ATTACHMENT 3

ASTM STANDARD C618-89a

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AMERICAN SOCIETY FOR TESTING AND MATERIALS
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Standard Specification for Fly Ash and Raw or Calcined Natural Pozzolan for use as a Mineral Admixture in Portland Cement Concrete[1]

This standard is issued under the fixed designation C 618; the number immediately following the designation indicates the year of original adoption or, in the case of revision, the year of last revision. A number in parentheses indicates the year of last reapproval. A superscript epsilon (ε) indicates an editorial change since the last revision or reapproval.

This specification has been approved for use by agencies of the Department of Defense. Consult the DoD Index of Specifications and Standards for the specific year of issue which has been adopted by the Department of Defense.

1. Scope

1.1 This specification covers fly ash and raw or calcined natural pozzolan for use as a mineral admixture in concrete where cementitious or pozzolanic action, or both, is desired, or where other properties normally attributed to finely divided mineral admixtures may be desired or where both objectives are to be achieved.

NOTE—Finely divided materials may tend to reduce the entrained air content of concrete. Hence, if a mineral admixture is added to any concrete for which entrainment of air is specified, provision should be made to assure that the specified air content is maintained by air content tests and by use of additional air-entraining admixture or use of an air-entraining admixture in combination with air-entraining hydraulic cement.

1.2 The values stated in inch-pound units are to be regarded as the standard.

2. Referenced Documents

2.1 *ASTM Standards:*

C 260 Specification for Air-Entraining Admixtures for Concrete[2]

C 311 Methods of Sampling and Testing Fly Ash or Natural Pozzolans for Use as a Mineral Admixture in Portland Cement Concrete[2]

3. Terminology

3.1 *Definitions:*

3.1.1 *fly ash*—finely divided residue that results from the combustion of ground or powdered coal.

NOTE—This definition of fly ash does not include, among other things, the residue resulting from: (1) the burning of municipal garbage or any other refuse with coal; or (2) the injection of lime directly into the boiler for sulfur removal; or (3) the burning of industrial or municipal garbage in incinerators commonly known as "incinerator ash."

3.1.2 *pozzolans*—siliceous or siliceous and aluminous materials which in themselves possess little or no cementitious value but will, in finely divided form and in the presence of moisture, chemically react with calcium hydroxide at ordinary temperatures to form compounds possessing cementitious properties.

4. Classification

4.1 *Class N*—Raw or calcined natural pozzolans that comply with the applicable requirements for the class as given herein, such as some diatomaceous earths; opaline cherts and shales; tuffs and volcanic ashes or pumicites, any of which may or may not be processed by calcination; and various materials requiring calcination to induce satisfactory properties, such as some clays and shales.

4.2 *Class F*—Fly ash normally produced from burning anthracite or bituminous coal that meets the applicable requirements for this class as given herein. This class fly ash has pozzolanic properties.

4.3 *Class C*—Fly ash normally produced from lignite or subbituminous coal that meets the applicable requirements for this class as given herein. This class of fly ash, in addition to having pozzolanic properties, also has some cementitious properties. Some Class C fly ashes may contain lime contents higher than 10 %.

5. Chemical Composition

5.1 Fly ash and natural pozzolans shall conform to the requirements as to chemical composition prescribed in Table 1. Supplementary optional chemical requirements are shown in Table 2.

6. Physical Properties

6.1 Fly ash and natural pozzolans shall conform to the physical requirements prescribed in Table 3. Supplementary optional physical requirements are shown in Table 4.

7. Methods of Sampling and Testing

7.1 Sample and test the mineral admixture in accordance with the requirements of Methods C 311.

7.2 Use cement of the type proposed for use in the work and, if available, from the mill proposed as the source of the cement, in all tests requiring the use of hydraulic cement.

8. Storage and Inspection

8.1 The mineral admixture shall be stored in such a manner as to permit easy access for proper inspection and identification of each shipment. Every facility shall be provided the purchaser for careful sampling and inspection, either at the source or at the site of the work as may be specified by the purchaser.

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[1] This specification is under the jurisdiction of ASTM Committee C-9 on Concrete and Concrete Aggregates, and is the direct responsibility of Subcommittee C09.03.10 on Fly Ash, Slag, Mineral Admixtures, and Supplementary Cementitious Materials.

Current edition approved Oct. 27, 1989. Published December 1989. Originally published as C 618 – 68 T to replace C 350 and C 402. Last previous edition C 618 – 87.

[2] *Annual Book of ASTM Standards*, Vol 04.02.

TABLE 1 Chemical Requirements

	Mineral Admixture Class		
	N	F	C
Silicon dioxide (SiO_2) plus aluminum oxide (Al_2O_3) plus iron oxide (Fe_2O_3), min, %	70.0	70.0	50.0
Sulfur trioxide (SO_3), max, %	4.0	5.0	5.0
Moisture content, max, %	3.0	3.0	3.0
Loss on ignition, max, %	10.0	6.0[A]	6.0

[A] The use of Class F pozzolan containing up to 12.0 % loss on ignition may be approved by the user if either acceptable performance records or laboratory test results are made available.

TABLE 1A Supplementary Optional Chemical Requirement

NOTE—This optional requirement applies only when specifically requested.

	Mineral Admixture Class		
	N	F	C
Available alkalies, as Na_2O, max, %[A]	1.5	1.5	1.5

[A] Applicable only when specifically required by the purchaser for mineral admixture to be used in concrete containing reactive aggregate and cement to meet a limitation on content of alkalies.

TABLE 2 Physical Requirements

	Mineral Admixture Class		
	N	F	C
Fineness:			
Amount retained when wet-sieved on 45 μm (No. 325) sieve, max, %[A]	34	34	34
Strength activity index:[B]			
With portland cement, at 7 days, min, percent of control	75[D]	75[D]	75[D]
With portland cement, at 28 days, min, percent of control	75[D]	75[D]	75[D]
With lime, at 7 days min, psi (kPa)	800 (5500)	800 (5500)	...
Water requirement, max, percent of control	115	105	105
Soundness:[C]			
Autoclave expansion or contraction, max, %	0.8	0.8	0.8
Uniformity requirements:			
The specific gravity and fineness of individual samples shall not vary from the average established by the ten preceding tests, or by all preceding tests if the number is less than ten, by more than:			
Specific gravity, max variation from average, %	5	5	5
Percent retained on 45-μm (No. 325), max variation, percentage points from average	5	5	5

[A] Care should be taken to avoid the retaining of agglomerations of extremely fine material.

[B] Neither the *strength* activity index with portland cement nor the pozzolanic activity index with lime is to be considered a measure of the compressive strength of concrete containing the mineral admixture. The *strength* activity index with portland cement is determined by an accelerated test, and is intended to evaluate the contribution to be expected from the mineral admixture to the longer strength development of concrete. The weight of mineral admixture specified for the test to determine the *strength* activity index with portland cement is not considered to be the proportion recommended for the concrete to be used in the work. The optimum amount of mineral admixture for any specific project is determined by the required properties of the concrete and other constituents of the concrete and should be established by testing. *Strength* activity index with portland cement is a measure of reactivity with a given cement and may vary as to the source of both the fly ash and the cement.

[C] If the mineral admixture will constitute more than 20 % by weight of the cementitious material in the project mix design, the test specimens for autoclave expansion shall contain that anticipated percentage. Excessive autoclave expansion is highly significant in cases where water to mineral admixture and cement ratios are low, for example, in block or shotcrete mixes.

[D] Meeting the 7 day or 28 day *strength* activity index will indicate specification compliance.

9. Rejection

9.1 The mineral admixture may be rejected if it fails to meet any of the requirements of this specification.

9.2 Packages varying more than 5 % from the stated weight may be rejected. If the average weight of the packages in any shipment, as shown by weighing 50 packages taken at random, is less than that specified, the entire shipment may be rejected.

9.3 Mineral admixture in storage prior to shipment for a period longer than 6 months after testing may be retested and may be rejected if it fails to meet the fineness requirements.

TABLE 2A Supplementary Optional Physical Requirements

NOTE—These optional requirements apply only when specifically requested.

	Mineral Admixture Class		
	N	F	C
Multiple factor, calculated as the product of loss on ignition and fineness, amount retained when wet-sieved on No. 325 (45-μm) sieve, max, % [A]	....	255	....
Increase of drying shrinkage of mortar bars at 28 days, max, % [B]	0.03	0.03	0.03
Uniformity Requirements:			
In addition, when air-entraining concrete is specified, the quantity of air-entraining agent required to produce an air content of 18.0 vol % of mortar shall not vary from the average established by the ten preceding tests or by all preceding tests if less than ten, by more than, %	20	20	20
Reactivity with Cement Alkalies: [C]			
Reduction of mortar expansion at 14 days, min, %	75	....	....
Mortar expansion at 14 days, max, %	0.020	0.020	0.020

[A] Applicable only for Class F mineral admixtures since the loss on ignition limitations predominate for Class C.

[B] Determination of compliance or noncompliance with the requirement relating to increase in drying shrinkage will be made only at the request of the purchaser.

[C] The indicated tests for reactivity with cement alkalies are optional and alternative requirements to be applied only at the purchaser's request. They need not be requested unless the fly ash or pozzolan is to be used with aggregate that is regarded as deleteriously reactive with alkalies in cement. The test for reduction of mortar expansion may be made using any high-alkali cement in accordance with Methods C 311, Section 35.1 if the portland cement to be used in the work is not known, or is not available at the time the mineral admixture is tested. The test for mortar expansion is preferred over the test for reduction of mortar expansion if the portland cement to be used in the work is known and available. The test for mortar expansion should be performed with each of the cements to be used in the work.

10. Packaging and Package Marking

10.1 When the mineral admixture is delivered in packages, the class, name, and brand of the producer, and the weight of the material contained therein shall be plainly marked on each package. Similar information shall be provided in the shipping invoices accompanying the shipment of packaged or bulk mineral admixture.

ATTACHMENT 4

AUGUST 2, 1991 LETTER
FROM OUC TO EPA

Beals

ORLANDO UTILITIES COMMISSION
500 SOUTH ORANGE AVENUE • P. O. BOX 3193 • ORLANDO, FLORIDA 32802 • 407/423-9100

August 2, 1991

Ms. Jewell A. Harper
Chief, Air Enforcement Branch
U. S. Environmental Protection Agency
Region IV
345 Courtland Street, N.E.
Atlanta, GA 30365

Dear Ms. Harper:

RE: Orlando Utilities Commission
SEC Unit 2
Permit Modification (PSD-FL-084)

Enclosed are OUC's responses to the questions your staff raised regarding our submittal, as transmitted in your letter of July 2, 1991.

The staff and management of OUC appreciate the frank and efficient working relationship that our staffs have developed during this project.

Please have Gregg Worley give Jim Crall a call at (407) 423-9141 if it would be helpful to have an additional meeting prior to your preparation of the preliminary determination and draft permit.

Very truly yours,

Thomas Tart

Thomas Brogden Tart
General Counsel

cc: Gregg Worley, EPA
Nancy Pommelleo, Esq., EPA
Hamilton S. Oven, FDER
Clair M. Fancy, FDER

AUG 2 91

COMMENT:

(Reference EPA Region IV staff July 2, 1991 letter to Mr. James P. Crall of the Orlando Utilities Commission.)

"The SO2 emission limit which you have proposed is 0.32 lb/MMBTU on a thirty-day rolling average, based on a design coal with a maximum sulfur content of 2.5% and a control system removal efficiency of 92%. The presentation made by your consultant gave the basis of this estimate as a statistical analysis utilizing a computer model which estimated that the reduction level that could be achieved with 99% confidence limit over a thirty-day rolling average would be 92%. The assumptions made for this model include the use of 95% as the "target" removal efficency since this is the highest guaranteed by any vendor. What is the basis for the vendor guarantee of 95%? It would seem that the 95% removal number, if it was guaranteed by the vendor, is the result of experience and analysis rather than a "target" number which is the starting point of the analysis."

RESPONSE:

(Reference July 12, 1991 memorandum from M. F. McClernon to E. C. Windisch, B&V File 16805.32.0402.)

The information concerning performance tests and guarantees included here is based on the "offer to ABB" and is not finalized in a conformed document at this time. It does, however, represent the current state of negotiated agreement.

"Target", as referred to in the BACT analysis, implies conditions achieved when parameters that might be responsible for variation in SO2 removal rate are held in strict design tolerance levels, i.e "on target." These parameters include slurry pH, L/G ratio, limestone grind and quality, coal quality, gas flow magnitude and distribution, scrubber slurry liquid phase alkalinity, spray distribution, module pressure drop, mist eliminator cleanliness, and makeup water quality. When these conditions meet target, "target removal efficiency" results.

EPA has requested information on how "target removal", as described above and used in the computer simulation model, relates to the "manufacturer's guarantee." (The manufacturer's guarantee of 95 per cent removal efficiency has been used as target removal in the computer modeling.) EPA has also raised questions of whether a 95 per cent removal efficiency "guarantee" might not actually represent a "confidence limit", based on manufacturer experience and analysis, that assures consistent success in achieving 95 per cent removal, and indicates a target substantially higher than 95 per cent.

To answer these questions, it is informative to examine conditions that constitute "meeting guarantee."

The guarantee test times are basically at the discretion of the manufacturer. He is allowed to pre-test, inspect, and adjust the system until he is satisfied with it's performance. This ensures that all performance parameters are "on target" before the test begins. Limestone grind is tested for fineness; limestone is quality tested for minimum 90 per cent calcium carbonate content and available alkalinity of 1.0; "design" coal, blended to specified quality levels, is brought in specifically for the test; scrubber slurry pH is carefully controlled to a specified level optimum for the design coal(s); load (and consequently gas flow, temperature, and SO2 content) is held constant for the duration of the test; gas flow is checked both by experimental measurement and stoichometric flow calculation, and averaged for accuracy; the number of spray pumps operating is held constant; spray nozzles are clean and in unworn condition for uniform spray distribution; mist eliminator blades are in clean condition; ductwork and damper settings are clean and tuned for uniform gas flow distribution; makeup water is monitored for quality; and buffering of scrubber liquor is allowed (and monitored) through addition of adipic acid at maximum additive rate.

Under these controlled conditions, SO2 removal rate is monitored for a period of four (4) hours. Three such tests are performed and averaged at each load condition. Since the three tests are not necessarily consecutive, the manufacturer can adjust the system for each sample to assure "target" conditions. If an average removal efficiency of 95 per cent is achieved, the performance guarantee is met.

The test, as described above, basically is one that "guarantees" a "target" removal efficiency of 95 per cent. That is, when chemistry and process condition "targets" are achieved, 95 per cent average removal efficiency is "guaranteed" to result. This is the exact form of the simulation model, and the correct format for representation of the guarantee.

Several questions may be raised concerning the form of guarantee as described above. First, is a four-hour test a fair test of the system's performance? Deviation away from 95 per cent can only be caused by deviation away from "target" conditions. Although it is acknowledged that this variation is a "normal" part of day-to-day operation, the magnitude and rate of these variations are not completely within the control of the manufacturer. For his own protection, the manufacturer will only guarantee performance under controlled conditions. Test result variation is therefore only a function of measurement error propagation and minor fluctuations in "target" conditions, and is relatively small. The system either meets, or does not meet guarantee, and four hour tests are a sufficient and appropriate time frame to establish this condition.

Second, what level of expected performance is necessary for a manufacturer to prudently (or "confidently") guarantee 95 per cent removal efficiency? (This question is actually irrelevant to the engineer or owner at time of design, since the answer not guaranteed. It is interesting, however, to analyze the situation.)

From the manufacturer's point of view, a guarantee is not an absolute assurance that promised performance will be met. It is a single component of an overall risk evaluation. He must evaluate the benefits of success (his profit) against the consequences of failure (liquidated damages.) No real project presents a zero probability of either of these states. The most instructive example of this may be that the OUC Stanton Unit 1 scrubber, using similar (two hour) tests in a similar environment, did not meet guarantee requirement of 90 per cent removal at high sulfur design coal conditions.

At 95 per cent removal efficiency, the chemistry of the system has essentially been pushed to the limit, and remaining gains in efficiency are basically a fairly unpredictable function of uniformity in spray, inter-module and intra-module flow distribution, and fortuitous combinations of off-design conditions. A manufacturer with a true 95 per cent expected removal efficiency (50 per cent confidence) can expect a statistical distribution of random four-hour removal efficiencies characterized as follows for normal, non-outage hours:

4-Hour Removal Efficiency	Per Cent of Time	Cumulative % of Time
88	0.0000	0.0000
89	0.0002	0.0002
90	0.0006	0.0007
91	0.0039	0.0046
92	0.0376	0.0422
93	0.2127	0.2549
94	0.4164	0.6713
95	0.2700	0.9412
96	0.0552	0.9964
97	0.0035	0.9999
98	0.0001	1.0000

(These figures are based on OUC Stanton Unit 2 scrubber model predictions using 100 per cent availability and a target/guarantee removal efficiency performance level of 95 per cent.)

During normal, non-outage hours of operation, the scrubber is removing 95 per cent or more of the SO2 about 33 per cent of the time. Because of the high levels of autocorrelation in 4-hour performance levels, prediction of near term operation levels can be made with high levels of confidence. That is, if it observed that the scrubber is operating at 95 per cent on a given day (indicating target conditions), it is probable that those levels will be sustained for several days. The probability of a scrubber with 95 per cent target removal (zero design margin) passing the 95 per cent guarantee performance test is very high. Further, if the manufacturer should not pass the test, he simply "adjusts" the system, and calls for a new test.

The following summary points may be made. The scrubber performance test is a series of three short-term (4 hour) tests. This test is appropriate and sufficient to assure that under controlled (target) conditions, a guaranteed (target) removal efficiency will be achieved. No design margin is guaranteed, and no design margin (or confidence limit) is required to assure high likelihood of passing the guarantee test. Accordingly, the use of guarantee level as "target" in the computer simulation model is the most appropriate value available.

Supplemental NO_x BACT Analysis

The original Best Available Control Technology (BACT) analysis for the Orlando Utilities Commission C. H. Stanton Unit 2 was submitted on March 15, 1991 as part of the Supplemental Site Certification Application. This supplemental NO_x BACT analysis addresses specific issues identified by the Environmental Protection Agency in letter dated July 2, 1991. Assumptions regarding plant, fuels and evaluation criteria remain the same as presented in that document. The substantive issues identified for further information submittal included the effects of low NO_x burners on carbon losses, and a detailed technical and economic evaluation for installation of a selective catalytic NO_x emission reduction (SCR) system on Stanton 2. The following discussion addresses these specific issues identified.

1.0 Boiler Carbon Losses

Low NO_x burners reduce NO_x emissions by effectively staging combustion. Unfortunately, this results in less efficient combustion, increasing levels of unburned combustibles. This will be exhibited by higher fly ash carbon contents. It is estimated by the boiler manufacturer that unburned carbon levels will increase from 0.3 percent for burners designed to meet a New Source Performance Standard NO_x emission of 0.60 lb/MBtu to 0.4 percent for low NO_x burners designed to meet a NO_x emission of 0.32 lb/MBtu. This corresponds to a coincidental increase in fly ash carbon contents from 2.9 percent to 3.8 percent for low NO_x burners.

ASTM has established standard specifications for the use of fly ash as a mineral admixture in concrete (designation C618-91). These specifications indicate that fly ash with carbon contents up to 6 percent are allowed to be used as concrete admixture. Accordingly, fly ash carbon losses from the use of low NO_x burners will not prohibit the sale of fly ash from Stanton 2.

2.0 Selective Catalytic Reduction

Selective catalytic reduction systems limit NO_x emissions by injecting ammonia upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate reducing a significant portion of the NO_x into nitrogen and water. SCR systems may potentially reduce NO_x emissions by as much as 70 to 90 percent.

The ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by either compressed air or steam carrier. The optimum ammonia injection temperature occurs between 650 and 750 F. Therefore, the system is logically located between the economizer outlet and the air heater inlet. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

2.1 Coal Fired SCR Experience

Selective catalytic reduction (SCR) systems were first used in Japan during the 1970's. Through 1990, 40 SCR systems were operating on 10,852 MW of coal fired utility service. Japanese SCR systems were operated to achieve between 70 and 80 percent NO_x reduction with ammonia slip less than 10 ppm. Coals burned in the Japanese boilers have low sulfur (less than one percent) and low ash (less than 10 percent) contents.[1]

In response to acid rain legislation, SCR was retrofitted to 129 German coal fired boilers totalling 30,625 MW. Most of the Japanese and German SCR systems are generally operated to achieve 80 percent NO_x reduction to meet a NO_x emission limit of approximately 100 ppm while maintaining ammonia (NH_3) slip emissions to below 5 ppm. Similar to Japanese SCR experience, coals burned at these facilities have relatively low sulfur (0.7 to 1.2 percent) and low ash contents.[2]

To date, there are no coal fired boilers using SCR systems in the United States. However, a 140 MW coal fired pulverized coal boiler with SCR was recently permitted in New Jersey. For that facility NO_x emissions were limited to a maximum of 0.17 lb/MBtu based on the use of low NO_x burners and SCR. The facility will not operate for two to three years. Therefore, it is not possible to presently evaluate the effectiveness of SCR at facilities burning U.S. coals.

It is OUC's belief that the SCR technology is insufficiently developed for use on Stanton 2 based on inexperience with U.S. coals (detailed in subsequent sections). However, since the precedent has been established for use of SCR on a pulverized coal fired plant, this BACT analysis will evaluate SCR on a technical, economic, environmental, and energy basis. Based on the New Jersey facility, the analysis will be based on the use of low NO_x burners followed by an SCR system designed to limit NO_x emissions to 0.17 lb/MBtu.

There are two SCR system configurations that can be considered for application on pulverized coal boilers. A high dust application locates the SCR before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A low dust or cool side application is located downstream of the particulate and flue gas desulfurization control equipment.

The high dust application requires the SCR to be located between the economizer outlet and the air heater inlet in order the required SCR operating temperature of approximately 650 F to 750 F. The low dust application of SCR would locate the catalyst downstream of the particulate control and flue gas desulfurization equipment. Less catalyst volume is needed for the low dust application since the majority of the particulate and SO_2 has been removed. However, a major disadvantage of this alternative is a requirement for supplemental fuel firing to achieve sufficient flue gas operating temperatures. There is only a limited amount of low dust SCR experience worldwide. Considering the developmental nature of this alternative, this analysis will only consider the use of high dust SCR systems.

2.2 SCR Technology Status

The Japanese and European experience with SCR cannot be blindly applied to U.S. facilities. There remain two significant uncertainties about design, performance, operating parameters, and cost of SCR systems. First, U.S. utility power plants operate under more variable loads. Second the amounts and types of sulfur, ash, and trace elements in U.S. coals are different from those in coals consumed in Japan and Europe.[3] [4]

Variable load conditions results in variable temperatures in the SCR reactor. At lower temperatures SCR reaction efficiencies drop off markedly resulting in either lower NO_x reduction or additional ammonia slip emissions.

Japanese and German SCR experience has been with coals with relatively low sulfur and ash contents. Combustion of higher sulfur coals will result in the emission of larger quantities of sulfur trioxide (SO_3). In addition, SCR catalysts oxidize SO_2 resulting in an increase in SO_3 emissions of between 50 and 100 percent.[5] [6]

Sulfur trioxide in the presence of ammonia will form ammonia sulfate and ammonia bisulfate salts. Resultant particle diameters are on the order of 1 to 3 microns (potentially increasing plant PM10 emissions).[7] Ammonia bisulfate can foul the catalyst's micropore structure limiting reactivity.[8] In addition, ammonia bisulfate is a sticky substance which can deposit on downstream equipment. Ammonia bisulfate will tend to liquefy at a temperature of about 410 F in the intermediate baskets of the air heater. Once liquefied it solidifies in nodules in the space between the intermediate and cold end baskets. The result can be increased pressure drop, and eventual plugging (resulting in decreased unit reliability). Off-line water washings are necessary to remove the soluble deposits. Cold-end sootblowers are not generally effective in reaching and removing these deposits on-line. To alleviate this problem in Japan and Germany, recent SCR designs have limited ammonia slip emissions to between 3 and 5 ppm.[9] Based on the relatively high sulfur concentrations of coals under consideration for C. H. Stanton Unit 2 it may be necessary to limit ammonia slip to 2 ppm, further limiting maximum SCR effectiveness to somewhere between 60 and 70 percent NO_x reduction.

Increased SO_3 concentrations lead to an increase in the acid dew point. Hence higher air heater exit temperatures and decreased boiler efficiency will result from the use of SCR.[10]

A number of alkali metals and trace elements (especially arsenic) poison the catalyst significantly affecting reactivity and life.[11] Average arsenic concentrations for U.S. coals are three times the worldwide average.[12] Other elements such as sodium and potassium can also poison the catalyst by neutralizing the active acid sites. Poisoning of the catalyst does not occur immediately but is a continual process over the life of the catalyst. As the catalyst becomes deactivated more NH_3 must be injected to compensate and meet NO_x emission limits. This will result in an increased amount of NH_3 slip. Increased NH_3 slip will in turn result in additional ammonia salt formation and fouling of downstream equipment.

A significant quantity of ammonia slip from SCR system will condense onto fly ash. The ammonia content of the fly ash can have an impact on waste disposal or marketing practices. At elevated pH, ammonia in the fly ash will be released possibly leading to odorous emissions. While eastern U.S. coals are not inherently alkaline, fixation with alkaline species from the wet limestone scrubber or when used as admixture for cement manufacturing will result in ammonia releases.[13]

Fly ash NH_3 concentrations greater than 100 mg/kg fly ash results in noticeable odor and resultant rejection by the cement industry. Testing has indicated that for a coal with seven percent ash ammonia slip must be limited to below 2 ppm to avoid any potential problem.[14] [15] [16] Currently, SCR system suppliers will only guarantee ammonia slip levels of 5 ppm for a period of two years. It is likely that initial ammonia slip emissions will be below the 2 ppm criteria. However, as the catalyst ages ammonia slips will approach the guaranteed 5 ppm value. Accordingly, it is a possibility that Stanton 2 will lose fly ash sales should SCR be required.

2.3 SCR Economic Evaluation

Table 2.3-1 lists the estimated total capital and annual cost for installation of a SCR NO_x emission reduction system on C. H. Stanton Unit 2. The table lists all costs for a complete SCR system designed to meet a NO_x emission limit of 0.17 lb/MBtu. Costs presented in the table are based on manufacturers estimates for Stanton 2. The economic criteria used are identical to those used in the original BACT analysis.

The total capital cost for installation of a SCR system on Stanton 2 is estimated to be $31.2 million. The capital costs include ammonia receiving, storage, and injection equipment, catalyst, and balance of plant equipment. Ammonia receiving and storage equipment will primarily consist of ammonia truck receipt equipment, onsite ammonia storage tanks, piping and pumps to transport ammonia to the storage tanks, and foundations (including spill containment dikes). Ammonia injection equipment include ammonia vaporizers, air compressors or dilution air fans to provide a carrier medium, injections nozzles or headers, and associated piping and controls. Catalyst costs include four layers of catalyst, housing, maintenance access provisions, and associated transition ductwork. Balance-of-plant costs include air heater modifications to accommodate operational problems associated with unreacted ammonia and SO_3 in the flue gas stream, personnel safety equipment, boiler modification costs to accomodate the SCR catalyst reactor, and incremental ID fan capacity to overcome draft losses.

Table 2.3-1. SCR Capital and Annual Costs		
	2-Year Catalyst Life	2/4-Year Catalyst Life
	($1,000)	($1,000)
Capital Costs:		
Equipment	13,900	13,900
Field Labor	1,700	1,700
Balance of Plant	2,680	2,680
Total	18,280	18,280
Contingency	1,830	1,830
Escalation	3,340	3,340
Direct Capital Cost	23,450	23,450
Indirects	3,750	3,750
Interest During Construction	4,000	4,000
Total Capital Cost	31,200	31,200
Levelized Annual Costs:		
Operating Personnel	190	190
Maintenance	12,670	8,650
Additive	600	600
Energy	800	800
Demand	100	100
Loss in Fly Ash Sales	1,080	1,080
Fly Ash Landfill Costs	320	320
Boiler Efficiency Impact	910	910
Annual Operating Cost	16,670	12,650
Fixed Charges	2,460	2,460
Total Annual Cost	19,130	15,110
NO_x Emissions Reduced, tpy	2,810	2,810
Incremental Reduction Cost, $/ton	$6,810	$5,380

Levelized annual operating costs listed in Table 2.3-1 include operating personnel, maintenance, ammonia additive, electric energy and demand costs, and lost fly ash sales as well as the resulting fly ash disposal costs. The total levelized annual operating cost for installation of a SCR system on Stanton 2 is estimated to be $16.7 million assuming the maximum guaranteed catalyst life of 2 years. If a somewhat less conservative assumption is made that the first two layers of the catalyst have a life of two years and the last two layers have a life of four years the levelized annual operating cost decreases to $12.7 million.

Operating personnel costs include two full time equivalent personnel to operate the SCR system and associated auxiliaries. Maintenance costs are primarily related to the replacement of spent catalyst. Manufacturers typically provide a two year catalyst guarantee for coal fired applications. Ammonia costs are based on NO_x reduction requirements and the resulting molar ratios of ammonia to NO_x.

Energy costs reflect the energy required to operate air compressors and ammonia vaporizers. Energy costs also include the additional ID fan energy that would be necessary to overcome the added pressure drop from the catalyst. The demand cost is included to reflect the cost of building additional generating capacity into the unit to account for the capacity comsumed by the additional ID fan power requirements.

Stanton 1 has historically been capable of selling all ash production for use in the concrete industry. It was expected that Stanton 2 would be similarily capable. However should an SCR system be required, the potential for fly ash sales from Stanton 2 would greatly reduced due to ammonia contamination. As a result, this contaminated fly ash must be disposed of in an onsite landfill, incurring additional cost. For the purposes of costs presented in Table 2.3-1 it has been assumed that only 50 percent of these sales would be lost on the average (periodic catalyst replacements may result in cyclic possibilities for fly ash sales).

The total levelized annual cost for a SCR system on Stanton 2 would be $19.1 million based on a maximum guaranteed catlyst life of two years. These costs result in an incremental NO_x reduction cost of $6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to $5,380 per ton.

2.4 SCR Environmental Evaluation

Areas surrounding Stanton 2 are classified as attainment areas for nitrogen oxide emissions. Modeling analyses based on a NO_x emission rate of 0.32 lb/MBtu indicate ambient impacts below impacts predicted in the original Stanton 1 Site Certification Application.

Operation of a SCR system to meet a NO_x emission limitation of 0.17 lb/MBtu will result in ammonia slip emissions of between 2 and 10 ppm. Catalyst manufacturers will guarantee ammonia slip emissions of 5 ppm or less during the first two years of operation. When catalyst surfaces are relatively new ammonia slips will be very low. However, as the catalyst ages and becomes either deactivated or blinded, ammonia slip emissions will increase. As mentioned previously, should ammonia slip emissions exceed 2 ppm it is likely that all fly ash sales would be lost.

Use of SCR results in a 50 to 100 percent increase in SO_3 emissions. Unreacted ammonia and sulfur trioxide can react to form ammonia bisulfate and ammonia sulfate salts. These particulates will generally be smaller than 10 microns, and thereby, potentially increase PM_{10} emissions. Sulfur trioxide emissions that do not react with ammonia will exit the unit as sulfuric acid mist emissions.

Ammonia is a hazardous material. Therefore, ammonia must be handled and stored with extreme care. Storage and use of ammonia on-site will increase the likelyhood of hazardous or fatal accidents. Recent projects in California required to use ammonia have had difficulty obtaining local permits allowing ammonia use.

2.5 SCR Energy Evaluation

A SCR system consumes electrical energy for SCR auxiliary system operation and for incremental ID fan demand to overcome SCR draft losses. This energy requirement is approximately 1,870 kW. This represents approximately 0.5 percent of total plant power output.

2.6 Conclusions

Advances in the control of NO_x from pulverized coal boilers enable the project to lower anticipated NO_x emissions from the Stanton 1 emission limit of 0.6 lb/MBtu to 0.32 lb/MBtu. Selective catalytic reduction systems are insufficiently developed for use on pulverized coal fired boilers buring U.S. coal.

However, a recently permitted pulverized coal fired facility incorporated the use of low NO_x burners followed by a SCR system. This facility is not in operation.

The total levelized annual cost for a SCR system on Stanton 2 would be $19.1 million based on a maximum guaranteed catalyst life of two years. These costs result in an incremental NO_x reduction cost of $6,810 per ton to achieve an outlet emission of 0.17 lb/MBtu as compared to a low NO_x burner NO_x emission of 0.32 lb/MBtu. If a less conservative assumption is made regarding catalyst life incremental NO_x reduction costs are lowered to $5,380 per ton.

Since SCR systems are not demonstrated on plants burning U.S. coals it is likely that plant reliability would be reduced if an SCR system were used. These reliability decreases are likely to result from secondary effects such as air heater fouling by ammonia sulfate deposits. Previous experience with initial transfer of flue gas desulfurization technology resulted in increased plant forced outage rates of between 5 and 15 percent. In addition use of a more speculative technology will likely result in a reduction of bond rating for OUC of between 15 and 30 points. Considering the range of these cost impacts incremental NO_x reduction would increase to between $9,200/ton and $13,700/ton assuming a two year catalyst life.

The preceding discussion strongly supports that on the basis of technical, economic, energy, and environmental considerations, combustion controls designed to meet a NO_x emission requirement of 0.32 lb/MBtu represents BACT for Stanton 2 and SCR should not be applied to this installation.

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ATTACHMENT 5

TECHNICAL FEASIBILITY AND COST OF SCR
FOR U.S. UTILITY APPLICATION

PAPER PRESENTED BY
C.P. ROBIE, et. al.
AT THE MARCH, 1991 JOINT SYMPOSIUM ON
STATIONARY NOx CONTROL

TECHNICAL FEASIBILITY AND COST OF SCR FOR U.S. UTILITY APPLICATION

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ABSTRACT

The cost of utilizing Selective Catalytic Reduction (SCR) for NO_x reduction in both new and retrofit applications is presented. Retrofit cases include hot-side SCR technology applied to both PC and cyclone-fired units and post-FGD SCR technology applied to a PC-fired unit. Technology status is assessed based primarily on recent European experience. The impact of operational effects and resultant modifications on downstream equipment are included in the analysis. The hot-side capital costs (December 1989 dollars) range from \$78 to \$87/kW for the new PC-fired case, \$125 to \$140/kW for the retrofit cyclone case, \$96 to \$105/kW for the retrofit PC case. The single post-FGD SCR case evaluated is estimated at \$140/kW. The hot-side levelized costs range from 5.3 to 5.9 mills/kWh for the new case, 8.2 to 9.1 mills/kWh for the retrofit cyclone - fired case, and 5.9 to 6.5 mill/kWh for the retrofit PC-fired case. The levelized cost for the single post-FGD SCR case presented is 6.8 mills/kWh.

INTRODUCTION

The feasibility and cost of applying ammonia-based selective catalytic reduction (SCR) to control nitrogen oxide (NO_x) emissions from power plants firing U.S. coals is of considerable current interest. Although the NO_x control requirements of the 1990 Clean Air Act Amendments (CAAA) focus on low NO_x burner technology and other forms of combustion control, other factors - such as the CAAA NO_x emissions averaging provision, and strict NO_x control requirements considered by various state and local regulatory agencies provide the prospect of SCR application in the U.S. In fact, applications for several low sulfur coal-fired facilities developed by independent power producers in selected northeastern states either require SCR, or a detailed, factual accounting of the feasibility of SCR for the site. The considerable extent of SCR application in Japan and Europe for low sulfur fuels has been a significant factor in promoting the application of this technology in the U.S.

This paper completes the presentation of data from an EPRI-funded activity to evaluate the feasibility and cost for various potential applications of SCR.

This study addresses the following six applications, proposed as representing the range of potential SCR applications:

1. New Plant - low sulfur coal
2. New Plant - high sulfur coal
3. Retrofit - cyclone boiler, high sulfur coal
4. Retrofit - conventional (wall or T-fired) boiler, high sulfur coal
5. Retrofit - post-FGD (e.g. reactor following SO_2 scrubber)
6. Retrofit - oil-fired boiler

Results for cases 4 and 6 were reported at the 1989 Symposium (8). This paper summarizes results for cases 2, 3, and 5, with limited case 4 results repeated for comparison.

DESIGN PREMISES

Key design Assumptions. SCR costs are significantly influenced by several key design assumptions. The most important design variables used in this study are:

1. Catalyst life - Several coal-fired European SCR installations have operated for over two years without catalyst replacement and only moderate measured loss in activity. A catalyst life of four years for coal-fired hot-side SCR applications and four years for post-FGD SCR applications has been used in this evaluation.

2. Catalyst cost - Catalyst costs in Europe have decreased since 1985 by a factor of approximately 2.5, primarily due to a very competitive supply situation. Accordingly, this evaluation covers catalyst costs from $\$330/ft^3$ to $\$660/ft^3$, covering the range seen in Europe.

3. Ammonia slip - Ammonia slip in European SCR installations is typically specified at 5 ppm, while some utilities recommend even lower levels (2 ppm). For several coal cases in this study, both 5 ppm and 2 ppm slips have been evaluated.

4. Space Velocity - Advances have been made in catalyst formulation to minimize SO_2 to SO_3 conversion, to develop smaller pitches and to provide resistance to fouling by trace elements. These various advances are reflected in the space velocities used for the cases evaluated.

Case Definition. In order to develop representative costs for both the new and retrofit SCR study cases, typical power plant layouts and design conditions were selected. In the case of the retrofits, actual U.S. power plant layouts provided the basis for design conditions selected. For the new plant application, design conditions and layout were selected based on similar EPRI studies evaluating the cost of flue gas desulfurization processes. Six study cases were evaluated in this study, however, only Cases 2 to 5 are the subject of this paper and are described in Table 1. General arrangement drawings for the study cases evaluated in this paper are provided in Figures 1 to 4.

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the conventional hot-side SCR applications (reactor between economizer it and air heater inlet), the reactors were located above the particulate llection device. In the post-FGD application, a wet FGD system precedes the actors which were placed above the heat recovery units (Gas-Gas-Heaters).

R Process Design. To obtain budgetary SCR system costs, a performance ecification for the catalyst and reactor was developed for each case. The ecifications were developed using fuel analyses, plant performance and issions data, and desired control of NO_x, residual NH_3, and byproduct SO_3. cluded in the specification was variation in certain process variables such NO_x removal and ammonia slip for selected cases. Three SCR system ppliers provided quotations to these specifications.

ie design basis and vendor supplied design data for each of the cases aluated in this paper are shown in Table 2. Sensitivity analyses are ovided for the new plant, hot-side design (Case 2) and the cyclone-fired, it-side retrofit design (Case 3), to show the cost and performance impacts of educing the ammonia slip from 5 to 2 ppmvd. For retrofit of hot-side SCR to conventional pulverized coal-fired boiler (Case 4), the effect of reducing ne uncontrolled NO_x emission rate (by adding combustion controls) while still eeting the same NO_x emission limit is evaluated; specifically, lowering ncontrolled NO_x emission rate from 0.60 to 0.40 lb NO_x/MM Btu reduces the SCR O_x removal from 80% to 70%.

onsistent with typical practice, one reactor per air heater was used as the esign basis; the cyclone-fired retrofit (Case 3) uses a single reactor (1 x 00% tubular air heater), while the other hot-side SCR cases utilize two eactors (2 x 50% trisector air heaters). The post-FGD case utilizes twin eactors because two (2 x 50%) Ljungstrom heat recovery units were utilized.

he hot-side applications utilize downflow reactors, with additional capacity o add a spare catalyst layer. Also, steam sootblowers are employed in the lesign along with ash hoppers and ash transfer equipment. In the post-FGD application the reactor is also designed as a downflow unit with capacity to add a spare layer. The post-FGD reactor design does not require sootblowers and ash collection hoppers.

The hot-side cases employ a catalyst with a 7.07 mm pitch (20 x 20 grid) while the post-FGD case employs a catalyst with a 4.2 MM pitch (35 x 35 grid). The lower pitch (higher specific area) and higher activity (per unit volume) of the post-FGD catalyst allows a space velocity considerably higher than required for the hot-side cases.

The ammonia storage and supply systems were designed using a truck unloading station and a storage island providing seven days storage at an MCR rating. Steam vaporizers are utilized for ammonia vaporization and dilution air is provided from the discharge of the primary air fans in the hot-side cases, while the post-FGD case utilizes separate dilution air fans.

SCR PROCESS IMPACT

The hot-side SCR process, because of its location directly downstream of the boiler and upstream of the air heater, impacts every component of the flue gas train and the boiler itself through its effect on the air heater (and in some s the economizer). The degree of impact varies with power plant iguration, environmental control components, type of fuel, and emission rol requirements. The post-FGD SCR process impact is much less severe use of its location at the end of the flue gas train.

Side SCR (coal) Impact

impacts of hot-side SCR in coal-fired applications are summarized on re 5. The principal impacts are on the boiler, air heater and ID fan. r impacts are on the particulate collection device (ESP), wet limestone gas desulfurization (FGD) process, FGD reheat system, waste disposal em and water treatment system.

er. The principal effects of hot-side SCR on the boiler will be the loss verall thermal efficiency, and additional operations and control lexity, particularly for cycling units. Also, auxiliary power consumed by SCR process will reduce the net generating capacity.

s of thermal efficiency results from air heater modifications and an nomizer bypass which will result in higher air heater flue gas exit eratures. The result will be loss in the net generating capacity for the e quantity of fuel consumption.

