that other methods of obtaining emissions estimates may be more accurate than industry-average emission factors, and encourages the use of better methods whenever the source and/or the State or local regulating authority is able to support those methods*.

Public Participation Procedures for EPA Emission Estimation Guidance Materials, at 2 (May 1997) (second and third emphasis added).[18]

33. EPA has specifically recognized that state permitting authorities may use other methods *without* obtaining approval under § 7430, so long as the permitting authority "is able to support these methods." *Id.*

34. UDAQ had substantial evidence in the record to support its decision to use the NEI emission factors as set forth in section *ii.* below.

[18] *Available at* http://tinyurl.com/EPA-guidance.

35. Petitioners have failed to establish any valid legal basis mandating the use of AP-42 emission factors for estimating PTE for permitting purposes. Therefore this claim fails on the merits.

ii. ***It Was Reasonable for UDAQ to Accept Holly's Use of the NEI Emission Factors***

36. UDAQ did not abuse its discretion by following EPA's instruction and looking to alternative methods of calculating emissions in this case. As noted above, the determination of which emission factors to use falls squarely within the discretion of UDAQ. That determination is entitled to substantial deference, particularly given its technical nature. *See, e.g.,* Utah Code § 19-1-301.5(13)(b); *accord In re: N. Mich. Univ. Ripley Heating Plant*, PSD Appeal No. 08-02, at 53 (EAB Feb. 18, 2009) ("[Q]uestions pertaining to the appropriate pollutant emissions rates and other inputs to air quality models raise scientific and technical concerns that generally are best left to the specialized expertise and reasoned judgment of the permitting authority."); *In re: Newmont Nev. Energy Inv., LLC, TS Power Plant*, 12 E.A.D. 429, 444 (EAB 2005) ("[W]e accord broad deference to permitting authorities with respect to issues requiring the exercise of technical judgment and expertise."); *Utah Dep't of Admin. Servs. v. Pub. Serv. Comm'n*, 658 P.2d 601, 610 (Utah 1983) ("[A] court should afford great deference to the technical expertise or more extensive experience of the responsible agency.").

37. Before explaining why UDAQ's acceptance of the NEI emissions factors is reasonable, supported by substantial evidence, and does not constitute an abuse of discretion, it is necessary to provide some brief background regarding PM and emission factors generally.

38. Particulate matter (PM) is comprised of a complex mixture of extremely small particles and liquid droplets. [Utah $PM_{2.5}$ State Implementation Plan, adopted December 4, 2013 ("2013 SIP"), § 1.1.] PM_{10} is particulate matter with an aerodynamic diameter of 10 microns or

less. 40 C.F.R. § 51.50. $PM_{2.5}$ is particulate matter with an aerodynamic diameter of 2.5 microns or less. *Id.*

39. There are two types of PM emissions: primary and secondary. The type on which Petitioners focus in their challenge, primary PM, is comprised of particles that are directly emitted from a source as a solid or liquid ("filterable PM") or vapor that immediately condenses after discharge to form solid or liquid PM ("condensable PM"). *See* 40 C.F.R. § 51.50. According to EPA's AP-42 emission factors, condensable PM accounts for 75% of PM emissions from the type of natural gas combustion sources at issue here. [*See* AP-42 Compilation of Air Pollutant Emission Factors (1998); *see also* England II at IR008029.]

40. An emission factor attempts to estimate the quantity of a pollutant released into the atmosphere with an activity associated with the release of that pollutant. 47 Fed. Reg. 52723-01, 52724 (Oct. 14, 2009). EPA's AP-42 emission factors were "initially developed for emission inventory purposes only"—i.e., to assist national, regional, state, and local regulatory authorities with making air quality management decisions and developing emission control strategies. *Id.* at 52723, 52725. Since then, however, EPA has recognized the AP-42 emission factors have been "used for many other air pollution control activities for which they were not designed," including permitting and enforcement. *Id.*

41. Various testing methods have been developed for calculating primary $PM_{2.5}$ emissions (both filterable and condensable). The AP-42 factors on which Petitioners rely were originally developed almost twenty years ago using a "stack test impinger method," which draws a gas sample through a heated filter and then a series of iced "impingers." [England I at IR007240.] As explained in the England Reports, the problem with this method is that cooling the sample with chilled water causes emissions—and particularly SO_2 emissions—to condense

and particulate out as "pseudo-particulate" matter. Although the gas emissions would not condense to form particulate matter under normal operating conditions, the AP-42 factors nevertheless measure this pseudo-particulate matter as primary $PM_{2.5}$. [England II at IR008027-8029; England I at IR007240, IR007242.]

42. EPA has recognized this same problem with the stack test impinger method. EPA has observed, for example, that "sulfur dioxide (SO_2) gas (a typical component of emissions from several types of stationary sources) can be absorbed partially in the impinger solutions and can react chemically to form sulfuric acid. This sulfuric acid 'artifact' is not related to the primary emission of [condensable particulate matter] from the source, but may be counted erroneously as [condensable particulate matter]." 75 Fed. Reg. 80,118, 80,121 (Dec. 21, 2010). EPA also has acknowledged "that SO_2 in particular, and perhaps other gaseous compounds, can react with the collecting liquids used in the [stack test impinger] method to form materials (artifacts) that would not otherwise be solid or liquid or would not condense upon exiting the stack." 72 Fed. Reg. 20,586, 20,653 (Apr. 25, 2007).

43. The Glen England Reports explain that this problem is particularly acute for gas-fired sources. EPA developed its test methods for sources such as coal-fired boilers, which emit PM concentrations at much higher levels than gas-fired sources, and EPA has never evaluated the performance of these methods for gas-fired sources. [England II at IR008029, IR008034.] These measurement errors caused by the hot filter/iced impinger methods "are so significant when applied to gas-fired boilers and heaters … that they partially or completely obscure the true emission level."[19] [England II at IR008029.]

[19] In addition to being based on flawed test methods which measure artifacts that do not actually constitute particulate matter, the relevant AP-42 $PM_{2.5}$ factors are based on limited data. The AP-42 $PM_{2.5}$ factors are based on only 11 tests of four emissions units for condensable

44. The NEI factors, by contrast, were developed using a newer "dilution method." Unlike the old stack test methods, dilution-based testing does not create artificial pseudo-particulate matter because the gas sample is cooled with filtered air, similar to what happens to emissions in the course of actual operations. According to the England Reports, this results in much more representative and accurate $PM_{2.5}$ measurements. [England II at IR008027, IR008030-8032; England I at IR007241.]

45. EPA has recognized the benefits of this newer testing method, observing "that a dilution sampling method for measuring direct $PM_{2.5}$ eliminates essentially all artifact formation *and provides the most accurate emissions quantification*." 72 Fed. Reg. 20,586, 20,653 (Apr. 25, 2007) (emphasis added). In fact, EPA has expressly identified certain applications "where dilution sampling provides advantages over the standard test methods," and actively "*encourage[d]* sources that encounter these situations to request that the regulatory authority … use this method to approve the use of dilution sampling as an alternative to the test method specified for determining compliance." 75 Fed. Reg. 80118-01, 80132 (emphasis added).

46. In this case, EPA raised no objection to use of the NEI emission factors during the public comment period.[20] [*See* Response to Comments at 43 (noting that "during the public comment period, EPA did not object to the use of [the NEI] emission factors").] Nor has EPA

particulate matter (which forms the majority of $PM_{2.5}$ emissions). [England II at IR008039.] These tests were not performed by EPA, but by contractors on behalf of individual facilities or industry trade associations. [England II at IR008035.] Moreover, the measurement uncertainty of the AP-42 $PM_{2.5}$ factors for gas-fired sources is greater than the average estimate of emissions. [England II at 4.] The England Reports describe these and a number of other flaws with the AP-42 $PM_{2.5}$ factors that are not reiterated in detail here. [*See* England II at 3.]

[20] While EPA did ask for more information as to the basis for the reduction of PM_{10} and $PM_{2.5}$ potential-to-emit numbers in Holly's second netting analysis, [*see* IR007840-7841], UDAQ addressed this inquiry in its Response to Comments, explaining that the calculations were "based on the 2006 EPA-published National Emissions Inventory (NEI) Information." [IR009176] Subsequent to this direct identification of the use of NEI emission factors, EPA has raised no further questions concerning the netting analysis or otherwise challenged Holly's AO.

challenged the issuance of the AO. EPA also has raised no objection to UDAQ's recent authorization of the NEI factors for purposes of calculating $PM_{2.5}$ under UDAQ's $PM_{2.5}$ State Implementation Plan. [*See* Utah SIP § I.X.H.11(k)(i), dated January 8, 2014 ("SIP Part H") at 60.]

47. In arguing that UDAQ must use the AP-42 emission factors, Petitioners do not defend the accuracy of the AP-42 factors on a technical basis. Nor do they address any of the criticisms, expressed by both EPA and the England Reports, about the inaccuracies of the stack test impinger methods on which the AP-42 factors are based.

48. The fact that AP-42 factors have been used in the past does not mean that UDAQ must continue to rely on those same factors for the Holly AO. UDAQ's determinations—including the "technical" and "scientific" questions such as what emission factors are to be used—are to be made on the basis of the evidence provided to UDAQ and placed in the administrative record in a particular permitting action. Utah Code § 19-1-301.5(13)(b). Holly provided UDAQ with data regarding the flaws in the AP-42 $PM_{2.5}$ factors and outlining the superior accuracy of the NEI $PM_{2.5}$ factors. UDAQ evaluated this evidence and "determined that the NEI emission factors can be used." [IR009216, Response to Comments Memo.] Prior use of the AP-42 $PM_{2.5}$ factors does not undermine this conclusion.[21]

[21] Petitioners' claim that the May 2011 RTI International Emission Estimation Protocol for Petroleum Refineries endorses the use of the AP-42 emission factors and does not identify the NEI $PM_{2.5}$ data. [*See* IR008661, attachment F to Mark Hall Second Comment Letter.] However, the purpose of the protocol was not to identify the *absolute* level of $PM_{2.5}$ emissions from each refinery, but to require the tested refineries to use the same emissions factor so that their *relative* emissions could be compared. In responding to comments on the protocol, EPA explained that "it is important that default emission factors are consistent between different reporters so we can properly compare the results." [*Summary of Comments and Responses*, EPA-HQ-OAR-2010-0682 (Feb. 2, 2011), Appx. V of Holly's Opposition to Motion for Stay, also available at www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2010-0682-0028.] In any event, the protocol itself states that the "emission factors in AP-42 are *the recommended default* emission

49. Based on the substantial evidence in the record providing technical support for UDAQ's decision to accept use of the NEI emission factors and the emission calculations based on those factors, and given the lack of contradictory technical evidence, Petitioners cannot meet their burden to demonstrate that UDAQ acted unreasonably.

iii. The NEI $PM_{2.5}$ Emission Factors are Based on Sound Technical Data and Petitioners' Reference to Other Information Does Not Undermine the Data.

50. The majority of the technical data supporting the NEI emission factors is found in the England Reports, which state that "[t]he NEI PM2.5 emission factors were derived by EPA staff from data contained in GE EER's comprehensive test reports published from 2002-2004," along with "detailed supporting test data." [England II at IR008032.]

51. This testing program "included extensive quality assurance measures," and more comprehensive data than is provided in the compliance tests used to developed the AP-42 factors. [England II at IR008034-8035.] These results have been subject to peer review and have been corroborated by other independent scientific studies. [England II at IR008032.] The NEI test data is also quantitatively superior when it comes to condensable particulate matter emissions, which form the majority of $PM_{2.5}$ emissions: the AP-42 factors were based on 11 test runs of four units, while the NEI factors were based on 20 test runs of six units. [England II at IR008039, IR008041.]

52. The cautionary statements regarding the NEI emission factors upon which Petitioners rely "do not suggest in any way that those factors are insufficiently supported by data or should not be used." [England II at IR008033.] The AP-42 PM emission factors are accompanied by similar language explaining that the emission factors are based on limited data

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factors," not that the AP-42 factors are the only permissible emission factors. [IR008715 (emphasis added).]

and may not be accurate. [England II at IR008029-8030.] Such cautionary language is generally found in all instances where emission factors are used.

53. The boiler sampling data and performance guarantees from the John Zink Company are an incomplete compilation of data that is not explained, nor relatable to Holly's gas fired heaters and boilers. The boiler standards were provided to UDAQ on a one-page sheet of test results, without the full test reports or any explanation as to the testing methodology or nature of the emissions sources. [*See* IR008586, Mark Hall Second Comment Letter.] Additionally, two of the four boilers did not burn natural gas during their tests and so are not analogous to the gas-fired sources at issue here. [England II at IR008030 n.1.] The emissions from the remaining two sources vary widely, resulting in "very low" confidence in the average. [England II at IR008040.] Accordingly, this data does not undermine use of the NEI emission factors.

54. The Zink guarantees were similarly provided without context or explanation. Without the testing data, it is impossible to verify that these factors were not based on the same flawed test methods as the AP-42 factors. Moreover, the Zink guarantees are not emission factors or estimates, but rather guarantees provided by a commercial manufacturer that emissions will not exceed a certain level. Equipment manufacturers have an incentive to guarantee emissions that are conservatively high so that the commercial risk associated with failing to meet the guarantee is low. [England II at IR008034 ("If PM guarantees are not met during performance tests on a new unit, tens or hundreds of millions of dollars in customer payments may be at stake.").]

55. In weighing the evidence in the record, as this tribunal must do in accordance with Utah Code Section 19-1-301.5, it is clear that the use of the NEI emission factors is

supported by the majority of sound scientific evidence in the record and UDAQ was therefore reasonable in its acceptance of the NEI factors.

iv. ***UDAQ Was Reasonable in its Reliance on Enforceable Emissions Limits in the Holly AO in Determining the Potential to Emit for Holly's Heaters and Boilers.***

56. Petitioners argue that emission limits on Holly's heaters and boilers cannot be used to limit the facility's potential to emit and so UDAQ erred in its determination that Holly's project was minor for $PM_{2.5}$. This tribunal disagrees.

57. The AO imposes an enforceable limit on $PM_{2.5}$ emissions from each of the emissions units for which the NEI emission factors were used in an amount equal to the NEI emission factors. [IR009248, Holly AO (providing that "[t]he emissions of PM_{10} from the following NSPS Boilers and heaters shall not exceed 0.00051 lb/MMBtu").]

58. The methodology used in this case to determine whether the proposed modification was "major" for PSD/NSR purposes was a comparison of the refinery's potential to emit after the expansion project versus its baseline actual emissions before the expansion. *See* 40 C.F.R. § 52.21(a)(2)(iv)(*d*). [*See also* IR008560, Source Plan Review (noting that Holly has used the potential to emit methodology to determine the projected increases from the expansion project).] Under this method, the estimated potential emissions are compared to the baseline emissions; if the difference between the two exceeds a certain quantity, the modification is deemed "major" for that pollutant.

59. "Potential to emit" is defined as

> 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.*[22]

40 C.F.R. § 52.21(b)(4) (emphasis added); Utah Admin. Code R307-101-2 (same definition).[23]

60. The emissions limit imposed on the NSPS boilers and heaters is an enforceable limitation in the Holly AO. [*See* IR009218, Response to Comments Memo ("If the stack testing indicates that Holly Refinery cannot comply with these emission factors, it would be out of compliance with its AO….")]; *see also* 67 Fed. Reg. 80,186, 80,190-91 (Dec. 31, 2002) (explaining when an emissions limitation is enforceable). Accordingly, the potential to emit of these emissions units was properly limited to 0.00051 lb/MMBtu – the same level as established by the NEI emission factors.

61. UDAQ was reasonable in relying on this limiting factor in its determination that Holly's project would only be a minor modification for PM.

62. Ultimately, none of Petitioners' arguments challenging Holly's use of the NEI emission factors undermines' UDAQ's reasonable decision to accept Holly's emission calculations based on those factors. Petitioners' arguments on this claim all fail on the merits and should be dismissed with prejudice.

XI. <u>The Emission Reductions From the Decommissioning of the Propane Pit Flare Were Properly Included in Holly's Netting Analysis.</u>

[22] The term "federally" in this definition is interpreted as meaning "practically enforceable" by a federal, state, or local entity. 67 Fed. Reg. 80,186, 80,191 (Dec. 31, 2002). [*See also* Memorandum from John S. Seitz re: Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit, at 3 (Jan. 22, 1996).]

[23] Petitioners suggest that the NSPS regulations provide a definition for calculating "potential to emit." This is incorrect. The NSPS rules nowhere use the concept of "potential to emit" to determine whether a modification has taken place. Instead, the NSPS definition of modification is based on whether there has been a change in the hourly emissions rate, while the PSD regulations are based on total annual emissions. *See Duke Energy Corp.*, 549 U.S. at 577-78.

1. Petitioners final argument is that Holly inaccurately calculated the emission reductions from its decommissioning of the propane pit flare and should not have included such emissions in its netting analysis. [Petitioners' Opening Brief at 60-61]. For the reasons stated below, this final argument should be rejected.

A. <u>Findings of Fact</u>

2. The emission reductions that Holly claimed from its decommissioning of the propane pit flare came from actual emission inventory information submitted to UDAQ in 2008 and 2009 and were not re-calculated specifically for purposes of this project. [IR009218, Response to Comments Memo ("flare emissions came from the UDAQ inventory record for reported actual emissions from 2008-2009 based on 259 MMBtu/hr and actual throughput data").]

3. The historic modifications to the propane pit flare to bring it into compliance with NSPS did not affect the baseline calculations or the AP-42 emission factor calculations. [IR007337, Revised NOI ("Compliance with NSPS affects neither the AP-42 emission factor calculation, which is based on the amount of propane used, nor the baseline calculations.").]

4. None of Holly's modifications to the Propane Pit Flare affected overall emissions. Therefore Holly was free to take credit for the emission reductions when the flare was decommissioned. [IR009182, Response to Comments Memo ("Because compliance with 40 CFR 60 Subparts A & J did not affect emissions, reductions from the removal of this propane pit flare are creditable reductions.").]

5. In connection with its independent review of the Holly AO, EPA submitted two separate comment letters to UDAQ. [*See* IR004001, EPA First Comment Letter; IR007840-7841, EPA Second Comment Letter.] While the Second Comment Letter requested more

information regarding (a) “the basis for the estimate of emissions reduced by converting from gas fired to electric motors for the compressors” [IR007840] and (b) the netting calculations relating to the new benzene saturation unit #23 and applying a boiler #5 NOx limit [IR007841], the EPA raised no concerns about the netting issues raised by Petitioners in their final argument on appeal. Moreover, EPA’s request for supplemental information on this issue was satisfied in UDAQ’s response to comments.

B. Findings and Conclusions on Preservation

6. Petitioners preserved this argument in accordance with 19-1-301.5(4) by raising this issue during the public comment period. [*See* IR007857 Petitioners’ Second Comment Letter.]

C. Findings and Conclusions on Burden of Proof

7. The issue of whether Holly accurately estimated reduction of PM emissions from the removal of its propane pit flare presents highly technical factual questions. It also presents legal questions about what data may be used for reduction purposes in a netting analysis. Accordingly, this issue is a mixed question of law and fact and UDAQ’s decision to include the emission reductions in the netting analysis will be analyzed under a reasonableness standard.

8. Petitioners failed to marshal all of the evidence pertaining to this issue—namely the 2008 and 2009 emission inventory data. Petitioners merely question the final calculations without presenting any conflicting evidence or analyzing the evidence in the record.

9. Accordingly, Petitioners have not met their burden of proof on this claim and it fails on that basis.

D. Conclusions of Law on the Merits

10. Even if Petitioners had carried their burden of proof, or to the extent marshaling is not properly applied to this claim (being a question of law), Petitioners' claims fail on the merits for the independent reasons discussed below.

11. Petitioners argue that the propane pit flare emissions were overestimated based on Holly's use of AP-42 emission factors. Petitioners contend the emission reduction must be overestimated because based on the calculated reduction, the propane pit flare would have been burning every day of the year.

12. Petitioners submit no evidence in support of this contention. Specifically, Petitioners do not address the fact that the emission reduction was based on the 2008 and 2009 historic emission inventory data that Holly submitted to UDAQ as required by Utah Admin. Code R307-150.

13. Part of this calculation involved the use of AP-42 emission factors to calculate the emissions from the flares because emission factors are necessary where emissions are generated from an open flame. [*See* IR007337, Revised NOI, ("Baseline emissions for the flare at the propane pit were calculated based on the AP-42 emission factors for flares.").]

14. For purposes of netting, the regulations expressly provide that the historical inventory information may be used as a baseline for calculating emissions increases and decreases. *See* 40 C.F.R. § 52.21(b)(48)(ii).

15. That Holly used NEI emission factors to calculate emissions from its heaters and boilers is irrelevant to the question of whether the flare emissions were properly calculated with AP-42 factors. Petitioners have pointed to no statute or regulation that would require Holly or UDAQ to re-calculate historic inventory information every time new emission factors are developed.

16. Petitioners' claim that there is no evidence in the record to support these historic emission calculations also fails because all parties, including Petitioners, agreed to exclude the emission inventory calculations from the record given the volume of those files. [*See* Holly's Surreply at 28; *see also* UDAQ's Surreply at 33.] If Petitioners thought there was an error in the calculations, the information could have been made available to them for their review. Petitioners may not now argue, without having asked to review the calculations, that the lack of such evidence supports their claim.

17. Petitioners have failed to present any evidence that would undermine the significant deference afforded to UDAQ in its review of highly technical emission calculations and review of netting analyses. Moreover, Petitioners have presented no technical evidence that undermines the accuracy of the historical inventory information. Accordingly, Petitioners' challenge to the propane pit flare emission calculations fails on the merits and should be dismissed with prejudice.

CONCLUSION AND PROPOSED ORDER

1. Based on the foregoing, Petitioners have not met their burden to demonstrate that UDAQ erred in issuing the Holly AO.

2. Further based on the foregoing and having satisfied my charge to undertake a permit review adjudicative proceeding in connection with this matter in accordance with Utah law, I recommend that the Executive Director deny Petitioners' Request for Agency Action and affirm UDAQ's issuance of the Holly AO.

DATED this 11th day of March, 2015.

BRET F. RANDALL
Administrative Law Judge

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 11th day of March 2015, I served the foregoing **FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDED ORDER REGARDING THE MERITS** via email on the following:

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/s/ Bret F. Randall, ALJ

APPENDIX A

Table of Waived Claims Petitioners Raised in Their RAA But Failed to Brief on the Merits

RAA Page Number	Description of Waived Claim	Claim # in Briefs
27-29	"The AO Does Not Adequately Address Co Emissions and CO BACT"	8
29-30	"The Director Failed to Respond to Public Comments as Required by Law"	9
43-44	"It is Impossible to Verify the Facility's SO_2 Potential to Emit"	17
47-48	"The BACT for the South Flare is Inadequate"	20
50	"The AO Does Not Comply with the Federally Enforceable PM_{10} SIP"	24
51	"There is No Adequate Basis in the Record for the AO as the Record Does Not Reflect Independent Analysis of the Assertions and Calculations Made in the NOI"	25
51-52	"There is Insufficient Information and Analysis in the Record to Support the AO"	26
53	"The Netting Analysis is Insufficient and Does Not Support the Finding that the Expansion Project is a Minor Modification"	28
53-55	"The Holly Refining NOI is Incomplete for its Failure to address Hydrogen Sulfide, Total Reduced Sulfur and Sulfuric Acid Aerosal as Required NSR-Regulated Pollutants"	29
55-57	"The AO is Not Based on PM Emissions During Emission Characterization, Project Related Emission Increases, Netting and Net Increase Calculations and in the Required BACT Determinations; the Refinery Onsite Road Network is an Emission Unit Not Listed in the AO Approved Installations and Holly Refining Plans to Increase Site-Road-Related PM, PM10 & PM2.5 Emissions Through a Physical Change or Change in the Method of Operation of this Emission Unit"	30
59-60	"Table 3-4 and 3-5 NO_2 Reference [is incorrect]"	32

60-61	“Facility Configuration and Operations in Compliance with Holly Refining’s Notice of Intent”	33
61-62	“Holly Refining’s NOI Contains Significant Errors on the Matter of the Specific Start of the Contemporaneous Period”	34
62-63	“The AO is Based on an Improper Characterization of the Contemporaneous Period”	35
63-65	“The AO is Unlawful Because the Director Failed to Require and Base his Permitting Analysis on the Necessary Process Flow Diagrams and New Source Review Forms”	36
65-67	“The Evaluation and Characterization of Contemporaneous Emission Increases is Inadequate”	37
67-69	“The Section 2.3.1 "Fuel Gas" Process Support Group Analysis and Related Section 3 Emission Tables Do Not Show an Adequate 40 C.F.R. §52.21(b)(3)(i)(b) Determination of Contemporaneous Creditable Emission Increases and Decreases”	38
69-70	“The Section 2.3.2 Disclosure of Cooling Tower Changes Fails to Provide Sufficient Information to Determine Contemporaneous Creditable Emission Increases from Non-Modified Portions of Existing Cooling Towers”	39
70	“The Section 2.3.3 Disclosure Concerning Flares Does Not Provide Sufficient Information to Determine Contemporaneous Creditable Emission Increases at Non-Modified Flare Emission Units”	40
70-71	“The Section 2.3.6 Discussion of Wastewater Treatment and the Refinery Wastewater Sewer System Does Not Provide Sufficient Information to Determine Contemporaneous Creditable Emission Increases”	41
74-75	“Holly Refining's Section 3 Emission Increase and Net Emission Increase Tables Contain Erroneous Specification of Volatile Organic Compound and Hazardous Air Pollutant Emissions from Cooling Tower #11”	43
76-77	“VOC Emissions and Waxy Crude Handling, Transfer and Storage”	45
78	“Holly Refining Erroneously Claimed VOC Emission Reduction from Removal of a Floating Roof”	46

79-81	"The Director Fails to Enforce Notice of Intent and Compliance Report Certification by Holly Refining"	48
81	"Condition II.B.1.b in the AO is Too Vague to be Enforceable"	49
81	"The AO Production Rates During Compliance Stack Tests Are Insufficient"	50
81-82	"The AO Fails to Contain a Section Addressing the Regulatory Status, Method of Emission Control and Monitoring-Inspection-Recordkeeping-Reporting Requirements for Tank Sources of VOC and HAP"	51
83-84	"The AO Fails to Enforce Specific Requirements of the July, 2008 EPA Consent Decree Covering PM Emission Limitations for FCCU Unit 4 and Fails to Require Sufficient Monitoring Necessary to Assure Compliance with PM Emission Requirements from FCCU Units 5 and 25"	53
84-86	"The AO Fails to Provide a Best Available Control Technology Emission Limitation for PM, PM10 or PM2.5 to Control Emissions from FCC Unit 4"	54
86-87	"Setting NO_x Emission Limitations for 4FCCU and 25FCCU Catalyst Regenerator Exhaust Must be Explained and Justified on the Record to Eliminate Error and Ambiguity"	55
87-88	"The AO Omits Oxygen Corrections for NO_x and SO_2 Emission Limitations that are Stack Flue Gas Concentration Limits"	56
91-93	"The Record Does Not Include Maximum Potential to Emit for Short Term SO2 Emissions from the FCC Unit 25 Wet Scrubber Exhaust Vent Compliance Determination Point that are Associated with Sulfur Recovery Unit/SRU Incinerator Outages"	59
93-94	"The AO Fails to Contain Oxygen Monitoring and Wet Scrubber Outlet Volumetric Flow Rate Determination at FCC Units 4 & 25 Wet Scrubber Controlled Vent Stacks"	60
95-96	"The Director Eliminated a Previously Established PM Limits for FCC Unit 4 Without Replacing Such a Limit with a Revised BACT Determination"	62
96-97	"Holly Refining Has Not Demonstrated that the 15% Opacity Limit for 25 FCCU Constitutes a BACT Visible Emission Limitation"	63

97-98	"The Director Must Regulate the FCC 34" Flue Gas Bypass"	65
98-99	"Nothing Provided by Holly Refining's Final Revised Notice of Intent Justifies the Claimed 98% Control Efficiency Claimed for VOC, HAP and CO Destruction Efficiency from the Open Air Flares"	66
99-100	"The Record Fails to Address All Parts of the Existing and Proposed Flare Gas System and Failed to Carry Out a "Top Down" Best Available Control Technology Analysis"	67
100-102	"The AO May Not Dismiss Flare Gas Recovery Systems as a BACT Requirement Without Considering Prevailing Industry Practice in Favor of Such Systems at Larger Refineries"	68
104-105	"Flare Opacity Limitation is Not a BACT Limitation"	71
106-107	"The AO Fails to Adequately Address the SRU Incinerator"	73
107	"The AO Fails to Adequately Address the Controlled Refinery Process Wastewater Sewers"	74
107-108	"Neither the Approval Order Nor Holly Refining's Final Revised Notice of Intent Contain Any Limitation on Cooling Tower Water Total Dissolved Solids"	75
108-109	"The AO Fails to Incorporate a VOC BACT Determination and Fails to Address EPA Consent Decree Requirements for LDAR Programs at Holly Refining's Facility"	76
109-110	"Condition II.B.l.d Should Require Continuous Total Sulfur Analyzer"	77
111-112	"The Director Must Address the Heater/Boiler NO_x CEM Requirement"	79
115	"Utah Physicians Reserves the Right to Respond to Any Argument Data and/or Analysis Which Was Not Available at the Beginning of the Public Comment Period"	81

F

BEFORE THE EXECUTIVE DIRECTOR
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF WATER QUALITY

In the Matter of: Approval Order No. DAQE-AN101230041-13 Holly Refining & Marketing Company – Woods Cross, LLC Heavy Crude Processing Project Project No. N10123-0041	**ORDER ADOPTING FINDINGS OF FACT, CONCLUSIONS OF LAW, AND RECOMMENDED ORDER ON THE MERITS** Date: March 31, 2015

On March 11, 2015, the administrative law judge issued a *Findings of Fact, Conclusions of Law, and Recommended Order on the Merits* (proposed dispositive action) in the above referenced Division of Air Quality permit review adjudicative proceeding, conducted in accordance with Utah Code Ann. §19-1-301.5 and Utah Admin. Code r. 305-7. When an administrative law judge submits a proposed dispositive action, I may adopt, adopt with modifications, or reject the proposed dispositive action; or return the proposed dispositive action to the administrative law judge for further action as required. Utah Code Ann. § 19-1-301.5(13)(a). I am required to uphold all factual, technical, and scientific agency determinations that are supported by substantial evidence taken from the record as a whole. Utah Code Ann. § 19-1-301.5(13)(b).

Having reviewed the *Findings of Fact, Conclusions of Law, and Recommended Order on the Merits* and the accompanying record, I am satisfied that the factual, technical, and scientific agency determinations are supported by substantial evidence taken from the record as a whole.

ORDER

WHEREFORE, I adopt the *Findings of Fact, Conclusions of Law, and Recommended Order on the Merits.* For the reasons stated therein, I affirm the Division of Air Quality's decision to issue the approval order described above and I order the dismissal with prejudice of each of the Petitioners' arguments.

NOTICE OF RIGHT TO PETITION FOR JUDICIAL REVIEW

Judicial review of this final order may be sought in the Utah Court of Appeals in accordance with Sections 63G-4-401, 63G-4-403, and 63G-4-405 of the Utah Code Ann. and the Utah Rules of Appellate Procedure by filing a proper petition within thirty days after the date of this order.

DATED this 31 day of March, 2015.

AMANDA SMITH
Executive Director
Utah Department of Environmental Quality

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 31st day of March 2015, I served the foregoing **ORDER ADOPTING FINDINGS OF FACT, CONCLUSIONS OF LAW AND RECOMMENDED ORDER ON THE MERITS** via email on the following:

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G

FACT SHEET: New Source Review (NSR)

What is New Source Review?

New Source Review (NSR) is a Clean Air Act program that requires industrial facilities to install modern pollution control equipment when they are built or when making a change that increases emissions significantly. The program accomplishes this when owners or operators obtain permits limiting air emissions before they begin construction. For that reason, NSR is commonly referred to as the "preconstruction air permitting program."

The purpose of the NSR program is to protect public health and the environment, even as new industrial facilities are built and existing facilities expand. Specifically, its purpose is to ensure that air quality:

- does not worsen where the air is currently unhealthy to breathe (i.e. nonattainment areas)
- is not significantly degraded where the air is currently clean (i.e. attainment areas)

What are permits?

Permits are enforceable legal documents that an industrial facility, or stationary source, must comply with. Permits may place restrictions on:

- What construction is allowed
- What air emission limits must be met
- How the source can be operated

To assure that sources comply with a permit's emission limits, a permit almost always contains monitoring, recordkeeping, and reporting requirements.

What pollutants are regulated under the NSR program?

The NSR program applies to regulated NSR pollutants. In the PSD program, the regulated NSR pollutants include the National Ambient Air Quality Standards (NAAQS) pollutants and some other pollutants including sulfuric acid mist, hydrogen sulfide, etc. In nonattainment NSR, the regulated NSR pollutants are only the NAAQS pollutants.

EPA sets NAAQS for six principal pollutants, which are commonly called "criteria" pollutants and include: ozone, carbon monoxide, particulate matter, sulfur dioxide, lead, and nitrogen oxide. The NAAQS are set at levels that protect human health and the environment.

For each criteria pollutant, every area of the United States has been designated as one of the following categories:

- **Attainment:** air quality is equal to or better than the level of the NAAQS; these areas must maintain clean air
- **Unclassifiable:** there are no data on air quality for the area; the area is treated as attainment

- **Nonattainment:** air quality is worse than the level of the NAAQS; these areas must take actions to improve air quality and attain the NAAQS within a certain period of time

What are the types of NSR permitting programs and what do they require?

There are three types of NSR permitting programs, each with a different set of requirements. A facility may have to meet one or more of these sets of permitting requirements.

1. **Prevention of Significant Deterioration (PSD) program** applies to a new major source or a source making a major modification in an attainment area. The program requirements include:
    - Installation of the Best Available Control Technology (BACT)
        - Emission limitation based on the maximum degree of emission reduction (considering energy, environmental, and economic impacts) achievable through application of production processes and available methods, systems, and techniques
    - An Air Quality Analysis
        - Assesses existing air quality and predicts through modeling the ambient concentrations that will result from the proposed project and future growth associated with the project
    - An Additional Impacts Analysis
        - Assesses the impacts of air, ground, and water pollution on soils, vegetation and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review
    - Public Involvement
        - Opportunities include public comment period, hearings, appeals, etc. during the permit issuance process.

2. **Nonattainment NSR program** applies to a new major source or a source making a major modification in a nonattainment area. The program requirements include:
    - Installation of the Lowest Achievable Emission Rate (LAER)
        - The rate of emissions that reflects: (1) the most stringent emission limitation included in the implementation plan of any state for a similar source unless the facility owner or operator demonstrates such limitations are not achievable; or (2) the most stringent emissions limitation achieved in practice, whichever is more stringent.
    - Emission Offsets
        - To avoid increases in emissions, proposed emissions increases from new or modified facilities are balanced by equivalent or greater reductions from existing sources.
    - Public Involvement
        - Opportunities include public comment period, hearings, appeals, etc. during the permit issuance process.

3. **Minor NSR program** applies to a new minor source and/or a minor modification at both major and minor sources, in both attainment and nonattainment areas. Minor NSR may apply to criteria pollutants as well as other pollutants depending on the state. The program requirements include:
   - New sources or modifications at existing sources must comply with any emissions control measures required by the state.
   - The program must not interfere with attainment or maintenance of the National Ambient Air Quality Standards or the control strategies of a State Implementation Plan (SIP) or Tribal Implementation Plan (TIP).
     - An implementation plan is a set of programs and regulations developed by the appropriate regulatory agency in order to assure that the NAAQS are attained and maintained.

Who issues the permits?

Usually NSR permits are issued by state or local air pollution control agencies. State, tribal and local air pollution control agencies may have developed their own NSR permit programs, as part of their State Implementation Plans (SIP) or Tribal Implementation Plans (TIP), that are approved by EPA or they may be delegated the authority to issue permits on behalf of EPA. If a state or a tribe chooses not to develop a SIP or a TIP and also not seek delegation of the federal NSR programs, , EPA would implement the programs and issue the NSR permit, as we do for the PSD program in Indian country.

What sources are regulated under NSR?

The NSR permitting program applies to both: major and minor stationary sources.

1. **Major sources** are facilities that have the potential to emit pollutants in amounts equal to or greater than the corresponding major source threshold levels. These threshold levels vary by pollutant and/or source category. Major sources must comply with specific emission limits; which are generally more stringent in nonattainment areas.

2. **Minor sources** are facilities that have the potential to emit pollutants in amounts less than the corresponding major source thresholds.

   Synthetic minor sources are facilities that have the potential to emit pollutants at or above the major source threshold level, but voluntarily accept enforceable limits to keep their emissions below the major source thresholds and avoid the major NSR requirements.

Where can I find additional information about NSR?

EPA's NSR Web site: http://www.epa.gov/nsr/
The NSR Web site provides links to regulations, publications and state permitting contacts pertaining to New Source Review

H

Utah Division of Air Quality
New Source Review Section

Company ______________________
Site/Source ____________________
Date __________________________

Form 19
Natural Gas Boilers and Liquid Heaters

Boiler Information

1. Boiler Manufacturer: ____

2. Model Number: ______________________ 3. Serial Number: ______________________

4. Boiler Rating: ________________(10^6 Btu per Hour)

5. Operating Schedule: __________ hours per day __________ days per week ___________ weeks per year

6. Use: ☐ steam: psig ________ ☐ hot water ☐ other hot liquid: ______________________

7. Fuels:

☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol

☐ Process Gas - H_2S content in process gas __________ grain/100cu.ft.

☐ Fuel Oil - specify grade: _____ ☐ Other, specify: ______________________

Sulfur content _______ % by weight Days per year during which unit is oil fired: ______________

Backup Fuel: ☐ Diesel ☐ Natural Gas ☐ LPG ☐ Butane ☐ Methanol ☐ Other ______________

8. Is unit used to incinerate waste gas liquid stream? ☐ yes ☐ no

(Submit drawing of method of waste stream introduction to burners)

Gas Burner Information

9. Gas Burner Manufacturer: ____

10. No. of Burners: ______________________ 11. Minimum rating per burner: _____________ cu. ft/hr

12. Average Load: _______% 13. Maximum rating per burner: ____________ cu. ft/hr

14. Performance Guarantee (ppm dry corrected to 3% Oxygen):

NO_x: ______________ CO: ______________ Hydrocarbons: ______________

15. Gas burner mode of control: ☐ Manual ☐ Automatic on-off ☐ Automatic hi-low ☐ Automatic full modulation

Oil Burner Information

16. Oil burner manufacturer:

17. Model: _______________ number of burners: _________________ Size number: _______________

18. Minimum rating per burner: _____________ gal/hr 19. Maximum rating per burner: ___________ gal/hr

Form 11 - Natural Gas Boiler and Liquid Heater
(Continued)

Modifications for Emissions Reduction

20. Type of modification: ☐ Low NO_X Burner ☐ Flue Gas Recirculation (FGR)
☐ Oxygen Trim ☐ Other (specify) ______________________________

For Low-NO_X Burners	
21. Burner Type: ☐ Staged air ☐ Staged fuel ☐ Internal flue gas recirculation ☐ Ceramic ☐ Other (specify): ______________	
22. Manufacturer and Model Number: ______________	
23. Rating: ______________ 10^6 BTU/HR	24. Combustion air blower horsepower: ________
For Flue Gas Recirculation (FGR)	
25. Type: ☐ Induced ☐ Forced Recirculation fan horsepower: ______________	
26. FGR capacity at full load: _______ scfm _______%FGR	
27. FGR gas temperature or load at which FGR commences: _______ ^OF _______% load	
28. Where is recirculation flue gas reintroduced? ______________	
For Oxygen Trim Systems	
29. Manufacturer and Model Number: ______________	
30. Recorder: ☐ yes ☐ no Describe: ______________	

Stack or Vent Data	
31. Inside stack diameter or dimensions ________ Stack height above the ground ________ Stack height above the building ________	32. Gas exit temperature: ________ ^OF
33. Stack serves: ☐ this equipment only, ☐ other equipment (submit type and rating of all other equipment exhausted through this stack or vent)	
34. Stack flow rate: ____________ acfm Vertically restricted? ☐ Yes ☐ No	

Emissions Calculations (PTE)

35. Calculated emissions for this device

PM_{10} ________Lbs/hr________ Tons/yr $PM_{2.5}$ ________Lbs/hr________ Tons/yr
NO_x ________Lbs/hr ________Tons/yr SO_x ________Lbs/hr________ Tons/yr
CO ________Lbs/hr ________Tons/yr VOC ________Lbs/hr ________Tons/yr
CO_2 ________ Tons/yr CH_4 ________Tons/yr
N_2O ________Tons/yr
HAPs________ Lbs/hr (speciate)________Tons/yr (speciate)

Submit calculations as an appendix. If other pollutants are emitted, include the emissions in the appendix.

Instructions Form 19 – Natural Gas Boiler and Liquid Heater

This application form is applicable to natural gas-fired boilers and liquid heaters. Boiler(s) rated for a total of less than five million Btu per hr and fueled by natural gas and one million Btu per hour and fired by fuel oil numbers 1-6 are exempt from filing a Notice of Intent to construct. See Source Category Exemptions R307-401-10 (1) and (2).

NOTE:
1. **<u>Submit this form in conjunction with Form 1 and Form 2.</u>**
2. Call the Division of Air Quality (DAQ) at **(801) 536-4000** if you have problems or questions in filling out this form. Ask to speak with a New Source Review engineer. We will be glad to help!
3. Attach specification sheets for all burners, equipment and modifications to boiler.

1. Company name of manufacturer of boiler (specifically the pressure vessel or shell).
2. Manufacturer's model number.
3. Specific identification, serial, number of the boiler.
4. The maximum heat input for which the boiler is rated. Give the value in million British thermal units per hour.
5. The operating schedule for which you want to be permitted. The air quality impact will be evaluated according to this schedule. Note: The approval order will limit operating hours to what you request.
6. Mark the box indicating the purpose of the boiler.
7. Mark all fuels that you wish to be approved to use, also list the backup fuel to be used if any.
8. If a waste stream is burned, answer *yes* and submit drawings, etc. to characterize the method.
9. Company name of manufacturer of gas burners. If the boiler is a packaged boiler, list the manufacturer of the boiler.
10. How many gas burners will be installed in the boiler?
11. Minimum gas flow rate at which each burner can operate (in cubic feet per hour)
12. The average load at which you plan to operate each burner, compared to the maximum burner rating.
13. Maximum gas flow rate at which each burner can operate (in cubic feet per hour)
14. List the maximum concentration which the manufacturer guarantees the burners will produce in parts per million of Nitrogen Oxides (NO_X), Carbon Monoxide (CO), and Total Hydrocarbons. If the percentage of Non-methane hydrocarbons is known, please provide that information.
15. Indicate the method used to control the flame for the burners.
16. Company name of manufacturer of oil burners. If the boiler is a packaged boiler, and has duel fuel capability, list the manufacturer of the boiler.
17. Manufacturer's model, number (quantity), and size of oil burners to be installed in the boiler.
18. Minimum oil flow rate at which each burner can operate (in gallons per hour).
19. Maximum oil flow rate at which each burner can operate (in gallons per hour).
20. Indicate the type of emissions reduction strategy(ies) used in the proposed boiler.
21. Indicate the low-NO_X strategy used in the burner design.
22. Company name of manufacturer of the burners. Manufacturer's model number for the burners.
23. The heat input rating of each burner in million British thermal units per hour.
24. In a forced draft design, the horsepower of the fan motor used.
25. Method for delivering the flue gas to the combustion zone. Forced draft indicates the presence of a fan. Give the fan horsepower if so equipped.
26. The amount of flue gas which can be recirculated, in standard cubic feet per minute. And the percentage of the flue gas that can be recirculated at full load.
27. Generally, flue gas recirculation systems start up at a given load or temperature. Give that specification.
28. Where in relation to the burner/combustion zone is the flue gas reintroduced to the boiler?
29. Name of the manufacturer and the model number of the oxygen trim system.
30. Is there a data recorder? If so, describe it: What is recorded? How is it read?
31. Give the inside diameter or the dimensions of the stack. List the stack height above the ground and above the building in which it is located, describe if the gas flow is vertically restricted. This information will be used in modeling the impact of emissions on the ambient air.
32. Give the expected gas exit temperature at the end of the stack. Also to be used in modeling.
33. Indicate if other equipment is also vented to this stack. If other equipment is served by the stack, provide the flow rates, operating parameters, fuel and combustion information that can be used to characterize the total emissions from the stack.
34. Give the gas flow rate out of the stack in actual cubic feet per minute (acfm).
35. Supply calculations for all criteria pollutants, greenhouse gases and HAPs. Use AP42 or Manufacturers' data to complete your calculations.

Air Emissions
Boiler Emissions - Natural Gas

Date: **0-00-00**

Company Name:	**Test**
Facility Name:	**test**
Equipment Name:	**Admin E Boiler**

Enter Maximum Heat Rate, (Btu/hr or Btuh) **90000000**

Gas Consumption per Hour (cubic feet per hour) 90000

Calculated using a 1000 Btu/cu ft heating value for natural gas and 100% boiler load.

Enter Number Hours Operated per Year **400**

The calculated emissions will be :

Emission Factors listed below are for **Natural Gas Boilers . . . .**
Less Than 100 Million Btuh

b	c	d	
Pollutant	**Emission Factor**	**Emission Rate**	**Emissions**
	lbs/cu ft gas	lbs/hr c x cubic feet hour	tons/yr d x hours/2000
Particulate Material - PM_{10}	0.0000076	0.684	**0.137**
Sulfur Dioxide - SO2	0.0000006	0.054	**0.011**
Nitrogen Oxides - NO_x	0.0001	9.000	**1.800**
Volitile Organic Compounds - VOC	0.0000055	0.495	**0.099**
Carbon Monoxide - CO	0.000084	7.560	**1.512**

Note: This calculation chooses the correct set of emission factors, from the table below, based on the boiler heat rate. The correct emission factor will automatically be choosen to match the maximum heat rate input. Each boiler must have it's own calculation, do **not** total the heat rates for the site and use the one number for emission calculations.

Air Emissions
Boiler Emissions - Natural Gas

Instructions

These calculation sheets have been written using Microsoft Excel.

Step 1 Fill in the name and identifying information.
Enter the boiler heat output, in Btu/hour or Btuh, from the boiler name plate. Every boiler needs an emission calculaton sheet.

Step 2 Enter the hours the boiler will be operated.

Step 3 Once you have entered in all the values click anywhere on the sheet and the calculation will be done by the program. Remember the information is being used for permitting purposes, so be sure the numbers are right and realistic.

Step 4 If this is the only piece of equipment you are done with the calculations.
Save a copy by printing out the page.
You now need to determine what type of permit you need . .. . .

Step 5 If this is one of several emission points, download the Air Emission Summary page and enter the equipment name and emissions.

Emission Factors - Natural Gas Boilers	Less Than 100 Million Btuh (lb/cu ft gas)	Greater Than 100 Million Btuh (lb/cu ft gas)
Particulate Material - PM_{10}	0.0000076	0.0000076
Sulfur Dioxide - SO2	0.0000006	0.0000006
Nitrogen Oxides - NO_x	0.0001	0.00028
Volitile Organic Compounds - VOC	0.0000055	0.0000055
Carbon Monoxide - CO	0.000084	0.000084

Emission factors are from EPA AP 42, 1.4 Natural Gas Combustion, Emission Factors are for an uncontrolled boiler. Most newer boilers have smaller emission rates, if you have manufacturers emission rates you should use them. Please include the manufacturers literature as a reference for why you are using different factors. Emission factors used could become a permit condition, and the Division of Air Quality can ask for a test to confirm emissions.

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13.5 Industrial Flares

13.5.1 General

Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. Natural gas, propane, ethylene, propylene, butadiene and butane constitute over 95 percent of the waste gases flared. In combustion, gaseous hydrocarbons react with atmospheric oxygen to form carbon dioxide (CO_2) and water. In some waste gases, carbon monoxide (CO) is the major combustible component. Presented below, as an example, is the combustion reaction of propane.

$$C_3H_8 + 5\ O_2 \longrightarrow 3\ CO_2 + 4\ H_2O$$

During a combustion reaction, several intermediate products are formed, and eventually, most are converted to CO_2 and water. Some quantities of stable intermediate products such as carbon monoxide, hydrogen, and hydrocarbons will escape as emissions.

Flares are used extensively to dispose of (1) purged and wasted products from refineries, (2) unrecoverable gases emerging with oil from oil wells, (3) vented gases from blast furnaces, (4) unused gases from coke ovens, and (5) gaseous wastes from chemical industries. Gases flared from refineries, petroleum production, chemical industries, and to some extent, from coke ovens, are composed largely of low molecular weight hydrocarbons with high heating value. Blast furnace flare gases are largely of inert species and CO, with low heating value. Flares are also used for burning waste gases generated by sewage digesters, coal gasification, rocket engine testing, nuclear power plants with sodium/water heat exchangers, heavy water plants, and ammonia fertilizer plants.

There are two types of flares, elevated and ground flares. Elevated flares, the more common type, have larger capacities than ground flares. In elevated flares, a waste gas stream is fed through a stack anywhere from 10 to over 100 meters tall and is combusted at the tip of the stack. The flame is exposed to atmospheric disturbances such as wind and precipitation. In ground flares, combustion takes place at ground level. Ground flares vary in complexity, and they may consist either of conventional flare burners discharging horizontally with no enclosures or of multiple burners in refractory-lined steel enclosures.

The typical flare system consists of (1) a gas collection header and piping for collecting gases from processing units, (2) a knockout drum (disentrainment drum) to remove and store condensables and entrained liquids, (3) a proprietary seal, water seal, or purge gas supply to prevent flash-back, (4) a single- or multiple-burner unit and a flare stack, (5) gas pilots and an ignitor to ignite the mixture of waste gas and air, and, if required, (6) a provision for external momentum force (steam injection or forced air) for smokeless flaring. Natural gas, fuel gas, inert gas, or nitrogen can be used as purge gas. Figure 13.5-1 is a diagram of a typical steam-assisted elevated smokeless flare system.

Complete combustion requires sufficient combustion air and proper mixing of air and waste gas. Smoking may result from combustion, depending upon waste gas components and the quantity and distribution of combustion air. Waste gases containing methane, hydrogen, CO, and ammonia usually burn without smoke. Waste gases containing heavy hydrocarbons such as paraffins above methane, olefins, and aromatics, cause smoke. An external momentum force, such as steam injection or blowing air, is used for efficient air/waste gas mixing and turbulence, which promotes smokeless

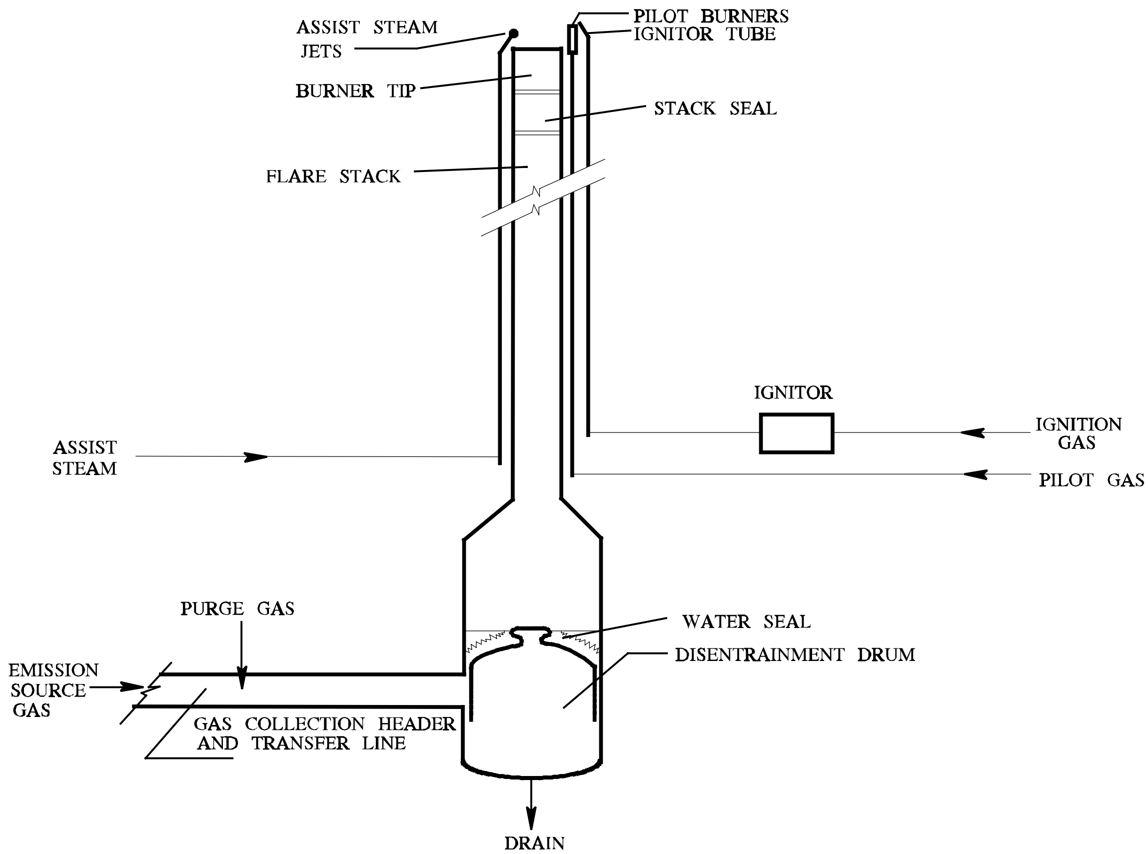

Figure 13.5-1. Diagram of a typical steam-assisted smokeless elevated flare.

flaring of heavy hydrocarbon waste gas. Other external forces may be used for this purpose, including water spray, high velocity vortex action, or natural gas. External momentum force is rarely required in ground flares.

Steam injection is accomplished either by nozzles on an external ring around the top of the flare tip or by a single nozzle located concentrically within the tip. At installations where waste gas flow varies, both are used. The internal nozzle provides steam at low waste gas flow rates, and the external jets are used with large waste gas flow rates. Several other special-purpose flare tips are commercially available, one of which is for injecting both steam and air. Typical steam usage ratio varies from 7:1 to 2:1, by weight.

Waste gases to be flared must have a fuel value of at least 7500 to 9300 kilojoules per cubic meter kJ/m^3 (200 to 250 British thermal units per cubic foot [Btu/ft^3]) for complete combustion; otherwise fuel must be added. Flares providing supplemental fuel to waste gas are known as fired, or endothermic, flares. In some cases, even flaring waste gases having the necessary heat content will also require supplemental heat. If fuel-bound nitrogen is present, flaring ammonia with a heating value of 13,600 kJ/m^3 (365 Btu/ft^3) will require higher heat to minimize nitrogen oxides (NO_x) formation.

At many locations, flares normally used to dispose of low-volume continuous emissions are designed to handle large quantities of waste gases that may be intermittently generated during plant emergencies. Flare gas volumes can vary from a few cubic meters per hour during regular operations up to several thousand cubic meters per hour during major upsets. Flow rates at a refinery could be from 45 to 90 kilograms per hour (kg/hr) (100 - 200 pounds per hour [lb/hr]) for relief valve leakage but could reach a full plant emergency rate of 700 megagrams per hour (Mg/hr) (750 tons/hr). Normal process blowdowns may release 450 to 900 kg/hr (1000 - 2000 lb/hr), and unit maintenance or minor failures may release 25 to 35 Mg/hr (27 - 39 tons/hr). A 40 molecular weight gas typically of 0.012 cubic nanometers per second (nm^3/s) (25 standard cubic feet per minute [scfm]) may rise to as high as 115 nm^3/s (241,000 scfm). The required flare turndown ratio for this typical case is over 15,000 to 1.

Many flare systems have 2 flares, in parallel or in series. In the former, 1 flare can be shut down for maintenance while the other serves the system. In systems of flares in series, 1 flare, usually a low-level ground flare, is intended to handle regular gas volumes, and the other, an elevated flare, to handle excess gas flows from emergencies.

13.5.2 Emissions

Noise and heat are the most apparent undesirable effects of flare operation. Flares are usually located away from populated areas or are sufficiently isolated, thus minimizing their effects on populations.

Emissions from flaring include carbon particles (soot), unburned hydrocarbons, CO, and other partially burned and altered hydrocarbons. Also emitted are NO_x and, if sulfur-containing material such as hydrogen sulfide or mercaptans is flared, sulfur dioxide (SO_2). The quantities of hydrocarbon emissions generated relate to the degree of combustion. The degree of combustion depends largely on the rate and extent of fuel-air mixing and on the flame temperatures achieved and maintained. Properly operated flares achieve at least 98 percent combustion efficiency in the flare plume, meaning that hydrocarbon and CO emmissions amount to less than 2 percent of hydrocarbons in the gas stream.

