

**BEFORE THE ADMINISTRATOR
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY**

In the Matter of Cargill's Gainesville Vegetable Oil Mill & Refinery)))	
Part 70 Operating Permit Amendment 2075-139-0002-V-01-1))))	
)	PA Permit No. 2075-139-0002-V-01-0
Proposed by the Georgia Environmental Protection Division))	

PETITION TO HAVE THE ADMINISTRATOR OBJECT TO CARGILL'S GAINESVILLE
VEGETABLE OIL MILL & REFINERY TITLE V PERMIT AMENDMENT

I. INTRODUCTION

Air pollution is a major problem in Georgia. A scientific study, published in 2000, found that air pollution from just one industrial segment shortens the lives of over 1,600 people in Georgia each year.¹ Over 2,500,000 Georgians live in areas that have been designated as failing to meet the health based ambient air quality standard for ground level, or tropospheric, ozone by the United States Environmental Protection Agency (EPA).² Tropospheric ozone is a powerful lung irritant that can cause shortness of breath, coughing, burning eyes, chest pain, asthma attacks and other respiratory problems and a lessened ability to fight off disease and infection.³ There are also significant economic consequences of air pollution. For example, the EPA has concluded that the direct benefits for the Clean Air Act (CAA) from 1970 to 1990 has a central

¹ Death, Disease and Dirty Power, Clean Air Task Force, October 2000, at 22 available at http://www.cleartheair.org/fact/mortality/mortalitystudy.shtml?PROACTIVE_ID=cecfcfcecfccc6cdccc5cecfcfcf5cef9cbcccac6c6c7c9c5cf (emphasis added).

² Smog Watch 2000, Clean Air Network, June, 2000 at 11 available at http://www.cleartheair.org/fact/SmogWatch2000.pdf?PROACTIVE_ID=cecfcfcfcacacac8c6c5cecfcfcf5cecfcfcf9c6c8cecec9c5cf.

³ *Id.* at 16.

tendency estimate of \$22.2 trillion dollars. During the same period, implementing the CAA had a direct cost of \$523 billion. This means that the economic benefit of the CAA outweighed the costs by more than a factor of 42.⁴ Georgia's air pollution problems have reached such levels as to catch the attention of the media including major local newspapers. *See e.g.* May 1, 2001 Atlanta Journal, "Bad air days: Atlanta ranks sixth in pollution."

EPA has oversight to regulate and reduce the emission of harmful pollutants under the authority granted by Congress through the CAA. In addition to setting safe ambient air standards, EPA has the power to enforce those standards through the review of stationary source permits issued by authorized state agencies. In Georgia, major stationary sources are issued permits through Georgia's Environmental Protection Division (Georgia EPD) of the Georgia Department of Natural Resources. Under the CAA, this federalized review process provides the public with extra assurance that air pollution from stationary sources does not exceed the ambient air quality standards set by EPA.

The Title V permit program is a major component of the CAA's regulatory regime. The Title V permit program was designed to reduce violations and improve enforcement of those laws. This purpose is fulfilled by recording all control requirements for a specific stationary source into that facility's single permit document. Through this integrated approach, Congress intended to provide a clear reference for the public, as well as the regulators, seeking to monitor a facility's compliance with the regulatory and legal restrictions applicable to that facility. Furthermore, Title V permits streamline the system of monitoring and enforcement through an emissions reporting and tracking system. The state permitting agencies are authorized to require this reporting as a condition of the permit when it is issued. When effectively enforced, this

⁴ EPA, The Benefit and Costs of the Clean Air Act: 1970 to 1990 EPA Report to Congress, EPA-410-R-97-002, Oct. 1997 at Abstract.

unique reporting and monitoring system assures compliance with its emission limits or other pollution control requirements. Finally, the Title V permit allows enforcement by the public, the state, and the federal government.

Additionally, under Congressional requirements, EPA has established guidance for meeting the goals of the CAA. Relevant to this petition are the standards stated in Section 172, which require States with “nonattainment areas” (areas that have not achieved the national air quality standards set by the EPA) to revise the State Implementation Plans (SIPS) to require existing stationary sources in certain nonattainment areas to adopt, at a minimum, “reasonably available control technology” (RACT) to reduce emissions in furtherance of attainment goals. 42 USC §7502(c)(1). EPA has defined the RACT standard as “the lowest emission limitation that a particular source is capable of meeting by technological and economic feasibility.” 45 Fed. Reg. 59329 (Sept. 9, 1980). RACT is therefore implemented on a case-by-case basis based on consideration of particular site-specific circumstances including available technology and cost of implementation. Id. Although states have primary responsibility in determining RACT requirements, the state agency’s RACT analysis for a particular facility clearly must be reasonable for determining appropriate control technology. Therefore, EPA must also review state RACT decisions on a case-by-case basis to determine if the RACT permit provisions satisfy the CAA. Similar to the state agencies, EPA must review all relevant facts and circumstances for a particular case to make this determination. Furthermore, the state permitting agency must demonstrate to EPA that the permitting decision is based on adequate documentation of all relevant technological and economic circumstances for the particular permit applicant.⁵

⁵ Wooley, David R. and Elizabeth M. Morss, Air Act Handbook: A Practical Guide to Compliance, 81-83, 12th Ed., West Publ. 2002.

II. PARTIES

Cargill's Gainesville Vegetable Oil Mill & Refinery (Cargill Gainesville) is a soybean oil extraction facility that extracts oil from soybeans through complicated food-processing technology. The facility includes mechanized operations for transporting, storing, cleaning, hulling, drying, cracking and flaking, and the application of chemicals. One chemical applied to the beans is hexane, which is highly toxic but efficient for extracting the oil from the processed beans. The oil is also processed through bleaching, deodorizing, hydrogenation and blending operations.

The facility uses a coal-fired boiler to generate steam for its extraction process. The unit was installed at the facility over twenty years ago and has only had minor updates and minimal (if any) emissions testing since that time. Georgia EPD's Air Protection Branch has estimated NOx emissions to be about 92 tons or 0.6 tons per day (based on 85% capacity factor). Under Title V of the CAA, Cargill's facility is considered a "major source" of the following emissions: PM, PM-10, SO₂, VOCs, NOx, CO, and HAPs.

Petitioners, Sierra Club, Georgia Forestwatch, and Newtown Florist Club represent a combined membership of more than 15,000 Georgia residents.

The Sierra Club, a non-profit corporation, is one of the nation's oldest and largest environmental organizations. The Sierra Club has been involved in air pollution issues in Georgia as well as throughout the nation. The Georgia Chapter of the Sierra Club has over 14,000 members alone. Sierra Club's members live, work, farm, recreate, grow food, own land and structures, and obtain spiritual and aesthetic enjoyment from locations that are directly and adversely affected by air pollution from the Cargill facility. In addition, the Sierra Club requires Title V monitoring information to conduct air clean-up work in Georgia.

Georgia Forestwatch is a non-profit organization of Georgia citizens interested in the protection and restoration of public lands in Georgia's Piedmont and Mountain regions. Georgia Forestwatch members live, work, farm, recreate, grow food, own land and structures, and obtain spiritual and aesthetic pleasure from locations in north and north-central Georgia that are directly and adversely affected by air pollution from the Cargill facility.

Directly juxtaposed with Cargill's processing plant is the Newtown Florist Club, a local community group whose membership consists of Gainesville residents. The Newtown Section of Gainesville was started when a tornado destroyed large portions of Gainesville in the 1930s. The City placed most of the debris in a landfill and built homes on top of the landfill which were advertised as dwellings "for colored purchasers" who had been dislocated because of the tornado. At the same time, the City encouraged heavy industry to move in right next door. Now, this community, which literally sits in the shadows of the Cargill Facility as well as several other heavy industries, has unexplained rates of throat and mouth cancers, excessive cases of immune-system lupus, and a variety of respiratory ailments.

The Newtown Florist Club started collecting money to buy flowers for families as they buried their dead; their mission quickly expanded to helping care and comfort those families. As the community faced the challenges of living in such close proximity to heavy industry, including releases of hazardous chemicals that have led to evacuations, noxious odors, and accumulation of waste and debris, the Newtown Florist Club now works to improve the community and protect citizens from the health and environmental impacts of the surrounding industrial facilities. The organization has members that live only a short distance from Cargill's smokestack.

III. PROCEDURAL HISTORY

EPA approved and federalized the State of Georgia's Title V Operating Permit Program under the CAA. The Environmental Protection Division (Georgia EPD) of the Georgia Department of Natural Resources is the authorized state agency responsible for issuing Title V Operating Permits in Georgia. O.C.G.A. §§12-9-3(12), 12-9-4, 12-9-6(b)(3).

On March 21, 2002, Cargill's Gainesville Vegetable Oil Mill and Refinery applied to amend its Title V/Part 70 Permit to comply with Georgia State Rules 391-3-1-.02(2)(tt) and (yy), which became effective on May 1, 2003. A VOC and NOx RACT standard now applies to sources having more than one ton/year of VOC or NOx emissions. Additionally, a NOx RACT standard is required for coal-fired boiler NOx emissions. Cargill's amendment application, No. TV-13727, was initiated by Georgia EPD to incorporate the VOC and NOx RACT permit conditions as required.

A draft Permit Amendment, No. 2075-139-0002-V-01-1, was issued for consideration on December 12, 2002. Georgia EPD accepted written comments and held a public hearing on the amendment. The Georgia Center for Law in the Public Interest (Georgia Center) submitted written and oral comments on behalf of Petitioners, Newtown Florist Club, Sierra Club, and Georgia ForestWatch. Ms. Faye Bush, president of the Newtown Florist Club, Ms. Belinda Dickey, Newtown resident, and Brent Martin, Executive Vice-president of Forestwatch also made comments. Georgia EPD submitted a proposed permit to EPA for review pursuant to Section 505(b), 42 USC §7661(b). EPA did not publish any written objection prior to the expiration of the statutory deadline on August 4, 2003. Pursuant to Section 505(c), the Georgia Center for Law in the Public Interest, on behalf of Newtown Florist Club, petitions the EPA to object to the proposed permit for the following reasons. All arguments stated in this petition are

based on issues and objections raised to Georgia EPD during the state public comment period. The last day within the sixty day period for submitting petitions to the EPA is October 3, 2003, and pursuant to EPA's policy, this petition has been timely submitted with a US Mail postmark of October 3, 2003.

IV. SUMMARY OF THE ARGUMENT

1. Under the Reasonably Available Control Technology (RACT) standard, the NO_x limit for Cargill's coal-fired boiler should be lower than the permit emission limit of 0.41lb/MMBtu. Cost-effective technology, such as selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR), should be required to meet RACT requirements and a lower permit emission limit.

2. The "Annual Tune-ups" requirements contained in Condition 3.4.10 is insufficient under a RACT standard.

3. The narrative section of the permit is insufficient because it does not provide a complete factual and legal basis for the permit conditions.

4. The permit has insufficient monitoring and reporting requirements and therefore, has insufficient guarantees for assuring compliance under the CAA.

5. Permit condition 5.2.6.A must specify a load, or loads, at which testing is to occur.

V. ARGUMENT

A. STANDARD OF REVIEW

The CAA contains an important component to facilitate the protection of our air: the Title V Operating Permit Program. The Title V permit program was designed to ease the compliance monitoring of the permit holder by both regulatory agencies and concerned citizens.

See generally S. Rep. No. 101-228 at 346-47; *see also* In re: Roosevelt Regional Landfill, EPA Administrator, May 11, 1999) at 64 FR 25336.

EPA has determined that it will object to any permit submitted for review by a state or local air quality permitting authority if that permit is not in compliance with any applicable requirement of the CAA or under 40 CFR Part 70. *See* CFR § 70.8(c). However, if the EPA does not object, then “any person may petition the Administrator within 60 Days after the expiration of the Administrator’s 45-day review period. 40 CFR § 70.8(d). A petitioner must demonstrate that the permit is not in compliance with an applicable requirement of the CAA, including requirements of Part 70. 40 CFR 70.8(d) and In re: PacifiCorp’s Jim Bridger and Naughton Plants, VIII-00-1 (EPA Administrator Nov. 16, 2000) at 4.

As stated above, states have primary responsibility in RACT determinations and use a case-by-case approach in evaluating the appropriate RACT requirements for a particular facility. The case-by-case evaluation includes consideration of specific circumstances, including technical and economic feasibility, for the particular facility. However, the state agency’s RACT evaluation and determination of appropriate control must be reasonable.

EPA must similarly review Georgia EPD’s RACT decisions on a case-by-case basis to determine if the RACT determinations and permit conditions satisfy the CAA. Similar to the state agencies, EPA must review all relevant facts and circumstances for a particular case to make this determination. Furthermore, the state permitting agency must demonstrate to EPA that the permitting decision is based on adequate documentation of all relevant technological and economic circumstances for the particular permit applicant. If EPA determines that the state failed to properly consider all relevant information, or if that information is not adequate or not

accurate, then EPA must object to the permit either on its own initiative or in response to a petition.

B. THE FACILITY'S PERMIT IS NOT IN COMPLIANCE WITH THE FOLLOWING APPLICABLE REQUIREMENTS OF THE CLEAN AIR ACT:

1. UNDER REASONABLY AVAILABLE CONTROL TECHNOLOGY (RACT) REQUIREMENTS, THE NO_x LIMIT FOR CARGILL'S COAL-FIRED BOILER SHOULD BE LOWER THAN 0.41 lb//MMBtu. COST-EFFECTIVE TECHNOLOGY, SUCH AS SCR OR SNCR, SHOULD BE REQUIRED TO MEET RACT STANDARDS AND TO MEET A LOWER PERMIT LIMIT.

Georgia EPD's proposed permit conditions are based on its determination that SCR is not cost-effective and is therefore, not appropriate under a RACT standard. Georgia EPD based its determination on the cost analysis data submitted by Cargill and Trinity Consultants (Cargill's Consultant). However, the Cargill-Trinity analysis was based on inaccurate baseline data. The Cargill-Trinity analysis is, therefore, inaccurate and should not even be considered in a RACT determination.

Georgia EPD initially seriously considered and encouraged SCR as an appropriate RACT standard/requirement for the Cargill facility. In its initial analysis (see Ronald Methier's letter to Mike Dobeck, April 8, 2002), Georgia EPD calculated a cost-effectiveness NO_x estimate of \$4,937/ton for SCR. Based on this estimate, Georgia EPD determined that SCR was "cost effective for purposes of NO_x RACT." Similarly, on February, 5, 2002, James Capp, Georgia EPD, informed Cargill "that EPD considered SCR to be technically feasible and that [Georgia EPD] believed it would be cost effective for reducing NO_x emissions on the [Cargill] coal-fired boiler." (See April 4, 2002, Memorandum from James Capp to Jimmy Johnson, Georgia EPD). Capp further recommended sending Cargill notification that EPD was "proceeding to amend their permit to require the implementation of SCR control to reduce NO_x emissions to 0.08

lb/mmBtu and that they should plan accordingly.” Georgia EPD has previously found that cost-estimates in this range justify a finding that SCR is appropriate under a RACT analysis.

However, Georgia EPD later changed its cost-effectiveness estimate solely based on the additional data submitted by Cargill-Trinity during the permit amendment hearing process. In the Title V Significant Modification Application Review Narrative, Georgia EPD clearly stated that it had revised its cost-effectiveness evaluation to match the cost estimates submitted by Cargill on July 17, 2002. EPD further stated, “Based on this analysis, EPD determined that SCR ... should not be required as NO_x RACT.”

At Petitioner’s request, an independent consultant, Bill Powers, has reviewed the Cargill-Trinity figures. Bill Powers is a registered professional engineer with over 20 years of experience testing and permitting combustion systems (See attached resume and report). Powers determined that the Trinity analysis was flawed because it is based exhaust flow rates from a CEMEX, Inc. kiln instead of the Cargill boiler. The kiln’s flowrate, which was used in the Cargill-Trinity analysis, is not representative of the exhaust flowrate of the Cargill boiler. In fact, the kiln’s flowrate is at least double the flowrate of the Cargill boiler. Cargill-Trinity’s figures also overstate exhaust gas temperature. The cost estimates for pollution control equipment are based on Cargill-Trinity’s incorrect flowrate, temperature, and related exhaust figures. This faulty analysis has resulted in an overstatement of cost estimates for pollution control equipment. As reported by Powers, the cost effectiveness of both SCR and SNCR for Cargill’s Gainesville boiler is below the figures used by Georgia EPD in its initial conclusion that SCR was appropriate for the Cargill Gainesville facility. Therefore, Permit Amendment conditions must be revised to include either SCR or SNCR pollution control technology consistent with the accurate cost-estimates provided by Bill Powers in his attached analysis.

2. THE "ANNUAL TUNE-UPS" REQUIREMENT IN CONDITION 3.4.10 IS INSUFFICIENT UNDER RACT

In consideration of the above information, Georgia EPD's determination that an annual tune-up for NOx emissions from Cargill's units, B002, HPB1, HPB2, HRO1 and L11A, is clearly not sufficient under the CAA's RACT requirements. The use of low NOx burners on these emission units would result in cost-effective emission reductions and is more appropriate for meeting RACT requirements. A condition that these units only use natural gas with propane as a back up and additionally controls, particularly combustion technologies, should be considered. Such technology was not considered for the RACT determination.

3. THE NARRATIVE DOES NOT PROVIDE A COMPLETE FACTUAL AND LEGAL BASIS FOR THE PERMIT CONDITIONS.

Narratives are an essential component of the permitting process. The narrative section(s) of the permit must include a complete discussion of all factual and legal issues that were considered by Georgia EPD in deciding all Permit conditions. This requirement is particularly important in a RACT determination because the RACT regulatory scheme and EPA's review each require a separate case-by-case review and determination. This permit narrative does not provide a complete discussion of the required factual and legal discussions.

The narrative also fails to explain in detailed discussion of all NOx monitoring techniques considered by Georgia EPD and its reasons for choosing the test method for gas fired boilers for B001, which is coal fired.

4. THE PERMIT HAS INSUFFICIENT MONITORING AND REPORTING REQUIREMENTS AND IS INADEQUATE FOR ASSURING COMPLIANCE FOR THE FOLLOWING REASONS:

a. THE MONITORING AND REPORTING REQUIREMENTS IN PERMIT CONDITION 2.2.5 DO NOT ASSURE COMPLIANCE WITH THE PERMIT CONDITIONS.

Conditions 2.2.5 and 5.2.7.d lack adequate monitoring requirements. Part 70 requires monitoring as a condition of the Title V permit. Under Part 70 and Title V, the public is entitled to review and comment on the monitoring during the permit review process. Consideration of the monitoring requirements.

b. THE PERMIT IS INADEQUATE UNDER THE CLEAN AIR ACT
BECAUSE THE PERMIT DOES NOT ADEQUATELY REQUIRE CARGILL
TO REPORT NO_x MONITORING RESULTS TO GEORGIA EPD.

Permit Condition 5.2.6.f does not require Cargill to report its NO_x monitoring results to the Georgia EPD. As presently written, Cargill is only required to keep its results on-site. As such, Cargill is permitted to hide its results from the public. A central goal behind the Title V Permit Program is increased public monitoring and enforcement. Since the CAA relies heavily on self-monitoring and self-reporting, public scrutiny is essential to effective enforcement. To meet the requirements of the CAA, Cargill's permit must include regular and open reporting of its emissions testing results. Furthermore, once "every six months" is so minimal that the reporting requirement is ineffective under the CAA. In particular, Cargill must report its deviations more frequently than once every six months to adequately fulfill the requirements of the CAA. The CAA provides for self-reporting and self-monitoring; it does not provide for self-regulation.

c. MANUFACTURING SPECIFICATIONS NEED TO BE AVAILABLE TO
THE PUBLIC.

Permit condition 5.2.7 is not practically enforceable because that condition fails to include manufacturers specifications. Implicitly stating that relying on manufacturers specifications that are not incorporated in the permit is not sufficient.⁶

⁶ See Consolidated Edison Co. of NY, Inc. 74th Street Station, II-2001-02 at 13.

d. THE CURRENT NO_x LIMIT FOR B001 LACKS ADEQUATE REQUIREMENTS FOR MONITORING AND REPORTING AND IS NOT ENFORCEABLE AS A PRACTICAL MATTER.

The stated NO_x RACT limit for B001 under Part 3.4.1.c. of Cargill's permit is not enforceable as a practical matter. The limit lacks adequate monitoring and reporting requirements and as stated, does not assure compliance through monitoring and reporting as required by the CAA. The permit does not contain any monitoring requirement that will assure B001 will be in compliance with the NO_x limit under all operating conditions. The permit must require CEMS monitoring for B001's NO_x emissions to adequately meet the regulatory and legal requirements under the CAA. Additionally, a standard must be included for operating the CEMS. The standards from 40 CFR Part 75 are most the most appropriate and should be incorporated into the permit as the required standard.

Under 40 CFR 70.6(a)(3)(iii)(A) and 42 U.S.C. §7661(c)(a), Georgia EPD must include a permit condition requiring Cargill to submit reports of any required monitoring at least every six months. Condition 6.1.4 only requires Cargill to report excess emissions, exceedances and/or excursions. These deviations are required under 40 CFR 70.6(a)(iii)(B). However, 40 CFR 70.6(a)(iii)(A) additionally requires Cargill to report all monitoring. Any other interpretation would render section 70.6(a)(iii)(A) meaningless.

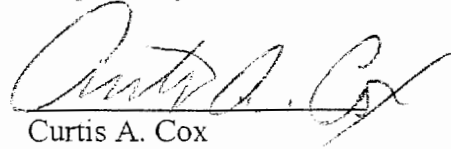
5. CONDITION 5.2.6.a. SHOULD SPECIFY A LOAD OR LOADS AT WHICH TESTING IS TO OCCUR.

Permit Condition 5.2.6.a. is not enforceable as a practical matter because it fails to adequately state or specify any mandatory operating conditions during Cargill's NO_x testing. As presently written, Cargill could even turn off the coal burner during NO_x testing. To be effective under the requirements of the CAA, Condition 5.2.6 must include a 100 percent load requirement for the coal burner during testing.

VI. CONCLUSION

For the reasons explained above and pursuant to 40 CFR § 70.8(d), the EPA should object to this permit and require the modifications explained above.

Respectfully Submitted,



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Counsel for Newtown Florist Club,
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Dated: October 2, 2003

CC: Faye Bush, Newtown Florist Club
Brent Martin, Georgia Forestwatch
Curt Smith, Sierra Club
Stan Kukier, US EPA Region 4
Georgia Environmental Protection Division
Cargill's Gainesville Vegetable Oil Mill & Refinery

**PETITION ATTACHMENT 1
POWERS ENGINEERING REPORT**

POWERS ENGINEERING

October 3, 2003

Curtis Cox , Staff Attorney
Georgia Center for Law in the Public Interest
175 Trinity Avenue SW
Atlanta, GA 30303

Subject: Proposed NO_x RACT for Stoker Coal Boiler at Cargill, Incorporated Gainesville, Georgia Facility

Dear Curtis:

As you requested in your letter dated September 20, 2003, I have reviewed the calculations prepared by Cargill to justify the company's position that good combustion practices alone meet NO_x RACT requirements for the Gainesville Plant boiler. It is my professional opinion that Cargill greatly overstates the NO_x control cost effectiveness of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) for the Gainesville boiler. I estimate a control cost effectiveness for SCR ranging from \$2,151/ton to \$4,410/ton, with equipment operation only during the ozone season. I also estimate a control cost effectiveness for SNCR ranging from \$1,345/ton to \$2,981/ton. These estimates are consistent with recent U.S. EPA estimates of SCR and SNCR control cost effectiveness on industrial coal-fired boilers. The NO_x cost effectiveness depends on the assumed NO_x emission rate, which varies markedly between the Application for Permit to Construct (1978), the Permit to Operate (1979), and recent calculations prepared by Trinity Consultants for Cargill, Inc. (2002). Both the SCR and SNCR cost effectiveness ranges are below the \$4,937/ton value described as "*cost effective for the purposes of NO_x RACT*" for the boiler in the April 8, 2002 letter from Ronald Methier of Georgia DNR to Plant Superintendent Mike Dobeck of Cargill's Gainesville Plant.