Heater. The potential for formation of ammonium sulfates and bisulfates oled with the presence of fly ash necessitates air heater modifications in hot-side SCR cases. Modifications to the air heaters in the PC boiler es include adding high pressure steam soot blowers at both the cold and hot s, adding high pressure water wash capability, replacing 24 gage heat nsfer surface material with 18 gage, replacing intermediate and cold end ble undulating (DU) heat transfer surface with notched flat (NF) surface, adding bypasses and dampers for on-line washing capability.

the cyclone-fired boiler case, to reduce the rate of ammonium compound osition and build-up, all the existing 2" diameter tubes in the cold end, 25% of the tubes in the hot end were replaced with 3" diameter tubes. o, a steam soot blowing system utilizing medium pressure superheated steam both the hot and cold ends was added to reduce the rate of deposits.

this case, it is expected that some residual ammonia may be captured by the system resulting in a build-up of ammonium species in the FGD liquor. hough this may complicate scrubber sludge reuse or disposal, no cost impact s been assigned.

ack. The increase in the flue gas SO_3 concentration across the SCR could sult in increased opacity of the flue gas plume. Recent data from an EPRI onsored study with a member utility shows a direct correlation between stack acity and sulfuric acid concentration. To reduce opacity control measures y be required to reduce the SO_3 concentration. A typical method of reducing $_3$ in the flue gas would be to inject NH_3 upstream of the ESP. The specific pacts or costs associated with this effect have not been evaluated in this udy, however.

Fan. To overcome additional pressure drop (up to 11" wc) associated with e hot-side SCR, the existing ID fans were modified. For the retrofit cases it was assumed that new, larger diameter wheels could be placed into the existing fan housing to overcome the additional static pressure drop. The modifications included replacing the fan wheel, shaft, bearings and motor.

<u>ESP</u>. SCR effects on the ESP include higher volumetric flowrate, higher negative operating pressure, higher SO_3 concentration, higher flue gas temperature and precipitation of ammonium compounds on fly ash.

Higher flue gas volume (an increase of up to 9.4% in the PC-fired cases) results from higher flue gas temperature (20°F), lower flue gas static pressure, and increased mass flow (the latter due to increases air heater leakage and dilution air), and will have a significant impact on ESP operation. The increase in flue gas volume will effectively reduce the Specific Collecting Area (SCA) and the concentration of particulate in the flue gas. The result will be that the ESP may require additional power to deliver the same particulate removal efficiency.

Greater negative operating pressure could require re-enforcement of the ESP. This effect was not considered in the capital cost analysis.

In the high sulfur coal applications, the SO_3 concentration in the flue gas is estimated to increase by 18 ppm across the SCR. Typically, an increase in SO_3 would be expected to reduce the fly ash resistivity significantly. However, the increase in the flue gas temperature in the PC-fired cases (to keep the flue gas above the acid dew point) may counteract the effect of the SO_3 increase, possibly producing little net change.

Ammonium compound precipitation on the fly ash typically has a beneficial impact on ESP performance by helping the fly ash agglomerate, preventing reentrainment.

The cumulative effects of all the above could be significant on an ESP; a pilot test program would be required to determine actual design and operations impacts. In this study case it was assumed that the only net effect on the ESP operation was an increase in power consumption by about 12%.

In the cyclone-fired boiler case the flue gas volume increase is expected to be 3.8%. This result is lower than the PC cases because of a negligible increase in the leakage rate across the tubular air heater and only an 8°F flue gas temperature increase at the air heater exit. Only a slight increase in the ESP power consumption was assumed in this case.

<u>Ash Disposal/Reuse</u>. Ammonium compound content in the fly ash can have an impact on waste disposal or marketing practices; for example, these compounds decompose and release ammonia at elevated pH. While Eastern U.S. coals are not alkaline in nature and ammonia would not be expected to gas off upon wetting, fixation with alkaline species could result in an ammonia odor problem.

Similarly, reuse options for fly ash contaminated with ammonium compounds may be limited. Direct use as an admixture in cement manufacturing may be jeopardized if the ammonium compound content is too high.

FGD/Reheat. The chief effect on the FGD system is an increase in the water evaporation rate and steam reheat requirement. The higher inlet temperature and higher mass flow rate will result in an increase in water evaporation in the absorber, as well as a significant increase in steam use by the FGD reheat system (50°F reheat assumed).

A slight increase in power consumption could occur from having to increase the FGD liquor recirculation rate in order to maintain the same SO_2 removal efficiency. The higher liquor recirculation rate might be required as a result of dilution of SO_2 in the flue gas, and higher flue gas volumetric flow rate (saturated gas flowrate). This effect was not considered in this analysis.

FD Fan. In the PC-fired boiler cases (e.g. employing Ljungstrom air heaters) the FD fan will consume slightly more power to account for a higher mass flow rate. The mass flow increase results from an expected higher air heater leakage rate.

Water Treatment. Introduction of nitrogen species into the air heater wash water requires additional water treatment equipment. Nitrogen species are introduced into the wash water as ammonium bisulfate and sulfates. A biological treatment process is utilized to convert the nitrogen species to free nitrogen. The effluent is assumed to be discharged to the existing on-site water treatment equipment.

Post-FGD SCR Process Impact

The impact of post-FGD SCR on power plant operations and equipment is less significant than that expected with hot-side SCR, as the SCR reactor and ancillary equipment follow all major process equipment. The impacts are shown by Figure 6.

Boiler. The boiler is affected only insofar as auxiliary power consumption is increased. The increase in the auxiliary power consumption (reduction in the net generating capacity) will increase the Net Plant Heat Rate. Natural gas consumed in elevating the SCR inlet gas temperature will also increase the NPHR.

ID Fan/Booster Fan. The increase in the flue gas pressure drop associated with the post-FGD SCR process is estimated at 14.5 in w.c. The pressure losses are principally across the inlet and outlet of the Gas-Gas-Heater (GGH) and the SCR reactor. Addition of a booster fan into the flue gas train will increase the complexity in flow and pressure control. In this case the booster fans are located upstream of the stack; one booster fan is supplied for each SCR reactor train.

Water Treatment. Nitrogen species will be introduced into the air heater wash water as a result of ammonium bisulfate deposition on heat transfer surface. With relatively little SO_3 capture expected within the FGD system, some additional SO_3 generation across the catalyst, and the absence of fly ash, the rate of chemical deposition on the GGH equipment is expected to be quite significant. A biological treatment process was included to treat the wastewater.

The SCR process affects the FGD system only indirectly. Because of the tion of the GGH, FGD system mist eliminator operation will be critical. ssive mist carryover could result in loss of heat recovery (resulting in eased natural gas consumption) and an increase flue gas pressure drop, ibly limiting generation capacity in addition to detracting from plant rate.

ck. Retrofit of the post-FGD SCR process will almost certainly have an act on the stack. If the original plant design included a wet stack, the °F GGH exit gas temperature will require liner replacement. In this design e it was assumed that the original design included steam reheat (50°F) and t the stack was designed for approximately 180°F. The effect of the rease in the flue gas temperature to 225°F was considered negligible.

her SO_3 concentration in the flue gas may result from oxidation of SO_2 ross the catalyst. While some of the SO_3 is likely to form ammonium/sulfur mpounds and deposit on the GGH surface, there may be a net increase in the $_3$ concentration which could increase plume opacity.

ST DEVELOPMENT

develop total process capital costs, physical layouts of the ductwork and R reactors were developed. From these drawings, lengths of ductwork and tructural requirements were estimated. All costs are presented in December 989 dollars.

he operating and capital cost impact of SCR on other plant components was lso estimated. For major pieces of equipment, such as the air heaters, mmonia storage system and ID fans, vendors were consulted in developing the ost of the modifications. For smaller equipment items and piping runs, UE&C utilized in-house data to arrive at equipment costs.

EPRI's Technical Assessment Guide (TAG) provided the basis to estimate fixed operating and maintenance costs. Variable operating costs were determined by calculating utility and raw material consumption rates. Considered in the variable operating costs were the following:

- o SCR catalyst replacement
- o Ammonia consumption
- o Ammonia vaporization steam
- o Incremental Sootblowing steam
- o Incremental ID/Booster fan horsepower consumption
- o Incremental FD fan horsepower consumption
- o Incremental ESP power consumption
- o Water treatment chemicals
- o Air heater efficiency loss
- o Incremental FGD reheat steam consumption
- o SCR catalyst disposal
- o Incremental fly ash disposal cost
- o Natural gas consumption

LTS

cted results from this study are summarized in Figures 7 to 10, while itivity of results to catalyst cost and life are provided in Figures 11 to Highlights are discussed as follows:

tal Costs. Total capital requirement (TCR) for each of the cases is ented, indicating the contribution of the reactor/catalyst, structural fications and/or support equipment, air heater, ductwork, NH_3 injection, gas handling, and contingencies. Figure 7 shows capital cost is least new units, due to the absence of retrofit considerations, and reduced alyst quantity from lower boiler exit NO_x emissions. These same factors, ofit considerations and boiler exit NO_x emissions, are responsible for the lone boiler having the highest cost for the hot-side application. Post-FGD ital cost is high due to the GGH, which adds significantly more cost than saved through simplifying reactor design and reduced catalyst quantity.

reasing the ammonia slip from 5 to 2 ppm (shown for both cases 2 and 3) is ected to increase the TCR by about 12% due to a larger catalyst volume uirement.

cost impact on the SCR of reducing the boiler NO_x emission rate from 0.60 0.40 lb NO_x/MM Btu is shown by Case 4.0 and 4.1. Reduction of the boiler emission rate (through combustion modifications), while meeting the same ssion limit of 0.12 lb NO_x /MM Btu, reduces the SCR capital cost by 4/kW. (Levelized costs reflecting both capital and operating costs must be pared to judge the full benefit.)

catalyst and reactor cost represents about 40-50% of the TCR in the hot-le SCR cases. In the post-FGD SCR case, the catalyst cost represents only ut 17% of the TCR. The largest cost item in the post-FGD SCR case are the n GGH's used for heat recovery.

contingency ranges from 14.4% to 18.2%. The highest contingency is signed to Case 3 due to uncertainties in high sulfur coal applications, pled with tubular air heaters and a very high boiler NO_x emission rate.

velized Cost. Figure 8 presents levelized costs for the same design cases, picting generally the same trends between costs for new units, cyclone ilers, conventional PC boiler, and post-FGD application. The data shows at variable operating costs and fixed charges represent about 50% of total velized cost for the hot-side application. The most significant component fixed charge is the recovery of capital for the reactor and catalyst. milarly, the most significant component for variable O&M is catalyst placement cost. Comparison of cases 4.0 and 4.1 shows the benefit of adding mbustion controls to reduce the NO_x reduction requirement of the SCR; the sults indicate that the SCR cost can be reduced from 6.54 to 5.88 mills/kWh reducing the boiler emission rate from 0.60 to 0.40 lb NO_x/MM Btu. In the se of the post-FGD SCR process, fixed charges represent about 65% of the tal levelized cost. Note that the results consider a 0.93 mills/kWh credit r a 50°F steam reheat system that is no longer required upon retrofit of the st-FGD SCR process. This credit would, of course, not apply for units that ploy wet stack operation.

The levelized costs for Case 3.0, the cyclone boiler, are significantly higher than the costs expected with retrofit to a PC-fired boiler. This is due both to higher capital requirement and catalyst replacement cost due to the large volume of catalyst required in this application.

Figure 9 shows levelized costs in terms of \$/ton NO_x removed. Primarily, the data shows the impact of the boiler NO_x emission rate on the cost to remove a ton of NO_x. The cyclone-fired boiler (Case 3.0) shows the lowest levelized cost (about \$1,100/ton NO_x). Although the cost of SCR for application to cyclone boilers is significant, the high uncontrolled boiler NO_x emissions reduce costs on a per ton basis.

The highest levelized cost is shown by Case 4.1 where combustion controls were added to reduce the SCR NO_x reduction requirement from 80% to 70%. Lowering the boiler exit NO_x emission rate correspondingly increased costs on a per ton basis.

Figure 10 provides a more detailed cost comparison between a post-FGD and hot-side SCR process in terms of levelized costs (mills/kWh). The power plant, fuel, and NO_x reduction performance is identical for both cases. The levelized costs for the two process options are comparable, however, as described earlier, the reheat credit of 0.93 mills/kWh for the post-FGD process may not be applicable to specific sites if a wet stack is used. Also, note that a 4-year catalyst life was used in the post-FGD cost development, six years is closer to the currently expected life. Catalyst replacement is the most significant O&M cost item for the hot-side process, while natural gas cost (and heat rate penalty) is the most significant O&M cost item for the cold-side process.

6 YRS

<u>Effect of Catalyst Life and Unit Costs</u>. Sensitivities of the cost results to both catalyst cost and life are provided by Figures 11 to 14. Base case economics were developed assuming a four year catalyst life for both hot-side and post-FGD SCR processes; a six year catalyst life for the post-FGD SCR is now being predicted. Base case catalyst cost of \$660/ft^3 was utilized; this cost reflected budgetary quotations from the primary U.S. SCR catalyst vendors with coal-fired experience. It is possible that catalyst costs will approach those in Europe (\$400-450/ft^3) due to world market competition.

The figures show that the SCR applications which require the largest quantity of catalyst are most sensitive to both catalyst life and cost. The post-FGD process (Case 5) is the least sensitive due to its relatively small catalyst charge.

CONCLUSIONS

Conclusions developed from this study are:

o The capital cost of SCR in 500 MW (nominal) size U.S. plants is expected to be:
   A. \$96 - \$105/kW for hot-side retrofits to conventional (tangential or wall) coal-fired power plants.
   B. \$125 - \$140/kW for hot-side retrofits to cyclone-fired boilers.
   C. \$78-87/kW in new plant hot-side applications.
   D. \$140/kW for post-FGD retrofits.

- The levelized cost of SCR in U.S. coal-fired power plants (500 MW size range) is expected to be:
  - A. 5.3-5.9 mills/kWh for new hot-side power plant applications.
  - B. 5.9 to 6.5 mills/kWh for hot-side retrofits to conventional-fired units.
  - C. 8.2 to 9.1 mills/kWh for hot-side retrofits to cyclone-fired units.
  - D. Approximately 6.8 mills/kWh for post-FGD retrofits to conventional units assuming a credit for reheat (0.93 mills/kWh).

- The levelized cost of removing a ton of NO_x utilizing SCR is expected to range as follows:
  - A. \$3,300 - \$3,800/ton NO_x for new coal-fired plant hot-side applications.
  - B. \$1,100 - \$1,250/ton NO_x for coal-fired cyclone boiler hot-side retrofits.
  - C. \$2,750 - \$4,250/ton NO_x for coal-fired conventional boiler hot-side retrofits.
  - D. \$2,850/ton NO_x for post-FGD SCR retrofit to a conventional boiler.

- The levelized cost of removing a ton of NO_x is lowest with high NO_x emission rates. The levelized cost of removing a ton of NO_x for a cyclone-fired boiler with a 1.80 lb NO_x/MM Btu NO_x emission rate is estimated at \$1,100/ton NO_x.

- The SCR capital cost in a new power plant application is substantially less than in a retrofit application. The cost of a new plant SCR is expected to be about 34% lower than a retrofit. the lower cost is due largely to new boilers having lower NO_x emission rates and an attendant reduced catalyst requirement, and the absence of costly existing equipment modifications required in SCR retrofit applications.

- SCR capital costs are higher for cyclone-fired boilers because of their high NO_x emission rate. The SCR capital cost for cyclone-fired units is expected to be about 45% higher than that expected for conventionally-fired power plants.

- Catalyst life and catalyst unit cost significantly affect levelized process costs. For most hot-side SCR applications, an increase in catalyst life from 2 to 4 years reduces levelized cost by 30%. A reduction in catalyst unit cost from \$660/ft^3 to \$450/ft^3 (for cases assuming a four year catalyst life) reduces levelized costs by 15%.

- The levelized cost of NO_x removal for both hot-side and post-FGD SCR processes is similar, but the components of the cost vary significantly. Compared to hot-side SCR, post-FGD applications requires 30% more capital, but feature lower catalyst replacement costs.

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2. Cichanowicz, J. E., Offen, G. P., "Applicability of European SCR Experience to U.S. Utility Operation," Proceedings: 1987 Joint Symposium on Stationary NO_x Control, EPA/EPRI, New Orleans, 1987.
3. Cichanowicz, J. E. et. al., "Technical Feasibility and Economics of SCR NO_x Control in Utility Applications," Proceedings: 1989 Joint Symposium on Stationary Combustion NO_x Control, EPA/EPRI, March 1989.
4. Electric Power Research Institute (EPRI), TAG - Technical Assessment Guide, Volume I: Electricity Supply - 1986, EPRI P-4463-SR, December 1986.
5. Ellison, W., "Assessment of SO_2 and NO_x Emission Control Technology in Europe," EPA-600/2-88-013, February 1988.
6. Nakabayashi, Y., Abe, R., "Current Status of SCR in Japan," Proceedings: 1987 Joint Symposium on Stationary NO_x Control, EPA/EPRI, New Orleans, 1987.
7. Necker, P., "Operating Experience with the SCR $DeNO_x$ Plant in Unit 5 of Altbach/Deizisau Power Station," Proceedings: 1987 Joint Symposium on Stationary NO_x Control, EPA/EPRI, New Orleans, 1987.
8. Osborn, H. H., "The Effect of Ammonia SCR $DeNO_x$ Systems on Ljungstrom Air Preheaters," C-E Air Preheater, EPRI RP 835-2, June 1979.

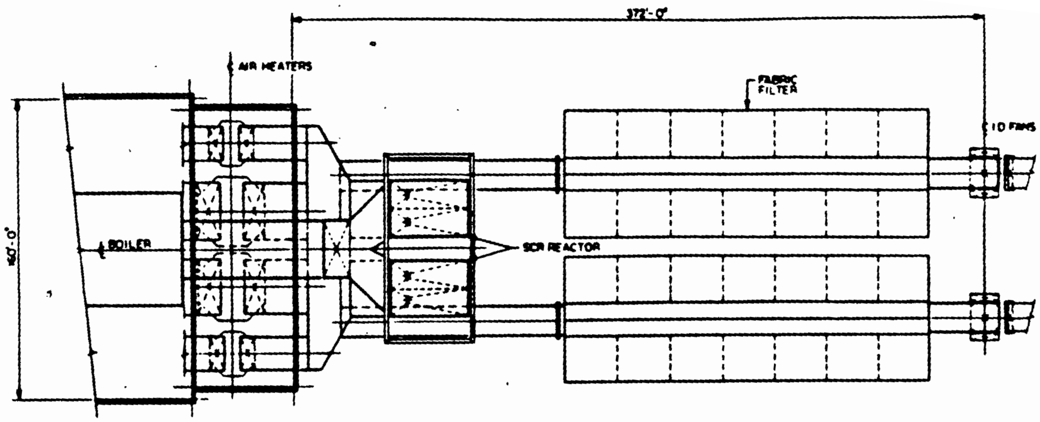
Table 1
Case Definition

PLANT DESCRIPTION				
Case	2.0	3.0	4.0	5.0
Retrofit	No	Yes	Yes	Yes
Capacity, MW (gross)	546,600	536,000	536,000	536,000
Boiler Type	PC	Cyclone	PC	PC
Air Heaters	Ljungstrom	Tubular	Ljungstrom	Ljungstrom
Particulate Control	Baghouse	ESP	ESP	ESP
SO2 Control	Wet FGD	None	Wet FGD	Wet FGD
Reheat	yes	No	Yes	Yes
Gross Plant Heat Rate, Btu/kWh	9,137	9,974	9,197	9,197
Capacity Factor, %	65	65	65	65
Remaining Life, years	30	20	20	20
SITE CONDITIONS				
Location	Kenosha, WI	Kenosha, WI	Kenosha, WI	Kenosha, WI
Seismic Zone	I	I	I	I
Urban Site	No	No	No	No
FUEL				
Type	Coal	Coal	Coal	Coal
Area	Illinois No. 6	Illinois No. 6	Appalachian	Appalachian
Higher Heating Value, Btu/lb	10,533	10,533	13,100	13,100
Sulfur Content, wt. %	3.74	3.74	2.60	2.60
Ash Content, wt. %	9.51	9.51	9.10	9.10

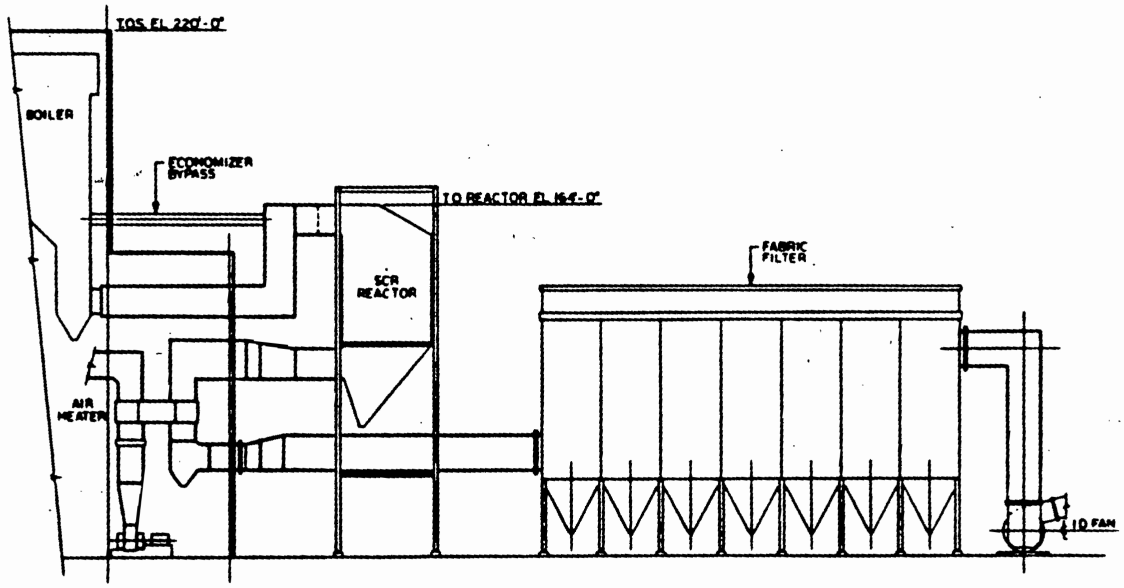
Table 2
SCR Process Design

CASE NUMBER DESCRIPTION	2.0 New, hot-side	2.1 New, hot-side	3.0 Retrofit, hot-side	3.1 Retrofit, hot-side	4.0 Retrofit, hot-side	4.1 Retrofit, hot-side	5.0 Retrofit, cold-side
SCR DESIGN BASIS							
Boiler Type	PC	PC	Cyclone	Cyclone	PC	PC	PC
Economizer Outlet Temp. @MCR, °F	725	725	682	682	725	725	NA
Economizer Excess Air, %	24	24	20	20	24	24	24
Boiler NOx Emission Rate, lb/MM Btu	0.40	0.40	1.80	1.80	0.60	0.40	0.60
NOx Concentration, ppmv (actual)	364	364	1700	1700	572	381	428
NOx Emission Limit, lb/MM Btu	0.08	0.08	0.36	0.36	0.12	0.12	0.12
NOx Reduction Rate, %	80	80	80	80	80	70	80
NH3 Slip Rate, ppmvd (@ 3% O2)	5	2	5	2	5	5	5
Guaranteed Catalyst Life, years	2	2	2	2	2	2	2
Reactor Configuration	Twin, Vertical	Twin, Vertical	Single, Vertical	Single, Vertical	Twin, Vertical	Twin, Vertical	Twin, Vertical
Ammonia Storage, days	7	7	7	7	7	7	7
SCR DESIGN							
Space Velocity, SCF*/ft3-hr	2,750	2,300	1,800	1,500	2,530	2,960	6,000
Linear Velocity, actual fps	18.2	18.2	18.2	18.2	18.2	18.2	22.0
Operating Temperature, °F	725	725	682	682	725	725	625
SO2 Oxidation rate, %	1.10	1.20	1.10	1.10	1.20	1.20	0.39
Catalyst Geometry	Grid	Grid	Grid	Grid	Grid	Grid	Grid
Surface Area, m2/m3	470	470	470	470	470	470	795
Pitch, mm	7.07	7.07	7.07	7.07	7.07	7.07	4.2
Catalyst Layers (active + spare)	4 + 1	4 + 1	6 + 1	6 + 1	4 + 1	4 + 1	2 + 1
Soot Blowers	Yes	Yes	Yes	Yes	Yes	Yes	No
Ammonia Consumption, lb/hr	941.4	932.3	4,478	4,468	1,383	807	1,383
Gas-Gas-Heater (GGH)							
-Number	NA	NA	NA	NA	NA	NA	2 X 50%
-Untreated Gas In/Out, °F	NA	NA	NA	NA	NA	NA	129/550
-Treated Gas In/Out, °F	NA	NA	NA	NA	NA	NA	625/226
SCR COST DEVELOPMENT							
Catalyst Cost, $/ft3	660	660	660	660	660	660	660
Expected Catalyst Life, years	4	4	4	4	4	4	4
Ammonia Cost, $/ton	145	145	145	145	145	145	145
Natural Gas Cost, $/MM Btu	NA	NA	NA	NA	NA	NA	2.98
Plant Life, years	30	30	20	20	20	20	20
Capacity Factor, %	65	65	65	65	65	65	65

* SCF @ 32°F



PLAN



ELEVATION

Figure 1. Case 2 Plan and Elevation General Arrangements.

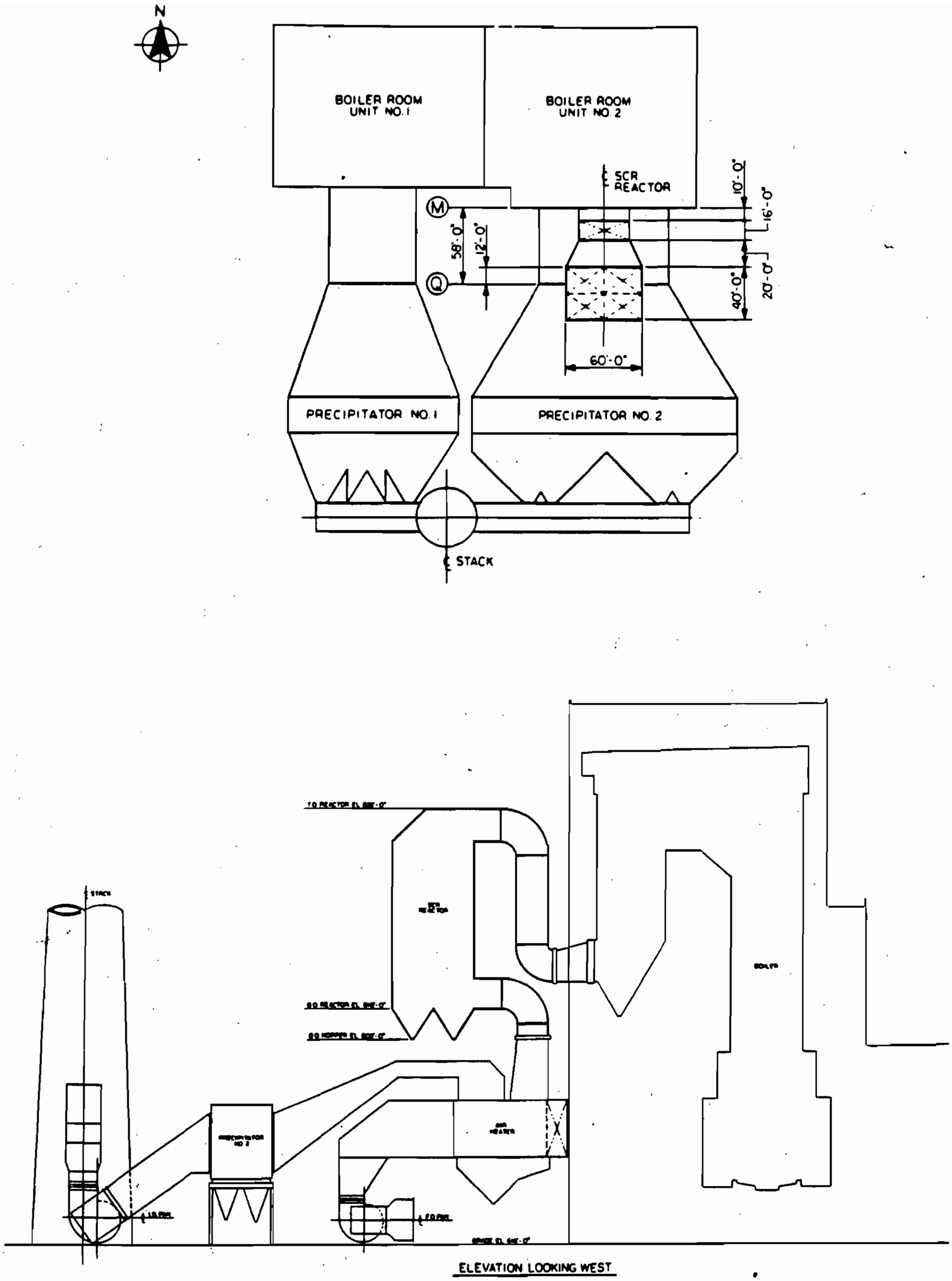


Figure 2. Case 3 Plan and Elevation General Arrangements.

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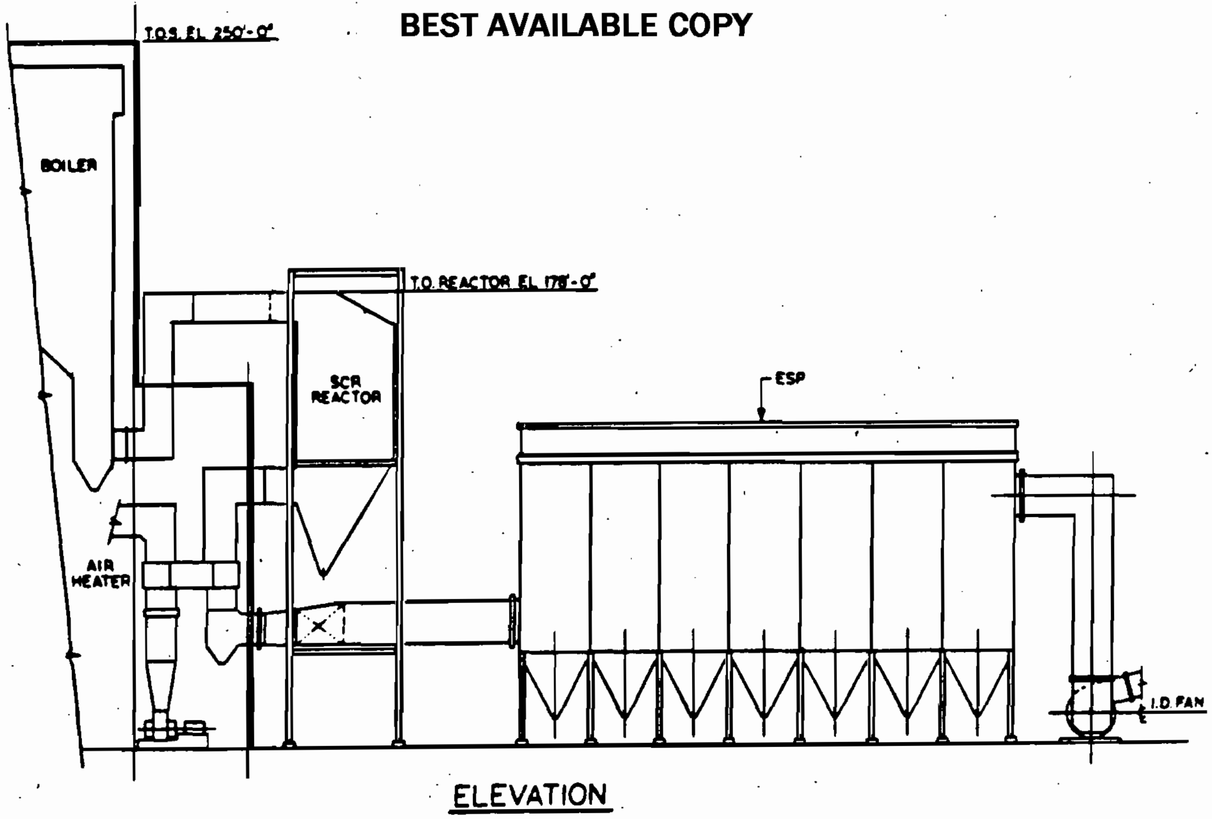

Figure 3. Case 4 Elevation General Arrangement.

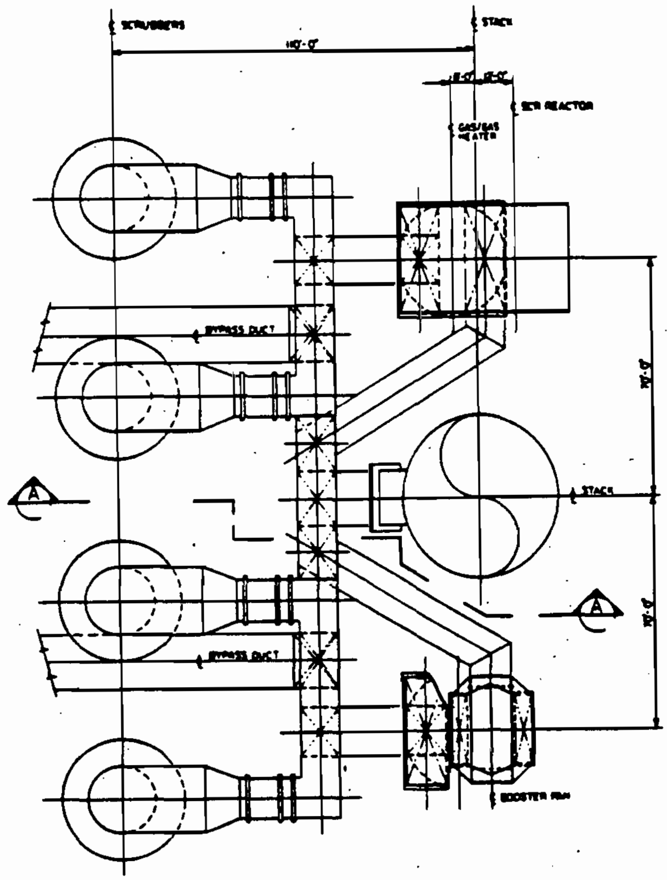

Figure 4. Case 5 Plan General Arrangement.

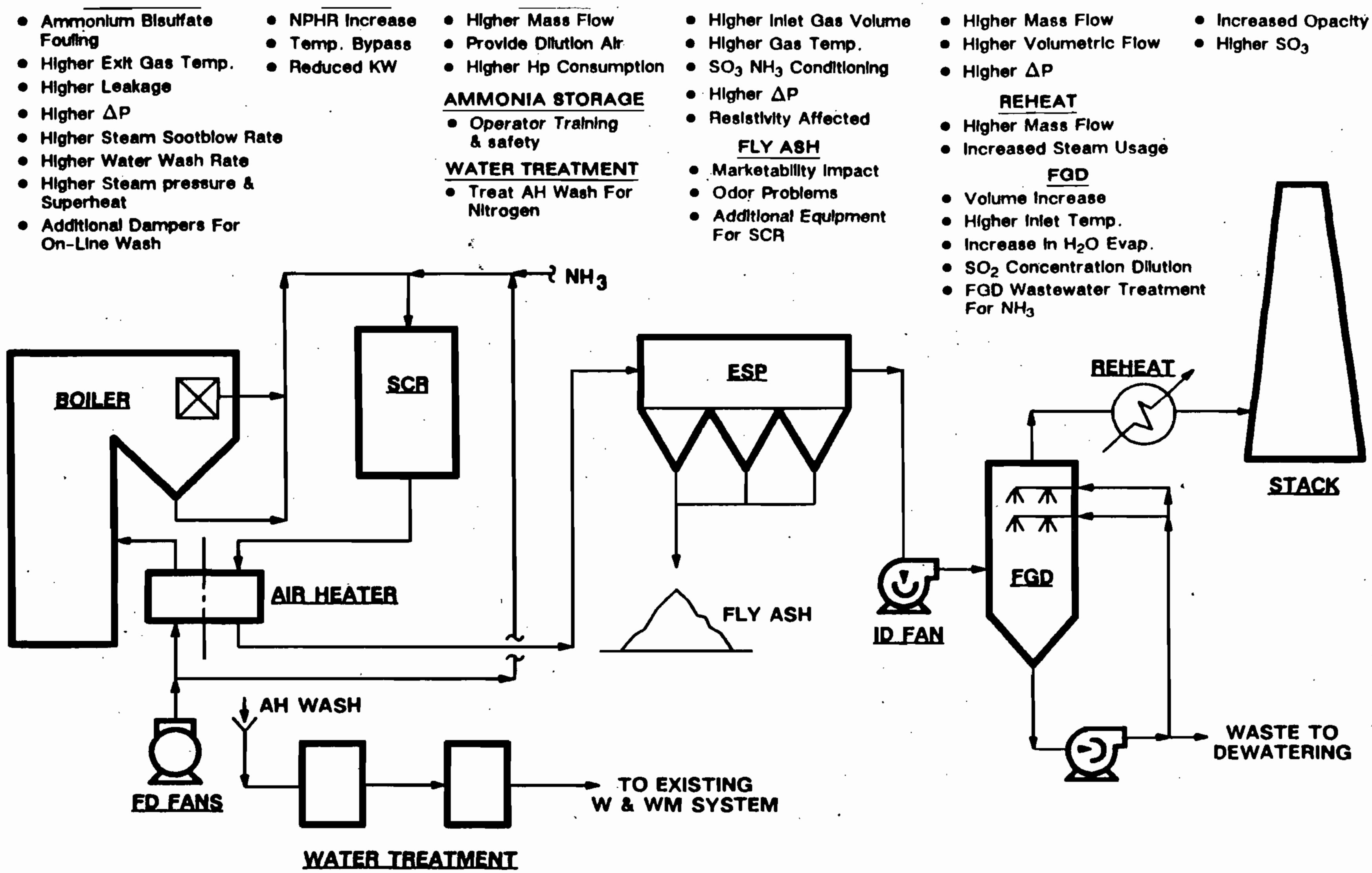

Figure 5. Hot-side SCR Design/Operations Impact.

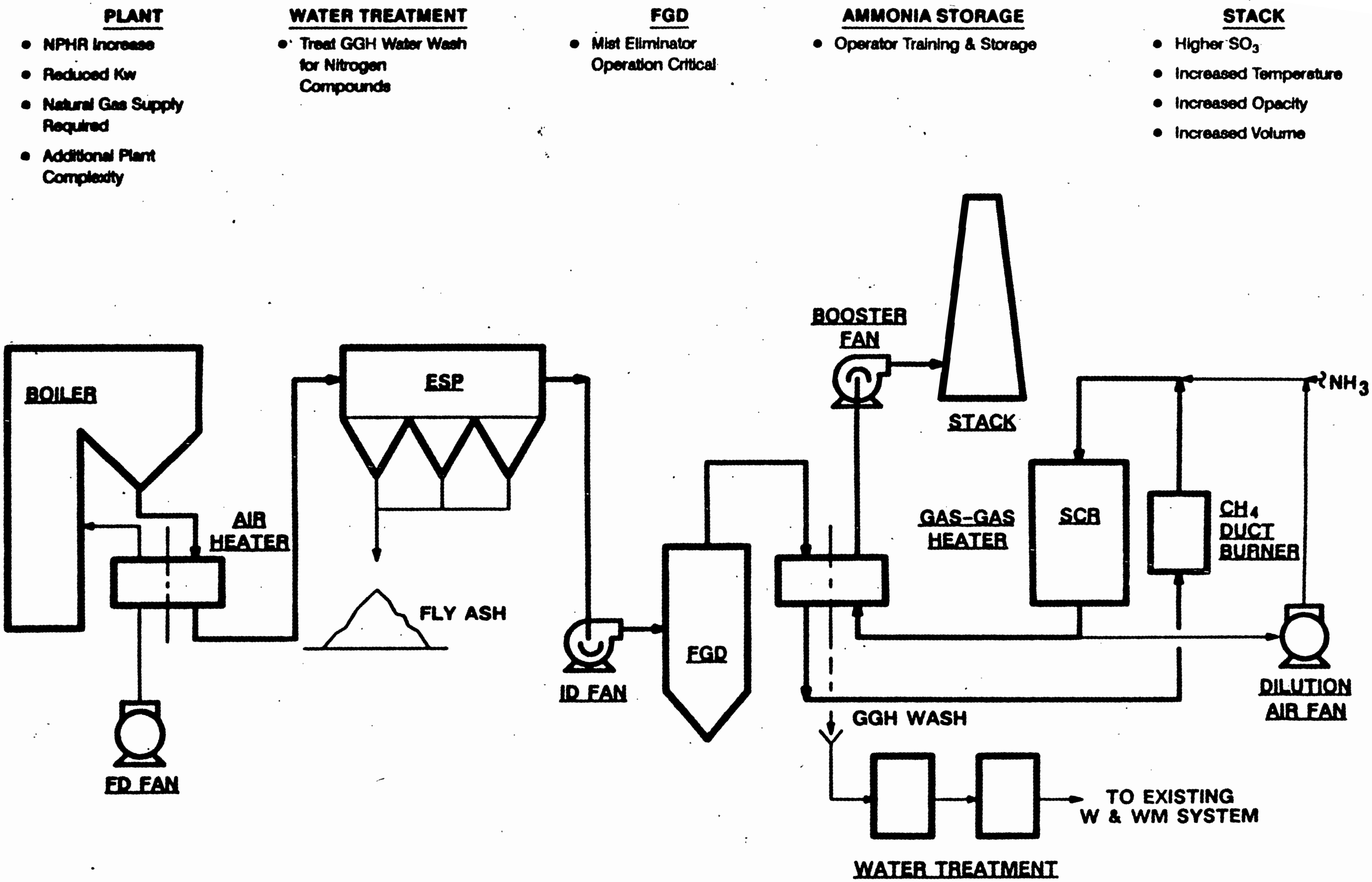

Figure 6. Post-FGD SCR Design/Operations Impact.