The tendency of a fuel to smoke or make soot is influenced by fuel characteristics and by the amount and distribution of oxygen in the combustion zone. For complete combustion, at least the stoichiometric amount of oxygen must be provided in the combustion zone. The theoretical amount of oxygen required increases with the molecular weight of the gas burned. The oxygen supplied as air ranges from 9.6 units of air per unit of methane to 38.3 units of air per unit of pentane, by volume. Air is supplied to the flame as primary air and secondary air. Primary air is mixed with the gas before combustion, whereas secondary air is drawn into the flame. For smokeless combustion, sufficient primary air must be supplied, this varying from about 20 percent of stoichiometric air for a paraffin to about 30 percent for an olefin. If the amount of primary air is insufficient, the gases entering the base of the flame are preheated by the combustion zone, and larger hydrocarbon molecules crack to form hydrogen, unsaturated hydrocarbons, and carbon. The carbon particles may escape further combustion and cool down to form soot or smoke. Olefins and other unsaturated hydrocarbons may polymerize to form larger molecules which crack, in turn forming more carbon.

The fuel characteristics influencing soot formation include the carbon-to-hydrogen (C-to-H) ratio and the molecular structure of the gases to be burned. All hydrocarbons above methane, i. e., those with a C-to-H ratio of greater than 0.33, tend to soot. Branched chain paraffins smoke more readily than corresponding normal isomers. The more highly branched the paraffin, the greater the tendency to smoke. Unsaturated hydrocarbons tend more toward soot formation than do saturated ones. Soot is eliminated by adding steam or air; hence, most industrial flares are steam-assisted and some are air-assisted. Flare gas composition is a critical factor in determining the amount of steam necessary.

Since flares do not lend themselves to conventional emission testing techniques, only a few attempts have been made to characterize flare emissions. Recent EPA tests using propylene as flare gas indicated that efficiencies of 98 percent can be achieved when burning an offgas with at least 11,200 kJ/m^3 (300 Btu/ft^3). The tests conducted on steam-assisted flares at velocities as low as 39.6 meters per minute (m/min) (130 ft/min) to 1140 m/min (3750 ft/min), and on air-assisted flares at velocities of 180 m/min (617 ft/min) to 3960 m/min (13,087 ft/min) indicated that variations in incoming gas flow rates have no effect on the combustion efficiency. Flare gases with less than 16,770 kJ/m^3 (450 Btu/ft^3) do not smoke.

Table 13.5-1 presents flare emission factors, and Table 13.5-2 presents emission composition data obtained from the EPA tests.[1] Crude propylene was used as flare gas during the tests. Methane was a major fraction of hydrocarbons in the flare emissions, and acetylene was the dominant intermediate hydrocarbon species. Many other reports on flares indicate that acetylene is always formed as a stable intermediate product. The acetylene formed in the combustion reactions may react further with hydrocarbon radicals to form polyacetylenes followed by polycyclic hydrocarbons.[2]

In flaring waste gases containing no nitrogen compounds, NO is formed either by the fixation of atmospheric nitrogen (N) with oxygen (O) or by the reaction between the hydrocarbon radicals present in the combustion products and atmospheric nitrogen, by way of the intermediate stages, HCN, CN, and OCN.[2] Sulfur compounds contained in a flare gas stream are converted to SO_2 when burned. The amount of SO_2 emitted depends directly on the quantity of sulfur in the flared gases.

Table 13.5-1 (English Units). EMISSION FACTORS FOR FLARE OPERATIONS[a]

EMISSION FACTOR RATING: B

Component	Emission Factor ($lb/10^6$ Btu)
Total hydrocarbons[b]	0.14
Carbon monoxide	0.37
Nitrogen oxides	0.068
Soot[c]	0 - 274

[a] Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.
[b] Measured as methane equivalent.
[c] Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.

Table 13.5-2. HYDROCARBON COMPOSITION OF FLARE EMISSION[a]

Composition	Volume %	
	Average	Range
Methane	55	14 - 83
Ethane/Ethylene	8	1 - 14
Acetylene	5	0.3 - 23
Propane	7	0 - 16
Propylene	25	1 - 65

[a] Reference 1. The composition presented is an average of a number of test results obtained under the following sets of test conditions: steam-assisted flare using high-Btu-content feed; steam-assisted using low-Btu-content feed; air-assisted flare using high-Btu-content feed; and air-assisted flare using low-Btu-content feed. In all tests, "waste" gas was a synthetic gas consisting of a mixture of propylene and propane.

References For Section 13.5

1. *Flare Efficiency Study*, EPA-600/2-83-052, U. S. Environmental Protection Agency, Cincinnati, OH, July 1983.

2. K. D. Siegel, *Degree Of Conversion Of Flare Gas In Refinery High Flares*, Dissertation, University of Karlsruhe, Karlsruhe, Germany, February 1980.

3. *Manual On Disposal Of Refinery Wastes, Volume On Atmospheric Emissions*, API Publication 931, American Petroleum Institute, Washington, DC, June 1977.

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D R A F T
OCTOBER 1990

New Source Review Workshop Manual

Prevention of Significant Deterioration and Nonattainment Area Permitting

TABLE OF CONTENTS

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

TABLE OF CONTENTS - Continued

Page

TABLES - Continued

TABLE OF CONTENTS - Continued

Page

FIGURES

TABLE OF CONTENTS - Continued

PREFACE

This document was developed for use in conjunction with new source review workshops and training, and to guide permitting officials in the implementation of the new source review (NSR) program. It is not intended to be an official statement of policy and standards and does not establish binding regulatory requirements; such requirements are contained in the regulations and approved state implementation plans. Rather, the manual is designed to (1) describe in general terms and examples the requirements of the new source regulations and pre-existing policy; and (2) provide suggested methods of meeting these requirements, which are illustrated by examples. Should there be any apparent inconsistency between this manual and the regulations (including any policy decisions made pursuant to those regulations), such regulations and policy shall govern. This document can be used to assist those people who may be unfamiliar with the NSR program (and its implementation) to gain a working understanding of the program.

The focus of this manual is the prevention of significant deterioration (PSD) portion of the NSR program found in the Federal Regulations at 40 CFR 52.21. It does not necessarily describe the specific requirements in those areas where the PSD program is conducted under a state implementation plan (SIP) which has been developed and approved in accordance with 40 CFR 51.166. The reader is cautioned to keep this in mind when using this manual for general program guidance. In most cases, portions of an approved SIP that are different from those described in this manual will be more restrictive. Consequently, it is suggested that the reader also obtain program information from a State or local agency to determine all requirements that may apply in a area.

The examples presented in this manual are presented for illustration purposes only. They are fictitious and are designed to impart a basic understanding of the NSR regulations and requirements.

A number of terms and acronyms used in this manual have specific meanings within the context of the NSR program. Since this manual is intended for use by those persons generally familiar with NSR these terms are used throughout this document, often without definition. To aid users of the document who are unfamiliar with these terms, general definitions of these terms can be found in Appendix A. The specific regulatory definitions for most of the terms can be found in 40 CFR 52.21. Should there be any apparent inconsistency between the definitions contained in Appendix A and the regulatory definitions or requirements found in Part 40 of the Code of Federal Regulations (including any policy decisions made pursuant to those regulations), the regulations and policy decisions shall govern.

MANUAL ORGANIZATION

The manual is organized into three parts. Part I contains five chapters (Chapters A - E) covering the PSD program requirements. Chapter A describes the PSD applicability criteria and process used to determine if a proposed new or modified stationary source is required to obtain a PSD permit. Chapter B discusses the process by which best available control technology (BACT) is determined for new or modified emissions units. Chapter C discusses the PSD air quality analysis used to demonstrate that the proposed construction will not cause or contribute to a violation of any applicable National Ambient Air Quality Standard or PSD increment. Chapter D discusses the PSD additional impacts analyses which assess the impact of air, ground, and water pollution on soils, vegetation, and visibility caused by an increase in emissions at the subject source. Chapter E identifies class I areas, describes the procedures involved in preparing and reviewing a permit application for a proposed source with potential class I area air quality impacts.

Part II of the manual (Chapters F and G) covers the nonattainment area (NAA) permit program requirements for new major sources and major modifications. Chapter F describes the NAA applicability criteria for new or modified stationary sources locating in a nonattainment area. Chapter G provides a basic overview of the NAA preconstruction review requirements.

Part III (Chapters H and I) covers the major source permit itself. Chapter H discusses the elements of an effective and enforceable permit. Chapter I discusses permit drafting.

INTRODUCTION AND OVERVIEW

Major stationary sources of air pollution and major modifications to major stationary sources are required by the Clean Air Act to a obtain an air pollution permit before commencing construction. The process is called new source review (NSR) and is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where air quality is acceptable (attainment and unclassifiable areas). Permits for sources in attainment areas are referred to as prevention of significant air quality deterioration (PSD) permits; while permits for sources located in nonattainment areas are referred to as NAA permits. The entire program, including both PSD and NAA permit reviews, is referred to as the NSR program.

The PSD and NAA requirements are pollutant specific. For example, a facility may emit many air pollutants, however, depending on the magnitude of the emissions of each pollutant, only one or a few may be subject to the PSD or NAA permit requirements. Also, a source may have to obtain both PSD and NAA permits if the source is in an area where one or more of the pollutants is designated nonattainment.

On August 7, 1977, Congress substantially amended the Clean Air Act and outlined a rather detailed PSD program. On June 19, 1978, EPA revised the PSD regulations to comply with the 1977 Amendments. The June 1978 regulations were challenged in a lengthy judicial review process. As a result of the judicial process on August 7, 1980, EPA extensively revised both the PSD and NAA regulations. Five sets of regulations resulted from those revisions. These regulations and subsequent modifications represent the current NSR regulatory requirements.

The first set of regulations, 40 CFR 51.166, specifies the minimum requirements that a PSD air quality permit program under Part C of the Act must contain in order to warrant approval by EPA as a revision to a State implementation plan (SIP). The second set, 40 CFR 52.21, delineates the federal PSD permit program, which currently applies as part of the SIP, in approximately one third of States that have not submitted a PSD program meeting the requirements of 40 CFR 51.166. In other words, roughly two thirds of the States are implementing their own PSD program which has been approved by EPA as meeting the minimal requirements for such a program, while the remaining States have been delegated the authority to implement the federal PSD program.

The basic goals of the PSD regulations are: (1) to ensure that economic growth will occur in harmony with the preservation of existing clean air resources to prevent the development of any new nonattainment problems; (2) to protect the public health and welfare from any adverse effect which might occur even at air pollution levels better than the national ambient air quality standards (NAAQS); and (3) to preserve, protect, and enhance the air quality in areas of special natural recreational, scenic, or historic value, such as national parks and wilderness areas. The primary provisions of the

PSD regulations require that new major stationary sources and major modifications be carefully reviewed prior to construction to ensure compliance with the NAAQS, the applicable PSD air quality increments, and the requirement to apply the BACT on the project's emissions of air pollutants.

The third set, 40 CFR 51.165(a) and (b), specifies the elements of an approvable State permit program for preconstruction review for nonattainment purposes under Part D of the Act. A major new source or major modification which would locate in an area designated as nonattainment and subject to a NAA permit must meet stringent conditions designed to ensure that the new source's emissions will be controlled to the greatest degree possible; that more than equivalent offsetting emissions reductions ("emission offsets") will be obtained from existing sources; and that there will be progress toward achievement of the NAAQS.

The forth and fifth sets, 40 CFR Part 51, Appendix S (Offset Ruling) and 40 CFR 52.24 (construction moratorium) respectively, can apply in certain circumstances where a nonattainment area SIP has not been fully approved by EPA as meeting the requirements of Part D of the Act.

Briefly, the requirements of the PSD regulations apply to new major stationary sources and major modifications. A "major stationary source" is any source type belonging to a list of 28 source categories which emits or has the potential to emit 100 tons per year or more of any pollutant subject to regulation under the Act, or any other source type which emits or has the potential to emit such pollutants in amounts equal to or greater than 250 tons per year. A stationary source generally includes all pollutant-emitting activities which belong to the same industrial grouping, are located on contiguous or adjacent properties, and are under common control.

A "major modification" is generally a physical change or a change in the method of operation of a major stationary source which would result in a contemporaneous significant net emissions increase in the emissions of any regulated pollutant. In determining if a proposed increase would cause a significant net increase to occur, several detailed calculations must be performed.

If a source or modification thus qualifies as major, its prospective location or existing location must also qualify as a PSD area, in order for PSD review to apply. A PSD area is one formally designated by the state as "attainment" or "unclassifiable" for any pollutant for which a national ambient air quality standard exists.

No source or modification subject to PSD review may be constructed without a permit. To obtain a PSD permit an applicant must:

1. apply the best available control technology (BACT);
A BACT analysis is done on a case-by-case basis, and considers energy, environmental, and economic impacts in determining the maximum degree of reduction achievable for the proposed source or modification. In no event can the

determination of BACT result in an emission limitation which would not meet any applicable standard of performance under 40 CFR Parts 60 and 61.

2. conduct an ambient air quality analysis;

Each PSD source or modification must perform an air quality analysis to demonstrate that its new pollutant emissions would not violate either the applicable NAAQS or the applicable PSD increment.

3. analyze impacts to soils, vegetation, and visibility;

An applicant is required to analyze whether its proposed emissions increases would impair visibility, or impact on soils or vegetation. Not only must the applicant look at the direct effect of source emissions on these resources, but it also must consider the impacts from general commercial, residential, industrial, and other growth associated with the proposed source or modification.

4. not adversely impact a Class I area; and

If the reviewing authority receives a PSD permit application for a source that could impact a Class I area, it notifies the Federal Land Manager and the federal official charged with direct responsibility for managing these lands. These officials are responsible for protecting the air quality-related values in Class I areas and for consulting with the reviewing authority to determine whether any proposed construction will adversely affect such values. If the Federal Land Manager demonstrates that emissions from a proposed source or modification would impair air quality-related values, even though the emissions levels would not cause a violation of the allowable air quality increment, the Federal Land Manager may recommend that the reviewing authority deny the permit.

5. undergo adequate public participation by applicant.

Specific public notice requirements and a public comment period are required before the PSD review agency takes final action on a PSD application.

CHAPTER A
PSD APPLICABILITY

I. INTRODUCTION

An applicability determination, as discussed in this section, is the process of determining whether a preconstruction review should be conducted by, and a permit issued to, a proposed new source or a modification of an existing source by the reviewing authority, pursuant to prevention of significant deterioration (PSD) requirements.

There are three basic criteria in determining PSD applicability. The first and primary criterion is whether the proposed project is sufficiently large (in terms of its emissions) to be a "major" stationary source or "major" modification. Source size is defined in terms of "potential to emit," which is its capability at maximum design capacity to emit a pollutant, except as constrained by federally-enforceable conditions (which include the effect of installed air pollution control equipment and restrictions on the hours of operation, or the type or amount of material combusted, stored or processed).

A new source is major if it has the potential to emit any pollutant regulated under the Act in amounts equal to or exceeding specified major source thresholds [100 or 250 tons per year (tpy)] which are predicated on the source's industrial category. A major modification is a physical change or change in the method of operation at an existing major source that causes a significant "net emissions increase" at that source of any pollutant regulated under the Act.

The second criterion for PSD applicability is that a new major source would locate, or the modified source is located, in a PSD area. A PSD area is one formally designated, pursuant to section 107 of the ACT and 40 CFR 81, by a State as "attainment" or "unclassifiable" for any criteria pollutant, i.e., an air pollutant for which a national ambient air quality standard exists.

The third criterion is that the pollutants emitted in, or increased by, "significant" amounts by the project are subject to PSD. A source's location can be attainment or unclassified for some pollutants and simultaneously nonattainment for others. If the project would emit only pollutants for which the area has been designated nonattainment, PSD would not apply.

The purposes of a PSD applicability determination are therefore:

(1) to determine whether a proposed new source is a "major stationary source," or if a proposed modification to an existing source is a "major modification;"

(2) to determine if proposed conditions and restrictions, which will limit emissions from a new source or an existing source that is proposing modification to a level that avoids preconstruction review requirements, are legitimate and federally-enforceable; and

(3) to determine for a major new source or a major modification to an existing source which pollutants are subject to preconstruction review.

In order to perform a satisfactory applicability determination, numerous pieces of information must be compiled and evaluated. Certain information and analyses are common to applicability determinations for both new sources and modified sources; however, there are several major differences. Consequently, two detailed discussions follow in this section: PSD applicability determinations for major new sources and PSD applicability determinations for modifications of existing sources. The common elements will be covered in the discussion of new source applicability. They are the following:

* defining the source;
* determining the source's potential to emit;
* determining which major source threshold the source is subject to; and
* assessing the impact on applicability of the local air quality, i.e., the attainment designation, in conjunction with the pollutants emitted by the source.

II. NEW SOURCE PSD APPLICABILITY DETERMINATIONS

II.A. DEFINITION OF SOURCE

For the purposes of PSD a <u>stationary source</u> is any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Clean Air Act (the Act). "Building, structure, facility, or installation" means all the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties and are under common ownership or control. An <u>emissions unit</u> is any part of a stationary source that emits or has the potential to emit any pollutant subject to regulation under the Act.

The term "same industrial grouping" refers to the "major groups" identified by two-digit codes in the Standard Industrial Classification (SIC)

Manual, which is published by the Office of Management and Budget. The 1972 edition of the SIC Manual, as amended in 1977, is cited in the current PSD regulations as the basis for classifying sources. Sources not found in that edition or the 1977 supplement may be classified according to the most current edition.

For example a chemical complex under common ownership manufactures polyethylene, ethylene dichloride, vinyl chloride, and numerous other chlorinated organic compounds. Each product is made in separate processing equipment with each piece of equipment containing several emission units. All of the operations fall under SIC Major Group 28, "Chemicals and Allied Products;" therefore, the complex and all its associated emissions units constitute one source.

In most cases, the property boundary and ownership are easily determined. A frequent question, however, particularly at large industrial complexes, is how to deal with multiple emissions units at a single location that do not fall under the same two-digit SIC code. In this situation the source is classified according to the primary activity at the site, which is determined by its principal product (or group of products) produced or distributed, or by the services it renders. Facilities that convey, store, or otherwise assist in the production of the principal product are called <u>support facilities</u>.

For example, a coal mining operation may include a coal cleaning plant, which is located at the mine. If the sole purpose of the cleaning plant is to process the coal produced by the mine, then it is considered to be a support facility for the mining operation. If, however, the cleaning plant is collocated with a mine, but accepts more than half of its feedstock from other mines (indicating that the activities of the collocated mine are incidental) then coal cleaning would be the primary activity and the basis for the classification.

Another common situation is the collocation of power plants with manufacturing operations. An example would be a silicon wafer and semiconductor manufacturing plant that generates its own steam and electricity with fossil fuel-fired boilers. The boilers would be considered part of the source because the power plant supports the primary activity of the facility.

An emissions unit serving as a support facility for two or more primary activities (sources) is to be considered part of the primary activity that relies most heavily on its support.

For example, a steam boiler jointly owned and operated by two sources would be included with the source that consumes the most steam.

As a corollary to the examples immediately above, suppose a power plant, is co-owned by the semiconductor plant and a chemical manufacturing plant. The power plant provides 70 percent of its total output (in Btu's per hour) as steam and electricity to the semiconductor plant. It sells only steam to the chemical plant. In the case of co-generation, the support facility should be assigned to a primary activity based on pro rata fuel consumption that is required to produce the energy bought by each of the support facility's customers, since the emission rates in pounds per Btu are different for steam and electricity. In this example then, the power plant would be considered part of the semiconductor plant.

It is important to note that if a new support facility would by itself be a major source based on its source category classification and potential to emit, it would be subject to PSD review even though the primary source, of which it is a part, is not major and therefore exempt from review. The conditions surrounding such a determination is discussed further in the section on major source thresholds (see Section II.C.).

II.B. POTENTIAL TO EMIT

II.B.1. BASIC REQUIREMENTS

The potential to emit of a stationary source is of primary importance in establishing whether a new or modified source is major. Potential to emit is 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, provided the limitation or its effect on emissions is federally-enforceable, shall be treated as part of its design. Example limitations include:

(1) *Requirements to install and operate air pollution control equipment at prescribed efficiencies;*

(2) *Restrictions on design capacity utilization [note that these types of limitations are not explicitly mentioned in the regulations, but in certain instances do meet the criteria for limiting potential to emit];*

(3) *Restrictions on hours of operation; and*

(4) *Restrictions on the types or amount of material processed, combusted or stored.*

II.B.2. ENFORCEABILITY OF LIMITS

For any limit or condition to be a legitimate restriction on potential to emit, that limit or condition must be federally-enforceable, which in turn requires practical enforceability (see Appendix A) [see U.S. v. Louisiana-Pacific Corporation, 682 F. Supp. 1122, Civil Action No. 86-A-1880 (D. Colorado, March 22, 1988). Practical enforceability means the source and/or enforcement authority must be able to show continual compliance (or noncompliance) with each limitation or requirement. In other words, adequate testing, monitoring, and record-keeping procedures must be included either in an applicable federally issued permit, or in the applicable federally approved SIP or the permit issued under same.

For example, a permit that limits actual source emissions on an annual basis only (e.g., the facility is limited solely to 249 tpy) cannot be considered in determining potential to emit. It contains none of the basic requirements and is therefore not capable of ensuring continual compliance, i.e., it is not enforceable as a practical matter.

The term "federally-enforceable" refers to all limitations and conditions which are enforceable by the Administrator, including:

! *requirements developed pursuant to any new source performance standards (NSPS) or national emission standards for hazardous air pollutants (NESHAP),*

! *requirements within any applicable federally-approved State implementation plan, and*

! *any requirements contained in a permit issued pursuant to federal PSD regulations (40 CFR 52.21), or pursuant to PSD or operating permit provisions in a SIP which has been federally approved in accordance with 40 CFR 51 Subpart I.*

Federally-enforceable permit conditions that may be used to limit potential to emit can be expressed in a variety of terms and usually include a combination of two or more of the following four requirements in conjunction with appropriate record-keeping requirements for verification of compliance:

(1) Installation and continuous operation and maintenance of air pollution controls, usually expressed as both a required abatement efficiency of the maximum uncontrolled emission rate and a maximum outlet concentration or hourly emission rate (flow rate x concentration);

A typical example might be a 255 tpy limit on a stone crushing operation. The enforceable permit conditions could be a maximum emission rate of 58 lbs/hr, a maximum concentration of 0.1 grains per dry standard cubic foot (gr/dSCF) and a maximum flow rate of 67,000 dSCFM based on nameplate capacity and 8760 hours per year. In addition, the permit should also stipulate a minimum 90 percent overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and a baghouse.

(2) Capacity limitations;

The stone crusher decides to limit its potential to emit to 180 tpy by limiting the feed rate to 70 percent of the nameplate capacity. One of the enforceable limits becomes a stone feed rate (tons/hr.) based on 70 percent of nameplate capacity with a federally-enforceable requirement for a method or device for measuring the feed rate on an hourly basis. Another approach is to limit the PM emissions rate to 41 lbs/hr. A third alternative is to retain a maximum concentration of 0.1 gr./dSCF, but limit the maximum exhaust rate to 47,000 dSCFM due to the decrease in feed rate. In all these cases, the 90 percent overall reduction of particulate matter (PM) emissions on an hourly basis via capture hoods and baghouse would also be maintained.

In another example, the potential to emit of a boiler with a design input capacity of 200 million Btu/hour is limited to a 100-million-Btu/hr fuel input rate by the permit, which *requires that the boiler's heat input not exceed 50 percent of its rated capacity. The permit would further require that compliance be demonstrated with a continuously recording fuel meter and concurrent monitoring and recording of fuel heating value to show that the fuel input does not exceed 100-million-Btu/hr.*

(3) Restrictions on hours of operation, including seasonal operation; and

In the stone crusher example, the operator may choose to limit the hours of operation per year to keep the potential to emit below the major source threshold of 250 tpy. For example, using the same maximum concentration and flow rate and minimum overall control efficiency limitations as in (1) above, a restriction on the number of 8-hour shifts to two, i.e., 16 hours per day would reduce the potential uncontrolled emissions by 33 percent to 170 tpy.

In another example, a citrus dryer that only operates during the growing season could have its potential to emit limited by a permit restriction on the hours of operation, and further, by prohibiting the dryer from operating between March and November.

(4) Limitations on raw materials used (including fuel combusted) and stored.

An example of this type of limit would be a maximum 1 percent sulfur content in the coal feed for a power plant. Another would be a condition that a surface coater only use water-based or higher solids coatings with a maximum VOC content of 2.0 pounds VOC per gallon solids deposited on the substrate with requisite limits on coating usage (gallons/hr or gallons/yr on a 12-month rolling time period).

In addition to limits in major source construction permits or federally approved SIP limits for major sources, terms and conditions contained in State operating permits will be considered federally-enforceable under the following conditions:

(1) the State's operating permit program is approved by EPA and incorporated into the applicable SIP under section 110 of the Act;

(2) the operating permits are legally binding on the source under the SIP and the SIP specifically provides that permits that

are not legally binding may be deemed not "federally-enforceable;"

(3) *all emissions limitations, controls, and other requirements imposed by such permits are no less stringent than any counterpart limitations and requirements in the SIP, or in standards established under sections 111 and 112 of the ACT;*

(4) *the limitations, controls and requirements in the operating permits are permanent, quantifiable, and otherwise enforceable as a practical matter; and*

(5) *the permits are issued subject to public participation, i.e., timely notice, opportunity for public comment, etc.*

(See also, 54 FR 27281, June 28, 1989.)

A minor (i.e., a non-major) source construction permit issued to a source by a State may be used to determine the potential to emit if:

! *the State program under which the permit was issued has been approved by EPA as meeting the requirements of 40 C.F.R. Parts 51.160 through 51.164, and*

- *the provisions of the permit are federally-enforceable and enforceable as a practical matter.*

Note, however, that a permit condition that temporarily restricts production to a level at which the source does not intend to operate for any extensive time is not valid if it appears to be intended to circumvent the preconstruction review requirements for major source by making the source temporarily minor. Such permit limits cannot be used in the determination of potential to emit. Another situation that should receive careful scrutiny is the construction of a manufacturing facility with a physical capacity far greater than the limits specified in a permit condition. See also 54 FR 27280, which specifically discusses "sham" minor source permits.

An example is construction of an electric power generating unit, which is proposed to be operated as a peaking unit but which by its nature can only be economical if it is used as a base-load facility.

Remember, if the permit or SIP requirements, conditions or limits on a source are not federally-enforceable (which includes enforceable as a practical matter), potential to emit is based on full capacity and year-round operation. For additional information on federally enforceability and limiting potential to emit see Appendix A.

II.B.3. FUGITIVE EMISSIONS

As defined in the federal PSD regulations, fugitive emissions are those "...which could not reasonably pass through a stack, chimney, vent, or other functionally equivalent opening." To the extent they are quantifiable, fugitive emissions are included in the potential to emit (and increases in same due to modification), if they occur at one of the following stationary sources:

- Any belonging to one of the 28 named PSD source categories listed in Table A-1, which were explicitly identified in Section 169 of the Act as being subject to a 100-tpy emissions threshold for classification of major sources;

- Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of proposal) by New Source Performance Standards (NSPS) pursuant to Section 111 of the Act (listed in Table A-2); and

- Any belonging to a stationary source category that as of August 7, 1980, is regulated (effective date of promulgation) by National Emissions Standards for Hazardous Air Pollutants (NESHAP) pursuant to Section 112 of the Act (listed in Table A-2).

Note also that, if a source has been determined to be major, fugitive emissions, to the extent they are quantifiable, are considered in any subsequent analyses (e.g., air quality impact).

Fugitive emissions may vary widely from source to source. Examples of common sources of fugitive emission include:

- coal piles - particulate matter (PM);

- road dust - PM;

- quarries - PM; and

- leaking valves and flanges at refineries and organic chemical processing equipment - volatile organic compounds (VOC).

TABLE A-1. PSD SOURCE CATEGORIES WITH
100 tpy MAJOR SOURCE THRESHOLDS

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1. Fossil fuel-fired steam electric plants of more than 250 million Btu/hr heat input
2. Coal cleaning plants (with thermal dryers)
3. Kraft pulp mills
4. Portland cement plants
5. Primary zinc smelters
6. Iron and steel mill plants
7. Primary aluminum ore reduction plants
8. Primary copper smelters
9. Municipal incinerators capable of charging more than 250 tons of refuse per day
10. Hydrofluoric acid plants
11. Sulfuric acid plants
12. Nitric acid plants
13. Petroleum refineries
14. Lime plants
15. Phosphate rock processing plants
16. Coke oven batteries
17. Sulfur recovery plants
18. Carbon black plants (furnace plants)
19. Primary lead smelters
20. Fuel conversion plants
21. Sintering plants
22. Secondary metal production plants
23. Chemical process plants
24. Fossil fuel boilers (or combinations thereof) totaling more than 250 million Btu/hr heat input
25. Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels
26. Taconite ore processing plants
27. Glass fiber processing plants
28. Charcoal production plants

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TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Phosphate rock plants	NN	Grinding, drying and calcining facilities	09/21/79
Ammonium sulfate manufacture	Pp	Ammonium sulfate dryer	02/04/80

National Emission Standards for Hazardous Air Pollutants 40 CFR 61

Pollutant	Subpart	Affected Facility	Promulgated Date
Beryllium	C	Extraction plants, ceramic plants, foundries, incinerators, propellant plants, machining operations	04/06/73
Beryllium, rocket motor firing	D	Rocket motor firing	04/06/73
Mercury	E	Ore processing, chloralkali manufacturing, sludge incinerators	04/06/73
Vinyl chloride	F	Ethylene dichloride manufacture via 02 HC1, vinyl chloride manufacture, polyvinyl chloride manufacture	10/21/76
Asbestos	M	Asbestos mills; roadway surfacing (asbestos tailings); demolition; spraying, fabri cation, waste disposal and insulting	04/06/73
		Manufacture of shotgun shells, renovation, fabrication, asphalt concrete, products containing asbestos	06/19/78

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Fossil-fuel fired steam generators for which construction is commenced after 08/17/71 and before 09/19/78	D	Utility and industrial (coal, oil, gas, wood, lignite)	08/17/71
Elect. utility steam generating units for which construction is commenced after 09/18/78	Da	Utility boilers (solid, liquid, and gaseous fuels)	09/19/78
Municipal incinerators (≥50 tons/day)	E	Incinerators	08/17/71
Portland cement plants	F	Kiln, clinker cooler	08/17/71
Nitric acid plants	G	Process equipment	08/17/71
Sulfuric acid plants	H	Process equipment	08/17/71
Asphalt concrete plants	I	Process equipment	06/11/73
Petroleum refineries	J	Fuel gas combustion devices Claus sulfur recovery	06/11/73
Storage vessels for petroleum liquids construction after 06/11/73 and prior to 05/19/78	K	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity	06/11/73
Storage vessels for petroleum liquids construction after 05/18/78	Ka	Gasoline, crude oil, and distillate storage tanks ≥40,000 gallons capacity, vapor pressure ≥1.5	05/18/78
Secondary lead smelters and refineries	L	Blast and reverberatory furnaces, pot furnaces	06/11/73

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Secondary brass and bronze ingot production plants	M	Reverberatory and electric furnaces and blast furnaces	06/11/73
Iron and steel mills	N	Basic oxygen process furnaces (BOPF) Primary emission sources	06/11/73
Sewage treatment plants	O	Sludge incinerators	06/11/73
Primary copper smelters	P	Roaster, smelting furnace, converter dryers	10/16/74
Primary zinc smelters	Q	Roaster sintering machine	10/16/74
Primary lead smelters	R	Sintering machine, electric smelting furnace, converter Blast or reverberatory furnace, sintering machine discharge end	10/16/74
Primary aluminum reduction plants	S	Pot lines and anode bake plants	10/23/74
Primary aluminum reduction plants 111(d)		Pot lines and anode bake plants	04/11/79
Phosphate fertilizer industry	T	Wet process phosphoric	10/22/74
	U	Superphosphoric acid	
	V	Diammonium phosphate	
	W	Triple superphosphate products	
	X	Granular triple superphosphate products	
Coal preparation plants	Y	Air tables and thermal dryers	10/24/74
Ferroalloy production facilities	Z	Specific furnaces	10/21/74

TABLE A-2. NEW SOURCE PERFORMANCE STANDARDS PROPOSED AND NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS PROMULGATED PRIOR TO August 7, 1980

New Source Performance Standards 40 CFR 60

Source	Subpart	Affected Facility	Proposed Date
Steel plants: electric arc furnaces	AA	Electric arc furnaces	10/21/74
Kraft pulp mills	BB	Digesters, lime kiln recovery furnace, washer, evaporator, strippers, smelt and BLO tanks Recovery furnace, lime, kiln, smelt tank	09/24/76
Glass manufacturing plants	CC	Glass melting furnace	06/15/79
Grain elevators	DD	Truck loading and unloading stations, barge or ship loading and unloading stations railcar loading and unloading stations, and grain handling operations	01/13/77
Stationary gas turbines	GG	Each gas turbine	10/03/77
Lime manufacturing plants	HH	Rotary kiln, hydrator	05/03/77
Degreasers (organic solvent cleaners)	JJ	Cold cleaner, vapor degreaser, conveyorized degreaser	06/11/80
Lead acid battery manufacturing plants	KK	Lead oxide production grid casting, paste mixing, three-process operation and lead reclamation	01/14/80
Automobile and light-duty truck surface coating operations	MM	Prime, guide coat, and top coat operations at assembly plants	10/05/79

Due to the variability even among similar sources, fugitive emissions should be quantified through a source-specific engineering analysis. Suggested (but by no means all of the useful) references for fugitive emissions data and associated analytic techniques are listed in Table A-3.

Remember, if emissions can be "reasonably" captured and vented through a stack they are not considered "fugitive" under EPA regulations. In such cases, these emissions, to the extent they are quantifiable, would count toward the potential to emit regardless of source or facility type.

For example, the emissions from a rock crushing operation that could reasonably be equipped with a capture hood are not considered fugitive and would be included in the source's potential to emit.

As another example, VOC emissions, even if in relatively small quantities, coming from leaking valves inside a large furniture finishing plant, are typically captured and exhausted through the building ventilation system. They are, therefore, measurable and should be included in the potential to emit.

As a counter example, however, it may be unreasonable to expect that relatively small quantities of VOC emissions, caused by leaking valves at outside storage tanks of the large furniture finishing operation, could be captured and vented to a stack.

II.B.4. SECONDARY EMISSIONS

Secondary emissions are not considered in the potential emissions accounting procedure. Secondary emissions are those emissions which, although associated with a source, <u>are not emitted from the source itself</u>. Secondary emissions occur from any facility that is not a part of the source being reviewed, but which would not be constructed or increase its emissions except as a result of the construction or operation of the major stationary source or major modification. Secondary emissions do not include any emissions from any off-site facility which would be constructed or increase its emissions for some reason other than the construction or operation of the major stationary source or major modification.

TABLE A-3. SUGGESTED REFERENCES FOR ESTIMATING FUGITIVE EMISSIONS

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1. Emission Factors and Frequency of Leak Occurrence for Fittings in Refinery Process Units. Radian Corporation. EPA-600/2-79-044. February 1979.

2. Protocols for Generating Unit - Specific Emission Estimates for Equipment Leaks of VOC and VHAP. U.S. Environmental Protection Agency. EPA-450/3-88-0100.

3. Improving Air Quality: Guidance for Estimating Fugitive Emissions From Equipment. Chemical Manufacturers Association. January 1989.

4. Compilation of Air Pollutant Emission Factors, 3rd ed. U.S. Environmental Protection Agency. AP-42 (including Supplements 1-8). May 1978.

5. Technical Guidance for Control of Industrial Process Fugitive Particulate Emissions. Pedco Environmental, Inc. EPA-450/3-77-010. March 1977.

6. Fugitive Emissions From Integrated Iron and Steel Plants. Midwest Research Institute, Inc. EPA-600/2-78-050. March 1978.

7. Survey of Fugitive Dust from Coal Mines. Pedco Environmental, Inc. EPA-908/1-78-003. February 1978.

8. Workbook on Estimation of Emissions and Dispersion Modeling for Fugitive Particulate Sources. Utility Air Regulatory Group. September 1981.

9. Improved Emission factors for Fugitive Dust from Weston Surface Coal Mining Sources, Volumes I and II. U.S. Environmental Protection Agency. EPA-600/7-84-048.

10. Control of Open Fugitive Dust Sources. Midwest Research Institute. EPA-450/3-88-008. September 1988.

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An example is the emissions from an existing quarry owned by one company that doubles its production to supply aggregate to a cement plant proposed for construction as a major source on adjacent property by another company. The quarry's increase in emissions would be secondary emissions which the cement plant's ambient impacts analysis must consider.

Secondary emissions do not include any emissions which come directly from a mobile source, such as emissions from the tailpipe of a motor vehicle or from the propulsion unit of a train or a vessel. This exclusion is limited, however, to only those mobile sources that are regulated under Title II of the Act (see 43 FR 26403 - note #9). Most off-road vehicles are not regulated under Title II and are usually treated as area sources. [As a result of a court decision in NRDC v. EPA, 725 F.2d 761 (D.C. Circuit 1984), emissions from vessels at berth ("dockside") not to be included in the determination of secondary emissions but are considered primary emissions for applicability purposes.]

Although secondary emissions are excluded from the potential emissions estimates used for applicability determinations, they must be considered in PSD analyses if PSD review is required. In order to be considered, however, secondary emissions must be specific, well-defined, quantifiable, and impact the same general area as the stationary source or modification undergoing review.

II.B.5. REGULATED POLLUTANTS

The potential to emit must be determined separately for each pollutant regulated by the Act and emitted by the new or modified source. Twenty-six compounds, 6 criteria and 20 noncriteria, are regulated as air pollutants by the Act as of December 31, 1989. They are listed in Table A-4. Note that EPA has designated PM-10 (particulate matter with an aerodynamic diameter less than 10 microns) as a criteria pollutant by promulgating NAAQS for this pollutant as a replacement for total PM. Thus, the determination of potential to emit for PM-10 emissions as well as total PM emissions (which are still regulated by many NSPS) is required in applicability determinations. Several halons and chlorofluorocarbon (CFC) compounds have been added to the list of regulated pollutants as a result of the ratification of the Montreal Protocol by the United States in January 1989.

II.B.6. METHODS FOR DETERMINING POTENTIAL TO EMIT

In determining a source's potential to emit, two parameters must be measured, calculated, or estimated in some way. They are:

- *the worst case uncontrolled emissions rate, which is based on the dirtiest fuels, and/or the highest emitting materials and operating conditions that the source is or will be permitted to use under federally-enforceable requirements, and*

- *the efficiency of the air pollution control system, if any, in use or contemplated for the worst case conditions, where the use of such equipment is federally-enforceable.*

TABLE A-4. SIGNIFICANT EMISSION RATES OF POLLUTANTS
REGULATED UNDER THE CLEAN AIR ACT

	Pollutant	Emissions rate (tons/year)
Pollutants listed at 40 CFR 52.21(b)(23)		
*	Carbon monoxide	100
*	Nitrogen oxides[a]	40
*	Sulfur dioxide[b]	40
*	Particulate matter (PM/PM-10)	25/15
*	Ozone (VOC)	40 (of VOC's)
*	Lead	0.6
	Asbestos	0.007
	Beryllium	0.0004
	Mercury	0.1
	Vinyl chloride	1
	Fluorides	3
	Sulfuric acid mist	7
	Hydrogen sulfide (H_2S)	10
	Total Reduced sulfur compounds (including H_2S)	10

* Criteria Pollutants

[a] Nitrogen dioxide is the compound regulated as a criteria pollutant; however, significant emissions are based on the sum of all oxides of nitrogen.

[b] Sulfur dioxide is the measured surrogate for the criteria pollutant sulfur oxides. Sulfur oxides have been made subject to regulation explicitly through the proposal of 40 CFR 60 Subpart J as of August 17, 1989.

TABLE A-4. (Concluded) SIGNIFICANT EMISSION RATES OF POLLUTANTS REGULATED UNDER THE CLEAN AIR ACT

Pollutant	Emissions rate (tons/year)
Other pollutants regulated by the Clean Air Act:[cd]	
Benzene	Any emission rate
Arsenic	
Radionuclides	
Radon-222	
Polonium-210	
CFC's 11,12, 112, 114, 115	
Halons 1211, 1301, 2402	

[c] Significant emission rates have not been promulgated for these pollutants, and until such time, any emissions by a new major sources or any increase in emissions at an existing major source due to modification, are "significant."

[d] Regulations covering several pollutants such as cadmium, coke oven emissions, and municipal waste incinerator emissions have recently been proposed. Applicants should, therefore, verify what pollutants have been regulated under the Act at the time of application.

Sources of the worst-case uncontrolled emissions and applicable control system efficiencies could be any of the following:

- *Emissions data from compliance tests or other source tests,*
- *Equipment vendor emissions data and guarantees;*
- *Emission limits and test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111d standards for designated pollutants;*
- *AP-42 emission factors (see Table A-3, Reference 2);*
- *Emission factors from technical literature; and*
- *State emission inventory questionnaires for comparable sources.*

The effect of other restrictions (federally-enforceable and practically-enforceable) should also be factored into the results. The potential to emit of each pollutant, including fugitive emissions if applicable, is estimated for each individual emissions unit. The individual estimates are then summed by pollutant over all the emissions units at the stationary source.

II.C. EMISSIONS THRESHOLDS FOR PSD APPLICABILITY

II.C.1. MAJOR SOURCES

A source is a "major stationary source" or "major emitting facility" if:

(1) It can be classified in one of the 28 named source categories listed in Section 169 of the CAA (see Table A-1) and it emits or has the potential to emit 100 tpy or more of any pollutant regulated by the Act, or

(2) it is any other stationary source that emits or has the potential to emit 250 tons per year or more of any pollutant regulated by the CAA.

For example, one of the 28 PSD source categories subject to the 100-tpy threshold is fossil fuel-fired steam generators with a heat input greater than 250 million Btu/hr. Consequently, a 300 million Btu/hr boiler that is designed and *permitted to burn any fossil fuel, i.e., coal, oil, natural gas or lignite, that emits 100 tpy or more of any regulated pollutant, e.g., SO_2, is a major stationary source. If, however, the boiler were designed and permitted to burn wood only, it would not be classified as one of the 28 PSD sources and would instead be subject to the 250 tpy threshold.*

A single, fossil fuel-fired boiler with a maximum heat input capacity of 300 million Btu/hr takes a federally-enforceable design limitation that restricts heat input to 240 million Btu/hr. Consequently, this source would not be classified within one of the 28 categories and would therefore be subject to the 250-tpy, rather than the 100-tpy, emissions threshold.

A situation frequently occurs in which an emissions unit that is included in the 28 listed source categories (and so is subject to a 100 tpy threshold), is located within a parent source whose primary activity is not on the list (and is therefore subject to a 250 tpy threshold). A source which, when considered alone, would be major (and hence subject to PSD) cannot "hide" within a different and less restrictive source category in order to escape applicability.

As an example, a proposed coal mining operation will use an on-site coal cleaning plant with a thermal dryer. The source will be defined as a coal mine because the cleaning plant will only treat coal from the mine. The mine's potential to emit (including emissions from the thermal dryer) is less than 250 tpy for every regulated pollutant; therefore, it is a "minor" source. The estimated emissions from the thermal dryer, however, will be 150 tpy particulate matter. Thermal dryers are included in the list of 28 source categories that are subject to the 100 tpy major source threshold. Consequently, the thermal dryer would be considered an emissions unit that by itself is a major source and therefore is subject to PSD review, even though the primary activity is not.

Furthermore, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a major stationary source that is subject to PSD review.

To illustrate, consider the following scenarios at an existing glass fiber processing plant, which proposes to add new equipment to increase production. Glass fiber processing plants are included in the list of 28 source categories that are subject to the 100-tpy major source threshold. The existing plant emits 40 tpy particulate, which is both its potential to emit and permitted allowable rate. It also has a potential to emit all other pollutants in less than major quantities; therefore it is a minor source.

> *Scenario 1 - The physical change will increase the source's potential to emit particulate matter by 50 tpy. Since the plant is a minor source and the increase is not major by itself, the change is not subject to PSD review.*
>
> *Scenario 2 - The physical change will increase the source's potential to emit particulate matter by 65 tpy. Since the plant is a minor source and the increase is not major by itself, neither is subject to PSD review. However, the source's potential to emit after the change will exceed the 100-tpy major source threshold, so future modifications will be scrutinized under the netting provisions (see section A.3.2).*
>
> *Scenario 3 - The physical change will increase the source's potential to emit particulate matter by 110 tpy. Since the existing plant is a minor source and the change by itself results in an emissions increase greater than the major source threshold, that change is subject to PSD review. Furthermore, the physical change makes the entire plant a major source, so future physical changes or changes in the method of operation will be scrutinized against the criteria for major modifications (see section II.A.3.2).*

II.C.2. SIGNIFICANT EMISSIONS

A PSD review is triggered in certain instances when emissions associated with a new major source or emissions increases resulting from a major modification are "significant." "Significant" emissions thresholds are defined two ways. The first is in terms of emission rates (tons/year). Table A-4 listed the pollutants for which significant emissions rates have been established.

Significant increases in emission rates are subject to PSD review in two circumstances:

(1) For a new source which is major for at least one regulated attainment or noncriteria pollutant, i.e., is subject to PSD review, all pollutants for which the area is not classified as nonattainment and which are emitted in amounts equal to or greater than those specified in Table A-4 are also subject to PSD review for its VOC emissions.

For example, an automotive assembly plant is planned for an attainment area for all criteria pollutants. The plant has a potential to emit 350 tpy VOC, 50 tpy NO_x, 60 tpy SO_2, and 10 tpy PM including 5 tpy PM-10. The 350 tpy VOC exceeds the major source threshold, and therefore subjects the plant to PSD review. The "significant" emissions thresholds for NO_x and SO_2 are 40 tpy; therefore, the NO_x and SO_2 emissions, also, will be subject to PSD review. The PM and PM-10 emissions will not exceed their significant emissions thresholds; therefore they are not subject to review.

(2) For a modification to an existing major stationary source, if both the potential increase in emissions due to the modification itself, and the resulting net emissions increase of any regulated, attainment or noncriteria pollutants are equal to or greater than the respective pollutants' significant emissions rates listed in Table A-4, the modification is "major," and subject to PSD review. Modifications are discussed in detail in Section II.D.

The second type of "significant" emissions threshold is defined as any emissions rate at a new major stationary source (or any net emissions increase associated with a modification to an existing major stationary source) that is constructed within 10 kilometers of a Class I area, and which would increase the 24-hour average concentration of any regulated pollutant in that area by 1 $\mu g/m^3$ or greater. Exceedence of this threshold triggers PSD review.

II.D. LOCAL AIR QUALITY CONSIDERATIONS FOR CRITERIA POLLUTANTS

The air quality, i.e., attainment status, of the area of a proposed new source or modified existing source will impact the applicability determination in regard to the pollutants that are subject to PSD review. As previously stated, if a new source locates in an area designated attainment or unclassifiable for any criteria pollutant, PSD review will apply to any pollutant for which the potential to emit is major (or significant, if the source is major) so long as the area is not nonattainment for that pollutant.

> *For example, a kraft pulp mill is proposed for an attainment area for SO_2, and its potential to emit SO_2 equals 55 tpy. Its potential to emit total reduced sulfur (TRS) a noncriteria pollutant, equals 295 tpy. Its potential to emit VOC will be 45 tpy and PM/PM-10, 30/5 tpy; however, the area is designated nonattainment for ozone and PM. Applicability would be assessed as follows:*
>
> > *The source would be major and subject to PSD review due to the noncriteria TRS emissions.*
> >
> > *The SO_2 emissions would therefore be subject to PSD because they are significant and the area is attainment for SO_2.*
> >
> > *The VOC emission and PM emissions would not be subject to PSD, even though their emissions are significant, because the area is designated nonattainment for those pollutants.*
> >
> > *The PM-10 emissions are neither major nor significant and would therefore not be subject to review.*

Similarly, if the modification of an existing major source, which is located in an attainment area for any criteria pollutant, results in a significant increase in potential to emit and a significant net emissions increase, the modification is subject to PSD, unless the location is designated as nonattainment for that pollutant.

Note that if the source is major for a pollutant for which an area is designated nonattainment, all significant emissions or significant emissions increases of pollutants for which the area is attainment or unclassifiable are still subject to PSD review.

II.E. SUMMARY OF MAJOR NEW SOURCE APPLICABILITY

The elements and associated information necessary for determining PSD applicability to **new** sources are outlined as follows:

Element 1 - Define the source

- includes all related activities classified under the same 2-digit SIC Code number
- must have the same owner or operator
- must be located on contiguous or adjacent properties
- includes all support facilities

Element 2 - Define applicability thresholds for major source as a whole (primary activity)

- 100 tpy for individual emissions units or groups of units that are included in the list of 28 source categories identified in Section 169 of the CAA
- 250 tpy for all other sources

Element 3 - Define project emissions (potential to emit)

- Reflects federally-enforceable air pollution control efficiency, operating conditions, and permit limitations
- Determined for each pollutant by each emissions unit
- Summed by pollutant over all emissions units
- Includes fugitive emissions for 28 listed source categories and sources subject to NSPS or NESHAPS as of August 7, 1980

Element 4 - Assess local area attainment status

- Area must be attainment or unclassifiable for at least one criteria pollutant for PSD to apply

Element 5 - Determine if source is major by comparing its potential emissions to appropriate major source threshold

- Major if <u>any</u> pollutant emitted by defined source exceeds thresholds, regardless of area designation, i.e., attainment, nonattainment, or noncriteria pollutants

- Individual unit is major if classified as a source in one of the 28 regulated source categories and emissions exceed an applicable 100-tpy threshold

Element 6 - Determine pollutants subject to PSD review

- Each attainment area and noncriteria pollutant emitted in "significant" quantities

- Any emissions or emissions increase from a major source that results in an increase of 1 $\mu g/m^3$ (24 hour average) or more in a Class I area if the major source is located or constructed within 10 kilometers of that Class I area.

II.F. NEW SOURCE APPLICABILITY EXAMPLE

The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the PSD applicability process for a new source.

In this example the proposed project is a new coal-fired electric plant. The plant will have two 600-MW lignite-fired boilers. The proposed location is near a separately-owned surface lignite mine, which will supply the fuel requirements of the power plant, and will therefore, have to increase its mining capacity with new equipment. The lignite coal will be mined and then transported to the power plant to be crushed, screened, stored, pulverized and fed to the boilers. The power plant has informed the lignite coal mine that the coal will not have to be cleaned, so the mine will not expand its coal cleaning capacity. The power plant will have on-site coal and limestone storage and handling facilities. In addition, a comparatively small auxiliary boiler will be installed to provide steam for the facility when the main boilers are inoperable. The area is designated attainment for all criteria pollutants.

The applicant proposes pollution control devices for the two 600-MW boilers which include:

- an electrostatic precipitator (ESP) for PM/PM-10 emissions control,
- a limestone scrubber flue gas desulfurization (FGD) system for SO_2 emissions control;
- low-nitrogen oxide (NO_x) burners and low-excess-air firing for NO_x emissions control; and
- controlled combustion for CO emissions control.

The first step is to determine what constitutes the source (or sources). A source is defined as all pollutant-emitting activities associated with the same industrial grouping, located on contiguous or adjacent sites, and under common control or ownership. Industrial groupings are generally defined by two-digit SIC codes. The power plant is classified as SIC major group 49; the nearby mine is SIC major group 12. They are neither under the same SIC major group number nor have the same owners, so they constitute separate sources.

The second step is to establish which major source thresholds are applicable in this case. The proposed power plant is a fossil fuel-fired steam electric plant with more than 250 million Btu/hr of heat input, making it a source included in one of the 28 PSD-listed categories. It is therefore subject to both the 100 ton per year criterion for any regulated pollutant used to determine whether a source is major and to the requirement that quantifiable fugitive emissions be included in determining potential to emit.

The emissions units at the mine are neither classified within one of the 28 PSD source categories nor regulated under Sections 111 or 112 of the Act. Therefore, the mine is compared against the 250 tpy major source threshold and fugitive emissions from the mining operations are exempt from consideration in determining whether the mine is a major stationary source.

The third step is to define the project emissions. To arrive at the potential to emit of the proposed power plant, the applicant must consider all quantifiable stack and fugitive emissions of each regulated pollutant (i.e., SO_2, NO_x, PM, PM-10, CO, VOC, lead, and the noncriteria pollutants). Therefore, fugitive PM/PM-10 emissions from haul roads, disturbed areas, coal piles, and other sources must be included in calculating the power plant's potential to emit.

All stack and fugitive emissions estimates have been obtained through detailed engineering analysis of each emissions unit using the best available data or estimating technique. Fugitive emissions are added to the emissions from the two main boilers and the auxiliary boiler in order to arrive at the total potential to emit of each regulated pollutant. The auxiliary boiler in this case is restricted by enforceable limits on operating hours proposed to be included in the source's PSD permit. If the auxiliary boiler were not limited in hours of operation, its contribution would be based on full, continuous operation, and the resulting potential emissions estimates would be higher.

The potential to emit SO_2, NO_x, PM, CO, and sulfuric acid mist each exceeds 100 tons per year. From data collected at other lignite fired power plants it is known that emissions of lead, beryllium, mercury, fluorides, sulfuric acid mist and arsenic should also be quantified. It is known that fluoride compounds are contained in the coal in significant quantities; however, engineering analyses show fluoride removal in the proposed limestone scrubber will result in insignificant stack emissions. Similarly, liquid absorption, absorption of fly ash removed in the ESP, and removal of bottom ash have been shown to maintain emissions of lead and the other regulated noncriteria pollutants below significance levels.

The only emissions at the existing mine, and consequently the only emissions increase that will occur from the expansion to serve the power plant, are fugitive PM/PM-10 emissions from mining operations. The mine's potential to emit, for PSD applicability purposes, is zero and the mine is not subject to a PSD review. The increase in fugitive emissions from the mine, however, will be classified as secondary emissions with respect to the power plant and, therefore, must be considered in the air quality analysis and additional impacts analysis for the proposed power plant if the power plant is subject to PSD review.

The next step is to compare the potential emissions of the power plant to the 100 ton per year major source threshold. If the potential to emit of any regulated pollutant is 100 tons per year or more, the power plant is classified as a major stationary source for PSD purposes. In this case, the plant is classified as a major source because SO_2, NO_x, PM, CO, and sulfuric acid mist emissions each exceed 100 tons per year. (Note that emissions of any one of these pollutants classifies the source as major.)

Once it has been determined that the proposed source is major, any regulated pollutant (for which the location of the source is not classified as nonattainment) with significant emissions is subject to a PSD review. The applicant quantified, through coal and captured fly ash analyses and through performance test results from existing sources burning equivalent coals, emissions of fluorides, beryllium, lead, mercury, and the other regulated noncriteria pollutants to determine if their emissions exceed the significance levels (see Table A-4.). Pollutants with less than significant emissions are not subject to PSD review requirements (assuming the proposed controls are accepted as BACT for SO_2, or the application of BACT for SO_2 results in equivalent or lower noncriteria pollutant emissions).

Note that, because the proposed construction site is not within 10 kilometers of a Class I area, the source's emissions are not subject to the Class I area significance criteria.

III. MAJOR MODIFICATION APPLICABILITY

A modification is subject to PSD review only if (1) the existing source that is modified is "major," and (2) the net emissions increase of any pollutant emitted by the source, as a result of the modification, is "significant," i.e., equal to or greater than the emissions rates given on Table A-4 (unless the source is located in a nonattainment area for that pollutant). Note also that <u>any</u> net emissions increase in a regulated pollutant at a major stationary source that is located within 10 kilometers of a Class I area, and which will cause an increase of 1 $\mu g/m^3$ (24 hour average) or more in the ambient concentration of that pollutant within that Class I area, is "significant".

Typical examples of modifications include (but are not limited to) replacing a boiler at a chemical plant, construction of a new surface coating line at an assembly plant, and a switch from coal to gas requiring a physical change to the plant, e.g., new piping, etc.

As discussed earlier, when a "minor" source, i.e., one that does not meet the definition of "major," makes a physical change or change in the method of operation that is by itself a major source, that physical or operational change constitutes a <u>major stationary source</u> that is subject to PSD review. Also, if an existing minor source becomes a major source as a result of a SIP relaxation, then it becomes subject to PSD requirements just as if construction had not yet commenced on the source or the modification.

III.A. ACTIVITIES THAT ARE NOT MODIFICATIONS

The regulations do not define "physical change" or "change in the method of operation" precisely; however, they exclude from those activities certain specific types of events described below.

(1) Routine maintenance, repair and replacement.

[Sources should discuss any project that will significantly increase actual emissions to the atmosphere with their respective permitting authority, as to whether that project is considered routine maintenance, repair or replacement.]

(2) A fuel switch due to an order under the Energy Supply and Environmental Coordination Act of 1974 (or any superseding legislation) or due to a natural gas curtailment plan under the Federal Power Act.

(3) A fuel switch due to an order or rule under section 125 of the CAA.

(4) A switch at a steam generating unit to a fuel derived in whole or in part from municipal solid waste.

(5) A switch to a fuel or raw material which (a) the source was capable of accommodating before January 6, 1975, so long as the switch would not be prohibited by any federally-enforceable permit condition established after that date under a federally approved SIP (including any PSD permit condition) or a federal PSD permit, or (b) the source is approved to make under a PSD permit.

(6) Any increase in the hours or rate of operation of a source, so long as the increase would not be prohibited by any federally-enforceable permit condition established after January 6, 1975 under a federally approved SIP (including any PSD permit condition) or a federal PSD permit.

(7) A change in the ownership of a stationary source.