Background

Cargill asserts that the control cost effectiveness of all NO_x control options other than good combustion practices exceed applicable cost thresholds for NO_x RACT. The NO_x control cost effectiveness for all technically feasible NO_x control options was presented in two documents prepared for Cargill by Trinity Consultants. These documents are:

1. *Revised NO_x RACT Determination*, April 1, 2002 letter from Mr. Todd Cloud of Trinity Consultants to Mr. James Capp of Georgia DNR
2. *Second Revised NO_x RACT Determination*, July 17, 2002 letter from Mr. Todd Cloud of Trinity Consultants to Mr. James Capp of Georgia DNR

The Georgia DNR, in the April 8, 2002 letter cited above, calculated a NO_x cost effectiveness of \$4,937/ton for SCR and indicated that SCR would be considered RACT for the Gainesville Plant boiler. Trinity identifies a NO_x control cost effectiveness of \$13,421/ton for SCR in the July 17, 2002 letter. The purpose of the July 17, 2002 letter is to demonstrate why the Georgia DNR NO_x cost effectiveness value stated in the April 8, 2002 Georgia DNR letter is incorrect. Trinity goes

on to state in the July 17, 2002 letter that the “generally accepted” BACT cost threshold in EPA Region 4 is \$5,000/ton and that in Trinity’s experience the RACT cost threshold in the Atlanta non-attainment area does not exceed \$2,000/ton.

Trinity indicated in the April 1, 2002 letter that all available NO_x control options, including SCR, selective non-catalytic reduction (SNCR), natural gas conversion, natural gas reburn, and flue gas recirculation, have a control cost effectiveness greater than \$5,000/ton. Good combustion practices is identified by Trinity as NO_x RACT due to the apparent high cost of all other NO_x control options.

Documents Reviewed

I reviewed the following documents, in addition to the two Trinity letters cited above, in preparing this testimony:

1. February 21, 1978 Application for Permit to Construct (ATC) for a 145 MMBtu/hr Boiler at Cargill, Inc. Gainesville, GA Plant;
2. January 5, 1979 Permit to Construct (PTC) #2079-069-6098-C for 145 MMBtu/hr Boiler at Cargill, Inc. Gainesville, GA Plant;
3. December 1978, Final Determination of Permit to Construct Application for a 145 MMBtu/hr Boiler at Cargill, Inc. Gainesville, GA Plant;
4. February 5, 2002, letter regarding VOC and NO_x RACT Plans to Mike Dobeck, Cargill Plant Superintendent, from James Capp, Georgia DNR;
5. April 8, 2002, letter regarding NO_x RACT Plan for Coal-Fired Boiler to Mike Dobeck, Cargill Plant Superintendent, from Ronald Methier, Georgia DNR;
6. Selective Catalytic Reduction, Air Pollution Control Technology Fact Sheet – Industrial Boiler Applications, U.S. EPA, EPA-452/F-03-032;
7. Selective Non-Catalytic Reduction, Air Pollution Control Technology Fact Sheet, U.S. EPA, EPA-452/F-03-031;
8. October 2, 2003 quote received from Nathan White of Haldor Topsoe for retrofit SCR on 146 MMBtu/hr Cargill Gainesville boiler;
9. September 23, 2003 quote received from Akira Hattori of Mitsubishi Heavy Industries America for retrofit SCR on 146 MMBtu/hr Cargill Gainesville boiler;
10. October 2, 2003 clarification received from Nathan White of Haldor Topsoe regarding guaranteed catalyst life for retrofit SCR on 146 MMBtu/hr Cargill Gainesville boiler;
11. October 2, 2003 quote received from Dale Pfaff of Fuel Tech for retrofit SNCR on 146 MMBtu/hr Cargill Gainesville boiler;
12. September 26, 2003 e-mail from D. Jackson of Detroit Stoker regarding rating of Cargill Gainesville boiler. Detroit Stoker records indicated heat input rating of 146 MMBtu/hr.

Deficiencies in the Trinity Analysis

NO_x emission rate – Trinity assumes a generic EPA AP-42 NO_x emission factor of 0.41 lb/MMBtu (AP-42, September 1998, Table 1.1-3) is representative of the Cargill boiler. The 1978 ATC states a potential to emit of 0.83 lb/MMBtu. The 1979 PTC states an estimated actual NO_x emission rate of 0.535 lb/MMBtu. All three of these emission rates were used to develop the range of NO_x cost effectiveness values calculated for SCR and SNCR in this declaration.

The only reliable method for determining which of the three NO_x emission rates used for the Cargill boiler is representative of boiler operations during the summer ozone season is continuous NO_x emissions testing over a representative period of time. A representative period of time would be a minimum of one to two weeks. A single “snapshot” source test would be inadequate, as the boiler could be tuned for a few hours of testing to present a NO_x profile that is considerably cleaner than that achieved during typical operation over time.

Boiler exhaust flowrate and temperature – Trinity includes source test results for a CEMEX, Inc. (Southdown, Inc.) kiln as the last page of the July 17, 2002 letter. The kiln source test is not referenced in the body of the letter. However, the SCR quote provided by Peerless Manufacturing Company (PMC) and provided in the July 17, 2002 letter is based on the exhaust flow and stack temperature measured during the kiln source test. The kiln exhaust flow is at least double the exhaust flow of the Cargill boiler. The Cargill boiler exhaust gas flow can readily be calculated by multiplying the rated heat input of 145 MMBtu/hr by the f-factor (9,820 dscf/MMBtu) and adjusting for the design excess air level (20 percent, as noted in 1978 ATC). The kiln exhaust gas temperature of 460 °F is much lower than the actual temperature range of 700 to 800 °F that can typically be expected between the boiler outlet and the economizer (proposed SCR location). There is no need for the exhaust gas reheat system proposed by PMC for the SCR, as the reheat system presumes that the kiln stack temperature is representative of the boiler exhaust gas upstream of the economizer. Sizing the NO_x control equipment, either SCR or SNCR, to the correct exhaust gas flowrate dramatically reduces the cost of the control system.

Cost estimation procedure: The SCR and SNCR cost calculation spreadsheets are provided in Attachment A. The cost estimation procedure utilized is identical to the procedure used by Trinity Consultants in the April 1, 2002 and July 17, 2002 letters to Georgia DNR. The SCR and SNCR cost quotes that serve as the basis for the NO_x cost effectiveness estimates, received from Haldor Topsoe, Mitsubishi Heavy Industries America, and Fuel Tech, are provided in Attachment B. It is important to note that the Haldor Topsoe quote includes installation. However, the installation component was not broken out and for this reason the Haldor Topsoe quote is treated as a “purchased equipment cost” quote only. This results in a very conservative total cost estimate, as approximately \$700,000 in additional installation and contingency costs are added to the Haldor Topsoe quote in the factored U.S. EPA cost estimation methodology utilized.

U.S. EPA 2003 air pollution control technology fact sheets on SCR and SNCR, which include expected NO_x control cost effectiveness ranges for each control technology, are provided in

Mr. Curtis Cox
October 3, 2003
Page 4 of 4

Attachment C. The SCR control cost effectiveness range identified by the EPA in the SCR fact sheet for industrial coal boilers, \$2,000/ton to \$5,000/ton, bands the cost range of \$2,151/ton to \$4,410/ton calculated in this declaration for the Cargill boiler. The SNCR control cost effectiveness range identified in the EPA's SNCR fact sheet for seasonal control on industrial coal boilers, \$2,000/ton to \$3,000/ton, is very similar to the cost range of \$1,345/ton to \$2,981/ton calculated in this declaration.

Equipment life: Haldor Topsoe guarantees the catalyst for six ozone seasons. For this reason, catalyst life is assumed to be six (6) years. It is standard OAQPS cost estimation procedure to assume an equipment life of twenty (20) years for SCR and SNCR control systems. EPA has assigned a 20-year SCR and SNCR equipment life for control cost estimation purposes specifically to avoid individual applicants from assigning very limited equipment life estimates that drive up the annualized cost of the control equipment. Please refer to <http://www.epa.gov/ttn/catc/cica/cicaeng.html#cccinfo>, Section 4, Chapters 1 and 2, to corroborate the SCR and SNCR equipment life assigned by EPA in the Air Pollution Control Cost Manual (6th Edition).

Summary

The Trinity analyses of the NO_x control cost effectiveness of SCR and SNCR on the Cargill Gainesville boiler are flawed. The NO_x control cost effectiveness of SCR ranges from \$2,151/ton to \$4,410/ton. The NO_x control cost effectiveness of SNCR ranges from \$1,345/ton to \$2,981/ton. The control cost effectiveness ranges calculated for SCR and SNCR in this application are consistent with U.S. EPA cost estimates for industrial coal-fired boilers. The calculated SCR and SNCR cost effectiveness ranges are below the \$4,937/ton value described as "cost effective for the purposes of NO_x RACT" for the boiler in the April 8, 2002 letter from Ronald Methier of Georgia DNR to Plant Superintendent Mike Dobeck of Cargill's Gainesville Plant.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Bill Powers, P.E.
Bill Powers, P.E.

Oct 3, 2003
Dated

Attachment A

SCR and SNCR Cost Effectiveness Calculations

A-1a. SCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 1978 ATC NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment (without catalyst cost):		1,427,000	HT
Instrumentation: NO _x CEM system		150,000	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		75,000	Trinity
DC Total:	A	1,652,000	
Indirect Costs (IC):			
General facilities:	0.05 A	82,600	OAQPS
Engineering fees:	0.10 A	165,200	OAQPS
Process contingency:	0.05 A	82,600	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	330,400	OAQPS
Project Contingency:	C = 0.15 (A+B)	297,360	OAQPS
Total Plant Cost (TPC):	D = A+B+C	2,279,760	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	45,595	OAQPS
Inventory capital: (two weeks supply of reagent)	H	6,451	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	52,046	OAQPS
Total Capital Investment (TCI = TPC + OC), excluding catalyst cost:		2,331,806	
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator: hr/yr:	459 operator pay (\$/hr) 25	11,475	OAQPS
Supervisor: 15% of operator		1,721	OAQPS
Maintenance (M): Labor/materia 1.5% of TCI		34,977	OAQPS
Reagent use rate:	192 lb/hr		PMC
Reagent cost:	0.1 \$/lb		PMC
Hours per year usage:	3,672 (153 days)		Trinity
Reagent annual cost (\$):		70,502	
Electric air heater:	75 kw		PMC
Dilution air blowers:	5.6 kw		PMC
Compressor motor:	3.7 kw		PMC
Electricity costs (\$): @ 0.06 \$/kwh		18,573	
Gas Costs: (temperature between boiler and economizer > 600 °F)		0	
Catalyst requirement:	368 (10.42 m3)		HT
Unit catalyst cost:	198 \$/ft3		HT
Total catalyst cost (\$):	72,864		HT
Future Worth Factor (FWF): 0.1398 6 years, 7% interest			HT
Total annual catalyst cost:		10,186	
Capital Recovery (CR) interest rate (%): 7			
period (years): 20	0.09 TCI	220,106	OAQPS
Total Annual Cost (DAC + CR):		\$367,541	
Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.83 lb/MMBtu	2/21/78 ATC application	
Capacity factor during ozone season:	0.85		
Base case emission rate:	103.0		
SCR emission rate:	0.08 lb/MMBtu		
SCR emission rate:	9.9		
Ozone season:	153 days		
Total NO _x controlled:	170.9 tons		
NO_x Cost Effectiveness (\$/ton):		\$2,151	

HT = Haldor Topsoe October 1, 2003 SCR bid and October 2, 2003 catalyst life clarification

PMC = Peerless Manufacturing Company

Trinity = July 17, 2002 letter to Mr. James Capp, Second Revised NO_x RACT Determination

A-1b. SCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 1979 PTO NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment (without catalyst cost):		1,427,000	HT
Instrumentation: NO _x CEM system		150,000	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		75,000	Trinity
DC Total:	A	1,652,000	
Indirect Costs (IC):			
General facilities:	0.05 A	82,600	OAQPS
Engineering fees:	0.10 A	165,200	OAQPS
Process contingency:	0.05 A	82,600	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	330,400	OAQPS
Project Contingency:	C = 0.15 (A+B)	297,360	OAQPS
Total Plant Cost (TPC):	D = A+B+C	2,279,760	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	45,595	OAQPS
Inventory capital: (two weeks supply of reagent)	H	4,166	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	49,762	OAQPS
Total Capital Investment (TCI = TPC + OC), excluding catalyst cost:		2,329,522	
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator: hr/yr:	459 operator pay (\$/hr) 25	11,475	OAQPS
Supervisor: 15% of operator		1,721	OAQPS
Maintenance (M): Labor/materials 1.5% of TCI		34,943	OAQPS
Reagent use rate:	124 lb/hr		PMC
Reagent cost:	0.1 \$/lb		PMC
Hours per year usage:	3,672 (153 days)		Trinity
Reagent annual cost (\$):		45,533	
Electric air heater:	75 kw		PMC
Dilution air blowers:	5.6 kw		PMC
Compressor motor:	3.7 kw		PMC
Electricity costs (\$): @ 0.06 \$/kwh		18,573	
Gas Costs: (temperature between boiler and economizer > 600 °F)		0	
Catalyst requirement:	368 (10.42 m ³)		HT
Unit catalyst cost:	198 \$/ft ³		HT
Total catalyst cost (\$):	72,864		HT
Future Worth Factor (FWF):	0.1398 6 years, 7% interest		HT
Total annual catalyst cost:		10,186	
Capital Recovery (CR) interest rate (%):	7		
period (years):	20	0.09 TCI	219,890
Total Annual Cost (DAC + CR):		\$342,322	OAQPS
Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.535 lb/MMBtu	1/5/79 PTO final determination	
Capacity factor during ozone season:	0.85		
Base case emission rate:	66.4		
SCR emission rate:	0.08 lb/MMBtu		
SCR emission rate:	9.9		
Ozone season:	153 days		
Total NO _x controlled:	103.7 tons		
NO_x Cost Effectiveness (\$/ton):		\$3,302	

HT = Haldor Topsoe October 1, 2003 SCR bid and October 2, 2003 catalyst life clarification
 PMC = Peerless Manufacturing Company
 Trinity = July 17, 2002 letter to Mr. James Capp, Second Revised NO_x RACT Determination

A-1c. SCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 2002 Trinity NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment (without catalyst cost):		1,427,000	HT
Instrumentation: NO _x CEM system		150,000	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		75,000	Trinity
DC Total:	A	1,652,000	
Indirect Costs (IC):			
General facilities:	0.05 A	82,600	OAQPS
Engineering fees:	0.10 A	165,200	OAQPS
Process contingency:	0.05 A	82,600	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	330,400	OAQPS
Project Contingency:	C = 0.15 (A+B)	297,360	OAQPS
Total Plant Cost (TPC):	D = A+B+C	2,279,760	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	45,595	OAQPS
Inventory capital: (two weeks supply of reagent)	H	3,192	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	48,787	OAQPS
Total Capital Investment (TCI = TPC + OC), excluding catalyst cost:		2,328,547	
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator: hr/yr:	459 operator pay (\$/hr) 25	11,475	OAQPS
Supervisor: 15% of operator		1,721	OAQPS
Maintenance (M): Labor/material 1.5% of TCI		34,928	OAQPS
Reagent use rate:	95 lb/hr		PMC
Reagent cost:	0.1 \$/lb		PMC
Hours per year usage:	3,672 (153 days)		Trinity
Reagent annual cost (\$):		34,884	
Electric air heater:	75 kw		PMC
Dilution air blowers:	5.6 kw		PMC
Compressor motor:	3.7 kw		PMC
Electricity costs (\$): @ 0.06 \$/kwh		18,573	
Gas Costs: (temperature between boiler and economizer > 600 °F)		0	
Catalyst requirement:	368 (10.42 m3)		HT
Unit catalyst cost:	198 \$/ft3		HT
Total catalyst cost (\$):	72,864		HT
Future Worth Factor (FWF): 0.1398 6 years, 7% interest			HT
Total annual catalyst cost:		10,186	
Capital Recovery (CR) interest rate (%): 7			
period (years): 20	0.09 TCI	219,798	OAQPS
Total Annual Cost (DAC + CR):		\$331,566	

Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.41 lb/MMBtu	2002 Trinity NO _x EF	
Capacity factor during ozone season:	0.85		
Base case emission rate:	50.9		
SCR emission rate:	0.08 lb/MMBtu		
SCR emission rate:	9.9		
Ozone season:	153 days		
Total NO _x controlled:	75.2 tons		
NO_x Cost Effectiveness (\$/ton):		\$4,410	

HT = Haldor Topsoe October 1, 2003 SCR bid and October 2, 2003 catalyst life clarification

PMC = Peerless Manufacturing Company

Trinity = July 17, 2002 letter to Mr. James Capp, Second Revised NO_x RACT Determination

A-2a. SNCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 1978 ATC NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment:		508,000	Fuel Tech
Instrumentation: NO _x CEM system		0	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		0	PE
DC Total:	A	508,000	
Indirect Costs (IC):			
General facilities:	0.05 A	25,400	OAQPS
Engineering fees:	0.10 A	50,800	OAQPS
Process contingency:	0.05 A	25,400	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	101,600	OAQPS
Project Contingency:	C = 0.15 (A+B)	91,440	OAQPS
Total Plant Cost (TPC):	D = A+B+C	701,040	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	14,021	OAQPS
Inventory capital: (two weeks supply of reagent)	H	2,833	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	16,854	OAQPS
Total Capital Investment (TCI = TPC + OC):			717,894
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator: hr/yr:	459 operator pay (\$/hr) 25	11,475	Trinity
Supervisor: 15% of operator		1,721	OAQPS
Maintenance (M): Labor/material 1.5% of TCI		10,768	OAQPS
Reagent use rate:	9.9 gal/hr		Trinity
Reagent cost:	0.85 \$/gal		Trinity
Hours per year usage:	3,672 (153 days)		Trinity
Reagent annual cost (\$):		30,961	
Electric pump:	4.4 kw		Trinity
Electricity costs (\$): @ 0.06 \$/kwh		969	Trinity
Coal costs (\$):		3,563	Trinity
Capital Recovery (CR) interest rate (%):	7		
period (years):	20	0.09 TCI	67,764
Total Annual Cost (DAC + CR):			\$127,222

Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.83 lb/MMBtu	2/21/78 ATC application	
Capacity factor during ozone season:	0.85		
Base case emission rate:	103.0 lb/hr		
SNCR outlet emission rate:	0.415 lb/MMBtu	0.50 reduction	
SNCR outlet emission rate:	51.5 lb/hr		
Ozone season:	153 days		
Total NO _x controlled:	94.6 tons		
NO_x Cost Effectiveness (\$/ton):			\$1,345

Fuel Tech = October 2, 2003 SNCR quote for Cargill Gainesville boiler

[D. Pfaff of Fuel Tech estimates 40% to 50% NO_x removal, 50% assumed for high NO_x EF case of 0.83 lb/MMBtu.]

PE = Powers Engineering

PMC = Peerless Manufacturing Company

Trinity = April 1, 2002 letter to Mr. James Capp, Revised NO_x RACT Determination

A-2b. SNCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 1979 PTO NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment:		508,000	Fuel Tech
Instrumentation: NO _x CEM system		0	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		0	PE
DC Total:	A	508,000	
Indirect Costs (IC):			
General facilities:	0.05 A	25,400	OAQPS
Engineering fees:	0.10 A	50,800	OAQPS
Process contingency:	0.05 A	25,400	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	101,600	OAQPS
Project Contingency:	C = 0.15 (A+B)	91,440	OAQPS
Total Plant Cost (TPC):	D = A+B+C	701,040	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	14,021	OAQPS
Inventory capital: (two weeks supply of reagent)	H	1,826	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	15,847	OAQPS
Total Capital Investment (TCI = TPC + OC):		716,887	
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator: hr/yr: 459 operator pay (\$/hr) 25		11,475	Trinity
Supervisor: 15% of operator		1,721	OAQPS
Maintenance (M): Labor/material 1.5% of TCI		10,753	OAQPS
Reagent use rate: 6.4 gal/hr			Trinity
Reagent cost: 0.85 \$/gal			Trinity
Hours per year usage: 3,672 (153 days)			Trinity
Reagent annual cost (\$):		19,957	
Electric pump: 4.4 kw			Trinity
Electricity costs (\$): @ 0.06 \$/kwh		969	Trinity
Coal costs (\$):		3,563	Trinity
Capital Recovery (CR) interest rate (%): 7			
period (years): 20	0.09 TCI	67,669	OAQPS
Total Annual Cost (DAC + CR):		\$116,108	

Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.535 lb/MMBtu	1/5/79 PTO NO _x EF	
Capacity factor during ozone season:	0.85		
Base case emission rate:	66.4 lb/hr		
SNCR outlet emission rate:	0.321 lb/MMBtu	0.40 reduction	
SNCR outlet emission rate:	39.8 lb/hr		
Ozone season:	153 days		
Total NO _x controlled:	48.8 tons		
NO_x Cost Effectiveness (\$/ton):		\$2,381	

Fuel Tech = October 2, 2003 SNCR quote for Cargill Gainesville boiler

PE = Powers Engineering

PMC = Peerless Manufacturing Company

Trinity = April 1, 2002 letter to Mr. James Capp, Revised NO_x RACT Determination

A-2c. SNCR on 146 MMBtu/hr Cargill Gainesville Stoker Boiler - 2002 Trinity NO_x EF

Description of Cost	Cost Factor	Cost (\$)	Source
Direct Capital Costs (DC):			
Equipment:		508,000	Fuel Tech
Instrumentation: NO _x CEM system		0	Trinity
Sales taxes:		0	Trinity
Freight:		0	Trinity
Additional structural modifications:		0	Trinity
DC Total:	A	508,000	
Indirect Costs (IC):			
General facilities:	0.05 A	25,400	OAQPS
Engineering fees:	0.10 A	50,800	OAQPS
Process contingency:	0.05 A	25,400	OAQPS
Total Indirect Installation Costs:	B = 0.20 A	101,600	OAQPS
Project Contingency:	C = 0.15 (A+B)	91,440	OAQPS
Total Plant Cost (TPC):	D = A+B+C	701,040	
Other Costs (OC):			
Fund construction allowance:	E	0	OAQPS
Royalty allowance:	F	0	OAQPS
Preproduction cost:	G = 0.02 (D+E)	14,021	OAQPS
Inventory capital: (two weeks supply of reagent)	H	1,399	OAQPS
Initial capital and chemicals:	I	0	OAQPS
Total Other Costs (OC):	J = E+F+G+H+I	15,420	OAQPS
Total Capital Investment (TCI = TPC + OC):		716,460	
Direct Annual Costs (DAC):			
Operating Costs (O):			
Operator:	hr/yr: 459 operator pay (\$/hr) 25	11,475	Trinity
Supervisor:	15% of operator	1,721	OAQPS
Maintenance (M):	Labor/material 1.5% of TCI	10,747	OAQPS
Reagent use rate:	4.9 gal/hr		Trinity
Reagent cost:	0.85 \$/gal		Trinity
Hours per year usage:	3,672 (153 days)		Trinity
Reagent annual cost (\$):		15,294	
Electric pump:	4.4 kw		Trinity
Electricity costs (\$): @ 0.06 \$/kwh		969	Trinity
Coal costs (\$):		3,563	Trinity
Capital Recovery (CR):			
Interest rate (%):	7		
period (years):	20	0.09 TCI	67,629
Total Annual Cost (DAC + CR):		\$111,398	OAQPS

Cost Effectiveness Calculations:			
Rated boiler heat input:	146 MMBtu/hr		
Base case emission rate:	0.41 lb/MMBtu	2002 Trinity NO _x EF	
Capacity factor during ozone season:	0.85		
Base case emission rate:	50.9 lb/hr		
SNCR outlet emission rate:	0.246 lb/MMBtu	0.40 reduction	
SNCR outlet emission rate:	30.5 lb/hr		
Ozone season:	153 days		
Total NO _x controlled:	37.4 tons		
NO_x Cost Effectiveness (\$/ton):		\$2,981	

Fuel Tech = October 2, 2003 SNCR quote for Cargill Gainesville boiler

PE = Powers Engineering PMC = Peerless Manufacturing Company

Trinity = April 1, 2002 letter to Mr. James Capp, Revised NO_x RACT Determination

Attachment B

Vendor Cost Estimates

Hello Bill,

The required catalyst volume for your reduction requested is 10.42 m³ with a two layer design.