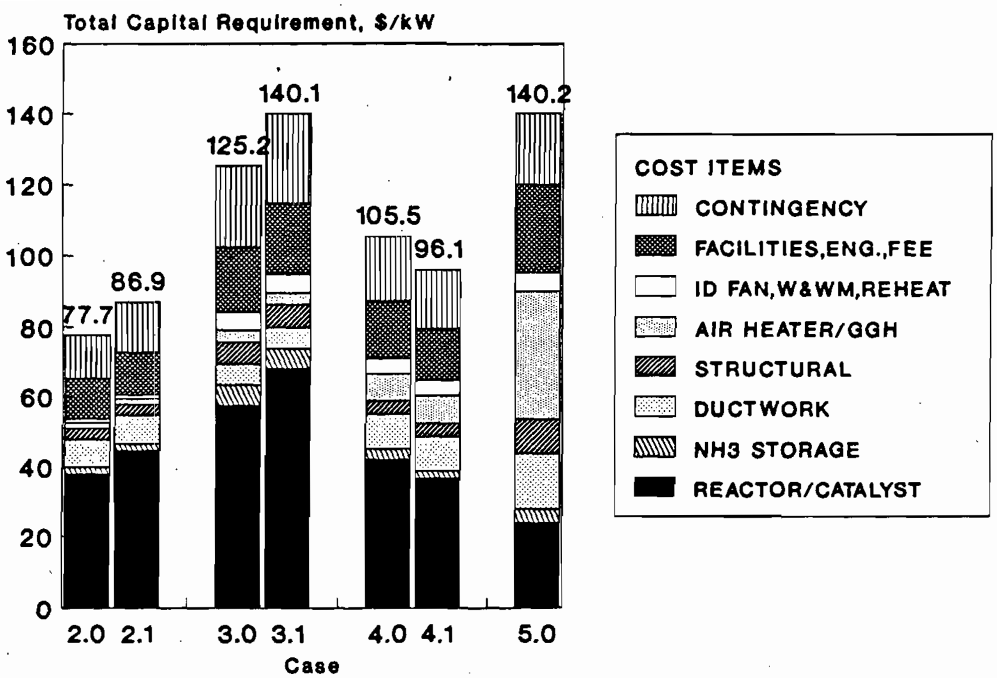

Figure 7. Total Capital Requirement.

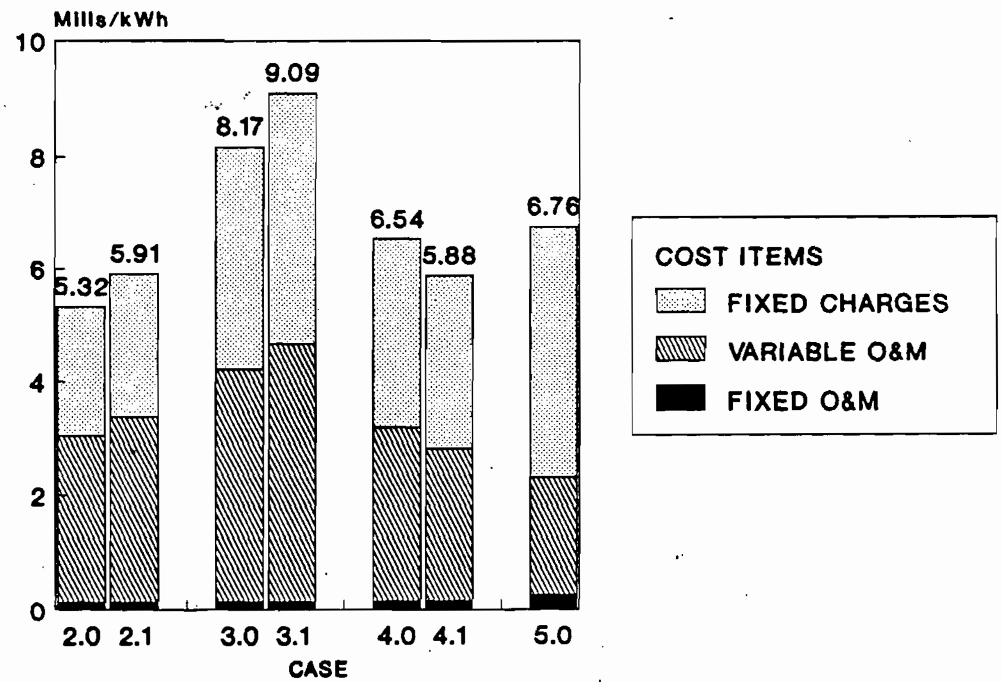

Figure 8. Levelized Cost (mills/kWh).

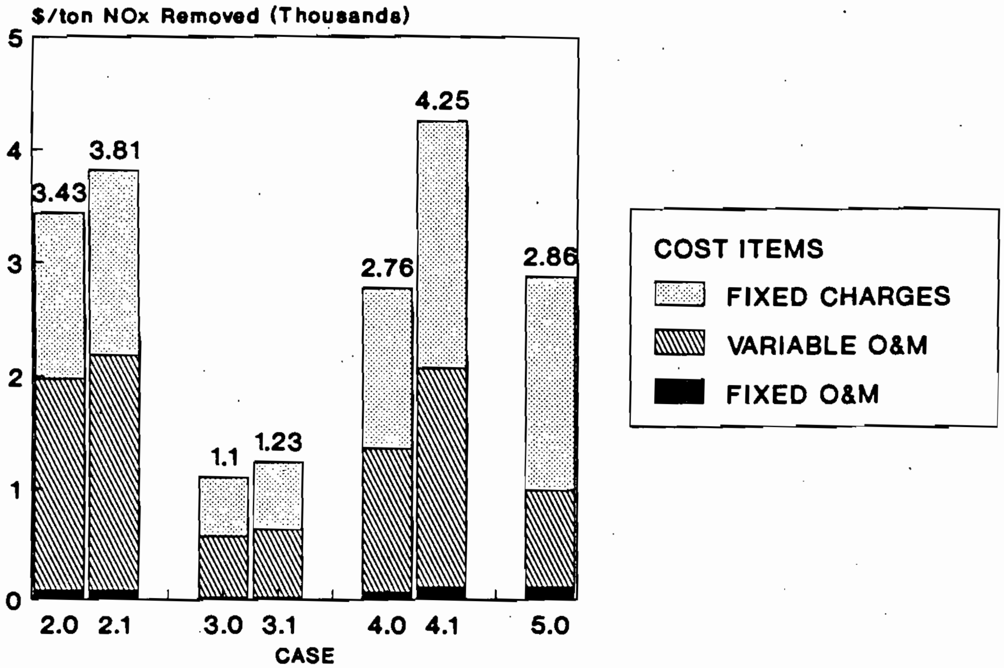

FIGURE 9. Levelized Cost ($/ton NOx removed).

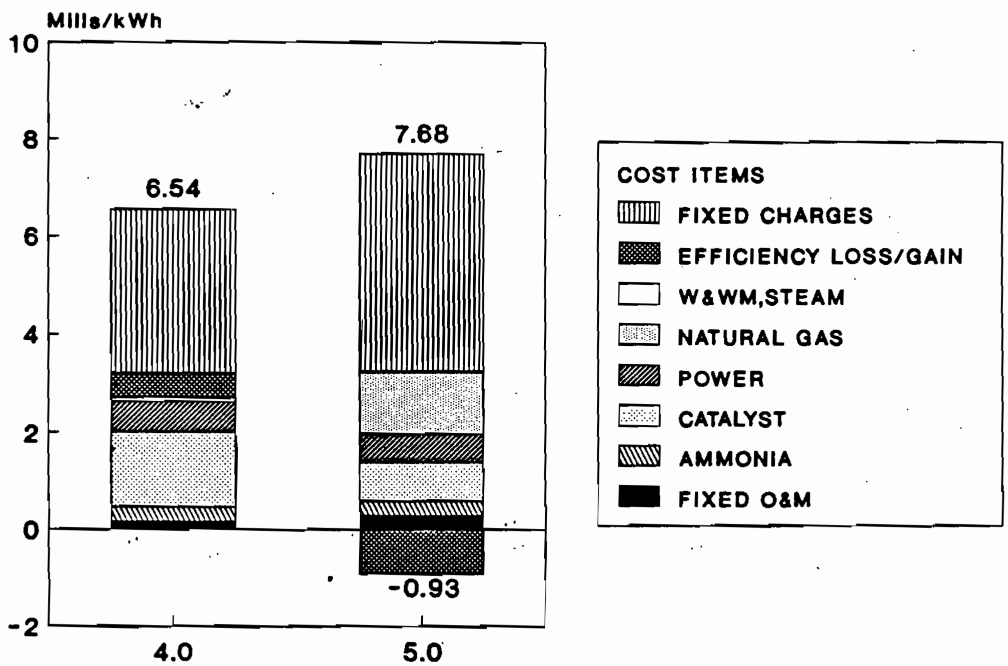

Figure 10. Hot-Side vs Post-FGD SCR Cost Comparison.

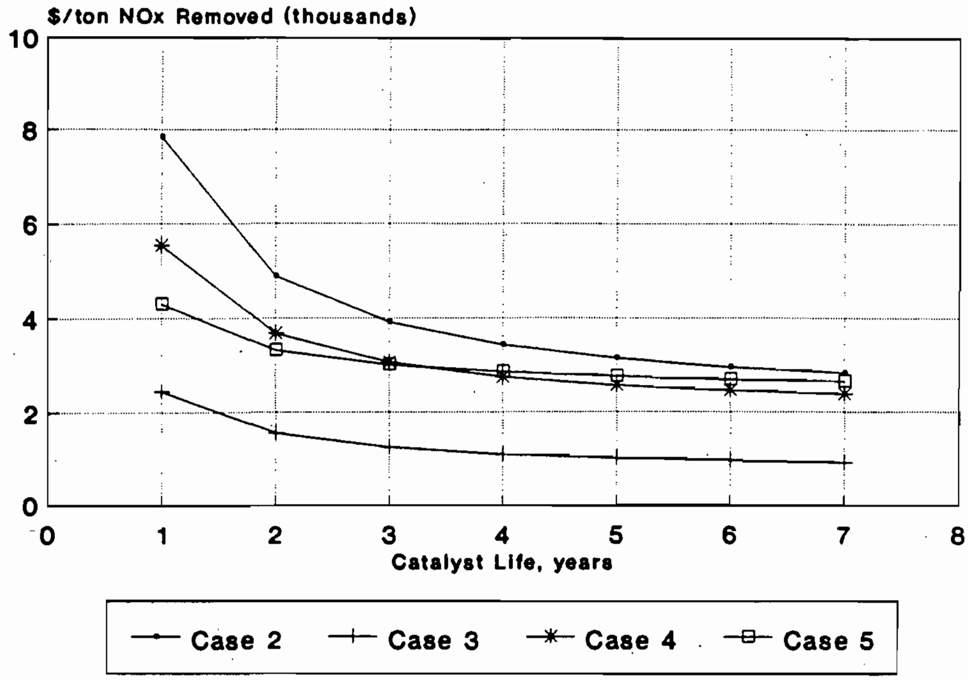

Figure 11. Levelized $/ton NOx versus Catalyst Life.

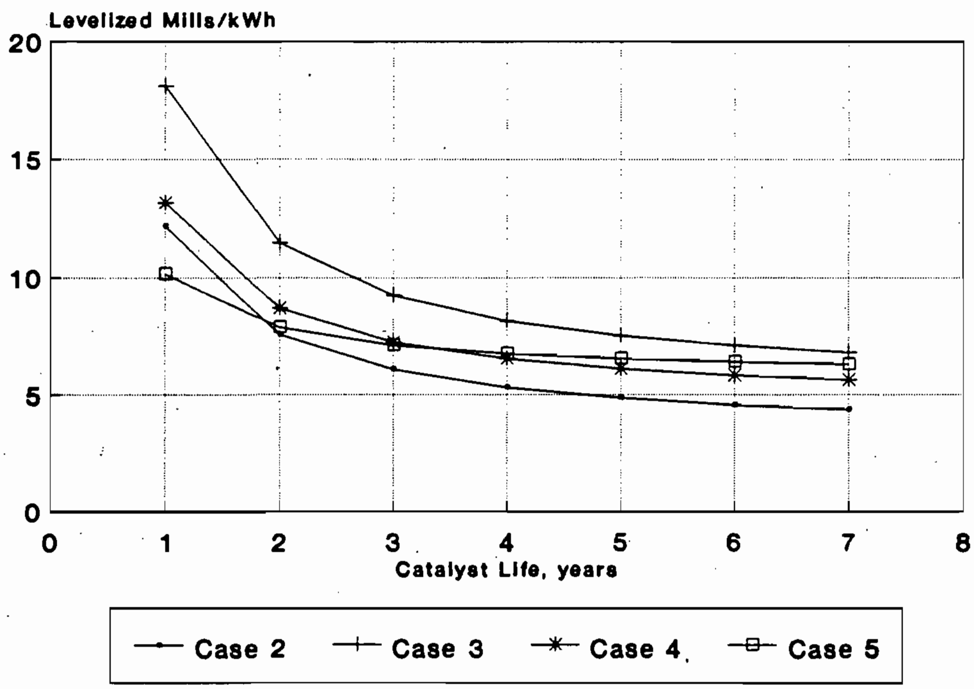

Figure 12. Levelized Mills/kWh versus Catalyst Life.

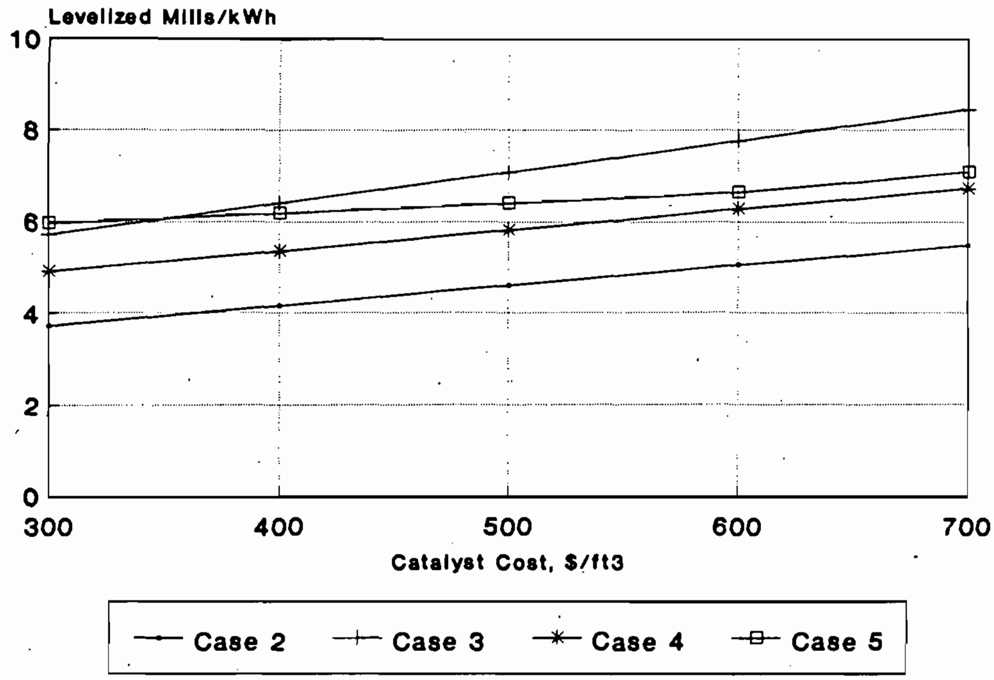

Figure 13. Levelized Mills/kWh versus Catalyst Cost.

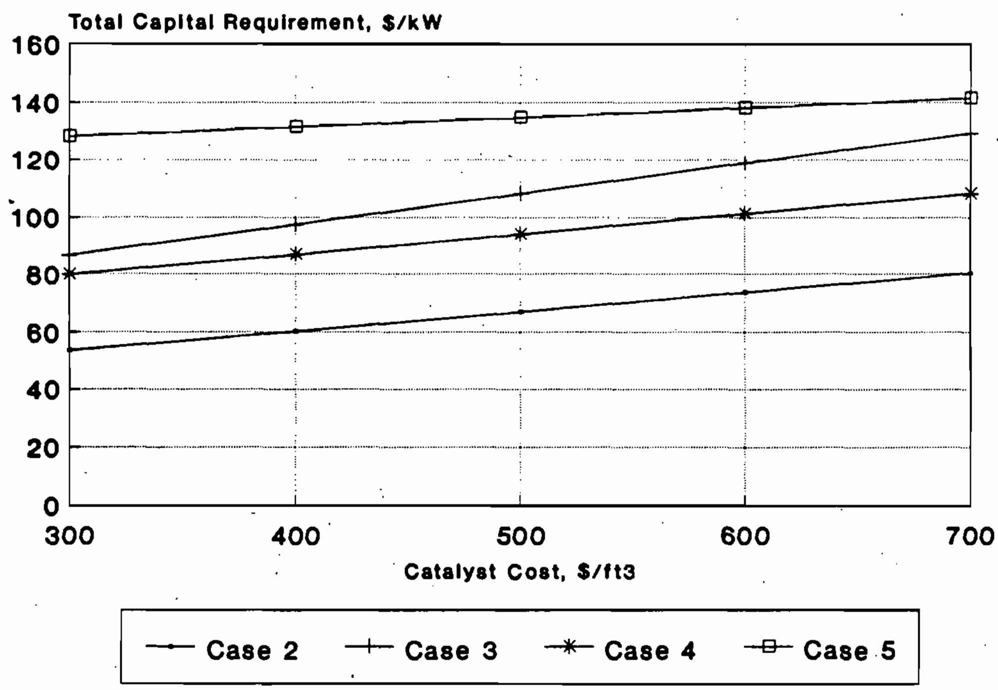

Figure 14. Total Capital Requirement versus Catalyst Cost.

ATTACHMENT 6

1985 DRAFT VERSION OF EPA'S
PERMIT MODIFICATION POLICY

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

JUL 5 1985

MEMORANDUM

SUBJECT: Revised Draft Policy on Permit Modifications and Extensions

FROM: Darryl D. Tyler, Director
Control Programs Development Division (MD-15)

TO: Directors, Air Division
Regions I-X

The attached draft policy for handling changes to sources which have PSD permits and extensions of these permits is a revision of the November 19, 1984, draft policy distributed to the Regions for comment. This revised policy incorporates your comments on that draft.

There are two major revisions to the November 19, 1984, package:

(1) the section dealing with extensions for phased construction projects has been altered to provide a better explanation of the manner in which extensions for dependent and independent multi-phased projects are handled and the rationale for a distinction between the two types of projects; and

(2) a new section devoted exclusively to permits for steam generators subject to 40 CFR Part 60 (NSPS) when the permit involves a rolling 30-day average emission limit for SO_2.

There have been other changes to clarify the text and respond to the comments we received, but those changes are relatively minor compared to the two revisions discussed above.

In particular, if you feel that the section dealing with the rolling 30-day average NSPS for SO_2 should be treated as a separate policy, please indicate this in your comments. We do not want to hold up the entire policy in order to resolve this recent addition. We also intend to hold a discussion on this topic at the Mid Pines NSR Workshop; please be prepared to take this opportunity to discuss your concerns. We would like to receive all your comments on this latest draft by July 19. Unless substantial adverse comment is received, we will begin review of this package for formal EPA policy adoption.

It should be noted that Section VII of the policy, Protection of Short-term Ambient Standards, includes new requirements for an agency which has issued PSD permits that do not specify short-term SO_2 emissions limits to adequately protect ambient air increments and standards. In such cases, the proposed policy requires the agency to revise the permit by adding limits which will provide such protection. For all other cases, the policy presumes that the applicant is the party requesting a change.

If you have any questions, please contact Gary McCutchen, (FTS 629-5591). Thanks again for your assistance in developing this important policy, particularly the efforts of Roger Pfaff, Region IV.

Attachment

cc: B. Bankoff
G. Emison
B. Pedersen
E. Reich
P. Wyckoff

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TABLE 1. SOURCE, APPLICATION, AND PERMIT CHANGES

ssification Proposed nge	Level of Action	ACTION TO BE TAKEN FOR SOURCE WHICH HAS: A. Been Exempted from PSD Permit Review	B. Submitted a PSD Permit Application	C. Been Issued a PSD Permit	D. Begun Operation
Administrative emissions or impact rease.	Amendments	1A. None	1B. Amend application as needed, but no additional review or repeat of already conducted review is required. Original increment is preserved.	1C. Amend permit. Change permit as needed, but no review is required or need be repeated. Original increment is preserved.	1D. Amend Permit. Change permit as needed. Original permit is valid until new permit is issued. Source can make change and operate even before new permit is issued. Original increment is preserved.
Minor ssions or impact rease, but less n the significance el (or equivalent).	Revisions or New Permit	2A. Review Exemption. Check to see if source or emissions unit is still exempt. If so, no further action. If not, initiate permit review process; original "increment" is preserved, but changed source is not allowed to construct until permit is issued. Changed source is processed as a new permit.*	2B. Revise Application. Change must be combined with original application. BACT and other review decisions already made should be screened and revised as needed. Public participation in change is required. Original increment allocation is preserved; additional increment allocations based on date proposed change was submitted. Change is subject to any new PSD rules.*	2C. Revise permit. Revise application to reflect change. Screen review decisions and repeat or add reviews as needed. Repeat public participation. Original increment is preserved; additional increment allocations are based on the date proposed change was submitted. Source or emissions unit as originally permitted can begin operation but changed source or emissions unit cannot construct until revised permit is issued. If construction or original source or emissions unit has not commenced, change is subject to new PSD rules.*	2D. Revise Permit. Unless change (or combination of changes) constitutes a major modification, review process is not screened or repeated. Change is not subject to any new PSD rules. Changed source or emissions unit cannot construct until revised permit is issued. Original increment is preserved.*
Significant ssions increase (or act increase equiva- t) is significant. operating sources, s class of change stitutes a major ification.	Revisions or Major Modification or New Permit	3A. Review Exemption. Check to see if source or emissions unit is still exempt. If so, no further action. If not, initiate permit review process; original "increment" is preserved, but changed source or emissions unit is not allowed to construct until permit is issued. Changed source or emissions unit is processed as a new permit*	3B. Revise Application. Change must be combined with original application. BACT and other review decisions already made should be screened and revised as needed. Public participation in change is required. Original increment allocation is preserved; additional increment allocations are based on date the proposed change was submitted. Change is subject to any new PSD rules.*	3C. Revise permit. Revise application to reflect change. Screen review decisions and repeat or add reviews as needed. Repeat public participation. Original increment is preserved; additional increment allocations are based on date the proposed change was submitted. Source or emissions unit as originally permitted can begin operation but changed source or emissions unit cannot construct until revised permit is issued. If construction on the original source or emissions unit has not commenced, change is subject to new PSD rules.*	3D. Major Modification. Process according to PSD rules. Original permit remains valid until new permit is issued. Original increment is preserved; additional increment allocations are based on date the modification application was submitted.*
Fundamental ange constitutes a source or emissions it due to magnitude emissions or impact crease, or to basic ysical or operational erations regardless net emission change.	New Permit	4A. Review Exemption. Check to see if source or emissions unit is still exempt. If so, no further action. If not, initiate permit review process; original "increment" is not preserved. Changed source or emissions unit is not allowed to construct until permit is issued and is processed as a new permit. New increment will be based on date the change was submitted.	4B. New Application. Change will require a new application. Review process begins all over again. Original increment "allocation" is not preserved; new increment allocations will be based on date the change was submitted.	4C. New permit. Change will require a new permit. Original increment allocation is not preserved; new increment allocations will be based on date the change was submitted.	4D. New source. Process according to PSD rules. Original increment allocation is not preserved, but original permit remains valid until change is made. Changed source cannot be constructed until new permit is issued. All increment allocations are based on date change was submitted.

)TE: Circumvention voids any and all original increment allocations for the entire source. A fundamental change in the nature or size of an emissions unit or source will void the original increment allocation for that emissions unit or source.

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FIGURE 1. DECISION PROCESS FOR PROPOSED SOURCE, APPLICATION AND PERMIT CHANGES

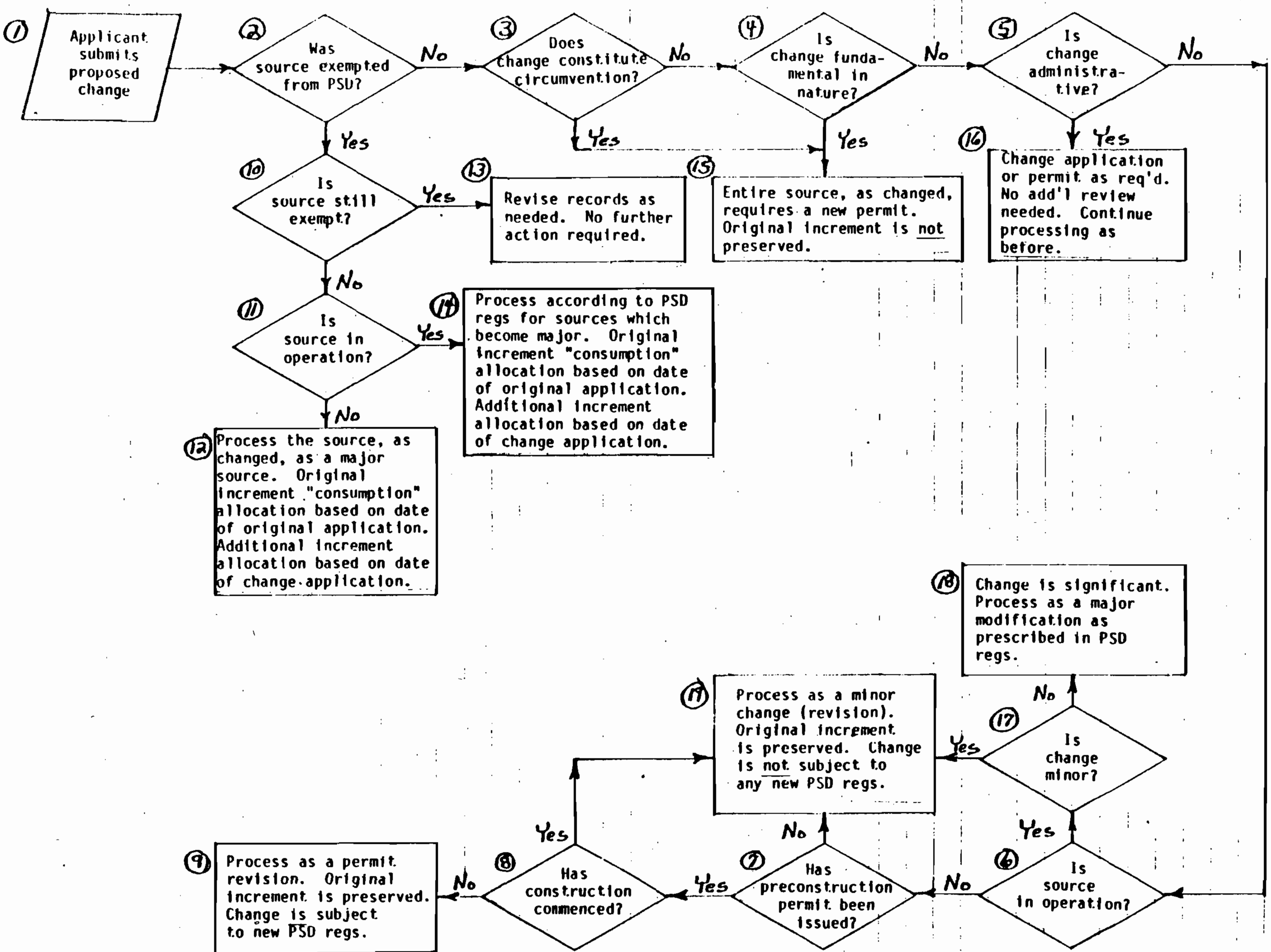

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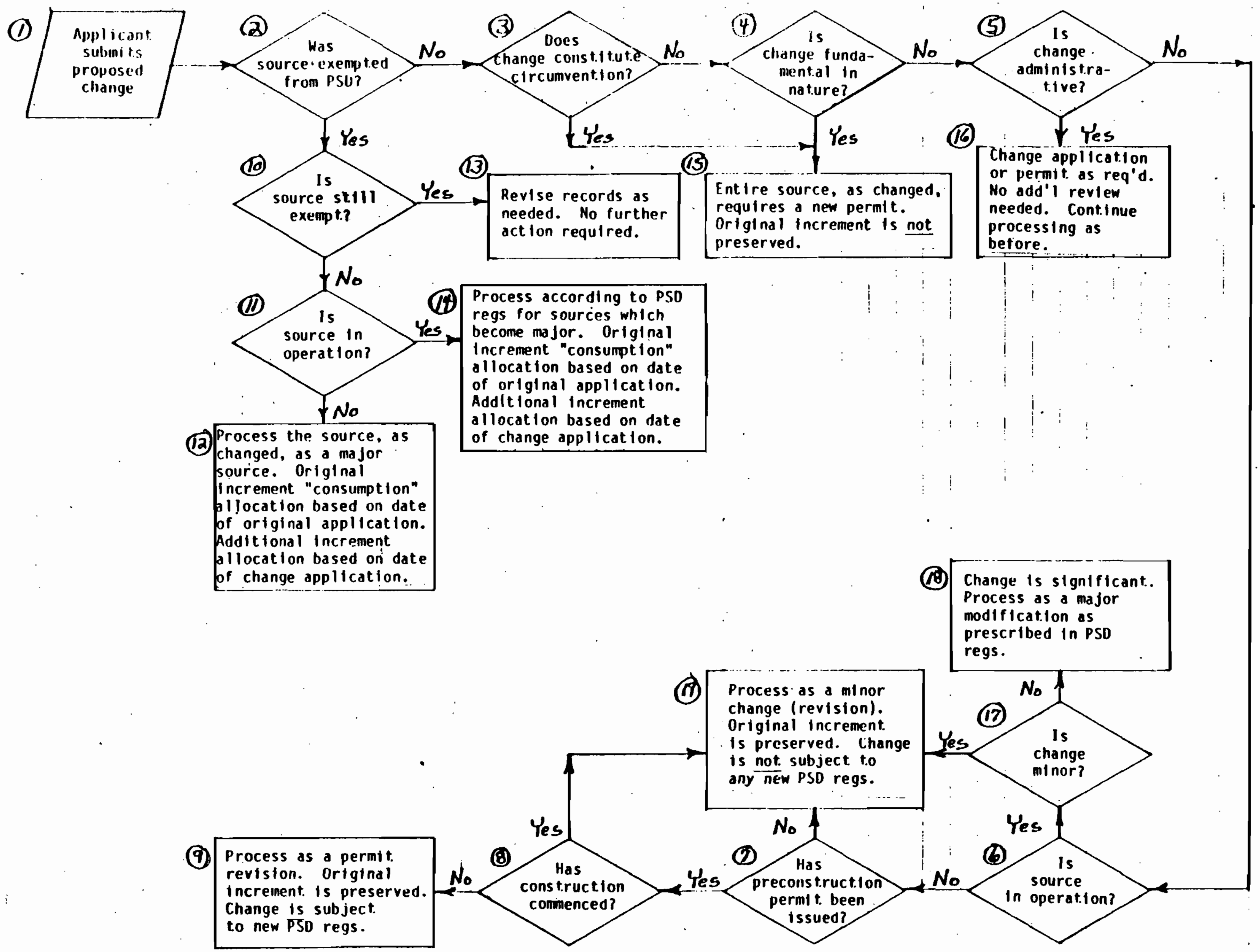
FIGURE 1. DECISION PROCESS FOR PROPOSED SOURCE, APPLICATION AND PERMIT CHANGES



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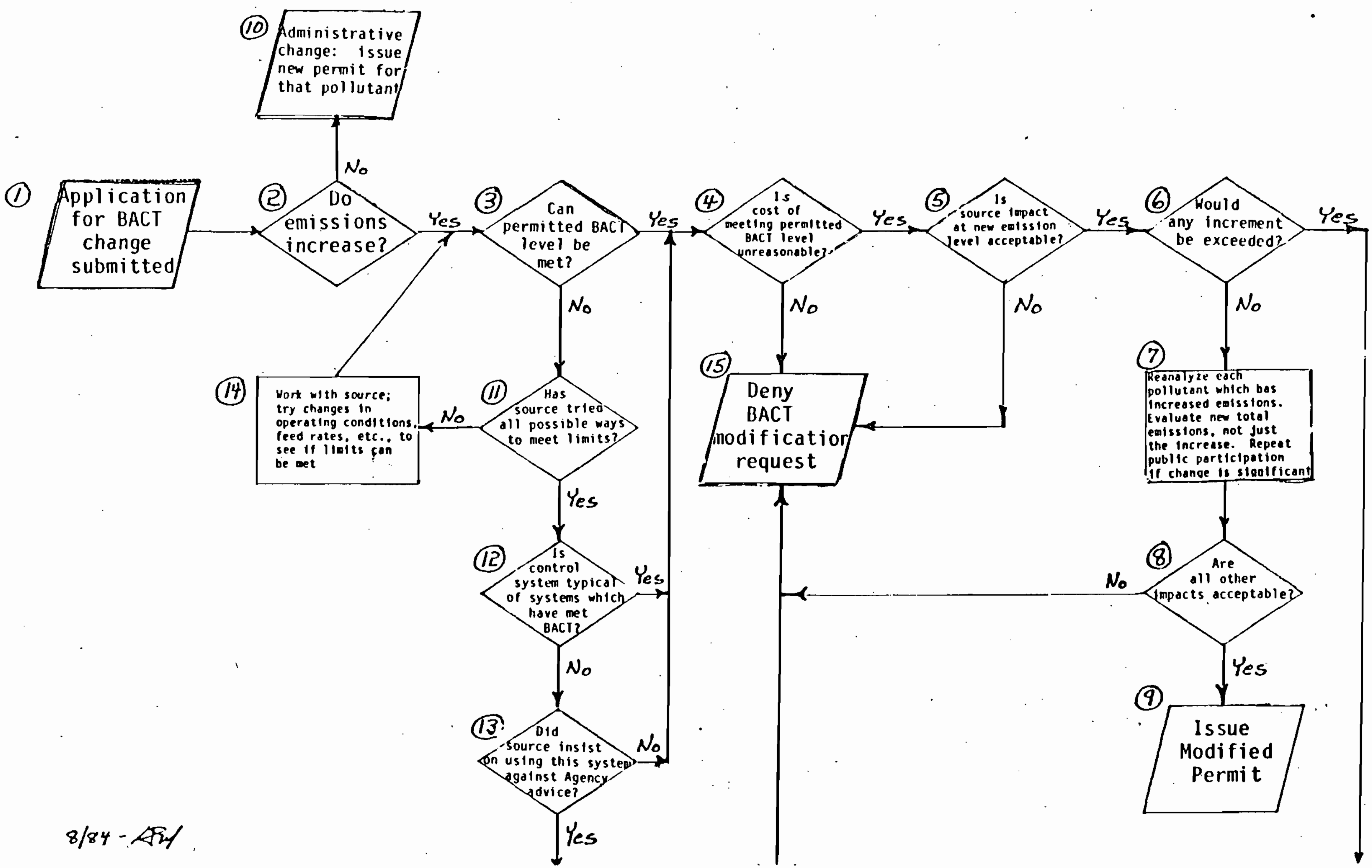
BACT CHANGE DETERMINATIONS
FOR OPERATING SOURCES



SUMMARY: For several years, both the Environmental Protection Agency (EPA) and various States have issued permits for the prevention of significant deterioration (PSD) of air quality to proposed new and modified major stationary sources. Some of the permits require revisions to reflect changes in construction or operating plans, including construction schedules. In other cases, changes in plans have been proposed by applicants prior to permit issuance, or after EPA has determined the source, as originally proposed, is exempt from PSD review. No formal policy has been issued which addresses how such changes are to be handled. Consequently, a source owner proposing changes to a source has no guidelines to determine what requirements must be met.

Since no provisions are contained in the Act for modifying PSD permits already issued, all the requirements of Part C and a repeat of the permitting process appear to be necessary for changes in sources not reflected in the originally issued permit in order to prevent obvious circumvention. That is, a new permit must be obtined if a proposed change would involve: (1) a major modification; (2) a difference in construction or design from what was originally planned, when an increase in emissions or ambient impact would result; (3) a fundamental alteration of an emissions unit or source; or (4) a difference in applicability, such as a source no longer being exempt from PSD review. Today's policy proposes to provide a new and less cumbersome route by which changes can be accommodated while ensuring the equivalent environmental protection required under the Act. In doing so, it extends the Alabama Power concept of de minimis to include changes which
[END OF E-MAIL]

are so small in terms of impacts that such changes could be excluded from the full rigors of permit review.

The policy statement provides guidance for (1) re-examining EPA-granted permit exemptions, (2) revising any EPA-issued PSD permit or PSD application, including those administered by States which have since obtained jurisdiction for PSD, and (3) the development of State and local agency permit revision regulations or policies. EPA encourages States to adopt similar policy statements concerning source changes and the processing of State-issued permits which need revision or extension and solicits comment as to whether such procedures should be required by 40 CFR Part 51.

Today's policy statement proposes to distinguish between sources which have begun operation and those which have not in determining the type of procedures used when a proposed change will require permit revisions. A permit revision for a source already operating generally can be treated like any other emissions increase or decrease at a major source using established procedures. For a source not yet operating, EPA proposes to group the range of possible changes to a PSD permit into three categories, based on their potential significance to the program: (1) those which can be expedited without detailed review (administrative changes); (2) those which can be processed as permit revisions after appropriate analysis (minor and significant changes); and (3) those which should be treated through issuance of a new PSD permit (fundamental changes). The required analysis for permit revisions typically would involve reconsideration of the basic decisions involved in the issuance of the original permit for the units that would be affected by the proposed change. Separate sections on the criteria for extending the 18-month commencement of construction deadline applicable to all PSD permits and on handling permit revisions resulting from the use of a 30-day rolling average SO_2 new source performance standard (NSPS) are also provided.

DATES: This policy statement is effective as interim guidance upon publication. The period for initial comment on the proposal closes on [date 30 days from the date this notice appears in the FEDERAL REGISTER]. A public hearing on the proposal will be held on __________, 1985, at 10:00 a.m., in ______________, ____________, Denver, Colorado 80295.

ADDRESSES: Comments should be sent in triplicate if possible to: Central Docket Section (LE-131), U.S. Environmental Protection Agency, 401 M St, S.W., Washington, D.C. 10460. Attn: Docket No. A-83-40.

DOCKET: EPA has established docket number A-83-40 for this action. This docket is an organized and complete file of all significant information submitted to or otherwise considered by EPA. The docket is available for public inspection and copying between 8:00 a.m. and 4:00 p.m., Monday through Friday, at EPA's Central Docket Section. A reasonable fee may be charged for copying.

FURTHER INQUIRIES: For further information, contact Gary McCutchen, New Source Review Section (MD-15), Environmental Protection Agency, Research Triangle Park, North Carolina 27711.

SUPPLEMENTAL INFORMATION:

I. BACKGROUND

A policy is needed to maintain the basic integrity of the PSD permitting process required by the Clean Air Act when requests are received to revise, add to, or delete conditions on issued permits or information contained in a complete application. A rigorous preconstruction review for PSD would ultimately not be effective if sources could readily obtain subsequent relaxations to their permit conditions under a lax policy for permit revisions. For example, the Act clearly intends state-of-the-art application of best available control technology (BACT) by PSD sources, but a lax policy for subsequent proposed changes could undercut the environmental protection offered by the original BACT determinations.

When EPA revised its PSD regulations in August 1980, the Agency deferred the development of guidance governing its PSD "permit modification" process, i.e., the procedures by which proposed changes to a source, application or permit would be handled. Since then, the Regions and States have handled requests for such changes on a case-by-case basis. These involve a broad variety of redeterminations of exemptions from permit requirements and permit changes, both minor and important, arising from sources which are already operating as well as those on which construction has not yet commenced. This has naturally led to a variety of decisions across the country and, hence, creates confusion and inefficiency in the permitting process for EPA, industry, and the States. A nationwide policy is necessary to assist all parties in dealing with PSD source changes and the need for PSD permit revisions in a consistent manner. In addition, such a policy will serve to establish a firm policy framework which resolves questions of legal risk when a judgment is made that new permits are not required.

Current policy requires that a new permit be obtained if a proposed change constitutes: (1) a major modification; (2) a difference in construction or design from what was originally planned, when an increase in emissions or ambient impact would result; (3) a fundamental alteration of an emissions unit or source; or (4) a difference in applicability, such as a source no longer being exempt from PSD review. Today's policy proposes to provide a new and less cumbersome route by which changes can be accommodated while ensuring equivalent environmental protection. In doing so, it extends the Alabama Power concept of de minimis to include changes which are so small in terms of impacts that such changes could be excluded from the full rigors of processing.

Due to the similarity between major and minor "source modification" and "permit modification," it is important to establish a terminology which will not be confused with existing PSD terms and which can be used consistently and precisely to describe the situations and actions regarding this policy. Therefore, the term "permit modification" will not be used. Instead, the following terms are used to describe this policy.

A "change" refers to the proposed or actual alteration of an application, permit, or source, or some combination of the three. An application for a proposed change initiates Agency action if the application is complete. When the proposed change has actually been made, the altered source, permit, or application is referred to as "changed" or "revised." Changes are classified according to the effect they would have on the reviewing agency's assessment of the source. In order of increasing importance, changes are considered:

1. Administrative. An administrative change involves no increase in either emissions or impacts and no fundamental change in either the source or one of the emission units at that source. Application or permit revisions may be necessary, but additional review or analysis would not normally be required; examples are typographical and company name changes. One exception is the extension of commence construction dates, which may require a limited additional review consisting of BACT reanalysis and public participation.

2. Minor. Minor changes require revisions to permit applications or issued permits and a certain amount of additional review and analysis, but do not constitute either a fundamental or significant change. Emissions or impacts increase as a result of minor changes, but not above the significance level.

3. Significant. Significant changes are changes where one or more pollutant emission increases exceed the applicable significance level(s) but which do not constitute a fundamental change. Major modification

review level is triggered unless the affected source is not yet operating; significant changes at preoperating sources are considered application or permit revisions.