For more details see 40 CFR 52.21(b)(2)(iii).

Notwithstanding the above, if a significant increase in actual emissions of a regulated pollutant occurs at an existing major source as a result of a physical change or change in the method of operation of that source, the "net emissions increase" of that pollutant must be determined.

III.B. EMISSIONS NETTING

Emissions netting is a term that refers to the process of considering certain previous and prospective emissions changes at an existing major source to determine if a "net emissions increase" of a pollutant will result from a proposed physical change or change in method of operation. If a net emissions increase is shown to result, PSD applies to each pollutant's emissions for which the net increase is "significant", as shown in Table A-4.

The process used to determine whether there will be a net emissions increase will result uses the following equation:

Net Emissions Change

EQUALS

Emissions <u>increases</u> associated with the proposed modification

MINUS

Source-wide creditable contemporaneous emissions <u>decreases</u>

PLUS

Source-wide creditable contemporaneous emissions <u>increases</u>

Consideration of contemporaneous emissions changes is allowed <u>only</u> in cases involving <u>existing</u> <u>major</u> <u>sources</u>. In other words, minor sources are not eligible to net emissions changes. As discussed earlier, existing minor sources are subject to PSD review only when proposing to increase emissions by "major" (e.g., 100 or 250 tpy, as applicable) amounts, which, for PSD purposes, are considered and reviewed as a major new source.

> *For example, an existing minor source (subject to the 100 tpy major source cutoff) is proposing a modification which involves the shutdown and removal of an old emissions unit (providing an actual contemporaneous reduction in NOx emissions of 75 tpy) and the construction of two new units with total potential NOx emissions of 110 tpy. Since the existing source is minor, the 75 tpy reduction is not considered for PSD applicability purposes. Consequently, PSD applies to the new units because the emissions increase of 110 tpy is itself "major". The new units are then subject to a PSD review for NOx and for any other regulated pollutant with a "significant" potential to emit.*

The consideration of contemporaneous emissions changes is also source specific. Netting must take place at the same stationary source; emissions reductions cannot be traded between stationary sources.

III.B.1. ACCUMULATION OF EMISSIONS

If the proposed emissions increase at a major source is by itself (without considering any decreases) less than "significant", EPA policy does not require consideration of previous contemporaneous small (i.e., less than significant) emissions increases at the source. In other words, the netting equation (the summation of contemporaneous emissions increases and decreases) is not triggered unless there will be a significant emissions increase from the proposed modification.

For example, a major source experienced less than significant increases of NO_x (30 tpy) and SO_2 (15 tpy) 2 years ago, and a decrease of SO_2 (50 tpy) 3 years ago. The source now proposes to add a new process unit with an associated emissions increase of 35 tpy NO_x and 80 tpy SO_2. For SO_2, the proposed 80 tpy increase from the modification by itself (before netting) is significant. The contemporaneous net emissions change is determined, by taking the algebraic sum of (-50) and (+15) and (+80), which equals +45 tpy. Therefore, the proposed modification is a major modification and a PSD review for SO_2 is required. However, the NO_x increase from the proposed modification is by itself less than significant. Consequently, netting for PSD applicability purposes is not performed for NO_x (even though the modification is major for SO_2) and a PSD review is not needed for NO_x.

It is important to note that when <u>any</u> emissions decrease is claimed (including those associated with the proposed modification), <u>all</u> source-wide creditable and contemporaneous emissions increases and decreases of the pollutant subject to netting must be included in the PSD applicability determination.

A deliberate decision to split an otherwise "significant" project into two or more smaller projects to avoid PSD review would be viewed as circumvention and would subject the entire project to enforcement action if construction on any of the small projects commences without a valid PSD permit.

For example, an automobile and truck tire manufacturing plant, an existing major source, plans to increase its production of both types of tires by *"debottlenecking" its production processes. For its passenger tire line, the source applies for and is granted a "minor" modification permit for a new extruder that will increase VOC emissions by 39 tons/yr. A few months later, the source applies for a "minor" modification permit to construct a new tread-end cementer on the same line which will increase VOC emissions by 12 tons/yr. The EPA would likely consider these proposals as an attempt to circumvent the regulations because the two proposals are related in terms of an overall project to increase source-wide production capacity. The important point in this example is that the two proposals are sufficiently related that the PSD regulations would consider them a single project.*

Usually, at least two basic questions should be asked when evaluating the construction of multiple minor projects to determine if they should have been considered a single project. First, were the projects proposed over a relatively short period of time? Second, could the changes be considered as part of a single project?

III.B.2. CONTEMPORANEOUS EMISSIONS CHANGES

The PSD definition of a net emissions increase [40 CFR 52.21(b)(3)(i)] consists of two <u>additive</u> components as follows:

(a) Any <u>increases</u> in actual emissions <u>from</u> a particular physical change or change in method of operation at a stationary source; and

(b) Any other <u>increase</u> <u>and</u> <u>decreases</u> <u>in</u> <u>actual</u> <u>emissions</u> at the source that are contemporaneous with the particular change and are otherwise creditable.

The first component narrowly includes only the emissions increases associated with a particular change at the source. The second component more broadly includes all contemporaneous, source-wide (occurring anywhere at the entire source), creditable emission increases and decreases.

To be <u>contemporaneous</u>, changes in <u>actual</u> emissions must have occurred after January 6, 1975. The changes must also occur within a period beginning 5 years before the date construction is expected to commence on the proposed modification (reviewing agencies may use the date construction is scheduled to commence provided that it is reasonable considering the time needed to issue a final permit) and ending when the emissions increase from the modification occurs. An increase resulting from a physical change at a source occurs when the new emissions unit becomes operational and begins to emit a pollutant. A replacement that requires a shakedown period becomes operational only after a reasonable shakedown period, not to exceed 180 days. Since the date construction actually will commence is unknown at the time the applicability determination takes place and is simply a scheduled date projected by the source, the contemporaneous period may shift if construction does not commence as scheduled. Many States have developed PSD regulations that allow different time frames for definitions of contemporaneous. Where approved by EPA, the time periods specified in these regulations govern the contemporaneous timeframe.

III.B.3. CREDITABLE CONTEMPORANEOUS EMISSIONS CHANGES

There are further restrictions on the contemporaneous emissions changes that can be credited in determining net increases. To be creditable, a contemporaneous reduction must be federally-enforceable on and after the date construction on the proposed modification begins. The actual reduction must take place before the date that the emissions increase from any of the new or modified emissions units occurs. In addition, the reviewing agency must ensure that the source has maintained any contemporaneous decrease which the source claims has occurred in the past. The source must either demonstrate that the decrease was federally-enforceable at the time the source claims it occurred, or it must otherwise demonstrate that the decrease was maintained until the present time and will continue until it becomes federally-enforceable. An emissions decrease cannot occur at, and therefore, cannot be credited from an emissions unit which was never constructed or operated, including units that received a PSD permit.

Reductions must be of the same pollutant as the emissions increase from the proposed modification and must be qualitatively equivalent in their effects on public health and welfare to the effects attributable to the proposed increase. Current EPA policy is to assume that an emissions decrease will have approximately the same qualitative significance for public health and welfare as that attributed to an increase, unless the reviewing agency has reason to believe that the reduction in ambient concentrations from the emissions decrease will not be sufficient to prevent the proposed emissions increase from causing or contributing to a violation of any NAAQS or PSD increment. In such cases, the applicant must demonstrate that the proposed netting transaction will not cause or contribute to an air quality violation before the emissions reduction may be credited. Also, in situations where a State is implementing an air toxics program, proposed netting transactions may be subject to additional tests regarding the health and welfare equivalency demonstration. For example, a State may prohibit netting between certain groups of toxic subspecies or apply netting ratios greater than the normally required 1:1 between certain groups of toxic pollutants.

A contemporaneous emissions increase occurs as the result of a physical change or change in the method of operation at the source and is creditable to the extent that the new emissions level exceeds the old emissions level. The "old" emissions level for an emissions unit equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the physical or operational change which resulted in the emissions increase. In certain limited situations where the applicant adequately demonstrates that the prior 2 years is not representative of normal source operation, a different (2 year) time period may be used upon a determination by the reviewing agency that it is more representative of normal source operation. Normal source operations may be affected by strikes, retooling, major industrial accidents and other catastrophic occurrences. The "new" emissions levels for a new or modified emissions unit which has not begun normal operation is its potential to emit.

An emissions increase or decrease is creditable only if the relevant reviewing authority has <u>not</u> relied on it in issuing a PSD permit for the source, and the permit is still in effect when the increase in actual emissions from the proposed modification occurs. A reviewing authority relies on an increase or decrease when, after taking the increase or decrease into account, it concludes that a proposed project would not cause or contribute to a violation of an increment or ambient standard. In other words, an emissions change at an emissions point which was considered in the issuance of a previous PSD permit for the source is not included in the source's "net emissions increase" calculation. This is done to avoid "double counting" of emissions changes.

For example, an emissions increase or decrease already considered in a source's PSD permit (state or federal) can not be considered a contemporaneous increase or decrease since the increases or decrease was obviously relied upon for the purpose of issuing the permit. Otherwise the increase or decrease would not have been specified in the permit. In another example, a decrease in emissions from having previously switched to a less polluting fuel (e.g., oil to gas) at an existing emissions unit would not be creditable if the source had, in obtaining a PSD permit (which is still in effect) for a new emissions unit, modeled the source's ambient impact using the less polluting fuel.

Changes in PM (PM/PM-10), SO_2 and NO_x emissions are a subset of creditable contemporaneous changes that also affect the available increment. For these pollutants, emissions changes which do not affect allowable PSD increment consumption are not creditable.

III.B.4. CREDITABLE AMOUNT

As mentioned above, only contemporaneous and creditable emissions changes are considered in determining the source-wide net emissions change. All contemporaneous and creditable emissions increases and decreases at the source must, however, be considered. The amount of each contemporaneous and creditable emissions increase or decrease involves determining old and new actual annual emissions levels for each affected emission unit.

The following basic criteria should be used when quantifying the increase or decrease:

- For proposed new or modified units which have not begun normal operations, the potential to emit must be used to determine the <u>increase</u> from the units.

- For an existing unit, actual emissions just prior to either a physical or operational change are based on the lower of the actual or allowable emissions levels. This "old" emissions level equals the average rate (in tons per year) at which the unit actually emitted the pollutant during the 2-year period just prior to the change which resulted in the emissions increase. These emissions are calculated using the <u>actual</u> hours of operation, capacity, fuel combusted and other parameters which affected the unit's emissions over the 2-year averaging period. In certain limited circumstances, where sufficient representative operating data do not exist to determine historic actual emissions and the reviewing agency has reason to believe that the source is operating at or near its allowable emissions level, the reviewing agency may presume that source-specific allowable emissions [or a fraction thereof] are equivalent to (and therefore are used in place of) actual emissions at the unit. For determining the difference in emissions from the change at the unit, emissions after the change are the potential to emit from the units.

- A source cannot receive emission reduction credit for reducing any portion of actual emissions which resulted because the source was operating out of compliance.

- An emissions decrease cannot be credited from a unit that has not been constructed or operated.

Examples of how to apply these creditability criteria for prospective emissions reductions is shown in Figure A-1. As shown in Case I of Figure A-1, the potential to emit for an existing emissions unit (which is based on the existing allowable emission rate) is greater than the actual emissions, which are based on actual operating data (e.g., type and amount of fuel combusted at the unit) for the past 2 years. The source proposes to switch to a lower sulfur fuel. The amount of the reduction in this case is the difference between the actual emissions and the revised allowable emissions. (Recall that *for reductions to be creditable, the revised allowable emission rate must be ensured with federally-enforceable limits.)*

Figure A-1 also illustrates in Case II that the previous allowable emissions were much higher than the potential to emit. Common examples are PM sources permitted according to process weight tables contained in most SIPs. Since process weight tables apply to a range of source types, they often overpredict actual emission rates for individual sources. In such cases, as in the previous case, the <u>only</u> creditable contemporaneous reduction is the difference between the actual emissions and the revised allowable emission rate for the existing emissions unit.

Case III in Figure A-1 illustrates a potential violation situation where the actual emissions level exceeds allowable limit. The creditable reduction in this case is the difference between what the emissions would have been from the unit had the source been in compliance with its old allowable limits (considering its actual operations) and its revised allowable emissions level.

Consider a more specific example, where a source has an emissions unit with an annual allowable emissions rate of 200 tpy based on full capacity year-round operation and an <u>hourly</u> unit-specific allowable emission rate. The source is, however, out of compliance with the allowable hourly emission rate by a factor of two. Consequently, if the unit were to be operated year-round at full capacity it would emit 400 tpy. However, in this case, although the unit operated at full capacity, it was operated on the average 75 percent of the time for the past 2 years. Consequently, for the past 2 years average actual emissions were 300 tpy. The unit is now to be shutdown. Assuming the reduction is otherwise creditable, the reduction from the shutdown is its allowable emissions prorated by its operating factor (200 tpy x .75 = 150 tpy).

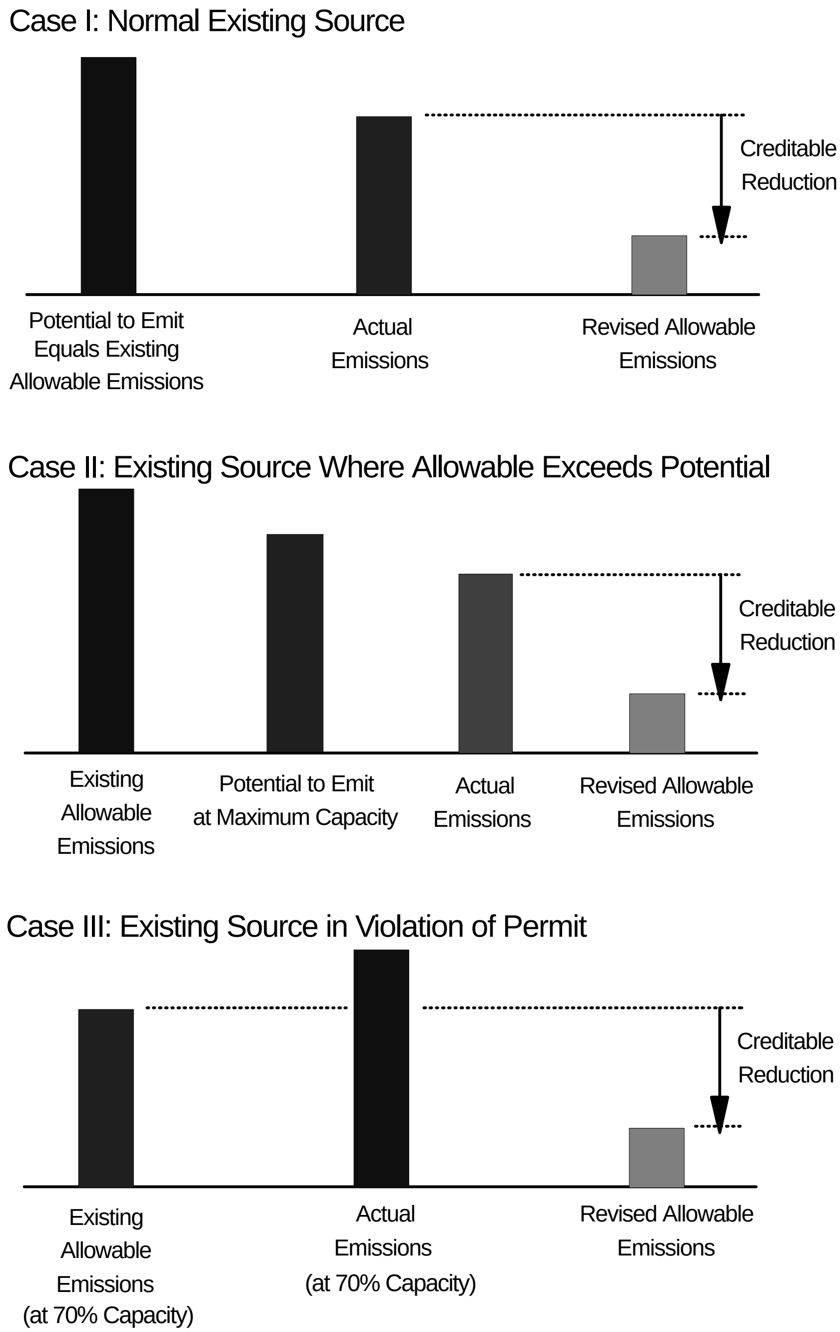

Figure A-1. Creditable Reductions in Actual Emissions

III.B.5. SUGGESTED EMISSIONS NETTING PROCEDURE

Through its review of many emissions netting transactions, EPA has found that, either because of confusion or misunderstanding, sources have used various netting procedures, some of which result in cases where projects should have been subjected to PSD but were not. Some of the most common errors include:

- Not including contemporaneous emissions increases when considering decreases;
- Improperly using allowable emissions instead of actual emissions level for the "old" emissions level for existing units;
- Using prospective (proposed) unrelated emissions decreases to counterbalance proposed emission increases without also examining all previous contemporaneous emissions changes;
- Not considering a contemporaneous increase creditable because the increase previously netted out of review by relying on a past decrease which was, but is no longer, contemporaneous. If contemporaneous and otherwise creditable, the increase must be considered in the netting calculus.
- Not properly documenting all contemporaneous emissions changes; and
- Not ensuring that emissions decreases are covered by federally-enforceable restrictions, which is a requirement for creditability.

For the purpose of minimizing confusion and improper applicability determinations, the six-step procedure shown in Table A-5 and described below is recommended in applying the emissions netting equation. Already assumed in this procedure is that the existing source has been defined, its major source status has been confirmed and the air quality status in the area is attainment for at least one criteria pollutant.

TABLE A-5. Procedures for Determining the Net Emissions Change at a Source

Determine the emissions increases (but not any decreases) from the proposed project. If increases are significant, proceed; if not, the sources is not subject to review.

Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

Determine which emissions units at the source experienced (or will experience, including any proposed decreases resulting from the proposed project) a creditable increase or decrease in emissions during the contemporaneous period.

Determine which emissions changes are creditable.

Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

Step 1. Determine the emissions increases from the proposed project.

First, only the emissions increases expected to result from the proposed project are examined. This includes emissions increases from the new and modified emissions units and any other plant-wide emissions increases (e.g., debottlenecking increases) that will occur as a result of the proposed modification. [Proposed emissions decreases occurring elsewhere at the source are not considered at this point. Emission decreases associated with a proposed project (such as a boiler replacement) are contemporaneous and may be considered along with other contemporaneous emissions changes at the source. However, they are <u>not</u> considered at this point in the analysis.]

A PSD review applies only to those regulated pollutants with a significant emissions increase from the proposed modification. If the proposed project will not result in a significant emissions increase of any regulated pollutant, the project is exempt from PSD review and the PSD applicability process is completed. However, if this is not the case, each regulated pollutant to be emitted in a significant amount is subject to a PSD review unless the source can demonstrate (using steps 2-6) that the sum of all other source-wide contemporaneous and creditable emissions increases and decreases would be less than significant.

Step 2 Determine the beginning and ending dates of the contemporaneous period as it relates to the proposed modification.

The period begins on the date 5 years (some States may have a different time period) before construction commences on the proposed modification. It ends on the date the emissions increase from the proposed modification occurs.

Step 3 Determine which emissions units at the source have experienced an increase or decrease in emissions during the contemporaneous period.

Usually, creditable emissions increases are associated with a physical change or change in the method of operation at a source which did not require a PSD permit. For example, creditable emissions increases may come from the construction of a new unit, a fuel switch or an increase in operation that (a) would have otherwise been subject to PSD but instead netted out of review (per steps 1-6) or (b) resulted in a less than significant emissions increase (per step 1).

Decreases are creditable reductions in actual emissions from an emissions unit that are, or can be made, federally-enforceable. A physical change or change in the method of operation is also associated with the types of decreases that are creditable. Specifically, in the case of an emissions decrease, once the decrease has been made federally-enforceable, any proposed increase above the federally-enforceable level must constitute a physical change or change in the method of operation at the source or the reduction is not considered creditable. For example, a source could only receive an emissions decrease for netting purposes from a unit that has been taken out of operation if, due to the imposition of federally-enforceable restrictions preventing the use of the unit, a proposal to reactivate the unit would constitute a physical change or change in the method of operation at the source. If operating the unit was not considered a physical or operational change, the unit could go back to its prior level of operation at any time, thereby producing only a "paper" reduction, which is not creditable.

Step 4 Determine which emissions changes are creditable.

The following basic rules apply:

1) A increase or decrease is creditable only if the relevant reviewing authority has not relied upon it in previously issuing a PSD permit and the permit is in effect when the increase from the proposed modification occurs. As stated earlier, a reviewing authority "relies" on an increase or decrease when, after taking the increase or decrease into account, it concludes in issuing a PSD permit that a project would not cause or contribute to a violation of a PSD increment or ambient standard.

2) For pollutants with PSD increments (i.e., SO2, particulate matter and NOx), an increase or decrease in actual emissions which occurs before the baseline date in an area is creditable only if it would be considered in calculating how much of an increment remains available for the pollutant in question. An example of this situation is a 39 tpy NO_x emissions increase resulting from a new heater at a major source in 1987, prior to the NO_x increment baseline date. Because these emissions do not affect the allowable PSD increment, they need not be considered in 1990 when the source proposes another unrelated project. The new emissions level for the heater (up to 39 tpy) would be adjusted downward to the old level (zero) in the accounting exercise. Likewise, decreases which occurred before the baseline date was triggered cannot be credited after the baseline date. Such reductions are included in the baseline concentration and are not considered in calculating PSD increment consumption.

3) A decrease is creditable only to the extent that it is "federally-enforceable" from the moment that the actual construction begins on the proposed modification to the source. The decrease

must occur before the proposed emissions increase occurs. An increase occurs when the emissions unit on which construction occurred becomes operational and begins to emit a particular pollutant. Any replacement unit that requires shakedown becomes operational only after a reasonable shakedown period not to exceed 180 days.

4) A decrease is creditable only to the extent that it has the same health and welfare significance as the proposed increase from the source.

5) A source cannot take credit for a decrease that it has had to make, or will have to make, in order to bring an emissions unit into compliance.

6) A source cannot take credit for an emissions reduction from potential emissions from an emissions unit which was permitted but never built or operated.

Step 5 Determine, on a pollutant-by-pollutant basis, the amount of each contemporaneous and creditable emissions increase and decrease.

An emissions increase is the amount by which the new level of "actual emissions" at the emissions unit exceeds the old level. The old level of "actual emissions" is that which prevailed just prior (i.e., prior 2 year average) to the physical or operational change at that unit which caused the increase. The new level is that which prevails just after the change. In most cases, the old level is calculated from the unit's actual operating data from a 2 year period which directly preceded the physical change. The new "actual emissions" level us the lower of the unit's "potential" or "allowable" emissions after the change. In other words, a contemporaneous emission increase is calculated as the positive difference between an emissions unit's potential to emit just after a physical or operation change at that unit (not the unit's current actual emissions) and the unit's actual emissions just prior to the change.

An emissions decrease is the amount by which the old level of actual emissions or the old level of allowable emissions, whichever is lower, exceeds the new level of "actual" emissions. Like emissions increases, the old level is calculated from the unit's actual operating data from a 2 year period which preceded the decrease, and the new emissions level will be the lower of the unit's "potential" or "allowable" emissions after the change.

Figure A-2 shows a example of how old and new actual S02 emissions levels are established for an existing emissions unit at a source. The applicant met with the reviewing agency in January 1988, proposing to commence construction on a new emissions unit in mid-1988. The contemporaneous time frame in this case is from mid-1983 (using EPA's 5-year definition) to the expected date of the new boiler start-up, about January 1990.

In mid-1984 an existing boiler switched to a low sulfur fuel oil. The applicant wishes to use the fuel switch as a netting credit. The time period for establishing the old S02 emissions level for the fuel switch is the 2 year period preceding the change [mid-1982 to mid-1984, when emissions were 600 tpy (mid-1982 through mid-1983) and 500 tpy (mid-1982 through mid-1983)]. The new S02 emissions level, 300 tpy, is established by the new allowable emissions level (which will be made federally-enforceable). The old level of emissions is 550 tpy (the average of 600 tpy and 500 tpy). Thus, if this is the only existing S02 emissions unit at the source, a decrease of 250 tpy S02 emissions (550 tpy minus 300 tpy) is creditable towards the emissions proposed for the new boiler. This example assumes that the reduction meets all other applicable criteria for a creditable emissions decrease.

Step 6 Sum all contemporaneous and creditable increases and decreases with the increase from the proposed modification to determine if a significant net emissions increase will occur.

The proposed project is subject to PSD review for each regulated pollutant for which the sum of all creditable emissions increases and decreases results in a significant net emissions increase.

If available, the applicant may consider proposing additional prospective and creditable emissions reductions sufficient to provide for a less than significant net emissions increase at the source and thus avoid PSD review. These reductions can be achieved through either application of emissions controls or placing restrictions on the operation of existing emissions units. These additional reductions would be added to the sum of all other creditable increases and decreases. As with all contemporaneous emissions reductions, these additional decreases must be based on actual emissions changes, federally-enforceable prior to the commencement of construction and occur before the new unit begins operation. They must also affect the allowable PSD increment, where applicable.

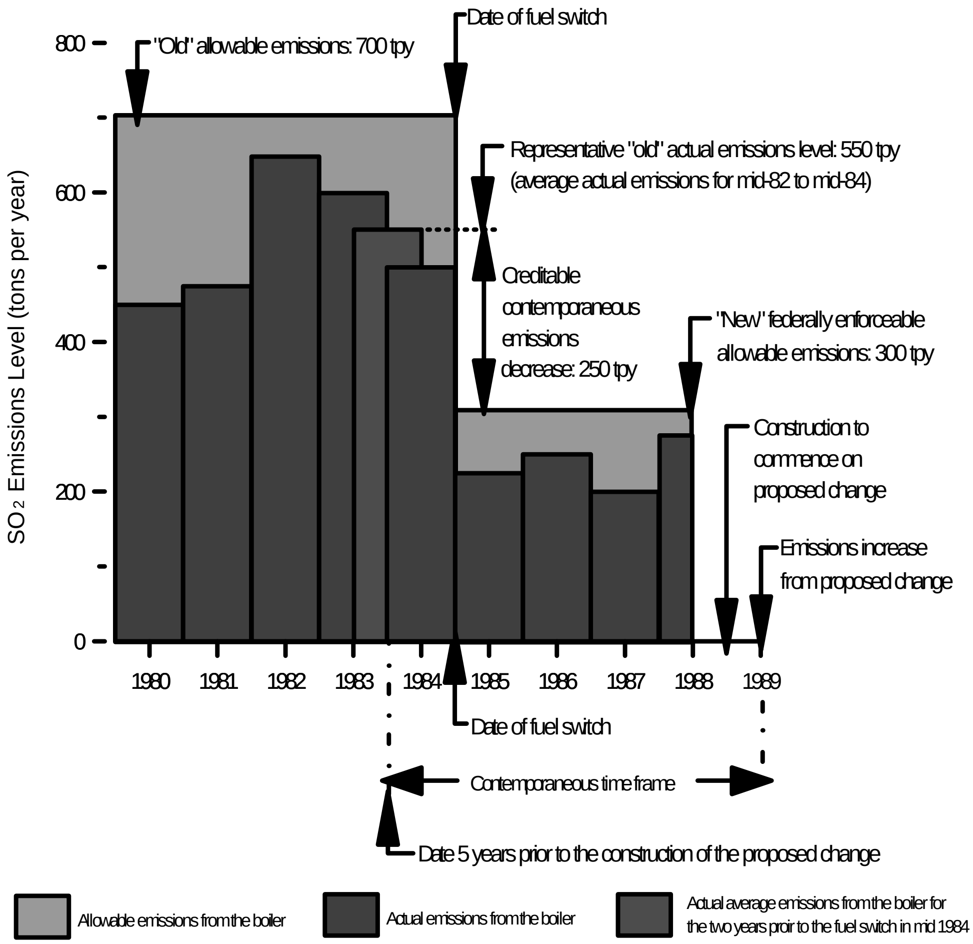

Figure A-2. Establishing "Old" and "New" Representative Actual SO_2 Emissions

III.B.6. NETTING EXAMPLE

An existing source has informed the local air pollution control agency that they are planning to construct a new emissions unit "G". The existing source is a major source and the construction of unit G will constitute a modification to the source. Unit G will be capable of emitting 80 tons per year (tpy) of the pollutant after installation of controls. The PSD significant emissions level for the pollutant in question is 40 tpy. Existing emissions units "A" and "B" at the source are presently permitted at 150 tpy each. The applicant has proposed to limit the operation of units A and B, in order to net out of PSD review, to 7056 hours per year (42 weeks) by accepting federally-enforceable conditions. The applicant has calculated that there will be an emissions reduction of -29.2 tpy [150 - 150x(7056/8760)] per unit for a total reduction of 58.4 tpy. Thus, the net emissions increase, as calculated by the applicant, will be +21.6 tpy (80-58.36). The applicant proposes to net out of PSD review citing the +21.6 tpy increase as less than the applicable 40 tpy PSD significance level for the pollutant.

The reviewing agency informed the source that 1) the emissions reductions being claimed from units A and B must be based on the prior actual emissions, not their allowable emissions and (2) because the increase from the modification will be greater than significant, all contemporaneous changes must be accounted for (not just proposed decreases) in order to determine the net emission change at the source.

To verify if, indeed, the source will be able to net out of PSD review, the reviewing agency requested information on the other emissions points at the source, including their actual monthly emissions. For illustrative purposes, the actual annual emissions of the pollutant in question from the existing emissions points (in this example all emissions points are associated with an emissions unit) are given as follows:

			Actual Emissions (tpy)			
Year	Unit A	Unit B	Unit C	Unit D	Unit E	Unit F
1983	70	130	60	85	50	0
1984	75	130	75	75	60	0
1985	80	150	65	80	65	0
1986	110	90	0	0	70	0
1987	115	85	0	0	75	75
1988	105	75	0	0	65	70
1989	90	90	0	0	60	65

The applicant's response indicates that units A and B will not be physically modified. However, the information does show that the modification will result in the removal of a bottleneck at the plant and that the proposed modification will result in an increase in the operation of these units.

The PSD baseline for the pollutant was triggered in 1978. The history of the emissions units at the source is as follows:

Emissions Unit(s)	History
A and B	Built in 1972 and still operational
C and D	Built in 1972 and retired from operation 01/86
E	Built in 1972 and still operational
F	PSD permitted unit; construction commenced 01/86 and the unit became operational on 01/87
G	New modification; construction scheduled to commence 01/90 and the unit is expected to be operational on 01/92

The contemporaneous period extends from 01/85 (5 years prior to 01/90, the projected construction date of the modification) until 01/92 (the date the emissions increase from the modification). The net emissions change at the source can be formulated in terms of the sum of the unit-by-unit emissions changes which are creditable and contemporaneous with the planned modification. Emission changes that are not associated with physical/operational changes are not considered.

In assessing the creditable contemporaneous changes the permit agency considered the following (all numbers are in tpy):

- Potential to emit is used for a new unit. The new unit will receive a federally-enforceable permit restricting allowable emissions to 80 tpy, which then becomes its potential to emit. Therefore, the new unit represents an increase of +80.

- Even though units A and B will not be modified, their emissions are expected to increase as a result of the modification and the anticipated increase must be included as part of the increase from the proposed modification. The emissions change for these units is based on their allowable emissions after the change minus their current actual emissions. Current actual emissions are based on the average emissions over the last 2 years. [Note that only the operations of exiting units A and B are expected to be affected by the modification.] The emissions changes at A and B are calculated as follows:

Unit A's change = +23.3

{new allowable [150x(7056/8760)] - old actual [(105+90)/2]}

Unit B's change = +38.3

{new allowable [150x(7056/8760)] - old actual [(75+90)/2]}

The federally-enforceable restriction on the hours of operation for units A and B act to reduce the amount of the emissions increase at the units due to the modification. However, contrary to the applicant's analysis, the restrictions did not restrict the units' emissions sufficiently to prevent an actual emissions increase.

- The emissions increase from unit F was permitted under PSD. Therefore, having been "relied upon" in the issuance of a PSD permit which is still in effect, the permitted emissions increase is not creditable and cannot be used in the netting equation.

- The operation of unit E is not projected to be affected by the proposed modification. It has not undergone any physical or operational change during the contemporaneous period which would otherwise trigger a creditable emissions change at the unit. Consequently, unit E's emissions are not considered for netting purposes by the reviewing agency.

- The retirement (a physical/operational change) of units C and D occurred within the contemporaneous period and may provide creditable decreases for the applicant. However, if the retirement of the units was relied upon in the issuance of the PSD permit for unit F (e.g, if the emissions of units C or D were modeled at zero in the PSD application) then the reductions would not be creditable. If they were not modeled as retired (zero emissions), then the reduction would be available as an emissions reduction. The reduction credit would be based on the last 2 years of actual data prior to retirement. As with all reductions, to be creditable the retirement of the units must be made federally-enforceable prior to construction of the modification to and start-up of the source. Upon checking the PSD permit application for unit F, the reviewing agency determined that units C and D were not considered retired and their emissions were included in the ambient impact analysis for unit F. Consequently, the emissions reduction from the retirement of unit C and D (should the reductions be made federally-enforceable) was determined as followed:

Unit C's change = -70

{its new allowable [0] - its old actual [(75+65)/2]}

Unit D's change = -77.5

{its new allowable [0] - its old actual [(75+80)/2]}

- The netting transaction would not cause or contribute to a violation of the applicable PSD increment or ambient standards.

The applicant, however, is only willing to accept federally-enforceable conditions on the retirement of unit C. Unit D is to be kept as a standby unit and the applicant is unwilling to have its potential operation limited. Consequently, the reduction in emissions at unit D is not creditable.

The net contemporaneous emissions change at the source is calculated by the reviewing agency as follows:

Emissions Change (tpy)

+80.0 increase from unit G.
+23.3 increase at A from modification at source.
+38.8 increase at B from modification at source.
-70.0 creditable decrease from retirement of unit C
+72.1 total contemporaneous net emissions increase at the source.

The +72.1 tpy net increase is greater than the +40 tpy PSD significance level; consequently the proposed modification is subject to PSD review for that pollutant.

If the applicant is willing to agree to federally-enforceable conditions limiting the allowable emissions from unit D (but not necessarily requiring the unit's permanent retirement), a sufficient reduction may be available to net unit G out of a PSD review. For example, the applicant could agree to accept federally-enforceable conditions limiting the operation of unit D to 672 hours a year (4 weeks), which (for illustrative purposes) equates to an allowable emissions of 15 tpy. The creditable reduction from the unit D would then amount to -62.5 tpy (-77.5 +15). This brings the total contemporaneous net emissions change for the proposed modification to +9.6 tpy (+72.1 - 62.5). The construction of Unit G would then not be considered a major modification subject to PSD review. It is important to note, however, that if unit D is permanently taken out of service after January 1991 and had not operated in the interim, the source would not be allowed an emissions reduction credit because there would have been no actual emissions decrease during the contemporaneous period. In addition, if the source later requests removal of restrictions on units which allowed unit G to net out of review, unit G then becomes subject to PSD review as though construction had not yet commenced.

IV. GENERAL EXEMPTIONS

IV.A. SOURCES AND MODIFICATIONS AFTER AUGUST 7,1980

Certain sources may be exempted from PSD review or certain PSD requirements. Nonprofit health or educational sources that would otherwise be subject to PSD review can be exempted if requested by the Governor of the State in which they are located. A portable, major stationary source that has previously received a PSD permit and is to be relocated is exempt from a second PSD review if (1) emissions at the new location will not exceed previously allowed emission rates, (2) the emissions at the new location are temporary, and (3) the source will not, because of its new location, adversely affect a Class I area or contribute to any known increment or national ambient air quality standard (NAAQS) violation. However, the source must provide reasonable advance notice to the reviewing authority.

IV.B. SOURCES CONSTRUCTED PRIOR TO AUGUST 7,1980

The 1980 PSD regulations do not apply to certain sources affected by previous PSD regulations. For example, sources for which construction began before August 7, 1977 are exempt from the 1980 PSD regulations and are instead reviewed for applicability under the PSD regulations as they existed before August 7, 1977. Several exemptions also exist for sources for which construction began after August 7, 1977, but before the August 7, 1980 promulgation of the PSD regulations (45 FR 52676). These exemptions and the criteria associated nonapplicability are detailed in paragraph (i) of 40 CFR 52.21.

CHAPTER B

BEST AVAILABLE CONTROL TECHNOLOGY

I. INTRODUCTION

Any major stationary source or major modification subject to PSD must conduct an analysis to ensure the application of best available control technology (BACT). The requirement to conduct a BACT analysis and determination is set forth in section 165(a)(4) of the Clean Air Act (Act), in federal regulations at 40 CFR 52.21(j), in regulations setting forth the requirements for State implementation plan approval of a State PSD program at 40 CFR 51.166(j), and in the SIP's of the various States at 40 CFR Part 52, Subpart A - Subpart FFF. The BACT requirement is defined as:

> "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."

During each BACT analysis, which is done on a case-by-case basis, the reviewing authority evaluates the energy, environmental, economic and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring. The reviewing authority then specifies an emissions limitation for the source that reflects the maximum degree of reduction achievable for each pollutant regulated under the Act. In no event can a technology be recommended which would not meet any applicable standard of performance under 40 CFR Parts 60 (New Source Performance Standards) and 61 (National Emission Standards for Hazardous Air Pollutants).

In addition, if the reviewing authority determines that there is no economically reasonable or technologically feasible way to accurately measure the emissions, and hence to impose an enforceable emissions standard, it may require the source to use design, alternative equipment, work practices or operational standards to reduce emissions of the pollutant to the maximum extent.

On December 1, 1987, the EPA Assistant Administrator for Air and Radiation issued a memorandum that implemented certain program initiatives designed to improve the effectiveness of the NSR programs within the confines of existing regulations and state implementation plans. Among these was the "top-down" method for determining best available control technology (BACT).

In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

The purpose of this chapter is to provide a detailed description of the top-down method in order to assist permitting authorities and PSD applicants in conducting BACT analyses.

II. BACT APPLICABILITY

The BACT requirement applies to each individual new or modified affected emissions unit and pollutant emitting activity at which a net emissions increase would occur. Individual BACT determinations are performed for each pollutant subject to a PSD review emitted from the same emission unit. Consequently, the BACT determination must separately address, for each regulated pollutant with a significant emissions increase at the source, air pollution controls for each emissions unit or pollutant emitting activity subject to review.

III. A STEP BY STEP SUMMARY OF THE TOP-DOWN PROCESS

Table B-1 shows the five basic steps of the top-down procedure, including some of the key elements associated with each of the individual steps. A brief description of each step follows.

III.A. STEP 1--IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" analysis is to identify, for the emissions unit in question (the term "emissions unit" should be read to mean emissions unit, process or activity), all "available" control options. Available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant. This includes technologies employed outside of the United States. As discussed later, in some circumstances inherently lower-polluting processes are appropriate for consideration as available control alternatives. The control alternatives should include not only existing controls for the source category in question, but also (through technology transfer) controls applied to similar source categories and gas streams, and innovative control technologies. Technologies required under lowest achievable emission rate (LAER) determinations are available for BACT purposes and must also be included as control alternatives and usually represent the top alternative.

In the course of the BACT analysis, one or more of the options may be eliminated from consideration because they are demonstrated to be technically infeasible or have unacceptable energy, economic, and environmental impacts on a case-by-case (or site-specific) basis. However, at the outset, applicants

TABLE B-1. - KEY STEPS IN THE "TOP-DOWN" BACT PROCESS

STEP 1: IDENTIFY ALL CONTROL TECHNOLOGIES.

- LIST is comprehensive (LAER included).

STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS.

- A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

STEP 3: RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS.
Should include:

- control effectiveness (percent pollutant removed);
- expected emission rate (tons per year);
- expected emission reduction (tons per year);
- energy impacts (BTU, kWh);
- environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
- economic impacts (total cost effectiveness, incremental cost effectiveness).

STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS.

- Case-by-case consideration of energy, environmental, and economic impacts.
- If top option is not selected as BACT, evaluate next most effective control option.

STEP 5: SELECT BACT

- Most effective option not rejected is BACT.

should initially identify all control options with potential application to the emissions unit under review.

III.B. STEP 2--ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

In the second step, the technical feasibility of the control options identified in step one is evaluated with respect to the source-specific (or emissions unit-specific) factors. A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

For example, in cases where the level of control in a permit is not expected to be achieved in practice (e.g., a source has received a permit but the project was cancelled, or every operating source at that permitted level has been physically unable to achieve compliance with the limit), and supporting documentation showing why such limits are not technically feasible is provided, the level of control (but not necessarily the technology) may be eliminated from further consideration. However, a permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit.

III.C. STEP 3--RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

In step 3, all remaining control alternatives not eliminated in step 2 are ranked and then listed in order of over all control effectiveness for the pollutant under review, with the most effective control alternative at the top. A list should be prepared for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The list should present the array of control technology alternatives and should include the following types of information:

- control efficiencies (percent pollutant removed);
- expected emission rate (tons per year, pounds per hour);
- expected emissions reduction (tons per year);
- economic impacts (cost effectiveness);
- environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and, at a minimum, the impact of each control alternative on emissions of toxic or hazardous air contaminants);
- energy impacts.

However, an applicant proposing the top control alternative need not provide cost and other detailed information in regard to other control options. In such cases the applicant should document that the control option chosen is, indeed, the top, and review for collateral environmental impacts.

III.D. STEP 4--EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After the identification of available and technically feasible control technology options, the energy, environmental, and economic impacts are considered to arrive at the final level of control. At this point the analysis presents the associated impacts of the control option in the listing. For each option the applicant is responsible for presenting an objective evaluation of each impact. Both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

If the applicant accepts the top alternative in the listing as BACT, the applicant proceeds to consider whether impacts of unregulated air pollutants or impacts in other media would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding should be documented for the public record. Then the next most stringent alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that alternative to be inappropriate as BACT.

III.E. STEP 5--SELECT BACT

The most effective control option not eliminated in step 4 is proposed as BACT for the pollutant and emission unit under review.

IV. TOP-DOWN ANALYSIS DETAILED PROCEDURE

IV.A. IDENTIFY ALTERNATIVE EMISSION CONTROL TECHNIQUES (STEP 1)

The objective in step 1 is to identify all control options with potential application to the source and pollutant under evaluation. Later, one or more of these options may be eliminated from consideration because they are determined to be technically infeasible or to have unacceptable energy, environmental or economic impacts.

Each new or modified emission unit (or logical grouping of new or modified emission units) subject to PSD is required to undergo BACT review. BACT decisions should be made on the information presented in the BACT analysis, including the degree to which effective control alternatives were identified and evaluated. Potentially applicable control alternatives can be categorized in three ways.

- ***Inherently Lower-Emitting Processes/Practices***, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and

- ***Add-on Controls***, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.

- ***Combinations of Inherently Lower Emitting Processes and Add-on Controls***. For example, the application of combustion and post-combustion controls to reduce NOx emissions at a gas-fired turbine.

The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review.

IV.A.1. DEMONSTRATED AND TRANSFERABLE TECHNOLOGIES

Applicants are expected to identify all demonstrated and potentially applicable control technology alternatives. Information sources to consider include:

- EPA's BACT/LAER Clearinghouse and Control Technology Center;
- Best Available Control Technology Guideline - South Coast Air Quality Management District;
- control technology vendors;
- Federal/State/Local new source review permits and associated inspection/performance test reports;
- environmental consultants;
- technical journals, reports and newsletters (e.g., JAPCA and the McIvaine reports), air pollution control seminars; and
- EPA's New Source Review (NSR) bulletin board.

The applicant should make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency. The permit agency should review the background search and resulting list of control alternatives presented by the applicant to check that it is complete and comprehensive.

In identifying control technologies, the applicant needs to survey the range of potentially available control options. Opportunities for technology transfer lie where a control technology has been applied at source categories other than the source under consideration. Such opportunities should be identified. Also, technologies in application outside the United States to the extent that the technologies have been successfully demonstrated in practice on full scale operations. Technologies which have not yet been applied to (or permitted for) full scale operations need not be considered available; an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice.

To satisfy the legislative requirements of BACT, EPA believes that the applicant must focus on technologies with a demonstrated potential to achieve the highest levels of control. For example, control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis.

The fact that a NSPS for a source category does not require a certain level of control or particular control technology does not preclude its consideration in the top-down BACT analysis. For example, post combustion NOx controls are not required under the Subpart GG of the NSPS for Stationary Gas Turbines. However, such controls must still be considered available technologies for the BACT selection process and be considered in the BACT analysis. An NSPS simply defines the minimal level of control to be considered in the BACT analysis. The fact that a more stringent technology was not selected for a NSPS (or that a pollutant is not regulated by an NSPS) does not exclude that control alternative or technology as a BACT candidate. When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emissions level less stringent than the NSPS. If so, the option is unacceptable.

IV.A.2. INNOVATIVE TECHNOLOGIES

Although <u>not required</u> in step 1, the applicant <u>may</u> also evaluate and propose innovative technologies as BACT. To be considered innovative, a control technique must meet the provisions of 40 CFR 52.21(b)(19) or, where appropriate, the applicable SIP definition. In essence, if a developing technology has the potential to achieve a more stringent emissions level than otherwise would constitute BACT or the same level at a lower cost, it may be proposed as an innovative control technology. Innovative technologies are distinguished from technology transfer BACT candidates in that an innovative technology is still under development and has not been demonstrated in a commercial application on identical or similar emission units. In certain instances, the distinction between innovative and transferable technology may not be straightforward. In these cases, it is recommended that the permit agency consult with EPA prior to proceeding with the issuance of an innovative control technology waiver.

In the past only a limited number of innovative control technology waivers for a specific control technology have been approved. As a practical matter, if a waiver has been granted to a similar source for the same technology, granting of additional waivers to similar sources is highly unlikely since the subsequent applicants are no longer "innovative".

IV.A.3. CONSIDERATION OF INHERENTLY LOWER POLLUTING PROCESSES/PRACTICES

Historically, EPA has not considered the BACT requirement as a means to redefine the design of the source when considering available control alternatives. For example, applicants proposing to construct a coal-fired electric generator, have not been required by EPA as part of a BACT analysis to consider building a natural gas-fired electric turbine although the turbine may be inherently less polluting per unit product (in this case electricity). However, this is an aspect of the PSD permitting process in which states have the discretion to engage in a broader analysis if they so desire. Thus, a gas turbine normally would not be included in the list of control alternatives for a coal-fired boiler. However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis. A production process is defined in terms of its physical and chemical unit operations used to produce the desired product from a specified set of raw materials. In such cases, the permit agency may require the applicant to include the inherently lower-polluting process in the list of BACT candidates.

In many cases, a given production process or emissions unit can be made to be inherently less polluting (e.g; the use of water-based versus solvent based paints in a coating operation or a coal-fired boiler designed to have a low emission factor for NOx). In such cases the ability of design considerations to make the process inherently less polluting must be considered as a control alternative for the source. Inherently lower-polluting processes/practice are usually more environmentally effective because of lower amounts of solid wastes and waste water than are generated with add-on controls. These factors are considered in the cost, energy and environmental impacts analyses in step 4 to determine the appropriateness of the additional add-on option.

Combinations of inherently lower-polluting processes/practices (or a process made to be inherently less polluting) and add-on controls are likely to yield more effective means of emissions control than either approach alone. Therefore, the option to utilize a inherently lower-polluting process does not, in and of itself, mean that no additional add-on controls need be included in the BACT analysis. These combinations should be identified in step 1 of the top down process for evaluation in subsequent steps.

IV.A.4. EXAMPLE

The process of identifying control technology alternatives (step 1 in the top-down BACT process) is illustrated in the following hypothetical example.

Description of Source

A PSD applicant proposes to install automated surface coating process equipment consisting of a dip-tank priming stage followed by a two-step spray application and bake-on enamel finish coat. The product is a specialized electronics component (resistor) with strict resistance property specifications that restrict the types of coatings that may be employed.

List of Control Options

The source is not covered by an applicable NSPS. A review of the BACT/LAER Clearinghouse and other appropriate references indicates the following control options may be applicable:

Option #1: **water-based primer and finish coat;**

[The water-based coatings have never been used in applications similar to this.]

Option #2: **low-VOC solvent/high solids coating for primer and finish coat;**

[The high solids/low VOC solvent coatings have recently been applied with success with similar products (e.g., other types of electrical components).]

Option #3: **electrostatic spray application to enhance coating transfer efficiency;** and

[Electrostatically enhanced coating application has been applied elsewhere on a clearly similar operation.]

Option #4: **emissions capture with add-on control via incineration or carbon adsorber equipment.**

[The VOC capture and control option (incineration or carbon adsorber) has been used in many cases involving the coating of different products and the emission stream characteristics are similar to the proposed resistor coating process and is identified as an option available through technology transfer.]

Since the low-solvent coating, electrostatically enhanced application, and ventilation with add-on control options may reasonably be considered for use in combination to achieve greater emissions reduction efficiency, a total of eight control options are eligible for further consideration. The options include each of the four options listed above and the following four combinations of techniques:

Option #5: **low-solvent coating with electrostatic applications without ventilation and add-on controls;**

Option #6: **low-solvent coating without electrostatic applications with ventilation and add-on controls;**

Option #7: **electrostatic application with add-on control;** and

Option #8: **a combination of all three technologies.**

A "no control" option also was identified but eliminated because the applicant's State regulations require at least a 75 percent reduction in VOC emissions for a source of this size. Because "no control" would not meet the State regulations it could not be BACT and, therefore, was not listed for consideration in the BACT analysis.

Summary of Key Points

The example illustrates several key guidelines for identifying control options. These include:

- All available control techniques must be considered in the BACT analysis.
- Technology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists.
- Combinations of techniques should be considered to the extent they result in more effective means of achieving stringent emissions levels represented by the "top" alternative, particularly if the "top" alternative is eliminated.

IV.B. TECHNICAL FEASIBILITY ANALYSIS (STEP 2)

In step 2, the technical feasibility of the control options identified in step 1 is evaluated. This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.

Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- concept stage;
- research and patenting;
- bench scale or laboratory testing;
- pilot scale testing;
- licensing and commercial demonstration; and
- commercial sales.

A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.

Commercial availability by itself, however, is not necessarily sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration.

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique had been applied previously. Absent an explanation of unusual circumstances by the applicant showing why a particular process cannot be used on the proposed source the review authority may presume it is technically feasible.

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary.

Within the context of the top-down procedure, an applicant addresses the issue of technical feasibility in asserting that a control option identified in Step 1 is technically infeasible. In this instance, the applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. Also a showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.

A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology (see later discussion at V.D.2).

Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, decisions about technical feasibility will be based on chemical, and engineering analyses (as discussed above) in conjunction with information about vendor guarantees.

A possible outcome of the top-down BACT procedures discussed in this document is the evaluation of multiple control technology alternatives which result in essentially equivalent emissions. It is not EPA's intent to encourage evaluation of unnecessarily large numbers of control alternatives for every emissions unit. Consequently, judgment should be used in deciding what alternatives will be evaluated in detail in the impacts analysis (Step 4) of the top-down procedure discussed in a later section. For example, if two or more control techniques result in control levels that are essentially identical considering the uncertainties of emissions factors and other parameters pertinent to estimating performance, the source may wish to point this out and make a case for evaluation and use only of the less costly of these options. The scope of the BACT analysis should be narrowed in this way only if there is a negligible difference in emissions and collateral environmental impacts between control alternatives. Such cases should be discussed with the reviewing agency before a control alternative is dismissed at this point in the BACT analysis due to such considerations.

It is encouraged that judgments of this type be discussed during a preapplication meeting between the applicant and the review authority. In this way, the applicant can be better assured that the analysis to be conducted will meet BACT requirements. The appropriate time to hold such a meeting during the analysis is following the completion of the control hierarchy discussed in the next section.

Summary of Key Points

In summary, important points to remember in assessing technical feasibility of control alternatives include:

- A control technology that is "demonstrated" for a given type or class of sources is assumed to be technically feasible unless source-specific factors exist and are documented to justify technical infeasibility.
- Technical feasibility of technology transfer control candidates generally is assessed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control had been applied previously.
- Innovative controls that have not been demonstrated on any source type similar to the proposed source need not be considered in the BACT analysis.
- The applicant is responsible for providing a basis for assessing technical feasibility or infeasibility and the review authority is responsible for the decision on what is and is not technically feasible.

IV.C. RANKING THE TECHNICALLY FEASIBLE ALTERNATIVES TO ESTABLISH A CONTROL HIERARCHY (STEP 3)

Step 3 involves ranking all the technically feasible control alternatives which have been previously identified in Step 2. For the regulated pollutant and emissions unit under review, the control alternatives are ranked-ordered from the most to the least effective in terms of emission reduction potential. Later, once the control technology is determined, the focus shifts to the specific limits to be met by the source.

Two key issues that must be addressed in this process include:

- What common units should be used to compare emissions performance levels among options?
- How should control techniques that can operate over a wide range of emission performance levels (e.g., scrubbers, etc.) be considered in the analysis?

IV.C.1. CHOICE OF UNITS OF EMISSIONS PERFORMANCE TO COMPARE LEVELS AMONGST CONTROL OPTIONS

In general, this issue arises when comparing inherently lower-polluting processes to one another or to add-on controls. For example, direct comparison of powdered (and low-VOC) coatings and vapor recovery and control systems at a metal furniture finishing operation is difficult because of the different units of measure for their effectiveness. In such cases, it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed. Examples are:

- pounds VOC emission per gallons of solids applied,
- pounds PM emission per ton of cement produced,
- pounds SO2 emissions per million Btu heat input, and
- pounds SO2 emission per kilowatt of electric power produced,

Calculating annual emissions levels (tons/yr) using these units becomes straightforward once the projected annual production or processing rates are known. The result is an estimate of the annual pollutant emissions that the source or emissions unit will emit. Annual "potential" emission projections are calculated using the source's maximum design capacity and full year round operation (8760 hours), unless the final permit is to include federally enforceable conditions restricting the source's capacity or hours of operation. However, emissions estimates used for the purpose of calculating and comparing the cost effectiveness of a control option are based on a different approach (see section V.D.2.b. COST EFFECTIVENESS).

IV.C.2. CONTROL TECHNIQUES WITH A WIDE RANGE OF EMISSIONS PERFORMANCE LEVELS

The objective of the top-down BACT analysis is to not only identify the best control technology, but also a corresponding performance level (or in some cases performance range) for that technology considering source-specific factors. Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. Scrubbers, high and low efficiency electrostatic precipitators (ESPs), and low-VOC coatings are examples of just a few. It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. Rather, the applicant should use the most recent regulatory decisions and performance data for identifying the emissions performance level(s) to be evaluated in all cases.

The EPA does not expect an applicant to necessarily accept an emission limit as BACT solely because it was required previously of a similar source type. While the most effective level of control must be considered in the

BACT analysis, different levels of control for a given control alternative can be considered.[1] For example, the consideration of a lower level of control for a given technology may be warranted in cases where past decisions involved different source types. The evaluation of an alternative control level can also be considered where the applicant can demonstrate to the satisfaction of the permit agency demonstrate that other considerations show the need to evaluate the control alternative at a lower level of effectiveness.

Manufacturer's data, engineering estimates and the experience of other sources provide the basis for determining achievable limits. Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative. However, the basis for choosing the alternate level (or range) of control in the BACT analysis must be documented in the application. In the absence of a showing of differences between the proposed source and previously permitted sources achieving lower emissions limits, the permit agency should conclude that the lower emissions limit is representative for that control alternative.

In summary, when reviewing a control technology with a wide range of emission performance levels, it is presumed that the source can achieve the same emission reduction level as another source unless the applicant demonstrates that there are source-specific factors or other relevant information that provide a technical, economic, energy or environmental justification to do otherwise. Also, a control technology that has been eliminated as having an adverse economic impact at its highest level of performance, may be acceptable at a lesser level of performance. For example, this can occur when the cost effectiveness of a control technology at its

[1] In reviewing the BACT submittal by a source the permit agency may determine that an applicant should consider a control technology alternative otherwise eliminated by the applicant, if the operation of that control technology at a lower level of control (but still higher than the next control alternative. For example, while scrubber operating at 98% efficiency may be eliminated as BACT by the applicant due to source specific economic considerations, the scrubber operating in the 90% to 95% efficiency range may not have an adverse economic impact.

highest level of performance greatly exceeds the cost of that control technology at a somewhat lower level (or range) of performance.

IV.C.3. ESTABLISHMENT OF THE CONTROL OPTIONS HIERARCHY

After determining the emissions performance levels (in common units) of each control technology option identified in Step 2, a hierarchy is established that places at the "top" the control technology option that achieves the lowest emissions level. Each other control option is then placed after the "top" in the hierarchy by its respective emissions performance level, ranked from lowest emissions to highest emissions (most effective to least stringent effective emissions control alternative).

From the hierarchy of control alternatives the applicant should develop a chart (or charts) displaying the control hierarchy and, where applicable,:

! expected emission rate (tons per year, pounds per hour);

! emissions performance level (e.g., percent pollutant removed, emissions per unit product, lb/MMbtu, ppm);

! expected emissions reduction (tons per year);

! economic impacts (total annualized costs, cost effectiveness, incremental cost effectiveness);

! environmental impacts (includes any significant or unusual other media impacts (e.g., water or solid waste), and the relative ability of each control alternative to control emissions of toxic or hazardous air contaminants);

! energy impacts (indicate any significant energy benefits or disadvantages).