Below, is the approximate cost of the system:

- Catalyst cost, supplied by Topsoe \$ 72,900.
- Flow Modeling, supplied by Topsoe = \$ 50,000.
- Mixer / AIG, supplied by Topsoe = \$ 20,000.
- Engineering (Design review), supplied by Topsoe = \$ 50,000.
- SCR materials, erection, fabrication, Ammonia Storage & Delivery, remainder of system = \$ 1,307,100.

Total Cost of Project \$ 1,500,000.

Please, give me a call if you would like to discuss the estimate.

Regards,

Nathan

Haldor Topsoe, Inc.

tnw@topsoe.com -----Original Message-----

From: Bill Powers [mailto:bpowers@powersengineering.com]

Sent: Thursday, September 25, 2003 11:46 PM

To: Nate White

Cc: Bill Powers

Subject: Cargill Gainesville, GA 145 MMBtu/hr stoker boiler

Hello Nate,

Thank you for the return call yesterday regarding the 145 MMBtu/hr Cargill stoker (coal) boiler in Georgia. Rated exhaust flow for the boiler is 34,000 dscfm (at 6% O₂). At 700 oF, the mean temperature I would expect upstream of the economizer, the exhaust flow would be 68,000 acfm. Estimated NO_x in to the SCR is 0.41 lb/MMBtu. The target NO_x outlet emission rate is 0.08 lb/MMBtu. Ammonia slip limit would be 10 ppm.

The SCR would only operate during the 5-month ozone season, so I agree the SCR would need to be constructed in a way that would allow isolation of the unit (to protect catalyst) for the other 7 months of the year.

You mentioned the installed SCR cost would probably be in the range of \$750,000 to \$1,000,000. I do not need a formal quote for the SCR, though if you could confirm the \$750,000 to \$1,000,000 range looks about right I would be grateful. It would also be helpful to know the approximate catalyst volume and catalyst replacement cost so I can estimate the annualized cost of the system with some accuracy.

Best regards,

Bill Powers, P.E.

Powers Engineering

4452 Park Blvd., Suite 209

San Diego, CA 92116

tel: 619-295-2072

fax: 619-295-2073

The only power plants going to a 40,000 hour catalyst guarantees are NG, Oil or low-dust units. The longest high-dust coal fired catalyst guarantee in the US is 24,000 hours. I have designed this project for a 24,000 hours operation or 6 ozone seasons.

Regards,

Nathan

Haldor Topsoe, Inc.

tnw@topsoe.com

-----Original Message-----

From: Bill Powers [mailto:bpowers@powersengineering.com]

Sent: Thursday, October 02, 2003 12:06 PM

To: Nathan White

Subject: 40,000 hr guarantee Re: Cargill Gainesville, GA 145 MMBtu/hr stoker boiler

Hello Nate,

Thank you for the timely information, I am putting together my report today. One question - I've read a couple of reports where powerplants have gone with 40,000 hr guarantees on the SCR catalyst. Is that an option here? If so, what would be the additional catalyst volume and system cost for a 40,000 hr guarantee? What would be the time limit on such a guarantee, considering the SCR would be isolated from exhaust gas flow for at least 7 months of the year?

Regards,

Bill Powers

Dear Bill:

Here is a quick summary of our proposed NOxOUT SNCR system for the Cargill Stoker fired boiler located in GA, Proposal 03-B-108:

- Boiler Heat Input, MMBTU/hr 146
 - Baseline NOx, lb/MMBTU (lb/hr) 0.41 (59.9)
 - Controlled NOx, lb/MMBTU (lb/hr) 0.246 (35.9)
 - NOx Reduction, % (NH3 Slip) 40 (10 ppm)
 - Required Temperature at Injection, °F 1,900 - 2,000
 - Maximum Average Furnace CO, ppm 200
 - NOxOUT LT (32.5% Urea by Weight) 20 GPH
- Fuel Tech Equipment Provided (Indoor Location or Freeze Protection Required by Others)
- One (1) - 6,000 Gallon FRP Storage Tank
 - One (1) - SLP3 Metering/Distribution Module
 - Two (2) Levels of Injection; Level 1 = four (4) Automatic Retract Injectors, Level 2 = two (2) Wall Injectors
 - One (1) Automatic Retract Mechanisms
 - One (1) Optical Pyrometer Temperature Monitor
 - One (1) Lot Process and Project Engineering
 - One (1) Lot P&ID's, Mechanical Drawings and BOM's
 - One (1) Lot Electrical Schematics, Interconnects and BOM's
 - Twenty (20) Mandays Startup and System Optimization
 - Five (5) Operation and Maintenance Manuals

For the Engineering, Equipment, Conveyance of Site License, and Services defined in this proposal, Fuel Tech quotes the price of \$ 508,000. For the installation ESTIMATE, for material and installation labor, Fuel Tech quotes the budgetary price of \$ 200,000. The installation estimate is budgetary in nature and is based upon projects of similar size and scope and will require adjustment following a detailed site walk down and review of the site by a Qualified Contractor.

I hope this meets your immediate needs. A more detailed hard copy of the proposal will follow in the mail. Call me if there are any questions or comments. Thank you.

Dale Pfaff
Fuel Tech Inc.
(630) 669-6730

-----Original Message-----

From: Bill Powers [mailto:bpowers@powersengineering.com]
Sent: Friday, September 26, 2003 1:28 PM
To: Dale Pfaff
Cc: Erik Parks; Michael Bisnett
Subject: Fuel Tech Budgetary SNCR Cost for 146 MMBtu/hr Stoker

Hello Dale,

I just received this information from Detroit Stoker on the Cargill stoker boiler in Gainesville, GA:

Steam load = 120000 lb/hr at MCR
Characteristics = 175 psi, sat, FW temp 225 F.
Ambient overfire air and undergrate air.
Input at MCR = 146.14 MBtu/hr
Fuel = Coal

Moisture = 9%
VM = 34.85
FC = 47.7
Ash = 2.45
HHV = 11962

Stoker : RotoGrate 12'-10 1/2" x 18'-0" (net)
No Boiler height available.

Fuel Tech may have already retrofitted SNCR onto a Detroit Stoker rotograte boiler of similar capacity, and as a result you may have a good idea of the boiler furnace height. Getting some feedback today on ballpark installed cost, and O&M cost, for an SNCR system on this unit today would be a great help. The estimated uncontrolled NOx level is 0.41 lb/MMBtu. The controlled NOx target is whatever you can do while maintaining 10 ppm ammonia slip, though hopefully the amount of NOx reduction will be at least 40 percent. You can assume O2 concentration of 6% for costing purposes (34,000 dscfm).

Regards,

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

tel: 619-295-2072
fax: 619-295-2073

We have coal fired retrofit experience in Japan and US.

The retrofit cost of the coal fired unit is probably around \$80/kW.

Regards,

> Hello Akira,

>

> Has Mitsubishi done any SCR retrofits on industrial coal-fired boilers in the U.S. or internationally? If so, I would be interested in knowing the sites and approximate installed cost of the retrofits.

>

> Regards,

>

> Bill Powers, P.E.

> Powers Engineering

> tel: 619-295-2072

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Akira Hattori

Mitsubishi Power Systems, Inc.

ahattori@mhia.com

tel/949-856-8417 fax/949-856-4481

Attachment C

EPA Technical Fact Sheets – SCR and SNCR



Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Catalytic Reduction (SCR)

Type of Technology: Control Device - Chemical reduction via a reducing agent and a catalyst.

Applicable Pollutants: Nitrogen Oxides (NO_x)

Achievable Emission Limits/Reductions: SCR is capable of NO_x reduction efficiencies in the range of 70% to 90% (ICAC, 2000). Higher reductions are possible but generally are not cost-effective.

Applicable Source Type: Point

Typical Industrial Applications: Stationary fossil fuel combustion units such as electrical utility boilers, industrial boilers, process heaters, gas turbines, and reciprocating internal combustion engines. In addition, SCR has been applied to nitric acid plants. (ICAC, 1997)

Emission Stream Characteristics:

- a. **Combustion Unit Size:** In the United States, SCR has been applied to coal- and natural gas-fired electrical utility boilers ranging in size from 250 to 8,000 MMBtu/hr (25 to 800 MW) (EPA, 2002). SCR can be cost effective for large industrial boilers and process heaters operating at high to moderate capacity factors (>100 MMBtu/hr or >10MW for coal-fired and >50 MMBtu/hr or >5MW for gas-fired boilers). SCR is a widely used technology for large gas turbines.
- b. **Temperature:** The NO_x reduction reaction is effective only within a given temperature range. The optimum temperature range depends on the type of catalyst used and the flue gas composition. Optimum temperatures vary from 480°F to 800°F (250°C to 427°C) (ICAC, 1997). Typical SCR systems tolerate temperature fluctuations of ± 200°F (± 90°C) (EPA, 2002).
- c. **Pollutant Loading:** SCR can achieve high reduction efficiencies (>70%) on NO_x concentrations as low as 20 parts per million (ppm). Higher NO_x levels result in increased performance; however, above 150 ppm, the reaction rate does not increase significantly (Envirox, 2000). High levels of sulfur and particulate matter (PM) in the waste gas stream will increase the cost of SCR.
- d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NO_x and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, and 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm. Ammonia slip at this levels do not result in plume formation or human health hazards. Process optimization after installation can lower slip levels.

Waste gas streams with high levels of PM may require a sootblower. Sootblowers are installed in the SCR reactor to reduce deposition of particulate onto the catalyst. It also reduces fouling of downstream equipment by ammonium sulfates.

The pressure of the waste gas decreases significantly as it flows across the catalyst. Application of SCR generally requires installation a new or upgraded induced draft fan to recover pressure.

Emission Stream Pretreatment Requirements: The flue gas may require heating to raise the temperature to the optimum range for the reduction reaction. Sulfur and PM may be removed from the waste gas stream to reduce catalyst deactivation and fouling of downstream equipment.

Cost Information:

Capital costs are significantly higher than other types of NO_x controls due to the large volume of catalyst that is required. The cost of catalyst is approximately 10,000 \$/m³ (283 \$/ft³). A 350 MMBtu/hr natural gas-fired boiler operating at 85% capacity requires approximately 17 m³ (600 ft³). For the same sized coal-fired boiler, the required catalyst is on the order of 42 m³ (1,500 ft³). (NESCAUM 2000).

SCR is a proprietary technology and designs on large combustion units are site specific. Retrofit of SCR on an existing unit can increase costs by over 30% (EPA, 2002). The increase in cost is primarily due to ductwork modification, the cost of structural steel, and reactor construction. Significant demolition and relocation of equipment may be required to provide space for the reactor.

The O&M costs of using SCR are driven by the reagent usage, catalyst replacement, and increased electrical power usage. SCR applications on large units (>100 MMBtu/hr) generally require 20,000 to 100,000 gallons of reagent per week (EPA, 2002). The catalyst operating life is on the order of 25,000 hours for coal-fired units and 40,000 hours for oil- and gas-fired units (EPA, 2002). A catalyst management plan can be developed so that only a fraction of the total catalyst inventory, rather than the entire volume, is replaced at any one time. This distributes the catalyst replacement and disposal costs more evenly over the lifetime of the system. O&M costs are greatly impacted by the capacity factor of the unit and annual versus seasonal control of NO_x.

O&M cost and the cost per ton of pollutant removed is greatly impacted by the capacity factor and whether SCR is utilized seasonally or year round.

Table 1a: Summary of Cost Information in \$/MMBtu/hr (1999 Dollars) ^{a, b}

Unit Type	Capital Cost (\$/MMBtu)	O&M Cost ^d (\$/MMBtu)	Annual Cost ^d (\$/MMBtu)	Cost per Ton of Pollutant Removed (\$/ton)
Industrial Coal Boiler	10,000 - 15,000	300	1,600	2,000 - 5,000
Industrial Oil, Gas, Wood ^c	4,000 - 6,000	450	700	1,000 - 3,000
Large Gas Turbine	5,000 - 7,500	3,500	8,500	3,000 - 6,000
Small Gas Turbine	17,000 - 35,000	1,500	3,000	2,000 - 10,000

Table 1b: Summary of Cost Information in \$/MW (1999 Dollars) ^{a, b}

Unit Type	Capital Cost (\$/MW)	O&M Cost ^c (\$/MW)	Annual Cost ^d (\$/MW)	Cost per Ton of Pollutant Removed (\$/ton)
Industrial Coal Boiler	1,000 - 1,500	30	160	2,000 - 5,000
Industrial Oil, Gas, Wood ^c	400 - 600	45	70	1,000 - 3,000
Large Gas Turbine	500 - 750	350	850	3,000 - 6,000
Small Gas Turbine	1,700- 3,500	150	300	2,000 - 10,000

^a (ICAC, 1997; NESCAUM, 2000; EPA, 2002)

^b Assumes 85% capacity factor and annual control of NO_x

^c SCR installed on wood fired boiler assumes a hot side electrostatic precipitator for PM removal

^d Coal and oil O&M and annual costs are based on 350MMBtu boiler, and gas turbine O&M and annual costs are based on 75 MW and 5 MW turbine

Theory of Operation:

The SCR process chemically reduces the NO_x molecule into molecular nitrogen and water vapor. A nitrogen based reagent such as ammonia or urea is injected into the ductwork, downstream of the combustion unit. The waste gas mixes with the reagent and enters a reactor module containing catalyst. The hot flue gas and reagent diffuse through the catalyst. The reagent reacts selectively with the NO_x within a specific temperature range and in the presence of the catalyst and oxygen.

Temperature, the amount of reducing agent, injection grid design and catalyst activity are the main factors that determine the actual removal efficiency. The use of a catalyst results in two primary advantages of the SCR process over the SNCR: higher NO_x control efficiency and reactions within a lower and broader temperature range. The benefits are accompanied by a significant increase in capital and operating costs. The catalyst is composed of active metals or ceramics with a highly porous structure. Catalysts configurations are generally ceramic honeycomb and pleated metal plate (monolith) designs. The catalyst composition, type, and physical properties affect performance, reliability, catalyst quantity required, and cost. The SCR system supplier and catalyst supplier generally guarantee the catalyst life and performance. Newer catalyst designs increase catalyst activity, surface area per unit volume, and the temperature range for the reduction reaction.

Catalyst activity is a measure of the NO_x reduction reaction rate. Catalyst activity is a function of many variables including catalyst composition and structure, diffusion rates, mass transfer rates, gas temperature, and gas composition. Catalyst deactivation is caused by:

- poisoning of active sites by flue gas constituents,
- thermal sintering of active sites due to high temperatures within reactor,
- blinding/plugging/fouling of active sites by ammonia-sulfur salts and particulate matter, and
- erosion due to high gas velocities.

As the catalyst activity decreases, NO_x removal decreases and ammonia slip increases. When the ammonia slip reaches the maximum design or permitted level, new catalyst must be installed. There are several different locations downstream of the combustion unit where SCR systems can be installed. Most coal-fired applications locate the reactor downstream of the economizer and upstream of the air heater and particulate control devices (hot-side). The flue gas in this location is usually within the optimum temperature window for NO_x reduction reactions using metal oxide catalysts. SCR may be applied after PM and sulfur removal

equipment (cold-side), however, reheating of the flue gas may be required, which significantly increases the operational costs.

SCR is very cost-effective for natural gas fired units. Less catalyst is required since the waste gas stream has lower levels of NO_x, sulfur, and PM. Combined-cycle natural gas turbines frequently use SCR technology for NO_x reduction. A typical combined-cycle SCR design places the reactor chamber after the superheater within a cavity of the heat recovery steam generator system (HRSG). The flue gas temperature in this area is within the operating range for base metal-type catalysts.

SCR can be used separately or in combination with other NO_x combustion control technologies such as low NO_x burners (LNB) and natural gas reburn (NGR). SCR can be designed to provide NO_x reductions year-round or only during ozone season.

Advantages:

- Higher NO_x reductions than low-NO_x burners and Selective Non-Catalytic Reduction (SNCR)
- Applicable to sources with low NO_x concentrations
- Reactions occur within a lower and broader temperature range than SNCR.
- Does not require modifications to the combustion unit

Disadvantages:

- Significantly higher capital and operating costs than low-NO_x burners and SNCR
- Retrofit of SCR on industrial boilers is difficult and costly
- Large volume of reagent and catalyst required.
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

References:

EPA, 1998. U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis", Prepared by Pechan-Avanti Group, Research Triangle Park, NC. 1998.

EPA, 1999. US Environmental Protection Agency, Clean Air Technology Center. "Technical Bulletin: Nitrogen Oxides (NO_x), Why and How They Are Controlled". Research Triangle Park, NC. 1998.

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Gaikwad, 2000. Gaikwad, Kurtides, and DePriest. "Optimizing SCR Reactor Design for Future Operating Flexibility". Presented at the Institute of Clean Air Companies Forum 2000. Washington D.C.

ICAC, 1997. Institute of Clean Air Companies, Inc. "White Paper: Selective Catalytic Reduction (SCR) Control of NO_x Emissions". Washington, D.C. 1997.

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NESCAUM, 2002. Northeast States for Coordinated Air Use Management. "Status Reports on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost Effectiveness". Boston, MA. 2002.

OTAG 1998. OTAG Emissions Inventory Workgroup. "OTAG Technical Supporting Document: Chapter 5." Raleigh, North Carolina, US Environmental Protection Agency. 1998.



Air Pollution Control Technology Fact Sheet

Name of Technology: Selective Non-Catalytic Reduction (SNCR)

Type of Technology: Control Device - Chemical reduction of a pollutant via a reducing agent.

Applicable Pollutants: Nitrogen Oxides (NO_x)

Achievable Emission Limits/Reductions:

NO_x reduction levels range from 30% to 50% (EPA, 2002). For SNCR applied in conjunction with combustion controls, such as low NO_x burners, reductions of 65% to 75% can be achieved (ICAC 2000).

Applicable Source Type: Point

Typical Industrial Applications:

There are hundreds of commercially installed SNCR systems on a wide range of boiler configurations including: dry bottom wall fired and tangentially fired units, wet bottom units, stokers, and fluidized bed units. These units fire a variety of fuels such as coal, oil, gas, biomass, and waste. Other applications include thermal incinerators, municipal and hazardous solid waste combustion units, cement kilns, process heaters, and glass furnaces.

Emission Stream Characteristics:

- a. **Combustion Unit Size:** In the United States, SNCR has been applied to boilers and other combustion units ranging in size from 50 to 6,000 MMBtu/hr (5 to 600MW/hr) (EPA, 2002). Until recently, it was difficult to get high levels of NO_x reduction on units greater than 3,000 MMBtu (300 MW) due to limitations in mixing. Improvements in SNCR injection and control systems have resulted in high NO_x reductions (> 60%) on utility boilers greater than 6,000 MMBtu/hr (600MW). (ICAC, 2000).
- b. **Temperature:** The NO_x reduction reaction occurs at temperatures between 1600°F to 2100°F (870°C to 1150°C) (EPA, 2002). Proprietary chemicals, referred to as enhancers or additives, can be added to the reagent to lower the temperature range at which the NO_x reduction reactions occur.
- c. **Pollutant Loading:** SNCR tends to be less effective at lower levels of uncontrolled NO_x. Typical uncontrolled NO_x levels vary from 200 ppm to 400 ppm (NESCAUM, 2000). SNCR is better suited for applications with high levels of PM in the waste gas stream than SCR.
- d. **Other Considerations:** Ammonia slip refers to emissions of unreacted ammonia that result from incomplete reaction of the NO_x and the reagent. Ammonia slip may cause: 1) formation of ammonium sulfates, which can plug or corrode downstream components, 2) ammonia absorption into fly ash, which may affect disposal or reuse of the ash, and 3) increased plume

visibility. In the U.S., permitted ammonia slip levels are typically 2 to 10 ppm (EPA, 2002). Ammonia slip at these levels do not result in plume formation or pose human health hazards. Process optimization after installation can lower slip levels.

Nitrous Oxide (N₂O) is a by-product formed during SNCR. Urea based reduction generates more N₂O than ammonia-based systems. At most, 10% of the NO_x reduced in urea-based SNCR is converted to N₂O. Nitrous oxide does not contribute to ground level ozone or acid formation. (ICAC,2000)

Emission Stream Pretreatment Requirements: None

Cost Information: All costs are in year 1999 dollars. (NESCAUM, 2000; ICAC, 2000; and EPA, 2002)

The difficulty of SNCR retrofit on existing large coal-fired boilers is considered to be minimal. However, the difficulty significantly increases for smaller boilers and packaged units. The primary concern is adequate wall space within the boiler for installation of injectors. Movement and/or removal of existing watertubes and asbestos from the boiler housing may be required. In addition, adequate space adjacent to the boiler must be available for distribution system equipment and for performing maintenance. This may require modifications to ductwork and other boiler equipment.

A typical breakdown of annual costs for industrial boilers will be 15% to 35% for capital recovery and 65% to-85% for operating expense (ICAC,2000). Since SNCR is an operating expense-driven technology, its cost varies directly with NO_x reduction requirements and reagent usage. Optimization of the injection system after start up can reduce reagent usage and, subsequently, operating costs. Recent improvements in SNCR injection systems have also lowered operating costs.

There is a wide range of cost effectiveness for SNCR due to the different boiler configurations and site-specific conditions, even within a given industry. Cost effectiveness is impacted primarily by uncontrolled NO_x level, required emissions reduction, unit size and thermal efficiency, economic life of the unit, and degree of retrofit difficulty. The cost effectiveness of SNCR is less sensitive to capacity factor than SCR. Control of NO_x is often only required during the ozone season, typically June through August. Since SNCR costs are a function of operating costs, SNCR is an effective control option for seasonal NO_x reductions.

Costs are presented below for industrial boilers greater than 100 MMBtu/hr.

- a. **Capital Cost:** 900 to 2,500 \$/MMBtu/hr (9,000 to 25,000 \$/MW)
- b. **O&M Cost:** 100 to 500 \$/MMBtu/hr (1,000 to 5,000 \$/MW)
- c. **Annualized Cost:** 300 to 1000 \$/MMBtu/hr (3,000 to 10,000 \$/MW)
- d. **Cost per Ton of Pollutant Removed:**

Annual Control: 400 to 2,500 \$/ton of NO_x removed

Seasonal Control: 2,000 to 3,000 \$/ton of NO_x removed

Theory of Operation:

SNCR is based on the chemical reduction of the NO_x molecule into molecular nitrogen (N₂) and water vapor (H₂O). A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the

post combustion flue gas. The reduction reaction with NO_x is favored over other chemical reaction processes at temperatures ranging between 1600°F and 2100°F (870°C to 1150°C), therefore, it is considered a selective chemical process (EPA, 2002).