4. Fundamental. A fundamental change is so basic in nature (size or type of source or emissions unit), regardless of the net emissions or impact differences, that the changed source or emissions unit is considered a new source or emissions unit and thus triggers a totally new permit review. A fundamental change could even result in an emissions decrease but still require the owner or operator to obtain a new permit. Examples include proposing a kiln in place of a dryer and proposing a 500 TPY unit in place of a 100 TPY unit.

The effect of a change depends in part on the status of a project. Project status milestones are:

1. Exempted from PSD review

2. Preconstruction PSD permit application submitted

3. Preconstruction PSD permit issued, but source is not operational (also, the applicability of new PSD rules is affected by whether construction of the source has commenced)

4. Preconstruction PSD permit issued and source in operation

The results of various combinations of changes and source status are summarized in Table 1. A procedure for determining which result is applicable to a specific source is diagramed in Figure 1. Note that both Table 1 and Figure 1 can only summarize this policy; more detailed information appears in the text.

II. AGENCY JURISDICTION

Today's policy covers all PSD applicability decisions and all PSD permits originally issued by EPA. This includes those PSD applicability decisions and permits which are still under Agency jurisdiction, as well as the applicability decisions and permits issued by EPA which subsequently come under State jurisdiction as a part of PSD program delegation or SIP approval.

The Agency intends that today's guidance also be used as a model for States developing their own permit revision processes for PSD, nonattainment area (Part D of the Clean Air Act) and other new source review purposes. EPA believes that regulations governing proposed changes to sources, permits or applications are needed as a legal alternative to having to issue a new permit for all except certain administrative changes. EPA solicits comment on the need for separate 40 CFR Part 51 regulations requiring State adoption of a similar policy to ensure the credibility of State PSD programs, as well as the need to extend this policy to include nonattainment area major sources and major modifications. As a minimum, EPA believes that state-of-the-art best achievable control technology (BACT) should be guaranteed by any State reevaluation of PSD applications and permits.

III. CLASSIFICATION AND REVIEW OF CHANGES

There are two primary factors to consider in determining the scope of review to be imposed upon a source in response to a proposed change. The first of these involves the significance of the proposed change; the more significant the change, the more involved the review will be. Four levels of change have been identified (administrative, minor, significant, and fundamental), leading to the same number of (but not always corresponding) levels of review stringency: amendment, revision, major modification and new permit. A second factor, stage of source development (whether the source has been issued a permit, whether the source is operating and, in certain cases, whether construction has commenced), is critical in determining what action is required and whether any of the original increment allocation (for particulate matter and sulfur dioxide) is preserved. For reasons explained below, various changes by a source that is not yet operating can reasonably be treated in a more stringent manner than would the same activity by a source already in operation.

(A) Stage of Source Development

EPA proposes to classify some PSD-related source changes differently depending on whether the change is for a source that has already begun the operation authorized in its PSD permit. This difference in treatment between sources not yet operating and those already doing so is based on several factors: (1) a project in its earlier phases is much more flexible than one already operating; (2) the company's commitment to the project prior to operation is less clear and its position regarding further changes at a plant which is not yet in operation differs from that of most existing sources; and (3) the test of whether a source can operate and produce a product under the original construction plans eliminates a great many possibilities of obvious circumvention of the regulations. Treating an operating source as essentially having completed the permitting process eliminates the burden of uncertainty on the company of constantly having to evaluate proposed projects in light of changes made years ago. Today's policy acknowledges these factors by typically imposing a less rigorous process for proposed changes at operating PSD sources. EPA solicits comment on the reasonableness of this approach and on whether other events such as commencement or completion of construction should have some greater standing in a final policy. It should be noted that commencement of construction already confers an exempt ("grandfather") status to a source not only in CFR Parts 51, 52, and 60, but also in this proposed policy when determining whether newly-issued rules are applicable (see below).

1. <u>Pre-operational Sources</u>. An application for a change to an application or permit for a source not yet in operation would generally

prompt reanalysis of the proposed project as if the original application had been submitted in that form. However, some changes would be considered sufficiently unimportant that they could be treated as application or permit amendments; these are termed administrative changes. Other changes would be important enough to prompt the need for a revised or new application or permit, and could require additional review actions. These various levels of change are discussed in detail in the next section.

For application and permit changes requested prior to operation, EPA is proposing that the changes be handled as part of the initially permitted project, rather than as new projects. The Agency is concerned that changes that are individually small would be accumulated such that a cumulative significant change would not be given the full review that such a change should receive. Thus, even a de minimis increase in a pollutant can be subject to PSD review if that pollutant would be significant when added to previous increases. (This is further explained below under (B)2. Revisions.) In order for EPA to treat such a change as a new project, and not as part of the already permitted project, the applicant would be required to make a demonstration that the two projects are physically independent and were considered to be separate projects for planning purposes. If the reviewing agency concurs that the new project is a separate project, the change can then be treated as such. These criteria are identical to those used for judging separation of projects already constructed (see below). The only difference is that EPA initially presumes that a change at the site of a nonoperating source is not a new project.

2. PSD Sources Already in Operation. Applications for changes which would affect sources which have already been issued PSD permits and been placed in operation have generally been treated the same as applications to change any existing major stationary source. That is, if the change is

significant, it constitutes a major modification, as defined at 40 CFR Part 52.21, and a complete PSD review is required; if the change is not significant, it does not constitute a major modification and no PSD review applies. Under today's policy, changes will instead be processed in the manner described in the next section.

The only exception to the approach described below arises from the need to avoid circumvention of the regulations: if the proposed change should reasonably have been part of the initial project rather than a separate project, it should be evaluated as part of a new total source impact rather than as a separate action. At times, such proposed changes take the form of "separate" sources or even projects involving more than one source. However, if the reviewing agency judges that such sources or projects are part of the same project covered in a previous PSD application, the changes should be treated identically to changes for sources which have not yet begun operation. This must be determined by the reviewing agency on a case-by-case basis, taking into account whether the proposal represents changes at the source which are physically independent of the original project, and whether the applicant can provide documentation to show that planning of the second project occurred after the planning for the first project. Thus, if a PSD-permitted boiler has been constructed, and the owner then applies for a de minimis increase in SO_2 emissions from the boiler, which in the judgment of the review agency should have been a part of the original permit application, the requested change cannot be treated as a new application (and therefore be exempt from review because it is de minimis). It will instead be subject to each PSD review element within the permit revision process as described below. Conversely, if the applicant applies for a new processing unit to be used in a completely separate production area of a chemical plant, this application can be treated as a new project and exempted from review, if de minimis.

(B) Levels of Review

1. Amendment. Changes to a permit or application are classified as amendments if they are administrative in nature and result in no increase in either the emissions or the air quality impact of a PSD source. In addition, neither the nature nor the size of the source or emissions unit can be altered to the extent that the change would be considered fundamental. Amendments may be quickly processed without any major reevaluation of the decisions originally made in permitting the source. Examples of the type of change which would often be treated as an amendment include company name or operator changes, requirements for more frequent monitoring or reporting by the permittee, correction of typographical errors, emission decreases (although such decreases, to be used in netting or trading, must be carefully documented) and minor wording clarifications. It should be noted that a fundamental change (see below) may also result in no increase in emissions or impact, but cannot be treated as an amendment.

The lack of emissions and impact increases for an amendment results in little or no review. Proposed amendments (which are nearly always administrative changes) to applications and permits do not require any reanalysis of the basic review originally submitted and need not be subject to public participation requirements as a general rule. However, the Agency emphasizes that there may be instances where changes which are normally administrative may be sufficiently important that the reviewing authority determines that review or public participation is necessary, e.g., a change of ownership of a proposed source to a company which has been involved in highly controversial projects or has received public attention as a result of the manner in which other air pollution sources owned by this company were operated.

One administrative change which always receives some level of review is the extension of commence construction dates. Such changes constitute amendments but must be reviewed to ensure state-of-the-art BACT; in addition, it is usually appropriate to seek public comment on the proposed extension, since other potential new sources may be affected. A more detailed discussion of this type of change appears in Section VI below.

2. Revision. The term revision encompasses the review level required for the large majority of minor and significant changes at all preoperational sources and at existing (operating) major stationary sources which do not qualify as "major modifications," as defined by the PSD regulations, or as fundamental changes. Revisions include, in the case of operating sources, most changes involving construction or changes in the method of operation of a source, including control equipment, that do not produce a net significant emissions increase; a net significant emissions increase resulting from a physical change or change in the method of operation at an operating source usually constitutes a major modification as defined in the rules and is processed as such. It should be noted that there is a distinction between (a) modifications (as defined in the PSD rules) which are not subject to NSR, and (b) changes (whether requested or necessary) to a permit or permit application. A change which does not result in a significant net increase in emissions is not considered a "major modification" and is not subject to PSD; however, the change may require (or the owner may request) a revision of the source permit (or application). In such cases, the reviewing agency may consider some level of reanalysis and review necessary before revising the permit or accepting an application revision. For example, a source may want to change a solvent used in one of its processes, with no increase in emissions, but the permit specifies the solvent to be used. Before revising the permit to allow use of the new solvent, the reviewing agency may decide

to repeat public comment if the new solvent is more odorous or toxic than the current solvent, repeat the impact analysis if the new solvent is more reactive or toxic than the current solvent, or revise some other component of the existing analysis.

Despite the possibility of a revised analysis, nonsignificant emission increases do not constitute the type and degree of review to which major modifications are subject. In many cases, it is anticipated that little or no revised analyses will be required of nonsignificant emissions increases. On the other hand, changes to permit (or application) parameters which the review agency considered important enough to include on the permit (or rely upon in the application) should certainly be subject to review before those parameters are revised.

The term revision also encompasses the level of review of most candidate application and permit changes which are proposed at sources which are nonoperational with respect to construction approved in their PSD permit. The only exceptions are those changes which are administrative, or which are so great that they require a totally new PSD review (fundamental changes).

Once a change is classified as requiring the revision level of review, it is screened to determine which elements of PSD review now apply and to what extent. A revision will first require a screening analysis to determine whether existing analyses addressing the PSD requirements are still accurate or whether there is a need for revised analyses. Major components of the new source review include BACT, ambient impact analysis, monitoring requirements, additional impacts analysis, Class I area protection, and public participation. A full description and explanation of these review components is contained in the August 7, 1980 FEDERAL REGISTER (45 FR 52676). Depending upon what change is proposed, this screening may be very simple, as in the case of a very small increase in the size of an emissions unit, or very involved, as in the case of the addition or replacement of a new unit at a preoperational source.

The proposed change must be examined not only to see if any existing analyses should be revised, but also to see if any new analyses should be performed. The criteria for requiring additional review elements will be whether the original new source or major modification application underwent all of the review which would have applied had the application been submitted in its revised form originally. In addition, any new requirements added to the PSD regulations since the time that the original permit was issued also could apply, unless construction had commenced so as to qualify for an exemption (as discussed below). If there is no circumvention of the permit requirements, the revision review would focus on only that portion of the source immediately involved in the proposed change, rather than all of those units previously reviewed.

An example is a proposed change prior to permit issuance to add a unit emitting 15 tons per year of SO_2 to an application for a source which originally provided for 100 tons per year of particulate matter and 35 tons per year of SO_2. This would constitute a minor change. Since the change is combined with the original application, both the new unit and the already permitted units must undergo each PSD review element for SO_2. This is because the original permitted level of SO_2 was de minimis, thereby exempting SO_2 from review, but the total new level of SO_2 is significant (35 TPY and 15 TPY together exceed the 40 TPY threshold). However, the original application date is used in allocating increment for the original 35 TPY SO_2 emissions level unless circumvention of the SO_2 review had been intended.

As another example, suppose a permit for a new PSD source allows 60 tons per year of SO_2 emissions and the source was not required to gather preconstruction monitoring data because it created a de minimis ambient impact. The source owner wishes to lower the stack which emits SO_2, making total SO_2 impact significant. The source owner would therefore be required to conduct a new modeling analysis and gather representative preconstruction monitoring data before the change could be approved.

In processing a revision, whether for a minor change or a significant change, the reviewing authority must follow the same public participation procedures noted in 40 CFR 52.21(q) for the processing of preconstruction PSD permits. EPA believes that the reconsideration of the conditions and review of an existing permit undergoing revision should receive no less an opportunity for public involvement than did the original permit application. This includes public notification by newspaper advertisement in the area of the source. The notice would contain information regarding the agency's preliminary determination, the expected ambient impact of the proposed change, the 30-day opportunity for written comment, and an opportunity for a public hearing.

A proposed change qualifying as a revision, rather than as a new permit, receives certain benefits. As mentioned previously, a revision can be exempted from any new PSD requirements that were added between the time of the original permit issuance and the submission of the proposed change if the source had commenced construction prior to the adoption of the new PSD requirement. "Commence construction" is defined in terms of the owner or operator having all the necessary preconstruction approvals or permits and either having (1) begun, or caused to begin, a continuous program of actual on-site construction of the source, to be completed within a reasonable time, or (2) entered into binding agreements or contractual obligations, which cannot be cancelled or modified without substantial loss to the owner or operator, to undertake a program of actual construction of the source to be completed within a reasonable time. The purpose of subjecting revisions to new requirements for sources not having commenced construction is to remove the potential benefit a source might obtain by submitting a questionable application to reserve increment or avoid new PSD provisions.

Another major advantage a source gains by qualifying for a revision, rather than having to obtain a new permit, is that the source retains the increment rights afforded by the original application or permit. Neither new permits nor fundamental changes to an original proposal (which by definition change the very character or nature of a source) preserve the original increment allocation, because that allocation was for a specific type and size of source at a specific location. An allocation is not automatically conferred to, for example, a cement plant which is proposed in lieu of a permitted power plant.

If a revision being considered by EPA would cause additional increment to be consumed beyond that originally allocated, today's policy would allow the additional increment consumption only when increment is available after prior complete applications have been processed and only at the concurrence of the State in which the source would locate or is located. If new increment consumption beyond the significance amounts identified in the 1978 preamble (excluding Class I areas where any new impacts must be authorized by the Federal Land Manager) would result at any point, such increment consumption must also be authorized by the State in which the source would locate or is located.

An especially significant issue arises from situations in which there is competition for the available air resource: other permit applications and changes are pending such that the ambient ceiling imposed by the NAAQS or increment would prevent the granting of all of the applications. In such circumstances, EPA would take a first come/first served approach to allocating the growth rights, subject to State approval. This means that the original emissions growth rights would be preserved but that the remaining growth rights would be awarded to intervening applicants filing applications prior to the filing of the proposed change. When EPA is implementing this policy, it will recognize the rights of complete PSD applications filed with States which have the responsibility under their own PSD program for future permit applicants. Any State taking jurisdiction of EPA-issued permits may develop alternatives to first come/first served allocation of air resources to which EPA would generally defer; of course, no such alternative system can allow an increment violation to result.

3. Major Modification. Operating units which propose changes that constitute a "major modification," within the meaning of the NSR regulations are subject to those requirements. Generally, this review is equivalent to the requirements for a new source (see below), but the review is conducted only for the modification, not for the entire existing source. The term "major modification" is defined as "any physical change in or change in the method of operation ... that would result in a net significant emissions increase...." Physical changes are, in general, readily identifiable, but changes in the method of operation are often more subtle. The latter includes such activities as removal or significant alteration of pollution control equipment. For a source not yet operating, however, proposals which would normally be considered major modifications would generally under this policy be treated as an application or permit revision (see above).

4. New Permit. Some changes are sufficiently important such that a separate new application or permit is required, rather than a revision to the existing application or permit. These are of two types. First, a change to an application or a permitted source which affects the fundamental nature of the source triggers the need for a new permit. A general guide

to whether the fundamental nature of a source is being changed is whether the proposed changes would result in either a different 2-digit SIC Code for the source or a large increase in size. However, the reviewing authority must use good judgment and make this decision on a case-by-case basis.

A new application or permit is required for fundamental changes because the proposed change would be of such major importance to source operation that the basic permitting process should be repeated, with no increment rights reserved. For example, a change from a dryer to a kiln may affect a review such that different emissions control or product recovery operations would be found to be feasible for the kiln where they were not for the dryer under the original analysis.

Since it is often inappropriate to apply SIC codes to portions of sources, this procedure cannot easily be used when the proposed action would affect only a part of an existing source. The reviewing authority should therefore decide on a case-by-case basis whether the fundamental nature of the permitted portion of the source is being changed. SIC codes could be used as a guide to do this. For example, if a new boiler is planned or permitted at a kraft pulp mill, and the applicant wishes to construct a lime kiln instead of a boiler, it is clear that the fundamental nature of the unit (the boiler) is being changed, even though the source (the kraft pulp mill) is not; the lime kiln would require a new permit.

Fundamental changes in the size of a permitted emissions unit or source are those changes which increase the fixed capital cost of the emissions unit or source by greater than 50 percent. This could often require more than a 50 percent increase in source or emissions unit size, since cost per production unit usually decreases as the size of the unit increases.

A decision to review a change as a new permit application would generally entail the same data development as would the original permit application, although the review would focus on the proposed changes. In many instances, data from the original permit application could be used to expedite the new permit review process. Additional data would often be required for the new or changed units and all units affected by them. If the new or changed units affect the original BACT, air quality, and modeling analyses, these analyses would need to be revised accordingly.

As noted above, one area where the processing of certain significant and all fundamental changes may differ greatly from that of many significant and all minor changes concerns the awarding of new increment rights: sources or emissions units involved in application and permit revisions (which assumes no fundamental change) retain their original increment rights during the revision process. In contrast, a change that is processed as a new permit must compete for available air resources behind any complete applications filed before the complete application for the change is filed. It is important to note that, while the permit as previously issued entitles the original project design to be built, the permit does not award equivalent increment rights to the source for any substantial shift in configuration, type, or size of units that it might wish to construct.

If there has been much growth in an area or if the area is heavily industrialized, air quality may have deteriorated so as to be near the ceiling imposed by the increments or NAAQS. In such a case, a new source permit may not be issuable. Consequently, either the one-year deadline for processing a complete application will be controlling (EPA must disapprove a permit if insufficient increment is available within a one-year timetable) or, if the original permit has already been issued, the 18-month deadline for commencing construction (assuming no extension) will force the source attempting to change its PSD permit to finish its original construction plans or to withdraw its proposed change and not construct at all.

Figure 1 outlines the process that a reviewing agency can follow in classifying an application for a change. EPA also offers Table 1 in order to convey summarized guidance on which of the above described levels of review should be applied to various types of permit changes. Table 1 lists a wide range of ways in which a source might be changed and indicates the Agency's proposed conclusions on which forms of review would apply. It should be noted that both Figure 1 and Table 1 are presented for purposes of illustration; other types of changes may occur and, in addition, special circumstances may arise which prompt the review authority to address a change differently. The Agency solicits comments regarding other types of events which should be included on the list or on the way that the listed items are classified.

IV. CIRCUMVENTION

A determination by a review agency that a proposed change constitutes circumvention results automatically in a requirement that a new permit application be filed. The applicant would be unable to preserve any of the increment allocated to the original permit. Although circumvention has been discussed in more detail elsewhere, the concept of circumvention within the framework of changes to a source presents additional complexities.

An example of circumvention would be the proposed addition of a 15-tons-per-year SO_2 emissions unit to a permit for a source originally proposed to emit 150 TPY particulate matter and 35 TPY SO_2. The reviewing agency then discovers that a 50 TPY SO_2 unit had been planned for that source from the beginning, but that the applicant had attempted to avoid SO_2 PSD review (including BACT) by applying in two stages. In such a case, the original permit is valid only for the source exactly as specified. If the applicant wants to change the source, a new permit application must be filed. None of the original increment allocation is preserved; the "complete application" date for the source would be the date the proposed change application was considered complete. This policy is intended to discourage the submission of deliberately incomplete or misleading applications through loss of any increment allocation that resulted from such actions. However, EPA would still intend, even in cases of circumvention, that any portion of the original application and review which are still applicable be retained, and that subsequent actions concentrate on the changes to the source that result in a need for additional review.

V. INCREMENT ALLOCATION AND PRESERVATION

Currently, EPA allocates increment on a first-come, first-served basis, using the date a complete application was submitted to determine an applicant's place in line. The allocated increment is assigned to the specific source (or emissions unit) and location described in the permit and application; it cannot be used by the applicant for another source, even if the second source is planned at the same location, nor can it be used for the same type of source at a different location.

For example, assume a permit has been issued for a cement plant at Location A, with an anticipated Class II (plant boundary) 24-hour total suspended particulate (TSP) impact of 40 micrograms per cubic meter (ug/m^3) and a nearby Class I 24-hour TSP impact of 2 ug/m^3. The increments reserved for the cement plant are the 2 and 40 ug/m^3 Class I and II impacts. If the owner decides instead to construct an asphalt plant at Location A, the increments assigned to the cement plant are not "preserved" for use by the asphalt plant. The owner must submit a new application for the asphalt plant, receive a new date of submittal of a complete application, and try again for an increment allocation. (In fact, without today's policy even minor changes to the cement plant could result in loss of the allotted increment, since the increment use is assigned to the source and location exactly as specified in the permit and application.)

Similarly, if the cement plant owner decides that location B would be a better place to construct than location A, the increment allocated to the cement plant at location A is not preserved for use at location B. The owner must submit a new application for location B and this new date of submittal of a complete application is used to establish the first-come, first-served increment allocation.

In addition, current policy does not provide any increment allocation for proposed sources which at first are exempt from PSD review but become subject to PSD review at a later date due to a proposed change. For example, assume a listed Source A (major at 100 TPY) is estimated to emit 85 TPY of SO_2. The owner submits an application to the reviewing agency, is told that the source is exempt from PSD review, and proceeds to obtain all the necessary State and local agency permits and commence construction. At this point, the owner discovers that SO_2 emissions from this source will be 115 TPY SO_2 rather than 85 TPY. Assuming that there is no indication of attempted circumvention, the source under current policy must still reapply and, even though already under construction, the new application date is used to allocate increment. If another application for a large SO_2 source had been submitted between the first and second Source A applications, Source A may be denied a permit despite the construction costs already committed to the project. Today's policy, in contrast, provides in certain cases for the "preservation" of increment that had previously been allocated to a source if (1) the proposed change is not fundamental, and (2) there was no intent to circumvent new source review provisions.

Preservation of increment refers to the retention by a review agency of the original complete application filing date in determining allocation of increment on a first-come, first-served basis. In other words, this policy specifies that for administrative, minor, and significant changes, the original complete application submittal date is used to allocate increment. However, the preserved increment is based on no more than the original emission rates and ambient impacts. If the revised emission rates or ambient impacts increase, only the "original" portions of the total new rates and impacts are preserved; the increases are allocated on the basis of the date a complete application for the proposed change was submitted. If the revision results in emission rates or impacts less than the original levels, the remaining portions of the original rates or impacts are no longer preserved; this is because this policy is not intended to provide trading or netting credits to a proposed source. The only intent is to reserve a qualifying source's place in line for increment allocation.

As an example, assume Source B submitted an original complete application for 275 TPY SO_2 on January 20, 1986. On August 15, 1986, before a permit has been issued, Source B files a complete application for a change which would increase SO_2 emissions by 55 TPY, to a total 330 TPY SO_2. On a first-come, first-served basis, increment from Source B is allocated using the following dates:

January 20, 1986 - 275 TPY SO_2

August 15, 1986 - 55 TPY SO_2

Note that the source's place in line for the original increment is based on the original application date, but that subsequent increases in emissions are allocated based on the date the application for the increase was filed. Source B, under today's policy, would not be competing for all 330 TPY SO_2 emissions on the basis of an August 15, 1986, increment allocation date as would have been the case under current policy. Instead, Source B competes for only the 55 TPY SO_2 additional increment on the basis of the later August 15, 1986, application filing date.

Sources which had previously been exempted from PSD review present a particularly difficult situation. These nonmajor sources consume increment but, unlike major sources, are not allocated increment. Today's policy, however, allows increment allocation preservation for sources which, as a result of a proposed administrative, minor, or significant (but not a fundamental) change, would become major as long as no circumvention was intended. Such sources would have increment allocated for the original emissions rates on the basis of the original (exemption) complete application date and the additional emissions rates on the basis of the proposed change complete application date. Thus, the original source, even though exempted from PSD review, is eligible for some degree of increment preservation. This policy is intended to apply to sources which have not yet completed construction. The PSD rules provide that exempted ("minor") sources not subject to PSD do not become subject to PSD until their emissions exceed the threshold limits and they then propose a major modification (with one exception: a modification to a minor source which would in itself qualify as a major source will result in PSD review), but this does not address proposed changes to a source prior to completion of that source.

Since increment preservation using first come, first served, relies to a great extent on the date of submission of the original application, this is a particularly important date to document. Owners and operators who feel that a source is exempt from PSD review are nevertheless encouraged to promptly submit complete applications for the State permit or for the record, even if they have already been informed verbally that a source is exempt, because the submission date establishes increment allocation priorities. Without a clearly documented original complete application date, this policy would be difficult to apply. In cases where the date a complete original application was filed cannot be determined, EPA will use the date construction is commenced.

VI. EXTENSION OF 18-MONTH COMMENCEMENT OF CONSTRUCTION DEADLINE

One permit revision topic that deserves special attention is extension of the 18-month commencement of construction deadline. The subject regulation, 40 CFR 52.21(r)(2), states that "Approval to construct becomes invalid if construction is not commenced within 18 months after receipt of such approval, if construction is discontinued for a period of 18 months or more, or if construction is not completed within a reasonable time. The Administrator may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between construction of the approved phases of a phased construction project; each phase must commence construction within 18 months of the projected and approved commencement date."

It is important to note that the Clean Air Act and 40 CFR Part 51 regulations do not expressly include the 18-month deadline. Therefore, those States that have taken over the PSD program through SIP development are not required to have the particular 18-month deadline in question. However, those States to whom the PSD program has been delegated are required to implement the 18-month deadline, since a delegate State is implementing the Federal regulations.

Often it is difficult to determine in the preconstruction phase how all aspects of the construction plan will develop. Many of the permits issued in the earlier part of the PSD program are maturing as projects. Consequently, the EPA has received several industry requests for various adjustments to their permits and construction schedules. These requests are usually based upon changes in the economy, weather, or consumer consumption in areas such as energy. EPA is responding to this need by interpreting the regulation and proposing the policy articulated here for reviewing extension requests. Effective implementation of these provisions is especially important in view of the prospects for economic growth.

The showing which a source must make in order to receive a permit extension has been a longstanding problem. Various approaches have been advocated, ranging from a stringent standard, such as impossibility in the legal sense, to such lesser showings as economic impracticality. Each of those approaches presented varying degrees of subjectivity and certain difficulties of factual analysis. Today's policy avoids those difficulties by providing extensions to virtually all good faith applications for extensions to which the affected States do not object. A good faith effort must include a certification that the company currently plans to commence construction by a specific date that usually should fall within the requested extension period, but may extend further into the future if it is still within what the review agency considers a reasonable period of time. The intent of this is to discourage situations where a source may not plan to actually commence construction for a number of years but continues to tie up increment and consequently prevent growth which could occur immediately.

Previous decisions often allowed a source making the threshold showing of justification of an extension to proceed without further analysis. There are persuasive reasons for reopening certain portions of the permit review, such as BACT, when a permit is extended. As described below, today's policy expressly provides for this further analysis. Providing extensions more readily but requiring more substantive review of those extensions presents a reasonable compromise that simplifies the policy while assuring important environmental protection.

The Clean Air Act requires review of new sources to be timely. This is especially important for key elements of review such as BACT determinations and ambient impact assessments. Consequently, there must be limitations on the period granted in which a source can construct without an updated review. In particular, BACT is an independent requirement under the Act and the Act contemplates that the BACT be current for the period in which the source's construction is actually commenced. Similarly, ambient air quality can change considerably, rendering inadequate an assessment performed at an earlier time. This policy generally outlines a method which addresses concerns about the consistency of extension requirements across the country, while complying with the Act's requirement that certain PSD determinations be timely. It is emphasized that timely requests for extensions or other modifications are the responsibility of the source. A permit will automatically cease to exist if a request for extension is not received before its expiration date. In the case of a later request, a new permit application must be filed.

Today's policy proposes that candidate permit extensions must meet the following tests for substance and processing in order to be issued:

A. BACT Review. EPA believes that in many cases the original BACT determination would still qualify as BACT if it were reviewed. This is especially the case since consideration during a BACT reevaluation is given to the costs that would be incurred in changing plans and equipment purchases if a different technology were employed. These costs and time delays may be prohibitive if construction had already commenced and the source was not designed to accommodate new state-of-the-art control technology, but EPA notes that there will also be cases in which alteration of construction plans is feasible. This could well be true of long-term, multi-unit projects for which major improvements in BACT have occurred and the expanded construction time frame has proven conducive to such project alterations. However, EPA will require a BACT reevaluation on all extension requests to the extent of reviewing EPA's BACT/LAER Clearinghouse. The original BACT determination can be assumed to remain appropriate, even if construction has not commenced, if no significant state-of-the-art advancement in BACT is noted from EPA's BACT/LAER Clearinghouse data or from the subsequent public comment period, and not more than five years has elapsed from the time of the original BACT determination.

B. Additional PSD Review Requirements. Other aspects of PSD review such as increment rights and air quality impacts will be assumed to remain valid unless adverse comments are received from affected State(s), Federal Land Managers, or other interested parties during the public comment period, since subsequent growth in the area should have considered the impacts of the permitted source. Adverse comments, if not reasonably addressed by the applicant, will typically trigger the need for a conference among EPA, the applicant, the affected State(s), and other interested parties such as Federal Land Managers. The conference may be combined with the public participation requirements for extensions. The State is responsible for ensuring that interim source growth in the area of the permitted source has not caused sufficient degradation of air quality to the extent that operation of the source requesting the extension would cause or contribute to increment or NAAQS exceedances; neither extensions of issued permits nor issuance of additional permits is allowed when they would cause or contribute to such exceedances. If the State inadvertently fails in this regard, it is responsible for remedying any subsequent violations by obtaining sufficient emissions reductions in the area. The State is also responsible for indicating whether an extension consumes all remaining increment, thereby prohibiting issuance of permits to other possible sources in the area. A source will not be subject to any other aspects of PSD review beyond those mentioned above.

C. Duration of Extension. EPA's regulations do not state the maximum length of extension which can be granted. In practice, EPA's Regional Offices have used 18 months as the norm and, in certain instances, have allowed longer extensions. Due to concerns of growth rights and public participation, EPA will presumptively limit extensions to durations of 18 months, or less, with renewal possible. This allows industry the possibility of multiple extensions if necessary but ensures that the impacted State(s) and public have control of their air resource and growth rights and that state-of-the-art BACT will be employed.

D. Public Comment. The Clean Air Act particularly emphasizes the importance of public comment on matters affecting air resource consumption. Therefore, EPA will require the same public participation procedures for extension requests as noted above for permit modifications, including a minimum 30-day public comment period.

E. Extension of Later Units of Phased Multi-Unit Projects. Phased multi-unit projects are considered either dependent or independent by EPA. In a footnote in the preamble to the 1978 final PSD regulations (43 FR 26388), EPA defined the difference between these types of phased projects:

> "The dependence of facilities within a source will be determined on an individual basis. Two or more facilities will generally be considered dependent if the construction of one would necessitate the construction of the other facility(ies) at the same site in order to complete a given project or provide a given type (not level of) service. A kraft pulp mill is an example of a source with dependent facilities, whereas a three-boiler power plant is a typical example of a source with major independent facilities."

The purpose of this approach was to differentiate between those phased projects which would be "grandfathered" (i.e., not subjected to new PSD rules) and those which would not. Dependent phased projects were considered fully committed as soon as construction began, so all of the dependent facilities were accorded the same status; if construction on the first phase of a dependent phased project commenced by an applicable grandfather date, then all of the dependent facilities were considered grandfathered even if construction of those phases of the project had not yet commenced. Conversely, each phase of an independent phased construction project had to individually commence construction by the grandfather date to be grandfathered. This approach to phased projects was upheld in Alabama Power Co. v. Costle.

The 1978 preamble also states that EPA does not generally intend to limit the time for construction of phased projects, but does intend to require commencement of construction of the first phase within 18 months of permit approval and of subsequent phases within 18 months of the date approved in the permit. Breaks in construction, as with single-phase projects, cannot exceed 18 months. These requirements appear in 40 CFR Part 52.21(r)(2), where extensions of the time period between construction of different phases of phased construction projects are not allowed.

The Utilities Air Regulatory Group (UARG) has petitioned EPA to delete the portion of the regulation limiting extensions of permitted construction intervals between phases at phased construction projects. Since the regulation could be interpreted as allowing for extension of the construction commencement deadline only for the first phase of independent, multi-unit projects, and since most utility construction projects are phased independent multi-unit projects, UARG is concerned that the regulations prohibit extensions for later phases of these utility independent multi-phase projects.

In response, EPA provides the following clarifications. First, it is EPA policy that both dependent and independent phased projects may obtain a single comprehensive PSD permit for all phases of the project. A single permit offers an applicant the advantages of reduced paperwork and assurance that the entire project (rather than only a portion of it) is permitted. Since comprehensive permits apply to projects which are often large and complex, such permits should specify at least two items that are not needed in permits for single-phase projects. These items are:

(i) Which BACT determinations will be reassessed prior to commencement of construction, and

(ii) The date by which later phases (but not necessarily the initial phase) of the project must commence construction.

BACT review (and redeterminations of BACT as appropriate) is required by 40 CFR 52.21(j)(4) at the latest reasonable time which occurs no later than 18 months prior to commencement of construction of each independent phase of a project, so inclusion in a permit of the BACT determinations which will be reassessed is not a requirement for being able to conduct such a reassessment. However, the inclusion of this information in the permit provides the owner/operator, the inspector, and the public advance notice of the intent of the review agency to conduct such a reassessment.

The commence construction dates <u>in the permit</u> cannot be extended using the mechanism embodied in 40 CFR 52.21(r)(2), but this does not mean that such dates are unchangeable. In fact, those dates <u>can</u> be changed, but not by the granting of extensions. Since these dates are a part of the permit, changes to the dates require a permit change, which will usually be considered an administrative change (albeit one which normally should include BACT review and public participation). The "projected and approved commencement date" referred to in 40 CFR 52.21(r)(2) is the date which appears in the permit, a date which can be changed by revising the permit. The procedure for changing commence construction dates which are embodied in a permit is the same procedure used for any other permit change, as outlined in today's policy. The initial phase commence construction date is extendable using the 40 CFR Part 52.21(4)(2) procedure unless that date is also embodied in the permit. When embodied in a permit, even the initial phase commence construction date can be changed only through a permit change.

The above policy concerning the initial phase commence construction date may appear to conflict with 40 CFR 52.21(r)(2); it does not. The intent of 40 CFR 52.21(r)(2) is to establish an automatic 18-month expiration date for permits, with provisions for extending the expiration date on a case-by-case basis. For phased projects with a single comprehensive permit, EPA presumed that commencement dates for each phase of the project, except the initial phase commencement date, would be incorporated into the permit. Therefore, initial phase commencement date changes would be handled with a 40 CFR 52.21(r)(2) extension, and subsequent phase commencement dates would be handled through permit changes. This acknowedges and preserves the validity and legality of the conditions specified in a permit.

If for some reason, such as a long planning lead time on a complex project, the initial phase commencement date is longer than 18 months but still within a reasonable period of time (e.g., 2 years and 6 months), the review agency may specify the initial phase commencement date in the permit, keeping in mind that the source is granted 18 months beyond this date to actually commence construction. Alternatively, the review agency may specify the permit expiration date in the permit. The expiration date simply includes the initial 18-month grace period; it is determined by adding 18 months to the commence construction date and avoids the confusion that could result when dealing with the commence construction date alone. The specified date in the permit takes precedent over the "automatic" 18-month expiration based on the permit issuance date, but in doing so renders the permit ineligible for the 18-month extension process described in 40 CFR 52.21(r)(2); a permit change is required to change a commencement (or expiration) date that appears in a permit. There is an exception to this: if the date specified in the permit for the initial phase of a project is simply the expiration date of the permit (the commence construction date plus the 18-month grace period), then that date is assumed to be in the permit for information purposes, does not make the source ineligible for 40 CFR 52.21(4)(21) extensions, and does not need to be changed to grant extensions of the expiration date.

For some projects, the commence construction dates for each phase may have been included in the application or other materials, but may not appear in the permit. In such cases, the commencement dates for each phase are those dates which the review agency used in evaluating the impact the source would have. Nearly always these will be the dates submitted by the applicant in the application, and these commencement dates are changed by following today's policy on changing applications and permits. As a part of any such change, review agencies should not only revise the dates in the application, but also include the extended commencement or expiration dates in a revised permit.

Independent phased multi-unit projects have the option of having separate permits for each phase; dependent phased projects do not have this option, because all phases of a dependent project must be completed for that project to operate as intended. Separate permits for each phase of an independent phased project are treated for processing purposes as if each permit was for a separate facility, with independent commencement dates, BACT determinations, enforcement actions, etc. Separate permits may increase paperwork, but in return provide an applicant with the option of proceeding with planning on a project one phase at a time.

The concept of "separate" permits versus a single comprehensive permit is more a matter of the manner in which the phases are treated than the physical manner in which the permit is issued. A single comprehensive permit, for example, could consist of a number of permits for various emission units and phases of the project, with possibly a general permit to address conditions common to all the project facilities. Conversely, "separate" permits for an independent phased project may physically consist of a "single" permit which nevertheless treats each phase separately. Of course, EPA would presume that single and multiple permits were what they appeared to be unless there actually existed some clear basis for treating a single permit as a set of separate permits, and vice versa.

The reason for distinguishing between dependent and independent phased projects lies in the applicability determinations when new or revised PSD rules become effective after construction commences on the initial phase, but before construction commences on the last phase. All phases of dependent phased projects are grandfathered [not subject to the new or revised PSD rules if construction on the project (usually the first phase) had commenced prior to the effective date of the rule change and no invalidity lapses in construction had occurred]. In contrast, each phase of an independent phased construction project must individually commence construction by the prescribed grandfather date(s); any phases which had commenced construction would not be subject to the new rules.

Since the concern expressed by UARG appears to be addressed toward multi-unit power plants which may have been permitted as dependent, rather than independent, multiphased projects, today's policy offers independent phased project applicants an opportunity to convert (or otherwise obtain acknowledgement from the review agency of such change in project classification) a dependent multiphased project permit for that project into independent multiphased project permits with full preservation of the increment allocated by the original permit, as long as no increment or NAAQS exceedances would result. This conversion (but not any simultaneous or subsequent requests for other actions, such as extensions) would be carried out without additional PSD review requirements, such as review of BACT, although such conversion does not abrogate any other authority either EPA or other review agencies have to reasssess permit analyses. In particular, this conversion would not allow circumvention of the BACT review prior to construction of each independent phase which is required in 40 CFR 52.21(j)(4).

UARG also expressed concern regarding the time taken by review agencies to decide whether to grant construction date extensions, citing a case where an applicant felt forced to initiate construction simply to protect the validity of the permit because no response to the request for an extension had been received. Although the new policy described above of providing extensions to virtually all good faith applications should resolve this problem, EPA shares the concern of UARG that such "forced construction" be prevented. Therefore, today's policy will also incorporate the following approach in handling such requests:

(1) A source has an obligation to provide sufficient time for an agency to review requests for extension of a commencement of construction date. Therefore, such requests (including adequate documentation) should be submitted to the review agency at least six months prior to the date on which the permit would become invalid (the scheduled commencement of construction date plus 18 months).

(2) EPA will make every effort to respond to such requests within three months of the date the request for an extension is submitted.

(3) If a request was submitted in accordance with paragraph (1) above, and EPA has not responded within the three-month time period indicated in paragraph (2) above, then the permit invalidation date will be considered extended automatically in such a manner that an applicant will always have at least three months between the date on which EPA does respond and the

new permit invalidation date. The three months provides the applicant time to either commence construction or take other action. This policy does not apply if the applicant does not meet the obligation expressed in paragraph (1); in such cases, there is no automatic extension of the invalidation date.

For example, assume a permit was issued for a large project with an anticipated commencement of construction date of 2/1/86. The date the permit would become invalid (unless construction had commenced) is 18 months after this date: 8/1/87. On 1/30/86, the source applies for an 18-month extension, meeting the six-months-in-advance source obligation. If EPA agrees to the extension, then the extension is for 18 months from either the invalidation date (8/1/87) or the date EPA responded, whichever is later. If EPA disapproves any extension, the invalidation date is either 8/1/87 or three months from the date of EPA's response, whichever is later.

VII. PROTECTION OF SHORT-TERM AMBIENT STANDARDS

It has been the practice of many review agencies to presume that any emissions limit comprises a "not-to-be-exceeded" continuous emissions limit, whether that limit is included in the permit (e.g., "SO_2 emissions shall not exceed 876 pounds per hour"), referenced in the permit specifically (e.g., "this source is subject to Regulation 6, Section IV.A.2.b.(ii), for fossil fuel-fired steam generators"), or referenced generally (e.g., "In addition to the specific conditions contained herein, source is subject to all applicable rules and regulations..."). That this assumption is widely held is evident in the number of cases where the review agency (and applicant) uses an emissions limit to determine 3-hour and 24-hour ambient air impacts, but does not specify the averaging time for the emissions limit. The New Source Performance Standards (NSPS) have reinforced this assumption of a continuous emissions limit through the prescribed reference test methods, which generally average three or more samples taken over periods of time ranging from one to three hours. Thus, use of NSPS limits or NSPS test methods has been considered sufficient indication of the intent of the review agency to establish not-to-be-exceeded continuous emissions limits.