This should be done for each pollutant and for each emissions unit (or grouping of similar units) subject to a BACT analysis. The chart is used in comparing the control alternatives during step 4 of the BACT selection process. Some sample charts are displayed in Table B-2 and Table B-3. Completed sample charts accompany the example BACT analyses provided in section VI.

At this point, it is recommended that the applicant contact the reviewing agency to determine whether the agency feels that any other applicable control alternative should be evaluated or if any issues require special attention in the BACT selection process.

IV.D. THE BACT SELECTION PROCESS (STEP 4)

After identifying and listing the available control options the next step is the determination of the energy, environmental, and economic impacts of each option and the selection of the final level of control. The applicant is responsible for presenting an evaluation of each impact along with appropriate supporting information. Consequently, both beneficial and adverse impacts should be discussed and, where possible, quantified. In general, the BACT analysis should focus on the direct impact of the control alternative.

Step 4 validates the suitability of the top control option in the listing for selection as BACT, or provides clear justification why the top candidate is inappropriate as BACT. If the applicant accepts the top alternative in the listing as BACT from an economic and energy standpoint, the applicant proceeds to consider whether collateral environmental impacts (e.g., emissions of unregulated air pollutants or impacts in other media) would justify selection of an alternative control option. If there are no outstanding issues regarding collateral environmental impacts, the analysis is ended and the results proposed as BACT. In the event that the top candidate

TABLE B-2. SAMPLE BACT CONTROL HIERARCHY

Pollutant	Technology	Range of control (%)	Control level for BACT analysis (%)	Emissions limit
SO_2	First Alternative	80-95	95	15 ppm
	Second Alternative	80-95	90	30 ppm
	Third Alternative	70-85	85	45 ppm
	Fourth Alternative	40-80	75	75 ppm
	Fifth Alternative	50-85	70	90 ppm
	Baseline Alternative	-	-	-

TABLE B-3. SAMPLE SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS

				Economic Impacts			Environmental Impacts		Energy Impacts
Pollutant/ Emissions Unit	Control alternative	Emissions (lb/hr,tpy)	Emissions reduction(a) (tpy)	Total annualized cost(b) ($/yr)	Average Cost effectiveness(c) ($/ton)	Incremental cost effectiveness(d) ($/ton)	Toxics impact(e) (Yes/No)	Adverse environmental impacts(f) (Yes/No)	Incremental increase over baseline(g) (MMBtu/yr)
NOx/Unit A	Top Alternative								
	Other Alternative(s)								
	Baseline								
NOx/Unit B	Top Alternative								
	Other Alternative(s)								
	Baseline								
SO2/Unit A	Top Alternative								
	Other Alternative(s)								
	Baseline								
SO2/Unit B	Top Alternative								
	Other Alternative(s)								
	Baseline								

(a) Emissions reduction over baseline level.
(b) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(c) Average Cost Effectiveness is total annualized cost for the control option divided by the emissions reductions resulting from the option.
(d) The incremental cost effectiveness is the difference in annualized cost for the control option and the next most effective control option divided by the difference in emissions reduction resulting from the respective alternatives.
(e) Toxics impact means there is a toxics impact consideration for the control alternative.
(f) Adverse environmental impact means there is an adverse environmental impact consideration with the control alternative.
(g) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline expressed in equivalent millions of Btus per year.

is shown to be inappropriate, due to energy, environmental, or economic impacts, the rationale for this finding needs to be fully documented for the public record. Then, the next most effective alternative in the listing becomes the new control candidate and is similarly evaluated. This process continues until the control technology under consideration cannot be eliminated by any source-specific environmental, energy, or economic impacts which demonstrate that the alternative is inappropriate as BACT.

The determination that a control alternative to be inappropriate involves a demonstration that circumstances exist at the source which distinguish it from other sources where the control alternative may have been required previously, or that argue against the transfer of technology or application of new technology. Alternately, where a control technique has been applied to only one or a very limited number of sources, the applicant can identify those characteristic(s) unique to those sources that may have made the application of the control appropriate in those case(s) but not for the source under consideration. In showing unusual circumstances, objective factors dealing with the control technology and its application should be the focus of the consideration. The specifics of the situation will determine to what extent an appropriate demonstration has been made regarding the elimination of the more effective alternative(s) as BACT. In the absence of unusual circumstance, the presumption is that sources within the same category are similar in nature, and that cost and other impacts that have been borne by one source of a given source category may be borne by another source of the same source category.

IV.D.1. ENERGY IMPACTS ANALYSIS

Applicants should examine the energy requirements of the control technology and determine whether the use of that technology results in any significant or unusual energy penalties or benefits. A source may, for example, benefit from the combustion of a concentrated gas stream rich in volatile organic compounds; on the other hand, more often extra fuel or electricity is required to power a control device or incinerate a dilute gas stream. If such benefits or penalties exist, they should be quantified. Because energy penalties or benefits can usually be quantified in terms of additional cost or income to the source, the energy impacts analysis can, in most cases, simply be factored into the economic impacts analysis. However, certain types of control technologies have inherent energy penalties associated with their use. While these penalties should be quantified, so long as they are within the normal range for the technology in question, such penalties should not, in general, be considered adequate justification for nonuse of that technology.

Energy impacts should consider only direct energy consumption and not indirect energy impacts. For example, the applicant could estimate the direct energy impacts of the control alternative in units of energy consumption at the source (e.g., Btu, kWh, barrels of oil, tons of coal). The energy requirements of the control options should be shown in terms of total (and in certain cases also incremental) energy costs per ton of pollutant removed. These units can then be converted into dollar costs and, where appropriate, factored into the economic analysis.

As noted earlier, indirect energy impacts (such as energy to produce raw materials for construction of control equipment) generally are not considered. However, if the permit authority determines, either independently or based on a showing by the applicant, that the indirect energy impact is unusual or significant and that the impact can be well quantified, the indirect impact may be considered. The energy impact should still focus on the application of the control alternative and not a concern over general energy impacts associated with the project under review as compared to alternative projects for which a permit is not being sought, or as compared to a pollution source which the project under review would replace (e.g., it would be inappropriate to argue that a cogeneration project is more efficient in the production of electricity than the powerplant production capacity it would displace and, therefore, should not be required to spend equivalent costs for the control of the same pollutant).

The energy impact analysis may also address concerns over the use of locally scarce fuels. The designation of a scarce fuel may vary from region to region, but in general a scarce fuel is one which is in short supply locally and can be better used for alternative purposes, or one which may not be reasonably available to the source either at the present time or in the near future.

IV.D.2. COST/ECONOMIC IMPACTS ANALYSIS

Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis. Cost effectiveness, is the dollars per ton of pollutant emissions reduced. Incremental cost is the cost per ton reduced and should be considered in conjunction with total average effectiveness.

In the economical impacts analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source. Consequently, applicants generally should not propose elimination of control alternatives on the basis of economic parameters that provide an indication of the affordability of a control alternative relative to the source. BACT is required by law. Its costs are integral to the overall cost of doing business and are not to be considered an afterthought. Consequently, for control alternatives that have been effectively employed in the same source category, the economic impact of such alternatives on the particular source under review should be not nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative. Thus, where a control technology has been successfully applied to similar sources in a source category, an applicant should concentrate on documenting significant cost differences, if **any,** between the application of the control technology on those other sources and the particular source under review.

Cost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant, are taken as an indication that unusual and persuasive differences exist with respect to the source under review. In addition, where the cost of a control alternative for the specific source reviewed is within the range of normal costs for that control alternative, the alternative, in certain limited circumstances, may still be eligible for elimination. To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations. If the circumstances of the differences are adequately documented and explained in the application and are acceptable to the reviewing agency they may provide a basis for eliminating the control alternative.

In all cases, economic impacts need to be considered in conjunction with energy and environmental impacts (e.g., toxics and hazardous pollutant considerations) in selecting BACT. It is possible that the environmental impacts analysis or other considerations (as described elsewhere) would override the economic elimination criteria as described in this section. However, absent overriding environmental impacts concerns or other considerations, an acceptable demonstration of a adverse economic impact can be adequate basis for eliminating the control alternative.

IV.D.2.a. ESTIMATING THE COSTS OF CONTROL

Before costs can be estimated, the control system design parameters must be specified. The most important item here is to ensure that the design parameters used in costing are consistent with emissions estimates used in other portions of the PSD application (e.g., dispersion modeling inputs and permit emission limits). In general, the BACT analysis should present vendor-supplied design parameters. Potential sources of other data on design parameters are BID documents used to support NSPS development, control technique guidelines documents, cost manuals developed by EPA, or control data in trade publications. Table B-4 presents some example design parameters which are important in determining system costs.

To begin, the limits of the area or process segment to be costed specified. This well defined area or process segment is referred to as the control system battery limits. The second step is to list and cost each major piece of equipment within the battery limits. The top-down BACT analysis should provide this list of costed equipment. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006, January 1990, Table B-4]. Inadequate documentation of battery limits is one of the most common reasons for confusion in comparison of costs of the same controls applied to similar sources. For control options that are defined as inherently lower-polluting processes (and not add-on controls), the battery limits may be the entire process or project.

Design parameters should correspond to the specified emission level. The equipment vendors will usually supply the design parameters to the applicant, who in turn should provide them to the reviewing agency. In order to determine if the design is reasonable, the design parameters can be compared with those shown in documents such as the OAQPS Control Cost Manual, Control Technology for Hazardous Air Pollutants (HAPS) Manual (EPA 625/6-86-014, September 1986), and background information documents for NSPS and NESHAP regulations. If the design specified does not appear reasonable, then the applicant should be requested to supply performance test data for the control technology in question applied to the same source, or a similar source.

TABLE B-4. EXAMPLE CONTROL SYSTEM DESIGN PARAMETERS

Control	Example Design parameters
Wet Scrubbers	Scrubber liquor (water, chemicals, etc.) Gas pressure drop Liquid/gas ratio
Carbon Absorbers	Specific chemical species Gas pressure drop lbs carbon/lbs pollutant
Condensers	Condenser type Outlet temperature
Incineration	Residence time Temperature
Electrostatic Precipitator	Specific collection area (ft2/acfm) Voltage density
Fabric Filter	Air to cloth ratio Pressure drop
Selective Catalytic Reduction	Space velocity Ammonia to NOx molar ratio Pressure drop Catalyst life

Once the control technology alternatives and achievable emissions performance levels have been identified, capital and annual costs are developed. These costs form the basis of the cost and economic impacts (discussed later) used to determine and document if a control alternative should be eliminated on grounds of its economic impacts.

Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis.

Normally the submittal of very detailed and comprehensive project cost data is not necessary. However, where initial control cost projections on the part of the applicant appear excessive or unreasonable (in light of recent cost data) more detailed and comprehensive cost data may be necessary to document the applicant's projections. An applicant proposing the top alternative usually does not need to provide cost data on the other possible control alternatives.

Total cost estimates of options developed for BACT analyses should be on order of plus or minus 30 percent accuracy. If more accurate cost data are available (such as specific bid estimates), these should be used. However, these types of costs may not be available at the time permit applications are being prepared. Costs should also be site specific. Some site specific factors are costs of raw materials (fuel, water, chemicals) and labor. For example, in some remote areas costs can be unusually high. For example, remote locations in Alaska may experience a 40-50 percent premium on installation costs. The applicant should document any unusual costing assumptions used in the analysis.

IV.D.2.b. COST EFFECTIVENESS

Cost effectiveness is the economic criterion used to assess the potential for achieving an objective at least cost. Effectiveness is measured in terms of tons of pollutant emissions removed. Cost is measured in terms of annualized control costs.

The Cost effectiveness calculations can be conducted on an average, or incremental basis. The resultant dollar figures are sensitive to the number of alternatives costed as well as the underlying engineering and cost parameters. There are limits to the use of cost-effectiveness analysis. For example, cost-effectiveness analysis should not be used to set the environmental objective. Second, cost-effectiveness should, in and of itself, not be construed as a measure of adverse economic impacts. There are two measures of cost-effectiveness that will be discussed in this section: (1) average cost-effectiveness, and (2) incremental cost-effectiveness.

Average Cost Effectiveness

Average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate) is a way to present the costs of control. Average cost effectiveness is calculated as shown by the following formula:

Average cost Effectiveness (dollars per ton removed) =

$$\frac{\text{Control option annualized cost}}{\text{Baseline emissions rate - Control option emissions rate}}$$

Costs are calculated in (annualized) dollars per year ($/yr) and emissions
rates are calculated in tons per year (tons/yr). The result is a cost effectiveness number in (annualized) dollars per ton ($/ton) of pollutant removed.

Calculating Baseline Emissions

The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions for the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of adding post process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for use of inherently lower polluting processes.

Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in
developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost

effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.

For example, VOC emissions from a storage tank might vary significantly with temperature, volatility of liquid stored, and throughput. In this case, potential emissions would be overestimated if annual VOC emissions were estimated by extrapolating over the course of a year VOC emissions based solely on the hottest summer day. Instead, the range of expected temperatures should be considered in determining annual baseline emissions. Likewise, potential emissions would be overestimated if one assumed that gasoline would be stored in a storage tank being built to feed an oil-fired power boiler or such a tank will be continually filled and emptied. On the other hand, an upper bound case for a storage tank being constructed to store and transfer liquid fuels at a marine terminal should consider emissions based on the most volatile liquids at a high annual throughput level since it would not be unrealistic for the tank to operate in such a manner.

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.

For example, suppose (based on verified historic data regarding the industry in question) a given source can be expected to utilize numerous colored inks over the course of a year. Each color ink has a different VOC content ranging from a high VOC content to a relatively low VOC content. The source verifies that its operation will indeed call for the application of numerous color inks. In this case, it is more realistic for the baseline emission calculation for the source (and other similar sources) to be based on the expected mix of inks that would be expected to result in an upper boundary case annual VOC emissions rather than an assumption that only one color (i.e, the ink with the highest VOC content) will be applied exclusively during the whole year.

In another example, suppose sources in a particular industry historically operate at most at 85 percent capacity. For BACT cost effectiveness purposes (but **not** for applicability), an applicant may calculate cost effectiveness using 85 percent capacity. However, in comparing costs with similar sources, the applicant must consistently use an 85 percent capacity factor for the cost effectiveness of controls on those other sources.

Although permit conditions are normally used to make operating assumptions enforceable, the use of "standard industry practice" parameters for cost effectiveness calculations (but **not** applicability determinations) can be acceptable without permit conditions. However, when a source projects operating parameters (e.g., limited hours of operation or capacity utilization, type of fuel, raw materials or product mix or type) that are lower than standard industry practice or which have a deciding role in the BACT determination, then these parameters or assumptions must be made enforceable with permit conditions. If the applicant will not accept enforceable permit conditions, then the reviewing agency should use the absolute worst case uncontrolled emissions in calculating baseline emissions. This is necessary to ensure that the permit reflects the conditions under which the source intends to operate.

For example, the baseline emissions calculation for an emergency standby generator may consider the fact that the source does not intend to operate more than 2 weeks a year. On the other hand, baseline emissions associated with a base-loaded turbine would not consider limited hours of operation. This produces a significantly higher level of baseline emissions than in the case of the emergency/standby unit and results in more cost effective controls. As a consequence of the dissimilar baseline emissions, BACT for the two cases could be very different. Therefore, it is important that the applicant confirm that the operational assumptions used to define the source's baseline emissions (and BACT) are genuine. As previously mentioned, this is usually done through enforceable permit conditions which reflect limits on the source's operation which were used to calculate baseline emissions.

In certain cases, such explicit permit conditions may not be necessary. For example, a source for which continuous operation would be a physical impossibility (by virtue of its design) may consider this limitation in estimating baseline emissions, without a direct permit limit on operations. However, the permit agency has the responsibility to verify that the source is constructed and operated consistent with the information and design specifications contained in the permit application.

For some sources it may be more difficult to define what emissions level actually represents uncontrolled emissions in calculating baseline emissions. For example, uncontrolled emissions could theoretically be defined for a spray coating operation as the maximum VOC content coating at the highest possible rate of application that the spray equipment could physically process, (even though use of such a coating or application rate would be unrealistic for the source). Assuming use of a coating with a VOC content and application rate greater than expected is unrealistic and would result in an overestimate in the amount of emissions reductions to be achieved by the installation of various control options. Likewise, the cost effectiveness of the options could consequently be greatly underestimated. To avoid these problems, uncontrolled emission factors should be represented by the highest realistic VOC content of the types of coatings and highest realistic application rates that would be used by the source, rather than by highest VOC based coating materials or rate of application in general.

Conversely, if uncontrolled emissions are underestimated, emissions reductions to be achieved by the various control options would also be underestimated and their cost effectiveness overestimated. For example, this type of situation occurs in the previous example if the baseline for the above coating operation was based on a VOC content coating or application rate that is too low [when the source had the ability and intent to utilize (even infrequently) a higher VOC content coating or application rate].

Incremental Cost Effectiveness

In addition to the average cost effectiveness of a control option, incremental cost effectiveness between control options should also be calculated. The incremental cost effectiveness should be examined in combination with the total cost effectiveness in order to justify elimination of a control option. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option, as shown in the following formula:

$$\text{Incremental Cost (dollars per incremental ton removed)} = \frac{\text{Total costs (annualized) of control option - Total costs (annualized) of next control option}}{\text{Next control option emission rate - Control option emissions rate}}$$

Care should be exercised in deriving incremental costs of candidate control options. Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between **dominant** alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis (see Figure B-1).

For example, assume that eight technically available control options for analysis are listed in the BACT hierarchy. These are represented as A through H in Figure B-1. In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options. In Figure B-1, the dominant set of control options, A, B, D, F, G, and H, represent the least-cost envelope depicted by the curvilinear line connecting them. Points C and E are inferior options and should not be considered in the

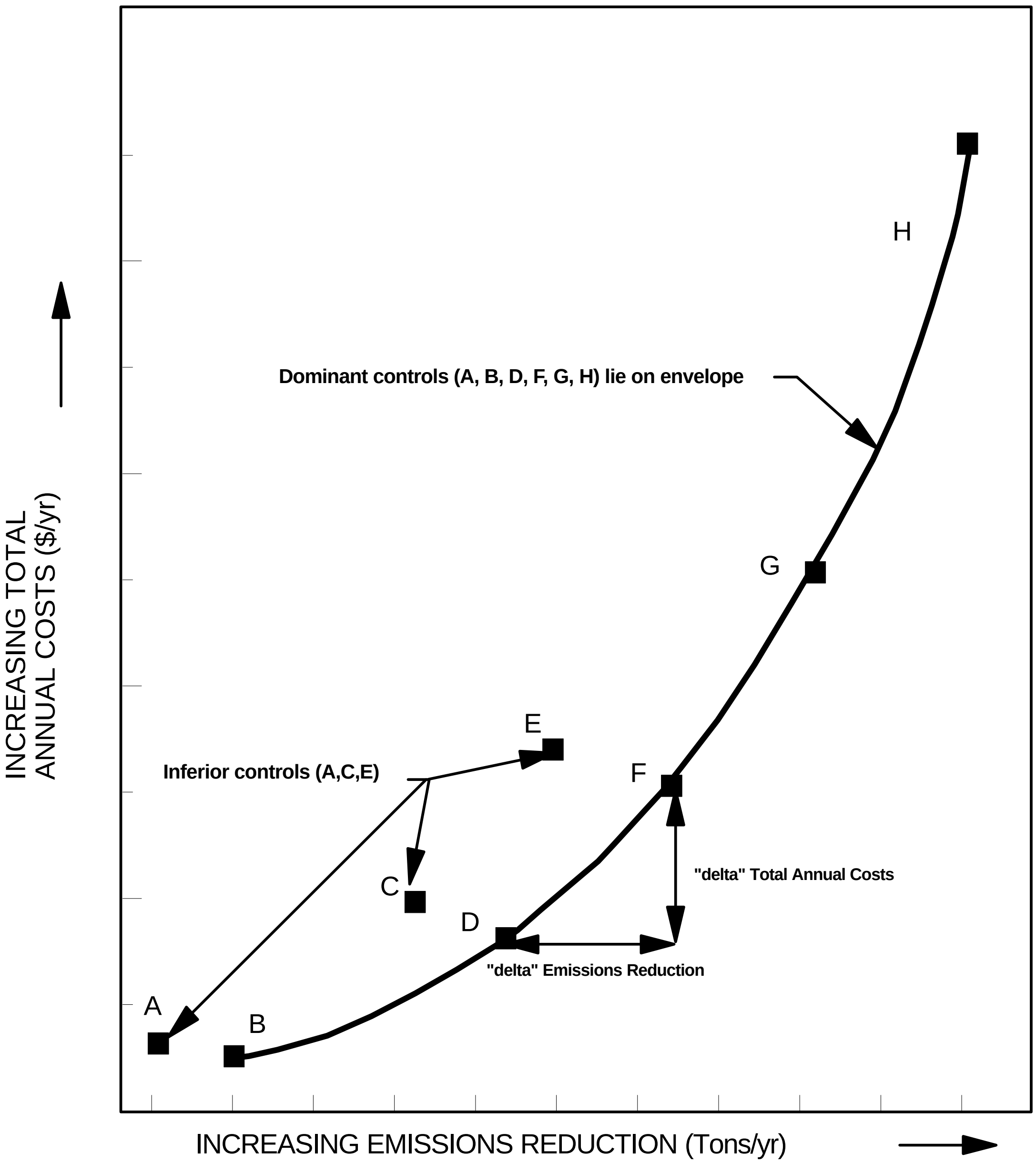

Figure B-1. LEAST-COST ENVELOPE

derivation of incremental cost effectiveness. Points A, C and E represent inferior controls because B will buy more emissions reduction for less money than A; and similarly, D and F will by more reductions for less money than E, respectively.

Consequently, care should be taken in selecting the dominant set of controls when calculating incremental costs. First, the control options need to be rank ordered in ascending order of annualized total costs. Then, as Figure B-1 illustrates, the most reasonable smooth curve of the control options is plotted. The incremental cost effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction. An example is illustrated in Figure B-1 for the incremental cost effectiveness for control option F. The vertical distance, "delta" Total Costs Annualized, divided by the horizontal distance, "delta" Emissions Reduced (tpy), would be the measure of the incremental cost effectiveness for option F.

A comparison of incremental costs can also be useful in evaluating the economic viability of a specific control option over a range of efficiencies. For example, depending on the capital and operational cost of a control device, total and incremental cost may vary significantly (either increasing or decreasing) over the operation range of a control device.

As a precaution, differences in incremental costs among dominant alternatives cannot be used by itself to argue one dominant alternative is preferred to another. For example, suppose dominant alternative is preferred to another. For example, suppose dominant alternatives B, D and F on the least-cost envelope (see Figure B-1) are identified as alternatives for a BACT analysis. We may observe the incremental cost effectiveness between dominant alternative B and D is $500 per ton whereas between dominant alternative D and F is $1000 per ton. Alternative D does <u>not</u> dominate alternative F. Both alternatives are dominant and hence on the least cost envelope. Alternative D cannot legitimately be preferred to F on grounds of incremental cost effectiveness.

In addition, when evaluating the total or incremental cost effectiveness of a control alternative, reasonable and supportable assumptions regarding control efficiencies should be made. An unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures.

The final decision regarding the reasonableness of calculated cost effectiveness values will be made by the review authority considering previous regulatory decisions. Study cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options.

IV.D.2.c. DETERMINING AN ADVERSE ECONOMIC IMPACT

It is important to keep in mind that BACT is primarily a technology-based standard. In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT. However, unusual circumstances may greatly affect the cost of controls in a specific application. If so they should be documented. An example of an unusual circumstance might be the unavailability in an arid region of the large amounts of water needed for a scrubbing system. Acquiring water from a distant location might add unreasonable costs to the alternative, thereby justifying its elimination on economic grounds. Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source.

Where the cost of a control alternative for the specific source being reviewed is within the range of normal costs for that control alternative, the alternative may also be eligible for elimination in limited circumstances. This may occur, for example, where a control alternative has not been required as BACT (or its application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS).

To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal (e.g., dollars per total ton removed) for the control alternative are disproportionately high when compared to the cost of control for the pollutant in recent BACT determinations. Specifically, the applicant should document that the cost to the applicant of the control alternative is significantly beyond the range of recent costs normally associated with BACT for the type of facility (or BACT control costs in general) for the pollutant. This type of analysis should demonstrate that a technically and economically feasible control option is nevertheless, by virtue of the magnitude of its associated costs and limited application, unreasonable or otherwise not "achievable" as BACT in the particular case. Total and incremental cost effectiveness numbers are factored into this type of analysis. However, such economic information should be coupled with a comprehensive demonstration, based on objective factors, that the technology is inappropriate in the specific circumstance.

The economic impact portion of the BACT analysis should not focus on inappropriate factors or exclude pertinent factors, as the results may be misleading. For example, the capital cost of a control option may appear excessive when presented by itself or as a percentage of the total project cost. However, this type of information can be misleading. If a large emissions reduction is projected, low or reasonable cost effectiveness numbers may validate the option as an appropriate BACT alternative irrespective of the apparent high capital costs. In another example, undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs.

IV.D.3. ENVIRONMENTAL IMPACTS ANALYSIS

The environmental impacts analysis is not to be confused with the air quality impact analysis (i.e., ambient concentrations), which is an independent statutory and regulatory requirement and is conducted separately from the BACT analysis. The purpose of the air quality analysis is to demonstrate that the source (using the level of control ultimately determined to be BACT) will not cause or contribute to a violation of any applicable national ambient air quality standard or PSD increment. Thus, regardless of the level of control proposed as BACT, a permit cannot be issued to a source that would cause or contribute to such a violation. In contrast, the environmental impacts portion of the BACT analysis concentrates on impacts other than impacts on air quality (i.e., ambient concentrations) due to emissions of the regulated pollutant in question, such as solid or hazardous waste generation, discharges of polluted water from a control device, visibility impacts, or emissions of unregulated pollutants.

Thus, the fact that a given control alternative would result in only a slight decrease in ambient concentrations of the pollutant in question when compared to a less stringent control alternative should not be viewed as an adverse **environmental** impact justifying rejection of the more stringent control alternative. However, if the cost effectiveness of the more stringent alternative is exceptionally high, it may (as provided in section V.D.2.) be considered in determining the existence of an adverse **economic** impact that would justify rejection of the more stringent alternative.

The applicant should identify any significant or unusual environmental impacts associated with a control alternative that have the potential to affect the selection or elimination of a control alternative. Some control technologies may have potentially significant secondary (i.e., collateral) environmental impacts. Scrubber effluent, for example, may affect water quality and land use. Similarly, emissions of water vapor from technologies using cooling towers may affect local visibility. Other examples of secondary environmental impacts could include hazardous waste discharges, such as spent catalysts or contaminated carbon. Generally, these types of environmental concerns become important when sensitive site-specific receptors exist or when the incremental emissions reduction potential of the top control is only marginally greater than the next most effective option. However, the fact that a control device creates liquid and solid waste that must be disposed of does not necessarily argue against selection of that technology as BACT, particularly if the control device has been applied to similar facilities elsewhere and the solid or liquid waste problem under review is similar to those other applications. On the other hand, where the applicant can show that unusual circumstances at the proposed facility create greater problems than experienced elsewhere, this may provide a basis for the elimination of that control alternative as BACT.

The procedure for conducting an analysis of environmental impacts should be made based on a consideration of site-specific circumstances. In general, however, the analysis of environmental impacts starts with the identification and quantification of the solid, liquid, and gaseous discharges from the control device or devices under review. This analysis of environmental impacts should be performed for the entire hierarchy of technologies (even if the applicant proposes to adopt the "top", or most stringent, alternative). However, the analysis need only address those control alternatives with any significant or unusual environmental impacts that have the potential to affect the selection or elimination of a control alternative. Thus, the relative environmental impacts (both positive and negative) of the various alternatives can be compared with each other and the "top" alternative.

Initially, a qualitative or semi-quantitative screening is performed to narrow the analysis to discharges with potential for causing adverse environmental effects. Next, the mass and composition of any such discharges should be assessed and quantified to the extent possible, based on readily available information. Pertinent information about the public or environmental consequences of releasing these materials should also be assembled.

IV.D.3.a. EXAMPLES (Environmental Impacts)

The following paragraphs discuss some possible factors for considerations in evaluating the potential for an adverse other media impact.

! **Water Impact**

Relative quantities of water used and water pollutants produced and discharged as a result of use of each alternative emission control system relative to the "top" alternative would be identified. Where possible, the analysis would assess the effect on ground water and such local surface water quality parameters as ph, turbidity, dissolved oxygen, salinity, toxic chemical levels, temperature, and any other important considerations. The analysis should consider whether applicable water quality standards will be met and the availability and effectiveness of various techniques to reduce potential adverse effects.

! **Solid Waste Disposal Impact**

The quality and quantity of solid waste (e.g., sludges, solids) that must be stored and disposed of or recycled as a result of the application of each alternative emission control system would be compared with the quality and quantity of wastes created with the "top" emission control system. The composition and various other characteristics of the solid waste (such as permeability, water retention, rewatering of dried material, compression strength, leachability of dissolved ions, bulk density, ability to support vegetation growth and hazardous characteristics) which are significant with regard to potential surface water pollution or transport into and contamination of subsurface waters or aquifers would be appropriate for consideration.

! Irreversible or Irretrievable Commitment of Resources

The BACT decision may consider the extent to which the alternative emission control systems may involve a trade-off between short-term environmental gains at the expense of long-term environmental losses and the extent to which the alternative systems may result in irreversible or irretrievable commitment of resources (for example, use of scarce water resources).

! Other Environmental Impacts

Significant differences in noise levels, radiant heat, or dissipated static electrical energy may be considered.

One environmental impact that could be examined is the trade-off between emissions of the various pollutants resulting from the application of a specific control technology. The use of certain control technologies may lead to increases in emissions of pollutants other than those the technology was designed to control. For example, the use of certain volatile organic compound (VOC) control technologies can increase nitrogen oxides (NOx) emissions. In this instance, the reviewing authority may want to give consideration to any relevant local air quality concern relative to the secondary pollutant (in this case NOx) in the region of the proposed source. For example, if the region in the example were nonattainment for NOx, a premium could be placed on the potential NOx impact. This could lead to elimination of the most stringent VOC technology (assuming it generated high quantities of NOx) in favor of one having less of an impact on ambient NOx concentrations. Another example is the potential for higher emissions of toxic and hazardous pollutants from a municipal waste combustor operating at a low flame temperature to reduce the formation of NOx. In this case the real concern to mitigate the emissions of toxic and hazardous emissions (via high combustion temperatures) may well take precedent over mitigating NOx emissions through the use of a low flame temperature. However, in most cases (unless an overriding concern over the formation and impact of the secondary pollutant is clearly present as in the examples given), it is not expected that this type impact would affect the outcome of the decision.

Other examples of collateral environmental impacts would include hazardous waste discharges such as spent catalysts or contaminated carbon. Generally these types of environmental concerns become important when site-specific sensitive receptors exist or when the incremental emissions reduction potential of the top control option is only marginally greater than the next most effective option.

IV.D.3.b. CONSIDERATION OF EMISSIONS OF TOXIC AND HAZARDOUS AIR POLLUTANTS

The generation or reduction of toxic and hazardous emissions, including compounds not regulated under the Clean Air Act, are considered as part of the environmental impacts analysis. Pursuant to the EPA Administrator's decision in North County Resource Recovery Associates, PSD Appeal No. 85-2 (Remand Order, June 3, 1986), a PSD permitting authority should consider the effects of a given control alternative on emissions of toxics or hazardous pollutants not regulated under the Clean Air Act. The ability of a given control alternative to control releases of unregulated toxic or hazardous emissions must be evaluated and may, as appropriate, affect the BACT decision. Conversely, hazardous or toxic emissions resulting from a given control technology should also be considered and may, as appropriate, also affect the BACT decision.

Because of the variety of sources and pollutants that may be considered in this assessment, it is not feasible for the EPA to provide highly detailed national guidance on performing an evaluation of the toxic impacts as part of the BACT determination. Also, detailed information with respect to the type and magnitude of emissions of unregulated pollutants for many source categories is currently limited. For example, a combustion source emits hundreds of substances, but knowledge of the magnitude of some of these emissions or the hazards they produce is sparse. The EPA believes it is appropriate for agencies to proceed on a case-by-case basis using the best information available. Thus, the determination of whether the pollutants would be emitted in amounts sufficient to be of concern is one that the permitting authority has considerable discretion in making. However, reasonable efforts should be made to address these issues. For example, such efforts might include consultation with the:

- EPA Regional Office;
- Control Technology Center (CTC);
- National Air Toxics Information Clearinghouse;
- Air Risk Information Support Center in the Office of Air Quality Planning and Standards (OAQPS); and
- Review of the literature, such as; EPA-prepared compilations of emission factors.

Source-specific information supplied by the permit applicant is often the best source of information, and it is important that the applicant be made aware of its responsibility to provide for a reasonable accounting of air toxics emissions.

Similarly, once the pollutants of concern are identified, the permitting authority has flexibility in determining the methods by which it factors air toxics considerations into the BACT determination, subject to the obligation to make reasonable efforts to consider air toxics. Consultation by the review authority with EPA's implementation centers, particularly the CTC, is again advised.

It is important to note that several acceptable methods, including risk assessment, exist to incorporate air toxics concerns into the BACT decision. The depth of the toxics assessment will vary with the circumstances of the particular source under review, the nature and magnitude of the toxic pollutants, and the locality. Emissions of toxic or hazardous pollutant of concern to the permit agency should be identified and, to the extent possible, quantified. In addition, the effectiveness of the various control alternatives in the hierarchy at controlling the toxic pollutant should be estimated and summarized to assist in making judgements about how potential emissions of toxic or hazardous pollutants may be mitigated through the selection of one control option over another. For example, the response to the Administrator made by EPA Region IX in its analysis of the North County permitting decision illustrates one of several approaches (for further information see the September 22, 1987 EPA memorandum from Mr. Gerald Emission titled "Implementation of North County Resource Recover PSD Remand" and July 28, 1988 EPA memorandum from Mr. John Calcagni titled "Supplemental guidance on Implementing the North County Prevention of Significant Deterioration (PSD) Remand").

Under a top-down BACT analysis, the control alternative selected as BACT will most likely reduce toxic emissions as well as the regulated pollutant. An example is the emissions of heavy metals typically associated with coal combustion. The metals generally are a portion of, or adsorbed on, the fine particulate in the exhaust gas stream. Collection of the particulate in a high efficiency fabric filter rather than a low efficiency electrostatic precipitator reduces criteria pollutant particulate matter emissions and toxic heavy metals emissions. Because in most instances the interests of reducing toxics coincide with the interests of reducing the pollutants subject to BACT, consideration of toxics in the BACT analysis generally amounts to quantifying toxic emission levels for the various control options.

In limited other instances, though, control of regulated pollutant emissions may compete with control of toxic compounds, as in the case of certain selective catalytic reduction (SCR) NOx control technologies. The SCR technology itself results in emissions of ammonia, which increase, generally speaking, with increasing levels of NOx control. It is the intent of the toxics screening in the BACT procedure to identify and quantify this type of toxic effect. Generally, toxic effects of this type will not necessarily be overriding concerns and will likely not to affect BACT decisions. Rather, the intent is to require a screening of toxics emissions effects to ensure that a possible overriding toxics issue does not escape notice.

On occasion, consideration of toxics emissions may support the selection of a control technology that yields less than the maximum degree of reduction in emissions of the regulated pollutant in question. An example is the municipal solid waste combustor and resource recovery facility that was the subject of the North County remand. Briefly, BACT for SO_2 and PM was selected to be a lime slurry spray drier followed by a fabric filter. The combination yields good SO_2 control (approximately 83 percent), good PM control (approximately 99.5 percent) and also removes acid gases (approximately 95 percent), metals, dioxins, and other unregulated pollutants. In this instance, the permitting authority determined that good balanced control of regulated and unregulated pollutants took priority over achieving the maximum degree of emissions reduction for one or more regulated pollutants. Specifically, higher levels (up to 95 percent) of SO_2 control could have been obtained by a wet scrubber.

IV.E. SELECTING BACT (STEP 5)

The most effective control alternative not eliminated in Step 4 is selected as BACT.

It is important to note that, regardless of the control level proposed by the applicant as BACT, the ultimate BACT decision is made by the permit issuing agency after public review. The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permit agency to review the documentation and rationale presented and; (1) ensure that the applicant has addressed all of the most effective control options that could be applied and; (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permit agency does not accept the basis for the proposed elimination of a control option, the agency may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided.

IV.F. OTHER CONSIDERATIONS

Once energy, environmental, and economic impacts have been considered, BACT can only be made more stringent by other considerations outside the normal scope of the BACT analysis as discussed under the above steps. Examples include cases where BACT does not produce a degree of control stringent enough to prevent exceedances of a national ambient air quality standard or PSD increment, or where the State or local agency will not accept the level of control selected as BACT and requires more stringent controls to preserve a greater amount of the available increment. A permit cannot be issued to a source that would cause or contribute to such a violation, regardless of the outcome of the BACT analysis. Also, States which have set ambient air quality standards at levels tighter than the federal standards may demand a more stringent level of control at a source to demonstrate compliance with the State standards. Another consideration which could override the selected BACT are legal constraints outside of the Clean Air Act requiring the application of a more stringent technology (e.g., a consent decree requiring a greater degree of control). In all cases, regardless of the rationale for the permit requiring a more stringent emissions limit than would have otherwise been chosen as a result of the BACT selection process, the emission limit in the final permit (and corresponding control alternative) represents BACT for the permitted source on a case-by-case basis.

The BACT emission limit in a new source permit is not set until the final permit is issued. The final permit is not issued until a draft permit has gone through public comment and the permitting agency has had an opportunity to consider any new information that may have come to light during the comment period. Consequently, in setting a proposed or final BACT limit, the permit agency can consider new information it learns, including recent permit decisions, subsequent to the submittal of a complete application. This emphasizes the importance of ensuring that prior to the selection of a proposed BACT, all potential sources of information have been reviewed by the source to ensure that the list of potentially applicable control alternatives is complete (most importantly as it relates to any more effective control options than the one chosen) and that all considerations relating to economic, energy and environmental impacts have been addressed.

V. ENFORCEABILITY OF BACT

To complete the BACT process, the reviewing agency must establish an enforceable emission limit for each subject emission unit at the source and for each pollutant subject to review that is emitted from the source. If technological or economic limitations in the application of a measurement methodology to a particular emission unit would make an emissions limit infeasible, a design, equipment, work practice, operation standard, or combination thereof, may be prescribed. Also, the technology upon which the BACT emissions limit is based should be specified in the permit. These requirements should be written in the permit so that they are specific to the individual emission unit(s) subject to PSD review.

The emissions limits must be included in the proposed permit submitted for public comment, as well as the final permit. BACT emission limits or conditions must be met on a continual basis at all levels of operation (e.g., limits written in pounds/MMbtu or percent reduction achieved), demonstrate protection of short term ambient standards (limits written in pounds/hour) and be enforceable as a practical matter (contain appropriate averaging times, compliance verification procedures and recordkeeping requirements). Consequently, the permit must:

! be able to show compliance or noncompliance (i.e., through monitoring times of operation, fuel input, or other indices of operating conditions and practices); and

! specify a reasonable averaging time consistent with established reference methods, contain reference methods for determining compliance, and provide for adequate reporting and recordkeeping so that the permitting agency can determine the compliance status of the source.

VI. EXAMPLE BACT ANALYSES FOR GAS TURBINES

Note: The following example provided is for illustration only. The example source is fictitious and has been created to highlight many of the aspects of the top-down process. Finally, it must be noted that the cost data and other numbers presented in the example are used only to demonstrate the BACT decision making process. Cost data are used in a relative sense to compare control costs among sources in a source category or for a pollutant. Determination of appropriate costs is made on a case-by-case basis.

In this section a BACT analysis for a stationary gas turbine project is presented and discussed under three alternative operating scenarios:

- Example 1--Simple Cycle Gas Turbines Firing Natural Gas
- Example 2--Combined Cycle Gas Turbines Firing Natural Gas
- Example 3--Combined Cycle Gas Turbines Firing Distillate Oil

The purpose of the examples are to illustrate points to be considered in developing BACT decision criteria for the source under review and selecting BACT. They are intended to illustrate the process rather than provide universal guidance on what constitutes BACT for any particular source category. BACT must be determined on a case-by-case basis.

These examples are not based on any actual analyses performed for the purposes of obtaining a PSD permit. Consequently, the actual emission rates, costs, and design parameters used are neither representative of any actual case nor do they apply to any particular facility.

VI.A. EXAMPLE 1--SIMPLE CYCLE GAS TURBINES FIRING NATURAL GAS

VI.A.1 PROJECT SUMMARY

Table B-5 presents project data, stationary gas design parameters, and uncontrolled emission estimates for the new source in example 1. The gas turbine is designed to provide peaking service to an electric utility. The planned operating hours are less than 1000 hours per year. Natural gas fuel will be fired. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. The area where the source is to be located is in compliance for all criteria pollutants. No other changes are proposed at this facility, and therefore the net emissions change will be equal to the emissions shown on Table B-5. Only NOx emissions are significant (i.e., greater than the 40 tpy significance level for NOx) and a BACT analysis is required for NOx emissions only.

VI.A.2. BACT ANALYSIS SUMMARY

VII.A.2.a. CONTROL TECHNOLOGY OPTIONS

The first step in evaluating BACT is identifying all candidate control technology options for the emissions unit under review. Table B-6 presents the list of control technologies selected as potential BACT candidates. The first three control technologies, water or steam injection and selective catalytic reduction, were identified by a review of existing gas turbine facilities in operation. Selective noncatalytic reduction was identified as a potential type of control technology because it is an add-on NOx control which has been applied to other types of combustion sources.

TABLE B-5. EXAMPLE 1--COMBUSTION TURBINE DESIGN PARAMETERS

Characteristics	
Number of emissions units	1
Unit Type	Gas Turbines
Cycle Type	Simple-cycle
Output	75 MW
Exhaust temperature,	1,000 °F
Fuel(s)	Natural Gas
Heat rate, Btu/kw hr	11,000
Fuel flow, Btu/hr	1,650 million
Fuel flow, lb/hr	83,300
Service Type	Peaking
Operating Hours (per year)	1,000
Uncontrolled Emissions, tpy(a)	
NO_x	564 (169 ppm)
SO_2	<1
CO	4.6 (6 ppm)
VOC	1
PM	5 (0.0097 gr/dscf)

(a) Based on 1000 hours per year of operation at full load

TABLE B-6. EXAMPLE 1--SUMMARY OF POTENTIAL NOx CONTROL TECHNOLOGY OPTIONS

Control technology(a)	Typical control efficiency range (% reduction)	In Service On: Simple cycle turbines	Combined cycle gas turbines	Other combustion sources(c)	Technically feasible on simple cycle turbines
Selective Catalytic Reductions	40-90	No	Yes	Yes	Yes(b)
Water Injection	30-70	Yes	Yes	Yes	Yes
Steam Injection	30-70	No	Yes	Yes	No
Low NOx Burner	30-70	Yes	Yes	Yes	Yes
Selective Noncatalytic Reduction	20-50	No	Yes	Yes	No

(a) Ranked in order of highest to lowest stringency.
(b) Exhaust must be diluted with air to reduce its temperature to 600-750°F.
(c) Boiler incinerators, etc.

In this example, the control technologies were identified by the applicant based on a review of the BACT/LAER Clearinghouse, and discussions with State agencies with experience permitting gas turbines in NOx nonattainment areas. A preliminary meeting with the State permit issuing agency was held to determine whether the permitting agency felt that any other applicable control technologies should be evaluated and they agreed on the proposed control hierarchy.

VI.A.2.b. TECHNICAL FEASIBILITY CONSIDERATIONS

Once potential control technologies have been identified, each technology is evaluated for its technical feasibility based on the characteristics of the source. Because the gas turbines in this example are intended to be used for peaking service, a heat recovery steam generator (HRSG) will not be included. A HRSG recovers heat from the gas turbine exhaust to make steam and increase overall energy efficiency. A portion of the steam produced can be used for steam injection for NOx control, sometimes increasing the effectiveness of the net injection control system. However, the electrical demands of the grid dictate that the turbine will be brought on line only for short periods of time to meet peak demands. Due to the lag time required to bring a heat recovery steam generator on line, it is not technically feasible to use a HRSG at the facility. Use of an HRSG in this instance was shown to interfere with the performance of the unit for peaking service, which requires immediate response times for the turbine. Although it was shown that a HRSG was not feasible and therefore not available, water and steam are readily available for NOx control since the turbine will be located near an existing steam generating powerplant.

The turbine type and, therefore, the turbine model selection process, affects the achievability of NOx emissions limits. Factors which the customer considered in selecting the proposed turbine model were outlined in the application as: the peak demand which must be met, efficiency of the gas turbine, reliability requirements, and the experience of the utility with the operation and maintenance service of the particular manufacturer and turbine design. In this example, the proposed turbine is equipped with a combustor designed to achieve an emission level, at 15 percent O2, of 25 ppm NOx with steam injection or 42 ppm with water injection.[2]

Selective noncatalytic reduction (SNCR) was eliminated as technically infeasible and therefore not available, because this technology requires a flue gas temperature of 1300 to 2100°F. The exhaust from the gas turbines will be approximately 1000°F, which is below the required temperature range.

Selective catalytic reduction (SCR) was evaluated and no basis was found to eliminate this technology as technically infeasible. However, there are no known examples where SCR technology has been applied to a simple-cycle gas turbine or to a gas turbine in peaking service. In all cases where SCR has been applied, there was an HRSG which served to reduce the exhaust temperature to the optimum range of 600-750oF and the gas turbine was operated continuously. Consequently, application of SCR to a simple cycle turbine involves special circumstances. For this example, it is assumed that dilution air can be added to the gas turbine exhaust to reduce its temperature. However, the dilution air will make the system more costly due to higher gas flows, and may reduce the removal efficiency because the NOx concentration at the inlet will be reduced. Cost considerations are considered later in the analysis.

VI.A.2.c. CONTROL TECHNOLOGY HIERARCHY

After determining technical feasibility, the applicant selected the control levels for evaluation shown in Table B-7. Although the applicant

[2] For some gas turbine models, 25 ppm is not achievable with either water or steam injection.

TABLE B-7. EXAMPLE 1--CONTROL TECHNOLOGY HIERARCHY

Control Technology	Emissions Limits ppm(a)	Emissions Limits TPY
Steam Injection plus SCR	13	44
Steam Injection at maximum[b] design rate	25	84
Water Injection at maximum[b] design rate	42	140
Steam Injection to meet NSPS	93	312

(a) Corrected to 15 percent oxygen.

(b) Water to fuel ratio.

reported that some sites in California have achieved levels as low as 9 ppm, at this facility a 13 ppm level was determined to be the feasible limit with SCR. This decision is based on the lowest achievable level with steam injection of 25 ppm and an SCR removal efficiency of 50 percent. Even though the reported removal efficiencies for SCR are up to 90 percent at some facilities, at this facility the actual NOx concentration at the inlet to the SCR system will only be approximately 17 ppm (at actual conditions) due to the dilution air required. Also the inlet concentrations, flowrates, and temperatures will vary due to the high frequency of startups. These factors make achieving the optimum 90 percent NOx removal efficiency unrealistic. Based on discussions with SCR vendors, the applicant has established a 50 percent removal efficiency as the highest level achievable, thereby resulting in a 13 ppm level (i.e., 50 percent of 25 ppm).

The next most stringent level achievable would be steam injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 25 ppm as supported by vendor NOx emissions guarantees and unit test data. The applicant provided documentation obtained from the gas turbine manufacturer[3] verifying ability to achieve this range.

After steam injection the next most stringent level of control would be water injection at the maximum water-to-fuel ratio achievable by the unit within its design operating range. For this particular gas turbine model, that level is 42 ppm as supported by vendor NOx emissions guarantees and actual unit test data. The applicant provided documentation obtained from the gas turbine manufacturer verifying ability to achieve this range.

The least stringent level evaluated by the applicant was the current NSPS for utility gas turbines. For this model, that level is 93 ppm at 15 percent O2. By definition, BACT can be no less stringent than NSPS.

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[3] It should be noted that achievability of the NO_x limits is dependent on the turbine model, fuel, type of wet injection (water or steam), and system design. Not all gas turbine models or fuels can necessarily achieve these levels.

Therefore, less stringent levels are not evaluated.

VI.A.2.d. IMPACTS ANALYSIS SUMMARY

The next steps completed by the applicant were the development of the cost, economic, environmental and energy impacts of the different control alternatives. Although the top-down process would allow for the selection of the top alternative without a cost analysis, the applicant felt cost/economic impacts were excessive and that appropriate documentation may justify the elimination of SCR as BACT and therefore chose to quantify cost and economic impacts. Because the technologies in this case are applied in combination, it was necessary to quantify impacts for each of the alternatives. The impact estimates are shown in Table B-8. Adequate documentation of the basis for the impacts was determined to be included in the PSD permit application.

The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Figure B-2 is a plot of the least-cost envelope defined by the list of control options.

VI.A.2.e. TOXICS ASSESSMENT

If SCR were applied, potential toxic emissions of ammonia could occur. Ammonia emissions resulting from application of SCR could be as large as 20 tons per year. Application of SCR would reduce NOx by an additional 20 tpy over steam injection alone (25 ppm)(not including ammonia emissions).

Another environmental impact considered was the spent catalyst which would have to be disposed of at certain operating intervals. The catalyst contains vanadium pentoxide, which is listed as a hazardous waste under RCRA regulations (40 CFR 261.3). Disposal of this waste creates an additional economic and environmental burden. This was considered in the applicant's proposed BACT determination.

TABLE B-8. EXAMPLE 1--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_x

	Emissions per Turbine			Economic Impacts				Energy Impacts	Environmental Impacts	
Control alternative	Emissions (lb/hr)	(tpy)	Emissions reduction(a) (tpy)	Installed capital cost(b) ($)	Total annualized cost(c) ($/yr)	Cost effectiveness over baseline(d) ($/ton)	Incremental cost effectiveness(e) ($/ton)	Incremental increase over baseline(f) (MMBtu/yr)	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)
13 ppm Alternative	44	22	260	11,470,000	1,717,000(g)	6,600	56,200	464,000	Yes	No
25 ppm Alternative	84	42	240	1,790,000	593,000	2,470	8,460	30,000	No	No
42 ppm Alternative	140	70	212	1,304,000	356,000	1,680	800	15,300	No	No
NSPS Alternative	312	156	126	927,000	288,000	2,285		8,000	No	No
Uncontrolled Baseline	564	282	-	-	-	-	-	-	-	-

(a) Emissions reduction over baseline control level.
(b) Installed capital cost relative to baseline.
(c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.
(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.
(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.
(g) Assued 10 year catalyst life since this turbine operates only 1000 hours per year. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.

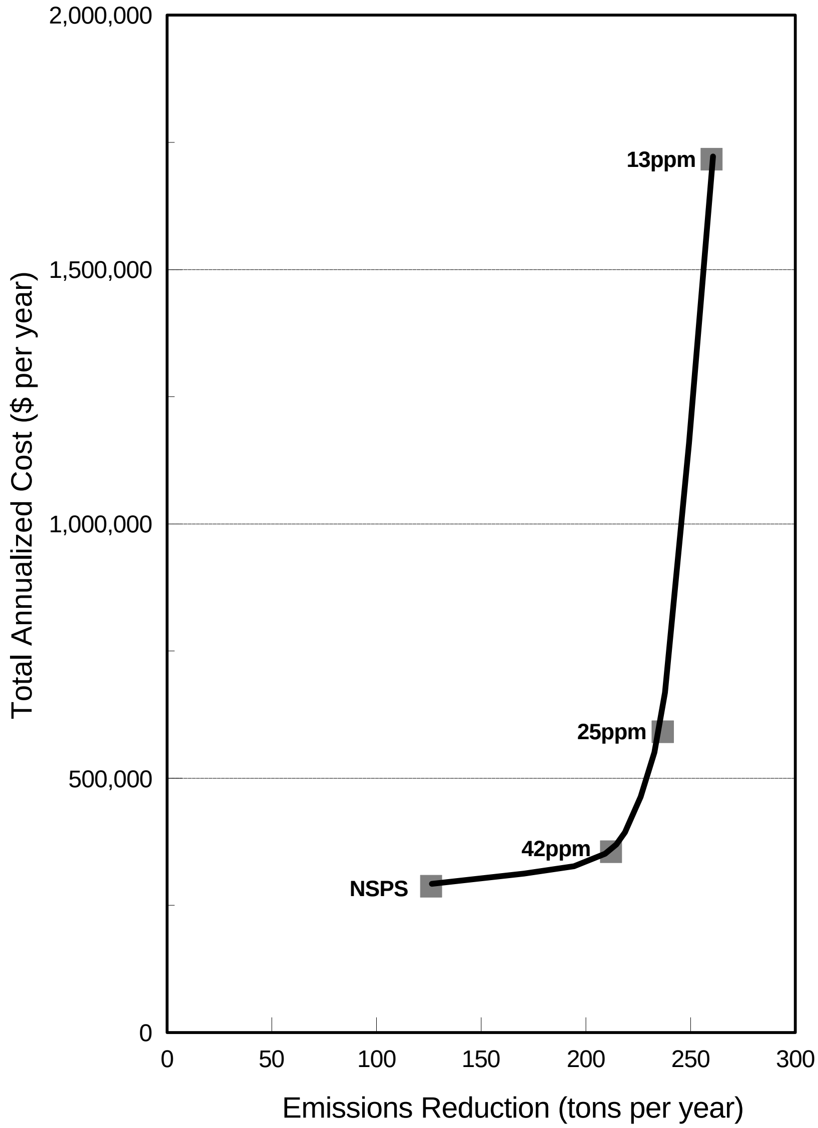

Figure B-2. Least-Cost Envelope for Example 1

VI.A.2.f. RATIONALE FOR PROPOSED BACT

Based on these impacts, the applicant proposed eliminating the 13 ppm alternative as economically infeasible. The applicant documented that the cost effectiveness is high at 6,600 $/ton, and well out of the range of recent BACT NOx control costs for similar sources. The incremental cost effectiveness of $56,200 also is high compared to the incremental cost effectiveness of the next option.

The applicant documented that the other combustion turbine sources which have applied SCR have much higher operating hours (i.e., all were permitted as base-loaded units). Also, these sources had heat recovery steam generators so that the cost effectiveness of the application of SCR was lower. For this source, dilution air must be added to cool the flue gas to the proper temperature. This increases the cost of the SCR system relative to the same gas turbine with a HRSG. Therefore, the other sources had much lower cost impacts for SCR relative to steam injection alone, and much lower cost effectiveness numbers. Application of SCR would also result in emission of ammonia, a toxic chemical, of possibly 20 tons per year while reducing NOx emissions by 20 tons per year. The applicant asserted that, based on these circumstances, to apply SCR in this case would be an unreasonable burden compared to what has been done at other similar sources.

Consequently, the applicant proposed eliminating the SCR plus steam injection alternative. The applicant then accepted the next control alternative, steam injection to 25 ppmv. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT. The use of steam injection was shown by the applicant to be consistent with recent BACT determinations for similar sources. The review authority concurred with the proposed elimination of SCR and the selection of a 25 ppmv limit as BACT.

VI.B. EXAMPLE 2--COMBINED CYCLE GAS TURBINES FIRING NATURAL GAS

Table B-9 presents the design parameters for an alternative set of circumstances. In this example, two gas turbines are being installed. Also, the operating hours are 5000 per year and the new turbines are being added to meet intermediate loads demands. The source will be limited through enforceable conditions to the specified hours of operation and fuel type. In this case, HRSG units are installed. The applicable control technologies and control technology hierarchy are the same as the previous example except that no dilution is required for the gas turbine exhaust because the HRSG serves to reduce the exhaust temperature to the optimum level for SCR operation. Also, since there is no dilution required and fewer startups, the most stringent control option proposed is 9 ppm based on performance limits for several other natural gas fired baseload combustion turbine facilities.

Table B-10 presents the results of the cost and economic impact analysis for the example and Figure B-3 is a plot of the least-cost envelope defined by the list of control options. The incremental cost impacts shown are the cost of the alternative compared to the next most stringent control alternative. Due to the increased operating hours and design changes, the economic impacts of SCR are much lower for this case. There does not appear to be a persuasive argument for stating that SCR is economically infeasible. Cost effectiveness numbers are within the range typically required of this and other similar source types.

In this case, there would also be emissions of ammonia. However, now the magnitude of ammonia emissions, approximately 40 tons per year, is much lower than the additional NOx reduction achieved, which is 270 tons per year.

Under these alternative circumstances, PM emissions are also now above the significance level (i.e., greater than 25 tpy). The gas turbine

TABLE B-9. EXAMPLE 2--COMBUSTION TURBINE DESIGN PARAMETERS

Characteristics	
Number of emission units	2
Emission units	Gas Turbine
Cycle Type	Combined-cycle
Output	
Gas Turbines (2 @ 75 MW each)	150 MW
Steam Turbine (no emissions generated)	70 MW
Fuel(s)	Natural Gas
Gas Turbine Heat Rate, Btu/kw-hr	11,000 Btu/kw-hr
Fuel Flow per gas turbine, Btu/hr	1,650 million
Fuel Flow per gas turbine, lb/hr	83,300
Service Type	Intermediate
Hours per year of operation	5000
Uncontrolled Emissions per gas turbine, tpy (a)(b)	
NO_x	1,410 (169 ppm)
SO_2	<1
CO	23 (6 ppm)
VOC	5
PM	25 (0.0097 gr/dscf)

(a) Based on 5000 hours per year of operation.