Both ammonia and urea are used as reagents. Urea-based systems have advantages over ammonia based systems. Urea is non-toxic, less volatile liquid that can be stored and handled more safely. Urea solution droplets can penetrate farther into the flue gas when injected into the boiler, enhancing the mixing with the flue gas which is difficult in large boilers. However, urea is more expensive than ammonia. The Normalized Stoichiometric Ratio (NSR) defines the ratio of reagent to NO_x required to achieve the targeted NO_x reduction. In practice, more than the theoretical amount of reagent needs to be injected into the boiler flue gas to obtain a specific level of NO_x reduction.

In the SNCR process, the combustion unit acts as the reactor chamber. The reagent is generally injected within the boiler superheater and reheater radiant and convective regions, where the combustion gas temperature is at the required temperature range. The injection system is designed to promote mixing of the reagent with the flue gas. The number and location of injection points is determined by the temperature profiles and flow patterns within the combustion unit.

Certain applications are more suited for SNCR due to the combustion unit design. Units with furnace exit temperatures of 1550°F to 1950°F (840°C to 1065°C), residence times of greater than one second, and high levels of uncontrolled NO_x are good candidates.

During low-load operation, the location of the optimum temperature region shifts upstream within the boiler. Additional injection points are required to accommodate operations at low loads. Enhancers can be added to the reagent to lower the temperature range at which the NO_x reduction reaction occurs. The use of enhancers reduces the need for additional injection locations.

Advantages:

- Capital and operating costs are among the lowest of all NO_x reduction methods.
- Retrofit of SNCR is relatively simple and requires little downtime for large and medium size units.
- Cost effective for seasonal or variable load applications.
- Waste gas streams with high levels of PM are acceptable.
- Can be applied with combustion controls to provide higher NO_x reductions.

Disadvantages:

- The waste gas stream must be within a specified temperature range.
- Not applicable to sources with low NO_x concentrations such as gas turbines.
- Lower NO_x reductions than Selective Catalytic Reduction (SCR).
- May require downstream equipment cleaning.
- Results in ammonia in the waste gas stream which may impact plume visibility, and resale or disposal of ash.

References:

EPA, 1998. U.S. Environmental Protection Agency, Innovative Strategies and Economics Group, "Ozone Transport Rulemaking Non-Electricity Generating Unit Cost Analysis", Prepared by Pechan-Avanti Group, Research Triangle Park, NC. 1998.

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<http://www.epa.gov/ttn/catc/dir1/cs4-2ch1.pdf>

ICAC, 2000. Institute of Clean Air Companies, Inc. "White Paper: Selective Non-Catalytic Reduction (SNCR) for Controlling NO_x Emissions". Washington, D.C. 2000.

NESCAUM, 2000. Northeast States for Coordinated Air Use Management. "Status Reports on NO_x Controls for Gas Turbines, Cement Kilns, Industrial Boilers, and Internal Combustion Engines: Technologies & Cost Effectiveness". Boston, MA. 2002.

**PETITION ATTACHMENT 2
RESUME OF BILL POWERS**

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Master of Public Health – Environmental Sciences, University of North Carolina
Bachelor of Science – Mechanical Engineering, Duke University

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Air & Waste Management Association
American Society of Mechanical Engineers
International Gas Turbine Institute

TECHNICAL SPECIALTIES

Twenty years of experience in:

- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Air emissions testing/criteria and hazardous air pollutants
- Petroleum refinery emission inventory development
- Oil and gas production emission inventory development
- Latin America environmental project experience

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

Air Permit for Hospital Cogeneration Plant Gas Turbines – High Temperature SCR Installation. Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for two Solar Centaur 3.4 MW cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and SCONO_x. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the wide availability of urea on the island. This unit will be the first known application of urea-injected SCR on a naphtha-fired turbine when the unit becomes operational in the summer of 2003.

NSR Permit Modification for Mars Gas Turbines – Upgrade of Turbine Power Output. Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed Solar Mars 100 gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and SCONO_x. Successfully negotiated air

and performance of NO_x control systems. A comparison of 1993 to 1999 "\$/kwh" and "\$/ton" cost of these control systems was developed in the evaluation.

Gas Turbines – Evaluation of Proposed NO_x Control System to Achieve 3 ppm Limit.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installations around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol.

Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO₂ and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO₂ and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Siemens-Westinghouse, and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards

potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible: potline current efficiency improvement, catalytic incineration, recuperative incineration and regenerative incineration. The high cost of these retrofit options precluded the identification of any of these technologies as RACT for CO. Four PM₁₀ control technologies were identified as technologically feasible: increased potline hooding efficiency through the addition of dense-phase conveying and automated puncher/feeders, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. It was determined that the potline air evacuation rate had already been optimized, and a further increase in air evacuation rate would result in no significant reduction in PM₁₀ emissions from the potlines. The cost of dense-phase conveying with automated puncher/feeders, wet scrubbers or fabric filters for potline PM₁₀ control exceeded regulatory guidelines for RACT cost effectiveness.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM₁₀ RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM₁₀ emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM₁₀ control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions. The cost of these potential PM₁₀ RACT controls exceeded regulatory guidelines for cost effectiveness, though testing of modified shield configurations and dense-phase conveying is being conducted under a separate regulatory compliance order.

RACT/BACT Testing/Evaluation of PM₁₀ Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM₁₀)/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM₁₀ emissions, though test results indicated that the majority of captured PM₁₀ evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM₁₀ RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications. The coater line was equipped with an afterburner for VOC and CO destruction prior to the initiation of the RACT study. It was determined that the afterburner meets or exceeds RACT requirements for the coater line. Significant sources of PM₁₀ emissions included the remelt furnaces and the 80-inch hot rolling mill. Chlorine fluxing in the melting and holding furnaces was identified as the principal source of PM₁₀ emissions from the remelt furnaces. The facility is in the process of minimizing/eliminating fluxing in the melting furnaces, and exhaust gases generated in holding furnaces during fluxing will be ducted to a baghouse for PM₁₀ control. These modifications are being performed under a separate compliance order, and were determined to exceed RACT requirements. A water-based emulsion coolant and inertial separators are currently in use on the 80-inch hot mill for PM₁₀ control. Current practices were determined to meet/exceed PM₁₀ RACT for the hot mill. Tray tower absorption/recovery systems were also evaluated to control PM₁₀ emissions from the hot mill, though it

Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide ±1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O₂ analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO₂ CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO₂ CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO₂) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Preliminary Design of Ambient Air Quality Monitoring Network – Lima, Peru. Project leader for project to prepare specifications for a fourteen station ambient air quality monitoring network for the municipality of Lima, Peru. Network includes four complete gaseous pollutant, particulate, and meteorological parameter monitoring stations, as well as eight PM₁₀ and TSP monitoring stations.

Evaluation of Proposed Ambient Air Quality Network Modernization Project – Venezuela. Analyzed a plan to modernize and expand the ambient air monitoring network in Venezuela. Project was performed for the U.S. Trade and Development Agency. Direct interaction with policy makers at the Ministerio del Ambiente y de los Recursos Naturales Renovables (MARNR) in Caracas was a major component of this project.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO₂ monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO₂ emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO₂ and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO₂ controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla, located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM

program. Translated test report into Spanish for review by the Mexican federal environmental agency (SEMARNAP).

Air Pollution Control Equipment Retrofit Evaluation – Mexico. Project manager and lead engineer for comprehensive evaluation of air pollution control equipment and industrial ventilation systems in use at assembly plant consisting of four major facilities. Equipment evaluated included fabric filters controlling blast booth emissions, electrostatic precipitator controlling welding fumes, and industrial ventilation systems controlling welding fumes, chemical cleaning tank emissions, and hot combustion gas emissions. Recommendations included modifications to fabric filter cleaning cycle, preventative maintenance program for the electrostatic precipitator, and redesign of the industrial ventilation system exhaust hoods to improve capture efficiency.

Comprehensive Air Emissions Testing at Assembly Plant – Mexico. Project manager and field supervisor of emissions testing for particulates, NO_x, SO₂ and CO at automotive components assembly plant in Acuña, Mexico. Source-specific emission rates were developed for each point source at the facility during the test program. Translated test report into Spanish.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application “templates” for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The

mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr⁺⁶, PAHs, H₂S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr⁺⁶ stack testing using the EPA Cr⁺⁶ test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr⁺⁶) to compare the results of EPA and ARB Cr⁺⁶ test methodologies. The ARB approved the test results generated using the high temperature EPA Cr⁺⁶ test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover.

S. S. Parmar, M. Short, W. E. Powers, "Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique," presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, "Air Toxics Emissions from Gas-Fired Internal Combustion Engines," presented at AIChE Summer Meeting, August 1990.

W. E. Powers, "Air Pollution Control of Plating Shop Processes," presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, "Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator," presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo

Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme

Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

Georgia Department Natural Resources

Environmental Protection Division, Air Protection Branch

4244 International Parkway, Suite 120, Atlanta, Georgia 30354

404/363-7000; Fax: 404/363-7100

Lonice C. Barrett, Commissioner

Harold F. Reheis, Director

APR 08 2002

Mr. Mike Dobeck
Plant Superintendent
Cargill, Inc.
826 West Ridge Rd.
Gainesville, GA 30501

RE: NOx RACT Plan for Coal-fired Boiler

Dear Mr. Dobeck:

The Division has reviewed your letter dated April 1, 2002 regarding the NOx RACT plan for the coal-fired boiler. In this letter, you reaffirmed your position in your September 2000 submittal that "no additional controls" meets the NOx RACT requirements for the 145 MMBtu/hr coal-fired boiler, assuming a NOx emission limit of 0.41 lb/mmBtu and proper operation and maintenance.

During a meeting between EPD and Cargill on March 12, 2002, attention was focused on the possible implementation of SCR control because, of all technically feasible control options, SCR resulted in the most NOx reduction at an average cost that was just slightly more expensive than the least expensive control alternative.

Cargill estimated the cost of implementing SCR on the coal-fired boiler at \$7,181 per ton. We have reviewed the analysis and agree with the estimates with two notable exceptions. The catalyst life was assumed to be only 3 years and the equipment life was assumed to be only 10 years. The OAQPS manual suggests that the catalyst life could be 24,000 hours (see page 2-47 of manual). When operating only during the ozone season, this works out to be about 6.5 years. The OAQPS manual also suggests that the equipment life can be estimated at 20 years (see page 2-48). Cargill did not provide any justification for the use of these alternative figures. Therefore, EPD has recalculated the cost effectiveness using the values from the OAQPS manual mentioned above and came up with a cost effectiveness of \$4,937 per ton. EPD believes that this is cost effective for purposes of NOx RACT.

Based on the fact that this is located in Hall County, just outside the current Atlanta area 1-hour ozone nonattainment area and within the planned Atlanta area 8-hour ozone nonattainment area, that SCR will result in actual NOx reductions of 0.5 tons per day during the ozone season, that there are no existing plans for this boiler to be retired or have environmental upgrades implemented, and that the estimated control costs are only \$4,937 per ton, we believe that NOx RACT should require SCR controls on the coal-fired boiler at a controlled emission rate of 0.08 lb/mmBtu. Therefore, we are proceeding to amend your Air Quality Permit accordingly.

If you have any questions or need more information, please contact Jac Capp at (404) 363-7143 or via email at james_capp@mail.dnr.state.ga.us.

Sincerely,



Ronald C. Methier

Chief

Air Protection Branch

Georgia Department of Natural Resources

Environmental Protection Division, Air Protection Branch

4244 International Parkway, Suite 120, Atlanta, Georgia 30354

404/363-7000; Fax: 404/363-7100

Lonice C. Barrett, Commissioner

Harold F. Reheis, Director

April 4, 2002

MEMORANDUM

TO: Jimmy Johnston
FROM: James A. Capp
SUBJECT: Review of NOx RACT Plan for Cargill, Gainesville

General Information

Cargill operates a 145 mmBtu/hr coal-fired stoker boiler in Gainesville, Hall County, Georgia. This boiler is subject to Rule (yy), NOx Emissions from Major Sources. Uncontrolled NOx emissions are estimated, based on AP-42, to be approximately 0.41 lb/mmBtu. To my knowledge, this boiler has never been tested for NOx emissions. It was installed around 1981. Ozone season NOx emissions are estimated to be about 92 tons or 0.6 tons per day (based on 85% capacity factor).

NOx RACT Background

Their initial NOx RACT Plan for the coal-fired boiler was submitted in September 2000. And Rule (yy) required a final control plan and application to construct/modify etc. to be submitted by April 1, 2001. Due to the large number of NOx plans to be reviewed in such a short period of time, four of the more complicated plans, including Cargill, were not reviewed by April 1, 2001. The Director, therefore, granted a one-year extension of the submittal date (note, the compliance date was not changed) until April 1, 2002.

The September 2000 NOx RACT Plan, amongst other things, excluded consideration of SCR NOx control technology on the basis that it was not technically feasible for the boiler at Cargill (due to temperature limitations). Thus, Cargill did not provide any cost estimates for SCR control. On February 5, 2002, I wrote Cargill stating that EPD considered SCR to be technically feasible and that we believed it would be cost effective for reducing NOx emissions on the coal-fired boiler. I did consider cost data that EPA had generated for slightly larger coal-fired boilers. However, at that time, I did not prepare a site specific cost analysis for Cargill's boiler. I further stated that a control efficiency of 80% was technically feasible, resulting in a controlled NOx emission rate of 0.08 lb/mmBtu.

I met with Cargill on March 12, 2002. At that time they acknowledged that SCR was a technically feasible control technology for the coal-fired boiler, contrary to their original submittal. However, they asserted that SCR, while technically feasible, would result in capital costs of about 2.8 million dollars resulting in a NOx control cost effectiveness of over \$7,000 per ton, which they felt was not cost effective for their boiler as RACT. I stated that I would probably be recommending that SCR be required as NOx RACT.

Final NOx Control Plan and Application to Modify Permit

On April 1, 2002, Cargill submitted their final NOx control plan and application to modify the permit to incorporate NOx RACT requirements. This submittal was consistent with the March 12 meeting. It asserts that NOx RACT for the coal-fired boiler should be "no additional controls." They have requested a NOx limit of 0.41 lb/mmBtu be added to their permit as RACT. They do not say how they expect to assure compliance with that limit and considering that the emission rate is based on estimated actual emissions from AP-42, there is a reasonable chance that actual emissions could be higher than that level right now. Implementing a limit as Cargill has requested could possibly put them out of compliance.

EPA has recently updated the OAQPS control costs manual to include a specific section on SCR for coal-fired boilers. Cargill used this section to estimate the cost of implementing SCR on their coal-fired boiler. They calculated a cost effectiveness of \$7,181 per ton. I have reviewed their analysis and agree with their estimates with two notable exceptions. They assumed a catalyst life of only 3 years and they assumed an equipment life of only 10 years. The OAQPS manual suggests a catalyst life of 24,000 hours (see page 2-47 of manual). When operating only during the ozone season, this works out to be about 6.5 years. The OAQPS manual suggests that the equipment life can be estimated at 20 years (see page 2-48). Cargill did not provide any justification for the use of these lower estimates. I have recalculated the cost effectiveness using the values from the OAQPS manual and came up with \$4,937 per ton.

Conclusion

Based on the fact that this is located in Hall County, just outside the current Atlanta area 1-hour ozone nonattainment area and within the planned Atlanta area 8-hour ozone nonattainment area, that SCR will result in actual NOx reductions of 0.5 tons per day during the ozone season, that there are no existing plans for this boiler to be retired or have environmental upgrades implemented, and that the estimated control costs are only \$4,937 per ton, I believe that we should require them to construct and operate SCR controls on the coal-fired boiler. Since I have already requested them to do so in writing, letter dated February 5, 2002, and they have refused, I believe that the Chief of the Air Branch should write them confirming that we are proceeding to amend their permit to require the implementation of SCR control to reduce NOx emissions to 0.08 lb/mmBtu and that they should plan accordingly.

A draft letter to that effect is attached to this memo.

**PETITION ATTACHMENT 3
COMMENT LETTERS
OF
GEORGIA CENTER FOR LAW IN THE PUBLIC INTEREST**

GEORGIA CENTER FOR LAW IN THE PUBLIC INTEREST

175 TRINITY AVENUE, SW
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404 659-3122, FAX 404 688-5912
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VIA E-MAIL AND FIRST CLASS MAIL

January 29, 2003

Mr. James P. Johnston, PE
Program Manager
Stationary Source Permitting Program
Air Protection Branch / Environmental Protection Division
Georgia Department of Natural Resources
4244 International Parkway, Suite 120
Atlanta, GA 30354

RE: Cargill's Gainesville Title V Permit Amendment, TV-13727

Dear Mr. Johnston:

On behalf of the Newtown Florist Club, the Sierra Club and Georgia ForestWatch and their over 15,000 members in Georgia, I am writing to submit comments and request a public hearing on Cargill's Gainesville's draft Title V amendment. You have assigned this draft permit amendment application number TV-13727. I would appreciate it if your staff would call Ms. Faye Bush, President of the Newtown Florist Club, to discuss the date and location of the public hearing before you schedule it. Ms. Bush can be reached at: 770-718-1343.

We will provide more comments at the public hearing. Our initial comments, for which will provide more detail at the public hearing, include:

- 1) NO_x RACT FOR BOO1 SHOULD BE 0.08 lb/MMBtu achieved with SCR

Condition 3.4.1.c of the permit amendment provides that the NO_x RACT emission limit for the Cargill's coal fired boiler, which is designated emission unit B001, is 0.41 lbs/MMBtu or 50.5 lbs/hour. We believe that the RACT limit should be 0.08 lb/MMBtu achieved through SCR. As you know, Ronald Methier, chief of the Air Protection Branch agreed with this position in an April 8, 2002 letter, which is hereby incorporated by reference.

- 2) THE CURRENT NO_x RACT LIMIT FOR B001 IS NOT ENFORCEABLE AS A PRACTICAL MATTER AND LACKS ADEQUATE MONITORING AND REPORTING.

Should you reject our suggestion in comment 1, above, in the alternative we believe that the NO_x RACT limit for B001 is not enforceable as a practical matter and lacks adequate monitoring and reporting to assure compliance. To begin with, the use of the “or” between the “lb/MMBtu” limit and the “lbs/hour” limit makes condition 3.4.1.c confusing and thus not enforceable as a practical matter. We suggest that the two limits be put in two separate permit conditions and that the permit clearly indicate that both limits must be met.¹

Furthermore, the permit lacks adequate monitoring and reporting for the NO_x RACT limit and especially of the “lbs/hour” limit that applies under any operating conditions. There is no monitoring to assure B001 will comply with the NO_x limit under all operating conditions. We suggest that the permit require a CEMS for NO_x for B001 and that the 40 CFR Part 75 standards for operating the CEMS be used as Part 75 represents a well known standard.

In addition, Condition 3.4.1.c lacks an averaging time. In order to be enforceable as a practical matter, this condition must have an averaging time. We suggest that a one-hour averaging time be written into Condition 3.4.1.c to apply to both the lb/MMBtu limit and the lbs/hour limit.

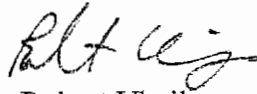
- 3) AN ANNUAL TUNE UP IS NOT RACT FOR THE OTHER EMISSION UNITS

Condition 3.4.10 requires an annual tune up for NO_x RACT for emission units B002, HPB1, HPB2, HRO1 and L11A. This is not RACT. We suggest that B002, HPB1 and HPB2 be limited to natural gas only with propane as a back up if that is possible. In addition, we may submit additional comments about add-on controls or different combustion technologies such as low NO_x burners.

If you have any questions, please do not hesitate to call me at 404-659-3122. Otherwise, we appreciate the opportunity to comment on this Title V permit amendment and look forward to further communications at the public hearing.

¹ In the past, Mr. Johnston has argued that our use of the term “suggests” means that we are merely making a permissive recommendation. We note for the record that this is not accurate. We use the term “suggest” to be polite. Please keep in mind, however, that our suggestions are based on legal mandates. This applies to all comments submitted by the Georgia Center for Law in the Public Interest to Georgia EPD.

Sincerely,



Robert Ukeiley
Counsel for Newtown Florist Club,
Sierra Club and Georgia ForestWatch

Cc: Faye Bush, Newtown Florist Club
Katie Producers, Georgia ForestWatch
Curt Smith, Sierra Club
Art Hofmeister, US EPA Region 4

GEORGIA CENTER FOR LAW IN THE PUBLIC INTEREST

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VIA HAND DELIVERY

March 27, 2003

Mr. James P. Johnston, PE
Program Manager
Stationary Source Permitting Program
Air Protection Branch / Environmental Protection Division
Georgia Department of Natural Resources
4244 International Parkway, Suite 120
Atlanta, GA 30354

RE: Cargill's Gainesville Title V Permit Amendment, TV-13727

Dear Mr. Johnston:

On behalf of the Newtown Florist Club, the Sierra Club and Georgia ForestWatch and their over 15,000 members in Georgia, I am writing to submit additional comments on Cargill's Gainesville's draft Title V amendment. You have assigned this draft permit amendment application number TV-13727.

- 1) THE RACT NO_x LIMIT FOR COAL-FIRED BOILER SHOULD BE MUCH LOWER.

Condition 3.4.1.c sets a RACT NO_x limit for the coal-fired boiler, B001 on 0.41 lbs/MMBtu and 50.5 lbs/hour. The RACT limit should be much lower.

A lower RACT limit can be achieved through applying the following techniques:

Selective Catalytic Reduction (SCR)
Over Fire Air
Fuel Reburning
Stage Combustion Air (Low Excess Air)(SCA)
Flue Gas Recirculation (FGR)
SCA + FGR
Selective Non-Catalytic Reduction (SNCR)

Dry Low NOx Burners
Alternative Fuel Introduction Systems
Natural Gas or Propane as a supplemental fuel.

EPD needs to evaluate each of these options. For example, SNCR can achieve a 40% to 70% NOx reduction with a 58% average on stoker coal fired boilers.¹ In addition, SNCR is usually less expensive than SCR because there is no catalyst. EPA's Alternative Control Technology document puts cost effectiveness in the \$1,360 to \$1,440 range. See Exhibit 3.

Many coal fired industrial boilers are permitted at lower NOx emission rates than the draft Cargill permit. For example, the GOLDEN VALLEY ELECTRIC ASSOCIATION - HEALY in Alaska has a NOx emission limit of .35 lbs/MMBtu. SEMINOLE KRAFT 174.7 MMBTU/H's boiler has a limit of .2 LB/MMBTU. International Paper's Boiler 22 uses natural gas as a supplemental fuel, which results in a NOx emission rather of .2 lb/MMBtu RACT limit. Low excess air, staged combustion resulted in NOx limit of .32 lb/MMBtu and 75.7 tons per year at VPI & STATE UNIVERSITY in MONTGOMERY / VA's boiler No. 11 with a heat input of 146.7 MMBtu/ hour versus Cargill's limit of .41lb/MMBtu and 221.19 tpy for its smaller, 145 MMBtu/hour. A print out fro the RBLC is attached as Exhibit 1. As you know, the RBLC is badly outdated and inadequate so it should only be considered to represent an emissions limit Floor.

Many other states have also set a NOx RACT limit for stoker boilers at below the level set for Cargill. For example, New York State's limit is 0.30 lbs/MMBtu. Massachusetts' limit is 0.33 lbs/MMBtu. Pennsylvania does not have a numeric limit but has a presumption of low NOx burners and separate overfire air. These regulations are attached as Exhibit 2.

In conclusion, we recommend that the NOx RACT limit for B001 be 0.08 lbs/MMBtu over a three-hour average using SCR. If that is rejected, then EPD should require RACT to be much less than the current limit using one of the above techniques.