A divergence between the NSPS emissions rate averaging time for fossil fuel-fired steam generating units and the PSD emissions rate averaging time requirements for these same units is affecting this assumed interrelationship. Protection of the PSD SO_2 increments requires emission limits with averaging times no longer than the averaging times for the increment. Thus, compliance with a 3-hour SO_2 increment requires an emissions limit averaging time of 3 hours or less. For example, assume that a continuous emissions limit is established for a source at a level that would result in a 3-hour ambient impact almost identical to the ambient impact increment allowed; the emission limit prevents "peak" emission rates that could result in exceedances of the increment. An emissions limit with a 6-hour averaging time would not necessarily provide this protection; a 3-hour "peak" could be offset by a 3-hour "low" to meet the 6-hour average emission limit, but the ambient impact during the 3-hour "peak" would exceed the 3-hour increment.

On October 21, 1983 (48 FR 48960), EPA proposed new SO_2 compliance, emissions measurement, and reporting requirements for sources subject to New Source Performance Standards (NSPS) under 40 CFR 60 Subpart D (fossil fuel-fired steam generators larger than 250 million btu per hour heat input). This proposal would require SO_2 compliance testing against the existing numerical NSPS limits of 1.2 and 0.8 pounds SO_2 per million btu for coal and oil, respectively, but requires compliance demonstrations on a continuous basis through the use of continuous emission monitors (CEM) or fuel sulfur analysis (FSA). Sulfur dioxide emissions would be calculated on a rolling 30-day average basis instead of a short-term (approximately 3-hour) stack test. Although a rolling 30-day average NSPS (Subpart Da) had been promulgated on June 11, 1979, for new electric utility boilers (44 FR 33580), the October 21, 1983, action would apply after the fact to nearly 500 operating Subpart D units for which the initial permits relied to some degree on the presumption that compliance with the NSPS would be achieved on a continuous short-term (3-hour and 24-hour) basis rather than on a continuous 30-day rolling average basis. Many reviewing agencies have determined air quality impacts by modeling the NSPS limit (1.2 or 0.8 pound SO_2 per million btu) as the maximum short-term emission rate for most Subpart D and many Subpart Da sources, but did not specify such short-term analyses or continuous compliance procedures in their permit conditions.

An emission level which averages 1.2 pound SO_2 per million btu over a period of 30 days can on a short-term basis be higher than that limit as long as the 30-day emissions average at or below 1.2 pounds SO_2 per million btu. For example, 10 days at 1.3 pounds SO_2 per million btu and 20 days of 1.0 pounds per million btu will average 1.1 pounds SO_2 per million btu and meet the 30-day average NSPS; but will exceed 1.2 pounds SO_2 per million btu for 10 of the 30 days. This is not intended to imply that a rolling 30-day average makes possible extremely large variations in emissions rates; it does not. The 10 days of 1.3 pounds SO_2 per million btu, for example, had to also be compensated for by the 20 days preceeding this higher 10-day rate, since this is a rolling average. However, policy is required to avoid confusion by both sources and review agencies regarding what short-term and long-term emission limits must be met by sources affected by these NSPS revisions.

Since the most important role of PSD permits is to prevent significant deterioration, EPA's policy regarding permits affected by this and other NSPS revisions is based on the effect of these actions on the ambient air. The NSPS action was based on both technical and cost considerations, but the revisions of permits for any PSD sources, whether related to NSPS revisions or not, are based on PSD goals and air quality considerations.

A. Subpart D Sources

EPA's policy regarding PSD permits for Subpart D sources affected by the October 21, 1983, NSPS proposed revision is this:

(1) If there are any SO_2 emission limits (e.g., pounds SO_2 per hour, pounds SO_2 per megawatt, etc.) in the permit, these limitations represent BACT and must be met by the source unless and until such limits are altered by a permit change using the procedures specified in today's policy. Any permit emission limit is considered a limit which must be complied with continuously unless specified otherwise.

(2) PSD permit emission averaging times are considered short-term averages, even for the Subpart D NSPS limits, as long as it can reasonably be presumed that at the time of permit issuance the emissions limits were considered short-term emission limits (e.g., by use of such limit in modeling 3-hour or 24-hour ambient impacts). That limit remains a short-term limit (regardless of the regulatory revisions to the NSPS) unless and until the permit is changed to specifically indicate otherwise. In fact, a short-term emission limit may not always be included as part of the permit (although good permit processing practices encourage the inclusion of all applicable conditions and limitations); the limits used in demonstration of short-term ambient air impacts comprise corresponding short-term emissions limits.

(3) If the only SO_2 emission limits associated with the permit are specifically stated to be long-term (longer than the 3-hour and 24-hour averaging times) and no short-term SO_2 ambient air impacts were determined, the PSD permit is incomplete, the 3-hour and 24-hour increments and NAAQS must be protected, and an analysis is needed to provide such assurance. In this case, the review agency (without waiting for a request from the

source) must reassess short-term impacts for all sources on the basis of maximum anticipated short-term emissions. If the legal authority exists for a review agency to initiate revision of an incomplete PSD permit, the agency should do so, specifying short-term limits. If a request for a permit revision must be initiated by the applicant, the agency should not only include short-term limits at the first opportunity, but also encourage the source to apply for a revision. At the least, any new levels of increment and NAAQS consumption resulting from a lack of enforceable short-term emission limits must be taken into account in future PSD permit analyses. If increment or NAAQS exceedances are predicted by the new analysis, the review agency must act to prevent such exceedances. The review agency must also establish a policy providing short-term limits on PSD permits to protect short-term increments and NAAQS.

With the possible exception of those sources falling under paragraph (3) above, owners and operators of sources with PSD permits wishing to take advantage of the relief from sulfur variability offered by the rolling 30-day average NSPS must apply for a PSD permit change and obtain a revised permit if exceedance of the NSPS or BACT emission level on a short-term (including never-to-be-exceeded and 3- or 24-hour) basis is anticipated. To be granted, these permit change requests must meet two criteria:

(1) The source must demonstrate that any BACT level of compliance embodied in the permit (including BACT limits with shorter averaging times as well as more stringent limits) is either (a) no longer feasible on either a technological or economic basis, or (b) will still be ensured by the use of the longer term average.

(2) The source must demonstrate that neither the NAAQS nor the increments for SO_2 would be exceeded (as demonstrated by dispersion modeling) by any revised short-term emission limits contained in either permits or the SIP.

During the processing of such requests, the review agency must take the opportunity to provide specific emission limits or other permit conditions which protect all applicable NAAQS and PSD increments. Although it is EPA's policy that the emissions limits used to determine compliance with short-term increments and NAAQS are enforceable even if such limits are not specified in the permit itself, EPA strongly encourages the inclusion of all applicable emissions limits, operating parameters, fuel specifications, averaging times, compliance methods, and other requirements in the permit. Such action will both decrease uncertainty regarding the limitations a source must meet and reinforce the legal basis of such limitations. The limitation's, to be fully effective, must specify averaging times corresponding to one or more short time periods consistent with the limiting PSD increment or NAAQS (e.g., pounds SO_2 per hour). A limitation such as pounds SO_2 per million btu heat input is an excellent control technology limitation, but either the heat input (boiler load) or the emissions per unit of time must also be limited to provide ambient air impact protection.

B. Subpart Da Sources

On June 11, 1979 (44 FR 33580), EPA promulgated new requirements for electric utility boilers (Subpart Da sources). These new requirements, actually in effect since September 18, 1978 (43 FR 52154), specified a rolling 30-day average NSPS for SO_2 for new Subpart Da sources. PSD permits issued subsequent to these dates, although intended to protect short-term as well as long-term increments and standards, may specify in the permit only the rolling 30-day average NSPS as an SO_2 emission limitation. This situation differs from that of Subpart D sources in that the NSPS for Subpart Da sources was not applied retroactively to sources already permitted; the Subpart Da permits were issued by review agencies with full knowledge that the SO_2 NSPS was a long-term (rolling 30-day average) limitation. EPA cannot presume that agencies considered the revised Subpart Da NSPS to be a "never-to-be-exceeded" short-term emission limitation as was assumed for the Subpart D sources.

As a result, EPA's policy regarding PSD permits for Subpart Da sources is this:

(1) If the PSD permit contains (or incorporates by reference) short-term SO_2 emissions limits, those limits must also (in addition to the Subpart Da NSPS) be met by the source and presumably represent BACT. The emission limit averaging times, even if not specifically stated (e.g., pounds per hour), are considered short-term averages as long as it can reasonably be presumed that they were considered as such (e.g., by use of such limit in modeling 3-hour or 24-hour ambient impacts). These emissions limits then comprise enforceable short-term limits which adequately protect the 3-hour and 24-hour increments and NAAQS.

(2) If the PSD permit does not contain (or incorporate by reference) short-term SO_2 emission limits adequate to protect short-term increments and NAAQS, the review agency responsible for PSD permits must take the following actions within six months of the date of publication of this policy in the FEDERAL REGISTER.

(a) Reassess short-term impacts for all such sources on the basis of maximum anticipated short-term emissions and take these new increment consumption levels into account in future PSD permit analyses.

(b) If increment exceedances are predicted by the new analysis, develop a revision to the SIP to prevent such exceedances.

(c) Develop and implement a policy or regulation requiring short-term limits in PSD permits that adequately protect short-term increments.

to EPA on the actions taken and the sources and areas affected ions must be submitted by the responsible review agency within by publication of this policy in the FEDERAL REGISTER.

8 num Anticipated Short-Term Emissions

ormally, ambient air impacts during permit processing are based on num allowable emissions since the source is not yet operating. Then, en the source begins operating, impacts are based on actual representative emissions. In these Subpart D and Da NSPS cases, however, not only is the source likely to already be in operation (which calls for use of actual emissions), but also there may not be any specified short-term emission limitation (so that no allowable emission limits are specified). Since these sources have been issued PSD permits (if the PSD permit has not yet been issued, there is still opportunity to include in the permit short-term emission limits, thus avoiding this problem), information on fuel-sulfur variability should be available. For example, the 24-hour average fuel samples or 24-hour CEM averages required by the NSPS for calculating rolling 30-day averages can be used directly to determine the variation in 24-hour SO_2 emission levels that can occur with the specific fuel being used by a specific source. Standard statistical techniques can determine the 3 sigma upper bound on the values and this 3 sigma value can be used as the maximum anticipated 24-hour emissions level.

In addition, the range of anticipated 3-hour emission levels can be derived from the 24-hour averages, a series of 30-day averages, and the annual average. From this range of 3-hour values, an equivalent 3 sigma maximum anticipated 3-hour emission level can be derived.

It should be noted that these short-term "maximum anticipated" emission levels are not enforceable (unless incorporated--specifically or by reference--into the applicable regulation or permit). They are instead a statistical estimate of the actual short-term emissions anticipated at a source based on the characteristics of the fuel that source is using. As such, they constitute an estimate of actual short-term emissions that can be used to assess short-term ambient air impacts in lieu of specific limitations.

D. Compliance with Short-Term Emission Limitations

In an effort to balance the cost of gathering data and the need for data to determine compliance with short-term emissions limits, EPA in today's policy is placing most of the emphasis on 24-hour average emissions data. There are two reasons for this:

(1) The NSPS for Subpart D and Da sources require that collection of data be based on 24-hour time periods. The average of 30 of these 24-hour average emissions rates is the enforceable limit, but the emissions rates are available and the monitoring equipment in place as a result of the NSPS requirement. At most, today's policy will require only that data be collected and reported as individual 24-hour averages in addition to the rolling 30-day average.

(2) For many of these sources, the fuel is handled in such quantities that even if data on emissions are available almost immediately, little or nothing could be done. For example, a low sulfur coal-fired boiler bunker may hold an 8 (or more) hour supply of coal; even if a CEM is in use (rather than fuel sampling), the knowledge that a 3-hour average limit has just been exceeded does little good; there is another 5 (or more) hour supply of coal in the bunker which has to be burned before any corrective steps (such as blending in a lower sulfur coal) take effect. Fuel sampling analysis (FSA) increases even further the time required to respond because it takes longer to obtain the sampling results.

From the above, it follows that the best approach to compliance with a 3-hour average emissions limit is to project, based on sampling data representing either the sulfur content of the fuel or sulfur dioxide emissions, the maximum anticipated 3-hour average emissions rate. As long as the projected rate is less than the allowable short-term emissions limit, the source would be considered in compliance with the 3-hour emmission limit, with one exception: if 3-hour average emission rate data are available (e.g., from a CEM or stack testing) and show exceedance of the 3-hour average allowable limit, then the 3-hour data can provide the basis for a noncompliance determination.

Thus, today's policy is that for PSD emissions limit compliance purposes, Subpart D and Da sources need gather only 24-hour average emissions data, using a method (CEM or FSA) specified by the appropriate NSPS. The 24-hour averages must, however, be reported individually rather than as rolling 30-day averages, and a statistical analysis must be conducted initially, then annually (unless waived in writing by the review agency) and whenever the fuel sulfur content (in terms of prounds of SO_2 per million btu) may have changed as evidenced by (1) use of fuel from a different source, or (2) evidence of a change in the average sulfur content of the fuel or sulfur dioxide emissions rate of the source.

Sources subject to the rolling 30-day average SO_2 NSPS must submit their initial report to EPA by (6 months from the date this policy is proposed in the FEDERAL REGISTER). The initial report shall include sufficient 24-hour average emissions rate data to demonstrate (1) compliance with any 24-hour emission limitation, and (2) that 24-hour SO_2 increment exceedances are not being caused or contributed to by the source. In addition, the report shall include a statistical analysis (or specific sampling data) showing the maximum anticipated 3-hour average SO_2 emissions rate expected to occur. Subsequent reports of 24-hour average SO_2 emission rates are to be submitted with the NSPS emissions data.

VIII. AMBIENT IMPACT EQUIVALENTS

Proposed changes to permits can affect the ambient air impacts of a source without changing the level of emissions from the source. For example, a shorter stack could increase ground level ambient impacts; so could relocation of a planned emissions unit closer to the source's restricted access boundary. Proposed changes of this type must also be taken into account, and today's policy proposes doing so by establishing the concept of equivalent ambient impacts.

When a change is proposed which would result in changes in the source's ambient impacts, today's policy proposes the following (unless some other aspect of the change requires more extensive documentation or review):

(1) Decreases in ambient air impacts are processed as administrative changes.

(2) Increases in ambient air impacts are subjected to appropriate dispersion modeling to determine the equivalent emissions increase from the prechange source or emissions unit which would produce the same impact as the proposed change. The equivalent emissions level is used to determine whether the proposed change is minor or significant.

In many cases, ambient impacts, once modeled, are proportional to emissions increases and decreases; if, for example, emissions double, the ambient impact doubles. For such cases, the equivalent emissions increase can be determined by ratio:

$$E = E_o (I_n/I_o) - E_o$$

where: E = "equivalent" emissions rate change, grams per second

E_o = original (prechange) emissions rate, grams per second

I_n = postchange ambient impact, micrograms per cubic meter

I_o = prechange ambient impact, micrograms per cubic meter

I_n and I_o, must be based on the same averaging time and must represent the maximum ambient air impact increase resulting from the proposed change.

If there is no proportional relationship between emissions and ambient impacts, dispersion modeling using different emissions rates may be necessary to determine equivalents. Any such complex cases should be handled by appropriate modeling experts.

IX. CONCLUSION

We believe that today's proposed policy statement addresses the classification and processing of the types of change requests most often referred to EPA for consultation. Because of the wide range of activity subject to proposed source changes, the Agency especially solicits comment from those with experience in this area regarding whether additional issues or topics should be included. Similarly, EPA seeks comment regarding the potential effectiveness of the general approach developed for processing proposed changes.

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Administrator

ATTACHMENT 7

CALCULATION OF SULFUR DIOXIDE EMISSIONS
FOR VARIOUS COALS AND REMOVAL EFFICIENCIES

SULFUR DIOXIDE

Variations in Sulfur Content of Coal vs. Removal Efficiency

2.5% Sulfur Coal

$$\frac{0.025\ \text{lb S}}{\text{lb coal}}\ \Big|\ \frac{64\ \text{lb SO2}}{32\ \text{lb S}}\ \Big|\ \frac{\text{lb coal}}{12{,}400\ \text{BTU}}\ \Big|\ 1EE6 = \frac{4.03\ \text{lb SO2}}{\text{MMBTU}}$$

92% - 0.32 lb/MMBTU * 0.312 lb/MMBTU
93% - 0.283 lb/MMBTU * 0.274 lb/MMBTU
94% - 0.242 lb/MMBTU * 0.234 lb/MMBTU
95% - 0.202 lb/MMBTU * 0.195 lb/MMBTU
97% - 0.129 lb/MMBTU * 0.117 lb/MMBTU

2.0% Sulfur Coal

$$\frac{0.020\ \text{lb S}}{\text{lb coal}}\ \Big|\ \frac{64\ \text{lb SO2}}{32\ \text{lb S}}\ \Big|\ \frac{\text{lb coal}}{12{,}400\ \text{BTU}}\ \Big|\ 1EE6 = \frac{3.226\ \text{lb SO2}}{\text{MMBTU}}$$

92% - 0.258 lb/MMBTU * 0.250 lb/MMBTU
93% - 0.225 lb/MMBTU * 0.219 lb/MMBTU
94% - 0.194 lb/MMBTU * 0.188 lb/MMBTU
95% - 0.161 lb/MMBTU * 0.156 lb/MMBTU
97% - 0.097 lb/MMBTU * 0.094 lb/MMBTU

1.5% Sulfur Coal

$$\frac{0.015\ \text{lb S}}{\text{lb coal}}\ \Big|\ \frac{64\ \text{lb SO2}}{32\ \text{lb S}}\ \Big|\ \frac{\text{lb coal}}{12{,}400\ \text{BTU}}\ \Big|\ 1EE6 = \frac{2.419\ \text{lb SO2}}{\text{MMBTU}}$$

92% - 0.194 lb/MMBTU * 0.188 lb/MMBTU
93% - 0.169 lb/MMBTU * 0.164 lb/MMBTU
94% - 0.145 lb/MMBTU * 0.140 lb/MMBTU
95% - 0.121 lb/MMBTU * 0.117 lb/MMBTU
97% - 0.073 lb/MMBTU * 0.070 lb/MMBTU

* - Takes into account 97% of Sulfur being converted to SO_2 per AP-42.

ATTACHMENT 8

COST ESTIMATES FOR SCR
CALCULATED BY EPA'S
AIR AND ENERGY ENGINEERING RESEARCH LAB

	Levelized Annual Costs ($1000)	Tons Removed Total (tpy)	Incr'mtl Annual Cost ($1000)	Incr'mtl Tons Removed (tpy)	Cost Effectiveness ($/ton) Total	Incr'mtl
1-Low-NOx	418.5	10,000	-	-	41.9	-
2-OUC (47%)	19,130	12,810	-	2810	1,493	6,807
3-OUC (70%)	19,130	14,287	-	4287	1,338	4,462
4-OUC (47%)	15,110	12,810	-	2810	1,179	5,377
5-OUC (70%)	15,110	14,287	-	4287	1,057	3,524
6-OUC (47%)	17,730	12,810	-	2810	1,384	6,309
7-OUC (70%)	17,730	14,287	-	4287	1,240	4,135
8-OUC (47%)	13,710	12,810	-	2810	1,070	4,879
9-OUC (70%)	13,710	14,287	-	4287	959	3,198
10-AEERL(47%)	12,655	12,881	12,246	2881	982	4,247
11-AEERL(70%)	12,934	14,287	12,515	4287	905	2,919

1-Low NO_x Burner estimate by AEERL
2,3 - OUC - 2 yr. catalyst life
4,5 - OUC - 2/4 yr. catalyst life
6,7 - OUC - w/o considering fly ash; 2 yr. cat. life
8,9 - OUC - w/o considering fly ash; 2/4 yr. cat. life
10,11 - AEERL estimate

Note 47% removal corresponds to 0.17 lb/MMBTU
70% removal corresponds to 0.10 lb/MMBTU

ATTACHMENT 9

PSD PERMIT FOR CHAMBERS COGENERATION

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State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF ENVIRONMENTAL QUALITY
[illegible]

PERMIT TO CONSTRUCT, INSTALL, OR ALTER

CONTROL APPARATUS OR EQUIPMENT AND TEMPORARY

CERTIFICATE TO OPERATE CONTROL APPARATUS OR EQUIPMENT

AND PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

NAME:	Chambers Cogeneration Limited Partnership (CCLP)
ID NUMBER:	To be assigned.
PLANT LOCATION:	Route 130, Shell Road, Carneys Point, NJ-08069, Salem County
STACK DESIGNATIONS:	001
SOURCE DESCRIPTION:	Two pulverized coal fired boilers each 1300 MMBTU/hr heat input, auxiliary boiler, lime silo, lime slurry preparation system, ash storage silo, coal unloading area, stack out and coal reclaim conveyor, crusher feeder, coal transfer conveyor, coal silo bay, active coal pile, and coal yard storage.
DATE OF PERMIT:	
EXPIRATION DATE:	90 calendar days after startup.
TRACKING [redacted]S:	01-89-3086, 01-90-1903, 01-90-1904, 01-90-1905, 01-90-1906, 01-90-1907, 01-90-1908, 01-90-1909, 01-90-1910, 01-90-1911, 01-90-1912, 01-90-1913

On the basis of all the information available to the Department regarding the proposed Chambers Cogeneration Limited Partnership (CCLP) facility, the New Jersey Department of Environmental Protection (the Department) concludes that this project will meet all applicable requirements of the Prevention of Significant Deterioration (PSD) regulations codified at 40 CFR 52.21, New Source Performance Standards (NSPS) codified at 40 CFR 60, Subparts A, Da, Db, and Dc and of the New Jersey Air Pollution Control Regulations codified at

N.J.A.C. 7:27-1 et. seq. Accordingly, the Department issues this determination of approval to CCLP for the proposed cogeneration facility.

You are authorized to commence construction on this project on the effective date of this permit provided all preconstruction permit conditions have been met. The effective date of this permit is 30 calendar days after the Department gives notice of permit issuance, except when there is a request for administrative review pursuant to 40 CFR 124.19, in which case the effective date is the date administrative review is denied, or the administrative review is completed and the permit is approved. Those who commented during the public comment period may file an appeal up to 30 calendar days after the notice of issuance of the permit. If construction is not commenced within 18 months of this approval, this permit shall become invalid upon cancellation by the Department. Commence, as applied to construction of this source, is defined in the Code of Federal Regulations, 40 CFR. 52.21(b) (9).

This permit incorporates by reference all conditions in the PSD application submitted in October 1989, and all other submittals, and the conditions of approval listed in Attachment I. The conditions of approval take precedence over conditions described in the application and subsequent submittals if there is any inconsistency.

The opportunity for administrative review of the final PSD permit decision will commence with notice of its issuance to the public. The procedural requirements for administrative review are defined in the Consolidated Permit Regulations codified at 40 CFR Part 124 (45 FR 33405). Requests for administrative review of a final PSD Permit decision should be made to the Administrator of the United States Environmental Protection Agency, 401 M Street S.W., Washington, DC 20460. Administrative review is available only to those persons who commented during the public comment period and is restricted to issues raised during the comment period with the exception that any person, including those who failed to file comments on the preliminary permit determination, may petition for administrative review of the changes from the draft PSD to the final PSD permit. Upon issuance by the Department of the final permit decisions, or in the case of an administrative review upon completion of the administrative review process, the PSD final permit decision will be a final U.S. Environmental Protection Agency (USEPA) action and will be published in the Federal Register. This final action may be challenged only by filing a petition for review in the United States Court of Appeals for the appropriate circuit within 60 calendar days of the date of the Federal Register notice. The final PSD permit shall not be subject to later judicial review in enforcement proceedings. Opportunity for judicial review is only provided at the completion of the administrative appeals process and is only provided to those persons who were parties in an administrative appeal.

You will be sent form VEM-017 at a later date. Form VEM-017 will include your New Jersey Plant ID Number, New Jersey Stack Number, and Permit/Certificate Number. The Temporary Operating Certificate may be extended for additional 90 calendar day periods to allow for testing and

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evaluation of the equipment. The Department will not issue a 5-year certificate to operate unless and until the applicant conducts the stack tests specified in Attachment I and demonstrates that the conditions of approval are met.

Sincerely,

Iclal Atay, Ph.D., Chief
Bureau of Engineering and
Regulatory Development

Date: 12/20/90

c: J. Keith, Assistant Commissioner
N. Wittenberg, Director, DEQ
A. McMahon, Deputy Director
J. Elston, Assistant Director
W. O'Sullivan, Assistant Director
C. Salmi, Acting Chief
H. Hornikel, Acting Regional Enforcement Officer (SRO)
S. Riva, Chief, USEPA Region II
J. Rees, Supervisor
Y. Doshi, Acting Supervisor

ATTACHMENT 1

CONDITIONS FOR AIR POLLUTION CONTROL

PERMIT TO CONSTRUCT, INSTALL OR ALTER

CONTROL APPARATUS OR EQUIPMENT AND

TEMPORARY CERTIFICATE TO OPERATE CONTROL APPARATUS OR EQUIPMENT

AND PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

FOR THE

CHAMBERS COGENERATION LIMITED PARTNERSHIP (CCLP)

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I. EMISSION LIMITS

A. **Maximum** PC Boiler Emission Rates

During any of the specified compliance time periods (see Table 1), the maximum emissions from each pulverized coal (PC) boiler, except during start-up and shut-down periods, shall not exceed the limits in Table 1. Compliance shall be determined by the use of New Jersey Air Test Methods 1 and 3 (N.J.A.C. 7:27-B), USEPA reference methods (40 CFR 60, Appendix A), and by continuous emission monitors (CEM) specified in permit condition V.

B. Maximum Auxiliary Boiler Emission Rates

During any one hour period, the maximum emissions from the auxiliary boiler, except during start-up and shut-down periods, shall not exceed the limits in Table 2. Compliance shall be determined by the use of New Jersey Air Test Methods 1 and 3 (N.J.A.C. 7:27-B) and USEPA reference methods (40 CFR 60, Appendix A).

C. Specific Organic Substances

Emissions of 2,3,7,8-tetrachloro dibenzo-p-dioxin (2,3,7,8 TCDD) and benzo(a) pyrene must be measured during the stack emission tests using methods approved by the Department. The emission rates from 3 successive stack emission tests conducted on one unit shall be determined.

D. PC Boiler Start-up and Shut-down

1. PC boiler start-up is defined as the period beginning with initial firing with No. 2 Fuel oil and ending at the time the boiler is being fired only with coal and/or No. 6 oil. No coal or No. 6 oil may be fired until all air pollution control equipment is in operation. The duration of the start up period, during which exemption from emission limits specified in permit condition I.A. applies, shall not exceed five hours.

2. **PC boiler shut-down is defined as the period of time beginning with the interruption of coal feed and ending when fuel is no longer being introduced into the combustion chamber of the boiler. All air pollution control equipment must be operating when coal or No. 6 oil is burning. This duration will not exceed 30 minutes.**

E. **Auxiliary Boiler Start-up and Shut-down**

1. **Auxiliary boiler start-up is defined as the period of time from boiler ignition until steam is available for customer use. This period shall not exceed 60 minutes.**

2. Auxiliary boiler shut-down is defined as the period of time after which steam is no longer available for customer use until cessation of fuel flow to the auxiliary boiler. This period shall not exceed 15 minutes.

F. Visible Emissions

1. The opacity of the emissions from each PC boiler shall not exceed 10% except for a period not longer than 3 minutes in any consecutive 30 minutes period, as determined by continuous opacity monitors and continuous recorders or by New Jersey Air Test Method 2. An exception to this requirement is that the opacity may not exceed 20% except for 3 minutes during a period of PC boiler start-up and shut-down. The Department may set lower opacity limits after the results from initial compliance testing are reviewed.

2. The auxiliary boiler shall not be operated in a manner which will cause visible emissions for more than 3 minutes in any consecutive 30 minute period. Compliance with this provision shall be determined by the use of New Jersey Air Test Method 2 (N.J.A.C. 7:27B.2) or approved equivalent.

G. General Prohibition of Air Pollution

The equipment in this permit shall not cause any air contaminant, including an air contaminant detectable by the sense of smell, to be present in the outdoor atmosphere in such quantity and duration which is, or tends to be, injurious to human health or welfare, animal or plant life or property, or would unreasonably interfere with the enjoyment of life or property, except in areas over which the owner or operator has exclusive use or occupancy.

II. OPERATING REQUIREMENTS

A. Limits on Operation

The auxiliary boiler shall not be operated at the same time as either PC boiler, except when auxiliary steam is required during PC boiler start-up or shut-down.

B. Limits on Fuel Firing

1. Total coal, No. 2 oil, and No. 6 oil fired in the two PC boilers is limited to 2.44 x 10^{13} BTU, (HHV) per calendar year.

2. Total No. 2 oil fired in the auxiliary boiler is limited to 7.7 x 10^{10} BTU, (HHV) per calendar year.

C. **Limits** on Substance Content

1. The sulfur content of the bituminous coal to be burned in the two PC boilers shall not exceed 2% by weight.

2. The sulfur content of the No. 2 fuel oil to be burned in the facility shall not exceed 0.2 percent by weight.

3. The sulfur content of the No. 6 fuel oil to be burned in the facility shall not exceed 0.3 percent by weight.

4. Water treatment chemicals containing hexavalent chromium shall not be added to the cooling tower circulating water.

III. EMISSIONS CONTROL

A. Particulate Matter

1. Particulate emissions from the PC boilers shall be controlled by fabric filters. The fabric filters shall be provided with adequate access for inspection. The fabric filters may only be bypassed when using No. 2 fuel oil.

2. Particulate emissions from the coal storage silos, lime storage silo, recycle silo, and ash storage silo shall be controlled by fabric filters. The fabric filters shall be provided with adequate access for inspection.

3. The design parameters for the baghouses (for all above listed sources) must be submitted to the Department for approval within two months of the date of approval of this permit.

B. Sulfur Dioxide (SO_2)

1. **Sulfur dioxide emissions from the PC boilers shall be controlled by lime spray dryer absorber scrubbers, except when burning No. 2 fuel oil. The average one-hour concentration and emission rate of SO_2 in the stack gas from each unit must comply with Table 1 as determined by the continuous emission monitoring and continuous recording and testing.**

2. **The design parameters for scrubbers must be submitted to the Department for approval within two months of the date of approval of this permit. The submittal shall contain details including, but not limited to: the redundancy of the reagent feed system, the spare parts inventory for the reagent injection devices, the time required to remedy typical equipment malfunctions, and the minimum ratio of actual lime to stoichiometric lime.**

C. **Nitrogen** Dioxide (NO_2)

1. **N**itrogen oxide emissions from the PC boilers shall be controlled with low NO_x burners, advanced combustion controls, and Selective Catalytic Reduction (SCR) technology.

2. Design

   a. The system will be designed to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU (HHV).

   b. The design specification of the proposed SCR system will be submitted to the Department for review and approval within two months of the date of approval of this permit. Such information will include, but not be limited to, the capacity of the ammonia feed system, catalyst replacement schedule to achieve maximum control of nitrogen oxides, and the operating range for nitrogen oxide to ammonia mole ratio.

3. Operation

   a. The catalyst bed shall be replaced as necessary so that the maximum allowable emission rate of NO_x does not exceed 0.17 pounds per million BTU (lbs/MMBTU, HHV) averaged over any consecutive 180 minutes.

   b. The SCR system shall be optimized to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU, (HHV) averaged over any consecutive 180 minutes by catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility.

   c. **At the end of the first 5-year operating period, permit condition III.C.1 for the maximum NO_x emission limit shall be modified by multiplying the optimized NO_x emission rate by 1.2. The new maximum allowable NO_x emission rate shall be the rate that is demonstrated to be consistently achievable (not including malfunctions) and shall not be less than 0.10 lbs/MMBTU (HHV) nor more than 0.17 lbs/mmBTU, (HHV).**

D. **Other Sources of Emissions**

1. **The maximum emissions from all other sources listed in Table 3 shall not exceed the limits specified in that table. Each source shall be equipped with control measures and/or control devices listed in Table 3.**

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2. Fugitive dust emissions from coal unloading and stack out shall be controlled by wet suppression and/or surfactant as necessary. Dust emissions at other coal conveyor transfer points shall be controlled by dust collectors.

3. There shall be no visible fugitive emissions to the outdoor air from the coal unloading, stack out, coal storage and other coal handling operations.

4. The pulverizers shall be located indoors. The coal crusher will be enclosed and provided with a dust collector to prevent fugitive dust emissions.

5. All conveyor belts shall be covered.

6. Inactive coal stockpiles shall be moistened or treated (wet suppression and/or surfactant) and the inactive stockpile surfaces shall be kept moist or otherwise treated at all times to minimize emissions during storage.

7. Fugitive emissions from all permanent facility access roads on facility property shall be controlled by paving and road cleaning.

IV. TESTING

A. Before a 5-year certificate to operate is issued, the applicant must:

1. Conduct stack emission tests in accordance with N.J.A.C. 7:27-8.4(c) for all the pollutants that are listed in Table 1 and Table 2. All tests, on a given unit must be conducted within 60 calendar days after achieving the coal combustion rate at which the facility will be normally operated, but not later than 180 calendar days after initial start-up.

2. A detailed description of the sampling point locations, sampling equipment, sampling and analytical procedures, data reporting forms, quality assurance procedures and operating conditions for such tests must be submitted to the Chief, Bureau of Technical Services, at least 180 calendar days prior to start-up of the facility to obtain approval of a stack emission test protocol.

3. Contact the Bureau of Technical Services, at (609) 530-4041, within 14 calendar days of approval of the stack test protocol to establish a mutually acceptable stack test date in order that representatives of this office may be scheduled to observe the conduct of the tests.

B. Three stack emission tests shall be conducted on each PC boiler and auxiliary boiler for the pollutants listed in Table 1 and 2. Such tests shall be conducted at 100% load.

C. **Heat** input (MMBTU/hr, HHV) shall be determined for each stack test. **Emission** levels of nitrogen oxides, carbon monoxide, sulfur oxides, **ammonia**, particulate matter and volatile organic compounds shall be reported in pounds per hour, parts per million on dry volume basis (ppmdv) corrected to 7% oxygen (except particulate matter) and pounds per million BTU (HHV) heat input.

D. The permittee must conduct comprehensive stack emission test and submit the test results at least 180 calendar days prior to expiration of each 5-year certificate to operate in order to renew a certificate to operate. A test protocol for such testing shall be submitted to the Department for approval one year prior to expiration of the certificate to operate.

E. Permanent sampling and testing facilities must be provided as required by the Department to determine the nature and quantity of emissions from the boiler. Such facilities shall conform to all applicable laws and regulations concerning safe construction and safe practices.

F. The Department may require at any time additional stack emission testing of the pollutants for which an emission limit has been set in permit condition I.A. of this permit or any other air pollutants potentially emitted by the facility.

V. MONITORING, RECORDING AND RECORDKEEPING

A. Continuous Emission Monitors and Recorders

1. For each PC unit, continuous monitors and continuous recorders shall be installed and operated to continuously measure and continuously record the opacity of the stack gas and emission concentrations of carbon monoxide, oxygen, nitrogen oxides, **ammonia**, and sulfur dioxide. Monitors must comply with EPA **performance and siting specification pursuant to 40 CFR Part 60, Appendix B as applicable.** Equipment specifications, calibration **and operating procedures, and data evaluation and** reporting **procedures must be submitted for approval to the Chief, Bureau of Technical Services, CN-411, Trenton, New Jersey 08625.** The **Department may require a continuous emission monitor** and **continuous emission recorder for non-methane hydrocarbons** in **each boiler stack.**

2. **All continuous emission monitors and recorders required pursuant to permit condition V.A.1. shall be operational prior to the initial burning of coal in the furnace.**

3. **All continuous emission monitors and continuous emission recorders required by permit condition V.A.1. shall undergo the appropriate Performance Specification Test (PST) and the report**

must be submitted to the Chief, Bureau of Technical Services. These performance tests must be conducted prior to conducting the compliance stack emission tests.

4. All continuous emission monitors required by permit condition V.A.1. must comply with the quality assurance requirements outlined in 40 CFR Part 60, Appendix F as applicable.

B. Operating Log

Operating logs shall be kept for each unit to maintain the following records accurately. Logs shall be maintained in a manner approved by the Regional Enforcement Officer.

1. The specific times of operation of each boiler.

2. The specific times of operation of the auxiliary boiler.

3. Exceedances of emission standards determined by continuous monitoring and recording.

4. Recording of pressure drop across entire fabric filters for the PC boilers.

C. Recordkeeping

1. CCLP shall maintain records of all shipping receipts from the fuel suppliers for each shipment of coal, No. 6 fuel oil and No. 2 fuel oil delivered certifying that the shipment contains maximum 2% sulfur by weight in coal, a maximum of 0.3% sulfur by weight in No. 6 fuel oil, and a maximum of 0.2% sulfur by weight in No. 2 fuel oil.

2. All continuous emission monitoring records and log books specified in permit conditions V.A. and V.B. must be maintained in a manner approved by the Regional Enforcement Officer and made available for inspection by the Department for a period of three years after the date of each record. The format of these reports shall be submitted to Regional Enforcement Officer, Southern Regional Office, 20 E. Clementon Road, 3rd Floor, Gibbsboro, New Jersey 08026, for approval 180 calendar days prior to initial start-up of the facility

D. **Telemetry of Continuous Monitoring Data**

The continuous emission monitoring data collected pursuant to permit condition V.A. shall be transmitted to the Department via a remote telemetry system. A plan identifying the specific details of the telemetry system and the reporting format must be submitted to the Chief, Bureau of Air Monitoring, Division of Environmental Quality,

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CN 027, Trenton, NJ 08625, for approval six months prior to purchase of the equipment. The Department reserves the right to suspend the requirement of remote telemetry system.

VI. REPORTING REQUIREMENTS

A. Three copies of the report of the results of each stack emission tests must be submitted within 60 calendar days after completion of the stack emission tests to:

Assistant Director, Enforcement Element
Division of Environmental Quality
CN 027
Trenton, New Jersey 08625

B. Occurrences of excess emissions and actions taken must be reported in writing within 3 calendar days to the Assistant Director, Enforcement, Division of Environmental Quality, CN 027, Trenton, New Jersey 08625.

C. Quarterly Excess Emission Reports (EER) required by 40 CFR 60.7(c) for all continuous emission monitors must be submitted to the Regional Enforcement Officer, Southern Regional Office, within 30 calendar days after each calendar quarter. The EER format must be approved by the Chief, Bureau of Technical Services, prior to the start-up of the facility. The quarterly EER must include a summary of any exceedances and the corrective action taken.

The quarterly EER must also be submitted to:

Chief, Air Monitoring Section
USEPA, Region II
Woodbridge Avenue
Edison, New Jersey 08839

VII. FEDERAL NSPS REQUIREMENTS:

The facility is subject to the federal New Source Performance Standards (NSPS) codified at 40 CFR Part 60 Subparts A (General provisions), Da (Electric steam generating units), Db (Industrial-Commercial-Institutional steam generating units), and Dc (Small Industrial-Commercial-Institutional steam generating units). Compliance with all applicable provisions of these regulations is required.

VIII. BIOLOGICAL MONITORING

The Chambers Cogeneration Limited Partnership shall provide a total $40,000 in funding support to the National Park Service, Air Quality Division, to help establish a biological monitoring program at the Brigantine Wildlife Refuge to determine the effects of air contaminants on

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plants and wildlife at the refuge. Funding shall be submitted to the National Park Service within 30 calendar days of the start of construction.

IX. AMBIENT AIR QUALITY MONITORING

1. The Chambers Cogeneration Limited Partnership (CCLP) shall install and operate ambient air monitoring samplers for sulfur dioxide, PM-10, and nitrogen oxides in order to determine ambient concentrations for comparison with National and New Jersey Ambient Air Quality Standards. Within 6 months of the effective date of this permit, the operator shall submit for approval of the Department, a detailed protocol for ambient air sampling and analysis, including proposed site locations and the rationale for site selection. This protocol shall be prepared in accordance with the Department's "Overall Strategy for Point Source Oriented Ambient Air Monitoring of Specific Criteria Pollutants and Air Toxics".

2. The Department shall oversee and audit the monitoring and shall be provided access to the monitoring sites upon request. Data shall be submitted at least once per calendar quarter.

3. The monitoring program shall be in operation for a minimum of six months before combustion of coal commences at the CCLP and shall continue in operation for a minimum of two years after the CCLP receives a five year certificate to operate, or longer if the Department determines that the contaminant levels detected, warrant additional sampling.

4. All contacts regarding the monitoring, location approval, methods of measurement, and data submittal, shall be made to the Chief, Bureau of Air Monitoring, Division of Environmental Quality, CN-027, Trenton, NJ-08625.

X. AMMONIA STORAGE

If the facility is subject to the New Jersey Toxic Catastrophe Prevention Act, N.J.A.C. 7:31-1 to 6, compliance with the applicable provisions of this regulation is required. Compliance shall be demonstrated by submitting all the design documents for ammonia storage and handling, six months prior to ordering the equipment, for review and approval to the Chief, Bureau of Release Prevention, CN-027, Trenton, NJ-08625.

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TABLE 1

MAXIMUM EMISSIONS RATES FOR EACH PULVERIZED COAL PC BOILER

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Total Suspended Particulates		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
PM-10		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
Sulfur Oxides (as SO_2)		
- lbs/hr	305.6	
- lbs/MM BTU	0.22	60 minutes
- ppm dry vol. at 7% O_2	100.0	
Nitrogen Oxides (as NO_2)*		
- lbs/hr	236.3	
- lbs/MM BTU	0.17	180 minutes
- ppm dry vol. at 7% O_2	100	
Carbon Monoxide		
- lbs/hr	152.8	
- lbs/MM BTU	0.11	180 minutes
- ppm dry vol. at 7% O_2	100.0	
Total Non-Methane Hydrocarbons (as CH_4)		
- lbs/hr	5.0	
- lbs/MM BTU	0.0036	60 minutes
Ammonia		
- lbs/hr	10	180 minutes
- ppm dry vol. at 7% O_2	10	180 minutes
- ppm dry vol. at 7% O_2	5	30 day
Fluorides (as HF)		
-lbs/hr	2.78	EPA Method 13B
Heavy Metals		
Arsenic		
- lbs/hr	0.117	EPA Multimetal test method
Beryllium		
- lbs/hr	0.0058	EPA Multimetal test method

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CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Cadmium - lbs/hr	0.003	EPA Multimetal test method
Chromium (Total) - lbs/hr	0.051	EPA Multimetal test method
Lead - lbs/hr	0.040	EPA Reference method 12
Mercury - lbs/hr	0.026	EPA Reference method 101A

*See permit Condition III.C.3. for additional provisions on NO_x emission limits.