(b) Total uncontrolled emissions for the proposed project is equal to the pollutants uncontrolled emission rate multiplied by 2 turbines. For example, total NO_x = (2 turbines) x 1410 tpy per turbine) = 2820 tpy.

TABLE B-10. EXAMPLE 2--SUMMARY OF TOP-DOWN BACT IMPACT ANALYSIS RESULTS FOR NO_x

	Emissions per Turbine			Economic Impacts				Energy Impacts	Environmental Impacts	
Control alternative	Emissions (lb/hr)	(tpy)	Emissions reduction(a,h) (tpy)	Installed capital cost(b) ($)	Total annualized cost(c) ($/yr)	Cost effectiveness over baseline(d) ($/ton)	Incremental cost effectiveness(e) ($/ton)	Incremental increase over baseline(f) (MMBtu/yr)	Toxics impact (Yes/No)	Adverse environmental impact (Yes/No)
9 ppm Alternative	30	75	1,335	10,980,000	3,380,000(g)	2,531	12,200	160,000	Yes	No
25 ppm Alternative	84	210	1,200	1,791,000	1,730,000	1,440	6,050	105,000	No	No
42 ppm Alternative	140	350	1,060	1,304,000	883,000	833	181	57,200	No	No
NSPS Alternative	312	780	630	927,000	805,000	1,280		27,000	No	No
Uncontrolled Baseline	564	1,410	-	-	-	-	-	-	-	-

(a) Emissions reduction over baseline control level.
(b) Installed capital cost relative to baseline.
(c) Total annualized cost (capital, direct, and indirect) of purchasing, installing, and operating the proposed control alternative. A capital recovery factor approach using a real interest rate (i.e., absent inflation) is used to express capital costs in present-day annual costs.
(d) Cost Effectiveness over baseline is equal to total annualized cost for the control option divided by the emissions reductions resulting from the uncontrolled baseline.
(e) The optional incremental cost effectiveness criteria is the same as the total cost effectiveness criteria except that the control alternative is considered relative to the next most stringent alternative rather than the baseline control alternative.
(f) Energy impacts are the difference in total project energy requirements with the control alternative and the baseline control alternative expressed in equivalent millions of Btus per year.
(g) Assumes a 2 year catalyst life. Assumptions made on catalyst life may have a profound affect upon cost effectiveness.
(h) Since the project calls for two turbines, actual project wide emissions reductions for an alternative will be equal to two times the reduction listed.

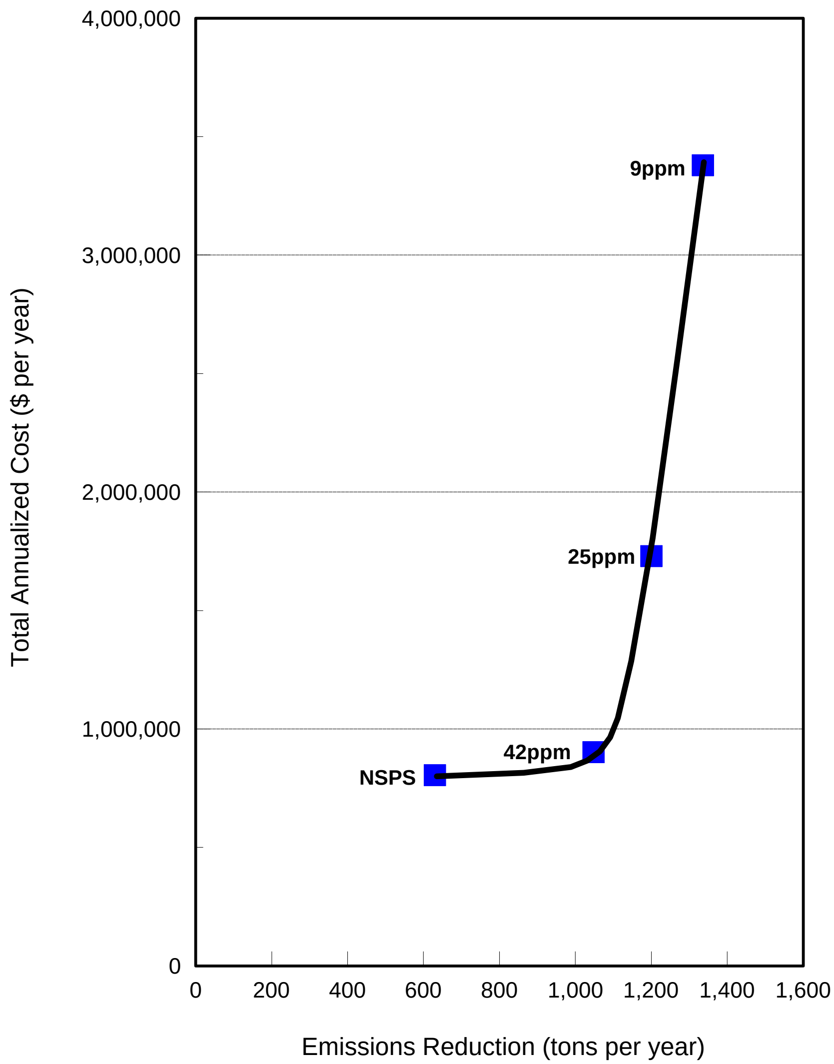

Figure B-3. Least-Cost Envelope for Example 2 combustors are designed to combust the fuel as completely as possible and therefore reduce PM to the lowest possible level. Natural gas contains no solids and solids are removed from the injected water. The PM emission rate without add-on controls is on the same order (0.009 gr/dscf) as that for other particulate matter sources controlled with stringent add-on controls (e.g., fabric filter). Since the applicant documented that precombustion or add-on controls for PM have never been required for natural gas fired turbines, the reviewing agency accepted the applicants analysis that natural gas firing was BACT for PM emissions and that no additional analysis of PM controls was required.

VI.C. EXAMPLE 3--COMBINED CYCLE GAS TURBINE FIRING DISTILLATE OIL

In this example, the same combined cycle gas turbines are proposed except that distillate oil is fired rather than natural gas. The reason is that natural gas is not available on site and there is no pipeline within a reasonable distance. The fuel change raises two issues; the technical feasibility of SCR in gas turbines firing sulfur bearing fuel, and NOx levels achievable with water injection while firing fuel oil.

In this case the applicant proposed to eliminate SCR as technically infeasible because sulfur present in the fuel, even at low levels, will poison the catalyst and quickly render it ineffective. The applicant also noted that there are no cases in the U.S. where SCR has been applied to a gas turbine firing distillate oil as the primary fuel.[4]

A second issue would be the most stringent NOx control level achievable with wet injection. For oil firing the applicant has proposed 42 ppm at 15 percent oxygen. Due to flame characteristics inherent with oil firing, and limits on the amount of water or steam that can be injected, 42 ppm is the lowest NOx emission level achievable with distillate oil firing. Since

[4] Though this argument was considered persuasive in this case, advances in catalyst technology have now made SCR with oil firing technically feasible.

natural gas is not available and SCR is technically infeasible, 42 ppm is the most stringent alternative considered. Based on the cost effectiveness of wet injection, approximately 833 $/ton, there is no economic basis to eliminate the 42 ppm option since this cost is well within the range of BACT costs for NOx control. Therefore, this option is proposed as BACT.

The switch to oil from gas would also result in SO2, CO, PM, and beryllium emissions above significance levels. Therefore, BACT analyses would also be required for these pollutants. These analyses are not shown in this example, but would be performed in the same manner as the BACT analysis for NOx.

VI.D. OTHER CONSIDERATIONS

The previous judgements concerning economic feasibility were in an area meeting NAAQS for both NOx and ozone. If the natural gas fired simple cycle gas turbine example previously presented were sited adjacent to a Class I area, or where air quality improvement poses a major challenge, such as next to a nonattainment area, the results may differ. In this case, even though the region of the actual site location is achieving the NAAQS, adherence to a local or regional NOx or ozone attainment strategy might result in the determination that higher costs than usual are appropriate. In such situations, higher costs (e.g., 6,600 $/ton) may not necessarily be persuasive in eliminating SCR as BACT.

While it is not the intention of BACT to prevent construction, it is possible that local or regional air quality management concerns regarding the need to minimize the air quality impacts of new sources would lead the permitting authority to require a source to either achieve stringent emission control levels or, at a minimum, that control cost expenditures meet certain cost levels without consideration of the resultant economic impact to the source.

Besides local or regional air quality concerns, other site constraints may significantly impact costs of particular control technologies. For the examples previously presented, two factors of concern are land and water availability.

The cost of the raw water is usually a small part of the cost of wet controls. However, gas turbines are sometimes located in remote locations. Though water can obviously be trucked to any location, the costs may be very high.

Land availability constraints may occur where a new source is being located at an existing plant. In these cases, unusual design and additional structural requirements could make the costs of control technologies which are commonly affordable prohibitively expensive. Such considerations may be pertinent to the calculations of impacts and ultimately the selection of BACT.

CHAPTER C

THE AIR QUALITY ANALYSIS

I. INTRODUCTION

An applicant for a PSD permit is required to conduct an air quality analysis of the ambient impacts associated with the construction and operation of the proposed new source or modification. The main purpose of the air quality analysis is to demonstrate that new emissions emitted from a proposed major stationary source or major modification, in conjunction with other applicable emissions increases and decreases from existing sources (including secondary emissions from growth associated with the new project), will not cause or contribute to a violation of any applicable **NAAQS** or **PSD increment**. Ambient impacts of noncriteria pollutants must also be evaluated.

A separate air quality analysis must be submitted for each regulated pollutant if the applicant proposes to emit the pollutant in a significant amount from a new major stationary source, or proposes to cause a significant net emissions increase from a major modification (see *Table I-A-4*, chapter A of this part). [***Note: The air quality analysis requirement also applies to any pollutant whose rate of emissions from a proposed new or modified source is considered to be "significant" because the proposed source would construct within 10 kilometers of a Class I area and would have an ambient impact on such area equal to or greater than 1 µg/m³, 24-hour average.]*** Regulated pollutants include (1) pollutants for which a NAAQS exists (criteria pollutants) and (2) other pollutants, which are regulated by EPA, for which no NAAQS exist (noncriteria pollutants).

Each air quality analysis will be unique, due to the variety of sources and meteorological and topographical conditions that may be involved. Nevertheless, the air quality analysis must be accomplished in a manner consistent with the requirements set forth in either EPA's PSD regulations under 40 CFR 52.21, or a State or local PSD program approved by EPA pursuant to 40 CFR 51.166. Generally, the analysis will involve (1) an assessment of existing air quality, which may include ambient monitoring data and air quality dispersion modeling results, and (2) predictions, using dispersion modeling, of ambient concentrations that will result from the applicant's proposed project and future growth associated with the project.

In describing the various concepts and procedures involved with the air quality analysis in this section, it is assumed that the reader has a basic understanding of the principles involved in collecting and analyzing ambient monitoring data and in performing air dispersion modeling. Considerable guidance is contained in EPA's Ambient Monitoring Guidelines for Prevention of Significant Deterioration [Reference 1] and Guideline on Air Quality Models (Revised) [Reference 2] . Numerous times throughout this chapter, the reader will be referred to these guidance documents, hereafter referred to as the *PSD Monitoring Guideline* and the *Modeling Guideline*, respectively.

In addition, because of the complex character of the air quality analysis and the site-specific nature of the modeling techniques involved, applicants are advised to review the details of their proposed modeling analysis with the appropriate reviewing agency before a complete PSD application is submitted. This is best done using a modeling protocol. The modeling protocol should be submitted to the reviewing agency for review and approval prior to commencing any extensive analysis. Further description of the modeling protocol is contained in this chapter.

The PSD applicant should also be aware that, while this chapter focuses primarily on compliance with the NAAQS and PSD increments, additional impact analyses are required under separate provisions of the PSD regulations for determining any impairment to visibility, soils and vegetation that might result, as well as any adverse impacts to Class I areas. These provisions are described in the following chapters D and E, respectively.

II. NATIONAL AMBIENT AIR QUALITY STANDARDS AND PSD INCREMENTS

As described in the introduction to this chapter, the air quality analysis is designed to protect the ***national ambient air quality standards*** (NAAQS) and ***PSD increments***. The NAAQS are maximum concentration "ceilings" measured in terms of the total concentration of a pollutant in the atmosphere (See *Table C-1*). For a new or modified source, compliance with any NAAQS is based upon the total estimated air quality, which is the sum of the ambient estimates resulting from existing sources of air pollution (modeled source impacts plus measured background concentrations, as described in this section) and the modeled ambient impact caused by the applicant's proposed emissions increase (or net emissions increase for a modification) and associated growth.

A PSD increment, on the other hand, is the maximum allowable <u>increase</u> in concentration that is allowed to occur above a baseline concentration for a pollutant (see section II.E). The baseline concentration is defined for each pollutant (and relevant averaging time) and, in general, is the ambient concentration existing at the time that the first complete PSD permit application affecting the area is submitted. Significant deterioration is said to occur when the amount of new pollution would exceed the applicable PSD increment. It is important to note, however, that the air quality cannot deteriorate beyond the concentration allowed by the applicable NAAQS, even if not all of the PSD increment is consumed.

II.A CLASS I, II, AND III AREAS AND INCREMENTS.

The PSD requirements provide for a system of area classifications which affords States an opportunity to identify local land use goals. There are three area classifications. Each classification differs in terms of the amount of growth it will permit before significant air quality deterioration would be deemed to occur. Class I areas have the smallest increments and thus allow only a small degree of air quality deterioration. Class II areas can

TABLE C-1. National Ambient Air Quality Standards

Pollutant/averaging time	Primary Standard	Secondary Standard
<u>Particulate Matter</u>		
o PM_{10}, annual[a]	50 µg/m^3	50 µg/m^3
o PM_{10}, 24-hour[b]	150 µg/m^3	150 µg/m^3
<u>Sulfur Dioxide</u>		
o SO_2, annual[c]	80 µg/m^3 (0.03 ppm)	
o SO_2, 24-hour[d]	365 µg/m^3 (0.14 ppm)	
o SO_2, 3-hour[d]		1,300 µg/m^3 (0.5 ppm)
<u>Nitrogen Dioxide</u>		
o NO_2, annual[c]	0.053 ppm (100 µg/m^3	0.053 ppm (100 µg/m^3)
<u>Ozone</u>		
o O_3, 1-hour[b]	0.12 ppm (235 µg/m^3)	0.12 ppm (235 µg/m^3)
<u>Carbon Monoxide</u>		
o CO, 8-hour[d]	9 ppm (10 mg/m^3)	--
o CO, 1-hour[d]	35 ppm (40 mg/m^3)	--
<u>Lead</u>		
o Pb, calendar quarter[c]	1.5 µg/m^3	--

a Standard is attained when the expected annual arithmetic mean is less than or equal to 50 µg/m^3.
b Standard is attained when the expected number of exceedances is less than or equal to 1.
c Never to be exceeded.
d Not to be exceeded more than once per year.

accommodate normal well-managed industrial growth. Class III areas have the largest increments and thereby provide for a larger amount of development than either Class I or Class II areas.

Congress established certain areas, e.g., wilderness areas and national parks, as mandatory Class I areas. These areas cannot be redesignated to any other area classification. All other areas of the country were initially designated as Class II. Procedures exist under the PSD regulations to redesignate the Class II areas to either Class I or Class III, depending upon a State's land management objectives.

PSD increments for SO_2 and particulate matter--measured as total suspended particulate (TSP)--have existed in their present form since 1978. On July 1, 1987, EPA revised the NAAQS for particulate matter and established the new PM-10 indicator by which the NAAQS are to be measured. (Since each State is required to adopt these revised NAAQS and related implementation requirements as part of the approved implementation plan, PSD applicants should check with the appropriate permitting agency to determine whether such State action has already been taken. Where the PM-10 NAAQS are not yet being implemented, compliance with the TSP-based ambient standards is still required in accordance with the currently-approved State implementation plan.) Simultaneously with the promulgation of the PM-10 NAAQS, EPA announced that it would develop PM-10 increments to replace the TSP increments. Such new increments have not yet been promulgated, however. Thus the national PSD increment system for particulate matter is still based on the TSP indicator.

The EPA promulgated PSD increments for NO_2 on October 17, 1988. These new increments become effective under EPA's PSD regulations (40 CFR 52.21) on November 19, 1990, although States may have revised their own PSD programs to incorporate the new increments for NO_2 on some earlier date. Until November 19, 1990, PSD applicants should determine whether the NO_2 increments are being implemented in the area of concern; if so, they must include the necessary analysis, if applicable, as part of a complete permit application. [NOTE: the "trigger date" (described below in section II.B) for the NO_2 increments has been established by regulation as of February 8, 1988. This applies to all State PSD programs as well as EPA's Part 52 PSD program. Thus, consumption of the NO_2 increments may actually occur before the increments become effective in any particular PSD program.] The PSD increments for SO_2, TSP and NO_2 are summarized in *Table C-2*.

II.B ESTABLISHING THE BASELINE DATE

As already described, the ***baseline concentration*** **is** the reference point for determining air quality deterioration in an area. The baseline concentration is essentially the air quality existing at the time of the first complete PSD permit application submittal affecting that area. In general, then, the submittal date of the first complete PSD application in an area is the "baseline date." On or before the date of the first PSD application, most emissions are considered to be part of the baseline concentration, and emissions changes which occur after that date affect the amount of available PSD increment. However, to fully understand how and when increment is consumed or expanded, three different dates related to baseline must be explained. In chronological order, these dates are as follows:

- *the **major source baseline date***;
- *the **trigger date***; and
- *the **minor source baseline date***.

The ***major source baseline date*** is the date after which actual emissions associated with construction (i.e., physical changes or changes in the method of operation) at a major stationary source affect the available PSD increment. Other changes in actual emissions occurring at any source after the major source baseline date do not affect the increment, but instead (until after the minor source baseline date is established) contribute to the baseline concentration. The ***trigger date*** is the date after which the minor source

TABLE C-2. PSD INCREMENTS

($\mu g/m^3$)

	Class I	Class II	Class III
<u>Sulfur Dioxide</u>			
o SO_2, annual[a]	2	20	40
o SO_2, 24-hour[b]	5	91	182
o SO_2, 3-hour[b]	25	512	700
<u>Particulate Matter</u>			
o TSP, annual[a]	5	19	37
o TSP, 24-hour[b]	10	37	75
<u>Nitrogen Dioxide</u>			
o NO_2, annual[a]	2.5	25	50

a Never to be exceeded.

b Not to be exceeded more than once per year.

baseline date (described below) may be established. Both the major source baseline date and the trigger date are fixed dates, although different dates apply to (1) SO_2 and particulate matter, and (2) NO_2, as follows:

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Pollutant	Major Source Baseline Date	Trigger Date
PM	January 6, 1975	August 7, 1977
SO_2	January 6, 1975	August 7, 1977
NO_2	February 8, 1988	February 8, 1988

The **minor source baseline date** is the earliest date after the trigger date on which a complete PSD application is received by the permit reviewing agency. If the application that established the minor source baseline date is ultimately denied or is voluntarily withdrawn by the applicant, the minor source baseline date remains in effect nevertheless. Because the date marks the point in time after which actual emissions changes from all sources affect the available increment (regardless of whether the emissions changes are a result of construction), it is often referred to as the "baseline date."

The minor source baseline date for a particular pollutant is triggered by a PSD applicant only if the proposed increase in emissions of that pollutant is significant. For instance, a PSD application for a major new source or modification that proposes to increase its emissions in a significant amount for SO_2, but in an insignificant amount for PM, will establish the minor source baseline date for SO_2 but not for PM. Thus, the minor source baseline dates for different pollutants (for which increments exist) need not be the same in a particular area.

II.C ESTABLISHING THE BASELINE AREA

The area in which the minor source baseline date is established by a PSD permit application is known as the ***baseline area***. The extent of a baseline area is limited to intrastate areas and may include one or more areas designated as attainment or unclassified under Section 107 of the Act. The baseline area established pursuant to a specific PSD application is to include 1) all portions of the attainment or unclassifiable area in which the PSD applicant would propose to locate, amd 2) any attainment or unclassifiable area in which the proposed emissions would have a significant ambient impact. For this purpose, a significant impact is defined as at least a 1 $\mu g/m^3$ annual increase in the average annual concentration of the applicable pollutant. Again, a PSD applicant's establishment of a baseline area in one State does not trigger the minor source baseline date in, or extend the baseline area into, another State.

II.D REDEFINING BASELINE AREAS (AREA REDESIGNATIONS)

It is possible that the boundaries of a baseline area may not reasonably reflect the area affected by the PSD source which established the baseline area. A state may redefine the boundaries of an existing baseline area by redesignating the section 107 areas contained therein. Section 107(d) of the Clean Air Act specifically authorizes states to submit redesignations to the EPA. Consequently, a State may submit redefinitions of the boundaries of attainment or unclassifiable areas at any time, as long as the following criteria are met:

! *area redesignations can be no smaller than the 1 $\mu g/m^3$ area of impact of the triggering source*; and

! *the boundaries of any redesignated area cannot intersect the 1 $\mu g/m^3$ area of impact of any major stationary source that established or would have established a minor source baseline date for the area proposed for redesignation.*

II.E INCREMENT CONSUMPTION AND EXPANSION

The amount of PSD increment that has been consumed in a PSD area is determined from the emissions increases and decreases which have occurred from sources since the applicable baseline date. It is useful to note, however, that in order to determine the amount of PSD increment consumed (or the amount of available increment), no determination of the baseline concentration needs to be made. Instead, increment consumption calculations must reflect only the ambient pollutant concentration change attributable to increment-affecting emissions.

Emissions increases that consume a portion of the applicable increment are, in general, all those not accounted for in the baseline concentration and specifically include:

! *actual emissions increases occurring after the* ***major source baseline date****, which are associated with physical changes or changes in the method of operation (i.e., construction) at a major stationary source*; and

!*actual emissions increases at any stationary source, area source, or mobile source occurring after the* ***minor source baseline date****.*

The amount of available increment may be added to, or "expanded," in two ways. The primary way is through the reduction of actual emissions from any source after the minor source baseline date. Any such emissions reduction would increase the amount of available increment to the extent that ambient concentrations would be reduced.

Increment expansion may also result from the reduction of actual emissions after the major source baseline date, but before the minor source baseline date, if the reduction results from a physical change or change in the method of operation (i.e., construction) at a major stationary source. Moreover, the reduction will add to the available increment only if the reduction is included in a federally enforceable permit or SIP provision. Thus, for major stationary sources, actual emissions reductions made prior to the minor source baseline date expand the available increment just as increases before the minor source baseline date consume increment.

The creditable increase of an existing stack height or the application of any other creditable dispersion technique may affect increment consumption or expansion in the same manner as an actual emissions increase or decrease. That is, the effects that a change in the effective stack height would have on ground level pollutant concentrations generally should be factored into the increment analysis. For example, this would apply to a raised stack height occurring in conjunction with a modification at a major stationary source prior to the minor source baseline date, or to any changed stack height occurring after the minor source baseline date. It should be noted, however, that any increase in a stack height, in order to be creditable, must be consistent with the EPA's stack height regulations; credit cannot be given for that portion of the new height which exceeds the height demonstrated to be the good engineering practice (GEP) stack height.

Increment consumption (and expansion) will generally be based on changes in actual emissions reflected by the normal source operation for a period of 2 years. However, if little or no operating data are available, as in the case of permitted emission units not yet in operation at the time of the increment analysis, the **potential to emit** must be used instead. Emissions data requirements for modeling increment consumption are described in *Section IV.D.4*. Further guidance for identifying increment-consuming sources (and emissions) is provided in *Section IV.C.2*.

II.F BASELINE DATE AND BASELINE AREA CONCEPTS -- EXAMPLES

An example of how a baseline area is established is illustrated in *Figure C-1*. A major new source with the potential to emit significant amounts of SO_2 proposes to locate in County C. The applicant submits a complete PSD application to the appropriate reviewing agency on October 6, 1978. (The trigger date for SO_2 is August 7, 1977.) A review of the State's SO_2 attainment designations reveals that attainment status is listed by individual counties in the state. Since County C is designated attainment for SO_2, and the source proposes to locate there, October 6, 1978 is established as the minor source baseline date for SO_2 for the entire county.

Dispersion modeling of proposed SO_2 emissions in accordance with approved methods reveals that the proposed source's ambient impact will exceed 1 ug/m^3 (annual average) in Counties A and B. Thus, the same minor source baseline date is also established throughout Counties A and B. Once it is triggered, the minor source baseline date for Counties A, B and C establishes the time after which all emissions changes affect the available increments in those three counties.

Although SO_2 impacts due to the proposed emissions are above the significance level of 1 $\mu g/m^3$ (annual average) in the adjoining State, the proposed source does not establish the minor source baseline date in that State. This is because, as mentioned in Section II.C of this chapter, baseline areas are <u>intrastate</u> areas only.

The fact that a PSD source's emissions cannot trigger the minor source baseline date across a State's boundary should not be interpreted as precluding the applicant's emissions from consuming increment in another State. Such increment-consuming emissions (e.g., SO_2 emissions increases resulting from a physical change or a change in the method of operation at a

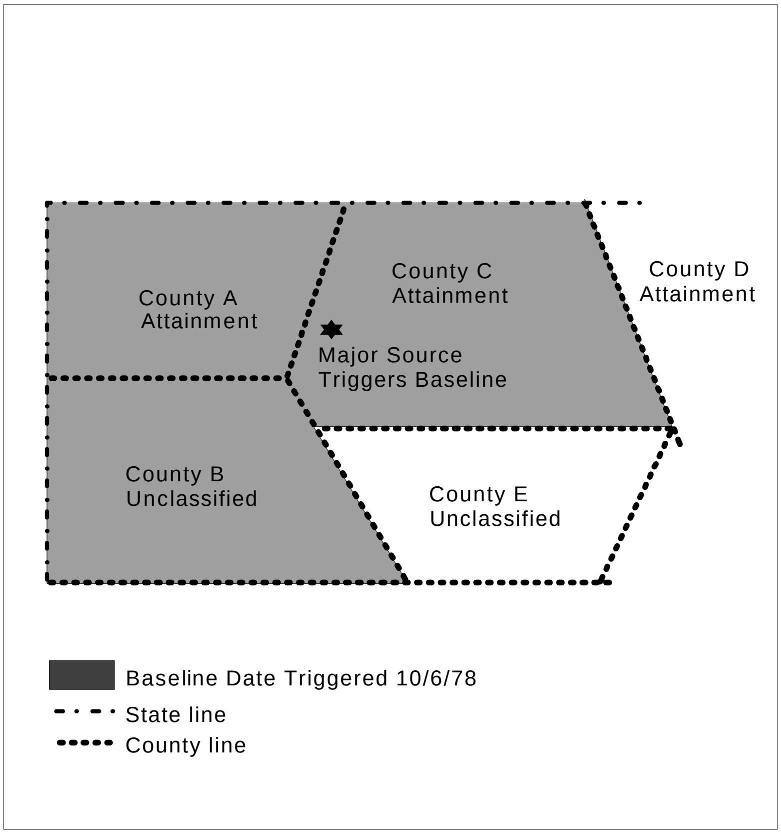

Figure C-1. Establishing the Baseline Area.

major stationary source after January 6, 1975) that affect another State will consume increment there even though the minor source baseline date has not been triggered, but are not considered for increment-consuming purposes until after the minor source baseline date has been independently established in that State. A second example, illustrated in *Figure C-2*, demonstrates how a baseline area may be redefined. Assume that the State in the first example decides that it does not want the minor source baseline date to be established in the western half of County A where the proposed source will not have a significant annual impact (i.e., 1 $\mu g/m^3$, annual average). The State, therefore, proposes to redesignate the boundaries of the existing section 107 attainment area, comprising all of County A, to create two separate attainment areas in that county. If EPA agrees that the available data support the change, the redesignations will be approved. At that time, the October 6, 1978 minor source baseline date will no longer apply to the newly-established attainment area comprising the western portion of County A.

If the minor source baseline date has not been triggered by another PSD application having a significant impact in the redesignated western portion of County A, the SO_2 emissions changes occurring after October 6, 1978 from minor point, area, and mobile sources, and from nonconstruction-related activities at all major stationary sources in this area will be transferred into the baseline concentration. In accordance with the major source baseline date, construction-related emissions changes at major point sources continue to consume or expand increment in the westerm poriton of County A which is no longer part of the original baseline area.

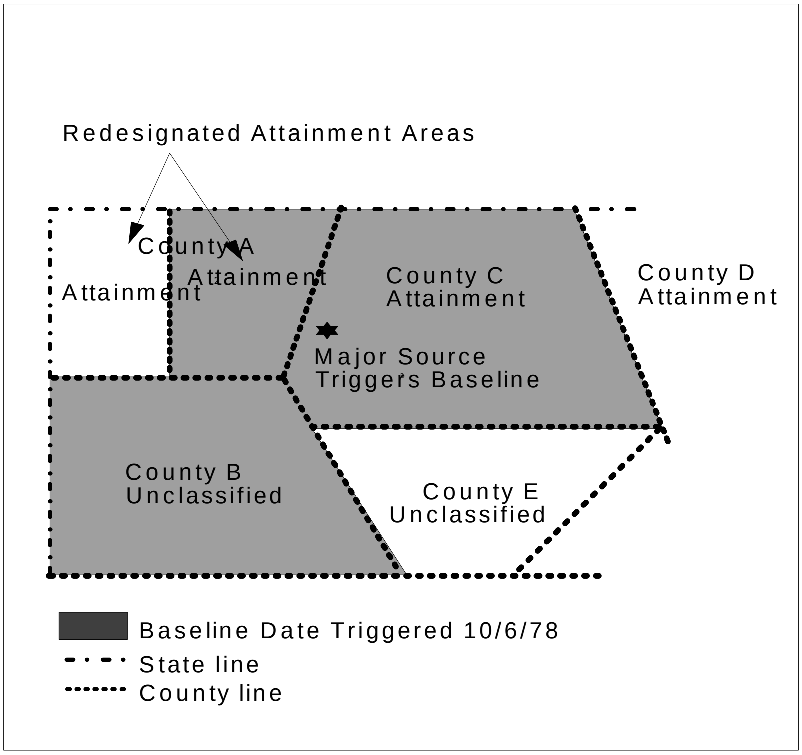

Figure C-2. Redefining the Baseline Area.

III. AMBIENT DATA REQUIREMENTS

An applicant should be aware of the potential need to establish and operate a site-specific monitoring network for the collection of certain ambient data. With respect to ***air quality data***, the PSD regulations contain provisions requiring an applicant to provide an ambient air quality analysis which may include pre-application monitoring data, and in some instances post-construction monitoring data, for any pollutant proposed to be emitted by the new source or modification. In the absence of available monitoring data which is representative of the area of concern, this requirement could involve the operation of a site-specific air quality monitoring network by the applicant. Also, the need for ***meteorological data***, for any dispersion modeling that must be performed, could entail the applicant's operation of a site-specific meteorological network.

Pre-application data generally must be gathered over a period of at least 1 year and the data are to represent at least the 12-month period immediately preceding receipt of the PSD application. Consequently, it is important that the applicant ascertain the need to collect any such data and proceed with the required monitoring activities as soon as possible in order to avoid undue delay in submitting a complete PSD application.

III.A PRE-APPLICATION AIR QUALITY MONITORING

For any criteria pollutant that the applicant proposes to emit in significant amounts, continuous ambient monitoring data may be required as part of the air quality analysis. If, however, either (1) the predicted ambient impact, i.e., the highest modeled concentration for the applicable averaging time, caused by the proposed significant emissions increase (or significant net emissions increase), or (2) the existing ambient pollutant concentrations are less than the prescribed significant monitoring value (see *Table C-3*), the permitting agency has discretionary authority to exempt an applicant from this data requirement.

TABLE C-3. SIGNIFICANT MONITORING CONCENTRATIONS

Pollutant	Air Quality Concentration (μg/m^3) and Averaging Time	
Carbon monoxide	575	(8-hour)
Nitrogen dioxide	14	(Annual)
Sulfur dioxide	13	(24-hour)
Particulate Matter, TSP	10	(24-hour)
Particulate Matter, PM-10	10	(24-hour)
Ozone	*a*	
Lead	0.1	(3-month)
Asbestos	*b*	
Beryllium	0.001	(24-hour)
Mercury	0.25	(24-hour)
Vinyl chloride	15	(24-hour)
Fluorides	0.25	(24-hour)
Sulfuric acid mist	*b*	
Total reduced sulfur (including H_2S)	*b*	
Reduced sulfur (including H_2S)	*b*	
Hydrogen sulfide	0.2	(1-hour)

a No significant air quality concentration for ozone monitoring has been established. Instead, applicants with a net emissions increase of 100 tons/year or more of VOC's subject to PSD would be required to perform an ambient impact analysis, including pre-application monitoring data.

b Acceptable monitoring techniques may not be available at this time. Monitoring requirements for this pollutant should be discussed with the permitting agency.

The determination of the proposed project's effects on air quality (for comparison with the significant monitoring value) is based on the results of the dispersion modeling used for establishing the impact area (see Section IV.B of this chapter). Modeling by itself or in conjunction with available monitoring data should be used to determine whether the existing ambient concentrations are equal to or greater than the significant monitoring value. The applicant may utilize a screening technique for this purpose, or may elect to use a refined model. Consultation with the permitting agency is advised before any model is selected. Ambient impacts from existing sources are estimated using the same model input data as are used for the NAAQS analysis, as described in section IV.D.4 of this chapter.

If a potential threat to the NAAQS is identified by the modeling predictions, then continuous ambient monitoring data should be required, even when the predicted impact of the proposed project is less than the significant monitoring value. This is especially important when the modeled impacts of existing sources are uncertain due to factors such as complex terrain and uncertain emissions estimates.

Also, if the location of the proposed source or modification is not affected by other major stationary point sources, the assessment of existing ambient concentrations may be done by evaluating available monitoring data. It is generally preferable to use data collected within the area of concern; however, the possibility of using measured concentrations from representative "regional" sites may be discussed with the permitting agency. The *PSD Monitoring Guideline* provides additional guidance on the use of such regional sites.

Once a determination is made by the permitting agency that ambient monitoring data must be submitted as part of the PSD application, the requirement can be satisfied in one of two ways. First, under certain conditions, the applicant may use existing ambient data. To be acceptable, such data must be judged by the permitting agency to be representative of the air quality for the area in which the proposed project would construct and operate. Although a State or local agency may have monitored air quality for several years, the data collected by such efforts may not necessarily be adequate for the preconstruction analysis required under PSD. In determining the representativeness of any existing data, the applicant and the permitting agency must consider the following critical items (described further in the PSD Monitoring Guideline):

- *monitor location*;
- *quality of the data*; and
- *currentness of the data*.

If existing data are not available, or they are judged not to be representative, then the applicant must proceed to establish a site-specific monitoring network. The EPA strongly recommends that the applicant prepare a monitoring plan before any actual monitoring begins. Some permitting agencies may require that such a plan be submitted to them for review and approval. In any case, the applicant will want to avoid any possibility that the resulting data are unacceptable because of such things as improperly located monitors, or an inadequate number of monitors. To assure the accuracy and precision of the data collected, proper quality assurance procedures pursuant to *Appendix B of 40 CFR Part 58* must also be followed. The recommended minimum contents of a monitoring plan, and a discussion of the various considerations to be made in designing a PSD monitoring network, are contained in the PSD Monitoring Guideline.

The PSD regulations generally require that the applicant collect 1 year of ambient data (EPA recommends 80 percent data recovery for PSD purposes). However, the permitting agency has discretion to accept data collected over a shorter period of time (but in no case less than 4 months) if a complete and adequate analysis can be accomplished with the resulting data. Any decision to approve a monitoring period shorter than 1 year should be based on a demonstration by the applicant (through historical data or dispersion modeling) that the required air quality data will be obtained during a time period, or periods, when maximum ambient concentrations can be expected.

For a pollutant for which there is no NAAQS (i.e., a noncriteria pollutant), EPA's general position is not require monitoring data, but to base the air quality analysis on modeled impacts. However, the permitting agency may elect to require the submittal of air quality monitoring data for noncriteria pollutants in certain cases, such as where:

- ! *a State has a standard for a non-criteria pollutant*;
- ! *the reliability of emissions data used as input to modeling existing sources is highly questionable*; and
- ! *available models or complex terrain make it difficult to estimate air quality or the impact of the proposed or modification.*

The applicant will need to confer with the permitting agency to determine whether any ambient monitoring may be required. Before the agency exercises its discretion to require such monitoring, there should be an acceptable measurement method approved by EPA or the appropriate permitting agency.

With regard to particulate matter, where two different indicators of the pollutant are being regulated, EPA considers the PM-10 indicator to represent the criteria form of the pollutant (the NAAQS are now expressed in terms of ambient PM-10 concentrations) and TSP is viewed as the non-criteria form. Consequently, EPA intends to apply the pre-application monitoring requirements to PM-10 primarily, while treating TSP on a discretionary basis in light of its noncriteria status. Although the PSD increments for particulate matter are still based on the TSP indicator, modeling data, not ambient monitoring data, are used for increment analyses.

Ambient air quality data collected by the applicant must be presented in the PSD application as part of the air quality analysis. Monitoring data collected for a criteria pollutant may be used in conjunction with dispersion modeling results to demonstrate NAAQS compliance. Each PSD application involves its own unique set of factors, i.e., the integration of measured ambient data and modeled projections. Consequently, the amount of data to be used and the manner of presentation are matters that should be discussed with the permitting agency.

III.B POST-CONSTRUCTION AIR QUALITY MONITORING

The *PSD Monitoring Guideline* recommends that post-construction monitoring be done when there is a valid reason, such as (1) when the NAAQS are threatened, and (2) when there are uncertainties in the data bases for modeling. Any decision to require post-construction monitoring will generally be made after the PSD application has been thoroughly reviewed. It should be noted that the PSD regulations do not require that the significant monitoring concentrations be considered by the permitting agency in determining the need for post-construction monitoring.

Existing monitors can be considered for collecting post-construction ambient data as long as they have been approved for PSD monitoring purposes. However, the location of the monitors should be checked to ascertain their appropriateness if other new sources or modifications have subsequently occurred, because the new emissions from the more recent projects could alter the location of points of maximum ambient concentrations where ambient measurements need to be made.

Generally, post-construction monitoring should not begin until the source is operating near intended capacity. If possible the collection of data should be delayed until the source is operating at a rate equal to or greater than 50 percent of design capacity. The *PSD Monitoring Guideline* provides, however, that in no case should post-construction monitoring be delayed later than 2 years after the start-up of the new source or modification.

Post-approval ozone monitoring is an alternative to pre-application monitoring for applicants proposing to emit VOC's if they choose to accept nonattainment preconstruction review requirements, including LAER, emissions and air quality offsets, and statewide compliance of other sources under the same ownership. As indicated in Table C-3, pre-application monitoring for ozone is required when the proposed source or modification would emit at least 100 tons per year of volatile organic compounds (VOC). Note that this emissions rate for VOC emissions is a surrogate for the significant monitoring concentration for the pollutant ozone (see *Table C-3*). Under 40 CFR 52.21(m)(1)(vi), post-approval monitoring data for ozone is required (and cannot be waived) in conjunction with the aforementioned nonattainment review requirements when the permitting agency waives the requirement for pre-application ozone monitoring data. The post-approval period may begin any time after the source receives its PSD permit. In no case should the post-approval monitoring be started later than 2 years after the start-up of the new source or modification.

III.C METEOROLOGICAL MONITORING

Meteorological data is generally needed for model input as part of the air quality analysis. It is important that such data be representative of the atmospheric dispersion and climatological conditions at the site of the proposed source or modification, and at locations where the source may have a significant impact on air quality. For this reason, site specific data are preferable to data collected elsewhere. On-site meteorological monitoring may be required, even when on-site air quality monitoring is not.

The <u>*PSD Monitoring Guideline*</u> should be used to establish locations for any meteorological monitoring network that the applicant may be required to operate and maintain as part of the preconstruction monitoring requirements. That guidance specifies the meteorological instrumentation to be used in measuring meteorological parameters such as wind speed, wind direction, and temperature. The <u>*PSD Monitoring Guideline*</u> also provides that the retrieval of valid wind/stability data should not fall below 90 percent on an annual basis. The type, quantity, and format of the required data will be influenced by the specific input requirements of the dispersion modeling techniques used in the air quality analysis. Therefore, the applicant will need to consult with the permitting agency prior to establishing the required network.

Additional guidance for the collection and use of on-site data is provided in the *PSD Monitoring Guideline*. Also, the EPA documents entitled On-Site Meteorological Program Guidance for Regulatory Modeling Applications (Reference 3), and Volume IV of the series of reports entitled Quality Assurance Handbook for Air Pollution Measurement Systems (Reference 4), contain information required to ensure the quality of the meteorological measurements collected.

IV. DISPERSION MODELING ANALYSIS

Dispersion models are the primary tools used in the air quality analysis. These models estimate the ambient concentrations that will result from the PSD applicant's proposed emissions in combination with emissions from existing sources. The estimated total concentrations are used to demonstrate compliance with any applicable NAAQS or PSD increments. The applicant should consult with the permitting agency to determine the particular requirements for the modeling analysis to assure acceptability of any air quality modeling technique(s) used to perform the air quality analysis contained in the PSD application.

IV.A OVERVIEW OF THE DISPERSION MODELING ANALYSIS

The dispersion modeling analysis usually involves two distinct phases: (1) a ***preliminary analysis*** and (2) a ***full impact analysis***. The ***preliminary analysis*** models only the <u>significant</u> increase in potential emissions of a pollutant from a proposed new source, or the <u>significant</u> net emissions increase of a pollutant from a proposed modification. The results of this preliminary analysis determine whether the applicant must perform a full impact analysis, involving the estimation of background pollutant concentrations resulting from existing sources and growth associated with the proposed source. Specifically, the ***preliminary analysis***:

- *determines whether the applicant can forego further air quality analyses for a particular pollutant*;
- *may allow the applicant to be exempted from the ambient monitoring data requirements* (described in *section III* of this chapter); and
- *is used to define the impact area within which a full impact analysis must be carried out*.

The EPA does not require a full impact analysis for a particular pollutant when emissions of that pollutant from a proposed source or modification would not increase ambient concentrations by more than prescribed significant ambient impact levels, including special Class I significance levels. However, the applicant should check any applicable State or local PSD program requirements in order to determine whether such requirements may contain any different procedures which may be more stringent. In addition, the applicant must still address the requirements for additional impacts required under separate PSD requirements, as described in Chapters D and E which follow this chapter.

A ***full impact analysis*** is required for any pollutant for which the proposed source's estimated ambient pollutant concentrations exceed prescribed significant ambient impact levels. This analysis expands the preliminary analysis in that it considers emissions from:

- *the proposed source*;
- *existing sources*;
- *residential, commercial, and industrial growth that accompanies the new activity at the new source or modification (i.e., secondary emissions)*.

For SO_2, particulate matter, and NO_2, the full impact analysis actually consists of separate analyses for the NAAQS and PSD increments. As described later in this section, the selection of background sources (and accompanying emissions) to be modeled for the NAAQS and increment components of the overall analysis proceeds under somewhat different sets of criteria. In general, however, the full impact analysis is used to project ambient pollutant concentrations against which the applicable NAAQS and PSD increments are compared, and to assess the ambient impact of non-criteria pollutants.

The reviewer's primary role is to determine whether the applicant selected the appropriate model(s), used appropriate input data, and followed recommended procedures to complete the air quality analysis. Appendix C in the Modeling Guideline provides an example checklist which recommends a standardized set of data to aid the reviewer in determining the completeness and correctness of an applicant's air quality analysis.

Figure C-3 outlines the basic steps for an applicant to follow for a PSD dispersion modeling analysis to demonstrate compliance with the NAAQS and PSD increments. These steps are described in further detail in the sections which follow.

IV.B DETERMINING THE IMPACT AREA

The proposed project's ***impact area*** is the geographical area for which the required air quality analyses for the NAAQS and PSD increments are carried out. This area includes all locations where the significant increase in the potential emissions of a pollutant from a new source, or significant net emissions increase from a modification, will cause a significant ambient impact (i.e., equal or exceed the applicable significant ambient impact level, as shown in *Table C-4)*. The highest modeled pollutant concentration for each averaging time is used to determine whether the source will have a significant ambient impact for that pollutant.

The ***impact area*** is a circular area with a radius extending from the source to (1) the most distant point where approved dispersion modeling predicts a significant ambient impact will occur, or (2) a modeling receptor distance of 50 km, whichever is less. Usually the area of modeled significant impact does not have a continuous, smooth border. (It may actually be comprised of pockets of significant impact separated by pockets of insignificant impact.) Nevertheless, the required air quality analysis is carried out within the circle that circumscribes the significant ambient impacts, as shown in *Figure C-4*.

Initially, for each pollutant subject to review an impact area is determined for every averaging time. The impact area used for the air quality analysis of a particular pollutant is the largest of the areas determined for that pollutant. For example, modeling the proposed SO_2 emissions from a new source might show that a significant ambient SO_2 impact occurs out to a distance from the source of 2 kilometers for the annual averaging period;

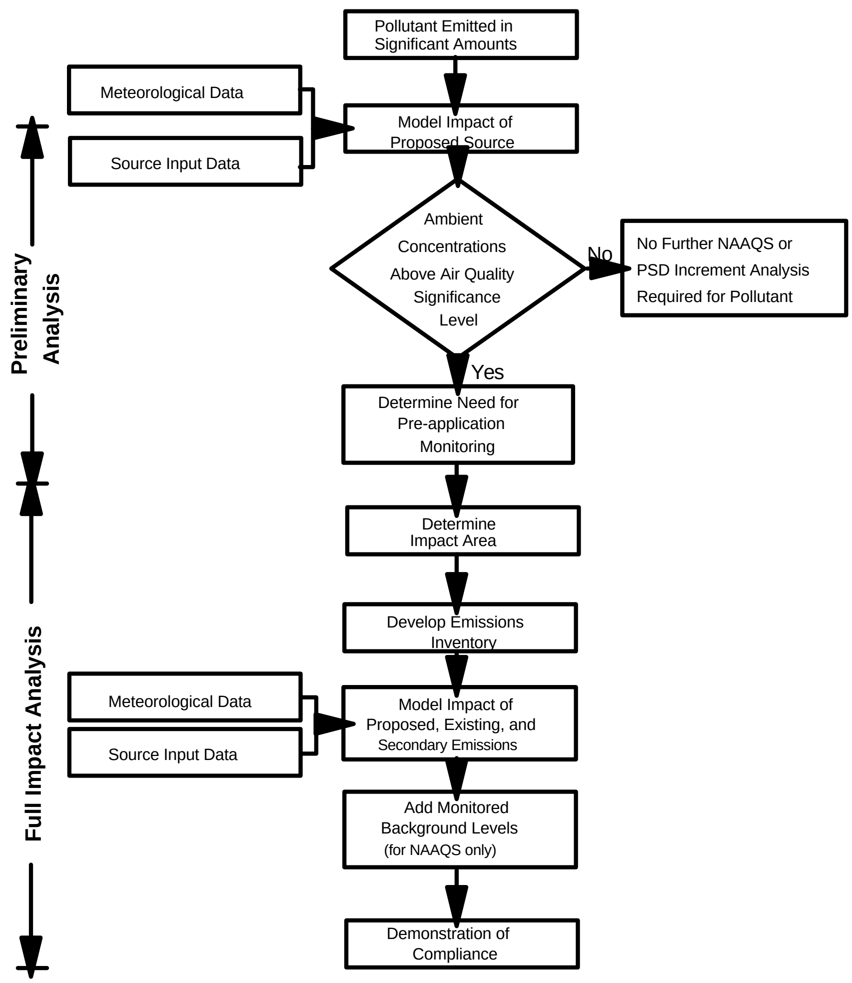

Figure I-C-3. Basic Steps in the Air Quality Analysis (NAAQS and PSD Increments)

TABLE C-4.

SIGNIFICANCE LEVELS FOR AIR QUALITY IMPACTS IN CLASS II AREAS[a]

Pollutant	Annual	24-hour	8-hour	3-hour	1-hour
SO_2	1	5	-	25	-
TSP	1	5	-	-	-
PM-10	1	5	-	-	-
NO_x	1	-	-	-	-
CO	-	-	500	-	2,000
O_3	-	-	-	-	[b]

[a] This table does not apply to Class I areas. If a proposed source is located within 100 kilometers of a Class I area, an impact of 1 μg/m^3 on a 24-hour basis is significant.

[b] No significant ambient impact concentration has been established. Instead, any net emissions increase of 100 tons per year of VOC subject to PSD would be required to perform an ambient impact analysis.

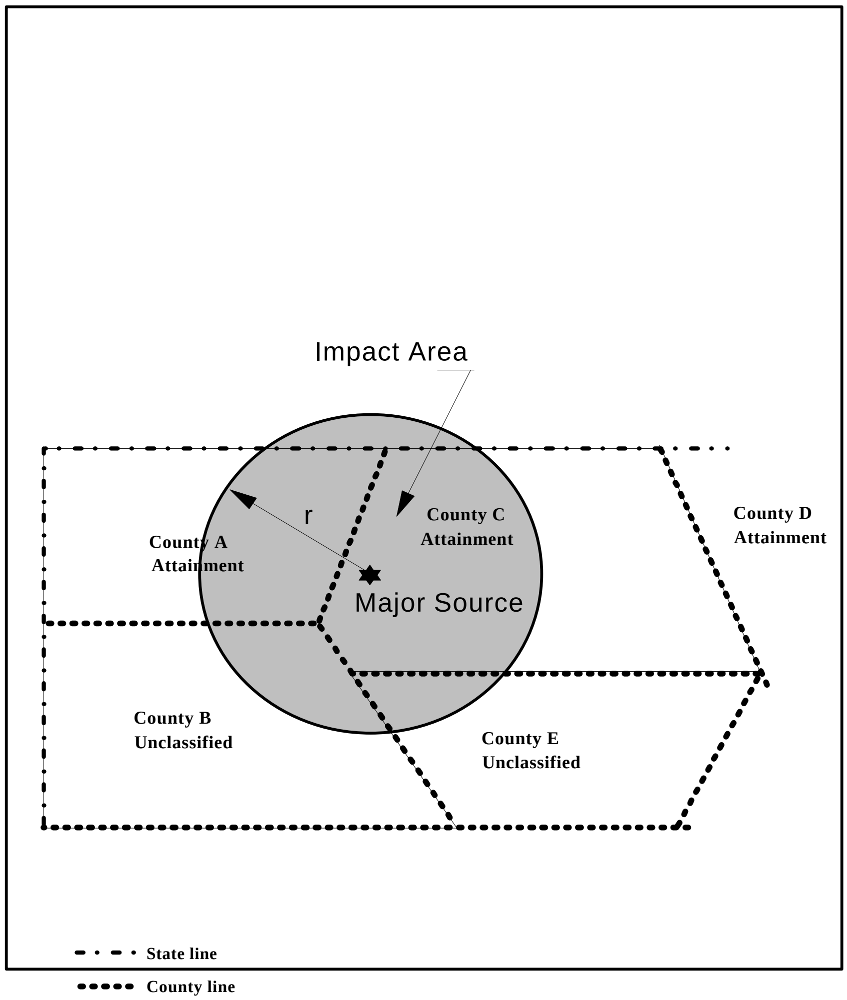

Figure C-4. Determining the Impact Area.

4.3 kilometers for the 24-hour averaging period; and 3.8 kilometers for the 3-hour period. Therefore, an impact area with a radius of 4.3 kilometers from the proposed source is selected for the SO_2 air quality analysis.

In the event that the maximum ambient impact of a proposed emissions increase is below the appropriate ambient air quality significance level for all locations and averaging times, a full impact analysis for that pollutant is not required by EPA. Consequently, a preliminary analysis which predicts an insignificant ambient impact everywhere is accepted by EPA as the required air quality analysis (NAAQS and PSD increments) for that pollutant. ***[NOTE: While it may be shown that no impact area exists for a particular pollutant, the PSD application (assuming it is the first one in the area) still establishes the PSD baseline area and minor source baseline date in the section 107 attainment or unclassifiable area where the source will be located, regardless of its insignificant ambient impact.]***

For each applicable pollutant, the determination of an impact area must include all stack emissions and quantifiable fugitive emissions resulting from the proposed source. For a proposed modification, the determination includes contemporaneous emissions increases and decreases, with emissions decreases input as negative emissions in the model. The EPA allows for the exclusion of temporary emissions (e.g., emissions occurring during the construction phase of a project) when establishing the impact area and conducting the subsequent air quality analysis, if it can be shown that such emissions do not impact a Class I area or an area where a PSD increment for that pollutant is known to be violated. However, where EPA is not the PSD permitting authority, the applicant should confer with the appropriate permitting agency to determine whether it allows for the exclusion of temporary emissions.

Once defined for the proposed PSD project, the impact area(s) will determine the scope of the required air quality analysis. That is, the impact area(s) will be used to

- *set the boundaries within which ambient air quality monitoring data may need to be collected,*
- *define the area over which a full impact analysis (one that considers the contribution of all sources) must be undertaken,* and
- *guide the identification of other sources to be included in the modeling analyses.*

Again, if no significant ambient impacts are predicted for a particular pollutant, EPA does not require further NAAQS or PSD increment analysis of that pollutant. However, the applicant must still consider any additional impacts which the proposed source may have concerning impairment on visibility, soils and vegetation, as well as any adverse impacts on air quality related values in Class I areas (see Chapters D and E of this part).

IV.C SELECTING SOURCES FOR THE PSD EMISSIONS INVENTORIES

When a full impact analysis is required for any pollutant, the applicant is responsible for establishing the necessary inventories of existing sources and their emissions, which will be used to carry out the required NAAQS and PSD increment analyses. Such special emissions inventories contain the various source data used as input to an applicable air quality dispersion model to estimate existing ambient pollutant concentrations. Requirements for preparing an emissions inventory to support a modeling analysis are described to a limited extent in the *Modeling Guideline*. In addition, a number of other EPA documents (e.g., References 5 through 11) contain guidance on the fundamentals of compiling emissions inventories. The discussion which follows pertains primarily to identifying and selecting existing sources to be included in a PSD emissions inventory as needed for a full impact analysis.

The permitting agency may provide the applicant a list of existing sources upon request once the extent of the impact area(s) is known. If the list includes only sources above a certain emissions threshold, the applicant is responsible for identifying additional sources below that emissions level which could affect the air quality within the impact area(s). The permitting agency should review all required inventories for completeness and accuracy.

IV.C.1 THE NAAQS INVENTORY

While air quality data may be used to help identify existing background air pollutant concentrations, EPA requires that, at a minimum, all nearby sources be explicitly modeled as part of the NAAQS analysis. The *Modeling Guideline* defines a "nearby" source as any point source expected to cause a significant concentration gradient in the vicinity of the proposed new source or modification. For PSD purposes, "vicinity" is defined as the impact area. However, the location of such nearby sources could be anywhere within the impact area or an annular area extending 50 kilometers beyond the impact area. (See *Figure C-5.*)

In determining which existing point sources constitute nearby sources, the *Modeling Guideline* necessarily provides flexibility and requires judgment to be exercised by the permitting agency. Moreover, the screening method for identifying a nearby source may vary from one permitting agency to another. To identify the appropriate method, the applicant should confer with the permitting agency prior to actually modeling any existing sources.