- 2) RACT FOR B002, HPB1, AND HPB2, THE HYDROGEN REFORMER HR01, AND THE AEROGLIDE DRYER L11A SHOULD BE MEET USING LOW NOX BURNERS.

RACT for B002, HPB1, and HPB2, the Hydrogen Reformer HR01, and the Aeroglidge Dryer L11A is currently an annual tune up. However, the use of low NOx burners on these emission units would result in cost effective emission reductions.

¹ Pers. Communication with Bill Neuffer, US EPA's Combustion Group ((919) 541-5435), March 27, 2003.

- 3) THE NARRATIVE DOES NOT PROVIDE A COMPLETE FACTUAL AND LEGAL BASIS FOR THE PERMIT CONDITIONS.

Narratives are required to contain a complete discussion about the factual and legal issues that lead to the permit conditions. This narrative does not do that. It does not contain any substantive discussion of RACT choices. The narrative also needs to explain a detailed discussion of the NO_x monitoring techniques considered and why EPD chose the one it did as it appears that EPD has chosen a test method for gas fired boilers to use on the coal fired B001..

- 4) CONDITION 2.2.5 DOES NOT CONTAIN ADEQUATE MONITORING

Conditions 2.2.5 and 5.2.7.d allow for monitoring to be done later. Part 70 requires monitoring to be part of the Title V permit that the public gets to comment on. Therefore, we suggest that the public be given an opportunity to formally comment on the monitoring that is eventually placed in Conditions 2.2.5 and 5.2.7.d.

- 5) CONDITION 5.2.6.a SHOULD SPECIFY A LOAD OR LOADS AT WHICH TESTING IS TO OCCUR

Condition 5.2.6.a does not specify any operating conditions that must be present during the NO_x test. As the permit is written, the coal boiler could be turned off while the NO_x test is being done. We suggest that Condition 5.2.6 require that the coal boiler be operating at 100% load while the test is performed.

- 5) CONDITION 3.4.1 NEEDS AN AVERAGING TIME

Condition 3.4.1 needs to have an averaging time to make this permit enforceable as a practical matter. It is not clear whether the averaging time is 30 minutes, based on 5.2.6, 1 hour based on Condition 4.1.3.j saying the run time is 60 minutes or three hours, based on EPD's belief that what they think should be the averaging time is the averaging time even if it is not written down.

- 6) NO_x MONITORING RESULTS NEED TO BE REPORTED TO EPD

5.2.6.f allows Cargill to keep the results on its NO_x monitoring on site and thus hidden from the public. However, Title V requires that the results of any monitoring needs to be reported. Thus, the results of Cargill's NO_x emission monitoring need to be reported. In addition, deviations from permit limits for NO_x and other requirements need to be promptly reported. Once every six months is not prompt.

- 7) MANUFACTURES SPECIFICATIONS NEED TO BE AVAILABLE TO THE PUBLIC

Manufacturers specifications need to be included in the permit, or at a minimum in the permit file in order to make Condition 5.2.7 practically enforceable. See Consolidated Edison Co of NY Inc 74th Street Station, II-2001-02 at 13 (implicitly stating that relying on manufactures specs that are not incorporated into the permit are not sufficient)

8) THE PERMIT NEEDS TO HAVE MONITORING AND REPORTING TO ASSURE COMPLIANCE WITH THE LB/HOUR NO_x LIMIT

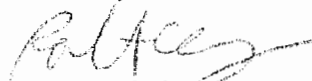
The permit does not contain monitoring and reporting requirements to assure compliance with the lbs/hour NO_x limit in Condition 3.4.1.c. Although there is monitoring for the lbs/MMBtu, there is no requirement that the permittee monitoring and report heat input in MMBtu per hour so that one could convert the lbs/MMBtu results into lbs/hour. This is especially important because the lbs/hour limit is stricter than the lbs/MMBtu limit. ($0.41 \text{ lbs/MMBtu} * 145 \text{ MMBtu/hr} = 59.45 \text{ lbs/hour} > 50.5 \text{ lbs/hour}$ permit limit).

9) THE PERMIT MUST REQUIRE THE PERMITTEE TO SUBMIT ALL MONITORING INFORMATION TO EPD

40 CFR § 70.6(a)(3)(iii)(A) and 42 U.S.C. § 7661(c)(a) require that permits issued by state agencies include a requirement for submittal of reports of any required monitoring at least every 6 months. The permit does not contain any such requirement.

EPD may claim that condition 6.1.4 of the permit satisfies the requirements of § 70.6(a)(3)(iii)(A). However, condition 6.1.4 requires reporting of excess emissions, exceedances and/or excursions. The reporting of these deviations is required by § 70.6(a)(iii)(B). However, § 70.6(a)(iii)(A) requires reporting of all monitoring. It is a cardinal rule of statutory and regulatory interpretation that a regulation should be interpreted in such a manner as to not render any provision of the regulation meaningless. However, EPD's claim that reporting of deviations constitutes reporting of any required monitoring renders § 70.6(a)(iii)(A) meaningless as it would be redundant to § 70.6(a)(iii)(B).

Sincerely,



Robert Ukeiley
Counsel for Newtown Florist Club,
Sierra Club and Georgia ForestWatch

Cc: Faye Bush, Newtown Florist Club
Brent Martin, Georgia ForestWatch
Curt Smith, Sierra Club
Art Hofmeister, US EPA Region 4

EXHIBIT 1

Ranking Report for Search Criteria

Pollutant: NOX

Process Category: Industrial-Size Boilers/Furnaces (more than 100 million Btu/hr, up to/including 250 million Btu/hr)

Process Type: 12.110

Process Name: Coal (includes bituminous, subbituminous, anthracite, and lignite)

Permit Date Between 03/26/1993 And 03/26/2003

RBLCID	PERMIT DATE	COMPANY & FACILITY NAME	STANDARD EMISSION
<u>FL-0077</u> BACT	07/07/1993	SEMINOLE KRAFT SEMINOLE KRAFT	<u>.2 LB/MMBTU</u>
<u>VA-0225</u> BACT	12/12/1994	VPI & STATE UNIVERSITY VPI & STATE UNIVERSITY	<u>.32 LB/MMBTU</u>
<u>ND-0016</u> BACT	06/11/1997	AMERICAN CRYSTAL SUGAR COMPANY AMERICAN CRYSTAL SUGAR COMPANY	<u>.43 LB/MMBTU</u>
<u>TN-0048</u> BACT	06/23/1994	TVA GALLATIN FOSSIL PLANT TVA GALLATIN FOSSIL PLANT	<u>.45 LB/MMBTU</u>
<u>PA-0145</u> BACT	12/21/1994	INTERNATIONAL PAPER COMPANY INTERNATIONAL PAPER COMPANY	<u>.51 LB/MMBTU</u>
<u>PA-0145</u>	12/21/1994	INTERNATIONAL PAPER COMPANY INTERNATIONAL PAPER COMPANY	<u>.51 LB/MMBTU</u>
<u>PA-0143</u>	12/21/1994	GENERAL ELECTRIC TRANSPORTATION SYSTEM GENERAL ELECTRIC TRANSPORTATION SYSTEM	<u>.59 LB/MMBTU</u>
<u>PA-0143</u>	12/21/1994	GENERAL ELECTRIC TRANSPORTATION SYSTEM GENERAL ELECTRIC TRANSPORTATION SYSTEM	<u>.59 LB/MMBTU</u>
<u>PA-0143</u> BACT	12/21/1994	GENERAL ELECTRIC TRANSPORTATION SYSTEM GENERAL ELECTRIC TRANSPORTATION SYSTEM	<u>.59 LB/MMBTU</u>
<u>NY-0070</u> BACT	04/04/1995	BLACK RIVER POWER LLC BLACK RIVER POWER LLC	<u>.6 LB/MMBTU</u>

EXHIBIT 2

STATE OF NEW YORK

6 NYCRR § 227-2.4

(b) Large boilers.

(1) Emission limits. Effective May 31, 1995, any owner or operator of a large boiler must comply with the following emission limits: NO_x RACT (pounds per million Btu per hour)

Fuel Type	Emission Limit
Gas Only	0.20
Gas/Oil	0.30
Pulverized Coal	0.50
Coal (Overfeed Stoker)	0.30*

* This emission limit is 0.33 pounds per million BTU when at least 25 percent other solid fuels (e.g. tire derived fuel, waste wood), on a Btu basis, are utilized.

Compliance with these emission limits shall be determined with a one hour average in accordance with the provisions of section 227-2.6 (a) (3) of this Subpart unless the owner/operator opts to utilize continuous emission monitoring systems (CEMS) under the provisions of section 227-2.6(a) (2) of this Subpart. If CEMS are utilized, the requirements of section 227-2.6(b) of this Subpart apply, including the use of a 24 hour averaging period.

Note: These limits are based on the use of combustion modifications. This includes, but is not limited to, the use of low NO_x burners, overfire air systems, staged combustion, gas reburning, burners out of service, and flue gas recirculation. The use of selective noncatalytic reduction can be considered to augment, be an alternative to combustion modifications. The use of selective catalytic reduction is not necessary, but may be utilized to comply with the May 31, 1995 requirements.

STATE OF MASSACHUSETTS

310 CMR 7.19

(4) Large Boilers.

(a) Applicability and NO_x RACT. After May 31, 1995, any person owning, leasing, operating or controlling a boiler having an energy input capacity of 100 million Btu per hour or greater, at a facility subject to 310 CMR 7.19, shall comply with the following NO_x emission standard, except as provided in 310 CMR 7.19(2)(b), 7.19(2)(e), 7.19(2)(f), 7.19(4)(b) and 7.19(4)(c).

1. For dry bottom boilers burning coal:
 - a. for tangential fired boilers, 0.38 pounds per million Btu,
 - b. for face fired boilers, 0.45 pounds per million Btu.
2. For stoker-fired boilers burning other solid fuels, 0.33 pounds per million Btu.

STATE OF PENNSYLVANIA
25 Pa. Code § 129.93

(b) The owner and operator shall develop and implement the following presumptive RACT emission limitations:

- (1) For a coal-fired combustion unit with a rated heat input equal to or greater than 100 million Btu/hour, presumptive RACT shall be the installation and operation of low NO [x]burners with separate overfire air.

EXHIBIT 3

TABLE 6-6. SUMMARY OF NO_x CONTROL COST EFFECTIVENESS, COAL-FIRED ICI BOILERS

Boiler type	Boiler capacity, MMBtu/hr	NO _x control technology	Controlled NO _x level, lb/MMBtu	Cost effectiveness, \$/ton NO _x removed ^{a,b}
PC wall-fired	250	LNB	0.35	1,340-1,760
	400	LNB	0.35	1,170-1,530
	500	LNB	0.35	1,090-1,430
	750	LNB	0.35	980-1,280
	250	SNCR-ammonia	0.39	1,360-1,450
	400	SNCR-ammonia	0.39	1,310-1,400
	500	SNCR-ammonia	0.39	1,300-1,370
	750	SNCR-ammonia	0.39	1,270-1,330
	250	SNCR-urea	0.39	1,120-1,340
	400	SNCR-urea	0.39	1,040-1,240
	500	SNCR-urea	0.39	1,010-1,190
	750	SNCR-urea	0.39	960-1,130
	250	SCR	0.14	3,800-4,800
	400	SCR	0.14	3,400-4,200
	500	SCR	0.14	3,200-4,000
	750	SCR	0.14	3,000-3,700
CFBC	250	SNCR-urea	0.08	960-1,130
	400	SNCR-urea	0.08	890-1,030
	500	SNCR-urea	0.08	860-980
	750	SNCR-urea	0.08	810-920
Spreader stoker	250	SNCR-urea	0.22	1,360-1,440
	400	SNCR-urea	0.22	1,320-1,380
	500	SNCR-urea	0.22	1,300-1,360
	750	SNCR-urea	0.22	1,280-1,320

^aCapacity factor: 0.50-0.66. Costs based on 10-percent interest rate and 10-year capital amortization.

^b1992 dollars.

PC-fired boilers, the actual cost of this control option is speculative at this stage. Overall, on a per-ton of NO_x removed basis of comparison, SNCR controls were the most cost effective for PC wall-fired boilers.

It should be noted that the controlled NO_x levels achieved using LNB were higher than those achieved using SNCR or SCR. This lower reduction efficiency, coupled with higher capital costs, results in higher cost effectiveness for LNB technology. For SCR controls, the most

Facility Name: **Cargill's Gainesville Vegetable Oil Mill & Refinery**
 City: Gainesville
 County: Hall
 AIRS #: 04-13-139-00002

Application #: TV- 13723
 Date SIP Application Received: NA
 Date Title V Application Received: March 21, 2002
 Date of Draft Permit: December 12, 2002
 Permit No: 2075-139-0002-V-01-1

Program	Review Engineers	Review Managers
SSPP	S. Ganapathy	Jac Capp
SSCP	Brandi Johnson	Lou Musgrove
ISMP	DeAnna Oser	Larry Webber
Toxics	NA	Karen Hayes

Introduction

This narrative is being provided to assist the reader in understanding the content of the attached SIP permit to construct and/or draft/proposed operating permit amendment. Complex issues and unusual items are explained herein simpler terms and/or greater detail than is sometimes possible in the actual permit. This permit amendment is being issued pursuant to: (1) Georgia Air Quality Act, O.C.G.A § 12-9-1, et seq. (2) Georgia Rules for Air Quality Control, Chapter 391-3-1, and (3) Title V of the Clean Air Act Amendments of 1990. Section 391-3-1-.03(10) of the Georgia Rules for Air Quality Control incorporates requirements of Part 70 of Chapter I of Title 40 of the Code of Federal Regulations promulgated pursuant to the Federal Clean Air Act. The primary purpose of this permit amendment is to identify state and federal air requirements applicable to the modification/construction to be performed at Cargill's Gainesville Vegetable Oil Mill & Refinery and to provide practical methods for determining compliance with these requirements. The following narrative is designed to accompany the draft permit amendment and is presented in the same general order as the permit amendment. It initially describes the facility receiving the permit amendment, the applicable requirements and their significance, and the methods for determining compliance with those applicable requirements. This narrative is intended as an adjunct for the reviewer and to provide information only. It has no legal standing. Any revisions made to the permit amendment in response to comments received during the public participation and EPA review process will be described in an addendum to this narrative.

I. Facility Description**A. Existing Permits**

Table 1 below lists the current Title V permit, and all administrative amendments, minor and significant modifications to that permit, and 502(b)(10) attachments. Comments are listed in Table 2 below.

Table 1: Current Title V Permit and Amendments

Permit/Amendment Number	Date of Issuance	Comments	
		Yes	No
2075-139-0002-V-01-0	April 30, 2002	X	

Table 2: Comments on Specific Permits

Permit Number	Comments
2075-139-0002-V-01-0	Permittee has requested incorporation of requirements of the vegetable oil MACT 40 CFR 63 Subpart GGGG and Georgia Rules (tt) and (yy)

B. Regulatory Status**1. PSD/NSR**

The facility is a major source under PSD/NSR regulations for NO_x, VOC, SO₂ and PM-10. Following are the PSD avoidance conditions in the existing permit.

Condition 3.2.1 limits consumption of all isomers of hexane by the vegetable/soy oil extraction process to 518.1 tons per year.

Condition 3.2.2 limits imported crude vegetable/soy oil in the refinery to 500 million pounds per year and the weighted average concentration of hexane in the crude vegetable/soy oil processed at the refinery to 100 ppm in a 12 consecutive month period.

Condition 3.4.9 limits the PM emissions from the meal dryer/cooler (P17A) to 4.25 pounds per hour.

C. PSD/NSR Applicability

For technical reasons the proposed modification is classified as a significant modification from a Title V Permitting standpoint. It is not a major modification from a PSD or NSR perspective. The draft permit amendment for the proposed amendment is included with this narrative.

III. Facility Wide Requirements

A. Emission and Operating Caps:

Under the vegetable oil MACT the oilseed solvent loss rate is limited to 0.2 gallons of HAP (hexane) per ton of oilseeds processed during any 12 consecutive months.

B. Applicable Rules and Regulations

Rules and Regulations Assessment – The facility is located in Hall county that adjoins the 13 county metro Atlanta ozone non-attainment area. Hall county is regarded as a county contributing to non-attainment in the 13 county metro Atlanta area. The subject facility is major source of VOC and NOx emissions and is subject to the State Rules 391-3-1-.02(2)(tt) and 391-3-1-.02(2)(yy) that requires RACT for VOC and NOx control for any sources having more than 1 ton/year of NOx or VOC emissions. EPD has determined that for VOC RACT, the limit should be equivalent to the limit under the Vegetable Oil MACT (40 CFR 63 Subpart GGGG) except that it would apply starting May 1, 2003 and that it would apply to all isomers of hexane.

Emission and Operating Standards

The Vegetable Oil MACT emission limit is an emission limit of 0.2 gallons of hexane per ton of soybeans processed. The facility is expected to comply with the MACT/RACT emission limit due to reasons explained in Section C.

C. Compliance Status

The Vegetable Oil MACT is a new regulation that was promulgated in April 2001 and facilities have three years to demonstrate compliance with the MACT limit.

The facility is subject to State Rule (tt) requiring RACT for VOC control from all sources at the facility having a potential VOC emission of 1 ton/year or more. The VOC RACT limit applies to all isomers of hexane. EPD has determined that the VOC RACT for this facility is the Vegetable Oil MACT (40 CFR 63 Subpart GGGG) to which the facility is subject. Thus the Vegetable Oil MACT limit has been adopted as RACT limit for VOC control. The facility is expected to be in compliance with the Vegetable Oil MACT standards. In 1998 the facility switched to a solvent (isomer of hexane) that is not a HAP unlike n-Hexane, which is a HAP. As a result, emissions on n-Hexane have been reduced more than 80% since Cargill made the solvent switch. An emission limit of 0.2 gallons of hexane per ton of soybean processed is the VOC RACT limit. Compliance with the VOC RACT limits begins on May 1, 2003.

2. Title V Major Source Status by Pollutant

Table 3: Title V Major Source Status

Pollutant	Is the Pollutant Emitted?	If emitted, what is the facility's Title V status for the Pollutant?		
		Major Source Status	Major Source Requesting SM Status	Non-Major Source Status
PM	y	✓		
PM ₁₀	y	✓		
SO ₂	y	✓		
VOC	y	✓		
NO _x	y	✓		
CO	y	✓		
TRS	n/a			
H ₂ S	n/a			
Individual	y	✓		
Total HAPs	y	✓		

The facility is not requesting a Synthetic Minor (SM) Status through this amendment for any pollutant.

Regulatory Analysis**II. Proposed Modification**

A. Description of Modification

The facility has not proposed any modification or changes to any sources or processes in place. EPD has initiated this permit amendment to incorporate the VOC and NO_x RACT permit conditions to assure compliance with the State Rules (tt) and (yy) which becomes effective in May 2003. A NO_x RACT limit is also specified for the coal-fired boiler NO_x emissions. VOC and NO_x RACT are specified in this amendment for all sources having more than 1 ton/year of VOC and NO_x emissions.

B. Emissions Change

The proposed modification will not result in any increase in the emissions of any pollutant from the current levels. There is a potential for slightly lower emissions due the improved maintenance and upkeep required for all fuel burning equipment at the facility.

D. Operational Flexibility

No operational flexibility was requested in the permit amendment application. The facility is not involved in alternate operating scenarios.

E. Permit Conditions

Condition 2.2.3 states that the oilseed solvent loss rate is 0.2 gallons per ton of soybean processed during any 12 consecutive month period and that the Compliance Ratio shall not exceed 1 as calculated in accordance with methods specified in the Vegetable Oil MACT.

Condition 2.2.4 lists all requirements under the Vegetable Oil MACT that apply to the facility under normal operation. This condition also incorporates the schedules for demonstrating compliance under the Vegetable Oil MACT.

Condition 2.2.5 requires the Permittee to develop and implement a site-specific plan for demonstrating compliance with all applicable provisions of the Vegetable Oil MACT. It also requires Permittee to keep the plan at the site in a readily accessible location as long as the source is operational.

Condition 2.2.6 requires Cargill to develop and implement a Startup, Shutdown and Malfunction Plan (SSM Plan) on or before April 12, 2004. It also requires Cargill to keep the plan at the site in a readily accessible location as long as the source is operational.

Condition 2.3.3 lays down the requirements for the facility to be compliance with Georgia Rule (tt) on May 1, 2003.

Condition 2.3.4 states that the VOC RACT limit is 0.20 gallons of hexane (all isomers) per ton of soybeans processed during any 12 consecutive month period.

IV. Regulated Equipment Requirements

A. Brief Process Description

There is no change in the equipment or process for this amendment.

B. Equipment List for the Process

No new sources, equipment or processes are proposed in this amendment.

C. Equipment & Rule Applicability

Emission and Operating Caps

Applicable Rules and Regulations

Effective May 1, 2003 the State Rule 391-3-1-.02(2)(yy) apply to all NOx sources at the facility with a potential emission in excess of 1 ton/year. For NOx sources at the facility EPD has determined that NOx RACT consist of good combustion practice (GCP) and routine maintenance such as annual tuneup for all boilers, the Hydrogen Reformer, and the Aeroglide Dryer. In addition, for the coal-fired boiler periodic NOx emission measurements are required to ensure compliance with NOx RACT limit.

Emission and Operating Standards :

The coal-fired boiler is the biggest source of NOx emissions at the facility accounting for more than 85% of the NOx emissions. Hence, emission limits are proposed for NOx emission from the coal-fired boiler at 0.41 lb/MMBtu (or 50.5 lb/hour) effective May 1, 2003, consistent with Condition 3.4.1.

In addition to the routine maintenance and annual boiler tuneup, periodic testing of NOx emissions is required for the Coal-fired boiler. For all other NOx sources the operating standards consist of routine maintenance, following best operational practices and annual tune-ups for the boilers, reformer and the Aeroglide dryer.

D. Compliance Status

Review of Section 11.1 of the application indicates that the facility is operating in compliance with all applicable rules and regulations.

E. Operational Flexibility

No operational flexibility is requested for any source at the facility. None of the process or equipment is involved in alternate operating scenarios

F. Permit Conditions

Condition 3.4.1 lists the NOx RACT emission limit for the coal-fired boiler as 0.41 lb/MMBtu or an emission rate of 50.5 lb/hour of NOx emissions from May 1, 2003.

Condition 3.4.10 specifies annual tune-ups as NOx RACT for boilers with source codes B002, HPB1 and HPB2, the Hydrogen Reformer HR01 and Aeroglide Dryer L11A.

V. Testing Requirements (with Associated Record Keeping and Reporting)

Condition 4.1.3 identifies Method 7 or 7E as the standard reference method for determining nitrogen oxide concentrations and specifies that each run shall be at least 60 minutes long.

A. Individual Equipment:

Condition 4.2.1 requires Permittee source test emissions from the Coal-fired boiler for NO_x emissions within 60 days of permit issuance. It also specifies test results to be reported to EPD within 30 days of completion of testing.

B. Equipment Groups (all subject to the same test requirements):

Not Applicable.

VI. Monitoring Requirements (with Associated Record Keeping and Reporting)**A. Individual Equipment:**

Condition 5.2.6 requires Cargill to monitor NO_x emissions from the coal-fired boiler B001 periodically to ensure compliance with the NO_x RACT limit. The initial NO_x measurement will be followed with a weekly measurement until two consecutive measurements are each less than the NO_x emission limit specified in Condition 3.4.1. Following the above occurrence, quarterly measurements of NO_x emissions from the boiler are required. If any quarterly measurement exceeds the NO_x emission limit, Permittee shall take immediate corrective action in the most expedient manner possible and conduct a new measurement within one day. Following this, measurements shall be conducted on a weekly basis and quarterly measurements may be resumed as specified in Condition 5.2.6c. Permittee shall maintain a record of all NO_x monitoring for five years.