TABLE 2

MAXIMUM HOURLY EMISSION RATES FROM AUXILIARY BOILER

(77 MM BTU/HR)

CONTAMINANT	NO. 2 FUEL OIL
Total Particulate Matter	
- lbs/hr	1.5
- lbs/MM BTU	0.02
PM-10	
- lbs/hr	1.54
- lbs/MM BTU	0.02
Sulfur Oxides (as SO_2)	
- lbs/hr	24.3
- lbs/MM BTU	0.315
Nitrogen Oxides (as NO_2)	
- lbs/hr	13.0
- lbs/MM BTU	0.17
Carbon Monoxide	
- lbs/hr	13.2
- lbs/MM BTU	0.172
- ppm dry vol. at 7% O_2	100
Total Non-Methane Hydrocarbons	
- lbs/hr	0.6
- lbs/MM BTU	0.008

TABLE 3

OTHER SOURCES IN THE FACILITY

	Source	Control	Maximum Particulate Emission (lbs/hr)
1.	Lime Silo	Baghouse	0.01
2.	Lime Slurry Tank	Baghouse	0.001
3.	Ash Storage Pile	Baghouse	0.6
4.	Coal Unloader	Water Spray	0.34
5.	Hopper Pit Unloader	Baghouse	0.001
6.	Stack out conveyor	Water Spray	0.03
7.	Crusher feeder	Baghouse	0.18
8.	Two silo feed conveyors	Baghouse	0.001
9.	Coal Pile	Spray	0.00003
10.	Inactive coal storage	Water Spray	0.00001
11.	Reclaim Conveyor	Baghouse	0.0001
12.	Coal Transfer Conveyor	Baghouse	0.001

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[illegible]. CHANGES TO THE PSD PERMIT

The following changes were made in response to the public comment. Changes are marked by underlines:

I. Permit Condition II. B.2

B. Limits on Fuel Firing

2. Total No. 2 oil fired in the auxiliary boiler is <u>limited to 10^{10} BTU (HHV)</u> per calendar year.

II. Permit Condition III. C.3.b & III. C.3.c.

C. Nitrogen Oxides (NO_x)

3. Operation

b. The SCR system shall be optimized to achieve a NO_x emission rate of less than 0.10 lbs/MMBTU (HHV) averaged over a consecutive 180 minutes by <u>catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility.</u>

c. At the end of the first 5-year operating period, permit condition III. C.1 for the maximum NO_x emission limit shall be modified by multiplying the <u>optimized</u> NO_x emission rate by 1.2. The new maximum allowable NO_x emission rate shall be the rate that is demonstrated to be consistently achievable (not including malfunctions) and shall not be less than 0.10 lbs/MMBTU (HHV) nor more than 0.17 lbs/MMBTU (HHV).

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III. Permit Condition V.B.4.

B. Operating Log

4. Recording of pressure <u>drop across entire fabric filters for the</u> FC boilers.

IV. Permit Condition V.D.

D. Telemetry of Continuous Monitoring Data

<u>The continuous emission monitoring data collected as per [illegible] Condition [illegible] shall be transmitted to the Department via a suitable telemetry system. A plan identifying the specific details of the telemetry system and the reporting format must be submitted to the Chief, Bureau of Air Monitoring, Division of Environmental Quality, CN 027, Trenton, NJ 08625, for approval six months prior to purchase of the equipment.</u>

V. Permit Condition IX. 1.

IX. AMBIENT AIR QUALITY MONITORING

1. The Chambers Cogeneration Limited Partnership (CCLP) shall install and operate ambient air monitoring samplers for sulfur dioxide, <u>PM-10, and nitrogen oxides</u> in order to determine actual concentrations for comparison with National and New Jersey Ambient Air Quality Standards. Within 6 months of the effective date of this permit, the operator shall submit for approval of the Department, a detailed protocol for ambient air sampling and analysis, including proposed site locations and the rationale for site selection. This protocol shall be prepared in accordance with the Department's "Overall Strategy for Point Source Oriented Ambient Air Monitoring of Specific Criteria Pollutants and Air Toxics".

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VI.

TABLE 1

MAXIMUM EMISSIONS RATES FOR EACH PULVERIZED COAL PC BOILER

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Total Suspended Particulates		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
PM-10		
- lbs/hr	25.0	
- lbs/MM BTU	0.018	60 minutes
Sulfur Oxides (as SO_2)		
- lbs/hr	305.6	
- lbs/MM BTU	0.22	60 minutes
- ppm dry vol. at 7% O_2	100.0	
Nitrogen Oxides (as NO_2)*		
- lbs/hr	236.3	
- lbs/MM BTU	0.17	180 minutes
- ppm dry vol. at 7% O_2	100	
Carbon Monoxide		
- lbs/hr	152.8	
- lbs/MM BTU	0.11	180 minutes
- ppm dry vol. at 7% O_2	100.0	
Total Non-Methane Hydrocarbons (as CH_4)		
- lbs/hr	5.0	
- lbs/MM BTU	0.0036	60 minutes
Ammonia		
- lbs/hr	10	180 minutes
- ppm dry vol. at 7% O_2	10	180 minutes
- ppm dry vol. at 7% O_2	5	30 day
Fluorides (as HF)		
-lbs/hr	2.78	EPA Method 13B
Heavy Metals		
Arsenic		
- lbs/hr	0.117	EPA Multimetal test method
Beryllium		
- lbs/hr	0.0058	EPA Multimetal test method

CONTAMINANT	MAXIMUM EMISSIONS	COMPLIANCE BASIS
Cadmium - lbs/hr	0.003	EPA Multimetal test method
Chromium (Total) - lbs/hr	0.051	EPA Multimetal test method
Lead - lbs/hr	0.040	EPA Reference method 12
Mercury - lbs/hr	0.026	EPA Reference method 101A

*See permit Condition III.C.3. for additional provisions on NO_x emission limits.

APPENDIX A

Following people commented during the public hearing. The names appear in order of appearance.

1. Mr. Dennis Dubberley, NUS Corporation

2. Mr. Carl Graskill, Carneys Point Township Planning Board

3. Mr. Frank Santucci, Community Advisory Coalition

4. Chief Ed Spinelli, Pennsgrove Police Department

APPENDIX B

Following parties have provided written comments:

1. United States Department of the Interior, Fish and Wildlife Service

2. Chambers Cogeneration Limited Partnership

APPENDIX C

Following people represented the Department during the public hearing:

1. Anthony McMahon, Deputy Director, Division of Environmental Quality

2. Iclal Atay, Ph.D., Chief, Bureau of Engineering and Regulatory Development, Division of Environmental Quality

3. Yogesh Doshi, Principal Environmental Engineer, Bureau of Engineering and Regulatory Development, Division of Environmental Quality

4. Gay Pearson, Senior Environmental Specialist, Bureau of Air Quality Planning and Evaluation, Division of Environmental Quality

5. Rajesh Patel, Assistant Environmental Engineer, Bureau of Engineering and Regulatory Development, Division of Environmental Quality.

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Let's protect our earth

State of New Jersey
DEPARTMENT OF ENVIRONMENTAL PROTECTION
DIVISION OF ENVIRONMENTAL QUALITY
CN 027, TRENTON, N.J. 08625-0027
Fax # (609) 292-1074

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NEW SOURCE REVIEW SECTION
EPA Region III

December 26, 1990

Mr. William Brown
Chief, Air Permits Section
USEPA Region 3
841 Chestnut St.
Philadelphia, PA 19107

REFERENCE: Chambers Cogeneration Limited Partnership
Proposed Coal-Fired Cogeneration Facility

Dear Sir/Madam:

Enclosed please find the hearing officer's report on the referenced facility.

After considering all the comments received, the Department approved the proposed air pollution control permit for the Chambers Cogeneration Limited Partnership (CCLP), with minor modification of the permit conditions in response to public comments. The hearing officer's report contains final permit, final permit conditions and the Department's responses to the relevant comments raised during the public comment period.

In response to comments received, the Department added ambient air monitoring for PM-10 and nitrogen oxides. The Department has also required telemetry of continuous emission monitoring data.

Thank you for your concern for the environment.

Sincerely,

Iclal Atay, Ph.D.
Chief
Bureau of Engineering & Regulatory Development

c: Anthony McMahon, Deputy Director
William O'Sullivan, Assistant Director
Yogesh Doshi, Principal Environmental Engineer

DEPARTMENT OF ENVIRONMENTAL PROTECTION

DIVISION OF ENVIRONMENTAL QUALITY

HEARING OFFICER'S REPORT FOR THE APPLICATION BY

CHAMBERS COGENERATION LIMITED PARTNERSHIP

TO CONSTRUCT AND OPERATE A COGENERATION FACILITY

Anthony J. McMahon
Deputy Director
Hearing Officer

December 26, 1990

TABLE OF CONTENTS

I. INTRODUCTION

A. Facility Application

On July 5, 1989, a pulverized coal fired cogeneration facility permit application package, including Best Available Control Technology Analysis (BACT) and air quality modelling studies, were submitted by the Chambers Cogeneration Limited Partnership (CCLP). The permit application package was reviewed by the Division and following additional submissions at the request of the Department, the application was found administratively complete on November 1, 1990. Copies of the air pollution control permit conditions and project summary document were subsequently distributed to various agencies and United States Environmental Protection Agency for their review and comments.

During the period from July 1989 to October 1990, the Bureau of Engineering and Regulatory Development requested additional information, clarifications and modifications from the applicant. The applicant forwarded submittals and addendums responding to the comments and issues raised during this review period.

On November 5, 1990, in conformance with New Jersey Air Pollution Control Laws and the Federal Prevention of Significant Deterioration (PSD) regulations codified at 40 CFR 52.21, the Division of Environmental Quality issued a draft permit (tentative approval subject to public comments) for the construction and operation of the proposed cogeneration facility and scheduled a public hearing to solicit testimony concerning this decision.

B. Public Comment Period

The public comment period for the draft air pollution control permit began on November 5, 1990, and ended on December 10, 1990. Copies of the draft permit, the project summary document and supporting permit application were made available for public review at the following locations: Office of the Mayor of Carneys Point Township, Southern Regional Office, Gibbsboro, and the Department of Environmental Protection, Trenton.

During this public comment period, written and verbal comments were received. The list of those who provided testimony and written comments are identified in Appendix A and B respectively. The concerns reflected in the verbal and written commentary are addressed in this response to comment document.

C. Public Hearing

The public hearing was held at Pennsgrove High School, Carneys Point, New Jersey on December 5, 1990. The Department's hearing panel consisted of:

Anthony J. McMahon (Hearing Officer)
Deputy Director
Air Programs
Division of Environmental Quality

And

Iclal Atay, Ph.D.
Chief, Bureau of Engineering and Regulatory Development
Division of Environmental Quality.

Other Departmental staff who were present during the public hearing are listed in Appendix C.

Prior to opening the hearing to public comment at 5:00 P.M., Mr. Anthony McMahon, Deputy Director, read statements into the record, which described the project, outlined the Department's review process relative to the application, briefly discussed the project and outlined the procedures which would be followed during the hearing. The hearing was then opened for the receipt of public comment. Approximately 15 individuals were present during the session and 4 of these individuals offered verbal testimony. The hearing was adjourned at 9:00 P.M. that evening, with no one present offering additional verbal testimony.

2. RESPONSE TO COMMENTS

Comment 1: How did the Department model for ammonia slip and what considerations were given in determining the concentrations of ammonia at the plant boundary and in the surrounding area?

Response: The amnmonia emissions were modeled using the same modeling procedures applied to other pollutants. The impacts (shown below) are well below the threshold levels for odor and health effects.

Ammonia Emissions

1.	Chronic Health Effect Criteria (24 hour average) 34 ug/m^3	CCLP Contribution (24 hour average) 0.16 ug/m^3
2.	Odor Threshold (1 hour average) 3600 ug/m^3	Predicted Concentration from CCLP (1 hour average) 1.74 ug/m^3

Comment 2: The applicant must be required to install, operate and maintain three ambient air quality monitoring stations at various locations within Carneys Point Township. These monitoring stations will record ambient air quality for PM-10 (particulate matter having aerodynamic diameter less than 10 microns), sulfur oxides and nitrogen oxides.

Response: Draft Permit Condition IX required the CCLP to install and operate ambient air monitoring samplers for sulfur dioxide.

Permit Condition IX.1 has been revised to require ambient air monitoring for PM-10 and nitrogen oxides.

Regarding the number of ambient air quality monitoring stations, Permit Condition IX.1 requires the permittee to submit for Departmental approval a detailed protocol, including proposed site locations and the rational for site selection. The number and location of monitoring stations shall be determined at the completion of the review of these documents.

Comment 3: The Department must receive all continuous emission monitoring data via remote telemetry and review this data for compliance with permit requirements.

Response: Permit Condition V.D. is revised to require telemetry of the continuous emission monitoring data to the offices of the Department.

Comment 4: Will this facility be a danger to the community? What corrective steps will be taken to ensure the public safety and well-being of the people?

Department's Response: The CCLP has been permitted under federal PSD regulations codified at 40 CFR 52.21, which requires the applicant to employ Best Available Control Technology (BACT) to reduce the emissions of each PSD applicable pollutant. The CCLP has demonstrated to the satisfaction of the Department that the technology used is BACT. Also, the long term effects of criteria pollutants emitted from the proposed facility are accounted for in the demonstration of compliance with the state and federal ambient air quality standards. The health risk assessment of non-criteria pollutants (heavy metals) has predicted maximum increased cancer risk at the point of maximum impact for 70 years of constant exposure in the range of 0.01 to 0.5 in a million, which is considered negligible by the Department.

Applicant's Response: The plant will not handle, store, or use materials more hazardous than No. 2 fuel oil, which is contemplated as the back-up fuel for the boilers, or the catalyst, which is essential for the required stringent NO_x control. The fuel oil will be stored in a tank which will be properly surrounded by a dike to retain any potential spill. The catalyst will be delivered and removed by the manufacturer under controlled conditions and is not subject to spill.

The facility will use aqueous ammonia (less than 28% solution in water), rather than anhydrous ammonia, in the Selective Catalytic Reduction (SCR) system.

With respect to the emergencies with CCLP's plant, such as fires or employee safety, CCLP has coordinated with the Carney's Point Fire Department regarding its emergency planning, in-plant training and the design of emergency equipment (see attached letter). Additionally, there will be coordination with the Salem County Emergency Fire and Disaster Control Center to improve response times, particularly with respect to train traffic.

Comment 5: The following comment was made by the US Department of the Interior, Fish and Wildlife Services.

CCLP has made an investment in SYCOM, an energy conservation company. SYCOM presently has 15 MW under contract in New Jersey, and CCLP anticipates that within ten years they will have enough energy conservation investments to offset all of the emissions from the proposed facility. However, we are concerned that the energy conservation program proposed by Chambers may not fullfill their expectations, and may not result in a total offset of emissions.

Department's Response: Emission offsets are not required pursuant to present state and federal air pollution control rules.

Applicant's Response: SYCOM Partners Inc., is a demand-side (or energy conservation) company. Principal to Chambers's agreement with SYCOM are the rights to air offsets, which result from the partnerships investments in energy conservation projects. SYCOM has 15 MW of conservation contracts with New Jersey Utilities. Those "megawatts" convert into roughly 59,130 MW hours (1 MW of conservation yields about 45% in reduced energy demand on an annual basis). The average NO_x emission rate for utility boilers in the state of New Jersey for 1985-1987 was 9.09 lbs/MW hr. Thus, 59,130 MW hrs equals about 270 tons/year of NO_x reduction. The corresponding reductions for SO_2 and particulates are 289 tons and 3.5 tons respectively.

And as utilities in New Jersey hold new energy conservation bid programs, it is possible that Chambers can make enough energy conservation investments over the next ten years to offset nearly all of the emissions from the Chambers facility.

Comment 6: Air Quality staff of the US Fish and Wildlife Service has performed visibility screening analysis. The results indicate that the proposed facility passes the Level 1 screening test for the Brigantine Wilderness Area, but fails both Level 1 and Level 2 tests for the Killcohook National Wildlife Refuse (NWR). The results predict that a plume will be visible in the refuge even when using favorable dispersion conditions (D stability, 2 m/s wind speed).

Response: The Air Quality staff of the U.S. Fish & Wildlife indicated that there may be visibility impairment at the Killcohook National Wildlife Refuge (NWR). They also recommend that VISCREEN model be used to determine visibility impairment. The applicant is not required to address these issues for the following reasons:

1. The Killcohook NWR is in a Class II area, therefore not subject to Class I requirements.

2. The VISCREEN model, although more realistic and sophisticated than the EPA approved PLUVUE model, has not been officially adopted for regulatory use.

The following comments were submitted to the Department by the Applicant, Chambers Cogeneration Limited Partnership:

Comment 1: All reference to 2.0% coal should be followed by "(based on 12,500 BTU heat value coal)".

Response: The Department does not agree with this comment. The permittee is only allowed to burn up to 2% sulfur coal, regardless of the other physical or chemical properties of the coal.

Comment 2: The Chambers Works fabric filter will be the reverse air, rather than pulse jet, type (summary document).

Response: A reverse air baghouse is acceptable.

Comment 3: The source listed as "lime slurry preparation tank" should be "lime slurry preparation system.". There are several tanks and all are indoors. (Draft permit condition, Page 1, Source Description).

Response: The correction has been incorporated into the permit condition document. The source description now reads as "lime slurry preparation system".

Comment 4: The PSD submittals were based on 1000 hours per year of auxiliary boiler operation at a full load of 77 MMBTU/hour. Thus, the limit should be 7.7×10^{10} BTU rather than 2.3×10^{10} BTU, (HHV) per calendar year. (Permit Condition II.B.2 Operating Requirement).

Response: The comment is correct. Permit Condition II.B.2 is now corrected to read as "Total No. 2 oil fired in the auxiliary boiler is limited to 7.7×10^{10} BTU, (HHV) per calendar year."

Comment 5: Catalyst "replacement" should be "catalyst addition and/or replacement, but no more than 50% of the <u>initial</u> catalyst bed. (Draft Permit Condition III.C.3.b.)

Response: Permit Condition III.C.3.b., now incorporates the suggested change in language. It now reads as follows: "The SCR system shall be optimized to achieve a NO_x emissions rate of less than 0.10 lbs/MMBTU, (HHV) averaged over any consecutive 180 minutes, by catalyst addition and/or replacement as necessary, but no more than 50% of the initial catalyst bed within each 5-year operating period for this facility."

Comment 6: The pressure drop across each fabric filter compartment is not monitored and reported separately. The pressure drop across the entire filter is monitored. (Draft Permit Condition V.B.4)

Response: Permit Condition V.B.4 is now changed as follows:

"Recording of pressure drop across entire fabric filters for the PC boilers."

Comment 7: Particulate and PM-10 compliance will be determined by New Jersey Test Method 1. Averaging time is not applicable (Reference Table 1).

Response: Averaging times for certain air contaminants are specified in Table 1 of the conditions of approval. Where such averaging times are specified, each of the three required test runs shall be for the duration specified, and compliance shall be required for each test run. These averaging times are also relevant for determining if the continuous emission monitoring data complies with the concentration limits.

For trace pollutants, averaging time have not been specified because the need to obtain a quantifiable sample may require longer sampling times than the 1 or 3 hour times typically specified by the Department for compliance demonstration purposes. For these air contaminants, the duration of each test run shall be approved by the Department after review of the test protocol submitted by the applicant. Here also, compliance with the specified maximum emission rate shall be demonstrated by each test run.

The above response also applies to comments 8 and 9.

Comment 8: VOC compliance will be determined by New Jersey Method 3. Averaging time is not applicable. (Ref. Table-1)

Response: New Jersey rules for VOC require 1-hour or batch average, whichever is greater to determine compliance. In this particulate case, the batch average is not applicable. Hence, the compliance basis of 60 minutes averaging is correct.

Comment 9: Trace element compliance will be determined by sampling tests. Averaging time is not applicable.

Response: The compliance basis for heavy metals is changed as follows:

1. Arsenic, Beryllium, Cadmium and Chromium-EPA multimetal test method.

2. Lead: EPA Reference Method 12.

3. Mercury: EPA Reference Method 101A.

Comment 10: Ammonia should be measured at 7% O_2, the same O_2 level as the other emissions. Nowhere is O_2 expected to be 15%.

Response: Table 1 of the permit conditions requires concentration of ammonia in terms of parts per million by dry volume corrected to 15% Oxygen. This oxygen correction is now changed to 7% O_2, which is consistent with oxygen correction applied to other pollutants. The emission limit becomes more stringent based on 7% oxygen than based on 15% oxygen, because 10 ppm of ammonia corrected to 15% oxygen is roughly equivalent to 24 ppm corrected to 7% oxygen. **The permit emission limit will be 10 ppm corrected to 7% oxygen.**

B. PREVENTION OF SIGNIFICANT DETERIORATION PERMIT

The NO_x Reduction System shall be designed for safe and reliable operation under the following steam generator operating conditions in any combination.

Daily startup following an overnight shutdown of approximately 8 hours duration

Weekly startup following weekend shutdown of approximately 48 hours duration

Continuous load following from 25 to 100 percent of maximum continuous rating

Operation at 25 percent of maximum continuous rating over extended periods of time

Continuous operation at maximum continuous rating

The limitations or bypass requirements, if any, to operation during startup and partial load conditions at loads below 25 percent of maximum #continuous rating or while firing No. 6 fuel oil, shall be **as** stated ~~as~~ in the Proposal.

2A.5.3 Fuel Data. The primary fuel for the steam generator will be washed Appalachian coal.

No. 6 fuel oil will be used for ignition, warmup, and flame stabilization.

Firing of the steam generator with fuel oil or with a combination of fuel oil and coal will routinely occur. The NO_x Reduction System shall be capable of successfully operating under such conditions without deterioration or degraded performance in excess of the guaranteed catalyst deactivation.

Coal properties of potential coal supplies are tabulated herein. The NO_x Reduction System shall be designed to provide the required performance for any of the coals listed herein either singly or in combination.

Both range and average values of properties are presented. The NO_x Reduction System shall be designed and guaranteed to operate as specified with any coal which has properties defined by the ranges stated. The values listed as "average" are included only for the Proposal Data purposes and are not to be used as a basis for design or guarantee.

#Addendum 2

Coal properties are as follows.

2A.5.3.1 Coal Supply A.

	Average	Range
Proximate Analysis, As-Received, percent by weight		
Moisture	5.0	4.5 - 5.5
Ash	10.0	8.5 - 11.0
Volatile matter	28.4	28.2 - 29.2
Fixed carbon	56.6	54.3 - 58.4
Total	100.00	
Sulfur	0.77	0.71 - 0.82
Heating Value, Btu per lb	13,000	12,900 - 13,150
Ultimate Analysis, As-Received, percent by weight		
H_2O	5.0	4.5 - 5.5
Ash	10.0	8.3 - 11.0
Sulfur	0.77	0.71 - 0.82
Nitrogen	1.26	1.24 - 1.49
Carbon	74.09	73.0 - 78.0
Hydrogen	4.71	4.65 - 4.90
Oxygen	4.04	2.38 - 4.04
Chlorine	0.13	0.02 - 0.15
Total	100.00	
Sulfur Forms, As-Received, percent by weight		
Pyritic	0.22	0.20 - 0.24
Sulfate	0.00	0.00
Organic	0.55	0.52 - 0.56
Total average	0.77	
Hardgrove Grindability Index	73	65 - 75
Ash Fusion Temperatures Reducing, F		
Initial	2,350	2,320 - 2,400
Softening	2,510	2,500 - 2,600
Hemispherical	2,670	2,000 - 2,740
Fluid	2,770	2,750 - 2,800

	Average	Range
Ash Analysis, percent by weight		
Phosphorous pentoxide, P_2O_5	0.30	0.25 - 0.45
Silica, SiO_2	47.94	46.09 - 48.77
Ferric oxide, Fe_2O_3	9.39	8.60 - 11.82
Alumina, Al_2O_3	28.95	27.5 - 30.36
Titania, TiO_2	1.27	1.20 - 1.48
Lime, CaO	3.21	2.97 - 3.27
Magnesia, MgO	1.28	1.27 - 1.33
Potassium oxide, K_2O	2.08	1.39 - 2.15
Sodium oxide, Na_2O	0.14	0.12 - 0.45
Sulfur trioxide, SO_3	2.66	1.91 - 3.21
Undetermined	2.78	
Total	100.00	

2A.5.3.2 Coal Supply B.

Proximate Analysis, As-Received, percent by weight	Average	Range
Moisture	8.0	7.0 - 9.0
Ash	7.80	7.0 - 8.5
Volatile matter	39.2	38.0 - 40.4
Fixed carbon	45.0	43.0 - 47.0
Total	100.00	
* Sulfur	2.5	2.2 - ~~3.4~~ *2.5*
Heating Value, Btu per lb	12,400	12,200 - 12,600

Ultimate Analysis, As-Received, percent by weight	Average	Range
H_2O	8.0	7.0 - 9.0
Ash	7.8	7.0 - 8.5
* Sulfur	2.50	2.2 - ~~3.4~~ *2.5*
Nitrogen	1.14	1.0 - 1.3
Carbon	68.73	66.0 - 70.0
Hydrogen	4.86	4.5 - 5.1
Oxygen	6.81	6.0 - 7.0
Chlorine	0.16	0.12 - 0.20
Total	100.00	

Contract Revision

Sulfur Forms, As-Received, percent by weight	Average	Range
Pyritic	1.20	1.20 - 1.40
Sulfate	0.08	0.07 - 0.11
Organic	1.22	1.20 - 1.77
Total average	2.5	
Hardgrove Grindability Index	55	50 - 60
Ash Fusion Temperatures Reducing, F		
Initial	2,000	1,950 - 2,050
Softening	2,150	2,100 - 2,200
Hemispherical	2,200	2,150 - 2,250
Fluid	2,610	2,550 - 2,650
Ash Fusion Temperatures Oxidizing, F		
Initial	2,150	2,100 - 2,200
Softening	2,290	2,250 - 2,350
Hemispherical	2,350	2,300 - 2,400
Fluid	2,560	2,600 - 2,700
Ash Analysis, percent by weight		
Phosphorous pentoxide, P_2O_5	0.12	0.08 - 0.16
Silica, SiO_2	49.67	48.0 - 51.0
Ferric oxide, Fe_2O_3	19.09	17.5 - 20.5
Alumina, Al_2O_3	20.25	19.0 - 21.5
Titania, TiO_2	0.98	0.75 - 1.25
Lime, CaO	3.01	2.5 - 3.5
Magnesia, MgO	1.02	0.8 - 1.2
Potassium oxide, K_2O	2.65	2.2 - 3.2
Sodium oxide, Na_2O	0.50	0.4 - 0.7
Sulfur trioxide, SO_3	2.42	2.0 - 3.0
Undetermined	0.29	
Total	100.00	

2A.5.3.3 Coal Trace Elements.

Constituent	Typical, ppm (mass) in Coal	Maximum, ppm (mass) in Coal
Arsenic	22.2	113.2
Lead	8.3	33

Constituent	Typical, ppm (mass) in Coal	Maximum, ppm (mass) in Coal
Cadmium	5.47	42.5
Beryllium	2.27	5.63
Chromium	27.2	135.4
Copper	18.2	54.6
Mercury	0.24	1.18
Manganese	100	700
Nickel	15.4	91.9

Source: Estimating Air Toxic Emissions from Coal and Oil Combustion Sources, EPA-450/2-89-001, April 1989.

2A.5.4 Flue Gas Conditions. The NO_x Reduction System shall be designed for operation with the following flue gas conditions at the economizer outlet. Standard temperature and pressure conditions shall be defined as 70 F and 29.92 in. Hg absolute.

2A.5.4.1 Flue Gas Flow Rates.

#100 Percent of MCR.

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	181,236	5,664	5,664	3,668
Nitrogen	3,013,005	106,768	106,768	99,259
Carbon dioxide	838,766	19,059	19,059	19,059
Sulfur dioxide	16,636	260	260	260
Chlorine	533	8	8	8
Moisture	222,969	12,377	0	0
Flue gas flow	4,273,145	144,135	131,758	122,252

Flue gas temperature/ pressure		706 F	-7 in. wg
Volumetric flow		2,079,501 acfm	925,483 scfm
#Volumetric flow	~~864,014~~	***846,014*** dscfm	
Volumetric flow		784,975 dscfm (3 percent O_2, dry basis)	

#Addendum 2

#90 Percent of MCR.

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	163,244	5,102	5,102	3,303
Nitrogen	2,713,893	96,169	96,169	89,405
Carbon dioxide	755,499	17,167	17,167	17,167
Sulfur dioxide	14,985	234	234	234
Chlorine	480	7	7	7
Moisture	200,834	11,148	0	0
Flue gas flow	3,848,935	129,826	118,678	110,115

Flue gas temperature/ pressure	676 F	-7 in. wg
Volumetric flow	1,824,869 acfm	833,607 scfm
Volumetric flow	762,027 dscfm	
Volumetric flow	707,048 dscfm (3 percent O_2, dry basis)	

80 Percent of MCR.

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	145,252	4,539	4,539	2,939
Nitrogen	2,414,781	85,570	85,570	79,551
Carbon dioxide	672,232	15,275	15,275	15,275
Sulfur dioxide	13,333	208	208	208
Chlorine	427	6	6	6
Moisture	178,699	9,919	0	0
Flue gas flow	3,424,724	115,517	105,598	97,979

Flue gas temperature/ pressure	671 F	-7 in. wg
Volumetric flow	1,616,594 acfm	741,731 scfm
Volumetric flow	678,040 dscfm	
Volumetric flow	629,120 dscfm (3 percent O_2, dry basis)	

#Addendum 2

#60 Percent of MCR.

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	109,707	3,428	3,428	2,220
Nitrogen	1,823,853	64,630	64,630	60,084
Carbon dioxide	507,728	11,537	11,537	11,537
Sulfur dioxide	10,070	157	157	157
Chlorine	323	5	5	5
Moisture	134,969	7,492	0	0
Flue gas flow	2,586,650	87,249	79,757	74,002

Flue gas temperature/ pressure	662 F	-7 in. wg
Volumetric flow	1,211,277 acfm	560,220 scfm
Volumetric flow	512,115 dscfm	
Volumetric flow	475,166 dscfm (3 percent O_2, dry basis)	

40 Percent of MCR.

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	157,101	4,910	4,910	1,590
Nitrogen	1,566,639	55,515	55,515	43,026
Carbon dioxide	363,533	8,260	8,260	8,260
Sulfur dioxide	7,210	113	113	113
Chlorine	231	3	3	3
Moisture	101,117	5,613	0	0
Flue gas flow	2,195,830	74,414	68,801	52,992

Flue gas temperature/ pressure	627 F	-7 in. wg
Volumetric flow	1,000,862 acfm	477,807 scfm
Volumetric flow	441,768 dscfm	
Volumetric flow	340,261 dscfm (3 percent O_2, dry basis)	

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#25 *Percent of MCR.*

	Actual lb/h	Actual mols/h	Actual Dry mols/h	3 percent O_2 Dry mols/h
Oxygen	157,030	4,907	4,907	1,119
Nitrogen	1,256,957	44,541	44,541	30,290
Carbon dioxide	255,895	5,814	5,814	5,814
Sulfur dioxide	5,075	79	79	79
Chlorine	163	2	2	2
Moisture	73,825	4,098	0	0
Flue gas flow	1,748,946	59,443	55,345	37,306

Flue gas temperature/ pressure	601 F	-7 in. wg
Volumetric flow	780,379 acfm	381,679 scfm
Volumetric flow	355,367 dscfm	
Volumetric flow	239,538 dscfm (3 percent O_2, dry basis)	

2A.5.4.2 Flue Gas Composition.

	Uncorrected	Corrected to 3 percent O_2
Uncontrolled SO_2		2,126 ppmdvc
Sulfur tioxide		25.5 ppmdvc
Carbon monoxide		181 ppmdvc
Uncontrolled NO_x		234 ppmdvc
VOC		32 ppmdvc
Uncontrolled particulate	1.918 gr/acf	3.074 gr/dscf

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The steam generator is guaranteed to have an outlet NO_x emission of 0.32 lb/MBtu average as measured at the boiler economizer outlet by EPA Method 7. The NO_x Reduction System shall be designed and guaranteed to **#limit NO_x emissions (as specified in Section 2B under Nitrogen Oxides Reduction Efficiency) including the effects of SCR bypass damper leakage at an ammonia slip concentration as specified in Section 2B (under Ammonia Emissions). The Contractor is responsible for accommodating any maldistribution of gas from the boiler.

2A.5.5 Ammonia Additive. Ammonia additive for the NO_x Reduction System will be furnished by the Owner and will be as described herein. Commercial grade anhydrous ammonia will be used which is expected to have the following specifications.

Ammonia, minimum weight percent*	99.5
Moisture, maximum weight percent	0.05

*Ammonia weight percent is determined as the difference between 100 percent and total residue.

The maximum or minimum allowable percentages of various constituents of the ammonia additive shall be as stated in the Proposal Data.

2A.5.6 Service Water. Service water will be used for washing the NO_x Reduction System catalyst during unit outages. Analyses of the service water are expected to be variable, but the following analysis is considered typical. Any limitations on catalyst washing shall be stated in the Proposal Data.

Constituent	Typical
Calcium, mg/l as $CaCO_3$	35
Magnesium, mg/l as $CaCO_3$	38
Sodium, mg/l as $CaCO_3$	30
Potassium, mg/l as $CaCO_3$	1
M-Alkalinity, mg/l as $CaCO_3$	35
Sulfate, mg/l as $CaCO_3$	41
Chloride, mg/l as $CaCO_3$	28
Silica, mg/l as SiO_2	15
pH	7.0 to 8.0

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2A.6 EQUIPMENT SIZING. All equipment shall be sized for the design conditions specified and, where specified herein, standby equipment shall be provided to ensure reliability.

2A.7 CONSTRUCTION CRITERIA. The NO_x Reduction System and auxiliary equipment shall be designed for the following conditions.

2A.7.1 General Site Conditions. The following general site conditions are applicable.

Site elevation, feet above mean sea level	80
Barometric pressure, in. Hg abs	29.93
Ambient temperature range, F	20 to 102
Indoor temperature range, F	34 to 104

2A.7.2 Design Pressures and Temperatures. Design pressures and temperatures shall be as follows.

Ductwork minimum design pressure	
At allowable design stress at continuous operating temperature or maximum transient temperature if applicable *	~~+43~~ ***+26*** in. H_2O
At yield stress at continuous operating temperature	+43 in. H_2O
Ductwork minimum design vacuum	
At allowable design stress at continuous operating temperature or maximum transient temperature if applicable *	~~-43~~ ***-26*** in. H_2O
At yield stress at continuous operating temperature	-43 in. H_2O

Damper pressure differential	Structural and Operator Design	Leakage Determination
SCR inlet damper	43 in. H_2O	6 in. H_2O
SCR bypass damper	43 in. H_2O	6 in. H_2O

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Design temperature	Continuous Operating	Maximum Transient
SCR reactor module and catalyst	706 F	750 F
SCR inlet damper	706 F	750 F
SCR bypass damper	706 F	750 F

2A.7.3 Ash Properties. Fly ash densities for the coals specified shall be as follows.

Fly Ash Bulk Density, lb/ft^3	Typical
For volume design	45
For weight determination	120

2A.7.4 Seismic Loads. Effects of seismic loads on design of all structures shall be given full consideration.

These design considerations shall be submitted by the Contractor and shall be acceptable to the Engineer and Owner.

These specifications cover equipment which will be installed in a seismic Zone 0 location in accordance with ASCE 7-88, and the Standard Building Codes 1991 edition.

2A.8 PLANT SERVICES. The following plant services will be available for connection to equipment furnished under these specifications.

2A.8.1 Compressed Air. Compressed air will be available as specified in Section 1B.

2A.8.2 Soot Blowing Steam. Auxiliary steam will be available for catalyst soot blowing. The steam will be available at an operating #pressure ***450 psig*** ~~150 psia~~ and a temperature of ***880 F.*** ~~90 F of superheat.~~ The auxiliary steam design conditions shall be ***600 psig*** ~~200 psia~~ at a temperature of ***890 F.*** ~~100 F of superheat.~~ All steam pressure and flow controls shall be the responsibility of the Contractor and shall be suitable for the conditions specified.

2A.8.3 Service Water. Plant service water will be available from the Owner's service water distribution system. Use of service water shall be minimized.

2A.8.4 Electrical Power. Electrical power will be available at the voltages specified in Section 1B.

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2A.9 PERFORMANCE DATA AND CURVES. Data and curves specified herein shall be submitted as specified in Section 1A.

2A.9.1 Materials Balance Diagrams. Materials balance diagrams shall be submitted showing flow rates, pressures, temperatures, and complete constituent analysis of flue gas upstream and downstream of the SCR reactor, ammonia flow, conveying airflow, air/ammonia mixture flow, etc., for the complete system furnished under these specifications.

The materials balance diagrams shall be based on the NO_x reduction rate as specified in the article entitled Flue Gas Conditions and on the gas constituents and material flow rates for each load and coal specified in the following tabulations.

Flow Rate at Steam Generator Operating Conditions, lb/h

	25 Percent of MCR	40 Percent of MCR	60 Percent of MCR	80 Percent of MCR	90 Percent of MCR	MCR
Fuel heat input to steam generator, million Btu/h	1,033	1,652	2,478	3,304	3,717	4,130
Flue gas temperature at economizer outlet, F	601	627	662	671	676	706
Flue gas density at specified nominal temperature, lb/cu ft	0.038	0.037	0.036	0.035	0.035	0.034
Coal A						
Oxygen	46,000	73,500	110,300	147,100	165,500	183,900
Nitrogen	764,300	1,222,300	1,833,400	2,444,600	2,750,100	3,055,700
Carbon dioxide	215,700	345,000	517,500	690,000	776,200	862,500
Sulfur dioxide	1,200	1,900	2,900	3,900	4,400	4,900
Moisture	50,500	80,800	121,200	161,600	181,800	202,000
Chlorine	100	200	200	300	400	400
Total flue gas	1,077,800	1,723,700	2,585,500	3,447,500	3,878,400	4,309,400
Ash	6,400	10,200	15,200	20,300	22,900	25,400
Nitrogen oxides						
lb/MBtu	0.32	0.32	0.32	0.32	0.32	0.32
ppmdv	184	184	184	184	184	184
ppmdv@3 percent O_2	231	231	231	231	231	231
Coal B						
Oxygen	45,300	72,400	108,600	144,800	162,800	181,000
Nitrogen	752,400	1,203,100	1,804,700	2,406,300	2,707,100	3,007,800
Carbon dioxide	209,800	335,500	503,300	671,000	754,900	838,800
Sulfur dioxide	4,200	6,700	10,000	13,300	15,000	16,700
Moisture	55,800	89,200	133,700	178,300	200,600	222,900
Chlorine	100	200	300	400	500	500
Total flue gas	1,067,400	1,707,100	2,560,600	3,414,100	3,840,900	4,267,700
Ash	5,200	8,300	12,500	16,600	18,700	20,800

Flow Rate at Steam Generator
Operating Conditions, lb/h (Continued)

	25 Percent of MCR	40 Percent of MCR	60 Percent of MCR	80 Percent of MCR	90 Percent of MCR	MCR
Nitrogen oxides						
lb/MBtu	0.32	0.32	0.32	0.32	0.32	0.32
ppmdv	186	186	186	186	186	186
ppmdv@3 percent O_2	234	234	234	234	234	234

The flue gas consituents and flow rates are included only for the purpose of obtaining material balances and are not to be utilized as a basis of design or guarantee.

The Contractor shall submit, as a part of the Engineering Data, complete and detailed material diagrams for reduction of NO_x emissions in the flue gas generated by the specified coals for steam generator operation at 25, 40, 60, 80, 90, and 100 percent of the maximum continuous rating of the steam generator.

2A.9.2 $\underline{NO_x}$ Reduction System Performance Curves. Curves as follows shall be submitted. Performance indicated shall be guaranteed.

a. Flange-to-flange pressure loss through the NO_x Reduction System including the limits of Contractor-furnished ductwork and accessories versus inlet flue gas flow rate in pounds per hour for the quantity of catalyst originally furnished. Curve shall take into consideration the effects of fly ash accumulation and other potential deposits on the catalyst.

b. Flange-to-flange pressure loss through the NO_x Reduction System including the limits of Contractor-furnished ductwork and accessories versus inlet flue gas flow rate in pounds per hour for the quantity of catalyst originally furnished plus one additional layer of catalyst. Curve shall take into consideration the effects of fly ash accumulation and other potential deposits on the catalyst.

c. Flange-to-flange pressure loss through the No_x Reduction System including the limits of Contractor-furnished ductwork and accessories versus inlet flue gas flow rate in pounds per hour for the maximum quantity of catalyst that
may be installed in the SCR housing. ***The maximum quantity of catalyst shall be defined as four full-height layers of catalyst.*** Curve shall take into consideration the effects of fly ash accumulation and other potential deposits on the catalyst.

d. Pressure drop versus flue gas flow rate in pounds per hour for SCR inlet damper with damper in the fully open position

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e. Pressure drop versus flue gas flow rate in pounds per hour for SCR bypass damper with damper in the fully open position

f. Maximum NO_x reduction capability at 2 ppm, 5 ppm, and 10 ppm ammonia slip versus time, indicating rate of catalyst deactivation and recommended point of addition of additional catalyst material and catalyst replacement by layer

g. Ammonia in fly ash, $lb/10^6$ lb, versus time at maximum NO_x reduction rate

2A.9.3 Fan Characteristic Curves. Characteristic curves shall be submitted for each fan furnished under these specifications. The curves shall show pressure rise, horsepower, and efficiency as ordinates and flow rate as the abscissa.