The *Modeling Guideline* indicates that the useful distance for guideline models is 50 kilometers. Occasionally, however, when applying the above source identification criteria, existing stationary sources located in the annular area beyond the impact area may be more than 50 kilometers from portions of the impact area. When this occurs, such sources' modeled impacts throughout the entire impact area should be calculated. That is, special steps should not be taken to cut off modeled impacts of existing sources at receptors within the applicants impact area merely because the receptors are

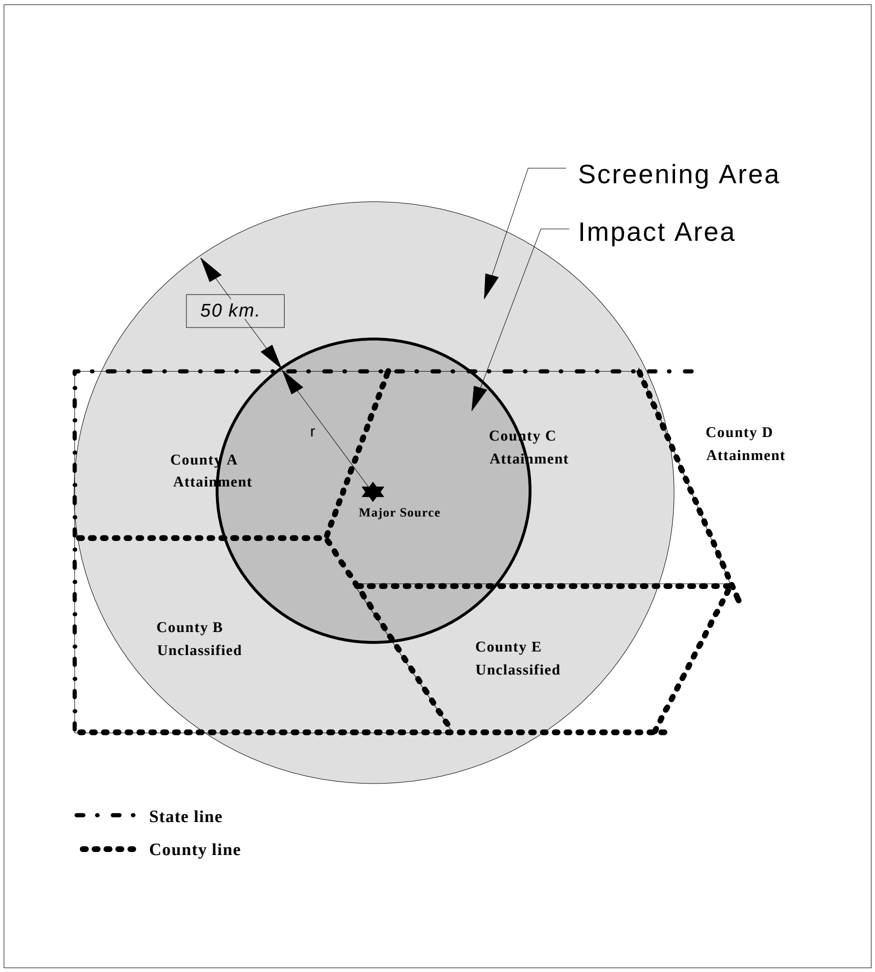

Figure C-5
Defining the Emissions Inventory Screening Area.

located beyond 50 kilometers from such sources. Modeled impacts beyond 50 kilometers should be considered as conservative estimate in that they tend to overestimate the true source impacts. Consequently, if it is found that an existing source's impact include estimates at distances exceeding the normal 50-kilometer range, it may be appropriate to consider other techniques, including long-range transport models. Applicants should consult with the permitting agency prior to the selection of a model in such cases.

It will be necessary to include in the NAAQS inventory those sources which have received PSD permits but have not yet not begun to operate, as well as any complete PSD applications for which a permit has not yet been issued. In the latter case, it is EPA's policy to account for emissions that will occur at sources whose complete PSD application was submitted as of thirty days prior to the date the proposed source files its PSD application. Also, sources from which secondary emissions will occur as a result of the proposed source should be identified and evaluated for inclusion in the NAAQS inventory. While existing mobile source emissions are considered in the determination of background air quality for the NAAQS analysis (typically using existing air quality data), it should be noted that the applicant need not model estimates of future mobile source emissions growth that could result from the proposed project because the definition of "secondary emissions" specifically excludes any emissions coming directly from mobile sources.

Air quality data may be used to establish background concentrations in the impact area resulting from existing sources that are not considered as <u>nearby</u> sources (e.g., area and mobile sources, natural sources, and distant point sources). If, however, adequate air quality data do not exist (and the applicant was not required to conduct pre-application monitoring), then these "other" background sources are also included in the NAAQS inventory so that their ambient impacts can be estimated by dispersion modeling.

IV.C.2 THE INCREMENT INVENTORY

An emissions inventory for the analysis of affected PSD increments must also be developed. The increment inventory includes all increment-affecting sources located in the impact area of the proposed new source or modification. Also, all increment-affecting sources located within 50 kilometers of the impact area (see *Figure C-5*) are included in the inventory if they, either individually or collectively, affect the amount of PSD increment consumed. The applicant should contact the permitting agency to determine what particular procedures should be followed to identify sources for the increment inventory.

In general, the stationary sources of concern for the increment inventory are those stationary sources with actual emissions changes occurring since the <u>minor source baseline date</u>. However, it should be remembered that certain actual emissions changes occurring before the minor source baseline date (i.e., at major stationary point sources) also affect the increments. Consequently, the types of stationary point sources that are initially reviewed to determine the need to include them in the increment inventory fall under two specific time frames as follows:

<u>After the major source baseline date-</u>

- ! *existing <u>major</u> stationary sources having undergone a physical change or change in their method of operation*; and
- ! *new <u>major</u> stationary sources.*

<u>After the minor source baseline date-</u>

- ! *existing stationary sources having undergone a physical change or change in their method of operation*;
- ! *existing stationary sources having increased hours of operation or capacity utilization (unless such change was considered representative of baseline operating conditions)*; and
- ! *new stationary sources.*

If, in the impact area or surrounding screening area, area or mobile source emissions will affect increment consumption, then emissions input data for such minor sources are also included in the increment inventory. The change in such emissions since the minor source baseline date (rather than the absolute magnitude of these emissions) is of concern since this change is what may affect a PSD increment. Specifically, the rate of growth and the amount of elapsed time since the minor source baseline date was established determine the extent of the increase in area and mobile source emissions. For example, in an area where the minor source baseline date was recently established (e.g., within the past year or so of the proposed PSD project), very little area and mobile source emissions growth may have occurred. Also, sufficient data (particularly mobile source data) may not yet be available to reflect the amount of growth that has taken place. As with the NAAQS analysis, applicants are not required to estimate future mobile source emissions growth that could result from the proposed project because they are excluded from the definition of "secondary emissions."

The applicant should initially consult with the permitting agency to determine the availability of data for assessing area and mobile source growth since the minor source baseline date. This information, or the fact that such data is not available, should be thoroughly documented in the application. The permitting agency should verify and approve the basis for actual area source emissions estimates and, especially if these estimates are considered by the applicant to have an insignificant impact, whether it agrees with the applicant's assessment.

When area and mobile sources are determined to affect any PSD increment, their emissions must be reported on a gridded basis. The grid should cover the entire impact area and any areas outside the impact area where area and mobile source emissions are included in the analysis. The exact sizing of an emissions inventory grid cell generally should be based on the emissions density in the area and any computer constraints that may exist. Techniques for assigning area source emissions to grid cells are provided in Reference 11. The grid layout should always be discussed with, and approved by, the permitting agency in advance of its use.

IV.C.3 NONCRITERIA POLLUTANTS INVENTORY

An inventory of all noncriteria pollutants emitted in significant amounts is required for estimating the resulting ambient concentrations of those pollutants. Significant ambient impact levels have not been established for non-criteria pollutants. Thus, an impact area cannot be defined for non-criteria pollutants in the same way as for criteria pollutants. Therefore, as a general rule of thumb, EPA believes that an emissions inventory for non-criteria pollutants should include sources within 50 kilometers of the proposed source. Some judgment will be exercised in applying this position on a case-by-case basis.

IV.D MODEL SELECTION

Two levels of model sophistication exist: screening and refined dispersion modeling. Screening models may be used to eliminate more extensive modeling for either the preliminary analysis phase or the full impact analysis phase, or both. However, the results must demonstrate to the satisfaction of the permitting agency that all applicable air quality analysis requirements are met. Screening models produce conservative estimates of ambient impact in order to reasonably assure that maximum ambient concentrations will not be underestimated. If the resulting estimates from a screening model indicate a threat to a NAAQS or PSD increment, the applicant uses a refined model to re-estimate ambient concentrations (of course, the applicant can select other options, such as reducing emissions, or to decrease impacts). Guidance on the use of screening procedures to estimate the air quality impact of stationary sources is presented in EPA's <u>Screening Procedures for Estimating Air Qaulity Impact of Stationary Sources</u> [Reference 12].

A refined dispersion model provides more accurate estimates of a source's impact and, consequently, requires more detailed and precise input data than does a screening model. The applicant is referred to *Appendix A* of the *<u>Modeling Guideline</u>* for a list of EPA-preferred models, i.e., *guideline models*. The guideline model selected for a particular application should be the one which most accurately represents atmospheric transport, dispersion, and chemical transformations in the area under analysis. For example, models have been developed for both simple and complex terrain situations; some are designed for urban applications, while others are designed for rural applications.

In many circumstances the guideline models known as Industrial Source Complex Model Short- and Long-term (ISCST and ISCLT, respectively) are acceptable for stationary sources and are preferred for use in the dispersion modeling analysis. A brief discussion of options required for regulatory applications of the ISC model is contained in the *Modeling Guideline*. Other guideline models, such as the Climatological Dispersion Model (CDM), may be needed to estimate the ambient impacts of area and mobile sources.

Under certain circumstances, refined dispersion models that are not listed in the *Modeling Guideline*, i.e., *non-guideline models*, may be considered for use in the dispersion modeling analysis. The use of a non-guideline model for a PSD permit application must, however, be pre-approved on a case-by-case basis by EPA. The applicant should refer to the EPA documents entitled Interim Procedures for Evaluating Air Quality Models (Revised) [Reference 13] and Interim Procedures for Evaluating Air Quality Models: Experience with Implementation [Reference 14]. Close coordination with EPA and the appropriate State or local permitting agency is essential if a non-guideline model is to be used successfully.

IV.D.1 METEOROLOGICAL DATA

Meteorological data used in air quality modeling must be spatially and climatologically (temporally) representative of the area of interest. Therefore, an applicant should consult the permitting authority to determine what data will be most representative of the location of the applicant's proposed facility.

Use of site-specific meteorological data is preferred for air quality modeling analyses if 1 or more years of quality-assured data are available. If at least 1 year of site-specific data is not available, 5 years of meteorological data from the nearest National Weather Service (NWS) station can be used in the modeling analysis. Alternatively, data from universities, the Federal Aviation Administration, military stations, industry, and State or local air pollution control agencies may be used if such data are equivalent in accuracy and detail to the NWS data, and are more representative of the area of concern.

The 5 years of data should be the most recent consecutive 5 years of meteorological data available. This 5-year period is used to ensure that the model results adequately reflect meteorological conditions conducive to the prediction of maximum ambient concentrations. The NWS data may be obtained from the National Climatic Data Center (Asheville, North Carolina), which serves as a clearinghouse to collect and distribute meteorological data collected by the NWS.

IV.D.2 RECEPTOR NETWORK

Polar and Cartesian networks are two types of receptor networks commonly used in refined air dispersion models. A ***polar network*** is comprised of concentric rings and radial arms extending outward from a center point (e.g., the modeled source). Receptors are located where the concentric rings and radial arms intersect. Particular care should be exercised in using a polar network to identify maximum estimated pollutant concentrations because of the inherent problem of increased longitudinal spacing of adjacent receptors as their distance along neighboring radial arms increases. For example, as illustrated in *Figure C-6*, while the receptors on individual radials, e.g., *A1, A2, A3*... and *B1, B2, B3*..., may be uniformly spaced at a distance of 1 kilometer apart, at greater distances from the proposed source, the longitudinal distance between the receptors, e.g., *A4* and *B4*, on neighboring radials may be several kilometers. As a result of the presence of larger and larger "blind spots" between the radials as the distance from the modeled source increases, finding the maximum source impact can be somewhat problematic. For this reason, using a polar network for anything other than initial screening is generally discouraged.

A ***cartesian network*** (also referred to as a rectangular network) consists of north-south and east-west oriented lines forming a rectangular grid, as shown in *Figure C-6*, with receptors located at each intersection point. In most refined air quality analyses, a cartesian grid with from 300 to 400 receptors (where the distance from the source to the farthest receptor is 10 kilometers) is usually adequate to identify areas of maximum concentration. However, the total number of receptors will vary based on the specific air quality analysis performed.

In order to locate the maximum modeled impact, perform multiple model runs, starting with a relatively coarse receptor grid (e.g., one or two kilometer spacing) and proceeding to a relatively fine receptor grid (e.g., 100 meters). The fine receptor grid should be used to focus on the area(s) of higher estimated pollutant concentrations identified by the coarse grid model runs. With such multiple runs the maximum modeled concentration can be identified. It is the applicant's responsibility to demonstrate that the final receptor network is sufficiently compact to identify the maximum estimated pollutant concentration for each applicable averaging period. This applies both to the PSD increments and to the NAAQS.

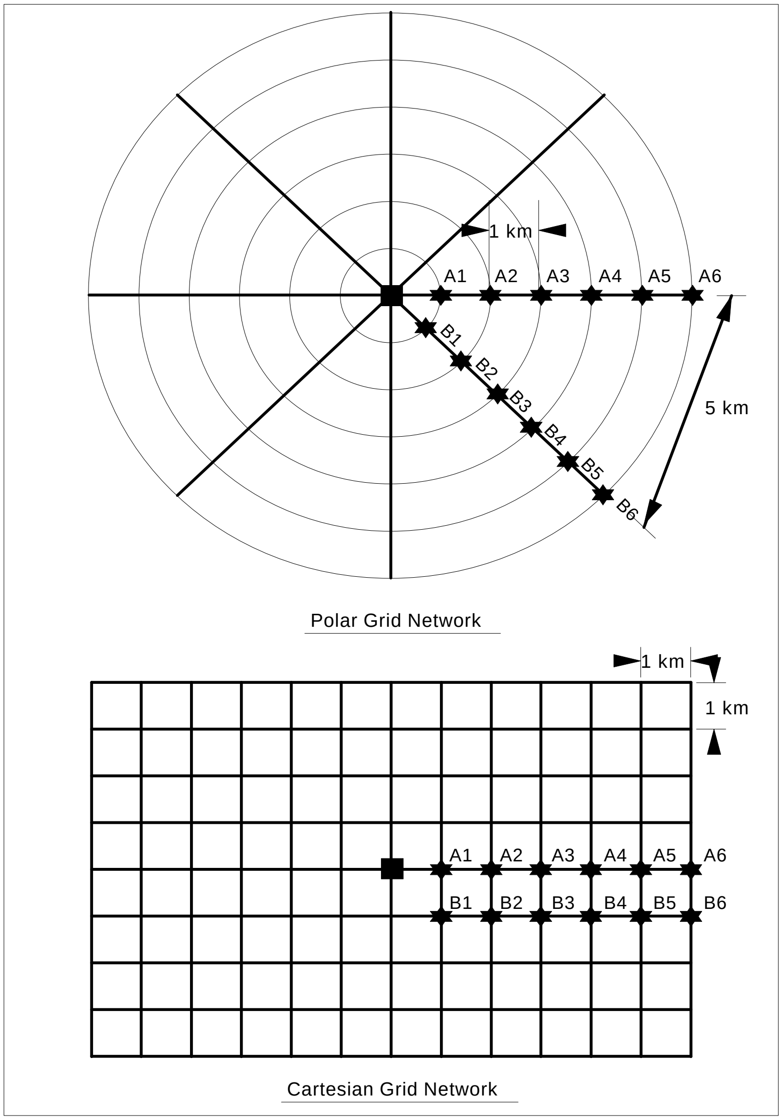

Figure C-6. Examples of Polar and Cartesian Grid Networks.

Some air quality models allow the user to input discrete receptors at user-specified locations. The selection of receptor sites should be a case-by-case determination, taking into consideration the topography, the climatology, the monitor sites, and the results of the preliminary analysis. For example, receptors should be located at:

- ! *the fenceline of a proposed facility*;
- ! *the boundary of the nearest Class I or nonattainment area*;
- ! *the location(s) of ambient air monitoring sites*; and
- ! *locations where potentially high ambient air concentrations are expected to occur*.

In general, modeling receptors for both the NAAQS and the PSD increment analyses should be placed at ground level points anywhere except on the applicant's plant property if it is inaccessible to the general public. Public access to plant property is to be assumed, however, unless a continuous physical barrier, such as a fence or wall, precludes entrance onto that property. In cases where the public has access, receptors should be located on the applicant's property. It is important to note that ground level points of receptor placement could be over bodies of water, roadways, and property owned by other sources. For NAAQS analyses, modeling receptors may also be placed at elevated locations, such as on building rooftops. However, for PSD increments, receptors are limited to locations at ground level.

IV.D.3 GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT

Section 123 of the Clean Air Act limits the use of dispersion techniques, such as merged gas streams, intermittent controls, or stack heights above GEP, to meet the NAAQS or PSD increments. The GEP stack height is defined under Section 123 as "the height necessary to insure that emissions from the stack do not result in excessive concentrations of any air pollutant in the immediate vicinity of the source as a result of atmospheric downwash, eddies or wakes which may be created by the source itself, nearby structures or nearby terrain obstacles." The EPA has promulgated stack height regulations under 40 CFR Part 51 which help to determine the GEP stack height for any stationary source.

Three methods are available for determining "GEP stack height" as defined in 40 CFR 51.100(ii):

! *use the 65 meter (213.5 feet) de minimis height as measured from the ground-level elevation at the base of the stack;*

! *calculate the refined formula height using the dimensions of nearby structures (this height equals H + 1.5L, where H is the height of the nearby structure and L is the lesser dimension of the height or projected width of the nearby structure); or*

! *demonstrate by a fluid model or field study the equivalent GEP formula height that is necessary to avoid excessive concentrations caused by atmospheric downwash, wakes, or eddy effects by the source, nearby structures, or nearby terrain features.*

That portion of a stack height in excess of the GEP height is generally not creditable when modeling to develop source emissions limitations or to determine source impacts in a PSD air quality analysis. For a stack height less than GEP height, screening procedures should be applied to assess potential air quality impacts associated with building downwash. In some cases, the aerodynamic turbulence induced by surrounding buildings will cause stack emissions to be mixed rapidly toward the ground (downwash), resulting in higher-than-normal ground level concentrations in the vicinity of the source. Reference 12 contain screening procedures to estimate downwash concentrations in the building wake region. The <u>Modeling Guideline</u> recommends using the Industrial Source Complex (ISC) air dispersion model to determine building wake effects on maximum estimated pollutant concentrations.

For additional guidance on creditable stack height and plume rise calculations, the applicant should consult with the permitting agency. In addition, several EPA publications [References 15 through 19] are available for the applicant's review.

IV.D.4 SOURCE DATA

Emissions rates and other source-related data are needed to estimate the ambient concentrations resulting from (1) the proposed new source or modification, and (2) existing sources contributing to background pollutant concentrations (NAAQS and PSD increments). Since the estimated pollutant concentrations can vary widely depending on the accuracy of such data, the most appropriate source data available should always be selected for use in a modeling analysis. Guidance on the identification and selection of existing sources for which source input data must be obtained for a PSD air quality analysis is provided in *section IV.C.* Additional information on the specific source input data requirements is contained in EPA's *Modeling Guideline* and in the users' guide for each dispersion model.

Source input data that must be obtained will depend upon the categorization of the source(s) to be modeled as either a point, area or line source. Area sources are often collections of numerous small emissions sources that are impractical to consider as separate point or line sources. Line sources most frequently considered are roadways.

For each stationary point source to be modeled, the following minimum information is generally necessary:

- *pollutant emission rate (see discussion below)*;
- *stack height (see discussion on GEP stack height)*;
- *stack gas exit temperature, stack exit inside diameter, and stack gas exit velocity*;
- *dimensions of all structures in the vicinity of the stack in question*;
- *the location of topographic features (e.g., large bodies of water, elevated terrain) relative to emissions points*; and
- *stack coordinates*.

A source's ***emissions rate*** as used in a modeling analysis for any pollutant is determined from the following source parameters (where MMBtu means "million Btu's heat input"):

- ***emissions limit*** *(e.g., lb/MMBtu)*;
- ***operating level*** *(e.g., MMBtu/hour)*; and
- ***operating factor*** *(e,g., hours/day, hours/year)*.

Special procedures, as described below, apply to the way that each of these parameters is used in calculating the emissions rate for either the proposed new source (or modification) or any existing source considered in the NAAQS and PSD increment analyses. *Table C-5* provides a summary of the point source emissions input data requirements for the NAAQS inventory.

For both NAAQS and PSD increment compliance demonstrations, the ***emissions rate*** for the proposed new source or modification must reflect the <u>maximum allowable</u> operating conditions as expressed by the federally enforceable ***emissions limit***, ***operating level***, and ***operating factor*** for each applicable pollutant and averaging time. The applicant should base the emissions rates on the results of the BACT analysis (see *Chapter B, Part I*). ***Operating levels*** less than 100 percent of capacity may also need to be modeled where differences in stack parameters associated with the lower operating levels could result in higher ground level concentrations. A value representing less than continuous operation (8760 hours per year) should be used for the ***operating factor*** only when a federally enforceable operating limitation is placed upon the proposed source. [NOTE: It is important that the applicant demonstrate that all modeled emission rates are consistent with the applicable permit conditions.]

TABLE C-5 POINT SOURCE MODEL INPUT DATA (EMISSIONS) FOR NAAQS COMPLIANCE DEMONSTRATIONS

Averaging Time	Emission Limit (#/MMBtu)[1]	X	Operating Level (MMBtu/hr)[1]	X	Operating Factor (e.g., hr/yr, hr/day)
Proposed Major New or Modified Source					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit		Design capacity or Federally enforceable permit condition		Continuous operation (i.e, 8760 hours)[2]
Short term (24 hours or less)	Maximum allowable emission limit or Federally enforceable permit limit		Design capacity or Federally enforceable permit condition[3]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]
Nearby Background Source(s)[4]					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit		Actual or design capacity (whichever is greater), or Federally enforceable permit condition		Actual operating factor averaged over the most recent 2 years[5]
Short term	Maximum allowable emission limit or Federally enforceable permit limit		Actual or design capacity (whichever is greater), or Federally enforceable permit condition[3]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]
Other Background Source(s)[6]					
Annual and quarterly	Maximum allowable emission limit or Federally enforceable permit limit		Annual level when actually operating, averaged over the most recent 2 years[5]		Actual operating factor averaged over the most recent 2 years[5]
Short term	Maximum allowable emission limit or Federally enforceable permit limit		Annual level when actually operating, averaged over the most recent 2 years[5]		Continuous operation (i.e., all hours of each time period under consideration) (for all hours of the meteorological data base)[2]

[1] Terminology applicable to fuel burning sources; analogous terminology (e.g., #/throughput) may be used for other types of sources.
[2] If operation does not occur for all hours of the time period of consideration (e.g., 3 or 24 hours) and the source operation is constrained by a Federally enforceable permit condition, an appropriate adjustment to the modeled emission rate may be made (e.g., if operation is only 8:00 a.m. to 4:00 p.m. each day, only these hours will be modeled with emissions from the source. Modeled emissions should not be averaged across non-operating time periods).
[3] Operating levels such as 50 percent and 75 percent of capacity should also be modeled to determine the load causing the highest concentration.
[4] Includes existing facility to which modification is proposed if the emissions from the existing facility will not be affected by the modification. Otherwise use same parameters as for major modification.
[5] Unless it is determined that this period is not representative.
[6] Generally, the ambient impacts from non-nearby background sources can be represented by air quality data unless adequate data do not exist.

For those existing point sources that must be explicitly modeled, i.e., "nearby" sources (see *section IV.C.1* of this chapter), the NAAQS inventory must contain the maximum allowable values for the ***emissions limit***, and ***operating level***. The ***operating factor*** may be adjusted to account for representative, historical operating conditions only when modeling for the annual (or quarterly for lead [Pb]) averaging period. In such cases, the appropriate input is the actual ***operating factor*** averaged over the most recent 2 years (unless the permitting agency determines that another period is more representative). For short-term averaging periods (24 hours or less), the applicant generally should assume that nearby sources operate continuously. However, the ***operating factor*** may be adjusted to take into account any federally enforceable permit condition which limits the allowable hours of operation. In situations where the actual ***operating level*** exceeds the design capacity (considering any federally enforceable limitations), the actual level should be used to calculate the ***emissions rate.***

If other background sources need to be modeled (i.e., adequate air quality data are not available to represent their impact), the input requirements for the ***emissions limit*** and ***operating factor*** are identical to those for "nearby" sources. However, input for the ***operating level*** may be based on the annual level of actual operation averaged over the last 2 years (unless the permitting agency determines that a more representative period exists).

The applicant must also include any quantifiable **fugitive emissions** from the proposed source or any nearby sources. Fugitive emissions are those emissions that cannot reasonably be expected to pass through a stack, vent, or other equivalent opening, such as a chimney or roof vent. Common quantifiable fugitive emissions sources of particulate matter include coal piles, road dust, quarry emissions, and aggregate stockpiles. Quantifiable fugitive emissions of volatile organic compounds (VOC) often occur at components of process equipment. An applicant should consult with the permitting agency to determine the proper procedures for characterizing and modeling fugitive emissions.

When building **downwash** affects the air quality impact of the proposed source or any existing source which is modeled for the NAAQS analysis, those impacts generally should be considered in the analysis. Consequently, the appropriate dimensions of all structures around the stack(s) in question also should be included in the emissions inventory. Information including building heights and horizontal building dimensions may be available in the permitting agency's files; otherwise, it is usually the responsibility of the applicant to obtain this information from the applicable source(s).

Sources should not automatically be excluded from downwash considerations simply because they are located <u>outside</u> the impact area. Some sources located just outside the impact area may be located close enough to it that the immediate downwashing effects directly impact air quality in the impact area. In addition, the difference in downwind plume concentrations caused by the downwash phenomenon may warrant consideration within the impact area even when the immediate downwash effects do not. Therefore, any decision by the applicant to exclude the effects of downwash for a particular source should be justified in the application, and approved by the permitting agency.

For a PSD increment analysis, an estimate of the amount of increment consumed by existing point sources generally is based on increases in <u>actual</u> emissions occurring since the minor source baseline date. The exception, of course, is for major stationary sources whose <u>actual</u> emissions have increased (as a result of construction) before the minor source baseline date but on or after the major source baseline date. For any increment-consuming (or increment-expanding) emissions unit, the actual ***emissions limit***, ***operating level***, and ***operating factor*** may all be determined from source records and other information (e.g., State emissions files), when available, reflecting actual source operation. For the annual averaging period, the change in the actual ***emissions rate*** should be calculated as the difference between:

- *the current average actual **emissions rate**,* and
- *the average actual **emissions rate** as of the minor source baseline date (or major source baseline date for major stationary sources).*

In each case, the average rate is calculated as the average over previous 2-year period (unless the permitting agency determines that a different time period is more representative of normal source operation).

For each short-term averaging period (24 hours and less), the change in the actual ***emissions rate*** for the particular averaging period is calculated as the difference between:

- *the current maximum actual* ***emissions rate****, and*
- *the maximum actual* ***emissions rate*** *as of the minor source baseline date (or major source baseline date for applicable major stationary sources undergoing consturction before the minor source baseline date).*

In each case, the maximum rate is the highest occurrence for that averaging period during the previous 2 years of operation.

Where appropriate, air quality impacts from **fugitive emissions** and **building downwash** are also taken into account for the PSD increment analysis. Of course, they would only be considered when applicable to increment-consuming emissions.

If the change in the actual emissions rate at a particular source involves a change in stack parameters (e.g., stack height, gas exit temperature, etc.) then the stack parameters and emissions rates associated with both the baseline case and the current situation must be used as input to the dispersion model. To determine increment consumption (or expansion) for such a source, the baseline case emissions are input to the model as negative emissions, along with the baseline stack parameters. In the same model run, the current case for the same source is modeled as the total current emissions associated with the current stack parameters. This procedure effectively calculates, for each receptor and for each averaging time, the difference between the baseline concentration and the current concentration (i.e., the amount of increment consumed by the source).

Emissions changes associated with area and mobile source growth occurring since the minor source baseline date are also accounted for in the increment analysis by modeling. In many cases state emission files will contain information on area source emissions or such information may be available from EPA's AIRS-NEDS emissions data base. In the absence of this information, the applicant should use procedures adopted for developing state area source emission inventories. The EPA documents outlining procedures for area source inventory development should be reviewed.

Mobile source emissions are usually calculated by applying mobile source emissions factors to transportation data such as vehicle miles travelled (VMT), trip ends, vehicle fleet characteristics, etc. Data are also required on the spatial arrangement of the VMT within the area being modeled. Mobile source emissions factors are available for various vehicle types and conditions from an EPA emissions factor model entitled MOBILE4. The MOBILE4 users manual [Reference 20] should be used in developing inputs for executing this model. The permitting agency can be of assistance in obtaining the needed mobile source emissions data. Oftentimes, these data are compiled by the permitting agency acting in concert with the local planning agency or transportation department.

For both area source and mobile source emissions, the applicant will need to collect data for the minor source baseline date and the current situation. Data from these two dates will be required to calculate the increment-affecting emission changes since the minor source baseline date.

IV.E THE COMPLIANCE DEMONSTRATION

An applicant for a PSD permit must demonstrate that the proposed source will not cause or contribute to air pollution in violation of any NAAQS or PSD increment. This compliance demonstration, for each affected pollutant, must result in one of the following:

! ***The proposed new source or modification will not cause a significant ambient impact anywhere.***

If the significant net emissions increase from a proposed source would not result in a significant ambient impact anywhere, the applicant is usually not required to go beyond a preliminary analysis in order to make the necessary showing of compliance for a particular pollutant. In determining the ambient impact for a pollutant, the <u>highest</u> estimated ambient concentration of that pollutant for each applicable averaging time is used.

! ***The proposed new source or modification, in conjunction with existing sources, will not cause or contribute to a violation of any NAAQS or PSD increment.***

In general, compliance is determined by comparing the predicted ground level concentrations (based on the full impact analysis and existing air quality data) at each model receptor to the applicable NAAQS and PSD increments. If the predicted pollutant concentration increase over the baseline concentration is below the applicable increment, and the predicted total ground level concentrations are below the NAAQS, then the applicant has successfully demonstrated compliance.

The modeled concentrations which should be used to determine compliance with any NAAQS and PSD increment depend on 1) the type of standard, i.e., deterministic or statistical, 2) the available length of record of meteorological data, and 3) the averaginign time of the standard being analyzed. For example, when the analysis is based on 5 years of National Weather Service meteorological data, the following estimates should be used:

- for deterministically based standards (e.g., SO_2), the highest, second-highest short term estimate and the highest annual estimate; and

- for statistically based standards (e.g., PM-10), the highest, sixth-highest estimate and highest 5-year average estimate.

Further guidance to determine the appropriate estimates to use for the compliance determination is found in *Chapter 8* of the ***Modeling Guideline*** for SO_2, TSP, lead, NO_2, and CO; and in EPA's **PM-10 SIP Development Guideline** [Reference 21] for PM-10.

When a violation of any NAAQS or increment is predicted at one or more receptors in the impact area, the applicant can determine whether the net emissions increase from the proposed source will result in a significant ambient impact at the point (receptor) of each predicted violation, and at the time the violation is predicted to occur. The source will not be considered to cause or contribute to the violation if its own impact is not significant at any violating receptor at the time of each predicted violation. In such a case, the permitting agency, upon verification of the demonstration, may approve the permit. However, the agency must also take remedial action through applicable provisions of the state implementation plan to address the predicted violation(s).

- ***The proposed new source or modification, in conjunction with existing sources, will cause or contribute to a violation, but will secure sufficient emissions reductions to offset its adverse air quality impact.***

If the applicant cannot demonstrate that only insignificant ambient impacts would occur at violating receptors (at the time of the predicted violation), then other measures are needed before a permit can be issued. Somewhat different procedures apply to NAAQS violations than to PSD increment violations. For a **NAAQS violation** to which an applicant contributes significantly, a PSD permit may be granted only if sufficient emissions reductions are obtained to compensate for the adverse ambient impacts caused by the proposed source. Emissions reductions are considered to compensate for the proposed source's adverse impact when, at a minimum, (1) the modeled net concentration, resulting from the proposed emissions increase and the federally enforceable emissions reduction, is less than the applicable significant ambient impact level at each affected receptor, and (2) no new violations will occur. Moreover, such emissions reductions must be made federally enforceable in order to be acceptable for providing the air quality offset. States may adopt procedures pursuant to federal regulations at 40 CFR 51.165(b) to enable the permitting of sources whose emissions would cause or contribute to a NAAQS violation anywhere. The applicant should determine what specific provisions exist within the State program to deal with this type of situation.

In situations where a proposed source would cause or contribute to a **PSD increment violation**, a PSD permit cannot be issued until the increment violation is entirely corrected. Thus, when the proposed source would cause a new increment violation, the applicant must obtain emissions reductions that are sufficient to offset enough of the source's ambient impact to avoid the violation. In an area where an increment violation already exists, and the proposed source would significantly impact that violation, emissions reductions must not only offset the source's adverse ambient impact, but must be sufficient to alleviate the PSD increment violation, as well.

V. AIR QUALITY ANALYSIS -- EXAMPLE

This section presents a hypothetical example of an air quality analysis for a proposed new PSD source. In reality, no two analyses are alike, so an example that covers all modeling scenarios is not possible to present. However, this example illustrates several significant elements of the air quality analysis, using the procedures and information set forth in this chapter.

An applicant is proposing to construct a new coal-fired, steam electric generating station. Coal will be supplied by railroad from a distant mine. The coal-fired plant is a new major source which has the potential to emit significant amounts of SO_2, PM (particulate matter emissions and PM-10 emissions), NO_x, and CO. Consequently, an air quality analysis must be carried out for each of these pollutants. In this analysis, the applicant is required to demonstrate compliance with respect to -

- the ***NAAQS*** for SO_2, PM-10, NO_2, and CO, and
- the ***PSD increments*** for SO_2, TSP, and NO_2.

V.A DETERMINING THE IMPACT AREA

The first step in the air quality analysis is to estimate the ambient impacts caused by the proposed new source itself. This preliminary analysis establishes the impact area for each pollutant emitted in significant amounts, and for each averaging period. The largest impact area for each pollutant is then selected as the impact area to be used in the full impact analysis.

To begin, the applicant prepares a modeling protocol describing the modeling techniques and data bases that will be applied in the preliminary analysis. These modeling procedures are reviewed in advance by the permitting agency and are determined to be in accordance with the procedures described in the *Modeling Guideline* and the stack height regulations.

Several pollutant-emitting activities (i.e., emissions units) at the source will emit pollutants subject to the air quality analysis. The two main boilers emit particulate matter (i.e., particulate matter emissions and PM-10 emissions), SO_2, NO_x, and CO. A standby auxiliary boiler also emits these pollutants, but will only be permitted to operate when the main boilers are not operating.

Particulate matter emissions and PM-10 emissions will also occur at the coal-handling operations and the limestone preparation process for the flue gas desulfurization (FGD) system. Emissions units associated with coal and limestone handling include:

- *Point sources--the coal car dump, the fly ash silos, and the three coal baghouse collectors*;
- *Area sources--the active and the inactive coal storage piles and the limestone storage pile*; and
- *Line sources--the coal and limestone conveying operation.*

The emissions from all of the emissions units at the proposed source are then modeled to estimate the source's area of significant impact (impact area) for each pollutant. The results of the preliminary analysis indicate that significant ambient concentrations of NO_2 and SO_2 will occur out to distances of 32 and 50 kilometers, respectively, from the proposed source. No significant concentrations of CO are predicted at any location outside the fenced-in property of the proposed source. Thus, an impact area is not defined for CO, and no further CO analysis is required.

Particulate matter emissions from the coal-handling operations and the limestone preparation process result in significant ambient TSP concentrations out to a distance of 2.2 kilometers. However, particulate matter emissions from the boiler stacks will cause significant TSP concentrations for a distance of up to 10 kilometers. Since the boiler emissions of particulate matter are predominantly PM-10 emissions, the same impact area is used for both TSP and PM-10.

This preliminary analysis further indicates that pre-application monitoring data may be required for two of the criteria pollutants, SO_2 and NO_2, since the proposed new source will cause ambient concentrations exceeding the prescribed significant monitoring concentrations for these two pollutants (see *Table C-3*). Estimated concentrations of PM-10 are below the significant monitoring concentration. The permitting agency informs the applicant that the requirement for pre-application monitoring data will not be imposed with regard to PM-10. However, due to the fact that existing ambient concentrations of both SO_2 and NO_2 are known to exceed their respective significant monitoring concentrations, the applicant must address the pre-application monitoring data requirements for these pollutants.

Before undertaking a site-specific monitoring program, the applicant investigates the availability of existing data that is representative of air quality in the area. The permitting agency indicates that an agency-operated SO_2 network exists which it believes would provide representative data for the applicant's use. It remains for the applicant to demonstrate that the existing air quality data meet the EPA criteria for data sufficiency, representativeness, and quality as provided in the *PSD Monitoring Guideline*. The applicant proceeds to provide a demonstration which is approved by the permitting agency. For NO_2, however, adequate data do not exist, and it is necessary for the applicant to take responsibility for collecting such data. The applicant consults with the permitting agency in order to develop a monitoring plan and subsequently undertakes a site-specific monitoring program for NO_2.

In this example, four intrastate counties are covered by the applicant's impact area. Each of these counties, shown in *Figure C-7*, is designated attainment for all affected pollutants. Consequently, a NAAQS and PSD

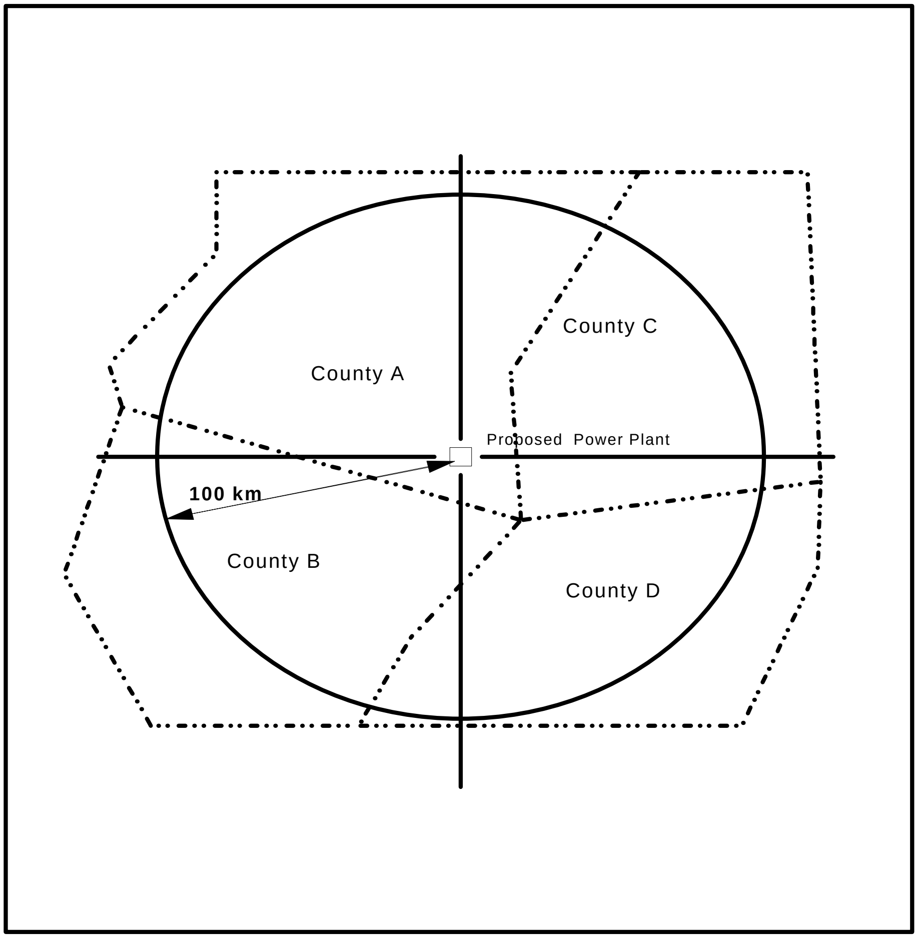

Figure I-C- 7. Counties Within 100 Kilometers of Proposed Source.

analysis must be completed in each county. With the exception of CO (for which no further analysis is required) the applicant proceeds with the full impact analysis for each affected pollutant.

V.B DEVELOPING THE EMISSIONS INVENTORIES

After the impact area has been determined, the applicant proceeds to develop the required emissions inventories. These inventories contain all of the source input data that will be used to perform the dispersion modeling for the required NAAQS and PSD increment analyses. The applicant contacts the permitting agency and requests a listing of all stationary sources within a 100-kilometer radius of the proposed new source. This takes into account the 50-kilometer impact area for SO_2 (the largest of the defined impact areas) plus the requisite 50-kilometer annular area beyond that impact area. For NO_2 and particulate matter, the applicant needs only to consider the identified sources which fall within the specific screening areas for those two pollutants.

Source input data (e.g., location, building dimensions, stack parameters, emissions factors) for the inventories are extracted from the permitting agency's air permit and emissions inventory files. Sources to consider for these inventories also include any that might have recently been issued a permit to operate, but are not yet in operation. However, in this case no such "existing" sources are identified. The following point sources are found to exist within the applicant's impact area and screening area:

- *Refinery A;*
- *Chemical Plant B;*
- *Petrochemical Complex C;*
- *Rock Crusher D;*
- *Refinery E;*
- *Gas Turbine Cogeneration Facility F; and*
- *Portland Cement Plant G.*

A diagram of the general location of these sources relative to the location proposed source is shown in *Figure C-8*. Because the Portland Cement Plant G is located 70 kilometers away from the proposed source, its impact is not considered in the NAAQS or PSD increment analyses for particulate matter. (The area of concern for particulate matter lies within 60 kilometers of the proposed source.) In this example, the applicant first develops the NAAQS emissions inventory for SO_2, particulate matter (PM-10), and NO_2.

V.B.1 THE NAAQS INVENTORY

For each criteria pollutant undergoing review, the applicant (in conjunction with the permitting agency) determines which of the identified sources will be regarded as "nearby" sources and, therefore, must be explicitly modeled. Accordingly, the applicant classifies the candidate sources in the following way:

Pollutant	Nearby sources (explicitly model)	Other Background Sources (non-modeled background)
SO_2	Refinery A Chemical Plant B Petro. Complex C Refinery E	Port. Cement Plant G
NO_2	Refinery A, Chemical Plant B Petro. Complex C Gas Turbines F	Refinery E
Particulate Matter (PM-10)	Refinery A Petro. Complex C Rock Crusher D	Chemical Plant B Refinery E Gas Turbines F

For each nearby source, the applicant now must obtain emissions input data for the model to be used. As a conservative approach, emissions input data reflecting the maximum allowable emissions rate of each nearby source could be used in the modeling analysis. However, because of the relatively

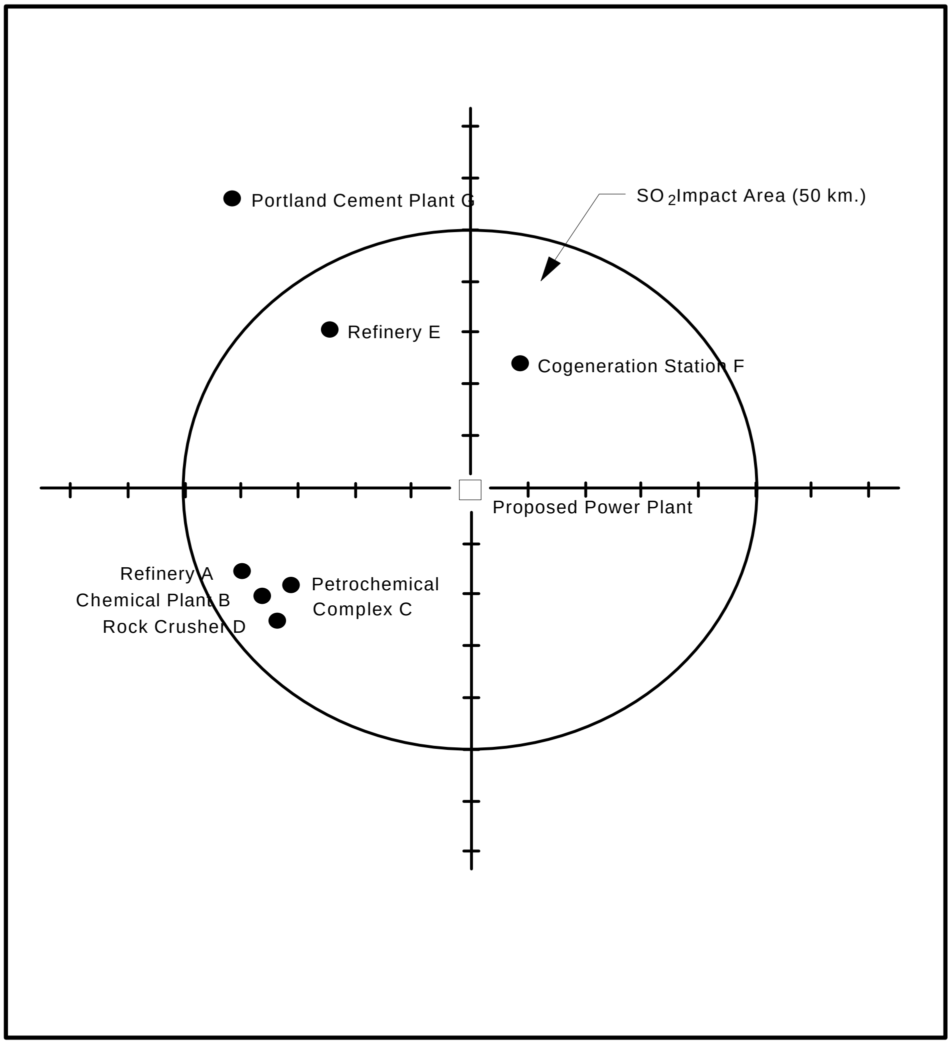

Figure C-8. Point Sources Within 100 Kilometers of Proposed Source.

high concentrations anticipated due to the clustering of sources A, B, C and D, the applicant decides to consider the actual operating factor for each of these sources for the annual averaging period, in accordance with *Table C-5*. For example, for SO_2, the applicant may determine the actual operating factor for sources A, B, and C, because they are classified as nearby sources for SO_2 modeling purposes. On the other hand, the applicant chooses to use the maximum allowable emissions rate for Source E in order to save the time and resources involved with determining the actual operating factors for the 45 individual NO_2 emissions units comprising the source. If a more refined analysis is ultimately warranted, then the actual hours of operation can be obtained from Source E for the purposes of the annual averaging period.

As another example, for particulate matter (**PM-10**), the applicant may determine the actual annual operating factor for sources A, C, and D, because they are nearby sources for PM-10 modeling purposes. Again, the applicant chooses to determine the actual hours of annual operation because of the relatively high concentrations anticipated due to the clustering of these particular sources.

For each pollutant, the applicant must also determine if emissions from the sources that were <u>not</u> classified as nearby sources can be adequately represented by existing air quality data. In the case of SO_2, for example, data from the existing State monitoring network will adequately measure Source G's ambient impact in the impact area. However, for **PM-10**, the monitored impacts of Source B cannot be separated from the impacts of the other sources (A, C, and D) within the proximity of Source B. The applicant therefore must model this source but is allowed to determine both the actual operating factor and the actual operating level to model the source's annual impact, in accordance with *Table C-5*. For the short-term (24-hour) analysis the applicant may use the actual operating level, but <u>continuous</u> operation must be used for the operating factor. The ambient impacts of Source E and Source F will be represented by ambient monitoring data.

For the NO_2 NAAQS inventory, the only source not classified as a nearby source is Refinery E. The applicant would have preferred to use ambient data to represent the ambient impact of this source; however, adequate ambient NO_2 data is not available for the area. In order to avoid modeling this source with a refined model for NO_2, the applicant initially agrees to use a screening technique recommended by the permitting agency to estimate the impacts of Source E.

Air quality impacts caused by building downwash must be considered because several nearby sources (A, B, C, and E) have stacks that are less than GEP stack height. In consultation with the permitting agency, the applicant is instructed to consider downwash for all four sources in the SO_2 NAAQS analysis, because the sources are all located in the SO_2 impact area. Also, after consdieration of the expected effect of downwash for other pollutants, the applicant is told that, for NO_2, only Source C must be modeled for its air quality impacts due to downwash, and no modeling for downwash needs to be done with respect to particulate matter.

The applicant gathers the necessary building dimension data for the NAAQS inventory. In this case, these data are available from the permitting agency through its permit files for sources A, B, and E. However, the applicant must contact Source C to obtain the data from that source. Fortunately, the manager of Source C readily provide the applicant this information for each of the 45 individual emission units.

V.B.2 THE INCREMENT INVENTORY

An increment inventory must be developed for **SO_2**, **particulate matter (TSP)**, and **NO_2**. This inventory includes all of the applicable emissions input data from:

- *increment-consuming sources within the impact area*; and
- *increment-consuming sources outside the impact area that affect increment consumption in the impact area.*

In considering emissions changes occurring at any of the major stationary sources identified earlier (see *Figure C-8*), the applicant must consider actual emissions changes resulting from a physical change or a change in the method of operation since the major source baseline date, and any actual emissions changes since the applicable minor source baseline date. To identify those sources (and emissions) that consume PSD increment, the applicant should request information from the permitting agency concerning the baseline area and all baseline dates (including the existence of any prior minor source baseline dates) for each applicable pollutant.

A review of previous PSD applications within the total area of concern reveals that minor source baseline dates for both **SO_2** and **TSP** have already be established in Counties A and B. For **NO_2**, the minor source baseline date has already been established in County C. A summary of the relevant baseline dates for each pollutant in these three counties is shown in *Table C-6*. The proposed source will, however, establish the minor source baseline date in Counties C and D for **SO_2** and **TSP**, and in Counties A, B and D for **NO_2**.

For **SO_2**, the increment-consuming sources deemed to contribute to increment consumption in the impact area are sources A, B, C and E. Source B underwent a major modification which established the minor source baseline date (April 21, 1984). The actual emissions increase resulting from that physical change is used in the increment analysis. Source A underwent a major modification and Source E increased its hours of operation after the minor source baseline date. The actual emissions increases resulting from both of these changes are used in the increment analysis, as well. Finally, Source C received a permit to add a new unit, but the new unit is not yet operational. Consequently, the applicant must use the potential emissions increase resulting from that new unit to model the amount of increment consumed. The existing units at Source C do not affect the increments because no actual emissions changes have occurred since the April 21, 1984 minor source baseline

TABLE C-6. EXISTING BASELINE DATES FOR SO_2, TSP, AND NO_2 FOR EXAMPLE PSD INCREMENT ANALYSIS

Pollutant	Major Source Baseline Date	Minor Source Baseline Date	Affected Counties
Sulfur dioxide	January 6, 1975	April 21, 1984	A and B
Particulate Matter (TSP)	January 6, 1975	March 14, 1985	A and B
Nitrogen Dioxide	February 8, 1988	June 8, 1988	C

date. Building dimensions data are needed in the increment inventory for nearby sources A, B, and E because each has increment-consuming emissions which are subject to downwash problems. No building dimensions data are needed for Source C, however, because only the emissions from the newly-permitted unit consume increment and the stack built for that unit was designed and constructed at GEP stack height.

For **NO_2**, only the gas turbines located at Cogeneration Station F have emissions which affect the increment. The PSD permit application for the construction of these turbines established the minor source baseline date for NO_2 (June 8, 1988). Of course, all construction-based actual emissions changes in NO_x occurring after the major source baseline date for NO_2 (February 8, 1988), at any major stationary source affect increment. However, no such emissions changes were discovered at the other existing sources in the area. Thus, only the actual emissions increase resulting from the gas turbines is included in the NO_2 increment inventory.

For **TSP**, sources A, B, C, and E are found to have units whose emissions may affect the **TSP increment** in the impact area. Source A established the minor source baseline date with a PSD permit application to modify its existing facility. Source B (which established the minor source baseline date for SO_2) experienced an insignificant increase in particulate matter emissions due to a modification prior to the minor source baseline date for particulate matter (March 14, 1985). Even though the emissions increase did not exceed the significant emissions rate for particulate matter emissions (i.e., 25 tons per year), increment is consumed by the actual increase nonetheless, because the actual emissions increase resulted from construction (i.e., a physical change or a change in the method of operation) at a major stationary source occurring after the major source baseline date for particulate matter. The applicant uses the allowable increase as a conservative estimate of the actual emissions increase. As mentioned previously, Source C received a permit to construct, but the newly-permitted unit is not yet in operation. Therefore, the applicant must use the potential emissions to model the amount of TSP increment consumed by that new unit.

Finally, Source E's actual emissions increase resulting from an increase in its hours of operation must be considered in the increment analysis. This source is located far enough outside the impact area that its effects on increment consumption in the impact area are estimated with a screening technique. Based on the conservative results, the permitting agency determines that the source's emissions increase will not affect the amount of increment consumed in the impact area.

In compiling the increment inventory, increment-consuming TSP and SO_2 emissions occurring at minor and area sources located in Counties A and B must be considered. Also, increment-consuming NO_x emissions occurring at minor, area, and mobile sources located in County C must be considered. For this example, the applicant proposes that because of the low growth in population and vehicle miles traveled in the affected counties since the applicable minor source baseline dates, emissions from area and mobile sources will not affect increment (SO_2, TSP, or NO_2) consumed within the impact area and, therefore, do not need to be included in the increment inventory. After reviewing the documentation submitted by the applicant, the permitting agency approves the applicant's proposal not to include area and mobile source emissions in the increment inventory.

V.C The Full Impact Analysis

Using the source input data contained in the emissions inventories, the next step is to model existing source impacts for both the NAAQS and PSD increment analyses. The applicant's selection of models--ISCST, for short-term modeling, and ISCLT, for long-term modeling--was made after conferring with the permitting agency and determining that the area within three kilometers of the proposed source is rural, the terrain is simple (non-complex), and there is a potential for building downwash with some of the nearby sources.

No on-site meteorological data are available. Therefore, the applicant evaluates the meteorological data collected at the National Weather Service station located at the regional airport. The applicant proposes the use of

5 years of hourly observations from 1984 to 1988 for input to the dispersion model, and the permitting agency approves their use for the modeling analyses.

The applicant, in consultation with the permitting agency, determines that terrain in the vicinity is essentially flat, so that it is not necessary to model with receptor elevations. (Consultation with the reviewing agency about receptor elevations is important since significantly different concentration estimates may be obtained between flat terrain and rolling terrain modes.)

A single-source model run for the auxiliary boiler shows that its estimated maximum ground-level concentrations of SO_2 and NO_2 will be less than the significant air quality impact levels for these two pollutants (*see Table C-4*). This boiler is modeled separately from the two main boilers because there will be a permit condition which restricts it from operating at the same time as the main boilers. For particulate matter, the auxiliary boiler's emissions are modeled together with the fugitive emissions from the proposed source to estimate maximum ground-level PM-10 concentrations. In this case, too, the resulting ambient concentrations are less than the significant ambient impact level for PM-10. Thus, operation of the auxiliary boiler would not be considered to contribute to violations of any NAAQS or PSD increment for SO_2, particulate matter, or NO_2. The auxiliary boiler is eliminated from further modeling consideration because it will not be permitted to operate when either of the main boilers is in operation.

V.C.1 NAAQS ANALYSIS

The next step is to estimate total ground-level concentrations. For the **SO_2 NAAQS** compliance demonstration, the applicant selects a coarse receptor grid of one-kilometer grid spacing to identify the area(s) of high impact caused by the combined impact form the proposed new source and nearby sources. Through the coarse grid run, the applicant finds that the area of highest estimated concentrations will occur in the southwest quadrant. In order to determine the highest total concentrations, the applicant performs a second model run for the southwest quadrant using a 100-meter receptor fine-grid.

The appropriate concentrations from the fine-grid run is added to the monitored background concentrations (including Source G's impacts) to establish the total estimated SO_2 concentrations for comparison against the NAAQS. The results show maximum SO_2 concentrations of:

! *600 µg/m³, 3-hour average*;
! *155 µg/m³, 24-hour average*; and
! *27 µg/m³, annual average*.

Each of the estimated total impacts is within the concentrations allowed by the NAAQS.

For the **NO_2 NAAQS** analysis, the sources identified as "nearby" for NO_2 are modeled with the proposed new source in two steps, in the same way as for the SO_2 analysis: first, using the coarse (1-kilometer) grid network and, second, using the fine (100-meter) grid network. Appropriate concentration estimates from these two modeling runs are then combined with the earlier screening results for Refinery E and the monitored background concentrations. The highest average annual concentration resulting from this approach is 85 µg/m³, which is less than the NO_2 NAAQS of 100 µg/m³, annual average.

For the **PM-10 NAAQS** analysis, the same two-step procedure (coarse and fine receptor grid networks) is used to locate the maximum estimated PM-10 concentration. Recognizing that the PM-10 NAAQS is a statistically-based standard, the applicant identifies the sixth highest 24-hour concentration (based on 5 full years of 24-hour concentration estimates) for each receptor in the network. For the annual averaging time, the applicant averages the 5 years of modeled PM-10 concentrations at each receptor to determine the 5-year average concentration at each receptor. To these long- and short-term results the applicant then added the monitored background reflecting the impacts of sources E and F, as well as surrounding area and mobile source contributions.

For the receptor network, the highest, sixth-highest 24-hour concentration is 127 µg/m³, and the highest 5-year average concentration is

38 µg/m^3. These concentrations are sufficient to demonstrate compliance with the PM-10 NAAQS.

V.C.2 PSD Increment Analysis

The applicant starts the increment analysis by modeling the increment-consuming sources of SO_2, including the proposed new source. As a conservative first attempt, a model run is made using the maximum allowable SO_2 emissions changes resulting from each of the increment-consuming activities identified in the increment inventory. (Note that this is not the same as modeling the allowable emissions rate for each entire source.) Using a coarse (1-kilometer) receptor grid, the area downwind of the source conglomeration in the southwest quadrant was identified as the area where the maximum concentration increases have occurred. The modeling is repeated for the southwest quadrant using a fine (100-meter) receptor grid network.

The results of the fine-grid model run show that, in the case of peak concentrations downwind of the southwest source conglomeration, the allowable SO_2 increment will be violated at several receptors during the 24-hour averaging period. The violations include significant ambient impacts from the proposed power plant. Further examination reveals that Source A in the southwest quadrant is the large contributor to the receptors where the increment violations are predicted. The applicant therefore decides to refine the analysis by using actual emissions increases rather than allowable emissions increases where needed.