B. Equipment Groups (all subject to the same monitoring requirements):

Boilers B002, HPB1, and HPB2, the Hydrogen Reformer and the Aeroglide Dryer are subject to annual tuneup to assure compliance with NO_x RACT rules in Condition 5.2.7. The annual tuneup requires measurement of NO_x levels using a portable analyzer. This condition also requires permittee to submit a tuneup report highlighting the NO_x emission levels recorded following the tuneup.

Condition 5.2.8 requires Cargill to determine the actual solvent loss each operating month. It also requires Cargill to calculate 12 operating months rolling sum of actual solvent loss if that information is available.

Condition 5.2.9 requires Cargill to determine the weighted average volume fraction of HAP in the actual solvent loss each operating month. If permittee has the pervious 12 month weighted average volume fraction of solvent, then they will determine an overall 12 month weighted average volume fraction of HAP and use it to determine the compliance ratio.

Condition 5.2.10 requires Cargill to determine the quantity of oilseeds processed on an as received basis. Permittee shall determine monthly, the quantity of each oilseed processed.

Condition 5.2.11 requires Cargill to calculate the Compliance Ratio each month, which compares the actual HAP loss to the allowable HAP loss for the previous 12 operating months.

VII. Other Record Keeping and Reporting Requirements

Condition 6.1.7b.vii. requires reporting associated with the exceedance of the VOC RACT limit.

Condition 6.1.7b.viii. requires reporting of the exceeding of the NOx RACT emission limit for the coal-fired boiler B001.

Condition 6.1.7c.iii. requires reporting of the failure to perform the required tune up on the boilers B002, HPB1, and HPB2, the Hydrogen Reformer (HR01) and the Aeroglide Dryer (L11A).

Condition 6.2.11 requires Cargill to submit the initial compliance certification and subsequent annual compliance certifications.

Condition 6.2.12 a. requires Cargill to submit annual compliance certifications as specified in the Vegetable Oil MACT.

Condition 6.2.12 b. requires Cargill to submit a deviation notification report for each Compliance Determination in which the Compliance Ratio exceeds 1.00.

Condition 6.2.12 c. requires submission of periodic startup, shutdown and malfunction reports as required by the Vegetable Oil MACT.

Condition 6.2.12 d. requires Cargill to submit an immediate startup, shutdown and malfunction report if it handles a SSM during an initial startup period or a malfunction period differently from the procedures in the SSM Plan.

Condition 6.2.13 requires Cargill to comply with the recordkeeping requirements of the Vegetable oil MACT by April 12, 2004.

Condition 6.2.13 a. requires Cargill to maintain records specified in 40 CFR 63.2862(c)(1) – (C)(3).

Condition 6.2.13 b. requires Cargill to record items in 40 CFR 63.2862d(1) –d(5) by the end of the calendar month following each operating month.

Condition 6.2.13 c. for each startup, shutdown, or malfunction event subject to an initial startup or malfunction period, Cargill shall record all data as indicated in 40 CFR 63.2862(e)(1) to (e)(3) by the end of the calendar month in which the initial startup or malfunction occurred.

VII. Specific Requirements

Discuss any of the following specific requirements as they apply to the modification.

- A. Operational Flexibility
None requested in this modification.
- B. Alternative Requirements
None requested in this modification
- C. Insignificant Activities
None requested in this modification
- D. Temporary Sources
None requested in this modification.
- E. Short-Term Activities
None requested in this modification.
- F. Compliance Schedule/Progress Reports
Not Applicable.
- G. Emissions Trading
None.
- H. Acid Rain Requirements
Not Applicable.
- I. Prevention of Accidental Releases
Not Applicable.
- J. Stratospheric Ozone Protection Requirements
Not Applicable.
- K. Pollution Prevention
Not Applicable.
- L. Specific Conditions
None

Addendum to Narrative

Cargill's (Gainesville Facility) draft significant permit amendment was public noticed in the December 31, 2002 issue of "The Times", a newspaper of general circulation in the Gainesville Area. The public comment period of the draft permit amendment expired on January 30, 2003. During the Public comment period comments were received from Cargill and Georgia Center for Law in Public Interest. The Georgia Center for Law also requested a public hearing on the Proposed Title V Permit Amendment. The Public Hearing was public noticed in the February 24, 2003 issue of "The Times", a newspaper of general circulation in the Gainesville Area. A public hearing was held on March 27, 2003, at the Georgia Mountain Center in Gainesville to receive more public comments on Cargill's Draft Permit Amendment. The section below describes the comments and EPD responses to the comments received during the public comment period and during the public hearing.

Comments Received During the Public Comment Period

Cargill's Comments

Trinity Consultants submitted written comments on behalf of Cargill on January 28 and 30, 2003. According to Cargill, the January 30 comments supersede the January 28 comments. Hence, only the January 30 comments are addressed in this addendum. No comments were received from Cargill during the public hearing.

NOx RACT Comments:

Comment: NOx RACT limits should only apply from May 1 through September 30 each year. Wording to this effect should be added to the permit under Condition 3.4.1.

Response: The NOx RACT limit is established to reduce NOx emissions from major sources during the summer ozone season. This limit is not a BACT limit. Condition 3.4.1 is amended to include the suggested wording of NOx RACT applicability during the summer ozone season.

Comment: Annual tune-ups should be eliminated for equipment that is not used for extended time. Cargill suggested addition of a Condition 5.2.7(f): "If an emission unit is not operated during the Ozone season, then such equipment shall be exempt from the annual tune-up requirement."

Response: Condition 5.2.7(e) is amended requiring annual tune-ups only if the equipment will be used during the ozone season.

Georgia Center for Law in Public Interest Comments

Comment: NOx RACT for B001 Should be 0.08 lb/MMBtu achieved with SCR. Ronald Methier agreed with this position in an April 8, 2002 letter.

Response: Ronald Methier's letter was based on an old analysis submitted by Cargill on April 1, 2002 that showed the cost effectiveness for installing a SCR on the coal fired boiler to be approximately \$7000/ton of NOx reduction. EPD reviewed the cost effectiveness data and concluded that NOx control could be achieved with a cost effectiveness of \$4,900 per ton of NOx reduction. However, this analysis was based on cost assumptions developed from SCR retrofits at large scale pulverized coal-fired electric utility boilers.

A subsequent site-specific cost analysis data presented by Cargill on July 17, 2002 indicated that the cost effectiveness of NO_x control using a SCR for boiler B001 exceeds \$13,400/ton of NO_x removed. Based on this analysis, EPD determined that SCR should not be required as NO_x RACT. Hence, the Draft Permit Amendment concluded that NO_x RACT for the coal-fired boiler should be proper maintenance and operation and annual tune-ups of the boiler. The NO_x emission limit for the coal-fired boiler was set at 0.41 lb/MMBtu. Hence no changes are made to the proposed NO_x emission RACT limit in the proposed permit amendment. Cargill looked at the feasibility of i) Natural gas reburn, iii) SCR and ii) Switching to natural gas from coal as RACT for NO_x control for the coil fired boiler and concluded that none of these options was cost effective to be RACT for NO_x control for the coal-fired boiler.

Comment: The current NO_x RACT limit for boiler B001 is not enforceable as a practical matter and lacks adequate monitoring and reporting.

Response: In Condition 3.4.1, the reference to the lb/hr NO_x emission rate is dropped to avoid confusion. Condition 5.2.6 requires monitoring of NO_x emissions from the boiler using a portable NO_x analyzer on a weekly and quarterly basis. Condition 6.1.7 b. viii requires reporting of NO_x emissions in excess of the NO_x RACT limit. The commenter has not presented any data regarding the cost-effectiveness for the various NO_x control options as RACT for NO_x control for the coal-fired boiler. After the changes to Condition 3.4.1 the NO_x RACT limit for the boiler B001 is enforceable as a practical matter.

Comment: An annual tune-up is not RACT for other emission units. Boilers B002, HPB1 and HPB2 should be fired with natural gas only with propane as a backup if possible.

Response: The York-Shipley boiler B002 is a standby boiler. The high pressure boiler HPB1, and high pressure steam vaporizer HPB2 are smaller units that are fired primarily with gas. It is not cost effective to force these sources to use propane as a backup fuel. Since propane is derived from natural gas its supply is subject to the same uncertainty as that of natural gas. Hence, propane does not qualify to be considered as a backup fuel. Hence no change is made to the backup fuel for boilers B002, HPB1 and HPB2.

Comments Received during the Public Hearing: During the Public Hearing on Cargill's Draft Title V Permit Amendment Georgia Center for Law in the Public Interest made oral and written comments. GA Center also submitted written comments during the public comment period for Cargill's Draft Title V Permit Amendment. The president of Newtown Florist Club (Ms. Faye Bush), Ms. Belinda Dickey, a Newtown resident and Mr. Brent Martin, Executive VP of Georgia Forest Watch made oral comments during the public hearing. The section below represents EPD's response to those comments.

Comment: The RACT NO_x limit for coal-fired boiler should be much lower. A lower RACT limit can be achieved through applying the following techniques: SCR, Over Fire Air, Fuel Reburning, Stage Combustion Air (Low Excess Air) (SCA), Flue Gas Recirculation (FGR), SCA + FGR, Selective Non-Catalytic Reduction (SNCR). EPD needs to evaluate each of these options. For example, SNCR can achieve a 40% to 70% NO_x reduction with a 58% average on stoker coal fired boilers. In addition, SNCR is usually less expensive than SCR because there is no catalyst. EPA's Alternative Control Technology document puts cost effectiveness in the \$1360 to \$1440 range. In conclusion, NO_x RACT limit for B001 be 0.08 lbs/MMBtu over a three-hour average using SCR. If that is rejected, then EPD should require RACT to be much less than the current limit using one of the above techniques.

Response: Cargill evaluated the cost effectiveness of Gas Reburning and Natural gas conversion of the coal-fired boiler B001 and found cost estimates to be \$17,518 and \$24,231 per ton of NOx reduced. A subsequent site-specific cost analysis data presented by Cargill on July 17, 2002 indicated that the cost effectiveness of NOx control using a SCR for boiler B001 exceeds \$13,400/ton of NOx removed. Based on this analysis, EPD determined that SCR, Gas Reburning or Natural gas conversion of boiler B001 should not be required as NOx RACT. Commenter has not provided any information to support a conclusion that the proposed technologies can cost effectively be retrofitted onto the coal-fired boiler at Cargill. No change is made to the proposed draft permit amendment in response to the above comments.

Comment: RACT for B002, HPB1, and HPB2, The Hydrogen Reformer HR01, and the Aeroglide Dryer L11A should be met using Low NOx burners.

Response: The remaining combustion units listed above contribute only 15% of the facility total NOx emissions and it is not cost effective to replace the burners in all of these sources to Low NOx burners. Hence the RACT determination for NOx control for these sources remain combustion of a clean fuel such as pipeline quality natural gas, good combustion practices and an annual tuneup. No changes are made to the draft permit amendment conditions.

Comment: The narrative does not provide a complete factual and legal basis for the permit conditions.

Response: The legal basis of each permit condition appears in a separate line at the end of each permit condition. For brevity the citations are not repeated in the narrative as it does not have any legal standing and is for informational purposes only. The factual basis is briefly discussed in the narrative.

Comment: Condition 2.2.5 does contain adequate monitoring. Conditions 2.2.5 and 5.2.7d allow for monitoring to be done later. Part 70 requires monitoring to be part of the Title V Permit that the public gets to comment on. The commenter suggests that the public be given an opportunity to formally comment on the monitoring that is eventually placed in Conditions 2.2.5 and 5.2.7d.

Response: Condition 2.2.5 specifies monitoring and recordkeeping for demonstrating compliance with the Vegetable Oil MACT. This condition adopts by reference all applicable monitoring and recordkeeping necessary for demonstrating compliance directly from the Vegetable Oil MACT itself. This procedure of adoption of federal monitoring, recordkeeping and reporting schemes are routine where the federal standards themselves are adopted as State Standards. No change is made to condition 2.2.5 in response to comments. Condition 5.2.7d is a reporting condition that requires to Cargill to report on the results of the boiler tune-ups within 30 days of completion of the same. No changes are made to Condition 5.2.7d.

Comment: Condition 5.2.6a should specify a load or loads at which testing is to occur. Condition 5.2.6a does not specify any operating conditions during the test. As written, the boiler could be turned off during testing. Condition 5.2.6a should require testing at 100% load.

Response: Condition 5.2.6a requires NOx monitoring of the coal-fired boiler using GRI's CTM-30 and EPD continues to believe that this meets the applicable monitoring requirements. It is completely illogical that the boiler would not be operating during testing as suggested by the commenter. Hence no change is made to Condition 5.2.6a.

Comment: Condition 3.4.1 needs an averaging time to make it enforceable as a practical matter. It is not clear whether the averaging times is 30 minutes based on 5.2.6, or 1 hour based on Condition 4.1.3j saying the run time is 60 minutes or 3 hours, based on EPD's belief that what they think should be the averaging time,

Response: Condition 3.4.1 sets the NOx RACT emission limit for the coal-fired boiler B001. The averaging time for this standard is based on the runtimes for the applicable reference method test, in this case Method 7 or 7E, required for demonstrating compliance. This is clearly explained in the introductory paragraph to Part 3.0 of the permit. Condition 5.2.6 establishes monitoring that is used to provide a reasonable assurance of compliance. The fact that the duration and frequency of monitoring may be different from the averaging time of the emission standard does not make the emission standard unenforceable. Condition 3.4.1 was not changed.

Comment: NOx Monitoring results need to be reported to EPD.

Response: Condition 6.1.7b viii requires reporting of exceedance of NOx RACT limit for the coal-fired boiler. Condition 6.1.2 requires reporting in writing within 7 days any deviations from applicable requirements associated with any malfunction of process, fuel burning, or emission control equipment for a period of four hours or more and which result in excess emissions. Condition 6.1.3 requires semi-annual reports of failure to meet an applicable emission limitation or standard in the permit. The reporting provision in condition 6.1.7b viii and 6.1.3 is standard in most Title V Permits. No change is made to these permit conditions.

Comment: Manufacturer's specifications need to be available to the public and must be included in the permit file in order to make Condition 5.2.7 enforceable as a practical matter.

Response: EPD disagrees with the commenter. Condition 5.2.7 is enforceable as a practical matter as written. The issue of what information is required to be submitted to the permitting authority is also addressed in the final comment/response of this addendum. No change is made to Condition 5.2.7.

Comment: The Permit need to have monitoring and reporting to assure compliance with the lb/hour NOx limit. The lb/hour limit is more stringent than the lb/MMbtu NOx emission limit.

Response: Changes made to Condition 3.4.1 consisted of dropping the lb/hr NOx emission rate limit. With this change the above comments are not relevant now. The NOx emission rate in lb/hour was not proposed by Cargill and was not meant to be the NOx RACT limit for the coal-fired boiler. EPD thanks the commenter for bringing this matter to its attention.

Comment: The Permit must require the permittee to submit all monitoring information to EPD. Title V Permitting regulation requires submission of reports of any required monitoring at least every 6 months. The permit does not contain such a requirement.

Response: The section of the United States Code cited by the commenter requires that the Permittee submit, no less than every six months, the results of any required monitoring. 40 CFR 70.6(a)(3)(iii) and Georgia Rule 391-3-1-.03(10)(d)1.(i), which incorporates this federal requirement, require the submittal, at least every six months, of reports of any required monitoring. These citations do not require the submittal of copies of all monitoring data recorded by the Permittee; rather, they require submittal of reports on the results of this monitoring. Condition 6.1.4 of the permit, for which these comments were submitted, requires such reports to be submitted semi-annually, by July 30 and January 30, for the preceding calendar semi-annual periods of each year. The permit has therefore not been modified in response to this comment.



RECEIVED

JAN 31 2003

AIR PROTECTION BRANCH

January 30, 2003

Mr. James Capp
Air Protection Branch
Environmental Protection Division
Georgia Department of Natural Resources
4244 International Parkway, Suite 120
Atlanta, Georgia 30354

RE: *Comments on Cargill's Gainesville Title V Permit Amendment 2075-139-0002-V-01-1*

Dear Mr. Capp:

This letter is being submitted before the January 30th comment deadline to address the recent amendment to Cargill's Gainesville Title V permit. Cargill requests that the Georgia Environmental Protection Division (EPD) incorporate the following updates into the Cargill Title V Permit Amendment 2075-139-0002-V-01-1.

REQUESTED CHANGES TO NO_x RACT REQUIREMENTS

The EPD has proposed a NO_x emission limit of 0.41 lb/MMBtu (or 50.5 lb/hr) from the coal fired boiler (B001) effective May 1, 2003. For all other NO_x sources at the facility, boilers (B002, HPB1, and HPB2), hydrogen reformer (HR01), and the Aeroglide dryer (L11A), the operating standards consist of routine maintenance which includes following the best operational practices and performing annual tune-ups.

Reasonably Available Control Technology (RACT) limits are established to reduce emissions during the ozone season. The emission limits should only apply from May 1 through September 30 each year. Cargill requests that wording to this effect be added to the permit under Condition 3.4.1 (NO_x RACT).

Since there may be combustion units at the facility that are not used for extended periods of time, up to several years, Cargill requests that annual tune-ups be eliminated from such pieces of equipment. Pursuant to this request, Cargill asks that Condition 5.2.7 (e) reflect this change with the additional text shown below. Alternatively, this text could be added under Condition 5.2.7 as item (f):

"If an emission unit is not operated during the Ozone season, then such equipment shall be exempt from the annual tune-up requirement."

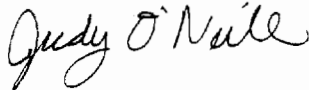
Mr. James Capp – Page 2
January 30, 2003

* * * * *

If you need any additional information, please do not hesitate to call me at (770) 394-4001 or Mr. Mike Dobeck at (770) 531-4731.

Sincerely,

TRINITY CONSULTANTS

A handwritten signature in cursive script that reads "Judy O'Neill".

Judy O'Neill, P.E.
Project Supervisor

cc: Mr. Tom Flynn, Cargill (Minneapolis, MN)
Mr. Mike Dobeck, Cargill (Gainesville, GA)



RECEIVED
JAN 29 2003
AIR PROTECTION BRANCH

January 28, 2003

Mr. James Capp
Air Protection Branch
Environmental Protection Division
Georgia Department of Natural Resources
4244 International Parkway, Suite 120
Atlanta, Georgia 30354

RE: *Comments on Cargill's Gainesville Title V Permit Amendment 2075-139-0002-V-01-1*

Dear Mr. Capp:

This letter is being submitted before the January 30th comment deadline to address the recent amendment to Cargill's Gainesville Title V permit. Cargill requests that the Georgia Environmental Protection Division (EPD) incorporate the following updates into the Cargill Title V Permit Amendment 2075-139-0002-V-01-1.

RACT APPLICABILITY DURING OZONE SEASON

Reasonably Available Control Technology (RACT) limits are established to reduce emissions during the ozone season. The emission limits should only apply from May 1 through September 30 each year. Cargill requests that wording to this effect be added to the permit under Conditions 2.3.4 (VOC RACT) and 3.4.1 (NO_x RACT).

VOC RACT

Georgia EPD has determined that for VOC RACT, emission limits should be equivalent to the limit under the vegetable oil National Emission Standard for Hazardous Air Pollutants (NESHAP) except that it would apply to all isomers of hexane and compliance would start on May 1, 2003. The vegetable oil NESHAP (codified under 40 CFR 63 Subpart GGGG) restricts emissions to 0.2 gallons of hexane per ton of soybeans processed. Additional requirements of the VOC RACT amendment include:

1. Develop a site specific plan for demonstrating compliance with the vegetable oil NESHAP and make sure that the plan is accessible as long as the facility is in operation.
2. Develop and implement a Startup, Shutdown, and Malfunction Plan (SSM Plan) on or before April 12, 2004. This plan must be kept accessible as long as the facility is in operation.
3. Determine the actual solvent loss each operating month.
4. Determine the weighted average volume fraction of HAP in the actual solvent loss each operating month.
5. Determine the quantity of oilseeds processed on an "as received basis."

6. Calculate the Compliance Ratio each month, which compares the actual HAP loss to the allowable HAP loss for the previous 12 operating months.
7. Comply with the reporting requirements of the NESHAP General Provisions in 40 CFR 63 Subpart A (periodic reports, SSM events).

REQUESTED REVISION

The Gainesville facility is a minor source of HAP emissions and as such is not subject to the vegetable oil MACT. While Cargill agreed to the MACT emission limit as VOC RACT, using the exact procedures given in the MACT to demonstrate ongoing compliance is overly burdensome. In an April 1, 2002 submittal to EPD, Cargill proposed a more appropriate method to track data for compliance with the emission limit. This method is similar to the vegetable oil MACT monitoring methods; however, it is not identical and as such a direct citation of the MACT monitoring requirements would require Cargill to make unneeded changes to the current tracking system.

The Title V permit revisions also contain reporting requirements taken from the federal NESHAP General Provisions in 40 CFR 63 Subpart A (periodic reports, SSM events). Because the facility is a minor HAP source, 40 CFR 63 Subpart A does not apply to the site. The same rigor of compliance established for NO_x RACT should be applied to VOC RACT, which does not include SSM reporting, as these requirements would cause an unnecessary burden on a facility maintaining compliance with a state-required RACT.

For these reasons, Cargill requests that EPD remove the proposed conditions based on NESHAP General Provisions and that EPD revise the monitoring conditions for VOC RACT:

1. Remove Section 2.2 – Facility Wide Federal Rule Standards
2. Remove Section 6.2 – Specific Record Keeping and Reporting Requirements
3. Replace Conditions 5.2.8 through 5.2.11 with the following monitoring method for VOC RACT:

Each month, Cargill will record the following data related to solvent losses.

- a. gallons of solvent in inventory at beginning of each month
- b. gallons of solvent in inventory at end of each month
- c. gallons of solvent received during the month
- d. gallons of solvent added or removed during the month
- e. tons of oilseed processed during the month

Cargill will use the above records with the following equations to calculate the twelve-month rolling average for solvent loss rate.

- a. Monthly solvent loss (gallons) = gallons of solvent in inventory at beginning of each month - gallons of solvent in inventory at end of each month + gallons of solvent received during the month +/- gallons of solvent added or removed during the month.

- b. $\text{Monthly solvent loss rate (gal/ton)} = \frac{\text{Monthly solvent loss (gallons)}}{\text{Monthly oilseed processed (tons)}}$

NO_x RACT

The EPD has proposed a NO_x emission limit of 0.41 lb/MMBtu (or 50.5 lb/hr) from the coal fired boiler (B001) effective May 1, 2003. For all other NO_x sources at the facility, boilers (B002, HPB1, and HPB2), hydrogen reformer (HR01), and the Aeroglide dryer (L11A), the operating standards consist of routine maintenance which includes following the best operational practices and performing annual tune-ups.

REQUESTED REVISION

Since there may be combustion units at the facility that are not used for extended periods of time, up to several years, Cargill requests that annual tune-ups be eliminated from such pieces of equipment. Pursuant to this request, Cargill asks that Condition 5.2.7 (e) reflect this change with the additional text shown below. Alternatively, this text could be added under Condition 5.2.7 as item (f):

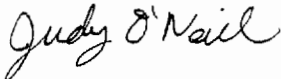
“If an emission unit is not operated during the Ozone season, then such equipment shall be exempt from the annual tune-up requirement.”

* * * * *

If you need any additional information, please do not hesitate to call me at (770) 394-4001 or Mr. Mike Dobeck at (770) 531-4731.