2A.10 MODEL TEST. A three-dimensional model, of not less than 1/12 scale, shall be constructed and tested by an independent model testing *contractor. The testing contractor shall be NELS Consulting Services, ***Fossil Energy Research Co. (FERCO),*** or Engineer-~~approved~~ ***acceptable*** equal.

The model test shall be described in the proposal.

The objectives of the model test shall include the following.

Determine the optimum arrangement of Owner-furnished and Contractor-furnished SCR reactor module inlet and outlet ductwork, and the shape and location of gas distribution devices in this ductwork, so that uniform gas flow conditions exist, ash fallout is minimized, and pressure loss is minimized.

Determine the optimum arrangement of the ammonia injection grid to enhance ammonia distribution.

Determine the shape and location of corrective devices to minimize ash fallout and pressure losses in the SCR reactor module.

Verify the system pressure losses with initial and ultimate catalyst quantities installed.

Locate gas test ports for performance testing of the NO_x Reduction System.

Velocity profiles shall be demonstrated to have a minimum of 85 percent of the readings within ±15 percent of the average with no reading more

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than ±25 percent from the average, and an rms distribution of ±10 percent at the following locations.

Inlet to first active catalyst layer (following dummy layer)

Outlet of last catalyst layer

Velocity profiles shall be demonstrated to have an rms distribution of ***#±15*** ~~10~~ percent at the following locations.

SCR module inlet

SCR module outlet

Ammonia injection grid location

NO_x Reduction System test port locations

The model shall be geometrically similar to the full size NO_x Reduction System. The model shall include the SCR reactor module and all ductwork #from the steam generator economizer outlet to the ~~outlet~~ ***inlet*** of the air preheater including the bypass ductwork, dampers, and damper frames. The model shall include the SCR catalyst and all internal structures of the equipment and the ductwork including such items as the ammonia injection grid, gas distribution devices, nonretractable soot blowing lances, beams, cross struts, and other incidental obstructions to gas flow.

The model shall be constructed entirely of clear plexiglass except for vanes and internal structures to permit observation during flow studies.

The model shall be tested with air velocity equivalent to the gas velocity in the full scale installation. The model shall be tested in the fully developed turbulent flow regime and shall take into account the effect of the catalyst blocks and air heater on flow patterns.

Gas flow distribution tests, ammonia distribution tests, dust distribution tests, and dust deposition tests shall be performed to simulate operation at 25 percent, 40 percent, 60 percent, 80 percent, 90 percent, and 100 percent of design flow conditions by adjusting air flow rates.

Dust distribution tests and dust deposition tests shall use prototype fly ash. Prototype fly ash will be provided to the test contractor by the Owner from Stanton Unit 1. Gas flow visualization shall use smoke or neutral buoyancy bubbles and tufts.

The Owner shall have the option of witnessing the model test. The model test shall be scheduled to comply with the schedule requirements for transmittal of the test report to the Engineer. The Contractor shall notify the Owner not less than fifteen days before the test.

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The model test report shall be developed and submitted to the Owner and the Engineer in accordance with the schedule specified in Section 1A. A minimum of two interim progress reports shall be submitted. These reports shall note progress to date, information which is still required to complete the model study, and work which is yet to be accomplished.

The Contractor shall be responsible for determining all gas flow vaning, straightening, or distribution devices required. The required devices shall be based on the model tests described herein. The Contractor shall implement those devices which are located within the limits of scope of equipment supplied under these specifications. The Contractor shall notify the Engineer of all required gas flow vaning, straightening, or distribution devices which are located outside the limits of scope of equipment supplied under these specifications. The required devices shall be included in the model test report which shall be developed.

The model shall be retained by the Contractor until the final performance test has demonstrated that the NO_x Reduction System has met the performance guarantees.

The Owner shall have the option of obtaining the model once the test results are accepted. All shipping costs from the point of testing to the Owner's office will be paid by the Owner.

2A.11 MATERIALS. Wherever, in these specifications, particular materials are specified, it is understood that such designation is intended in a generic sense as being suitable for the severity of service anticipated; and such designation is not intended to limit the proposal of other more highly corrosion- or erosion-resistant materials deemed more suitable. Materials shall be commensurate with the operating conditions anticipated.

2A.12 PROCESS SAMPLING PROVISIONS. The Contractor shall furnish provisions for obtaining samples of process gases and fluids. Gas sample locations shall be located as determined by the model test and to allow complete system characterization and optimization. The locations shall be acceptable to the Engineer.

*2A.13 SYSTEM ECONOMIC OPTIMIZATION. ~~The NO_x Reduction System shall be economically optimized by the Contractor based on the economic criteria specified herein. The system performance in reference to the parameters specified herein shall be as stated in the Proposal Data.~~

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*~~2A.13.1 Auxiliary Power Consumption. The equivalent capital cost for changes in auxiliary power consumption based on variation in the system operation may be determined by the use of the following values.~~

~~Unit Load Point, percent of MCR~~	~~Capital Equivalent of Demand Charges, $/kW~~	~~Capital Equivalent of Energy Charges, $/kW~~
~~100~~	~~789~~	~~1,305~~
~~90~~	--	~~103~~
~~80~~	--	~~357~~
~~60~~	--	~~354~~
~~40~~	--	~~67~~
~~25~~	--	--

~~The sum of each capital equivalent value stated above multiplied by the auxiliary power consumption at the corresponding load point will total the overall capital equivalent cost of the auxiliary power consumption. This cost is directly comparable to the equipment price at delivery.~~

*~~2A.13.2 Gas Pressure Drop. The equivalent capital cost for energy and demand due to 1.0 in. wg of pressure drop (at 100 percent load) through~~
*#~~the NO_x Reduction System may be determined by the use of the following values.~~

~~Year of Operation~~	~~Cost per 1.0 in. wg of Pressure Drop~~
~~1~~	~~$135,540~~
~~2~~	~~125,560~~
~~3~~	~~127,470~~
~~4~~	~~126,040~~
~~5~~	~~122,660~~
~~6~~	~~119,410~~
~~7~~	~~116,300~~
~~8~~	~~113,120~~
~~9~~	~~106,570~~
~~10~~	~~107,430~~

*~~2A.13.3 Ammonia Consumption. The equivalent capital cost for consumption of anhydrous ammonia is $2,100 per ton/yr.~~

*~~2A.13.4 Capacity Factor. The equivalent annual capacity factor is 72.5 percent for the first 10 years.~~

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Section 2B - GUARANTEED PERFORMANCE PARAMETERS, SYSTEM OPERATING REQUIREMENTS, RELIABILITY DEMONSTRATION, TESTS, AND SYSTEM PERFORMANCE PROGRAM

2B.1 GENERAL. This section defines the performance parameters; describes the operating requirements, the reliability demonstration, and the guarantee tests; and includes a system performance program for the NO_x Reduction System.

The Contractor shall guarantee the equipment and materials, with the exception of catalyst and overall performance, in accordance with the requirements of Article GC.25, GUARANTEE. Catalyst life and system ##performance shall be guaranteed ***to achieve the performance specified in this Section 2B*** for ~~3 years as described herein~~ ***24,000 hours of boiler operation***.

It is the intent of these specifications to purchase the NO_x reduction system specified herein with only the required amount of catalyst necessary to meet the guaranteed performance parameters.

However, the Owner desires the Contractor to develop a guaranteed 10 year performance program. The initial 3 years of this program incorporate the base contract guarantee. The 10 year guaranteed performance program shall be designed to minimize the amount of catalyst used for NO_x reduction while maintaining the guaranteed emission limits, SO_2 to SO_3 oxidation, ammonia stoichiometry, ammonia slip concentration and pressure drop. The program shall consider but not be limited to catalyst performance degradation over time, minimized maintenance and replacement outages, additional catalyst procurement and replacement cost, catalyst disposal, catalyst management and coupon testing frequency, performance monitoring program and a specific schedule of activities for the 10 year period. This performance program is discussed in more detail in #Article 2B.6.

Basic requirements concerning the guarantees and payments contingent upon system performance are specified in the General Conditions.

Field testing will be conducted in accordance with the following schedule.

- Damper field testing to be conducted within 30 days of start of commercial operation

- Initial formal performance guarantee test of the NO_x Reduction System shall be conducted within 30 days of start of commercial operation

- Reliability demonstration run of 60 days duration to be conducted within 6 months after successful completion of the initial formal performance guarantee test

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Interim formal performance guarantee test to be conducted after 8,000 hours of operation following the successful completion of the initial performance guarantee test but not before completion of the reliability demonstration run

Final performance guarantee test to be conducted after 15,000 hours of operation following the successful completion of the initial performance guarantee test but not before completion of the Interim Performance Guarantee Test

If, through no fault of the Contractor, the formal guarantee tests and reliability run are not successfully completed within 34 months of commercial operation, then the Owner shall issue its official acceptance and the Contractor shall have no future obligation to demonstrate reliability or pass any other performance guarantee test

Before performance of these tests, Contractor shall be given opportunity to inspect and adjust during an Owner scheduled outage.

These tests, as described above, to determine compliance with the performance guarantees shall be binding on the parties of this Contract.

All field performance guarantee tests will be conducted by a qualified independent testing laboratory mutually acceptable to the Owner and the Contractor.

The cost of three tests and the reliability demonstration run will be borne by the Owner whether successful demonstration of compliance with the performance guarantees is achieved or not. The costs of the tests paid for by the Owner will be limited to the costs for the independent testing laboratory and shall not include the costs for any of the Contractor's personnel, materials, or equipment involved in the testing. Any pretesting required by the Contractor shall be paid for by the Contractor.

The Owner's operating and maintenance personnel will operate the NO_x Reduction System during the reliability demonstration and formal performance guarantee test periods. They will perform only those operation and maintenance duties which are normally assigned to operation and maintenance personnel. Operating and maintenance personnel will not be responsible for modifications to equipment, disassembly to replace defective components, or inordinate maintenance to permit controlled operation of equipment which is experiencing unacceptable wear rates.

#The Contractor shall provide personnel to observe the performance guarantee tests and to provide technical assistance and advice to the Owner's operating and maintenance personnel. The cost for the Contractor's personnel to be present for the tests shall be included in the Contract price and the number of days and round trips shall be separate from the specified number of days and round trips for field service.

A copy of the test results will be provided to the Contractor.

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Should any of the performance guarantee tests or the reliability demonstration run show that the system has failed to meet its guarantees, the Contractor shall correct equipment by adjustment or repair in place, or, at its option by replacement of defective parts including catalyst, so that the equipment will be capable of meeting the performance guarantees. The system shall be considered as accepted if, during testing in accordance with this Section 2B, the tests show that the guarantees have been fulfilled.

Should any of the performance tests, including the reliability run, not meet the performance criteria, retesting shall be performed upon 30 days notification to Owner. Should the Owner's operating requirements delay the performance tests, the date for the test(s) shall be extended by the delay period but not to exceed the 36 month guarantee period.

Based upon the results of the Interim Performance Test, the Owner may release the final payment to the Contractor. Should the Interim Performance Test meet the performance criteria and if data collected to that date indicate the future performance will remain within the guaranteed values, final payment will be made in accordance with the requirements of Article GC.32.3. If the Interim Performance Test does not produce satisfactory results, if the test data is inconclusive, or if the data indicates that future performance will be outside the acceptance criteria, the Owner will continue to hold payment until the performance criteria is achieved or the 36 month guarantee period expires.

Should satisfactory performance testing not be achieved on or before the expiration of the guarantee period, the Contractor shall be excused from his performance obligations under the contract by replacing all or a proportionate amount of the then in-place catalyst based upon the results of the last completed performance test.

2B.2 GUARANTEED PERFORMANCE PARAMETERS. The following parameters of system performance shall be guaranteed.

Suitability for continuous operation

Rated capacity

Minimum load operation

Nitrogen oxides removal efficiency as a function of required permitted emissions

Ammonia emissions (ammonia slip)

Catalyst deactivation rate

Oxidation rate of sulfur dioxide to sulfur trioxide

Total system pressure drop

Ammonia usage rate

Ammonia stoichiometric ratio

Consumption of utility services

\## Damper flue gas leakage rate into isolated ductwork or equipment and to atmosphere

* ***Total system temperature drop***

The following articles define the guarantee parameters for each aspect of performance listed above.

The Contractor shall be consulted for the methods applied to measure these parameters.

2B.2.1 Suitability for Continuous Operation. The NO_x Reduction System shall operate safely and reliably without fouling, plugging, undue maintenance of the NO_x Reduction System or the air preheater, and without undue operator attention on a continuous basis under all operating conditions. Compliance with this requirement shall be demonstrated as specified in this section under RELIABILITY DEMONSTRATION. The NO_x Reduction System shall be guaranteed not to limit the required unit load during the run. The required unit load shall be defined as the load requested by the Owner's dispatch center.

2B.2.2 Rated Capacity. The NO_x Reduction System shall be guaranteed to operate satisfactorily and reliably for extended periods at 100 percent of steam generator maximum continuous rating. The rated capacity of the NO_x Reduction System shall be demonstrated by continuous operation at 100 percent of the flue gas flow for 48 hours when the steam generator is firing coal having a composition falling within the ranges specified in Section 2A.

2B.2.3 Minimum Load Operation. The NO_x Reduction System shall be guaranteed to operate satisfactorily and reliably for extended periods at 25 percent of steam generator maximum continuous rating.

2B.2.4 Nitrogen Oxides Reduction Efficiency. NO_x reduction is defined by the following equation:

$$\#NO_x \text{ Reduction} = \frac{(NO_x \text{ in}) - (NO_x \text{ out})}{(NO_x \text{ in})} \times 100, \text{ expressed on lb/h basis, } \%$$

The NO_x reduction efficiency shall be guaranteed to be equal to or greater than 70 percent for the initial performance test, based on a 3 day test. This removal efficiency is based on demonstrating achievement of an emission limit equal to or less than 0.10 lb NO_x per 10^6 Btu ##with new catalyst.

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After the initial performance test, the NO_x reduction efficiency for the 60 day reliability run and remaining performance tests shall be guaranteed to be equal to or greater than 47 percent on an actual 30 day rolling average basis. This removal efficiency is based on achieving the required emission limit of no greater than 0.17 lb NO_x per 10^6 Btu on a 30 day rolling average over the life of the unit.

The NO_x reduction guarantee specified above shall be achieved while maintaining the guaranteed values for ammonia emissions, ammonia consumption, oxidation of sulfur dioxide to sulfur trioxide, and system pressure drop.

2B.2.5 Ammonia Emissions. The NO_x Reduction System shall be guaranteed *#to limit the emissions of ammonia to ~~5~~ *2* ppm corrected to 3 percent O_2 for operation at 25, 40, 60, 80, 90, and 100 percent of steam generator maximum continuous rating.

2B.2.6 Catalyst Deactivation Rate. The deactivation rate of the #catalyst material shall be as indicated on the curve provided with the Proposal Data and shall support the guaranteed performance. The catalyst deactivation rate shall be demonstrated by a comparison of the results of the initial formal performance guarantee test, the interim formal performance guarantee test, and the final performance guarantee test.

2B.2.7 Oxidation Rate of Sulfur Dioxide to Sulfur Trioxide. The NO_x Reduction System shall be guaranteed to limit the oxidation of sulfur dioxide in the flue gas to sulfur trioxide that occurs in the NO_x Reduction System to less than 1.0 percent.

2B.2.8 Total System Pressure Drop. Pressure losses through the NO_x Reduction System from the takeover point of the Contractor's equipment to the inlet of the Owner-furnished air preheater shall be guaranteed not to exceed the amounts stated in the Proposal Data for operation at 25, 40, 60, 80, 90, and 100 percent of steam generator maximum continuous rating for each level of installed catalyst.

2B.2.9 Ammonia Usage Rate. The consumption of ammonia shall be guaranteed not to exceed the rates stated in the Proposal Data for operation at 25, 40, 60, 80, 90, and 100 percent of steam generator maximum continuous rating. Guarantees are based on the use of ammonia having properties as specified in Section 2A under Ammonia Additive.

2B.2.10 Ammonia Stoichiometric Ratio. The ammonia stoichiometric ratio shall be guaranteed not to exceed the ratio stated in the Proposal Data. Guarantees are based on the use of ammonia having properties as specified in Section 2A under Ammonia Additive.

2B.2.11 Consumption of Utility Services. The consumption rate of utility services such as but not limited to electric power, soot blowing steam, etc., for steam generator operation at 25, 40, 60, 80, 90, and 100 percent of steam generator maximum continuous rating shall be guaranteed not to exceed the values stated in the Proposal Data.

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#2B.2.12 Damper Performance. Flue gas leakage through a closed damper shall be guaranteed not to exceed 1 percent of the flue gas flow rate specified in Section 2A under Flue Gas Conditions. Flue gas leakage to atmosphere shall be zero.

#

*****2B.2.13 Total System Temperature Drop. Temperature losses through the NO_x Reduction System from the supply point of the Contractor's equipment to the inlet of the Owner-furnished air preheater shall be guaranteed not to exceed the amounts stated in the Proposal Data for operation at 25, 40, 60, 80, 90, 100 percent of steam generator maximum continuous rating for each level of installed catalyst. Temperature loss is defined as the decrease in temperature resulting from all NO_x reduction equipment with the exception of losses due to the Owner-furnished insulation and lagging system.***

2B.3 SYSTEM OPERATING REQUIREMENTS. The following is a listing of the operating requirements for the NO_x reduction system on which the guarantees shall be based.

Generating unit load model for the first 10 years of operation as follows.

Output percent	Net Output MW	Operating Time During Years 1-10* hours
100	415	4,311
90	374	339
80	332	1,181
60	249	1,170
40	166	222
25	104	0
Hours of Operation		7,223
Hours Inactive		1,537
Annual Capacity Factor, percent		72.5

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Output percent	Net Output MW	Operating Time During Years 1-10* hours
Average Load While Operating, percent		87.9

*Time interval begins on date of commercial operation (June 1, 1996) and ends 1 year later.

Generating unit designed for load following service and load fluctuates between 35 and 100 percent of MCR on a daily basis

One "hot restart" expected per month

Three "cold startups" expected annually

\## NO_x emission no greater than 0.17 lb NO_x per 10^6 Btu on a 30 day rolling average ***at all operating loads including 30 continuous days at 100 percent of MCR***

Cold startup procedures typically consist of the following major steps with the corresponding estimated durations, furnace heat input, and flue gas temperatures.

\##

Step	Duration, ~~h~~ ***hours***	Approximate Flue Gas Temperature, F	Furnace Heat Input, 10^6 Btu/h
Initial oil firing and boiler warmup	7	400	40
Turbine rollup and turbine metal heat soak	5	500	40
First pulverizer start and heat soak at 10 percent load	4	550	1,033
Overspeed and valve calibration checks and restart	1-2	550-600	1,033
Stable at 150 MW	5	600-650	1,033

\# Hot restart procedures typically consist of the following major steps with the corresponding estimated durations, furnace heat input, and flue gas temperatures.

\##

Step	Duration, ~~min~~ ***hours***	Flue Gas Temperature, F	Furnace Heat Input, 10^6 Btu/h
Initial oil firing and boiler warmup	1-2	450-500	40
Turbine rollup and turbine metal heat soak	1	500-600	1,033
Stable at 150 MW	2	600-650	1,033

\#Addendum 1
##Addendum 2

2B.4 <u>RELIABILITY</u> <u>DEMONSTRATION</u>. The adequacy of the NO_x Reduction System for continuous operation shall be demonstrated by a reliability demonstration run for an uninterrupted period of 60 days.

The rated capacity of the NO_x Reduction System and the minimum load operating capability shall be demonstrated as specified herein under GUARANTEED PERFORMANCE PARAMETERS as part of the reliability demonstration run.

The steam generator load may vary between 25 and 100 percent of its maximum continuous rating. There will be extended periods of operation at the maximum continuous rating.

If the reliability demonstration run is interrupted as a result of malfunction of the NO_x Reduction System or other plant equipment, the run shall be stopped. If a run is stopped within 7 days of its commencement, the run shall terminate and the reliability demonstration shall be restarted. If, after three attempts to start the 60 day reliability run, a total of 15 days of operation has been accumulated without having achieved 7 continuous days of operation, the requirement for 7 continuous days of operation shall be waived provided the NO_x Reduction System is not the cause of the restarts. The accumulated operating time will be credited toward the 60 day run. After 7 days, the running time shall be cumulative provided the NO_x Reduction System is not the cause of the outage. If the NO_x Reduction System causes an outage or derating of the #unit, the run shall terminate and a new run ***shall be*** started.

The running time shall, in any case, be cumulative if at any time the reliability demonstration run is terminated due to the failure of the Owner to follow the Contractor-provided and Owner-implemented operating instructions. Specific causes of run interruption that will allow the running time to be cumulative include, but are not limited to, the following.

Failure or insufficiency of plant services to the NO_x Reduction System

Damage or disruption to the NO_x Reduction System due to improper operation or performance of other plant equipment

The Contractor shall provide all replacement parts and perform all repair work on the system necessary to permit the reliability demonstration run to be completed.

Normal maintenance will be performed on auxiliaries located outside of the SCR reactor module at any time during the demonstration run provided it does not affect system performance or decrease removal rates below the limits specified in Section 2A under Flue Gas Conditions. Emissions will be monitored continuously during the reliability demonstration run and shall at no time exceed the guaranteed emissions except as provided by the Contractor's statement of limitations for startup and low load

#Addendum 1

operation in accordance with the requirements of Section 2A under Load Range and Operating Requirements.

#2B.5 PERFORMANCE GUARANTEE TESTS. Each performance guarantee test will be conducted at approximately the operating conditions specified at 25, 40, 60, 80, 90, and 100 percent of the maximum continuous rating of the ##steam generator. Each ~~final~~ ***performance guarantee*** test will be conducted over a continuous 72 hour period. Two tests will be conducted within a 24 hour period for continuous periods of a minimum of 4 hours for the nitrogen oxides removal efficiency, ammonia slip emission rate, sulfur dioxide oxidation, and total system pressure drop at the variable MCR conditions. The two 4 hour tests shall be run at least 12 hours apart. Ammonia consumption, ammonia stoichiometric ratio, and consumption of utility services at each load condition will be continuously monitored for the entire 24 hour period for compliance with the guarantees.

In addition, a single 4 hour test will be conducted within a 48 hour period with continuous plant operation at 100 percent MCR condition. Ammonia consumption, ammonia stoichiometric ratio, and consumption of utility services at each load condition will be continuously monitored for the entire 48 hour period for compliance with the guarantees.

Test objectives shall include determination of the following.

Nitrogen oxides reduction efficiency

Ammonia slip emission rate

Rate of oxidation of sulfur dioxide to sulfur trioxide

Total pressure drop from the takeover point of the Contractor's equipment to the inlet of the Owner-furnished air preheater

Ammonia usage rate and ammonia stoichiometric ratio

Consumption of utility services

The tests will be performed in accordance with the test procedures, where applicable, established by the Environmental Protection Agency for determination of compliance with New Source Performance Standards in effect on the date of the Contract. Other test methods shall be mutually agreed between the Contractor and Owner.

Gas flow, for purposes of determining performance, shall be taken as the arithmetic average of the experimentally measured flow and calculated stoichiometric flow adjusted for excess combustion air.

Each trial shall consist of concurrent measurements of nitrogen oxides and ammonia concentrations at the NO_x Reduction System inlet and outlet. Each trial will include at least one boiler soot blowing cycle.

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If a trial meets all necessary criteria, the calculated nitrogen oxides removal efficiency and ammonia emission rate will constitute acceptable data.

The arithmetic mean of the first three acceptable sets of data will be accepted by both the Owner and the Contractor as the true measure of the performance of the system.

Upon successful completion of the initial performance guarantee test and 60 day reliability run, the Owner may suspend the requirement for one or both of the remaining performance tests upon written notice to the Contractor.

2B.6 PERFORMANCE PROGRAM. As an option to the Contractor's base pro- *posal pricing, ***a 10 year performance program has been incorporated into this Contract in accordance with the requirements of the Basis of Contract (BC.6.4) and this Article.*** ~~a description of program activities and an anticipated schedule over 10 years is requested to provide continuous removal of~~ ~~NO_x~~ ~~in accordance with the not to exceed requirements as specified in Article 2B.2 along with~~ ~~SO_2~~ ~~to~~ ~~SO_3~~ ~~oxidation, stoichiometric ratio, ammonia slip, and pressure drop. The performance program shall include a yearly description of monitoring, maintenance, catalyst management, catalyst addition, catalyst replacement and cost for a 10 year operating period. The initial 3 years of the program shall be provided as part of the base guarantee.~~

~~Utilizing the information provided, a 10 year evaluation will be conducted as part of the Contractor's proposal review to determine the most responsive base proposal and effective 10 year plan. The Contractor's proposed performance program shall include a complete schedule of catalyst addition and catalyst replacement over the 10 year operating period. The performance program option (7 year) shall include pricing for catalyst added and catalyst replaced and disposed of by the Contractor, as required by the Contractor's catalyst management schedule. The Owner shall have the option to select all, a portion of the 10 year plan in yearly increments (starting with the 4th year), or none of the plan. The option period shall remain open for a period of 2 years~~
*#~~following commercial operation.~~

*~~To assist the Contractor in developing a performance based catalyst management scheme, the Owner will share in the cost adjustments for catalyst after the initial 34 month period following Commercial Operation (36 months from initial operation). Based upon the catalyst management schedule proposed by the Contractor and assigned yearly cost, the Owner will share with the Contractor on an equal basis the cost of catalyst additions, or replacement and disposal, above or below the established cost defined in the 10 year performance program. The Contractor shall define the projected cost of catalyst, either by fixed amounts or formula. Costs less than or greater than the defined costs shall be equally shared.~~ ***The Parties agree that f***or purposes of ***establishing the performance program costs for the Contractor,*** ~~assigning yearly cost to the program, the cost for~~ routine maintenance operations, labor for

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*adding catalyst or removing catalyst, ~~data collected~~ ***operating collection*** and other activities typically associated with Owner related requirements in operating a power plant will be ~~borne~~ ***furnished*** by the Owner.

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However, services to be performed by the Contractor for the specified categories of the Performance Program shall be in accordance with the following subarticles and summarized in the table below.

	Category 1	*Category 2*
Round trips per year	*4*	*2-4*
Estimated MDs per year	*8*	*4-8*
On-line test equipment	*Included*	*Included*
Reports per year	*Each visit*	*Each visit*
Laboratory testing of sample catalyst	*NA*	*Included*
Catalyst replacement supervision	*NA*	*Included*

2B.6.1 On-Line Testing and Monitoring (Category 1). Contractor shall monitor the performance of the SCR system at the site at least twice each year. The catalyst manufacturer will be present for at least one of the yearly visits. The Contractor's representatives will review the operating performance of the reactor and all subsystems. Unusual or abnormal operation will be tested on-line with adjustment and/or recommended corrective measures undertaken, as appropriate. Prior to leaving site the findings of the visit will be reviewed with the Owner and documented in the monitoring report.

2B.6.2 Inspection, Testing, Evaluation and Reporting (Category 2). Contractor shall provide these services during scheduled outages (anticipated twice each year). These inspections will occur for the first two years and each year when the deactivation rate indicates catalyst addition and/or replacement. Intervening years other than the above shall be limited to one inspection per year.

During each inspection trip catalyst samples (2-3 samples) which are representative of the catalyst cross-section will be selected for laboratory testing. Plates selected for sampling will be replaced during the inspection.

The Contractor will provide a written report of the findings to the Owner, including a discussion of catalyst performance deactivation condition and rate, predicted timing for additional catalyst addition or replacement, and other pertinent technical information.

2B.6.3 Catalyst Removal/Replacement/Disposal. Contractor will furnish catalyst as provided under the terms of this contract and assist in supervising the installation. Should catalyst be removed for disposal, Contractor shall furnish transportation to remove the catalyst from the site and dispose or reprocess the catalyst at an approved facility in accordance with the requirements of Article GC.21 LAWS AND REGULATIONS and Article 2C.3 OWNERSHIP OF CATALYST MATERIAL.

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2C.1 GENERAL. This section covers the specific design and construction requirements for the SCR catalyst, catalyst housing, and catalyst soot blowing system.

2C.2 TYPE. The SCR catalyst shall be of the high dust type, designed to *minimize pressure loss. ***Catalyst shall be Siemens SP-350 as stated in the Proposal.*** The direction of gas flow shall be vertically downward through the catalyst as shown on the drawings. The catalyst shall be of modular design which allows installation and removal of individual rows of catalyst blocks.

2C.3 OWNERSHIP OF CATALYST MATERIAL. The catalyst supplier shall assume ownership and responsibility for transportation and disposal or reuse of *deactivated catalyst ***within the requirements and in accordance with the provisions of Article GC.21, LAWS AND REGULATIONS***. Documentation shall be provided to the Owner confirming compliance with this requirement.

2C.4 MATERIALS. The SCR catalyst shall be constructed of suitable corrosion- and erosion-resistant materials designed for long service life.

The catalyst shall be either homogeneous extruded material or the catalyst surface shall be supported on a metallic or ceramic monolithic base material. The bonding procedure used and the design of the catalyst cells shall be such that delamination of the catalyst from the support material or permanent deformation of the catalyst or support material shall not occur due to stresses induced by the design seismic, pressure, and thermal conditions, or combinations thereof.

The NO_x Reduction System design shall incorporate provisions to minimize the formation of ammonia salts.

The catalyst shall be resistant to poisoning by trace elements as listed in Section 2A - SYSTEM DESIGN.

2C.5 CONSTRUCTION. The SCR catalyst shall be constructed in accordance with the following.

2C.5.1 General. Catalyst material shall be assembled into blocks for installation into the SCR catalyst housing. Blocks shall be the maximum practical size to facilitate and minimize field maintenance. Block dimensions shall meet shipping and handling limitations, and shall facilitate handling, installation, and removal of catalyst by the Owner's operating and maintenance personnel.

Each block shall be supported in a carbon steel frame with suitable lifting lugs or other handling provisions to permit installation and removal of the catalyst blocks. Each block shall consist of a single, full-depth layer of catalyst/substrate. Catalyst blocks shall be

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arranged in the catalyst housing in layers. Catalyst blocks less than
#1 meter high shall be considered half layer blocks. ***Catalyst block height and layer thickness shall not vary by more than 0.10 meter for any layer from any other layer.***

2C.5.2 Catalyst Housing. The catalyst housing shall be designed in accordance with the requirements of Section 2H - DUCTWORK AND EXPANSION JOINTS, and as specified herein. The housing shall be a fully self-supporting structure, supported from the Owner-furnished structural steel as described in Section 2A under ARRANGEMENT. The housing exterior dimensions shall be as shown on the drawings included with these specifications.

The housing shall be furnished with all required internal supports for catalyst loading, thermal stress, pressure loading, and internal access. The catalyst blocks and support structure shall provide, as a minimum, sufficient rigidity to support the combined ash and pressure loadings resulting from pluggage of 50 percent of the catalyst open area on any catalyst layer.

The catalyst housing and catalyst blocks shall include a sealing system that limits flue gas leakage past each layer of catalyst blocks to less than 1 percent. The sealing mechanism shall be capable of a service life equal to or greater than the catalyst.

The catalyst housing shall be designed for the initial installation of two layers of catalyst blocks, and shall have provisions for the future installation of additional catalyst blocks. The catalyst housing shall accommodate the ultimate installation of four layers of catalyst. The NO_x Reduction System shall be capable of achieving the specified performance without the addition of the third layer of catalyst blocks. The catalyst layers shall be arranged in the housing with at least a 10 foot
#spacing from top to top of adjacent catalyst layers ***and at least a 6 foot spacing from bottom to top of adjacent catalyst layers, excluding soot blowers and catalyst support steel. This spacing shall be achieved when catalyst of maximum height is installed in every layer.*** The catalyst housing design shall accommodate the installation of any catalyst ***satisfying the requirements of Article 2C.4, Materials,*** from any catalyst supplier.

A ceramic dummy layer shall be furnished upstream of the first layer of catalyst to assure flue gas distribution across the catalyst and to minimize fly ash erosion of the active catalyst. Perforated steel plate shall not be acceptable.

2C.5.3 Bypass. Tandem bypass ducts shall be provided as indicated on the drawings included with these specifications. The bypass ducts shall be sized for 50 percent bypass of the SCR at MCR conditions in accordance with the requirements of Section 2H - DUCTWORK AND EXPANSION JOINTS.

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2C.5.4 Soot Blowing System. A catalyst soot blowing system shall be provided which utilizes steam as the blowing medium. Steam for soot blowing will be provided as specified in Section 2A under PLANT SERVICES. The soot blowing system shall be designed to effectively remove ash from #the surface and internal passages of the catalyst layers. ~~Equipment~~

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#Traversing type soot blowers shall be manufactured by Diamond Power Specialty Corporation. A means of manually operating traversing type soot blowers shall be provided. Fixed position soot blowers will be acceptable provided the elements do not interfere with catalyst addition *and removal. Soot blowers shall initially be provided for the ***dummy layer and the*** first two catalyst layers. Provisions shall be included to allow for the future installation of soot blowers on the third and fourth catalyst layers. ***A total of 12 sootblowers shall be furnished.***

Each sootblower shall be provided with a blowing medium pressure switch and a local pressure indicator as specified in Section 1B.

The Contractor shall submit drawings identifying the location of all sootblowers and future sootblowers, complete with all design information to allow the Owner to design and route the piping system. The information shall be submitted as specified in Article 1A.8.4.

2C.5.4.1 Elements. All elements shall be designed and arranged for the catalyst and housing furnished. Location of elements and nozzle angles shall be such that maximum cleaning is obtained with a minimum of blowing #medium. Traversing type soot blowers shall be oriented for north-south motion. Location of elements shall not interfere with personnel access for operation or maintenance purposes.

All elements shall be constructed of seamless tubing with one end closed. The spun, forged, or welded end closure method shall be used. Hangers and bearings shall be arranged to prevent element contact with catalyst material. Connections between elements and soot blower heads shall preclude warping or binding of the element.

2C.5.4.2 Heads. Soot blower heads shall be installed so as to permit catalyst housing expansion without binding or unbalanced loading. Heads shall be designed for sharp and positive cutoff without critical adjustment, and for ease of blowing pressure adjustment after installation.

*2C.5.4.3 Piping and Accessories. All piping, insulation, valves, ~~control valves,~~ safety valves, drain valves, ~~pressure instrumentation,~~ orifices, steam traps, and other accessories required ~~for a complete and operating soot blower system shall~~ ***will*** be furnished ***by the Owner except as specified herein***. ~~The Owner will provide the piping from the steam supply to a common connection for all soot blowers, and the drain piping from a common connection to drain as indicated by the limits of Owner-furnished piping on the drawings included with these specifications. All piping and accessories shall be in accordance with Section 2F - PIPING.~~

#

Redundant pressure regulating valves for control of all sootblowers to be installed in Owner-furnished piping shall be furnished.

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2C.5.4.4 Control. The SCR catalyst soot blowing system will be controlled from the Owner-furnished steam generator soot blowing control system. The programming, programmable controller, operator interface, and wiring from the local soot blower junction boxes will be supplied by others. Catalyst soot blowing control shall be in accordance with Section 2K - CONTROLS AND INSTRUMENTS.

**2C.5.4.5 Sootblower Contract Requirements. The following requirements apply to the sootblowers furnished with the SCR. Reference to applicable contract article is noted for each supplementary requirement.*

* *1B.21 Lubrication. Lubrication connectors shall be provided for easy access that do not interfere with sootblower operation.*

* *1B.22 Enclosed Gear Drive Units. Gear drives shall be designed for intermittent operation in accordance with the latest AGMA standards.*

* *1B.23 Safety Guards. Safety guards shall be in accordance with OSHA requirements.*

* *1E2.1.3 Motor Enclosures. Motors shall have cast aluminum end bells, rolled steel frames, and steel terminal housings. No drain holes are required.*

* *1E2.1.7 Terminal Housings. Terminal housings shall be the Diamond Power Specialty Company standard.*

* *1E2.1.11.3 Bearing Lubrication Systems. The bearing lubrication system shall be the Diamond Power Specialty Company standard.*

* *2F.4.3 Flanges. Flanges on sootblowers shall be furnished in accordance with ANSI B31.1 as specified herein. Materials for flanges shall be ASTM A217 WC6 and shall meet the steam design conditions specified herein.*

* *2G.1.2 Code Requirements. Sootblower poppet valves shall not be required to meet the requirements of ANSI 16.5 at the option of the Contractor.*

2C.5.4.4.1 Electrical Devices. The following requirements apply to the electrical devices and equipment to be supplied by the Contractor. Additional requirements for electrical devices and equipment are specified in Section 1B. All motors required shall be furnished. Motors shall be rated 460 volt, 3-phase, 60 hertz. Motors shall be of the totally enclosed type. Aluminum end bells on motors are acceptable. No breather plug is required on drain hole. All other motor requirements shall be the manufacturer's standard for operation in a 65 C maximum ambient, with

*Class B insulation ***minimum***, 55 C maximum temperature rise, and grease lubricated ball bearings. Motor information sheets shall be submitted by the Contractor to the Engineer for all motors furnished, in accordance with Section 1C. Motors shall be manufactured by Baldor or Doerr ***or GE***. Motors shall be standard frame and shaft design with no modifications made to the shaft to match the soot blower shaft diameter.

All motor starters and enclosures for soot blowers shall be furnished. Starter units shall be mounted in a NEMA 4 enclosure on each soot blower. Starters shall be completely factory wired. All blowers requiring reversing shall be provided with individual reversing starters. Motor starters shall be in accordance with Section 1B.

Control power transformers, 480-120 volts, shall be furnished as required. They shall be furnished as part of the individual starters.

2C.5.4.4.2 Wiring. The Contractor shall wire all insert-retract position contacts, starter auxiliary contacts, overload contacts, blowing medium pressure switches, and other accessories to local soot blower external circuit junction boxes. All inputs and outputs as detailed in the Contractor's I/O list shall be wired through the soot blower external circuit junction box. States sliding link terminal blocks shall be provided for all control signals.

Local NEMA Type 4 push-button stations shall be provided for each soot blower. Push-button stations shall be factory mounted on the soot blower unit.

A set of control circuit disconnects shall be furnished at each soot blower. The disconnects shall be States type sliding link terminal blocks or alternate equipment acceptable to the Engineer. Disconnects, when opened, shall electrically isolate the soot blower controls from the remainder of the soot blowing system.

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Plug-in cables shall be used to interconnect internal soot blower equipment if the equipment thus interconnected must be disconnected as a part of normal routine maintenance. Plug-in cables, including plugs and receptacles, shall be completely factory wired. Components must be acceptable to the Engineer. All plugs and receptacles furnished shall be rated for outdoor service at 600 volts ac.

A gasketed, NEMA 4 external circuit junction box shall be provided on each soot blower for termination of external circuits. This junction box shall contain the following.

Terminal blocks or switch blocks for connection of external control circuits

Local starter

A 600 volt power circuit breaker with external operating handle for interruption of the motor supply circuit

Receptacles, as required, where plug type circuit disconnecting devices are furnished for power and control circuits to the soot blower local limit switch and motor connection box

Devices, as required, to maintain system operation while the soot blower is being serviced and the local power and control disconnecting switches are open

All electrical devices on each soot blower shall be completely factory wired into the external circuit junction box. Connection of field wiring to the external power circuit breaker, and to the terminal blocks or switch blocks provided for the external control circuit, shall be all that is necessary to place any soot blower in operation. All cables, connectors, terminal blocks, and other electrical components shall be suitable for a high temperature environment.

2C.5.5 Expansion Provisions. The catalyst housing design shall allow for thermal expansion and contraction of the housing and catalyst blocks without subjecting the catalyst, internal support members, or catalyst housing to excessive stress levels while heating up, operating, or cooling down.

#2C.5.6 Access, Observation, and Maintenance Provisions. ***All access stairs, platforms, walkways, handrails, and ladders internal to the SCR housing shall be provided in accordance with Section 2J - Access Provisions. External access will be furnished by the Owner according to the Contractor's design as specified in Section 2J.*** All access doors needed for maintenance of the SCR catalyst shall be provided. The number and location of access doors shall include, but not be limited to, those access doors indicated in Section 2J. Doors shall be large enough for entry of personnel, catalyst blocks, scaffolding, and other equipment. Personnel access doors shall be a minimum of 18 by 24 inches. Scaffold access doors shall be a minimum of 36 by 52 inches. Catalyst block access openings shall be sized as required to permit installation

#Addendum 2

and removal of catalyst blocks. Pressuretight and vacuumtight door seals shall be provided and doors and frames shall be structurally reinforced to prevent deflection which could result in leakage past the seals. Seals shall be appropriate for the expected operating temperature range.

A safety device shall be provided on each access opening to prevent the door from springing open during use or while the access door is being opened, as a result of internal pressure within the catalyst housing.

#A complete ***design for the Owner-furnished external*** monorail system shall be provided for catalyst handling and transfer from grade to the ~~installed location for all layers~~ ***transfer point to the Contractor-furnished monorail system as required by the Contractor's design***. All required electric hoists and trolleys, handling tools, platforms, stairs, ladders and support steel shall be ~~provided~~ ***included*** to support installation and removal of catalyst. Structural and miscellaneous steel shall be in accordance with Section 2J.

2C.6 CATALYST COUPONS. In order to monitor catalyst life and performance, a minimum of 10 test coupons shall be provided and installed in each catalyst layer in an arrangement recommended by the catalyst manufacturer. Spare catalyst coupons sufficient for two years of operation shall also be furnished for future reference performance and composition analysis. These samples will be tested to evaluate catalyst activity and physical properties as the catalyst ages. Each catalyst coupon shall be labeled with a serial number. All catalyst coupons shall be from the same lot as the installed catalyst.

Access shall be provided for removal of catalyst coupons as specified in Section 2J.