It is learned, and the permitting agency verifies, that the increment-consuming boiler at Source A has burned refinery gas rather than residual oil since start-up. Consequently, the actual emissions increase at Source A's boiler, based upon the use of refinery gas during the preceding 2 years, is substantially less than the allowable emissions increase assumed from the use of residual oil. Thus, the applicant models the actual emissions increase at Source A and the allowable emissions increase for the other modeled sources.

This time the modeling is repeated only for the critical time periods and receptors.

The maximum predicted SO_2 concentration increases over the baseline concentration are as follows:

- ! *302 µg/m^3, 3-hour average*;
- ! *72 µg/m^3, 24-hour average*; and
- ! *12 µg/m^3, annual average*.

The revised modeling demonstrates compliance with the SO_2 increments. Hence, no further SO_2 modeling is required for the increment analysis.

The full impact analysis for the **NO_2 increment** is performed by modeling Source F--the sole existing NO_2 increment-consuming source--and the proposed new source. The modeled estimates yield a maximum concentration increase of 21 µg/m^3, annual average. This increase will not exceed the maximum allowable increase of 25 µg/m^3 for NO_2.

With the SO_2 and NO_2 increment portions of the analysis complete, the only remaining part is for the **particulate matter (TSP) increments**. The applicant must consider the effects of the four existing increment-consuming sources (A, B, C, and E) in addition to ambient TSP concentrations caused by the proposed source (including the fugitive emissions). The total increase in TSP concentrations resulting from all of these sources is as follows:

- ! 28 µg/m^3, 24-hour average; and
- ! 13 µg/m^3, annual average.

The results demonstrate that the proposed source will not cause any violations of the TSP increments.

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VII. INDEX

CHAPTER D

ADDITIONAL IMPACTS ANALYSIS

I. INTRODUCTION

All *PSD* permit applicants must prepare an additional impacts analysis for each pollutant subject to regulation under the Act. This analysis assesses the impacts of air, ground and water pollution on soils, vegetation, and visibility caused by any increase in emissions of any regulated pollutant from the source or modification under review, and from associated growth.

Other impact analysis requirements may also be imposed on a permit applicant under local, State or Federal laws which are outside the PSD permitting process. Receipt of a PSD permit does not relieve an applicant from the responsibility to comply fully with such requirements. For example, two Federal laws which may apply on occasion are the ***Endangered Species Act*** and the ***National Historic Preservation Act***. These regulations may require additional analyses (although not as part of the PSD permit) if any federally-listed rare or endangered species, or any site that is included (or is eligible to be included) in the National Register of Historic Sites, are identified in the source's impact area.

Although each applicant for a *PSD* permit must perform an additional impacts analysis, the depth of the analysis generally will depend on existing air quality, the quantity of emissions, and the sensitivity of local soils, vegetation, and visibility in the source's impact area. It is important that the analysis fully document all sources of information, underlying assumptions, and any agreements made as a part of the analysis.

Generally, small emissions increases in most areas will not have adverse impacts on soils, vegetation, or visibility. However, an additional impacts analysis still must be performed. Projected emissions from both the new source or modification and emissions from associated residential, commercial, or industrial growth are combined and modeled for the impacts assessment analysis. While this section offers applicants a general approach to an additional impacts analysis, the analysis does not lend itself to a "cookbook" approach.

II. ELEMENTS OF THE ADDITIONAL IMPACTS ANALYSIS

The additional impacts analysis generally has three parts, as follows:

(1) growth;

(2) soil and vegetation impacts; and

(3) visibility impairment.

II.A. GROWTH ANALYSIS

The elements of the growth analysis include:

(1) a projection of the associated[5] industrial, commercial, and residential source growth that will occur in the area due to the source; and

(2) an estimate of the air emissions generated by the above associated industrial, commercial, and residential growth.

First, the applicant needs to assess the availability of residential, commercial, and industrial services existing in the area. The next step is to predict how much new growth is likely to occur to support the source or modification under review. The amount of residential growth will depend on the size of the available work force, the number of new employees, and the availability of housing in the area. Industrial growth is growth in those industries providing goods and services, maintenance facilities,and other large industries necessary for the operation of the source or modification under review. Excluded from consideration as associated sources are mobile sources and temporary sources.

Having completed this portrait of expected growth, the applicant then begins developing an estimate of the secondary air pollutant emissions which would likely result from this permanent residential, commercial, and

[5] Associated growth is growth that comes about as the result of the construction or modification of a source, but is not a part of that source. It does not include the growth projections addressed by 40 CFR 51.166(n)(3)(ii) and 40 CFR 52.21(n)(2)(ii), which have been called non-associated growth. Emissions attributable to associated growth are classified as secondary emissions.

industrial growth. The applicant should generate emissions estimates by consulting such sources as manufacturers specifications and guidelines, ***AP-42***, other ***PSD*** applications, and comparisons with existing sources.

The applicant next combines the secondary air pollutant emissions estimates for the associated growth with the estimates of emissions that are expected to be produced directly by the proposed source or modification. The combined estimate serves as the input to the air quality modeling analysis, and the result is a prediction of the ground-level concentration of pollutants generated by the source and any associated growth.

II.B. AMBIENT AIR QUALITY ANALYSIS

The ambient air quality analysis projects the air quality which will exist in the area of the proposed source or modification during construction and after it begins operation. The applicant first combines the air pollutant emissions estimates for the associated growth with the estimates of emissions from the proposed source or modification. Next, the projected emissions from other sources in the area which have been permitted (but are not yet in operation) are included as inputs to the modeling analysis. The applicant then models the combined emissions estimate and adds the modeling analysis results to the background air quality to arrive at an estimate of the total ground-level concentrations of pollutants which can be anticipated as a result of the construction and operation of the proposed source.

II.C. SOILS AND VEGETATION ANALYSIS

The analysis of soil and vegetation air pollution impacts should be based on an inventory of the soil and vegetation types found in the impact area. This inventory should include all vegetation with any commercial or recreational value, and may be available from conservation groups, State agencies, and universities.

For most types of soil and vegetation, ambient concentrations of criteria pollutants below the secondary national ambient air quality standards

(NAAQS) will not result in harmful effects. However, there are sensitive vegetation species (e.g., soybeans and alfalfa) which may be harmed by long-term exposure to low ambient air concentrations of regulated pollutants for which are no NAAQS. For example, exposure of sensitive plant species to 0.5 micrograms per cubic meter of fluorides (a regulated, non-criteria pollutant) for 30 days has resulted in significant foliar necrosis.

Good references for applicants and reviewers alike include the ***EPA Air Quality Criteria Documents***, a U.S. Department of the Interior document entitled ***Impacts of Coal-Fired Plants on Fish, Wildlife, and Their Habitats***, and the U.S. Forest Service document, ***A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas***. Another source of reference material is the National Park Service report, ***Air Quality in the National Parks***, which lists numerous studies on the biological effects of air pollution on vegetation.

II.D. VISIBILITY IMPAIRMENT ANALYSIS

In the visibility impairment analysis, the applicant is especially concerned with impacts that occur within the area affected by applicable emissions. Note that the visibility analysis required here is distinct from the Class I area visibility analysis requirement. The suggested components of a good visibility impairment analysis are:

- a determination of the visual quality of the area,
- an initial screening of emission sources to assess the possibility of visibility impairment, and
- if warranted, a more in-depth analysis involving computer models.

To successfully complete a visibility impairments analysis, the applicant is referred to an EPA document entitled ***Workbook for Estimating Visibility Impairment*** or its projected replacement, the ***Workbook for Plume Visual Impact Screening and Analysis***. In this workbook, EPA outlines a screening procedure designed to expedite the analysis of emissions impacts on the visual quality of an area. The workbook was designed for Class I area impacts, but the outlined procedures are generally applicable to other areas as well. The following sections are a brief synopsis of the screening procedures.

II.D.1. SCREENING PROCEDURES: LEVEL 1

The Level 1 visibility screening analysis is a series of conservative calculations designed to identify those emission sources that have little potential of adversely affecting visibility. The VISCREEN model is recommended for this first level screen. Calculated values relating source emissions to visibility impacts are compared to a standardized screening value. Those sources with calculated values greater than the screening criteria are judged to have potential visibility impairments. If potential visibility impairments are indicated, then the Level 2 analysis is undertaken.

II.D.2. SCREENING PROCEDURES: LEVEL 2

The Level 2 screening procedure is similar to the Level 1 analysis in that its purpose is to estimate impacts during worst-case meteorological conditions; however, more specific information regarding the source, topography, regional visual range, and meteorological conditions is assumed to be available. The analysis may be performed with the aid of either hand calculations, reference tables, and figures, or a computer-based visibility model called "***PLUVUE II***."

II.D.3. SCREENING PROCEDURES: LEVEL 3

If the Levels 1 and 2 screening analyses indicated the possibility of visibility impairment, a still more detailed analysis is undertaken in Level 3 with the aid of the plume visibility model and meteorological and other regional data. The purpose of the Level 3 analysis is to provide an accurate description of the magnitude and frequency of occurrence of impact.

The procedures for utilizing the plume visibility model are described in the document ***User's Manual for the Plume Visibility Model***, which is available from EPA.

II.E. CONCLUSIONS

The ***additional impacts analysis*** consists of a ***growth analysis***, a ***soil and vegetation analysis***, and a ***visibility impairment analysis***. After carefully examining all data on additional impacts, the reviewer must decide whether the analyses performed by a particular applicant are satisfactory. General criteria for determining the completeness and adequacy of the analyses may include the following:

- whether the applicant has presented a clear and accurate portrait of the soils, vegetation, and visibility in the proposed impacted area;
- whether the applicant has provided adequate documentation of the potential emissions impacts on soils, vegetation, and visibility; and
- whether the data and conclusions are presented in a logical manner understandable by the affected community and interested public.

III. ADDITIONAL IMPACTS ANALYSIS EXAMPLE

Sections D.1 and D.2 outlined, in general terms, the elements and considerations found in a successful additional impacts analysis. To demonstrate how this analytic process would be applied to a specific situation, a hypothetical case has been developed for a mine mouth power plant. This section will summarize how an additional impacts analysis would be performed on that facility.

III.A. EXAMPLE BACKGROUND INFORMATION

The mine mouth power plant consists of a power plant and an adjoining lignite mine, which serves as the plant's source of fuel. The plant is capable of generating 1,200 megawatts of power, which is expected to supply a utility grid (little is projected to be consumed locally). This project is located in a sparsely populated agricultural area in the southwestern United States. The population center closest to the plant is the town of Clarksville, population 2,500, which is located 20 kilometers from the plant site. The next significantly larger town is Milton, which is 130 kilometers away and has a population of 20,000. The nearest Class I area is more than 200 kilometers away from the proposed construction. The applicant has determined that within the area under consideration there are no National or State forests, no areas which can be described as scenic vistas, and no points of special historical interest.

The applicant has estimated that construction of the power plant and development of the mine would require an average work force of 450 people over a period of 36 months. After all construction is completed, about 150 workers will be needed to operate the facilities.

III.B. GROWTH ANALYSIS

To perform a growth analysis of this project, the applicant began by projecting the growth associated with the operation of the project.

III.B.1. WORK FORCE

The applicant consulted the State employment office, local contractors, trade union officers, and other sources for information on labor capability and availability, and made the following determinations.

Most of the 450 construction jobs available will be filled by workers commuting to the site, some from as far away as Milton. Some workers and their families will move to Clarksville for the duration of the construction. Of the permanent jobs associated with the project, about 100 will be filled by local workers. The remaining 50 permanent positions will be filled by nonlocal employees, most of whom are expected to relocate to the vicinity of Clarksville.

III.B.2. HOUSING

Contacts with local government housing authorities and realtors, and a survey of the classified advertisements in the local newspaper indicated that the predominant housing unit in the area is the single family house or mobile home, and the easy availability of mobile homes and lots provides a local capacity for quick expansion. Although there will be some emissions associated with the construction of new homes, these emissions will be temporary and, because of the limited numbers of new homes expected, are considered to be insignificant.

III.B.3. INDUSTRY

Although new industrial jobs often lead to new support jobs as well (i.e., grocers, merchants, cleaners, etc.), the small number of new people brought into the community through employment at the plant is not expected to generate commercial growth. For example, the proposed source will not require an increase in small support industries (i.e., small foundries or rock crushing operations).

As a result of the relatively self-contained nature of mine mouth plant operations, no related industrial growth is expected to accompany the operation of the plant. Emergency and full maintenance capacity is contained within the power-generating station. With no associated commercial or industrial growth projected, it then follows that there will be no growth-related air pollution impacts.

III.C. SOILS AND VEGETATION

In preparing a soils and vegetation analysis, the applicant acquired a list of the soil and vegetation types indigenous to the impact area. The vegetation is dominated by pine and hardwood trees consisting of loblolly pine, blackjack oak, southern red oak, and sweet gum. Smaller vegetation consists of sweetbay and holly. Small farms are found west of the forested area. The principal commercial crops grown in the area are soybeans, corn, okra, and peas. The soils range in texture from loamy sands to sandy clays. The principal soil is sandy loam consisting of 50 percent sand, 15 percent silt, and 35 percent clay.

The applicant, through a literature search and contacts with the local universities and experts on local soil and vegetation, determined the sensitivity of the various soils and vegetation types to each of the applicable pollutants that will be emitted by the facility in significant amounts. The applicant then correlated this information with the estimates of pollutant concentrations calculated previously in the air quality modeling analysis.

After comparing the predicted ambient air concentrations with soils and vegetation in the impact area, only soybeans proved to be potentially sensitive. A more careful examination of soybeans revealed that no adverse effects were expected at the low concentrations of pollutants predicted by the modeling analysis. The predicted sulfur dioxide (SO_2) ambient air concentration is lower than the level at which major SO_2 impacts on soybeans have been demonstrated (greater than 0.1 ppm for a 24-hour period).

Fugitive emissions emitted from the mine and from coal pile storage will be deposited on both the soil and leaves of vegetation in the immediate area of the plant and mine. Minor leaf necrosis and lower photosynthetic activity is expected, and over a period of time the vegetation's community structure may change. However, this impact occurs only in an extremely limited, nonagricultural area very near the emissions site and therefore is not considered to be significant.

The potential impact of limestone preparation and storage also must be considered. High relative humidity may produce a crusting effect of the fugitive limestone emissions on nearby vegetation. However, because of BACT on limestone storage piles, this impact is slight and only occurs very near the power plant site. Thus, this impact is judged insignificant.

III.D. VISIBILITY ANALYSIS

Next, the applicant performed a visibility analysis, beginning with a screening procedure similar to that outlined in the EPA document ***Workbook for Estimating Visibility Impairment***. The screening procedure is divided into three levels. Each level represents a screening technique for an increasing possibility of visibility impairment. The applicant executed a Level 1 analysis involving a series of conservative tests that permitted the analyst to eliminate sources having little potential for adverse or significant visibility impairment. The applicant performed these calculations for various distances from the power plant. In all cases, the results of the calculations were numerically below the standardized screening criteria. In preparing the suggested visual and aesthetic description of the area under review, the applicant noted the absence of scenic vistas. Therefore, the applicant concluded that no visibility impairment was expected to occur within the source impact area and that the Level 2 and Level 3 analyses were unnecessary.

III.E. EXAMPLE CONCLUSIONS

The applicant completed the additional impacts analysis by documenting every element of the analysis and preparing the report in straightforward, concise language. This step is important, because a primary intention of the PSD permit process is to generate public information regarding the potential impacts of pollutants emitted by proposed new sources or modifications on their impact areas.

NOTE: This example provides only the highlights of an additional impacts analysis for a hypothetical mine mouth power plant. An actual analysis would contain much more detail, and other types of facilities might produce more growth and more, or different, kinds of impacts. For example, the construction of a large manufacturing plant could easily generate air quality-related growth impacts, such as a large influx of workers into an area and the growth of associated industries. In addition, the existence of particularly sensitive forms of vegetation, the presence of Class I areas, and the existence of particular meteorological conditions would require an analysis of much greater scope.

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CHAPTER E

CLASS I AREA IMPACT ANALYSIS

I. INTRODUCTION

Class I areas are areas of special national or regional natural, scenic, recreational, or historic value for which the PSD regulations provide special protection. This section identifies Class I areas, describes the protection afforded them under the Clean Air Act (CAA), and discusses the procedures involved in preparing and reviewing a permit application for a proposed source with potential Class I area air quality impacts.

II. CLASS I AREAS AND THEIR PROTECTION

Under the CAA, three kinds of Class I areas either have been, or may be, designated. These are:

- ***mandatory Federal Class I areas*;**
- ***Federal Class I areas*;** and
- ***non-Federal Class I areas*.**

Mandatory Federal Class I areas are those specified as Class I by the CAA on August 7, 1977, and include the following areas in existence on that date:

- international parks;
- national wilderness areas (including certain national wildlife refuges, national monuments and national seashores) which exceed 5,000 acres in size;
- national memorial parks which exceed 5,000 acres in size; and
- national parks which exceed 6,000 acres in size.

Mandatory Federal Class I areas, which may not be reclassified, are listed by State in Table E-1. They are managed either by the Forest Service (FS), National Park Service (NPS), or Fish and Wildlife Service (FWS).

The States and Indian governing bodies have the authority to designate additional Class I areas. These Class I areas are not "mandatory" and may be reclassified if the State or Indian governing body chooses. States may reclassify either State or Federal lands as Class I, while Indian governing bodies may reclassify only lands within the exterior boundaries of their respective reservations.

TABLE E-1. MANDATORY CLASS I AREAS

State/Type/Area	Managing Agency
Alabama	
National Wilderness Areas	
Sipsey	FS
Alaska	
National Parks	
Denali	NPS
National Wilderness Areas	
Bering Sea	FWS
Simeonof	FWS
Tuxedni	FWS
Arizona	
National Parks	
Grand Canyon	NPS
Petrified Forest	NPS
National Wilderness Areas	
Chiricahua Nat. Monu.	NPS
Chiricahua	FS
Galiuro	FS
Mazatzal	FS
Mt. Baldy	FS
Pine Mountain	FS
Saguaro Nat. Monu.	NPS
Sierra Ancha	FS
Superstition	FS
Sycamore Canyon	FS
Arkansas	
National Wilderness Areas	
Caney Creek	FS
Upper Buffalo	FS
California	
National Parks	
Kings Canyon	NPS
Lassen Volcanic	NPS
Redwood	NPS
Sequoia	NPS
Yosemite	NPS
California - Continued	
National Wilderness Areas	
Agua Tibia	FS
Caribou	FS
Cucamonga	FS
Desolation	FS
Dome Land	FS
Emigrant	FS
Hoover	FS
John Muir	FS
Joshua Tree	NPS
Kaiser	FS
Lava Beds	NPS
Marble Mountain	FS
Minarets	FS
Mokelumne	FS
Pinnacles	NPS
Point Reyes	NPS
San Gabriel	FS
San Gorgonio	FS
San Jacinto	FS
San Rafael	FS
South Warner	FS
Thousand Lakes	FS
Ventana	FS
Yolla Bolly-Middle-Eel	FS
Colorado	
National Parks	
Mesa Verde	NPS
Rocky Mountain	NPS
National Wilderness Areas	
Black Canyon of the Gunn.	NPS
Eagles Nest	FS
Flat Tops	FS
Great Sand Dunes	NPS
La Garita	FS
Maroon Bells Snowmass	FS
Mount Zirkel	FS
Rawah	FS
Weminuche	FS
West Elk	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
Florida	
National Parks	
Everglades	NPS
National Wilderness Areas	
Bradwell Bay	FS
Chassahowitzka	FWS
Saint Marks	FWS
Georgia	
National Wilderness Areas	
Cohutta	FS
Okefenokee	FWS
Wolf Island	FWS
Hawaii	
National Parks	
Haleakala	NPS
Hawaii Volcanoes	NPS
Idaho	
National Parks	
Yellowstone (See Wyoming)	
National Wilderness Areas	
Craters of the Moon	NPS
Hells Canyon (see Oregon)	
Sawtooth	FS
Selway-Bitterroot	FS
Kentucky	
National Parks	
Mammoth Cave	NPS
Louisiana	
National Wilderness Areas	
Breton	FWS
Maine	
National Parks	
Acadia	NPS
National Wilderness Areas	
Moosehorn	FWS
Michigan	
National Parks	
Isle Royale	NPS
National Wilderness Areas	
Seney	FWS
Minnesota	
National Parks	
Voyageurs	NPS
National Wilderness Areas	
Boundary Waters Canoe Ar.	FS
Missouri	
National Wilderness Areas	
Hercules-Glades	FS
Mingo	FWS
Montana	
National Parks	
Glacier	NPS
Yellowstone (See Wyoming)	
National Wilderness Areas	
Anaconda-Pintlar	FS
Bob Marshall	FS
Cabinet Mountains	FS
Gates of the Mountain	FS
Medicine Lake	FWS
Mission Mountain	FS
Red Rock Lakes	FWS
Scapegoat	FS
Selway-Bitterroot (see Idaho)	
U.L. Bend	FWS
Nevada	
National Wilderness Areas	
Jarbridge	FS
New Hampshire	
National Wilderness Areas	
Great Gulf	FS
Presidential Range-Dry R.	FS

TABLE E-1. Continued

State/Type/Area	Managing Agency
New Jersey	
National Wilderness Areas	
Brigantine	FWS
New Mexico	
National Parks	
Carlsbad Caverns	NPS
National Wilderness Areas	
Bandelier	NPS
Bosque del Apache	FWS
Gila	FS
Pecos	FS
Salt Creek	FWS
San Pedro Parks	FS
Wheeler Peak	FS
White Mountain	FS
North Carolina	
National Parks	
Great Smoky Mountains (see Tennessee)	
National Wilderness Areas	
Joyce Kilmer-Slickrock	FS
Linville Gorge	FS
Shining Rock	FS
Swanquarter	FWS
North Dakota	
National Parks	
Theodore Roosevelt	NPS
National Wilderness Areas	
Lostwood	FWS
Oklahoma	
National Wilderness Areas	
Wichita Mountains	FWS
Oregon	
National Parks	
Crater Lake	NPS
Oregon - Continued	
National Wilderness Areas	
Diamond Peak	FS
Eagle Cap	FS
Gearhart Mountain	FS
Hells Canyon	FS
Kalmiopsis	FS
Mountain Lakes	FS
Mount Hood	FS
Mount Jefferson	FS
Mount Washington	FS
Strawberry Mountain	FS
Three Sisters	FS
South Carolina	
National Wilderness Areas	
Cape Romain	FWS
South Dakota	
National Parks	
Wind Cave	NPS
National Wilderness Areas	
Badlands	NPS
Tennessee	
National Parks	
Great Smoky Mountains	NPS
National Wilderness Areas	
Joyce Kilmer-Slickrock (see North Carolina)	
Texas	
National Parks	
Big Bend	NPS
Guadalupe Mountain	NPS

TABLE E-1.* Continued

State/Type/Area	Managing Agency	State/Type/Area	Managing Agency
Utah		***West Virginia***	
National Parks		*National Wilderness Areas*	
Arches	NPS	Dolly Sods	FS
Bryce Canyon	NPS	Otter Creek	FS
Canyonlands	NPS		
Capitol Reef	NPS	***Wisconsin***	
		National Wilderness Area	
		Rainbow Lake	FWS
Vermont			
National Wilderness Areas		***Wyoming***	
Lye Brook	FS	*National Parks*	
		Grand Teton	NPS
		Yellowstone	NPS
Virgin Islands			
National Parks		*National Wilderness Areas*	
Virgin Islands	NPS	Bridger	FS
		Fitzpatrick	FS
Virginia		North Absaroka	FS
National Parks		Teton	FS
Shenandoah	NPS	Washakie	FS
National Wilderness Areas		***International Parks***	
James River Face	FS	Roosevelt-Campobello	n/a
Washington			
National Parks			
Mount Rainier	NPS		
North Cascades	NPS		
Olypmic	NPS		
National Wilderness Areas			
Alpine Lakes	FS		
Glacier Peak	FS		
Goat Rocks	FS		
Mount Adams	FS		
Pasayten	FS		

Any Federal lands a State so reclassifies are considered *Federal Class I areas*. In so far as these areas are not mandatory Federal Class II areas, these areas may be again reclassified at some later date. (there are as of the date of this manual, no State-designated Federal Class I areas.) However, in accordance with the CAA the following areas may be redesignated only as Class I or II.

> an area which as of August 7, 1977, exceeded 10,000 acres in size and was a national monument, a national primitive area, a national preserve, a national recreation area, a national wild and scenic river, a national wildlife refuge, a national lakeshore or seashore; and
>
> a national park or national wilderness area established after August 7, 1977, which exceeds 10,000 acres in size.

Federal Class I areas are managed by the Forest Service (FS), the National Park Service (NPS), or the Fish and Wildlife Service (FWS).

State or Indian lands reclassified as Class I are considered non-Federal Class I areas. Four Indian Reservations which are non-Federal Class I areas are the Northern Cheyenne, Fort Peck, and Flathead Indian Reservations in Montana, and the Spokane Indian Reservation in Washington.

One way in which air quality degradation is limited in all Class I areas is by stringent limits defined by the Class I increments for sulfur dioxides, particulate matter [measured as total suspended particulate (TSP)], and nitrogen dioxide. As explained previously in Chapter C, Section II.A, PSD increments are the maximum increases in ambient pollutant concentrations allowed over the baseline concentrations. In addition, the FLM of each Class I area is charged with the affirmative responsibility to protect that area's unique attributes, expressed generically as air quality related values (AQRV's). The FLM, including the State or Indian governing body, where applicable, is responsible for defining specific AQRV's for an area and for establishing the criteria to determine an adverse impact on the AQRV's.

Congress intended the Class I increments to serve a special function in protecting the air quality and other unique attributes in Class I areas. In Class I areas, increments are a means of determining which party, i.e., the permit applicant or the FLM, has the burden of proof for demonstrating whether the proposed source would not cause or contribute to a Class I increment violation, the FLM may demonstrate to EPA, or the appropriate permitting authority, that the emissions from a proposed source would have an adverse impact on any AQRV's established for a particular Class I area.

If, on the other hand, the proposed source would cause or contribute to a Class I increment violation, the burden of proof is on the applicant to demonstrate to the FLM that the emissions from the source would have no adverse impact on the AQRV's. These concepts are further described in Section III.d of this chapter.

II.A. CLASS I INCREMENTS

The Class I increments for total suspended particulate matter (TSP), SO_2, and NO_2 are listed in Table E-2. Increments are the maximum increases in ambient pollutant concentrations allowed over baseline concentrations. Thus, these increments should limit increases in ambient pollutant concentrations caused by new major sources or major modifications near Class I areas. Increment consumption analyses for Class I areas should include not only emissions from the proposed source, but also include increment-consuming emissions from other sources.

TABLE E-2. CLASS I INCREMENTS (ug/m^3)

Pollutant	Annual	24-hour	3-hour
Sulfur dioxide	2	5	25
Particulate matter (TSP)	5	10	N/A
Nitrogen dioxide	2.5	N/A	N/A

II.B. AIR QUALITY-RELATED VALUES (AQRV's)

The AQRV's are those attributes of a Class I area that deterioration of air quality may adversely affect. For example, the Forest Service defines AQRV's as "features or properties of a Class I area that made it worthy of designation as a wilderness and that could be adversely affected by air pollution." Table E-3 presents an extensive (though not exhaustive) list of example AQRV's and the parameters that may be used to detect air pollution-caused changes in them. Adverse impacts on AQRV's in Class I areas may occur even if pollutant concentrations do not exceed the Class I increments.

Air quality-related values generally are expressed in broad terms. The impacts of increased pollutant levels on some AQRV's are assessed by measuring specific parameters that reflect the AQRV's status. For instance, the projected impact on the presence and vitality of certain species of animals or plants may indicate the impact of pollutants on AQRV's associated with species diversity or with the preservation of certain endangered species. Similarly, an AQRV associated with water quality may be measured by the pH of a water body or by the level of certain nutrients in the water. The AQRV's of various Class I areas differ, depending on the purpose and characteristics of a particular area and on assessments by the area's FLM. Also, the concentration at which a pollutant adversely impacts an AQRV can vary between Class I areas because the sensitivity of the same AQRV often varies between areas.

When a proposed major source's or major modification's modeled emissions may affect a Class I area, the applicant analyzes the source's anticipated impact on visibility and provides the information needed to determine its effect on the area's other AQRV's. The FLM's have established criteria for determining what constitutes an "adverse" impact. For example, the NPS

TABLE E-3. EXAMPLES OF AIR QUALITY-RELATED VALUES AND POTENTIAL AIR POLLUTION-CAUSED CHANGES

Air Quality Related Value	Potential Air Pollution-Caused Changes
Flora and Fauna	Growth, Mortality, Reproduction, Diversity, Visible Injury, Succession, Productivity, Abundance
Water	Total Alkalinity, Metals Concentration, Anion and Cation Concentration, pH, Dissolved Oxygen
Visibility	Contrast, Visual Range, Coloration
Cultural-Archeological and Paleontological	Decomposition Rate
Odor	Odor

defines an "adverse impact" as "any impact that: (1) diminishes the area's national significance; (2) impairs the structure or functioning of ecosystems; or (3) impairs the quality of the visitor experience." If an FLM determines, based on any information available, that a source will adversely impact AQRV's in a Class I area, the FLM may recommend that the reviewing agency deny issuance of the permit, even in cases where no applicable increments would be exceeded.

II.C. FEDERAL LAND MANAGER

The FLM of a Class I area has an affirmative responsibility to protect AQRV's for that area which may be adversely affected by cumulative ambient pollutant concentrations. The FLM is responsible for evaluating a source's projected impact on the AQRV's and recommending that the reviewing agency either approve or disapprove the source's permit application based on anticipated impacts. The FLM also may suggest changes or conditions on a permit. However, the reviewing agency makes the final decisions on permit issuance. The FLM also advises reviewing agencies and permit applicants about other FLM concerns, identifies AQRV's and assessment parameters for permit applicants, and makes ambient monitoring recommendations.

The U.S. Departments of Interior (USDI) and Agriculture (USDA) are the FLM's responsible for protecting and enhancing AQRV's in Federal Class I areas. Those areas in which the USDI has authority are managed by the NPS and the FWS, while the USDA Forest Service separately reviews impacts on Federal Class I national wildernesses under its jurisdiction. The PSD regulations specify that the reviewing authority furnish written notice of any permit application for a proposed major stationary source or major modification, the emissions from which may affect a Class I area, to the FLM and the official charged with direct responsibility for management of any lands within the area. Although the Secretaries of Interior and Agriculture are the FLM's for Federal Class I areas, they have delegated permit review to specific elements within each department. In the USDI, the NPS Air Quality Division reviews PSD permits for both the NPS and FWS. Hence, for sources that may affect wildlife refuges, applicants and reviewing agencies should contact and send correspondence to both the NPS and the wildlife refuge manager located at the refuge. Table E-4 summarizes the types of Federal Class I areas managed by each FLM. In the USDA, the Forest Service has delegated to its regional offices (listed in Table E-5) the responsibility for PSD permit application review.

TABLE E-4. FEDERAL LAND MANAGERS

Federal Land Manager	Federal Class I Areas Managed	Address
National Park Service (USDI)	National Memorial Parks National Monuments[1] National Parks National Seashores[1]	Air Quality Division National Park Service - Air P.O. Box 25287 Denver, CO 80225-0287
Fish and Wildlife Service (USDI)	National Wildlife Refuges[1]	Send to NPS, above, and to Wildlife Refuge Manager.[2]
Forest Service (USDA)	National Wildernesses	Send to Forest Service Regional Office (See Table E-5)

[1]Only those national monuments, seashores, and wildlife refuges which also were designated wilderness areas as of August 7, 1977 are included as mandatory Federal Class I areas.

[2]The Wildlife Refuge Manager is located at or near each refuge.

TABLE E-5. USDA FOREST SERVICE REGIONAL OFFICES AND STATES THEY SERVE*

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USDA Forest Service Northern Region Federal Building P.O. Box 7669 Missoula, MT 59807 [ID, ND, SD, MT]	USDA Forest Service Rocky Mountain Region 11177 West 8th Avenue P.O. Box 25127 Lakewood, CO 80225 [CO, KS, NE, SD, WY]
USDA Forest Service Southwestern Region Federal Building 517 Gold Avenue, SW Albuquerque, NM 87102 [AZ, NM]	USDA Forest Service Intermountain Region Federal Building 324 25th Street Ogden, UT 84401 [ID, UT, NV, WY]
USDA Forest Service Pacific Southwest Region 630 Sansome Street San Francisco, CA 94111 [CA, HI, GUAM, Trust Terr. of Pacific]	USDA Forest Service Pacific Northwest Region P.O. Box 3623 Portland, OR 97208 [WA, OR]
USDA Forest Service Southern Region 1720 Peachtree Road, NW Atlanta, GA 30367 [AL, AR, FL, GA, KY, LA, MS, NC, OK, PR, SC, TN, TX, VI, VA]	USDA Forest Service Eastern Region 310 W. Wisconsin Avenue, Room 500 Milwaukee, WI 53203 [CT, DE, IL, IN, IA, ME, MD, MA, MI, MN, MO, NH, NY, NJ, OH, PA, RI, VT, WV, WI]
USDA Forest Service Alaska Region P.O. Box 21628 Juneau, AK 99802-1628 [AK]	

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* Some Regions serve only part of a State.

III. CLASS I AREA IMPACT ANALYSIS AND REVIEW

This section presents the procedures an applicant should follow in preparing an analysis of a proposed source's impact on air quality and AQRV's in Class I areas, including recommended informal steps. For each participant in the analysis - the permit applicant, the FLM, and the permit reviewing agency - the section summarizes their role and responsibilities.

III.A. SOURCE APPLICABILITY

If a proposed major source or major modification ***may affect*** a Class I area, the Federal PSD regulations require the reviewing authority to provide written notification of any such proposed source to the FLM (and the USDI and USDA officials delegated permit review responsibility). The meaning of the term "may affect" is interpreted by EPA policy to include all major sources or major modifications which propose to locate within 100 kilometers (km) of a Class I area. Also, if a major source proposing to locate at a distance greater than 100 km is of such size that the reviewing agency or FLM is concerned about potential emission impacts on a Class I area, the reviewing agency can ask the applicant to perform an analysis of the source's potential emissions impacts on the Class I area. This is because certain meteorological conditions, or the quantity or type of air emissions from large sources locating further than 100 km, may cause adverse impacts on a Class I area's. A reviewing agency should exclude no major new source or major modification from performing an analysis of the proposed source's impact if there is some potential for the source to affect a Class I area's.

The EPA's policy requires, at a minimum, an AQRV impact analysis of any PSD source the emissions from which increase pollutant concentration by more than 1 $\mu g/m^3$ (24-hour average) in a Class I area. However, certain AQRV's may be sensitive to pollutant increases less than 1 $\mu g/m^3$. Also, some Class I areas may be approaching the threshold for effects by a particular pollutant on certain resources and consequently may be sensitive to even small increases in pollutant concentrations. For example, in some cases increases in sulfate concentration less than 1 $\mu g/m^3$ *may adversely* impact visibility. Thus, an increase of 1 $\mu g/m^3$ should not absolutely determine whether an AQRV impact analysis is needed. The reviewing agency should consult the FLM to determine whether to require all the information necessary for a complete AQRV impact analysis of a proposed source.

III.B. PRE-APPLICATION STAGE

A pre-application meeting between the applicant, the FLM, and the reviewing agency to discuss the information required of the source is highly recommended. The applicant should contact the appropriate FLM as soon as plans are begun for a major new source or modification near a Class I area (i.e., generally within 100 km of the Class I area). A preapplication meeting, while not required by regulation, helps the permit applicant understand the data and analyses needed by the FLM. At this point, given preliminary information such as the source's location and the type and quantity of projected air emissions, the FLM can:

- agree on which Class I areas are potentially affected by the source;
- discuss AQRV's for each of the areas(s) and the indicators that may be used to measure the source's impact on those AQRV's;
- advise the source about the scope of the analysis for determining whether the source potentially impacts the Class I area(s);
- discuss which Class I area impact analyses the applicant should include in the permit application; and
- discuss all pre-application monitoring in the Class I area that may be necessary to assess the current status of, and effects on, AQRV's (this monitoring usually is done by the applicant).

III.C. PREPARATION OF PERMIT APPLICATION

For each proposed major new source or major modification that may affect a Class I area, the applicant is responsible for:

- ! identifying all Class I areas within 100 km of the proposed source and any other Class I areas potentially affected;
- ! performing all necessary Class I increment analyses (including any necessary cumulative impact analyses);
- ! performing for each Class I area any preliminary analysis required by a reviewing agency to find whether the source may increase the ambient concentration of any pollutant by 1 $\mu g/m^3$ (24-hour average) or more;
- ! performing for each Class I area an AQRV impact analysis for visibility;
- ! providing all information necessary to conduct the AQRV impact analyses (including any necessary cumulative impact analyses);
- ! performing any monitoring within the Class I area required by the reviewing agency; and
- ! providing the reviewing agency with any additional relevant information the agency requests to "complete" the Class I area impacts analysis.

By involving the FLM early in preparation of the Class I area analysis, the applicant can identify and address FLM concerns, avoiding delays later during permit review.

The FLM is the AQRV expert for Class I areas. As such, the FLM can recommend to the applicant:

- ! the AQRV's the applicant should address in the PSD permit application's Class I area impact analysis;
- ! techniques for analyzing pollutant effects on AQRV's;
- ! the criteria the FLM will use to determine whether the emissions from the proposed source would have an adverse impact on any AQRV;

- the pre-construction and post-construction AQRV monitoring the FLM will request that the reviewing agency require of the applicant; and

- the monitoring, analysis, and quality assurance/quality control techniques the permit applicant should use in conducting the AQRV monitoring.

The permit applicant and the FLM also should keep the reviewing agency apprised of all discussions concerning a proposed source.

III.D. PERMIT APPLICATION REVIEW

Where a reviewing agency anticipates that a proposed source may affect a Class I area, the reviewing agency is responsible for:

- sending the FLM a copy of any advance notification that an applicant submits within 30 days of receiving such notification;

- sending EPA a copy of each permit application and a copy of any action relating to the source;

- sending the FLM a complete copy of all information relevant to the permit application, including the Class I visibility impacts analysis, within 30 days of receiving it and at least 60 days before any public hearing on the proposed source (the reviewing agency may wish to request that the applicant furnish 2 copies of the permit application);

- providing the FLM a copy of the preliminary determination document; and

- making a final determination whether construction should be approved, approved with conditions, or disapproved.

A reviewing agency's policy regarding Class I area impact analyses can ensure FLM involvement as well as aid permit applicants. Some recommended policies for reviewing agencies are:

- not considering a permit application complete until the FLM certifies that it is "complete" in the sense that it contains adequate information to assess adverse impacts on AQRV's;

- ! recommending that the applicant agree with the FLM (usually well before the application is received) on the type and scope of AQRV analyses to be done;

- ! deferring to the FLM's adverse impact determination, i.e., denying permits based on FLM adverse impact certifications; and

- ! where appropriate, incorporating permit conditions (e.g., monitoring program) which will assure protection of AQRV's. Such conditions may be most appropriate when the full extent of the AQRV impacts is uncertain.

In addition, the reviewing agency can serve as an arbitrator and advisor in FLM/applicant agreements, especially at meetings and in drafting any written agreements.

While the FLM's review of a permit application focuses on emissions impacts on visibility and other AQRV's, the FLM may comment on all other aspects of the permit application. The FLM should be given sufficient time (at least 30 days) to thoroughly perform or review a Class I area impact analysis and should receive a copy of the permit application either at the same time as the reviewing agency or as soon after the reviewing agency as possible.

The FLM can make one of two decisions on a permit application: (1) no adverse impacts; or (2) adverse impact based on any available information. Where a proposed major source or major modification adversely impacts a Class I area's AQRV's, the FLM can recommend that the reviewing agency deny the permit request based on the source's projected adverse impact on the area's AQRV's. However, rather than recommending denial at this point, the FLM may work with the reviewing agency to identify possible permit conditions that, if agreed to by the applicant, would make the source's effect on AQRV's acceptable. In cases where the permit application contains insufficient information for the FLM to determine AQRV impacts, the FLM should notify the reviewing agency that the application is incomplete.

During the public comment period, the FLM can have two roles: 1) final determination on the source's impact on AQRV's with a formal recommendation to the reviewing agency; and 2) a commenter on other aspects of the permit application (best available control technology, modeling, etc.). Even for PSD permit applications where a proposed source's emissions clearly would not cause or contribute to exceedances of any Class I increment, the FLM may demonstrate to the reviewing agency that emissions from the proposed source or modification would adversely impact AQRV's of a mandatory Federal Class I area and recommend denial. Conversely, a permit applicant may demonstrate to the FLM that a proposed source's emissions do not adversely affect a mandatory Federal Class I area's AQRV's even though the modeled emissions would cause an

exceedance of a Class I increment. Where a Class I increment is exceeded, the burden of proving no adverse impact on AQRV's is on the applicant. If the FLM concurs with this demonstration, the FLM may recommend approval of the permit to the reviewing agency and such a permit may be issued despite projected Class I increment exceedances.

IV. VISIBILITY IMPACT ANALYSIS AND REVIEW

Visibility is singled out in the regulations for special protection and enhancement in accordance with the national goal of preventing any future, and remedying any existing, impairment of visibility in Class I areas caused by man-made air pollution. The visibility regulations for new source review (40 CFR 51.307 and 52.27) require visibility impact analysis in PSD areas for major new sources or major modifications that have the potential to impair visibility in any Federal Class I area. Information on screening models available for visibility analysis can be found in the manual "Workbook for Plume Visual Impact Screening and Analysis," EPA-450/4-88-015 (9/88).

IV.A VISIBILITY ANALYSIS

An "adverse impact on visibility" means visibility impairment which interferes with the management, protection, preservation, or enjoyment of a visitor's visual experience of the Federal Class I area. The FLM makes the determination of an adverse impact on a case-by-case basis taking into account the geographic extent, duration, intensity, frequency and time of visibility impairment, and how these factors correlate with (1) times of visitor use of the Federal Class I area, and (2) the frequency and timing of natural conditions that reduce visibility. Visibility perception research indicates that the visual effects of a change in air quality requires consideration of the features of the particular vista as well as what is in the air, and that measurement of visibility usually reflects the change in color, texture, and form of a scene. The reviewing agency may require visibility monitoring in any Federal Class I area near a proposed new major source or modification as the agency deems appropriate.

An integral vista is a view perceived from within a mandatory Class I Federal area of a specific landmark or panorama located outside of the mandatory Class I Federal area. A visibility impact analysis is required for the integral vistas identified at 40 CFR 81, Subpart D, and for any other integral vista identified in a SIP.

IV.B PROCEDURAL REQUIREMENTS

When the reviewing agency receives advance notification (e.g., early consultation with the source prior to submission of the application) of a permit application for a source that may affect visibility in a Federal Class I area, the agency must notify the appropriate FLM within 30 days of receiving the notification. The reviewing agency must, upon receiving a permit application for a source that may affect Federal Class I area visibility, notify the FLM in writing within 30 days of receiving it and at least 60 days prior to the public hearing on the permit application. This written notification must include an analysis of the source's anticipated impact on visibility in any Federal Class I area and all other information relevant to the permit application. The FLM has 30 days after receipt of the visibility impact analysis and other relevant information to submit to the reviewing agency a finding that the source will adversely impact visibility in a Federal Class I area.

If the FLM determines that a proposed source will adversely impact visibility in a Federal Class I area and the reviewing agency concurs, the permit may not be issued. Where the reviewing agency does not agree with the FLM's finding of an adverse impact on visibility the agency must, in the notice of public hearing, either explain its decision or indicate where the explanation can be obtained.

V. BIBLIOGRAPHY

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5. USDA Forest Service (1987c). A Screening Procedure to Evaluate Air Pollution Effects on Class I Wilderness Areas. Rocky Mountain Forest and Range Experiment Station GTR 168. Fort Collins, Colorado.

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CHAPTER F

NONATTAINMENT AREA APPLICABILITY

I. INTRODUCTION

Many of the elements and procedures for source applicability under the nonattainment area NSR applicability provisions are similar to those of PSD applicability. The reader is therefore encouraged to become familiar with the terms, definitions and procedures from Part I.A., "PSD Applicability," in this manual. Important differences occur, however, in three key elements that are common to applicability determinations for new sources or modifications of existing sources located in attainment (PSD) and nonattainment areas. Those elements are:

- Definition of "source,"
- Pollutants that must be evaluated (geographic effects); and
- Applicability thresholds

Consequently, this section will focus on these three elements in the context of a nonattaiment area NSR program. Note that the two latter elements, pollutants that must be evaluated for nonattainment NSR due to the location of the source in designated nonattainment areas (geographic effects) and applicability thresholds, <u>are not independent</u>. They will, therefore, be discussed in section III.

II. DEFINITION OF SOURCE

The original NSR regulations required that a source be evaluated according to a ***dual*** source definition. On October 14, 1981, however, the EPA revised the new source review regulations to give a State the option of adopting a ***plantwide*** definition of stationary source in nonattainment areas, if the State's SIP did not rely on the more stringent "dual" definition in its attainment demonstration. Consequently, there are two stationary source definitions for nonattainment major source permitting: a "plantwide" definition and a "dual" source definition. <u>The permit application must use, and be reviewed according to, whichever of the two definitions is used to define a stationary source in the applicable SIP.</u>

II.A. "PLANTWIDE" STATIONARY SOURCE DEFINITION

The EPA definition of stationary source for nonattainment major source permitting uses the "plantwide" definition, which is the same as that used in PSD. A complete discussion of the concepts associated with the plantwide definition of source are presented in the PSD part of this manual (see section II). In essence, this definition provides that only physical or operation changes that result in a significant net emissions increase ***at the entire plant*** are considered a major modification to an existing major source (see sections II and III).

> ***For example, if an existing major source proposes to increase emissions by constructing a new emissions unit but plans to reduce actual emissions by the same amount at another emissions unit at the plant (assuming the reduction is federally enforceable and is the only contemporaneous and creditable emissions change at the source), then there would be no net increase in emissions at the plant and therefore no "major" modification to the stationary source.***

II.B. "DUAL SOURCE" DEFINITION OF STATIONARY SOURCE

The "dual" definition of stationary source defines the term stationary source as ". . . any building, structure, facility, or installation which emits or has the potential to emit any air pollutant subject to regulation under the Clean Air Act." Under this definition, the three terms ***building***, ***structure***, or ***facility*** are defined as a single term meaning ***all*** of the pollutant-emitting activities which belong to the same industrial grouping (i.e.,same two-digit SIC code), are located on one or more adjacent properties, and are under the control of the same owner or operator. The fourth term, ***installation***, means an identifiable piece of process equipment. Therefore, a stationary source is both:

- a building, structure, or facility (plantwide); and
- an installation (individual piece of equipment).

In other words, the "dual source" definition of stationary source treats each emissions unit as (1) a separate, independent stationary source, and (2) a component of the entire stationary source.

> ***For example, in the case of a power plant with three large boilers each emitting major amounts (i.e., >100 tpy) of NO_x, each of the three boilers is an individual stationary source and all three boilers together constitute a stationary source. [Note that the power plant would be seen only as a single stationary source under the plantwide definition (all three boilers together as one stationary source)].***

Consequently, under the dual source definition, the emissions from each physical or operational change at a plant are reviewed both with and without regard to reductions elsewhere at the plant.

> ***For example, a power plant is an existing major SO_2 source in an SO_2 nonattainment area. The power plant proposes to 1) install SO_2 scrubbers on an existing boiler and 2) construct a new boiler at the same facility. Under the "plantwide" definition, the SO_2 reductions from the scrubber installation could be considered, along with other contemporaneous emissions changes at the plant and the new emissions increase of the new boiler to arrive at the source's net emission increase. This might result in a net***

emissions change which would be below the SO_2 significance level and the new boiler would "net" out of review as major modification. Under the dual source definition, however, the new boiler would be regarded as a individual source and would be subject to nonattainment NSR requirements if its potential emissions exceed the 100 tpy threshold. The emissions reduction from the scrubber could not be used to reduce net source emissions, but would instead be regarded as an SO_2 emissions reduction from a separate source.

The following examples are provided to further clarify the application of the dual source definition to determine if a modification to an existing major source is major and, therefore, subject to major source NSR permitting requirements.

<u>Example 1</u> *An existing major stationary source is located in a nonattainment area for NO_x where the "dual source" definition applies, and has the following emissions units:*

Unit #1 with a potential to emit of 120 tpy of NO_x

Unit #2 with a potential to emit of 80 tpy of NO_x

Unit #3 with a potential to emit of 120 tpy of NO_x

Unit #4 with a potential to emit of 130 tpy of NO_x

Case 1 *A modification planned for Unit #1 will result in an emissions increase of 45 tpy of NO_x. The following emissions changes are contemporaneous with the proposed modification (all case examples assume that increases and decreases are creditable and will be made federally enforceable by the reviewing authority when the modification is permitted and will occur before construction of the modification):*

Unit #3 had an actual decrease of 10 tpy NO_x

Unit #4 had an actual decrease of 10 tpy NO_x

Only contemporaneous emissions changes at Unit #1 are considered because Unit #1 is a major source of NO_x by itself (i.e., potential emissions of NO_x are greater than 100 tpy). The proposed increase at unit #1 of 45 tpy is greater than the 40 tpy

NO_x significant emissions rate since the emissions changes at the other units are not considered. Consequently, the proposed modification to Unit #1 is major under the dual source definition.

Case 2 *A modification to unit #2 is planned which will result in an emissions increase of 45 tpy of $N0_x$. The following emissions changes are contemporaneous with the proposed modification:*

Unit #1 had an actual decrease of 10 tpy

Unit #3 had an actual decrease of 10 tpy

Unit #2 is not a major stationary source in and of itself (i.e., its potential to emission of 80 tpy NO_x is less than the 100 tpy major source threshold). Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 25 tpy (the sum of +45, -10, and -10) at the source is less than the applicable 40 tpy NO_x significant emissions rate. Consequently, the proposed modification is <u>not</u> major.

Case 3 *A brand new unit #5 with a potential to emission of 45 tpy of NO_x (note that potential emissions are less than the 100 tpy major source cutoff) is being added to the plant. The following emissions changes are contemporaneous with the proposed modification:*

Unit #1 had an actual decrease of 15 tpy

Unit #2 had an actual increase of 25 tpy

Unit #3 had an actual decrease of 20 tpy

The new unit #5 is not a major stationary source in and of itself. Therefore, the major stationary source being modified is the whole plant and the emissions decreases at units #1, #2 and #3 are considered in calculating the net emissions change at the source. The net emissions change of 35 tpy (the sum of + 45, -15, +25, and -20) at the source is less than the applicable 40 tpy NO_x significance level. Therefore, the proposed unit #5 is <u>not</u> a major modification.

Case 4 *A brand new unit #6 with a potential to emit of NO_x of 120 tpy is being added to the plant. Because the new unit is, by itself, a new major source (i.e., potential NO_x emissions are greater than* *the 100 tpy major source cutoff), it cannot net out of review (using emissions reductions achieved at other emissions units at the plant) under the dual source definition.*

<u>*Example 2*</u> *An existing plant has only two emissions units. The units have a potential to emit of 25 tpy and 40 tpy. Here, any modification to the plant would have to have a potential to emit greater than 100 tpy before the modification is major and subject to review. This is because neither of the two existing emissions units (at 25 tpy and 40 tpy), nor the total plant (at 65 tpy) are considered to be a major source (i.e., existing potential emissions do not exceed 100 tpy). If, however, a third unit with potential emissions of 110 tpy were added, that unit would be subject to review regardless of any emissions reductions from the two existing units.*

III. POLLUTANTS ELIGIBLE FOR REVIEW AND APPLICABILITY THRESHOLDS

III.A. POLLUTANTS ELIGIBLE FOR REVIEW (GEOGRAPHIC CONSIDERATIONS)

A new source will be subject to nonattainment area preconstruction review requirements only if it will emit, or will have the potential to emit, in major amounts any criteria pollutant for which the area has been designated nonattainment. Similarly, only if a modification results in a significant increase (and significant net emissions increase under the plantwide source definition) of a pollutant, for which the source is major and for which the area is designated nonattainment, do nonattainment requirements apply.

III.B. MAJOR SOURCE THRESHOLD

For the purposes of nonattainment NSR, a major stationary source is

- any stationary source which emits or has the potential to emit 100 tpy of any [criteria] pollutant subject to regulation under the CAA, or

- any physical change or change in method of operation at an existing non-major source that constitutes a major stationary source by itself.

Note that the 100 tpy threshold applies to all sources. The alternate 250 tpy major source threshold [for PSD sources not classified under one of the 28 regulated source categories identified in Section 169 of the CAA (See Section I.A.2.3 and Table I-A-1) as being subject to a 100 tpy threshold] does not exist for nonattainment area sources.

III.C. MAJOR MODIFICATION THRESHOLDS

Major modification thresholds for nonattainment areas are those same significant emissions values used to determine if a modification is major for PSD. Remember, however, that only criteria pollutants for which the location of the source has been designated nonattainment are eligible for evaluation.

IV. NONATTAINMENT APPLICABILITY EXAMPLE

The following example illustrates the criteria presented in sections II and III above.

Construction of a new plant with potential emissions of 500 tpy SO_2, 50 tpy VOC and 30 tpy NO_x is proposed for an area designated nonattainment for SO_2 and ozone and attainment for NO_x. (Recall that VOC is the regulated surrogate pollutant for ozone.) The new plant is major for SO_2 and therefore would be subject to nonattainment requirements for SO_2 only. Even though the VOC emissions are significant, the source is minor for VOC, and according to nonattainment regulations, is not subject to major source review. For purposes of PSD, the NO_x emissions are neither major nor significant and are, therefore, not subject to PSD review.

Two years after construction on the new plant commences, a modification of this plant is proposed that will result in an emissions increase of 60 tpy VOC and 35 tpy NO_x without any creditable contemporaneous emissions reductions. Again, the VOC emissions increase would not be subject, because the existing source is not major for VOC. The emissions increase of 35 tpy NO_x is not significant and again, is not subject to PSD review. Note, however, that the plant would be considered a major source of VOC in subsequent applicability determinations.

One year later, the plant proposes another increase in VOC emissions by 75 tpy and NO_x by another 45 tpy, again with no contemporaneous emissions reductions. Because the existing plant is now major for VOC and will experience a significant net emissions increase of that pollutant, it will be subject to nonattainment NSR for VOC. Because the source is major for a regulated pollutant (VOC) and will experience a significant net emissions increase of an attainment pollutant (NO_x), it will also be subject to PSD review.

CHAPTER G

NONATTAINMENT AREA REQUIREMENTS

I. INTRODUCTION

The preconstruction review requirements for major new sources or major modifications locating in designated nonattainment areas differ from prevention of significant deterioration (PSD) requirements. First, the emissions control requirement for nonattainment areas, lowest achievable emission rate (LAER), is defined differently than the best available control technology (BACT) emissions control requirement. Second, before construction of a nonattainment area source can be approved, the source must obtain emissions reductions (offsets) of the nonattainment pollutant from other sources which impact the same area as the proposed source. Third, the applicant must certify that all other sources owned by the applicant in the State are complying with all applicable requirements of the CAA, including all applicable requirements in the State implementation plan (SIP). Fourth, such sources impacting visibility in mandatory class I Federal areas must be reviewed by the appropriate Federal land manager (FLM).

II. LOWEST ACHIEVABLE EMISSION RATE (LAER)

For major new sources and major modifications in nonattainment areas, LAER is the most stringent emission limitation derived from either of the following:

- the most stringent emission limitation contained in the implementation plan of any State for such class or category of source; or
- the most stringent emission limitation achieved in practice by such class or category of source.

The most stringent emissions limitation contained in a SIP for a class or category of source must be considered LAER, unless (1) a more stringent emissions limitation has been achieved in practice, or (2) the SIP limitation is demonstrated by the applicant to be unachievable. By definition LAER can not be less stringent than any applicable new source performance standard (NSPS).

There is, of course, a range of certainty in such a definition. The greatest certainty for a proposed LAER limit exists when that limit is actually being achieved by a source. However, a SIP limit, even if it has not yet been applied to a source, should be considered initially to be the product of careful investigation and, therefore, achievable. A SIP limit's credibility diminishes if a) no sources exist to which it applies; b) it is generally acknowledged that sources are unable to comply with the limit and the State is in the process of changing the limit; or c) the State has relaxed the original SIP limit. Case-by-case evaluations need to be made in these situations to determine the SIP limit's achievability.

The same logic applies to SIP limits to which sources are subject but with which they are not in compliance. Noncompliance by a source with a SIP limit, even if it is the only source subject to that specific limit, does not automatically constitute a demonstration that the limit is unachievable. The specific reasons for noncompliance must be determined, and the ability of the source to comply assessed. However, such noncompliance may prove to be an indication of nonachievability, so the achievability of such a SIP limitation should be carefully studied before it is used as the basis of a LAER determination. Some recommended sources of information for determining LAER are:

- SIP limits for that particular class or category of sources;
- preconstruction or operating permits issued in other nonattainment areas; and
- the BACT/LAER Clearinghouse.