Sincerely,

TRINITY CONSULTANTS



Judy O'Neill, P.E.
Project Supervisor

cc: Mr. Tom Flynn, Cargill (Minneapolis, MN)
Mr. Mike Dobeck, Cargill (Gainesville, GA)



862 West Ridge Road
Gainesville, GA 30501

RECEIVED

AUG 13 2001

AIR PROTECTION BRANCH

July 31, 2001

**Georgia Department of Natural Resources
Environmental Protection Division, Air Protection Branch
4244 International Parkway, Suite 120
Atlanta, GA 30504**

Re: Initial Notification for Existing Sources under 40CFR63 Subp. GGGG National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production

This letter serves as the Initial Notification for Existing Sources as required under 63.2860(a) for the Cargill, Inc. oilseed processing facility identified below.

1. Name and Address of Owner

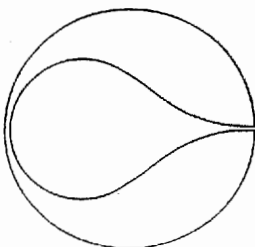
Cargill, Inc.
15407 McGinty Road West
Wayzata, MN 55391-2399

2. Physical Address of Vegetable Production Process

**862 West Ridge Road
Gainesville, Georgia 30501**

3. Relevant Standard and Compliance Date

40 CFR 63 Subp. GGGG National Emission Standards for Hazardous Air Pollutants: Solvent Extraction for Vegetable Oil Production. Compliance date April 12, 2004.



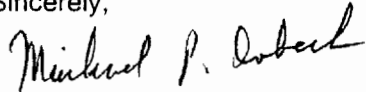
4. Source Description

This facility processes soybeans at a nominal operating capacity of 990,000 tons/year and uses a conventional DT for desolventizing.

5. Major Source Designation Statement

This source has the potential to emit greater than 10 tons per year of n-Hexane and is a major source as defined at 40 CFR 63.2832(a).

Sincerely,



Michael P. Dobeck
Facility Superintendent

Cc: Tom Flynn

Additional Impact Analysis

To date, there is not evidence or a history of incidents which indicate that the soil and/or vegetation in the surrounding area will be endangered by this installation. The modeling results show the ground level concentrations of the pollutants to be a concentration, such that, it will not cause a problem.

The required opacity limitation will prevent any impact on visibility in the neighborhood of the plant.

The plant location is physically limited such that future expansion to increase capacity will be impossible.

CONCLUSIONS

On February 22, 1978, Cargill, Inc. filed an application for permit to construct one 145 million BTU/hr coal fired boiler with capability of using natural gas or fuel oil on a standby basis. Supplemental information to the original application was received July 25, 1978.

In September, 1978, the Environmental Protection Division (EPD) made a preliminary determination that the proposed construction would be consistent with the intent of the federal Prevention of Significant Deterioration (PSD) Program and applicable state regulations and should be approved.

On October 16, 1978, public notice of the preliminary determination was made in THE TIMES newspaper serving the city of Gainesville and Hall County. The public notice provided for thirty (30) day period for the submittal of written comments which expired on November 16, 1978. Comments were received only from the Environmental Protection Agency, Region IV. In accordance with the procedures outlined in the Code of Federal Regulation 40CFR 52.21, Cargill was informed of EPA's comments. The EPD has reviewed EPA's comments and hereby responds to their comments in the narrative that follows.

EPA noted that we did not condition the Permit to Construct to limit the emissions from the baghouse. The baghouse manufacturer has guaranteed the performance to be .1 lbs/millionBTU heat input. Therefore, EPD has added on this condition to the permit.

The EPD is satisfied that all requirements under the federal PSD regulations and state regulations have been complied with and that the construction of the 145 million BTU/hr boiler is in accordance with these regulations. Therefore, the EPD has issued a Permit to Construct to Cargill, Inc. for the construction of the boiler. An EPD letter dated January 5, 1978 transmitting this permit to Cargill and a copy of the permit with conditions can be found in Appendix.

Appendix

AIR QUALITY CONTROL SECTION
 ENVIRONMENTAL PROTECTION DIVISION
 DEPARTMENT OF NATURAL RESOURCES
 270 WASHINGTON STREET, S.W.
 ATLANTA, GEORGIA 30334

RECEIVED
FEB 22 1978
AIR PROTECTION BRANCH

DO NOT WRITE IN THIS SPACE

Permit No. _____
 Region _____
 Date Submitted _____
 Approved
 Disapproved
 Date _____
 Permit Reviewer _____

APPLICATION FOR PERMIT TO CONSTRUCT OR
 MODIFY PROCESS EQUIPMENT, FUEL BURNING EQUIPMENT
 AND AIR POLLUTION CONTROL DEVICES.

SECTION I - GENERAL INFORMATION

Cargill, Inc.
 NAME OF FIRM, INSTITUTION OR ESTABLISHMENT
949 Ridge Road, S.E., P.O. Box 1298, Gainesville, Georgia 30501
 MAILING ADDRESS OF CENTRAL OFFICE (Street & P. O. Box) (City) (State) (Zip Code)
 Same
 FACILITY LOCATION (Street & P. O. Box) (City) (County) (Zip Code)
Mr. Hershel Austin - Plant Superintendent (404) 536-4368
 PERSON TO CONTACT REGARDING THIS REPORT TITLE TELEPHONE

PERMIT REQUEST FOR *

	CONSTRUCTION	MODIFICATION
Process Equipment		
Fuel Burning Equipment	X	
Air Pollution Control Device	X	
Starting Date <u>Jan. 79</u> Completion Date <u>Jul. 79</u>		

C. LIST FINISHED PRODUCTS:

1. N/A
2. _____
3. _____
4. _____

Comments on Schedule:
 Need to have initial approval from EPD at earliest possible date so that decision by Cargill to proceed may be made.

DESCRIBE THE OPERATION THAT IS TO BE CONSTRUCTED OR MODIFIED. Example: A new bag filter is to be constructed for use at the #2 dryer exhaust. "Use reverse side if more space is needed." New coal fired boiler and associated bag filter.

Smith Engineering Consultants, 711 Green St., Suite 119, Gainesville, Ga.
 NAME AND ADDRESS OF CONSULTING FIRM, IF USED. 30501

CHECK TYPE OF AIR CONTAMINANTS EMITTED TO ATMOSPHERE AND/OR CONTROLLED AT NEW OPERATION*

- | | | |
|--|--|---|
| <input checked="" type="checkbox"/> SMOKE | <input checked="" type="checkbox"/> PARTICULATE MATTER | <input checked="" type="checkbox"/> SULFUR DIOXIDE |
| <input checked="" type="checkbox"/> OXIDES OF NITROGEN | <input type="checkbox"/> ASBESTOS | <input type="checkbox"/> BERYLLIUM |
| <input type="checkbox"/> MERCURY | <input checked="" type="checkbox"/> HYDROCARBONS | <input checked="" type="checkbox"/> CARBON MONOXIDE |
| <input type="checkbox"/> FLUORIDES | <input type="checkbox"/> SULFURIC ACID MIST | <input type="checkbox"/> ODOR |
| <input type="checkbox"/> _____
OTHERS | | |

If an existing facility operating permit has been filed then complete this application only for that portion of operation which is to be constructed or modified, if otherwise then complete for the entire facility.

This application for a "Permit to Construct" is submitted in accordance with the provisions of the Air Quality Control Rules and Regulations, and to the best of my knowledge is true and correct.

H. Austin
 Applicant (if corporation, signature of officer or other authorized official)

Title: Plant Superintendent

Date: 2-21-78

AIR POLLUTION CONTROL SERVICE
DEPARTMENT OF NATURAL RESOURCES

SECTION III - FUEL BURNING EQUIPMENT (Sheet 1 of 2)

Normal operating schedule for fuel use: 24 Hours per day 7 Days per week 50 Weeks per year 8400 Hours per year.
 Dates of annually occurring shutdowns of operations: Sept. - 2 Wks. Additional operating information enclosed

Source Code	Boiler or Unit Designation	Design Capacity of Unit (Input) 10^6 BTU/hr.	Maximum Expected Load (% of Rated Capacity)	Average Annual Load (% of Rated Capacity)	Type of Unit	Percent Excess Air Used in Combustion (Design)	Power Output Megawatts
101	120,000 PPH	145	84	67	Spreaderstoker	20	N/A

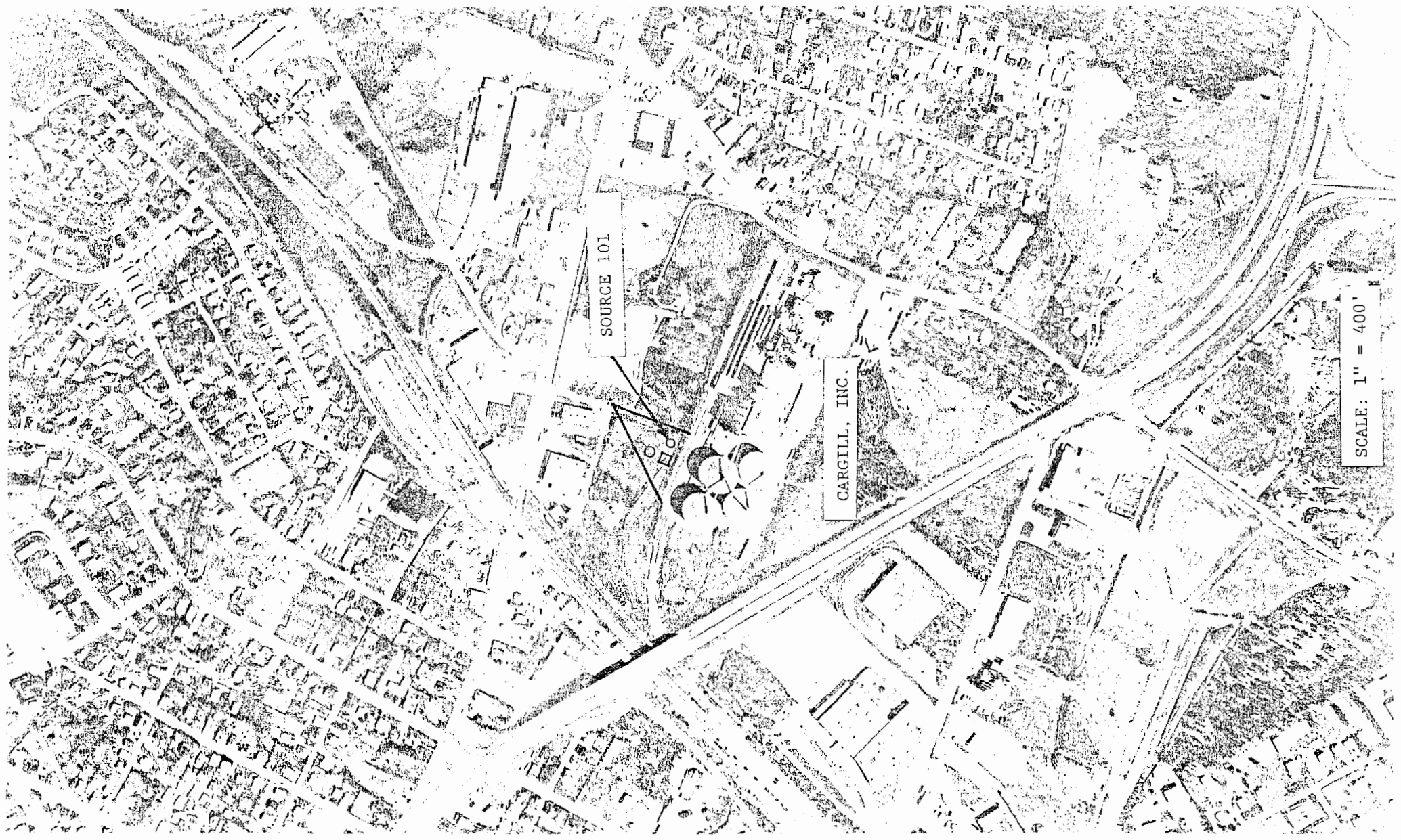
(See reverse side for instructions)

AIR POLLUTION CONTROL SERVICE
DEPARTMENT OF NATURAL RESOURCES

SECTION III - FUEL BURNING EQUIPMENT (Sheet 2 of 2)

Source Code	Type of Fuel	Annual Consumption					Hourly Consumption		Percent Used for Space Heat	* Heat Content BTU/Quantity	Percent Sulfur in Fuel, by weight			Percent Ash (Solid Fuel Only)			
		Quantity	Percent Distribution by Season				Maximum	Average			Average	Min.	Max.	Avg.	Min.	Max.	Av
			Spring March/ May	Summer June/ Aug.	Fall Sept./ Nov.	Winter Dec./ Febr.											
101	Coal	34,000 Tons	25	25	25	25	5.1T	4.1T	0°	11,962 BTU/lb	0.6	3.0	1.8	3	18	9	
												1.5					
										Min. 11,500 BTU/lb							
										Max. 14,500 BTU/lb							
	Emergency Standby																
	No. 6 Fuel Oil	Standby					3.4T	2.7T	0°	18,000 BTU/lb	1.2	3.0	1.6				
	Natural Gas	Standby					122M ft ³	97M ft ³	0°	1,000 BTU/ft ³	0	0.025	-				

*Use reverse side to list minimum and maximum values.



SOURCE 101

CARGILL, INC.

SCALE: 1" = 400'

Instructions For Completing Section III

Source Code - List code numbers for each source to correspond with code numbers in section V and VI.

Type of Unit - Ex: Hand-fired, underfeed, overfeed, pulverized, spreader stoker, gun type oil burner, etc.

Power Output - Megawatts - Power generating only.

Type of Fuel - Ex: Coal; No. 1, 2, 3, 4, 5, and 6 oil; natural gas; wood; bark; etc.

Complete a separate line for each fuel used including any standby fuel.

Attach a plot plan that shows the location of the facility and points of discharge in relation to the surrounding area, residences and other permanent structures and roadways. (Points should be identified by source code used in the other sections of this application. Show scale.)

AIR POLLUTION CONTROL SERVICE
DEPARTMENT OF NATURAL RESOURCES

SECTION V - AIR CLEANING EQUIPMENT

Source Code	Type of Air Cleaning Equipment	Δ P	Pollutant Removed	Efficiency		Inlet Gas Temperature, °F (Design)	Inlet Gas Flow Rate, CFM (Actual)	Inlet Loading lbs/hr	Exit Loading lbs/hr	DO NOT WRITE IN THIS SPACE Allowable lbs/hr
				Design Percent	Operating Percent					
101	Baghouse (Fabric Bags-Fiberglass & Teflon)	5 in.	Particulates	99.3	99.3+	350	64,300	1554	11 10.818	

(See reverse side for instructions)
Explain on reverse side how collected material is to be disposed of.

Instructions For Completing Section V

Source Code - List code numbers corresponding to each emission source listed in sections II and III.

Type of Air Cleaning Equipment - List the type of collectors. Ex: Venturi, electrostatic precipitator, fabric filter, water spray, etc.

Pollutant Removed - List pollutant removed by the collector. Ex: Particulate, sulfur dioxide, fluorides, etc.

ΔP - Pressure drop across the control device in inches of water.

Inlet Gas Flow Rate, CFM - Give the flow rate at actual flow conditions.

IMPORTANT

Description of Control Devices:

Attach separate sheets, giving details regarding principals of operations, manufacturer, model, size, and capacity of control device and the basis for calculating its efficiency. Show any by-pass of the control device and specify when and under what conditions they are to be used. For liquid scrubbers indicate the liquid scrubbing rate and liquid discharge rate.

Manufacturer has not been selected-efficiency specified 99.3%
Explain how you would propose to monitor the collector to insure the maintenance of operations and collection efficiency.

Monitoring

Continuous

Temperature in and out
Differential Pressure
Flow Rate

Periodic

Particulates

How is collected pollutant material to be disposed of or utilized? Is any of the material disposed through a sewer system or water discharge?

(a) Landfill

(b) No discharge through sewer system or water discharge

AIR POLLUTION CONTROL SERVICE
DEPARTMENT OF NATURAL RESOURCES

SECTION VI - STACK AND POLLUTANT EMISSIONS DATA

*Source Code	Height Above Grade, ft.	Inside Diameter at Top, ft.	STACK DATA						ESTIMATE OF POLLUTANT EMISSIONS				DO NOT WRITE IN THIS SPACE Allowable lbs/hr or lbs/10 ⁶ BTU In.
			Exit Gas Velocity, ft./sec.		Exit Gas Temperature °F		Exit Gas Flow Rate, CFM		Pollutants	Quantity Emitted			
			Average	Maximum	Average	Maximum	Average	Maximum		Tons Per Year (Avg.)	Maximum (Pounds/hr)	Maximum (lbs/10 ⁶ BTU Input)	
101	135 100	9	17	21	300 [±]	300 [±]	64,300	80,600	Particulates	46.2	13.5	0.11	
									NO _x (as NO ₂)	344	102	0.83	
									SO ₂	1240	581	4.8	
									Hydrocarbons (as CH ₄)	17.2	5.1	0.042	
									CO	51.7	15.3	0.13	

*IMPORTANT - See instructions

Instructions For Completing Section VI

*Source Code - List code numbers corresponding to each emission source listed in sections II and III. If the stack serves more than one emission point, please note.

Pollutants - Specify the material emitted. Use a separate line for each pollutant emitted from stack.

Emissions - lbs/10⁶ BTU input applicable to fuel burning equipment only.

Indicate how emission rates were determined Example - material balance, emission factors, guess, etc.

Particulates	- emission factor
NO _x	- emission factor
SO ₂	- material balance confirmed by emission factor
Hydrocarbons	- emission factor
CO	- emission factor

Final determination of a Permit to Construct application submitted by Cargill, Inc. for one 145 million BTU/hr coal fired boiler at the Cargill Plant in Gainesville, GA

Prepared by:
The Department of Natural Resources
Environmental Protection Division
Air Protection Branch

December, 1978

Abstract

The Air Protection Branch (APB) has reviewed a permit to construct application submitted by Cargill, Inc. for one 145 million BTU/hr coal fired boiler with capability for using fuel oil or natural gas on a standby basis. The boiler will be located at the existing Cargill plant, 949 Ridge Road, Gainesville, Georgia. The Branch's evaluation indicates that the emissions to the atmosphere will meet all applicable state regulations and federal prevention of significant deterioration. In addition, emissions from the boiler will not impact on a Class I area.

Introduction

On May 3, 1976, the Environmental Protection Division (EPD) received delegation of authority from the United States Environmental Protection Agency (EPA) for the implementation and enforcement of the Federal Prevention of Significant Deterioration (PSD) program.

On February 22, 1978, Cargill, Inc. filed an application for permit to construct along with supporting documents. Supplemental information to the original application was received July 25, 1978.

The Air Protection Branch has determined through its new source review procedure that this source is subject to the PSD regulations as well as the Georgia Rules and Regulations for Air Quality Control. The plant is governed by the PSD regulations because the uncontrolled potential emissions of particulate, sulfur dioxide and nitrous oxides are over 250 tons/yr.

The proposed new source must also comply with the Georgia Rules and Regulations for Air Quality Control... The results of the new source review performed by the APB indicate that the proposed construction is consistent with the intent of PSD and applicable state regulations and therefore should be issued a construction permit under certain conditions.

Nitrous Oxide Emissions

The Air Protection Branch has carefully considered the information provided by Cargill for nitrous oxide emissions. A comparison of future emissions while using coal as compared to present emissions using fuel oil was presented. The comparison indicates the overall effect to be a net decrease from their current level of emissions.

Based on factors obtained from AP-42 (Compilation of Air Pollutant Emission Factors), the following nitrous oxide emissions estimates for coal were obtained:

$$\text{Actual } 258.3 \frac{\text{tons}}{\text{yr}} \times \frac{\text{yr}}{8400 \text{ hr}} \times \frac{2000 \text{ lbs}}{\text{tons}} = 61.5 \text{ lbs/hr}$$

$$\text{Potential } 325.9 \frac{\text{tons}}{\text{Yr}} \times \frac{\text{yr}}{8400 \text{ hr}} \times \frac{2000 \text{ lbs}}{\text{tons}} = 77.59 \text{ lbs/hr}$$

$$\text{Potential } \frac{77.59 \text{ lbs/hr}}{145 \times 10^6 \text{ BTU/hr}} = \frac{0.535 \text{ lbs}}{10^6 \text{ BTU}}$$

Although there is not an applicable state regulation which applies in this case, the 0.535 lbs/10⁶ BTU is less than 0.7 lbs/10⁶ BTU allowable (state regulation) for coal fired boilers with a heat input of greater than 250 X 10⁶ BTU/hr.

In consideration of the foregoing, the Air Protection Branch believes that this mode of operation will not adversely impact on the ambient air level of nitrous oxides.

Control Technology Review 145 Million BTU/hr Coal Fired Boiler

The proposed boiler will replace three existing gas or oil fired boilers at the Cargill plant in Gainesville, Georgia. The boiler will be a spreader type stoker with traveling grates for continuous ash removal. This particular equipment was selected because of its ability to minimize particulate emissions. In addition, transfer points in the coal handling system will be enclosed.

Cargill has proposed to control particulate emissions from the boiler with a baghouse. The baghouse manufacturer has guaranteed that, the emission of particulate matter from the baghouse will not exceed .1 lbs/million BTU heat input and its performance will be verified by a particulate emissions test on the exhaust stack gases. The baghouse operational parameters will be monitored continuously with temperature, pressure and flow measuring devices. A properly designed and operated baghouse should be able to control particulate emissions as proposed. The Air Protection Branch accepts a properly sized, designed, installed and operated baghouse as the best available control technology for particulate emissions.

The original application specified use of coal with a maximum sulfur content of 3%. The supplemental information specified coal with a maximum sulfur content of 1.5%. Cargill contends and has presented information which makes the use of coal with less than 1.5% sulfur uneconomical. Coal availability and present coal costs were considered in their determination.

Four different control strategies for sulfur dioxide were investigated. In each case, the company would be forced to abandon the proposal because it would be economically infeasible. The vendor quotations for the considered control systems are included in the supplemental information document.

The availability of proven sulfur dioxide control, that is both economically feasible and functionally practical for this size boiler, is limited. Therefore, the Air Protection Branch accepts the use of coal with a maximum sulfur content of

*1.5% as the best available control technology for this proposal.

Nitrous oxide emissions can be controlled by proper combustion of the coal. This method includes controlling the amount of excess combustion air while simultaneously maintaining the appropriate flame temperature. Effective combustion practices can be construed to be the best available control technology and is acceptable to the Air Protection Branch.

A CRSTER dispersion model was used to determined the impact of particulate and sulfur dioxide emissions on the surrounding area. The model parameters and emissions data can be found in the included table of the same name. The results of the modeling indicate that the increased emissions, that result from the operation of the proposed boiler, will consume a small portion of the allowable incremental increase in ambient air concentration of particulate matter and sulfur dioxide.

In consideration of all the foregoing facts, as well as the switch from natural gas or fuel oil to coal as primary fuel to satisfy the energy demands of the plant, all applicable state and Federal Prevention of Significant Air Quality Deterioration requirements are satisfied.

TABLE
STACK PARAMETERS
AND EMISSION DATA

Stack Height	30.48	Meters
Stack Diameter	1.52	Meters
Exit Velocity	20.73	Meters/sec
Temperature	422.00	degrees Kelvin
Volumetric flow	37.62	meter ³ /sec
Emission Rate	1.70	grams/sec

PROPOSED 145×10^6 BTU/hr BOILER

	Allowable Emissions (State Regulations)		Potential Emissions Uncontrolled		Estimate Actual Emissions	
	lb/hr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr
Particulate	59.1	238.5	843.5	3400	13.5	56.7
Sulfur Dioxide	296.3	1194.6	253.0	1020	239.4	965.3

PSD INCREMENT STANDARDS
AND IMPACT OF CARGILL BOILER

	Class I Area	Class II Area	Model Prediction
Particulate			
annual geometric mean	5	19	.125
24 hour maximum	10	37	1.900
Sulfur Dioxide			
annual arithmetic mean	2	20	2.730
24 hour maximum	5	91	41.550
3 hour maximum	25	512	126.990

All numerical entries have units of micrograms per cubic meter

Ambient Air Analysis

The PSD Regulation requires that the ambient air impact of SO₂ and TSP emissions from Cargill's new boiler be assessed. Specific incremental increases of these two pollutants in the ambient air have been established and cannot be exceeded by a new facility.

To determine the ambient impact, a CRSTER atmospheric dispersion model was used. The CRSTER model is designed to calculate maximum one-hour, 3-hour, 24-hour, and annual average concentrations at a specified set of receptors for a full year of actual, hourly meteorological data. This model is based upon the assumption that the dispersion of a plume is primarily a function of wind direction and speed, atmospheric stability conditions, and the effective point of discharge of the plume. To predict ambient air concentrations of a pollutant, the models use mathematical formulas which simulate the plume emerging from a stack, rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat-terrain. The concentrations of pollutants are assumed to have a Gaussian distribution along the longitudinal center line of the plume.

The emission data utilized in the model corresponds to the boiler operating at its maximum design capacity. Although it is unlikely that the boiler will be used to this extent, assuming that the major air pollution sources operate at the maximum design capacity will define a "worst case" basis for the ambient review.

The meteorological data utilized in the models represent actual meteorological conditions measured in the area. Both surface conditions and upper air conditions are included in the meteorological data. The meteorological data used in the dispersion model was: UPPER AIR STATION-ATHENS, Georgia; and Surface Weather Station - Atlanta, Georgia.

The area impacted by the emissions from the Cargill boiler is in a region which has been designated PSD-Class II for SO₂ and TSP. The nearest Class I area is the Cohutta Wildlife Management Area, and is approximately 200 kilometers from

the plant. The air quality dispersion models are not accurate for distances greater than 50 kilometers; however, considering the prevailing wind directions and distance, the APB has determined that no measurable ambient impact should result at Cohutta from the Cargill boiler.

The APB has determined that soils, vegetation and visibility should not be significantly impacted because of the slight increase in the ambient concentration of TSP and SO₂ from the existing conditions.

A table is included to compare the impact of the Cargill boiler with the PSD increments. The APB has determined that the new effect of the installation will not have a significant effect on the surrounding area.

Source Information Analysis

Cargill has proposed to begin construction on the boiler in January, 1979 and it is expected that construction will be completed in July, 1979. Once the boiler is in operation, it is scheduled to operate 8400 hours per year. There will be a two week shutdown period annually for general maintenance. During this time period the existing boilers will satisfy the required steam demand. In any case, the Permit to operate will be conditioned, such that, operating the proposed boiler simultaneously with the existing boilers will be prohibited.

The boiler has a rated, design capacity of 145 million BTU/hr. However, the normal operating conditions will only require 67 percent of its design capacity to satisfy their needs.

A baghouse will be used to control particulate emissions. The APB accepts this control as the best available control technology for particulate matter.

Additional Impact Analysis

To date, there is not evidence or a history of incidents which indicate that the soil and/or vegetation in the surrounding area will be endangered by this installation. The modeling results show the ground level concentrations of the pollutants to be a concentration, such that, it will not cause a problem.

The required opacity limitation will prevent any impact on visibility in the neighborhood of the plant.

The plant location is physically limited such that future expansion to increase capacity will be impossible.

CONCLUSIONS

On February 22, 1978, Cargill, Inc. filed an application for permit to construct one 145 million BTU/hr coal fired boiler with capability of using natural gas or fuel oil on a standby basis. Supplemental information to the original application was received July 25, 1978.

In September, 1978, the Environmental Protection Division (EPD) made a preliminary determination that the proposed construction would be consistent with the intent of the federal Prevention of Significant Deterioration (PSD) Program and applicable state regulations and should be approved.

On October 16, 1978, public notice of the preliminary determination was made in THE TIMES newspaper serving the city of Gainesville and Hall County. The public notice provided for thirty (30) day period for the submittal of written comments which expired on November 16, 1978. Comments were received only from the Environmental Protection Agency, Region IV. In accordance with the procedures outlined in the Code of Federal Regulation 40CFR 52.21, Cargill was informed of EPA's comments. The EPD has reviewed EPA's comments and hereby responds to their comments in the narrative that follows.

EPA noted that we did not condition the Permit to Construct to limit the emissions from the baghouse. The baghouse manufacturer has guaranteed the performance to be .1 lbs/millionBTU heat input. Therefore, EPD has added on this condition to the permit.

The EPD is satisfied that all requirements under the federal PSD regulations and state regulations have been complied with and that the construction of the 145 million BTU/hr boiler is in accordance with these regulations. Therefore, the EPD has issued a Permit to Construct to Cargill, Inc. for the construction of the boiler. An EPD letter dated January 5, 1978 transmitting this permit to Cargill and a copy of the permit with conditions can be found in Appendix.

Appendix

**PETITION ATTACHMENT 5
EPA DOCUMENTS REGARDING
PETITION SUBMISSION DEADLINE**



U.S. Environmental Protection Agency

EPA Region 4 Proposed Title V Permits

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Georgia Proposed Title V Permits

Air Permitting Issues

ALABAMA

FLORIDA

GEORGIA

KENTUCKY

MISSISSIPPI

NORTH CAROLINA

SOUTH CAROLINA

TENNESSEE

Title V Permits

State	County	Source Name	PA Permit Number	End of 45-Day Review	Petition Deadline
GA	Haralson	Plantation Pipe Line	4613-143-0017-V-01-0	08/01/2003	09/30/2003
GA	Hall	Cargill Gainesville	2075-139-0002-V-01-1	08/04/2003	10/03/2003
GA	Chatham	Savannah Resource Recovery Facility	4953-051-0152-V-01-0	08/11/2003	10/10/2003
GA	Spaulding	Exopack	2673-255-0047-V-02-0	08/22/2003	10/21/2003
GA	Ware	GATX - Waycross	4741-299-0015-V-01-0	08/22/2003	10/21/2003
GA	Carroll	Printpack, Inc.	2759-045-0039-V-01-3	08/24/2003	10/23/2003
GA	Sumter	Collins & Aikman	3714-261-0005-V-02-1	08/24/2003	10/23/2003
GA	Taylor	Taylor County LFGTE Power Station	4911-269-0016-V-01-0	08/28/2003	10/27/2003
GA	Taylor	Taylor County Landfill	4953-269-0014-V-01-1	08/28/2003	10/27/2003
GA	Putnam	Horton Homes	2451-237-0131-V-01-0	08/30/2003	10/29/2003
GA	Liberty	Interstate Paper, LLC	2631-179-0001-V-01-2	09/06/2003	11/05/2003
GA	Dooly	Georgia-Pacific Resins	2821-093-0013-V-01-0	09/06/2003	11/05/2003
GA	Chatham	Arizona Chemical Company	2821-051-0148-V-01-1	09/08/2003	11/07/2003

GA	Fulton	Owens Corning	3296-121-0021-V-01-0	09/08/2003	11/07/2003
GA	Walton	Goodyear Tire & Rubber Company	3061-297-0036-V-06-0	09/11/2003	11/10/2003
GA	Clinch	B-Way Manufacturing	3411-065-0005-V-02-1	09/18/2003	11/17/2003
GA	Whitfield	Dow Chemical - Polyurethane Dispersion Operations	2822-313-0137-V-01-2	09/19/2003	11/18/2003
GA	Meriwether	Spurlin Industries, Inc.	3088-199-0020-V-01-0	09/19/2003	11/18/2003
GA	Fulton	Spurlin Industries, Inc.	3088-121-0705-V-01-0	09/20/2003	11/19/2003
GA	Chatham	Superior Landfill & Recycling Center	4953-051-0205-V-01-0	09/20/2003	11/19/2003
GA	Jackson	J.M. Huber Corporation	2493-157-0014-V-01-4	10/03/2003	12/02/2003
GA	Fulton	General Motors	3711-089-0086-V-01-0	10/05/2003	12/04/2003
GA	Lee	Woodgrain Millwork, Inc.	2431-177-0010-V-02-0	10/09/2003	12/08/2003
GA	Gordon	J.M. Huber	3295-129-0028-V-04-0	10/09/2003	12/08/2003
GA	Gwinnett	MTI Whirlpools	3088-135-0170-V-02-1	10/12/2003	12/11/2003
GA	Wayne	Jesup Mill, Rayonier Performance Fibers	2631-305-0001-V-01-1	10/25/2003	12/24/2003
GA	Heard	Tenaska Georgia Generating Station	4911-149-0004-V-02-0	10/26/2003	12/25/2003
GA	Richmond	US Army Signal Center and Fort Gordon	9711-245-0021-V-01-0	10/31/2003	12/30/2003
GA	Crisp	Lasco Bathware	3088-081-0019-V-01-2	11/01/2003	12/31/2003
GA	Troup	Guardian Automotive - LaGrange Moulding Plant	3089-285-0069-V-01-1	11/01/2003	12/31/2003
GA	Berrien	Chaparral Boats, Inc.	3732-019-0003-V-02-	11/01/2003	12/31/2003

			1		
GA	Gwinnett	Richland Creek Road LFGTE Power Station	4911-135- 0244-V-01- 0	11/02/2003	01/01/2004
GA	Gwinnett	UWL/Richland Creek Road Sanitary Landfill	4953-135- 0219-V-01- 1	11/02/2003	01/01/2004
GA	Clayton	Rexam Beverage Can Company	3411-063- 0020-V-02- 1	11/07/2003	01/06/2004

For information about the contents of this page please contact Stan Kukier.

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Last updated on Friday, September 26th, 2003
 URL: <http://www.epa.gov/region4/air/permits/Georgia.htm>

Curtis Cox

From: Hofmeister.Art@epamail.epa.gov
Sent: Thursday, October 02, 2003 12:06 PM
To: Curtis Cox
Subject: Re: CAA Title V Petition

Yes, your understanding is correct.

Art Hofmeister
Environmental Engineer
Air Permits Section
Air Division
EPA Region 4
Phone: (404) 562-9115
Fax: (404) 562-9019

Curtis Cox
<ccox@cleangeorgi
a.org> To: Art Hofmeister/R4/USEPA/US@EPA
cc:
Subject: CAA Title V Petition
10/01/2003 06:00
PM

I just wanted to verify our phone conversation that we had earlier today regarding submission of our petition to the EPA on this Cargill-Gainsville Title V amendment and specifically, that EPA will accept the petition as long it is postmarked by the US Mail with the last day of the 60 day statutory period (October 3 is the date stated on the EPA site).

I am going to send our petition via mail to both the Regional Office and to the Administrator in DC and will deliver it to the US Post Office on Friday afternoon.

Thanks for your help with this matter; its greatly appreciated, particularly since I am the new guy here.

Sincerely,

Curtis Cox
Staff Attorney
Georgia Center for Law in the Public Interest
175 Trinity Avenue, SW
Atlanta, GA 30303
(404) 659-3122



JOE D. TANNER
Commissioner

Department of Natural Resources

ENVIRONMENTAL PROTECTION DIVISION
270 WASHINGTON STREET, S.W.
ATLANTA, GEORGIA 30334

J. LEONARD LEDBETTER
Division Director

January 5, 1979

CERTIFIED

Mr. Hershel Austin
Cargill, Inc.
P. O. Box 1298
Gainesville, GA 30501

Dear Mr. Austin:

Enclosed is a copy of the Air Protection Branch's final determination concerning the proposed construction of the 145 million BTU/hr coal-fired boiler at the Cargil plant in Gainesville.

In addition, we are pleased to send you Permit to Construct #2079-069-6098-C. Please pay close attention to the attached pages of conditions which in some cases require written notification and/or consultation with an office prior to commencement of operation.

If I can be of further assistance, please contact me at 404/656-4867.

Sincerely,

Bill Mundy

Bill Mundy
Environmental Engineer
Air Pollution Compliance Program

BM:mah

Enclosure

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION



PERMIT NO. 2079-069-6098-C

COUNTY Hall

EFFECTIVE DATE
OF PERMIT: JAN 6 1979

PERMIT TO CONSTRUCT

In compliance with the provisions of Georgia's Air Quality Act of 1978 and the Rules and Regulations, Chapter 391-3-1, adopted pursuant to or in effect under that Act, Cargill, Inc., P. O. Box 1298, Gainesville, GA 30501

is issued a Permit to Construct the following: One spreader type stoker coal fired boiler with a maximum heat input of 145 million Btu/Hr and having the capability to fire #6 fuel oil or natural gas on a standby basis. Particulate emissions from the boiler shall be controlled by a baghouse and ultimately discharged to the atmosphere through a 100 foot stack.
located at:

929 Ridge Road, Gainesville, GA 30501

This Permit to Construct is conditioned upon compliance with all provisions of Georgia's Air Quality Act of 1978, the Rules and Regulations of Chapter 391-3-1 adopted or in effect under that act, or any other condition of this Permit.

This Permit may be subject to revocation, suspension, modification or amendment by the Director for cause including evidence of noncompliance with any of the above; or for any misrepresentation made in the application(s) dated July 25, 1978, supporting data entered therein or attached thereto, or any subsequent submittals or supporting data; or for any alterations affecting the emissions from this source.

Absent prior revocation, suspension, modification or amendment by the Director, this Permit shall expire at midnight, the 1st day of September 1979.

This Permit is further subject to and conditioned upon the terms, conditions, limitations, standards, or schedules contained in or specified on the attached 2 page(s), which page(s) are a part of this Permit.


Director
Environmental Protection Division

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

PERMIT NO. 2079-069-6098-C

PAGE 1 OF 2

1. The boiler shall comply with the emission limitations specified in the Rules and Regulations for Air Quality Control 391-3-1.
2. The Permittee shall install, calibrate, operate and maintain a continuous monitoring system to measure and record opacity. Such opacity monitor(s) shall be designed to comply with performance specifications, paragraph 3.1 of Appendix P of Part 60, Chapter I, Title 40, Code of Federal Regulations and shall be installed in location(s) approved by the Division.
3. Particulate Matter Emission Test
 - a. The Permittee shall conduct or cause to be conducted a particulate matter emission compliance performance test and furnish this Division a written report of the results of such test. The test procedure must be approved by the Division before the test(s) are performed. The test(s) shall be performed within ninety (90) days of written notification from the Division.
 - b. The Permittee shall provide compliance test ports which comply with criteria more fully described in Appendix A of Part 60, Chapter I, Title 40, Code of Federal Regulations.
 - c. All required continuous monitoring systems shall be installed, calibrated and operated when the compliance test(s) are conducted.
 - d. The Permittee shall provide the Division thirty (30) days prior notice of the date of the performance test to afford the opportunity to have an observer present.
4. The Permittee shall provide the Division with the results of all laboratory analysis performed on coal used in the boiler. This will include, but not be limited to, the average and maximum BTU, ash and sulfur content.
5. The Permittee must submit technical data to the Division, when it becomes available, pertaining to the particulate emissions control device. This would include, but not be limited to: equipment operator's manual; guaranteed efficiency or emission rate agreed to by the vendor; number and description of the bags which should include the type weave, melting temperature, maximum continuous operating temperature, acid resistance, alkali resistance flex abrasion and how and when the bags will be cleaned.

STATE OF GEORGIA
DEPARTMENT OF NATURAL RESOURCES
ENVIRONMENTAL PROTECTION DIVISION

PERMIT NO. 2079-069-6098-C

PAGE 2 OF 2

6. The Permittee shall furnish the Division written notification as follows:
 - a. The anticipated date of initial startup of this source, not more than sixty (60) nor less than thirty (30) days prior to such a date.
 - b. The actual date of initial startup of this source, within fifteen (15) days after such date.

For the purposes of this permit, "startup" shall mean the setting in operation of a source for any purpose.

7. The particulate emissions to the atmosphere shall not exceed .1 lbs/million Btu/Hr heat input.
8. The Permittee shall operate this boiler only when no other boilers at the plant are in operation.
9. The Maximum sulfur content of any coal used in this boiler shall not exceed 1.5%.
10. In the event of operating the boiler on fuel oil, the maximum sulfur content of the fuel oil shall not exceed 1.5%. In addition written notification to the Division shall be required for all time periods when coal is not being used.
11. The particulate emission control device shall be operated at all times except in the periods when fuel oil is being used.

Final determination of a Permit to
Construct application submitted by
Cargill, Inc. for one 145 million
BTU/hr coal fired boiler at the
Cargill Plant in Gainesville, GA

Prepared by:
The Department of Natural Resources
Environmental Protection Division
Air Protection Branch

December, 1978

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The proposed new source must also comply with the Georgia Rules and Regulations for Air Quality Control. The results of the new source review performed by the APB indicate that the proposed construction is consistent with the intent of PSD and applicable state regulations and therefore should be issued a construction permit under certain conditions.

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$$\text{Actual } 258.3 \frac{\text{tons}}{\text{yr}} \times \frac{\text{yr}}{8400 \text{ hr}} \times \frac{2000 \text{ lbs}}{\text{tons}} = 61.5 \text{ lbs/hr}$$

$$\text{Potential } 325.9 \frac{\text{tons}}{\text{Yr}} \times \frac{\text{yr}}{8400 \text{ hr}} \times \frac{2000 \text{ lbs}}{\text{tons}} = 77.59 \text{ lbs/hr}$$

$$\text{Potential } \frac{77.59 \text{ lbs/hr}}{145 \times 10^6 \text{ BTU/hr}} = \frac{0.535 \text{ lbs}}{10^6 \text{ BTU}}$$

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Control Technology Review 145 Million BTU/hr Coal Fired Boiler

The proposed boiler will replace three existing gas or oil fired boilers at the Cargill plant in Gainesville, Georgia. The boiler will be a spreader type stoker with traveling grates for continuous ash removal. This particular equipment was selected because of its ability to minimize particulate emissions. In addition, transfer points in the coal handling system will be enclosed.

Cargill has proposed to control particulate emissions from the boiler with a baghouse. The baghouse manufacturer has guaranteed that, the emission of particulate matter from the baghouse will not exceed .1 lbs/million BTU heat input and its performance will be verified by a particulate emissions test on the exhaust stack gases. The baghouse operational parameters will be monitored continuously with temperature, pressure and flow measuring devices. A properly designed and operated baghouse should be able to control particulate emissions as proposed. The Air Protection Branch accepts a properly sized, designed, installed and operated baghouse as the best available control technology for particulate emissions.

The original application specified use of coal with a maximum sulfur content of 3%. The supplemental information specified coal with a maximum sulfur content of 1.5%. Cargill contends and has presented information which makes the use of coal with less than 1.5% sulfur uneconomical. Coal availability and present coal costs were considered in their determination.

Four different control strategies for sulfur dioxide were investigated. In each case, the company would be forced to abandon the proposal because it would be economically infeasible. The vendor quotations for the considered control systems are included in the supplemental information document.

The availability of proven sulfur dioxide control, that is both economically feasible and functionally practical for this size boiler, is limited. Therefore, the Air Protection Branch accepts the use of coal with a maximum sulfur content of

1.5% as the best available control technology for this proposal.

Nitrous oxide emissions can be controlled by proper combustion of the coal. This method includes controlling the amount of excess combustion air while simultaneously maintaining the appropriate flame temperature. Effective combustion practices can be construed to be the best available control technology and is acceptable to the Air Protection Branch.

A CRSTER dispersion model was used to determine the impact of particulate and sulfur dioxide emissions on the surrounding area. The model parameters and emissions data can be found in the included table of the same name. The results of the modeling indicate that the increased emissions, that result from the operation of the proposed boiler, will consume a small portion of the allowable incremental increase in ambient air concentration of particulate matter and sulfur dioxide.

In consideration of all the foregoing facts, as well as the switch from natural gas or fuel oil to coal as primary fuel to satisfy the energy demands of the plant, all applicable state and Federal Prevention of Significant Air Quality Deterioration requirements are satisfied.

TABLE
STACK PARAMETERS
AND EMISSION DATA

Stack Height	30.48	Meters
Stack Diameter	1.52	Meters
Exit Velocity	20.73	Meters/sec
Temperature	422.00	degrees Kelvin
Volumetric flow	37.62	meter ³ /sec
Emission Rate	1.70	grams/sec

PROPOSED 145×10^6 BTU/hr BOILER

	Allowable Emissions (State Regulations)		Potential Emissions Uncontrolled		Estimate Actual Emissions	
	lb/hr	tons/yr	lb/hr	tons/yr	lb/hr	tons/yr
Particulate	59.1	238.5	843.5	3400	13.5	56.7
Sulfur Dioxide	296.3	1194.6	253.0	1020	239.4	965.3

PSD INCREMENT STANDARDS
AND IMPACT OF CARGILL BOILER

	Class I Area	Class II Area	Model Prediction
Particulate			
annual geometric mean	5	19	.125
24 hour maximum	10	37	1.900
Sulfur Dioxide			
annual arithmetic mean	2	20	2.730
24 hour maximum	5	91	41.550
3 hour maximum	25	512	126.990

All numerical entries have units of micrograms per cubic meter

Ambient Air Analysis

The PSD Regulation requires that the ambient air impact of SO₂ and TSP emissions from Cargill's new boiler be assessed. Specific incremental increases of these two pollutants in the ambient air have been established and cannot be exceeded by a new facility.

To determine the ambient impact, a CRSTER atmospheric dispersion model was used. The CRSTER model is designed to calculate maximum one-hour, 3-hour, 24-hour, and annual average concentrations at a specified set of receptors for a full year of actual, hourly meteorological data. This model is based upon the assumption that the dispersion of a plume is primarily a function of wind direction and speed, atmospheric stability conditions, and the effective point of discharge of the plume. To predict ambient air concentrations of a pollutant, the models use mathematical formulas which simulate the plume emerging from a stack, rising a certain distance in the atmosphere, leveling off, and continuing downwind over relatively flat-terrain. The concentrations of pollutants are assumed to have a Gaussian distribution along the longitudinal center line of the plume.

The emission data utilized in the model corresponds to the boiler operating at its maximum design capacity. Although it is unlikely that the boiler will be used to this extent, assuming that the major air pollution sources operate at the maximum design capacity will define a "worst case" basis for the ambient review.

The meteorological data utilized in the models represent actual meteorological conditions measured in the area. Both surface conditions and upper air conditions are included in the meteorological data. The meteorological data used in the dispersion model was: UPPER AIR STATION-ATHENS, Georgia; and Surface Weather Station - Atlanta, Georgia.

The area impacted by the emissions from the Cargill boiler is in a region which has been designated PSD-Class II for SO₂ and TSP. The nearest Class I area is the Cohutta Wildlife Management Area, and is approximately 200 kilometers from

the plant. The air quality dispersion models are not accurate for distances greater than 50 kilometers; however, considering the prevailing wind directions and distance, the APB has determined that no measurable ambient impact should result at Cohutta from the Cargill boiler.

The APB has determined that soils, vegetation and visibility should not be significantly impacted because of the slight increase in the ambient concentration of TSP and SO₂ from the existing conditions.

A table is included to compare the impact of the Cargill boiler with the PSD increments. The APB has determined that the new effect of the installation will not have a significant effect on the surrounding area.

Source Information Analysis

Cargill has proposed to begin construction on the boiler in January, 1979 and it is expected that construction will be completed in July, 1979. Once the boiler is in operation, it is scheduled to operate 8400 hours per year. There will be a two week shutdown period annually for general maintenance. During this time period the existing boilers will satisfy the required steam demand. In any case, the Permit to operate will be conditioned, such that, operating the proposed boiler simultaneously with the existing boilers will be prohibited.

The boiler has a rated, design capacity of 145 million BTU/hr. However, the normal operating conditions will only require 67 percent of its design capacity to satisfy their needs.

A baghouse will be used to control particulate emissions. The APB accepts this control as the best available control technology for particulate matter.