Several technological considerations are involved in selecting LAER. The LAER is an emissions rate specific to each emissions unit including fugitive emissions sources. The emissions rate may result from a combination of emissions-limiting measures such as (1) a change in the raw material processed, (2) a process modification, and (3) add-on controls. The reviewing agency determines for each new source whether a single control measure is appropriate for LAER or whether a combination of emissions-limiting techniques should be considered.

The reviewing agency also can require consideration of technology transfer. There are two types of potentially transferable control technologies: (1) gas stream controls, and (2) process controls and modifications. For the first type of transfer, classes or categories of sources to consider are those producing similar gas streams that could be controlled by the same or similar technology. For the second type of transfer, process similarity governs the decision.

Unlike BACT, the LAER requirement does not consider economic, energy, or other environmental factors. A LAER is not considered achievable if the cost of control is so great that a major new source could not be built or operated. This applies generically, i.e., if no new plants could be built in that industry if emission limits were based on a particular control technology. If some other plant in the same (or comparable) industry uses that control technology, then such use constitutes evidence that the cost to the industry of that control is not prohibitive. Thus, for a new source, LAER costs are considered only to the degree that they reflect unusual circumstances which in some manner differentiate the cost of control for that source from control costs for the rest of the industry. When discussing costs, therefore, applicants should compare control costs for the proposed source to the costs for sources already using that control.

Where technically feasible, LAER generally is specified as both a numerical emissions limit (e.g., lb/MMBtu) and an emissions rate (e.g., lb/hr). Where numerical levels reflect assumptions about the performance of a control technology, the permit should specify both the numerical emissions rate and limitation and the control technology. In some cases where enforcement of a numerical limitation is judged to be technically infeasible, the permit may specify a design, operational, or equipment standard; however, such standards must be clearly enforceable, and the reviewing agency must still make an estimate of the resulting emissions for offset purposes.

III. EMISSIONS REDUCTIONS "OFFSETS"

A major source or major modification planned in a nonattainment area must obtain emissions reductions as a condition for approval. These emissions reductions, generally obtained from existing sources located in the vicinity of a proposed source, must (1) offset the emissions increase from the new source or modification and (2) provide a net air quality benefit. The obvious purpose of acquiring offsetting emissions decreases is to allow an area to move towards attainment of the NAAQS while still allowing some industrial growth. Air quality improvement may not be realized if all emissions increases are not accounted for and if emissions offsets are not real.

In evaluating a nonattainment NSR permit, the reviewing agency ensures that offsets are developed in accordance with the provisions of the applicable State or local nonattainment NSR rules. The following factors are considered in reviewing offsets :

- the pollutants requiring offsets and amount of offset required;
- the location of offsets relative to the proposed source;
- the allowable sources for offsets;
- the "baseline" for calculating emissions reduction credits; and
- the enforceability of proposed offsets.

Each of these factors should be discussed with the reviewing agency to ensure that the specific requirements of that agency are met.

The offset requirement applies to each pollutant which triggered nonattainment NSR applicability. For example, a permit for a proposed petroleum refinery which will emit more than 100 tpy of sulfur dioxide (SO_2) and particulate matter in a SO_2 and particulate matter nonattainment area is required to obtain offsetting emissions reductions of SO_2 and particulate matter.

III.A. CRITERIA FOR EVALUATING EMISSIONS OFFSETS

Emissions reductions obtained to offset new source emissions in a nonattainment area must meet two important objectives:

- ! ensure reasonable progress toward attainment of the NAAQS; and
- ! provide a positive net air quality benefit in the area affected by the proposed source.

States have latitude in determining what requirements offsets must meet to achieve these NAA program objectives. The EPA has set forth minimum considerations under the Interpretive Ruling (40 CFR 51, Appendix S). Acceptable offsets also must be creditable, quantifiable, federally enforceable, and permanent.

While an emissions offset must always result in reasonable progress toward attainment of the NAAQS, it need not show that the area will attain the NAAQS. Therefore, the ratio of required emissions offset to the proposed source's emissions must be greater than one. The State determines what offset ratio is appropriate for a proposed source, taking into account the location of the offsets, i.e., how close the offsets are to the proposed source.

To satisfy the criterion of a net air quality benefit does not mean that the applicant must show an air quality improvement at every location affected by the proposed source. Sources involved in an offset situation should impact air quality in the same general area as the proposed source, but the net air quality benefit test should be made "on balance" for the area affected by the new source. Generally, offsets for VOC's are acceptable if obtained from within the same air quality control region as the new source or from other nearby areas which may be contributing to an ozone nonattainment problem. For all pollutants, offsets should be located as close to the proposed site as possible. Applicants should always discuss the location of potential offsets with the reviewing agency to determine whether the offsets are acceptable.

III.B. AVAILABLE SOURCES OF OFFSETS

In general, emissions reductions which have resulted from some other regulatory action are not available as offsets. For example, emissions reductions already required by a SIP cannot be counted as offsets. Also, sources subject to an NSPS in an area with less stringent SIP limits cannot use the difference between the SIP and NSPS limits as an offset. In addition, any emissions reductions already counted in major modification "netting" may not be used as offsets. However, emissions reductions validly "banked" under an approved SIP may be used as offsets.

III.C. CALCULATION OF OFFSET BASELINE

A critical element in the development or review of nonattainment area new source permits is to determine the appropriate baseline of the source from which offsetting emissions reductions are obtained. In most cases the SIP emissions limit in effect at the time that the permit application is filed may be used. This means that offsets will be based on emissions reductions below these SIP limits. Where there is no meaningful or applicable SIP requirement, the applicant be required to use actual emissions as the baseline emissions level.

III.D. ENFORCEABILITY OF PROPOSED OFFSETS

The reviewing agency ensures that all offsets are federally enforceable. Offsets should be specifically stated and appear in the permit, regulation or other document which establishes a Federal enforceability requirement for the emissions reduction. External offsets must be established by conditions in the operating permit of the other plant or in a SIP revision.

IV. OTHER REQUIREMENTS

An applicant proposing a major new source or major modification in a nonattainment area must certify that all major stationary sources owned or operated by the applicant (or by any entity controlling, controlled by, or under common control with the applicant) in that State are in compliance with all applicable emissions limitations and standards under the CAA. This includes all regulations in an EPA-approved SIP, including those more stringent than Federal requirements.

Any major new source or major modification proposed for a nonattainment area that may impact visibility in a mandatory class I Federal area is subject to review by the appropriate Federal land manager (FLM). The reviewing agency for any nonattainment area should ensure that the FLM of such mandatory class I Federal area receives appropriate notification and copies of all documents relating to the permit application received by the agency.

CHAPTER H

ELEMENTS OF AN EFFECTIVE PERMIT

I. INTRODUCTION

An effective permit is the legal tool used to establish all the source limitations deemed necessary by the reviewing agency during review of the permit application, as described in Parts I and II of this manual, and is the primary basis for enforcement of NSR requirements. In essence, the permit may be viewed as an extension of the regulations. It defines as clearly as possible what is expected of the source and reflects the outcome of the permit review process. A permit may limit the emissions rate from various emissions units or limit operating parameters such as hours of operation and amount or type of materials processed, stored, or combusted. Operational limitations frequently are used to establish a new potential to emit or to implement a desired emissions rate. The permit must be a "stand-alone" document that:

- identifies the emissions units to be regulated;
- establishes emissions standards or other operational limits to be met;
- specifies methods for determining compliance and/or excess emissions, including reporting and recordkeeping requirements; and
- outlines the procedures necessary to maintain continuous compliance with the emission limits.

To achieve these goals, the permit, which is in effect a contract between the source and the regulatory agency, must contain specific, clear, concise, and enforceable conditions.

This part of the manual gives a brief overview of the development of a permit, which ensures that major new sources and modifications will be constructed and operated in compliance with the applicable new source review (NSR) regulations [including prevention of signification deterioration (PSD) and nonattainment area (NAA) review], new source performance standards (NSPS), national emissions standards for hazardous air pollutants (NESHAP), and applicable state implementation plan (SIP) requirements. In particular, a permit contains the specific conditions and limitations which ensure that:

- an otherwise major source will remain minor;
- all contemporaneous emissions increases and decreases are creditable and federally-enforceable; and
- where appropriate, emissions offset transactions are documented clearly and offsets are real, creditable, quantifiable, permanent and federally-enforceable.

For a more in-depth study, refer to the Air Pollution Training Institute (APTI) course SI 454 (or Workshop course 454 given by APTI) entitled "Effective Permit Writing." This course is highly recommended for all permit writers and reviewers.

II. TYPICAL CONSTRUCTION PERMIT ELEMENTS

While each final permit is unique to a particular source due to varying emission limits and specific special terms and conditions, every permit must also contain certain basic elements:

- ! legal authority;
- ! technical specifications;
- ! emissions compliance demonstration;
- ! definition of excess emissions;
- ! administrative procedures; and
- ! other specific conditions.

Although many of these elements are inherent in the authority to issue permits under the SIP, they must be explicit within the construction of a NSR permit. Table H-1 lists a few typical subelements found in each of the above. Some permit conditions included in each of these elements can be considered standard permit conditions, i.e., they would be included in nearly every permit. Others are more specific and vary depending on the individual source.

II.A. LEGAL AUTHORITY

In general, the first provision of a permit is the specification of the legal authority to issue the permit. This should include a reference to the enabling legislation and to the legal authority to issue and enforce the conditions contained in the permit and should specify that the application is, in essence, a part of the permit. These provisions are common to nearly all permits and usually are expressed in standard language included in every permit issued by an agency. These provisions articulate the contract-like nature of a permit in that the permit allows a source to emit air pollution only if certain conditions are met. A specific citation of any applicable

TABLE H.1. SUGGESTED MINIMUM CONTENTS OF AIR EMISSION PERMITS

Permit Category	Typical Elements
Legal Authority	Basis--statute, regulation, etc. Conditional Provisions Effective and expiration dates
Technical Specifications	Unit operations covered Identification of emission units Control equipment efficiency Design/operation parameters Equipment design Process specifications Operating/maintenance procedures Emission limits
Emission Compliance Demonstration	Initial performance test and methods Continuous emission monitoring and methods Surrogate compliance measures - process monitoring - equipment design/operations - work practice
Definition of Excess Emissions	Emission limit and averaging time Surrogate measures Malfunctions and upsets Follow-up requirements
Administrative	Recordkeeping and reporting procedures Commence/delay construction Entry and inspections Transfer and severability
Other Conditions	Post construction monitoring Emissions offset

permit effective date and/or expiration date is usually included under the legal authority as well.

II.B. TECHNICAL SPECIFICATIONS

Overall, the technical specifications may be considered the core of the permit in that they specifically identify the emissions unit(s) covered by the permit and the corresponding emission limits with which the source must comply. Properly identifying each emissions unit is important so that (1) inspectors can easily identify the unit in the field and (2) the permit leaves no question as to which unit the various permit limitations and conditions apply. Identification usually includes a brief description of the source or type of equipment, size or capacity, model number or serial number, and the source's identification of the unit.

Emissions and operational limitations are included in the technical specifications and must be clearly expressed, easily measurable, and allow no subjectivity in their compliance determinations. All limits also must be indicated precisely for each emissions point or operation. For clarity, these limits are often best expressed in tabular rather than textual form. In general, it is best to express the emission limits in two different ways, with one value serving as an emissions cap (e.g., lbs/hr.) and the other ensuring continuous compliance at any operating capacity (e.g., lbs/MMBtu). The permit writer should keep in mind that the source must comply with <u>both</u> values to demonstrate compliance. Such limits should be of a short term nature, continuous and enforceable. In addition, the limits should be consistent with the averaging times used for dispersion modeling and the averaging times for compliance testing. Since emissions limitation values incorporated into a permit are based on a regulation (SIP, NSPS, NESHAP) or resulting from new source review, (i.e., BACT or LAER requirements), a reference to the applicable portion of the regulation should be included.

II.C. EMISSIONS COMPLIANCE DEMONSTRATION

The permit should state how compliance with each limitation will be determined, and include, but is not limited to, the test method(s) approved for demonstrating compliance. These permit compliance conditions must be very clear and enforceable as a practical matter (see Appendix C). The conditions must specify:

- ! when and what tests should be performed;
- ! under what conditions tests should be performed;
- ! the frequency of testing;
- ! the responsibility for performing the test;
- ! that the source be constructed to accommodate such testing;
- ! procedures for establishing exact testing protocol; and
- ! requirements for regulatory personnel to witness the testing.

Where continuous, quantitative measurements are infeasible, surrogate parameters must be expressed in the permit. Examples of surrogate parameters include: mass emissions/opacity correlations, maintaining pressure drop across a control (e.g., venturi throat of a scrubber), raw material input/mass emissions output ratios, and engineering correlations associated with specific work practices. These alternate compliance parameters may be used in conjunction with measured test data to monitor continuous compliance or may be independent compliance measures where source testing is not an option and work practice or equipment parameters are specified. Only those parameters that exhibit a correlation with source emissions should be used. Identifying and quantifying surrogate process or control equipment parameters (such as pressure drop) may require initial source testing or may be extracted from confirmed design characteristics contained in the permit application.

Parameters that must be monitored either continuously or periodically should be specified in the permit, including averaging time for continuously monitored data, and data recording frequency for periodically (continually) monitored data. The averaging times should be of a short term nature consistent with the time periods for which dispersion modeling of the respective emissions rate demonstrated compliance with air quality standards, and consistent with averaging times used in compliance testing. This requirement also applies to surrogate parameters where compliance may be time-based, such as weekly or monthly leak detection and repair programs (also see Appendix C). Whenever possible, "never to be exceeded" values should be specified for surrogate compliance parameters. Also, operating and maintenance (O&M) procedures should be specified for the monitoring instruments (such as zero, span, and other periodic checks) to ensure that valid data are obtained. Parameters which must be monitored continuously or continually are those used by inspectors to determine compliance on a real-time basis and by source personnel to maintain process operations in compliance with source emissions limits.

II.D. DEFINITION OF EXCESS EMISSIONS

The purpose of defining excess emissions is to prevent a malfunction condition from becoming a standard operating condition by requiring the source to report and remedy the malfunction. Conditions in this part of the permit:

- precisely define excess emissions;
- outline reporting requirements;
- specify actions the source must take; and
- indicate time limits for correction by the source.

Permit conditions defining excess emissions may include alternate conditions for startup, shutdown, and malfunctions such as maximum emission limits and operational practices and limits. These must be as specific as possible since such exemptions can be misused. Every effort should be made to include adequate definitions of both preventable and nonpreventable malfunctions. Preventable malfunctions usually are those which cause excess emissions due to negligent maintenance practices. Examples of preventable malfunctions may include: leakage or breakage of fabric filter bags; baghouse seal ruptures; fires in electrostatic precipitators due to excessive build up of oils or other flammable materials; and failure to monitor and replace spent activated carbon beds in carbon absorption units. These examples reinforce the need for good O&M plans and keeping records of all repairs. Permit requirements concerning malfunctions may include: timely reporting of the malfunction duration, severity, and cause; taking interim and corrective actions; and taking actions to prevent recurrence.

II.E. ADMINISTRATIVE PROCEDURES

The administrative elements of permits are usually standard conditions informing the source of certain responsibilities. These administrative procedures may include:

- recordkeeping and reporting requirements, including all continuous monitoring data, excess emission reports, malfunctions, and surrogate compliance data;
- notification requirements for performance tests, malfunctions, commencing or delay of construction;
- entry and inspection procedures;
- the need to obtain a permit to operate; and
- specification of procedures to revoke, suspend, or modify the permit.

Though many of these conditions will be entered into the permit via standard permit conditions, the reviewer must ensure the language is adequate to establish precisely what is expected or needed from the source, particularly the recordkeeping requirements.

II.F. OTHER CONDITIONS

In some cases, specific permit conditions which do not fit into the above elements may need to be outlined. Examples of these are conditions requiring: the permanent shutdown of (or reduced emissions rates for) other emissions units to create offsets or netting credits; post-construction monitoring; continued Statewide compliance; and a water truck to be dedicated solely to a haul road. In the case of a portable source, a condition may be included to require a copy of the effective permit to be on-site at all times. Some O&M procedures, such as requiring a 10 minute warmup for an incinerator, would be included in this category, as well as conditions requiring that replacement fabric filters and baghouse seals be kept available at all times. Any source-specific condition which needs to be included in the permit to ensure compliance should be listed here.

III. SUMMARY

Assuming a comprehensive review, a permit is only as clear, specific, and effective as the conditions it contains. As such, Table H-2 on the following page lists guidelines for drafting actual permit conditions. The listing specifies how typical permit elements should be written. For further discussion on drafting "federally enforceable" permit conditions as a practical matter, please refer to Appendix C - "Potential to Emit."

TABLE H.2. GUIDELINES FOR WRITING EFFECTIVE SPECIFIC CONDITIONS IN NSR PERMITS

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1. Make each permit condition ***simple, clear***, and ***specific*** such that it "stands alone."

2. Make certain ***legal authority*** exists to specify conditions.

3. Permit conditions should be ***objective*** and ***meaningful***.

4. Provide description of ***processes, emissions units*** and ***control equipment*** covered by the permit, including operating rates and periods.

5. Clearly ***identify each permitted emissions unit*** such that it can be located in the field.

6. Specify allowable emissions (or concentration, etc.) rates for ***each pollutant and emissions unit*** permitted, and specify each applicable emissions standard by name in the permit.

7. Allowable emissions rates should reflect the conditions of ***BACT/LAER*** and ***Air Quality Analyses*** (e.g., specify limits two ways: maximum mass/unit of process ***and*** maximum mass/unit time)

8. Specify for all emissions units (especially fugitive sources) permit conditions that require ***continuous application of BACT/LAER*** to achieve maximum degree of emissions reduction.

9. Initial and subsequent performance tests should be conducted at worst case operating (non-malfunction) conditions for all emissions units. Performance tests should determine ***both emissions and control equipment efficiency***.

10. Continual and continuous ***emissions performance monitoring*** and recordkeeping (direct and/or surrogate) should be specified where feasible.

11. Specify ***test method*** (citation) and ***averaging period*** by which all compliance demonstrations (initial and continuous) are to be made.

12. Specify what ***conditions*** constitute ***"excess emissions,"*** and what is to be done in those cases.

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CHAPTER I
PERMIT DRAFTING

I. RECOMMENDED PERMIT DRAFTING STEPS

This section outlines a recommended five-step permit drafting process (see Table I-1). These steps can assist the writer in the orderly preparation of air emissions permits following technical review.

Step 1 concerns the emissions units and requires the listing and specification of three things. First, list each new or modified emissions unit. Second, specify each associated emissions point. This includes fugitive emissions points (e.g., seals, open containers, inefficient capture areas, etc.) and fugitive emissions units (e.g., storage piles, materials handling, etc.). Be sure also to note emissions units with more than one ultimate exhaust and units sharing common exhausts. Third, the writer must describe each emissions unit as it may appear in the permit and identify, as well as describe, each emissions control unit. Each new or modified emissions unit identified in Step 1 that will emit or increase emissions of any pollutant is considered in Step 2.

Step 2 requires the writer to specify each pollutant that will be emitted from the new or modified source. Some pollutants may not be subject to regulation or are of de minimis amounts such that they do not require major source review. All pollutants should be identified in this step and reviewed for applicability. Federally enforceable conditions must be identified for de minimis pollutants to ensure they do not become significant (see Appendix C - Potential to Emit). An understanding of "potential to emit" is pertinent to permit review and especially to the drafting process.

TABLE I-1. FIVE STEPS TO PERMIT DRAFTING

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STEP 1. SPECIFY EMISSIONS UNITS

! Identify each new (or modified) emissions unit that will emit (or increase) any pollutant.

! Identify any pollutant and emissions units involved in a netting or emissions reduction proposal (i.e., all contemporaneous emissions increases and decreases).

! Include point and fugitive emissions units.

! Identify and describe emissions unit and emissions control equipment.

STEP 2. SPECIFY POLLUTANTS

! Pollutants subject to NSR/PSD.

! Pollutants not subject to NSR/PSD but could reasonably be expected to exceed significant emissions levels. Identify conditions that ensure de minimis (e.g., shutdowns, operating modes, etc..).

STEP 3. SPECIFY ALLOWABLE EMISSION RATES AND BACT/LAER REQUIREMENTS

! Minimum number of allowable emissions rates specified is equal to at least two limits per pollutant per emissions unit.

! One of two allowable limits is unit mass per unit time (lbs/hr) which reflects application of emissions controls at maximum capacity.

! Maximum hourly emissions rate must correspond to that used in air quality analysis.

! Specify BACT/LAER emissions control requirements for each pollutant/emissions unit pair.

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TABLE I-1. - Continued

STEP 4. SPECIFY COMPLIANCE DEMONSTRATION METHODS

- Continuous, direct emission measurement is preferable.

- Specify initial and periodic emissions testing where necessary.

- Specify surrogate (indirect) parameter monitoring and recordkeeping where direct monitoring is impractical or in conjunction with tested data.

- Equipment and work practice standards should complement other compliance monitoring.

STEP 5. OTHER PERMIT CONDITIONS

- Establish the basis upon which permit is granted (legal authority).

- Should be used to minimize "paper" allowable emissions.

- Federally enforceable permit conditions limiting potential to emit.

Step 3 pools the data collected in the two previous steps. The writer should specify the pollutants that will be emitted from each emission unit and identify associated emission controls for each pollutant and/or emission unit. (Indicate if the control has been determined to be BACT.) The writer also must assess the minimum number of allowable emissions rates to be specified in the permit. Each emissions unit should have at least two allowable emissions rates for each pollutant to be emitted. This is the most concise manner in which to present permit allowables and should be consistent with the averaging times and emissions ratio used in the air quality analysis. As discussed earlier in Section H, the applicable regulation should also be cited as well as whether BACT, LAER, or other SIP requirements apply to each pollutant to be regulated.

Step 4 essentially mirrors the items discussed in the previous Chapter H, Section IV., Emissions Compliance Demonstration. At this point the writer enters into the permit any performance testing required of the source. The conditions should specify what emissions test is to be performed and the frequency of testing. Any surrogate parameter monitoring must be specified. Recordkeeping requirements and any equipment and work practice standards needed to monitor the source's compliance should be written into the permit in Step 4. Any remaining or additional permit conditions, such as legal authority and conditions limiting potential to emit can be identified in ***Step 5***. (Other Permit Conditions, see Table I-1.) At this point, the permit should be complete. The writer should review the draft to ensure that the resultant permit is an effective tool to monitor and enforce source compliance. Also, the compliance inspector should review the permit to ensure that the permit conditions are enforceable as a practical matter.

II. PERMIT WORKSHEETS AND FILE DOCUMENTATION

Some agencies use permit drafting worksheets to store all the required information that will be incorporated into the permit. The worksheets may be helpful and are available at various agencies and in other EPA guidance documents. The worksheets serve as a summary of the review process, though this summation should appear in the permit file with or without a worksheet. Documenting the permit review process in the file cannot be overemphasized. The decision-making process which leads to the final permit for a source must be clearly traceable through the file. When filing documentation, the reviewer must also be aware of any confidential materials. Many agencies have special procedures for including confidential information in the permit file. The permit reviewer should follow any special procedures and ensure the permit file is documented appropriately.

III. SUMMARY

Listed below are summary "helpful hints" for the permit writer, which should be kept in mind when reviewing and drafting the permit. Many of these have been touched on throughout Part III, but are summarized here to help ensure that they are not overlooked:

- Document the review process throughout the file.
- Be aware of confidentiality items, procedures, and the consequences of the release of such information.
- Ensure the application includes all pertinent review information (e.g., has the applicant identified solvents used in some coatings; are solvents used, then later recovered; ultimate disposal of collected wastes identified; and applicable monitoring and modeling results included).
- Address secondary pollutant formation.
- Ensure that all applicable regulations and concerns have been addressed (e.g., BACT, LAER, NSPS, NESHAP, non-regulated toxics, SIP, and visibility).

- ! Ensure the permit is organized well, e.g., conditions are independent of one another, and conditions are grouped so as not be cover more than one area at a time.

- ! Surrogate parameters listed are clear and obtainable.

- ! Emissions limits are clear. In cases of multiple or common exhaust, limits should specify if per emissions unit or per exhaust.

- ! <u>Every</u> permit condition is 1) reasonable, 2) meaningful, 3) monitorable, and 4) always enforceable as a practical matter.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS

BACT	Best Available Control Technology is the control level required for sources subject to PSD. From the regulation (reference 40 CFR 52.21(b)) BACT means "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results."
Emission Units	The individual emitting facilities at a location that together make up the source. From the regulation (reference 40 CFR 52.21(b)), it means "any part of a stationary source which emits or would have the potential to emit any pollutant subject to regulation under the Act."
Increments	The maximum permissible level of air quality deterioration that may occur beyond the baseline air quality level. Increments were defined statutorily by Congress for SO_2 and PM. Recently EPA also has promulgated increments for NO_x. Increment is consumed or expanded by actual emissions changes occurring after the baseline date and by construction related actual emissions changes occurring after January 6, 1975, and February 8, 1988 for PM/SO_2 and NO_x, respectively.

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Innovative Control Technology	From the regulation (reference 40 CFR 52.21(b)(19)) "Innovative control technology" means any system of air pollution control that has not been adequately demonstrated in practice, but would have a substantial likelihood of achieving greater continuous emissions reduction than any control system in current practice or of achieving at least comparable reductions at lower cost in terms of energy, economics, or nonair quality environmental impacts. Special delayed compliance provisions exist that may be applied when applicants propose innovative control techniques.
LAER	Lowest Achievable Emissions Rate is the control level required of a source subject to nonattainment review. From the regulations (reference 40 CFR 51.165(a)), it means for any source "the more stringent rate of emissions based on the following: (a) The most stringent emissions limitation which is contained in the implementation plan of any State for such class or category of stationary source, unless the owner or operator of the proposed stationary source demonstrates that such limitations are not achievable; or (b) The most stringent emissions limitation which is achieved in practice by such class or category of stationary sources. This limitation, when applied to a modification, means the lowest achievable emissions rate of the new or modified emissions units within a stationary source. In no event shall the application of the term permit a proposed new or modified stationary source to emit any pollutant in excess of the amount allowable under an applicable new source standard of performance."

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

Major Modification A major modification is a modification to an existing major stationary source resulting in a significant net emissions increase (defined elsewhere in this table) that, therefore, is subject to PSD review. From the regulation (reference 40 CFR 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 net emissions increase of any pollutant subject to regulation under the Act.

(ii) Any net emissions increase that is significant for volatile organic compounds shall be considered significant for ozone.

(iii) A physical change or change in the method of operation shall not include:

(a) routine maintenance, repair and replacement;

(c) use of an alternative fuel by reason of an order or rule under Section 125 of the Act;

(d) Use of an alternative fuel at a steam generating unit to the extent that the fuel is generated from municipal solid waste;

(e) Use of an alternative fuel or raw material by a stationary source which:

(1) The source was capable of accommodating before January 6, 1975, unless such change would be prohibited under any Federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or

(2) The source is approved to use under any permit issued under 40 CFR 52.21 or under regulations approved pursuant to 40 CFR 51.166;

(f) an increase in the hours of operation or in the production rate, unless such change would be prohibited under any federally enforceable permit condition which was established after January 6, 1975, pursuant to 40 CFR 52.21 or under regulations approved pursuant to 40 CFR Subpart I or 40 CFR 51.166; or

(g) any change in ownership at a stationary source."

Major Stationary Source A major stationary source is an emissions source of sufficient size to warrant PSD review. Major modification to major stationary sources are also subject to PSD review. From the regulation (reference 40 CFR 52.21(b)(1)), (i) "Major stationary source" means:

"(a) Any of the following stationary sources of air pollutant which emits, or has the potential to emit, 100 tons per year or more of any pollutant subject to regulation under the Act: Fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input, coal cleaning plants (with thermal dryers), Kraft pulp mills, Portland cement plants, primary zinc smelters, iron and steel mill plants, primary aluminum ore reduction plants, primary aluminum ore reduction plants, primary copper smelters, municipal incinerators capable of charging more than 250 tons of refuse per day, hydrofluoric, sulfuric, and nitric acid plants, petroleum refineries, lime plants, phosphate rock processing plants, coke oven batteries, sulfur recovery plants, carbon black plants (furnace process), primary lead smelters, fuel conversion plants, sintering plants, secondary metal production plants, chemical process plants, fossil fuel boilers (or combinations thereof) totaling more than 250 million British thermal units per hour heat input, petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels, taconite ore processing plants, glass fiber processing plants, and charcoal production plants;

(b) Notwithstanding the stationary source size specified in paragraph (b)(1)(i) of this section, any stationary source which emits, or has the potential to emit, 250 tons per year or more of any air pollutant subject to regulation under the Act; or

(c) Any physical change that would occur at a stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source not otherwise qualifying under paragraph (b)(1) as a major stationary source, if the changes would constitute a major stationary source by itself.

(ii) A major stationary source that is major for volatile organic compounds shall be considered major for ozone."

NAAQS National Ambient Air Quality Standards are Federal standards for the minimum ambient air quality needed to protect public health and welfare. They have been set for six criteria pollutants including SO_2, PM/PM_{10}, NO_x, CO, O_3 (VOC), and Pb.

NESHAP NESHAP, or National Emission Standard for Hazardous Air Pollutants, is a technology-based standard of performance prescribed for hazardous air pollutants from certain stationary source categories under Section 112 of the Clean Air Act. Where they apply, NESHAP represent absolute minimum requirements for BACT.

NSPS NSPS, or New Source Performance Standard, is an emission standard prescribed for criteria pollutants from certain stationary source categories under Section 111 of the Clean Air Act. Where they apply, NSPS represent absolute minimum requirements for BACT.

PSD Prevention of significant deterioration is a construction air pollution permitting program designed to ensure air quality does not degrade beyond the NAAQS levels or beyond specified incremental amounts above a prescribed baseline level. PSD also ensures application of BACT to major stationary sources and major modifications for regulated pollutants and consideration of soils, vegetation, and visibility impacts in the permitting process.

Regulated Pollutants[6] Refers to pollutants that have been regulated under the authority of the Clean Air Act (NAAQS, NSPS, NESHAP):

O_3 (VOC)	- Ozone, regulated through volatile organic compounds as precursors			
NO_x	- Nitrogen oxides			
SO_2	- Sulfur dioxide			
PM (TSP)	- Total suspended particulate matter			
PM (PM_{10})	- Particulate matter with $\leq$10 micron aerometric diameter			
CO	- Carbon monoxide			
Pb	- Lead	5	TRS	- Total reduced sulfur (including H_2S)
As	- Asbestos	5	RDS	- Reduced Sulfur Compounds (including H_2S)
Be	- Beryllium	5	Bz	- Benzene
Hg	- Mercury	5	Rd	- Radionuclides
VC	- Vinyl chloride	5	As	- Arsenic
F	- Fluorides	5	CFC's	- Chlorofluorocarbons
H_2SO_4	- Sulfuric acid mist	5	Rn-222	- Radon-222
H_2S	- Hydrogen sulfide	5	Halons	

[6] The referenced list of regulated pollutants is current as of November 1989. Presently, additional pollutants may also be subject to regulation under the Clean Air Act.

Significant Emissions Increase For new major stationary sources and major modifications, a significant emissions increase triggers PSD review. Review requirements must be met for each pollutant undergoing a significant net emissions increase. From the regulation (reference 40 CFR 52.21(b)(23)).

(i) "Significant" means, in reference to a net emissions increase from a modified major source or the potential of a new major source to emit any of the following pollutants, a rate of emissions that would equal or exceed any of the following rates:

Carbon monoxide: 100 tons per year (tpy)
Nitrogen oxides: 40 tpy
Sulfur dioxide: 40 tpy
Particulate matter: 25 tpy
PM10: 15 tpy
Ozone: 40 tpy of volatile organic compounds
Lead: 0.6 tpy
Asbestos: 0.007 tpy
Beryllium: 0.0004 tpy
Mercury: 0.1 tpy
Vinyl chloride: 1 tpy
Fluorides: 3 tpy
Sulfuric acid mist: 7 tpy
Hydrogen Sulfide (H_2S): 10 tpy
Total reduced sulfur (including H_2S): 10 tpy
Reduced sulfur compounds (including H_2S): 10 tpy

(ii) "Significant" means, in reference to a net emissions increase or the potential of a source to emit a pollutant subject to regulation under the Act, that (i) above does not list, any emissions rate.

(For example, benzene and radionuclides are pollutants falling into the "any emissions rate" category.)

(iii) Notwithstanding, paragraph (b)(23)(i) of this section, "significant means any emissions rate or any net emissions increase associated with a major stationary source or major modification which would construct within 10 kilometers of a Class I area, and have an impact on such an area equal to or greater than 1 ug/m^3, (24-hour average).

APPENDIX A - DEFINITION OF SELECTED NSR TERMS (Continued)

SIP	State Implementation Plan is the federally approved State (or local) air quality management authority's statutory plan for attaining and maintaining the NAAQS. Generally, this refers to the State/local air quality rules and permitting requirements that have been accepted by EPA as evidence of an acceptable control strategy.
Stationary Source	For PSD purposes, refers to all emissions units at one location under common ownership or control. From the regulation (reference 40 CFR 52.21(b)(5) and 51.166(b)(5)), it means "any building, structure, facility, or installation which emits or may emit any air pollutant subject to regulation under the Act." "Building, structure, facility, or installation" means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or person under common control). Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same "Major Group" (i.e., which have the same first two digit code) as described in the Standard Industrial Classification Manual, 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101-0066 and 003-005-00176-0, respectively).

APPENDIX B

ESTIMATING CONTROL COSTS

APPENDIX B - ESTIMATING CONTROL COSTS

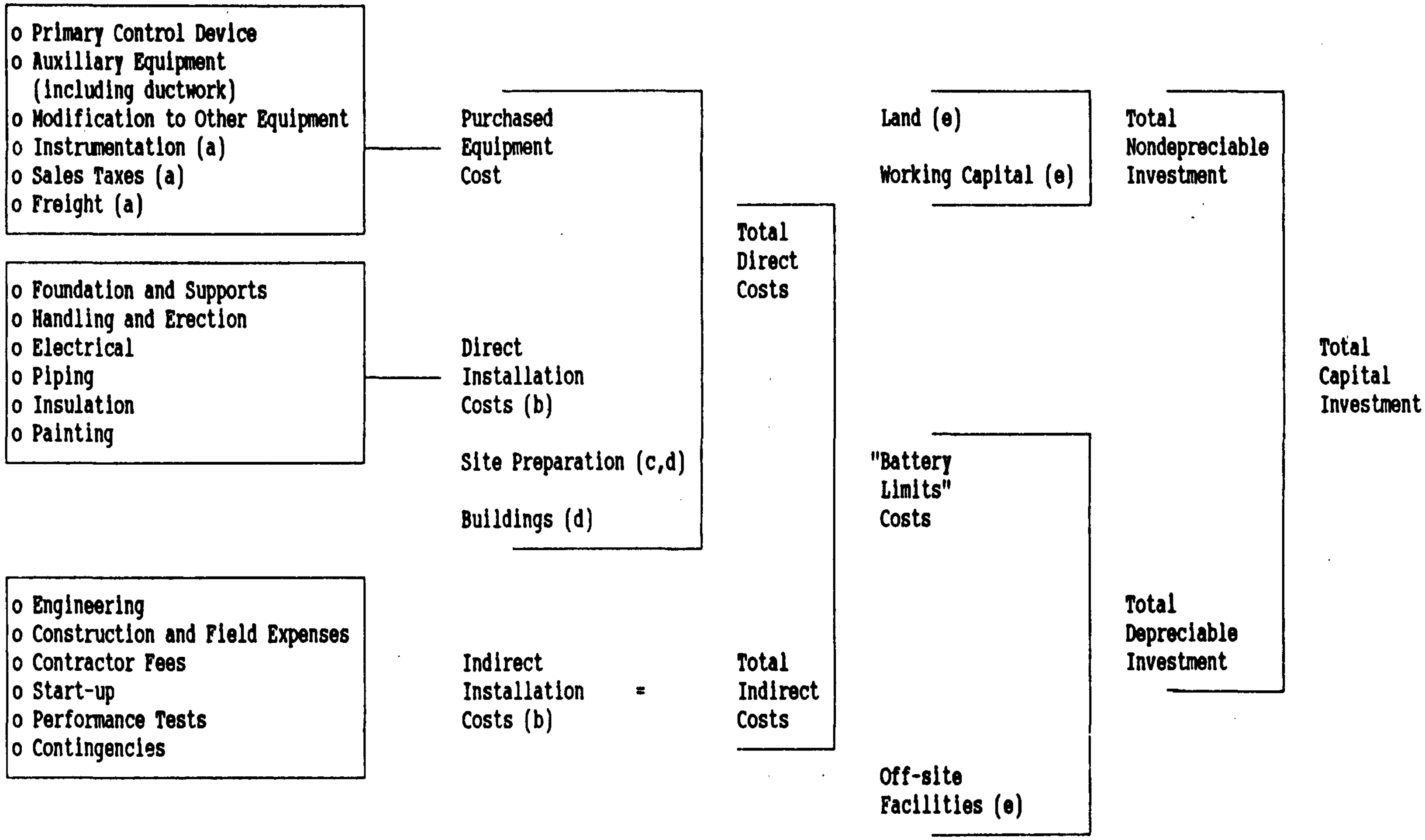
I. CAPITAL COSTS

Capital costs include equipment costs, installation costs, indirect costs, and working capital (if appropriate). Figure B-4 presents the elements of total capital cost and represents a building block approach that focuses on the control device as the basic unit of analysis for estimating total capital investment. The total capital investment has a role in the determination of total annual costs and cost effectiveness.

One of the most common problems which occurs when comparing costs at different facilities is that the battery limits are different. For example, the battery limit of the cost of a electrostatic precipitation might be the precipitator itself (housing, plates, voltage regulators, transformers, etc.), ducting from the source to the precipitator, and the solids handling system. The stack would not be included because a stack will be required regardless of whether or not controls are applied. Therefore, it should be outside the battery limits of the control system.

Direct installation costs are the costs for the labor and materials to install the equipment and includes site preparation, foundations, supports, erection and handling of equipment, electrical work, piping, insulation and painting. The equipment vendor can usually supply direct installation costs.

The equipment vendor should be able to supply direct installation costs estimates or general installation costs factors. In addition, typical installation cost factors for various types of equipment are available in the following references.



(a) These costs are factored from the sum of the control device and auxiliary equipment costs.
(b) These costs are factored from the purchased control equipment.
(c) Usually required only at "grass roots" installations.
(d) Unlike the other direct and indirect costs, costs for these items are not factored from the purchased equipment cost. Rather, they are sized and costed separately.
(e) Normally not required with add-on control systems.

FIGURE B-4. Elements of Total Capital Costs

- OAQPS Control Cost Manual (Fourth Edition), January 1990, EPA 450/3-90-006
- Control Technology for Hazardous Air Pollutants (HAPS) Manual, September 1986, EPA 625/6-86-014
- Standards Support Documents
  - Background Information Documents
  - Control Techniques Guidelines Documents
- Other EPA sponsored costing studies
- Engineering Cost and Economics Textbooks
- Other engineering cost publications

These references should also be used to validate any installation cost factors supplied from equipment vendors.

If standard costing factors are used, they may need to be adjusted due to site specific conditions. For example, in Alaska installation costs are on the order of 40-50 percent higher than in the contiguous 48 states due to higher labor prices, shipping costs, and climate.

Indirect installation costs include (but are not limited to) engineering, construction, start-up, performance tests, and contingency. Estimates of these costs may be developed by the applicant for the specific project under evaluation. However, if site-specific values are not available, typical estimates for these costs or cost factors are available in:

- OAQPS Control Cost Manual (Fourth Edition), EPA 450/3-90-006
- Cost Analysis Manual for Standards Support Documents, April 1979

These references can be used by applicants if they do not have site-specific estimates already prepared, and should also be used by the reviewing agency to determine if the applicant's estimates are reasonable.

Where an applicant uses different procedures or assumptions for estimating control costs than contained in the referenced material or outlined in this document, the nature and reason for the differences are to be documented in the BACT analysis.

Working capital is a fund set aside to cover initial costs of fuel, chemicals, and other materials and other contingencies. Working capital costs for add on control systems are usually relatively small and, therefore, are usually not included in cost estimates.

Table B-11 presents an illustrative example of a capital cost estimate developed for an ESP applied to a spreader-stoker coal-fired boiler. This estimate shows the minimum level of detail required for these types of estimates. If bid costs are available, these can be used rather than study cost estimates.

II. TOTAL ANNUAL COST

The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis. This approach is also called the "Equivalent Uniform Annual Cost" method, or simply "Total Annual Cost" (TAC). The components of total annual costs are their relationships are shown in Figure B-5. The total annual costs for control systems is comprised of three elements: "direct" costs (DC), "indirect costs" (IC), and "recovery credit" (RC), which are related by the following equation:

$$TAC = DC + IC - RC$$

TABLE B-11. EXAMPLE OF A CAPITAL COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR

	Capital cost ($)
Direct Investment	
Equipment cost	
ESP unit	175,800
Ducting	64,100
Ash handling system	97,200
Total equipment cost	337,100
Installation costs	
ESP unit	175,800
Ducting	102,600
Ash handling system	97,200
Total installation costs	375,600
Total direct investment (TDI) (equipment + installation)	712,700
Indirect Investment	71,300
Engineering (10% of TDI)	71,300
Construction and field expenses (10% of TDI)	71,300
Construction fees (10% of TDI)	71,300
Start-up (2% of TDI)	14,300
Performance tests (minimum $2000)	3,000
Total indirect investment (TII)	231,200
Contingencies (20% of TDI + TII)	188,800
TOTAL TURNKEY COSTS (TDI + TII)	1,132,700
Working Capital (25% of total direct operating costs)a	21,100
GRAND TOTAL	1,153,800

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+))))))))))))))))))))))))))),
*  o Raw Materials            *
*  o Utilities                *              S))))))))))),
*     - Electricity           /))))))))) Variable        *
*     - Steam                 *                          *
*     - Water                 *                          *     S)))))))),
*     - Others                *                          *              *
.)))))))))))))))))))))))))))-                            *    Direct    *
                                                         /))) Annual    *
+))))))))))))))))))))))))))),                            *    Costs     *
* o Labor                     *                          *              *
*   - Operating               *                          *              *
*   - Supervisory             /))))))))) Semivariable    *              *
*   - Maintenance             *              S)))))))))))-              *
* o Maintenance materials     *                                +        *
* o Replacement parts         *                                         *     Total
.)))))))))))))))))))))))))))-                                           *  =  Annual
                                                                        *     Costs
                              +))))))))))))))))))))),                   *
                              * o Overhead          *          Indirect *
                              * o Property Taxes    /)))))))) Annual    *
                              * o Insurance         *          Costs     *
                              * o Capital Recovery  *                   *
                              .))))))))))))))))))))-             -       *
                              +))))))))))))))))))))),                   *
                              * o Recovered Product*           Recovery *
                              * o Recovered Energy /))))))     Credits  *
                              * o Useful byproduct *                    *
                              * o Energy Gain      *           S))))))))-
                              .))))))))))))))))))))-
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FIGURE B-5. Elements of Total Annual Costs

Direct costs are those which tend to be proportional or partially proportional to the quantity of exhaust gas processed by the control system or, in the case of inherently lower polluting processes, the amount of material processed or product manufactured per unit time. These include costs for raw materials, utilities (steam, electricity, process and cooling water, etc.), and waste treatment and disposal. Semivariable direct costs are only partly dependent upon the exhaust or material flowrate. These include all associated labor, maintenance materials, and replacement parts. Although these costs are a function of the operating rate, they are not linear functions. Even while the control system is not operating, some of the semivariable costs continue to be incurred.

Indirect, or "fixed", annual costs are those whose values are relatively independent of the exhaust or material flowrate and, in fact, would be incurred even if the control system were shut down. They include such categories as overhead, property taxes, insurance, and capital recovery.

Direct and indirect annual costs are offset by recovery credits, taken for materials or energy recovered by the control system, which may be sold, recycled to the process, or reused elsewhere at the site. These credits, in turn, may be offset by the costs necessary for their purification, storage, transportation, and any associated costs required to make then reusable or resalable. For example, in auto refinishing, a source through the use of certain control technologies can save on raw materials (i.e., paint) in addition to recovered solvents. A common oversight in BACT analyses is the omission of recovery credits where the pollutant itself has some product or process value. Examples of control techniques which may produce recovery credits are equipment leak detection and repair programs, carbon absorption systems, baghouse and electrostatic precipitators for recovery of reusable or saleable solids and many inherently lower polluting processes.

Table B-12 presents an example of total annual costs for the control system previously discussed. Direct annual costs are estimated based on system design power requirements, energy balances, labor requirements, etc., and raw materials and fuel costs. Raw materials and other consumable costs should be carefully reviewed. The applicant generally should have documented delivered costs for most consumables or will be able to provide documented estimates. The direct costs should be checked to be sure they are based on the same number of hours as the emission estimates and the proposed operating schedule.

Maintenance costs in some cases are estimated as a percentage of the total capital investment. Maintenance costs include actual costs to repair equipment and also other costs potentially incurred due to any increased system downtime which occurs as a result of pollution control system maintenance.

Fixed annual costs include plant overhead, taxes, insurance, and capital recovery charges. In the example shown, total plant overhead is calculated as the sum of 30 percent of direct labor plus 26 percent of all labor and maintenance materials. The OAQPS Control Cost Manual combines payroll and plant overhead into a single indirect cost. Consequently, for "study" estimates, it is sufficiently accurate to combine payroll and plant overhead into a single indirect cost. Total overhead is then calculated as 60 percent of the sum of all labor (operating, supervisory, and maintenance) plus maintenance materials.

Property taxes are a percentage of the fixed capital investment. Note that some jurisdictions exempt pollution control systems from property taxes. Ad valorem tax data are available from local governments. Annual insurance charges can be calculated by multiplying the insurance rate for the facility by the total capital costs. The typical values used to calculate taxes and

TABLE B-12. EXAMPLE OF A ANNUAL COST ESTIMATE FOR AN ELECTROSTATIC PRECIPITATOR APPLIED TO A COAL-FIRED BOILER

	Annual costs ($/yr)
Direct Costs	
Direct labor at $12.02/man-hour	26,300
Supervision at $15.63/man-hour	0
Maintenance labor at $14.63/man-hour	16,000
Replacement parts	5,200
Electricity at $0.0258/kWh	3,700
Water at $0.18/1000 gal	300
Waste disposal at $15/ton (dry basis)	33,000
Total direct costs	84,500
Indirect Costs	
Overhead	
Payroll (30% of direct labor)	7,900
Plant (26% of all labor and replacement parts)	12,400
Total overhead costs	20,300
Capital charges	
G&A taxes and insurance (4% of total turnkey costs)	45,300
Capital recovery factor (11.75% of total turnkey costs)	133,100
Interest on working capital (10% of working capital)	2,100
Total capital charges	180,500
TOTAL ANNUALIZED COSTS	**285,300**

insurance is four percent of the total capital investment if specific facility data are not readily available.

The annual costs previously discussed do not account for recovery of the capital cost incurred. The capital cost shown in Table B-2 is annualized using a capital recovery factor of 11.75 percent. When the capital recovery factor is multiplied by the total capital investment the resulting product represents the uniform end of year payment necessary to repay the investment in "n" years with an interest rate "i".

The formula for the capital recovery factor is:

$$CRF = \frac{i\ (1 + i)^n}{(1 + i)^n - 1}$$

where:

CPF = capital recovery factor
n = economic life of equipment
i = real interest rate

The economic life of a control system typically varies between 10 to 20 years and longer and should be determined consistent with data from EPA cost support documents and the IRS Class Life Asset Depreciation Range System.

From the example shown in Table B-12 the interest rate is 10 percent and the equipment life is 20 years. The resulting capital recovery factor is 11.75 percent. Also shown is interest on working capital, calculated as the product of interest rate and the working capital.

It is important to insure that the labor and materials costs of parts of the control system (such as catalyst beds, etc.) that must be replaced before the end of the useful life are subtracted from the total capital investment before it is multiplied by the capital recovery factor. Costs of these parts should be accounted for in the maintenance costs. To include the cost of those parts in the capital charges would be double counting. The interest rate used is a real interest rate (i.e., it does not consider inflation). The value used in most control costs analyses is 10 percent in keeping with current EPA guidelines and Office of Management and Budget recommendations for regulatory analyses.

It is also recommended that income tax considerations be excluded from cost analyses. This simplifies the analysis. Income taxes generally represent transfer payments from one segment of society to another and as such are not properly part of economic costs.

III. OTHER COST ITEMS

Lost production costs are not included in the cost estimate for a new or modified source. Other economic parameters (equipment life, cost of capital, etc.) should be consistent with estimates for other parts of the project.

APPENDIX C[7]

POTENTIAL TO EMIT

Upon commencing review of a permit application, a reviewer must define the source and then determine how much of each regulated pollutant the source potentially can emit and whether the source is major or minor (nonmajor). A new source is major if its potential to emit exceeds the appropriate major emissions threshold, and a change at an existing major source is a major modification if the source's net emissions increase is "significant." This determination not only quantifies the source's emissions but dictates the level of review and applicability of various regulations and new source review requirements. The federal regulations, 40 CFR 52.21(b)(4), 51.165(a)(1)(iii), and 51.166(b)(4), define the "potential to emit" as:

"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."

In the absence of federally enforceable restrictions, the potential to emit calculations should be based on uncontrolled emissions at maximum design or achievable capacity (whichever is higher) and year-round continuous operation (8760 hours per year).

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[7] This Appendix is based largely on an EPA memorandum "Guidance on Limiting Potential to Emit in New Source Permitting," from Terrell E. Hunt, Office of Enforcement and Compliance Monitoring, and John S. Seitz, Office of Air Quality Planning and Standards, June 13, 1989.

When determining the potential to emit for a source, emissions should be estimated for individual emissions units using an engineering approach. These individual values should then be summed to arrive at the potential emissions for the source. For each emissions unit, the estimate should be based on the most representative data available. Methods of estimating potential to emit may include:

- Federally enforceable operational limits, including the effect of pollution control equipment;
- performance test data on similar units;
- equipment vendor emissions data and guarantees;
- test data from EPA documents, including background information documents for new source performance standards, national emissions standards for hazardous air pollutants, and Section 111(d) standards for designated pollutants;
- AP-42 emission factors;
- emission factors from technical literature; and
- State emission inventory questionnaires for comparable sources.

NOTE: Potential to emit values reflecting the use of pollution control equipment or operational restrictions are usable only to the extent that the unit/process under review utilizes the same control equipment or operational constraints and makes them federally enforceable in the permit.

Calculated emissions will embrace all potential, not actual, emissions expected to occur from a source on a continuous or regular basis, including fugitive emissions where quantifiable. Where raw materials or fuel vary in their pollutant-generating capacity, the most pollutant-generating substance must be used in the potential-to-emit calculations unless such materials are restricted by federally enforceable operational or usage limits. Historic usage rates alone are not sufficient to establish potential-to-emit.

Permit limitations are significant in determining a source's potential to emit and, therefore, whether the source is "major" and subject to new source review. Permit limitations are the easiest and most common way for a source to restrict its potential to emit. A source considered major, based on emission calculations assuming 8760 hours per year of operation, can often be considered minor simply by accepting a federally enforceable limitation restricting hours of operation to an actual schedule of, for example, 8 hours per day. A permit does not have to be a major source permit to legally restrict potential emissions. Minor source construction permits are often federally enforceable. Any limitation can legally restrict potential to emit if it meets three criteria: 1) it is federally enforceable as defined by 40 CFR 52.21(b)(17), 52.24(f)(12), 51.165(a)(1)(xiv), and 51.166(b)(17), i.e., contained in a permit issued pursuant to an EPA-approved permitting program or a permit directly issued by EPA, or has been submitted to EPA as a revision to a State Implementation Plan and approved as such by EPA; 2) it is enforceable as a practical matter; and (3) it meets the specific criteria in the definition of "potential to emit," (i.e., any physical or operational limitation on capacity, including control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed). The second criterion is an implied requirement of the first. A requirement may purport to be federally enforceable, but in reality cannot be federally enforceable if it cannot be enforced as a practical matter.

In the absence of dissecting the legal aspects of "federal enforceability," the permit writer should always assess the enforceability of a permit restriction based upon its practicability. Compliance with any limitation must be able to be established at any given time. When drafting permit limitations, the writer must always ensure that restrictions are written in such a manner that an inspector could verify instantly whether the source is or was complying with the permit conditions. Therefore, short-term averaging times on limitations are essential. If the writer does this, he or she can feel comfortable that limitations incorporated into a permit will be federally enforceable, both legally and practically.

The types of limitations that restrict potential to emit are emission limits, production limits, and operational limits. Emissions limits should reflect operation of the control equipment, be short term, and, where feasible, the permit should require a continuous emissions monitor. Blanket emissions limits alone (e.g., tons/yr, lb/hr) are virtually impossible to verify or enforce, and are therefore not enforceable as a practical matter. Production limits restrict the amount of final product which can be manufactured or produced at a source. Operational limits include all restrictions on the manner in which a source is run, e.g., hours of operation, amount of raw material consumed, fuel combusted or stored, or specifications for the installation, maintenance and operation of add-on controls operating at a specific emission rate or efficiency. All production and operational limits except for hours of operation are limits on a source's capacity utilization. To appropriately limit potential to emit consistent with a previous Court decision [United States v. Louisiana-Pacific Corporation, 682 F. Supp. 1122 (D. Colo. Oct. 30, 1987) and 682 F. Supp. 1141 (D. Colo. March 22, 1988)], all permits issued must contain a production or operational limitation in addition to the emissions limitation and emissions averaging time in cases where the emission limitation does not reflect the maximum emissions of the source operating at full design capacity without pollution control equipment. In the permit, these limits must be stated as conditions that can be enforced independently of one another. This emphasizes the idea of good organization when drafting permit conditions and is discussed in more detail in the Part III text. The permit conditions must be clear, concise, and independent of one another such that enforceability is never questionable.

When permits contain production or operational limits, they must also have requirements that allow a permitting agency to verify a source's compliance with its limits. These additional conditions dictate enforceability and usually take the form of recordkeeping requirements. For example, permits that contain limits on hours of operation or amount of final product should require use of an operating log for recording the hours of operation and the amount of final product produced. For organizational purposes, these limitations would be listed in the permit separately and records should be kept on a frequency consistent with that of the emission limits. It should be specified that these logs be available for inspection should a permitting agency wish to check a source's compliance with the terms of its permit.

When permits require add-on controls operated at a specified efficiency level, the writer should include those operating parameters and assumptions upon which the permitting agency depended to determine that controls would achieve a given efficiency. To be enforceable, the permit must also specify that the controls be equipped with monitors and/or recorders measuring the specific parameters cited in the permit or those which ensure the efficiency of the unit as required in the permit. Only through these monitors could an inspector instantaneously measure whether a control was operating within its permit requirements and thus determine an emissions unit's compliance. It is these types of additional permit conditions that render other permit limitations practically and federally enforceable.

Every permit also should contain emissions limits, but production and operational limits are used to ensure that emissions limits expressed in the permit are not exceeded. Production limits are most appropriately expressed in the shortest time periods as possible and generally should not exceed 1 month (i.e., pounds per hour or tons per day), because compliance with emission limits is most easily established on a short term basis. An inspector, for example, could not verify compliance for an emissions unit with only monthly and annual production, operational or emission limits if the inspection occurred anytime except at the end of a month. In some rare situations a 1-month averaging time may not be reasonable. In these cases, a limit spanning a longer period is appropriate if it is a rolling average limit. However, the limit should not exceed an annual limit rolled on a monthly basis. Note also that production and operational recordkeeping requirements should be written consistent with the emissions limits. Thus, if an emissions unit was limited to a particular tons per day emissions rate, then production records which monitor compliance with this limit should be kept on a daily basis rather than weekly.

One final matter to be aware of when calculating potential to emit involves identifying "sham" permits. A sham permit is a federally enforceable permit with operating restrictions limiting a source's potential to emit such that potential emissions do not exceed the major or de minimis levels for the purpose of allowing construction to commence prior to applying for a major source permit. Permits with conditions that do not reflect a source's ***planned*** mode of operation may be considered void and cannot shield the source from the requirement to undergo major source preconstruction review. In other words, if a source accepts operational limits to obtain a minor source construction permit but intends to operate the source in excess of those limitations once the unit is built, the permit is considered a sham. If the source originally intended or planned to operate at a production level that would make it a major source, and if this can be proven, EPA will seek enforcement action and the application of BACT and other requirements of the PSD program. Additionally, a permit may be considered a sham permit if it is issued for a number of pollution-emitting modules that keep the source minor, but within a short period of time an application is submitted for additional modules which will make the total source major. The permit writer must be aware of such sham permits. If an application for a source is suspected to be a sham, EPA enforcement and source personnel should be alerted so details may be worked out in the initial review steps such that a sham permit is not issued. The possibility of sham permits emphasizes the need, as discussed in the Part III text, to organize and document the review process throughout the file. This documentation may later prove to be evidence that a sham permit was issued, or may serve to refute the notion that a source was seeking a sham permit.

Overall, the permit writer should understand the extreme importance of potential to emit calculations. It must be considered in the initial review and continually throughout the review process to ensure accurate emission limits that are consistent with federally enforceable production and operational restrictions.