2C.7 PRESSURE PORTS. Ports shall be provided upstream and downstream of each catalyst layer to permit monitoring of the pressure drop across the individual catalyst layers and for performing a complete traverse of the catalyst cross-sectional area to measure the uniformity of the air/ammonia/flue gas mixture across the catalyst.

#Addendum 2

Section 2D - AMMONIA UNLOADING AND STORAGE EQUIPMENT

2D.1 GENERAL. This section covers the design and construction requirements for the ammonia unloading and storage equipment to be furnished under these specifications.

2D.2 ARRANGEMENT. The ammonia unloading and storage equipment shall consist of two horizontal cylindrical tanks designed for bolt-down installation on an Owner-furnished concrete pad, all piping and valves required for unloading of liquid anhydrous ammonia and return of displaced ammonia vapor to the unloading vehicle, and ammonia vaporizing equipment. The size of each tank shall be 30,000 gallons (nominal).

****Saddles shall be shipped separate from tanks for field assembly by the Owner's erection contractor if required.***

Each tank shall discharge ammonia vapor through a branch line to a common discharge manifold. The branch lines shall be equipped with pneumatic shutoff valves for isolation.

Access ladder, stairs, and platforms shall be provided to the tanks as required for maintenance. Access provisions shall be in accordance with Section 2J.

Ammonia vaporizers shall be skid mounted and shop fabricated to the maximum extent possible. All wiring included on the skid shall be terminated to a junction box. Each ammonia vaporizer shall be mounted on a separate skid.

All equipment furnished under this Section 2D will be located in an unprotected out-of-doors location.

2D.3 DESIGN AND CONSTRUCTION. Each tank shall be designed for a working pressure of 250 psig and shall be provided with lifting lugs and supports. The tanks shall be of the type manufactured by USS Chemicals *Division of United States Steel, ~~or~~ Hamler Industries, ***or equal, as approved by the Engineer***.

Each tank shall be fitted with the following accessories and instrumentation devices. Unless otherwise specified, instrumentation devices shall be as specified in Section 2K - CONTROLS AND INSTRUMENTS.

2D.3.1 Code Stamp. Each tank shall be constructed and tested in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII and shall bear an ASME pressure vessel code stamp, except that the construction under ASME Table UW12 at a basic joint efficiency of under 80 percent is not authorized.

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2D.3.2 Relief Valves. Each tank shall be equipped with a dual relief valve and manifold assembly. Relief valves shall be sized in accordance with ANSI K 61.1 Appendix B. Relief valves and manifold shall be Rego or acceptable equal.

2D.3.3 Piping. Piping shall be in accordance with Section 2F - PIPING. All tank openings other than relief valve, pressure gauge, and level indicator connections shall be provided with Rego excess flow check valves.

2D.3.4 Vaporizer Assembly. Dual redundant external immersion heater/vaporizer assemblies with primary and secondary pressure transmitters and external thermostat protection shall be provided. Pressure transmitters shall be as specified in Section 1B. The external thermostat shall not allow the heater to operate above 110 F tank temperature.

2D.3.5 Pressure Reducing Station. A pressure reducing station shall be provided in the common vapor discharge line from the ammonia storage tanks. The pressure reducing station shall be provided with appropriate pressure regulators, pressure gauges, valves, piping, and fittings to maintain the ammonia vaporizer operating pressure within the range required by the Contractor's design.

2D.3.6 Level Indicator. One float gauge level indicator shall be furnished for each tank with all required flanges and adapters. The float gauge shall be as manufactured by Rochester.

2D.3.7 Pressure Gauges. A local pressure indicator located on each tank shall be provided. A local pressure indicator located on the vapor discharge line from each tank shall also be provided. Pressure indicators shall be manufactured by Rego.

2D.3.8 Foot Step. One foot step attached to the tank sidewall to provide access to the level indicator shall be provided.

2D.3.9 Leak Detection. Four sets of ammonia gas leakage detectors shall be provided for installation around each ammonia storage tank.

2D.3.10 Ammonia Unloading Control. Local control shall be provided in the vaporizer building for ammonia unloading.

2D.3.11 Ammonia Compressors. Dual redundant ammonia compressors shall be furnished.

2D.4 SHOP COATING. Shop surface preparation and coating shall be in accordance with Section 1B.

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2D.5 SHOP CLEANING AND PREPARATION FOR SHIPMENT. All equipment and components shall be thoroughly cleaned, dried, and closed to prevent the entry of moisture or other foreign material. Any dirt, oil, residue, metal chips, or other surface contaminants shall be removed. Surfaces that have been cleaned or painted shall be maintained in a clean and undamaged condition up to, and including, packaging for shipment.

2D.6 INSPECTION AND TESTS. The Contractor shall perform the inspections and tests as described herein. The Engineer may elect to witness the inspections and/or tests.

Inspections and tests shall include, but not necessarily be limited to, the following.

1. Inspection of material, size, type, quantity, dimensions, and acceptability of all ammonia unloading and storage equipment. Subjection of each component and assembly to

standard shop tests to assure proper mechanical operation and "leaktight" connections. Copies of certified material reports shall be available to the Owner during shop fabrication of equipment and components.

2. Shop inspection of ammonia unloading and storage equipment, including instrumentation, piping, and valves to determine freedom from defects and compliance with specification requirements

3. Shop hydrostatic test. Test modular units including vessels and manifolds after assembly at 1-1/2 times maximum design working pressure

4. Welding and NDT processes (in accordance with ASME Code, Section VIII)

5. Shop coating

6. Assembly and preparation of equipment for shipment

Pressure or leak test reports shall be submitted in accordance with the Schedule of Activities in Section 1A. The reports shall state test requirements and the observed results. These reports shall contain the signature and title of the Contractor or the authorized contract representative of the agency performing the tests.

2D.7 <u>TRUCK UNLOADING FACILITIES</u>. The Contractor shall provide facilities for unloading of ammonia transport trucks. The facilities shall be acceptable to the Engineer. The design shall incorporate provisions for the future addition of rail unloading facilities.

2E.1 GENERAL. This section covers the design and construction requirements for the ammonia injection equipment to be furnished under these specifications.

All equipment furnished under this Section 2E and not internal to the SCR #housing shall be skid mounted for installation on Owner-furnished foundations.

2E.2 CONVEYING AIR SUPPLY. Air for transportation of ammonia shall be provided by two full capacity conveying air fans. Conveying air equipment shall be as follows.

2E.2.1 Conveying Air Fans. Conveying air fans shall be furnished in accordance with the requirements specified herein.

Type	Backward inclined, nonoverloading, horizontal shaft, single inlet centrifugal
Prime mover	Electric motor, direct drive, 1,800 rpm maximum

Fans shall meet the static pressure requirements without the use of an evase velocity recovery section. No credit shall be taken for velocity pressure recovery beyond the fan outlet. Damper losses shall be charged to the fans.

The conveying air fans shall be skid mounted to the maximum extent possible. This shall include complete wiring to the maximum extent.

Conveying air fans shall be as manufactured by Buffalo Forge, Champion Blower, Chicago Blower, Robinson, or acceptable equal.

2E.2.1.1 Housing. Fan scroll, side sheets, inlet box, and inlet venturi shall be of welded steel plate construction, minimum 1/4 inch thickness, and suitable for the duty. The housing shall be reinforced to withstand the imposed pressures and to prevent noise and vibration. Duct connections shall be flanged for bolt-up and seal welding.

2E.2.1.2 Rotor. The rotor shall have backward inclined, nonoverloading blades. The shaft shall be conservatively designed for stiffness and shall be of completely machined forged steel. Fan arrangement shall be AMCA Arrangement 8. The entire assembly shall be dynamically balanced. The assembly must be capable of withstanding any operating imbalance created by foreign material buildup on the blades.

All strength welding on the rotor shall be radiographically examined in accordance with AWS D14.4, Classification and Application of Welded Joints for Machinery and Equipment, Article 7, Part 4. Welds that do not meet the requirements of Article 7.3.9 of the referenced AWS Code shall be replaced or repaired with acceptable welds.

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The first resonant speed of the rotor shall be not less than 125 percent of the normal operating speed of the fan. Resonant speed of the rotor is defined as that speed equal to the natural frequency of the combined spring-mass system of rotor, bearing housing, oil film, and bearing support, but excluding the foundation.

2E.2.1.3 Bearings. Fan bearings shall be supported on a steel base. Bearing housings shall be provided with shaft seals and oil caps which prevent dirt and water contamination of the oil.

The bearings shall be self-aligning, split sleeve type. If required, bearing lubrication shall be of the flow through flood type.

2E.2.1.4 Motors. Conveying air fan motors shall be furnished in accordance with the requirements of Section 1E.

2E.2.1.5 Shaft Couplings. Fan shaft couplings shall be furnished in accordance with Section 1B. The maximum brake horsepower requirement shall be determined based on the motor torque developed during start, acceleration, and deceleration if stalled.

2E.2.2 Conveying Air Fan Outlet Dampers. The conveying air fan outlet dampers shall be of the parallel blade louver type and shall be furnished with pneumatic operators with speed control valves.

The damper operators shall be for on-off control of the dampers. A 120 volt ac solenoid valve shall be provided for each damper which opens the damper when energized. The solenoid valve shall be as specified in Section 1B and shall be in a NEMA 4X enclosure. Filter regulators shall be furnished for the damper operators.

Open and closed limit switches shall be furnished for each damper and shall be as specified in Section 1B. Limit switches shall be shop installed on dampers.

2E.3 AIR AND AMMONIA MIXING. The ammonia shall be diluted and mixed with conveying air prior to injection into the flue gas stream. The resultant air and ammonia mixture shall typically contain between 2 and 5 percent ammonia by volume for all load conditions, and in no case shall contain more than 8 percent ammonia by volume.

The air/ammonia mixing chamber shall meet all NFPA requirements regarding safety in handling air and ammonia mixtures.

2E.4 AMMONIA INJECTION GRID. An ammonia injection grid shall be provided to evenly distribute the air and ammonia mixture throughout the flue gas stream. The ammonia injection grid shall be located in the vertical ductwork run with upward flue gas flow upstream of the catalyst housing.

The injection grid shall be designed and arranged to ensure uniform mixing between the ammonia and the flue gas stream. The injection grid shall be designed with multiple injection branches. A combination of perpendicular branches oriented along both the long axis and the short axis of the ductwork shall be installed to provide a crossing pattern of the branches. Each branch of the injection grid shall be fed from a common supply manifold which shall be located external to the ductwork. Each branch shall include flow orifices and independent flow rate adjusting valves to allow maximum tuning flexibility. Valved test connections for a manometer shall be provided on each branch of the injection grid. The test connections shall be routed to an accessible location near the flow rate adjusting valves.

The injection grid shall be properly supported to prevent thermal distortion and damage due to vibration induced by the exhaust flow. The injection grid shall be designed for maximum thermal expansion, and the design shall consider maximum thermal expansion without cooling provided by the flow of ammonia and dilution air.

All injection grid piping connections inside the flue gas ductwork shall be socket or butt weld type. Nozzles shall be designed to be free from plugging.

A static mixing device shall be installed downstream of the injection grid to thoroughly mix the ammonia with the flue gas. Each stage of the static mixing device shall be oriented so as to redistribute the gas along the long axis of the ductwork cross section.

2E.5 INJECTION SHUTOFF VALVE. A motor-operated ammonia injection shutoff valve shall be provided to stop the flow of ammonia and dilution air to the ammonia injection grid. The injection shutoff valve shall be in accordance with Section 2G - VALVES.

2E.6 PIPING. Piping shall be in accordance with Section 2F - PIPING. Injection grid piping and nozzles shall be constructed of 316 stainless steel.

2E.7 AMMONIA VALVE ENCLOSURES. All valves shall be furnished with a valve enclosure. The enclosure shall be designed for leakage detection.

2E.8 AMMONIA METERING SKID. The ammonia metering skid shall include ammonia metering valves and inlet filter. Shop assembly shall be to the maximum extent.

The metering valves shall be sized for the full range of ammonia flows. Two sets of split range control valves shall be furnished if required for accurate control.

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Section 2F - PIPING

2F.1 GENERAL. This section covers the furnishing of interconnecting piping required for selected equipment furnished under these specifications except as otherwise specified herein. Piping to be furnished shall include all pipelines indicated in light lines on the Flow Diagrams included with these specifications. Piping shall be furnished in accordance with the Pipeline Listing included with these specifications.

Piping 2-1/2 inches and larger shall be shop fabricated as specified herein. Piping 2 inches and smaller shall be field fabricated and shall be shipped to the jobsite with pipe in random lengths and with loose fittings and valves. Fittings and valves for each pipeline shall be separately crated or boxed. Shipping crates or boxes shall be clearly marked to indicate the contents. Boxes and crates shall have waterproof linings to prevent entry of dirt and moisture.

It shall be the Contractor's responsibility to determine a feasible routing for each pipeline furnished under these specifications, including field fabricated pipelines, and to ship all materials, except welding rod, required to field fabricate and erect all piping. If additional materials are required to complete the field fabrication or erection of the piping, the Owner will notify the Contractor of such shortages. If the Contractor fails to ship the additional material within 10 days after receiving such notice, the Owner shall have the right to purchase the additional material directly and deduct the costs thereof from the agreed contract price.

The routing for all piping to be furnished under these specifications, including field fabricated piping, shall be shown in detail on piping arrangement drawings prepared by the Contractor. The Contractor shall have the Engineer's acceptance of the piping arrangement drawings before shop fabrication or shipment of loose materials for field fabrication is started.

Piping shall be easily ventable and drainable. Vent and drain connections and valves shall be provided as required.

Piping shall be designed to present a neat rectangular form and to allow convenient access to valves, instruments, and equipment. Piping shall not block passageways or walkways. A minimum overhead clearance of 7'-6" shall be main-tained through passageways and walkways.

2F.2 PIPELINE LIST. The Pipeline List for the work under this Contract is included under the scope of the following drawing bound at the end of this section.

Drawing No.	Rev	Title
*# 16805-2UUU-M0134	~~0~~ 1	PIPELINE LIST NO_x REDUCTION SYSTEM

The Pipeline List designates the pipeline identification number; line description; operating, design, and test pressures and temperatures; pipe material, nominal sizes end corresponding schedule or wall thickness; valve class rating, end preparation requirements, and material; insulation class; welding remarks; and special features.

2F.3 CODE REQUIREMENTS. Except as specified otherwise herein, all materials and fabrication shall be in accordance with the requirements of the American National Standard Code for Pressure Piping, ASME B31.1-1989, Power Piping and all addenda thereto through and including B31.1a-1989 as issued January 31, 1990; and all federal, state, and local regulations, when applicable. Ammonia piping shall conform to ANSI/ASME B31.3, Chemical Plant and Petroleum Refinery Piping.

2F.4 MATERIALS. Piping materials shall be in accordance with the following requirements except where special materials are specified in the Pipeline Listing.

2F.4.1 Pipe. Carbon steel and stainless steel pipe shall be ungalvanized seamless type with schedule numbers, sizes, and dimensions conforming to ANSI/ASME B36.10M. Steel pipe shall conform to the ASTM standards designated in the Pipeline Listing.

2F.4.2 Fittings. Except as otherwise specified herein, fittings shall be constructed from materials equivalent to the pipe with which they are used.

Fittings such as elbows, tees, crosses, reducers, and caps shall be used for all changes in piping direction, intersections of piping, piping size changes, and end closures.

Unless otherwise specified herein, fittings 2-1/2 inches in nominal size and larger shall be of the butt welding type and fittings 2 inches and smaller shall be of the socket welding type.

Butt welding fittings shall conform to ANSI/ASME B16.9 and shall be constructed in accordance with ASTM A234/A234M or ASTM A403/A403M. The wall thicknesses in the fittings shall be equal to the pipe with which the fittings are to be used.

Socket welding fittings shall conform to ANSI B16.11. The fittings shall be 3,000 pound minimum pressure class.

2F.4.3 Flanges. Carbon steel flanges shall be of the raised face welding neck type and shall conform to ANSI B16.5 with materials in

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accordance with ASTM A105/A105M. Flanges which mate with flat faced valve or equipment flanges shall be flat faced.

2F.4.4 Flange Bolting. Flange bolting shall conform to the applicable provisions of ANSI B16.1 and B16.5.

Bolting shall consist of threaded bolt studs with two nuts for each stud.

Bolts and nuts shall be heavy hexagonal head conforming to ANSI B18.2.1 and ANSI/ASME B18.2.2.

Materials for carbon steel bolting shall be in accordance with ASTM A307, Grade B.

2F.4.5 Gaskets. Spiral wound gaskets of stainless steel and nonasbestos filler shall be used for all flanged steel joints. Gaskets containing asbestos are not acceptable.

2F.5 PIPING FABRICATION. Piping 2-1/2 inches and larger shall be shop fabricated to a dimensional tolerance of ±1/8 inch and shall be designed to fit the equipment without field cutting, welding, or other modifications.

Welding shall be in accordance with the requirements of Section 1W, WELDING.

2F.5.1 End Preparation. Preparation of butt welding ends for field connections furnished by the Contractor shall be in accordance with the requirements stated below and the requirements for V-bevel end preparation indicated on the Field Butt Weld End Preparation drawings included with the Pipeline List.

Pipe ends for socket weld connections shall be reamed to full inside diameter to remove all burrs and obstructions.

2F.5.2 Fabricated Sections. The length of shop fabricated piping sections shall be the maximum allowable within the limitations of handling and shipping.

The choice of field weld locations and configuration of the sections shall be selected with consideration of the problems of field erection. Wherever possible, field welds shall be placed in convenient locations. Location of field welds shall be subject to the Engineer's concurrence.

2F.5.3 Cleaning and Painting. The interior and exterior of all piping shall be thoroughly cleaned before shipment to remove all mill scale and foreign matter.

The exterior surfaces of carbon steel shop fabricated piping shall be provided with one coat of primer in accordance with Section 1B.

Shop fabricated piping shall be clearly marked with identifying piece marks on each fabricated section. Piece marks shall be shown on all manufacturer's drawings.

Unless otherwise specified for "shotblast cleaning" in the Pipeline Listing, the interior surfaces of all shop fabricated piping shall be cleaned with a power driven mechanical cleaner. The interior surfaces of shop fabricated piping specified for shotblast cleaning shall be thoroughly blast cleaned using metal shot. After cleaning, interior surfaces of all piping shall be thoroughly air blown.

Shot blast or gritblast cleaning shall be free of silicon containing materials. Sandblasting will not be allowed. After cleaning, these surfaces shall be protected with a temporary water soluble coating of DuBois 910 or acceptable equal.

2F.5.4 Protection During Shipment. Open ends of shop fabricated piping shall be closed with suitable metal caps or wooden blind flanges securely attached to the piping to prevent their being dislodged during loading and unloading. All machined surfaces shall be coated with a rust-preventive compound of a type acceptable to the Engineer.

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PIPELINE LIST

POST COMBUSTION NOx REDUCTION

DRAWING ATTACHMENTS. The following drawing attachments are included as a part of this Pipeline List Drawing.

Document Number	Status	Description
16805-DM-9100 Sheets 1 thru 6 of 6	Rev. 0	Pipeline List Abbreviations
16805-DM-0102	Rev. 0	Field Butt Weld End Preparation Schedule Wall Thickness
16805-DM-0103	Rev. 0	Field Butt Weld End Preparation Schedule Wall Counterbore Diameters
16805-DM-8134 Sheets 1 of 1	Rev. 1	Pipeline List Computer Printout Post Combustion NOx Reduction

RODNEY I. UNRUH CERTIFICATE No. 28564 STATE OF FLORIDA REGISTERED ENGINEER

RELEASED FOR CONSTRUCTION
SIGNED J. C. Dawson DATE 10/7/92

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF FLORIDA.
SIGNED Rodney I. Unruh
DATE 9/30/92 REG NO. 28564

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
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1	8-11-92	CONTRACT ISSUE	MSA		KDM	

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ENGINEER KDM DRAWN MSA CHECKED DATE	PIPELINE LIST ABBREVIATIONS POST COMBUSTION NOx REDUCTION	CODE AREA	

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PIPELINE LIST ABBREVIATIONS

The following abbreviations are used in the attached Pipeline List.

Heading	List Entry	Description
PIPELINE ID NUMBER	2AAA-BBB-XXXX	Pipeline Identification Code with the format in accordance with the following.
		AAA System Code
		BBB Function Code
		XXXX Sequence Identifier
LINE DESCRIPTION		Pipeline Description
PRESSURES/ TEMPERATURES		
OPER/		Operating Pressure and Temperature
DSGN		Design Pressure and Temperature
TEST		Test Conditions
		Common abbreviations used as follows.
	P	lb/sq in, gauge
	A	lb/sq in, absolute
	W	in wg
	H	in Hg, absolute
	ATM	Atmosphere
	VAC	External pressure 15 psi
	ISLT	In-service leak test
	AMB	Ambient
	F	Fahrenheit

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PIPELINE LIST ABBREVIATIONS

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PROJECT 16805 - DRAWING NUMBER DM - 9100 REV 0

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SHEET 1 OF 6

Heading	List Entry	Description
PIPE		Pipeline Information Common abbreviations used as follows.
	CL	Class
	CM-LN	Cement-lined
	DI	Ductile Iron
	GR	Grade
	ID	Inside diameter
	LGR	Larger
	MW	Minimum wall
	NOM	Nominal pipe size
	RMK	Remark
	SCH	Schedule
	SMLR	Smaller
	SMLS	Seamless
	STD WT	Standard weight
	TP	Type
	XS	Extra strong
	XXS	Double extra strong
MATERIAL/		Piping Material Designation
NOMINAL SIZE (IN)		Nominal Pipe Size (inches)
SCH-MW		Piping Schedule, Minimum Wall, or Nominal Wall required for the corresponding piping size indicated under NOMINAL SIZE-IN.

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PIPELINE LIST ABBREVIATIONS

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Heading	List Entry	Description
VALVES		Valve Information
SIZE RANGE		
FROM		Minimum valve size for which valve information is applicable.
TO		Maximum valve size for which valve information is applicable.
CLASS	CL XXX	ANSI valve class
	XXX LB	UL working pressure
MATERIAL		Valve Body Material
	ALLOY 20	Alloy 20
	BRZ	Bronze
	CI	Cast iron
	CS	Carbon steel
	DI	Ductile iron
	IBBM	Iron body bronze mounted
	PVC	Polyvinylchloride
	SS	Stainless steel
	2-1/4 CR	2-1/4 percent chromium alloy steel
	5 CR	5 percent chromium alloy steel
END PREP		
	BTWLD	Butt-weld ends
	FLGD	Flanged ends
	LUG WFR	Lug wafer
	SCRD	Screwed ends
	SWLD	Socket-weld ends
	WAFER	Wafer

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Heading	List Entry	Description			
INSL CLS/		Piping Insulation Class designated as follows.			
			Insulation Thickness		
		Pipe Size inch	Inner Layer inch	Inner Layer inch	Total inch
	A	1-1/2 and smaller	2-1/2	--	2-1/2
		2 to 3	2	1-1/2	3-1/2
		4 to 8	2-1/2	2	4-1/2
		10 and larger	3	2-1/2	5-1/2
	B	1-1/2 and smaller	2-1/2	--	2-1/2
		2 to 3	1-1/2	1-1/2	3
		5 to 10	2	1-1/2	3-1/2
		12 and larger	3	2	5
	C	2 and smaller	1-1/2	--	1-1/2
		2-1/2 and larger	2-1/2	--	2-1/2
	D	2 and smaller	1 or Std	--	1 or Std
		2-1/2-10	1-1/2	--	1-1/2
		12 and larger	2-1/2	--	2-1/2
	D/H	Class D insulation for personnel protection.			
	H	1-1/2 and smaller	1/2	--	1/2
		2 and larger	1	--	1

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PROJECT 16805 - DRAWING NUMBER DM - 9100 REV 0

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PIPELINE LIST ABBREVIATIONS

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Heading	List Entry	Description				
WLDG CODE		Field Butt Welding and End Preparation requirements designated as follows.				
		GTAW Required (Note 1)	Backing Rings	Pipe Wall Thickness	End Prep Type	Butt Weld End Prep Drawing
	W-1	Yes	No	Min Wall	J	DM-0100
				SCH (greater than 3/8)	J	DM-0102 DM-0103
				SCH (less than or equal to 3/8)	V	DM-0102 DM-0103
	W-2	(Note 2)	No	SCH (greater than 3/8)	J	DM-0102 DM-0103
				SCH (less than or equal to 3/8)	V	DM-0102 DM-0103
	W-3	No	No	SCH (greater than 3/8)	J	DM-0102 DM-0103
				SCH (less than or equal to 3/8)	V	DM-0102 DM-0103
	W-4	No	Opt	SCH (greater than 3/8)	J	DM-0102 DM-0103
				SCH (less than or equal to 3/8)	V	DM-0102 DM-0103

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PIPELINE LIST ABBREVIATIONS

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SHEET 5 OF 6

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Heading	List Entry	Description

GTAW Required (Note 1)	Backing Rings	Pipe Wall Thickness	End Prep Type	Butt Weld End Prep Drawing
Yes	No	Min Wall	V	DM-0101

List Entry: W-5

Notes:

1. For piping that requires Gas Tungsten Arc Welding (GTAW), the GTAW process shall be used for the first pass.

2. The first pass welding process for all materials except carbon steel shall be gas tungsten arc welding.

   The first pass welding process for carbon steel materials shall be one of the following.

   - Gas Tungsten Arc Welding.
   - Shielding Metal Arc Welding using either E6010 or E7010 Electrodes with Open Butt Root Pass.

Heading	Description
FLUID FOR INSTR SEL/	Process Fluid for instrument selection.
PIPELINE FEATURES	Special Piping Design Requirements or Features.

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PIPELINE LIST ABBREVIATIONS

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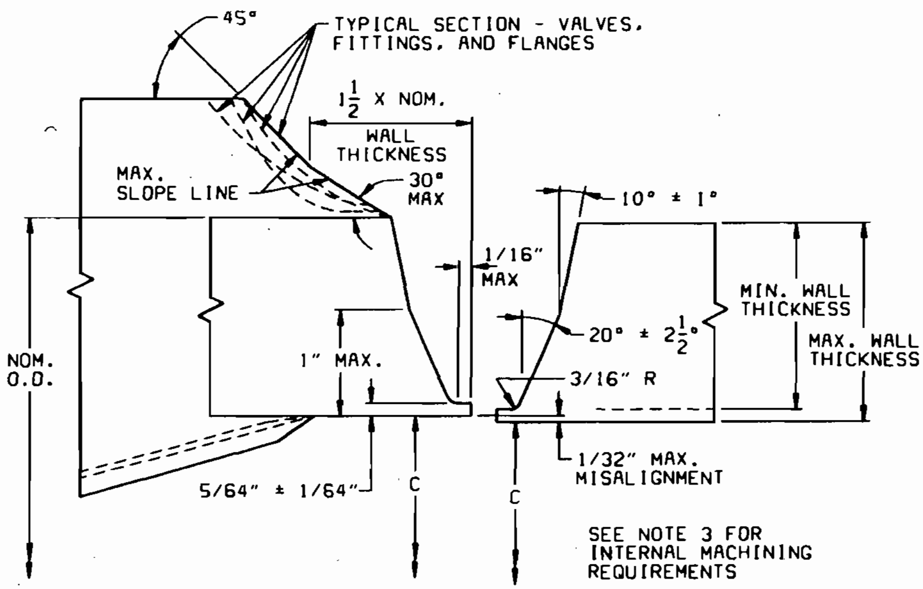
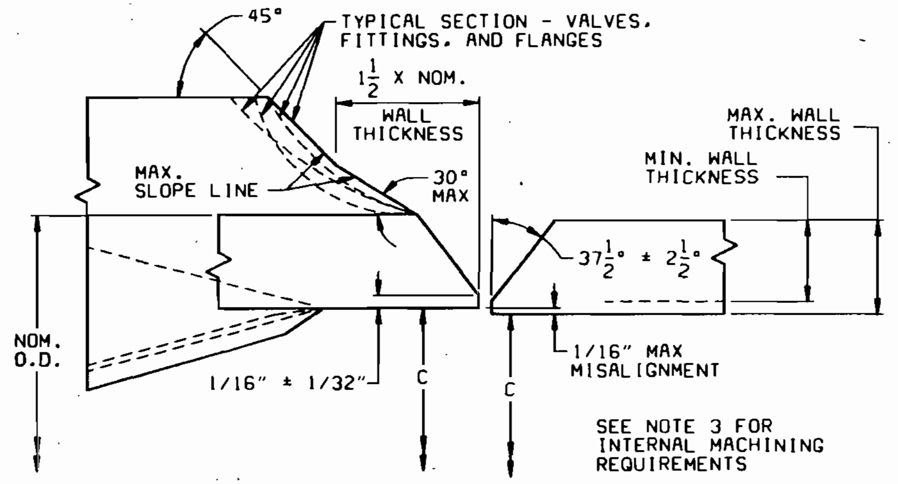


"J" BEVEL - NOMINAL WALL THICKNESS GREATER THAN 3/8"



"V" BEVEL - NOMINAL WALL THICKNESS GREATER THAN 1/8" TO 3/8" INCLUSIVE

NOTE:

1. ALL FIELD WELDS FOR PIPING, VALVES, FITTINGS, ETC. MUST HAVE WELD-ENDS MACHINED TO MEET THE REQUIREMENTS DESCRIBED BY THIS DETAIL. THE EXCEPTION IS PIPE TO PIPE FIELD WELDS WHEN BOTH WELD-ENDS ARE PREPARED BY THE SAME FABRICATOR. SUCH WELD-ENDS MUST MEET ALL CONDITIONS DESCRIBED EXCEPT ADHERENCE TO I.D. REQUIREMENT IS NOT REQUIRED IF 1/16" MAXIMUM I.D. DIFFERENCE IN WELD-ENDS IS MAINTAINED.

2. IF METAL MUST BE REMOVED TO MEET I.D. REQUIREMENT THE PIPE WALL THICKNESS MUST BE CHECKED TO ASSURE NO ENCROACHMENT ON MINIMUM WALL.

3. IF INTERNAL MACHINING IS REQUIRED TO MEET I.D. REQUIREMENTS TABULATED ON STANDARD DETAIL DRAWING DM-0103, THE DEPTH AND CONTOURS ASSOCIATED WITH SUCH MACHINING MUST MEET THE REQUIREMENTS OF PFI ES-21 FOR THE "J" BEVEL JOINT AND ANSI B16.25 FOR THE "V" BEVEL JOINT.

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ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2

FIELD BUTT WELD END PREPARATION
SCHEDULE WALL THICKNESS

PROJECT	DRAWING NUMBER	REV
16805	DM-0102	0

CODE

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PIPE SIZE	SCH	COUNTERBORE DIAMETER "C" MINIMUM	COUNTERBORE DIAMETER "C" MAXIMUM
2 1/2	40	2.439	2.489
	80	2.311	2.361
	160	2.138	2.188
	XXS	1.828	1.878
3	40	3.041	3.091
	80	2.894	2.944
	160	2.653	2.703
	XXS	2.369	2.419
4	40	4.004	4.054
	80	3.829	3.879
	120	3.653	3.703
	160	3.490	3.540
	XXS	3.240	3.290
5	40	5.031	5.081
	80	4.826	4.876
	120	4.607	4.657
	160	4.388	4.438
	XXS	4.170	4.220
6	40	6.054	6.104
	80	5.788	5.838
	120	5.561	5.611
	160	5.286	5.336
	XXS	5.032	5.082
8	20	8.107	8.157
	30	8.059	8.109
	40	7.981	8.031
	60	7.834	7.884
	80	7.669	7.719
	100	7.505	7.555
	120	7.286	7.336
	140	7.123	7.173
	XXS	7.013	7.063
	160	6.959	7.009

PIPE SIZE	SCH	COUNTERBORE DIAMETER "C" MINIMUM	COUNTERBORE DIAMETER "C" MAXIMUM
10	20	10.232	10.282
	30	10.132	10.182
	40	10.030	10.080
	60	9.794	9.844
	80	9.630	9.680
	100	9.411	9.461
	120	9.192	9.242
	140	8.919	8.969
	160	8.700	8.750
12	20	12.232	12.282
	30	12.092	12.142
	STD	12.013	12.063
	40	11.959	12.009
	XS	11.794	11.844
	60	11.686	11.736
	80	11.465	11.515
	100	11.192	11.242
	120	10.919	10.969
	140	10.700	10.750
	160	10.373	10.423
14	10	13.482	13.532
	20	13.373	13.423
	30	13.263	13.313
	40	13.153	13.203
	XS	13.044	13.094
	60	12.880	12.930
	80	12.607	12.657
	100	12.278	12.328
	120	12.005	12.055
	140	11.732	11.782
	160	11.459	11.509

PIPE SIZE	SCH	COUNTERBORE DIAMETER "C" MINIMUM	COUNTERBORE DIAMETER "C" MAXIMUM
16	10	15.482	15.532
	20	15.373	15.423
	30	15.263	15.313
	40	15.044	15.094
	60	14.771	14.821
	80	14.442	14.492
	100	14.115	14.165
	120	13.786	13.836
	140	13.403	13.453
	160	13.130	13.180
18	10	17.482	17.532
	20	17.373	17.423
	STD	17.263	17.313
	30	17.153	17.203
	XS	17.044	17.094
	40	16.936	16.986
	60	16.607	16.657
	80	16.278	16.328
	100	15.896	15.946
	120	15.513	15.563
	140	15.186	15.236
	160	14.802	14.852
20	10	19.482	19.532
	20	19.263	19.313
	30	19.044	19.094
	40	18.880	18.930
	60	18.498	18.548
	80	18.115	18.165
	100	17.677	17.727
	120	17.294	17.344
	140	16.857	16.907
	160	16.473	16.523

PIPE SIZE	SCH	COUNTERBORE DIAMETER "C" MINIMUM	COUNTERBORE DIAMETER "C" MAXIMUM
22	10	21.482	21.532
	20	21.263	21.313
	30	21.044	21.094
	60	20.388	20.438
	80	19.950	20.000
	100	19.513	19.563
	120	19.075	19.125
	140	18.638	18.688
	160	18.200	18.250
24	10	23.482	23.532
	20	23.263	23.313
	XS	23.044	23.094
	30	22.936	22.986
	40	22.715	22.765
	60	22.223	22.273
	80	21.786	21.836
	100	21.240	21.290
	120	20.748	20.798
	140	20.311	30.361
	160	19.817	19.867
26	10	25.373	25.423
	STD	25.263	25.313
	20	25.044	25.094
28	10	27.373	27.423
	STD	27.263	27.313
	20	27.044	27.094
	30	26.825	26.875
30	10	29.373	29.423
	STD	29.263	29.313
	20	29.044	29.094
	30	28.825	28.875

PIPE SIZE	SCH	COUNTERBORE DIAMETER "C" MINIMUM	COUNTERBORE DIAMETER "C" MAXIMUM
32	10	31.373	31.423
	STD	31.263	31.313
	20	31.044	31.094
	30	30.825	30.875
	40	30.715	30.765
34	10	33.373	33.423
	STD	33.263	33.313
	20	33.044	33.094
	30	32.825	32.875
	40	32.715	32.765
36	10	35.373	35.423
	STD	35.263	35.313
	20	35.044	35.094
	30	34.825	34.875
	40	34.607	34.657
38	STD	37.263	37.313
	XS	37.044	37.094
40	STD	39.263	39.313
	XS	39.044	39.094
42	STD	41.263	41.313
	XS	41.044	41.094
44	STD	43.263	43.313
	XS	43.044	43.094
46	STD	45.263	45.313
	XS	45.044	45.094
48	STD	47.263	47.313
	XS	47.044	47.094

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLM
0	04-22-83	INITIAL ISSUE	AGG	HKK	LET	

BLACK & VEATCH

ENGINEER LET · DRAWN AGG · CHECKED HKK · DATE 04-22-83

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2

FIELD BUTT WELD END PREPARATION
SCHEDULE WALL COUNTERBORE DIAMETERS

PROJECT 16805 - DRAWING NUMBER DM-0103 · REV 0

CODE
AREA

07762LOPEZ ACAD 10 c7
A01SL003 B1 1=1
09/06/91 14:37:34

SYS CODE: CCF SYS NAME: NOX REDUCTION

PIPELINE ID NUMBER	LINE DESCRIPTION	PRESSURES/TEMPERATURES OPER/DSGN	TEST	PIPE MATERIAL/NOMINAL SIZE (IN)	SCH-MW	VALVES SIZE RANGE FROM	TO	TYP	CLASS	MATERIAL/END PREP	INSL CLS/WLDG CODE	FLUID FOR INSTRUMENT SEL/PIPELINE FEATURES
2CCF- L-A	AMMONIA STORAGE AREA PIPING		400P	A106 GR B		0.5	2.0		600	CS	I	
										SWLD	W-4	AMMONIA GAS.
		265P		2.5 THRU 4	40	2.5	4.0		600	CS		HYDRO TEST WITH
		150F		0.5 THRU 2	80					BTWLD STD		SERVICE WATER.
2CCF- L-ZZ	MANUFACTURER'S PIPING			MANUFACTURERS PIPING MATERIAL								

Section 2G - VALVES

2G.1 GENERAL. This section covers the requirements for automatic, control, special, and general service valves to be used in the NO_x Reduction System. As a minimum, all numbered valves indicated on the flow diagrams shall be furnished by the Contractor.

2G.1.1 Valve Identification. Each valve shall be provided with a permanent stainless steel tag securely attached to the valve with 0.050 inch diameter stainless steel wire. The tags shall be stamped with the prefix and valve numbers corresponding to those given on the flow diagrams. Each accessory item furnished with the valve, but not securely attached to the valve, shall be provided with an identical identification tag. Drawings and correspondence referring to a valve or valves shall use the same valve identification number for reference.

2G.1.2 Code Requirements. Valves shall be designed and constructed in accordance with the latest applicable requirements of the Valve Manufacturer's Association, the ASME Code for Pressure Piping, ASME B31.1-89 and all addenda thereto through and including B31.1-1989 as issued January 31, 1990, and ASME Boiler and Pressure Vessel Code, Section VIII-1989, including the winter 1989 addenda, except where modified or supplemented by these specifications.

Except as otherwise specified, steel body valves shall be constructed in accordance with the latest applicable requirements of ANSI/ASME B16.34 for butt weld end valves and ANSI/ASME B16.5 for flanged valves; and shall be designed using stress values which do not exceed the maximum allowable stresses specified in the ASME Boiler and Pressure Vessel Code.

Flanged and butt weld valves shall have face-to-face and end-to-end dimensions which conform to the latest requirements of ANSI/ASME B16.10.

Valves furnished for use in ammonia applications shall be suitable for the service.

2G.2 AUTOMATIC VALVES. Automatic valves shall be provided in locations as indicated on the flow diagrams to provide for the automatic operation of the system and its component parts. Air operated valves shall be equipped with stem position indicators and with the required air chambers, adjustable orifices, and other devices to produce slow opening and closing operation to prevent water hammer.

2G.2.1 Automatic Shutoff Valves. Valves of the type indicated on the flow diagrams shall be furnished for the system.

The valve manufacturer shall be responsible for properly mounting the valve operators and limit switches on the valves.

2G.2.2 Control Valves. Control valves and accessories shall comply with the Control Valve Specification Sheets included at the end of this section. In addition to the control valves shown on the flow diagrams, the Contractor shall furnish all other control valves required for operation of the NO_x Reduction System. The control valves, operators, controllers, positioners, and filter-pressure regulators shall be as manufactured by the Fisher Controls Company.

All control valves shall be furnished with pneumatic spring opposed diaphragm operators. Diaphragm operators shall be Fisher Controls Model 667, or acceptable equal. Valve operators specified on the Control Valve Specification Sheets with valve action spring "open" or "closed" shall be provided with a mechanical spring to fully open or close the valve as applicable on loss of air pressure.

Valve operators and stems shall be adequate to handle the unbalanced forces occurring under the specified flow conditions or the maximum differential pressure specified. An adequate allowance of stem force, at least equivalent to 50 pounds per lineal inch of seating surface, shall be provided in the selection of the operator to assure tight seating unless otherwise specified. The operators shall be designed to produce the required stem force with supply air pressures not required to be greater than 45 psig.

Diaphragms shall be molded rubber and diaphragm housings shall be of pressed steel construction.

Operators shall be supplied with nameplates which indicate the air pressures at full open and full closed positions. The pressures shall be listed for maximum differential and for zero differential across the valve.

2G.2.3 Valve Air Supply. Instrument quality air will be supplied by the Owner. Air pressure will vary within the range indicated in Section 1B.

2G.2.4 Gaskets. Three sets of gaskets shall be furnished for each control valve: one set to be installed and two spare sets.

2G.3 MANUAL VALVES. Type, construction, and materials for manual general service valves shall be as specified in the Pipeline List. The valves shall be provided as indicated on the flow diagrams.

Type 316 stainless steel ball valves shall be Powell Figure 2490A-SWE, or acceptable equal, with socket-weld ends.

Solenoid valves shall be as specified in Section 1B.

Nonstainless steel valves shall be painted in accordance with the requirements of Section 1B.

CONTROL VALVE SPECIFICATION SHEET

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER, UNIT 2
B&V PROJECT 16805

VALVE DESCRIPTION

Piping & Instrument Diagram 16805-DM-1053A Number Required 2 Valve Tag(s) Later
Service Ammonia Control Valve

Fluid Ammonia Vapor Sp Gr -- Viscosity --

VALVE DESIGN

	DESIGN	LOW	OTHER
Flow Rate	As Required		
Inlet Pressure	Ammonia Vaporizer		
Inlet Temperature			
Outlet Pressure			
Percent Travel Preferred	20 percent to 70 percent		
Predicted			
Inner Valve Type	Tight shutoff, single port, linear characteristics		

Maximum Differential Pressure ______ Maximum Temperature ______

VALVE CONSTRUCTION

BODY

Body Type Fisher EZ or acceptable equal
Body Pressure Class CL 600
Body Material Forged Steel
Body Ends Socket
Guide Location

Cooling Fins No
Body Size

Mfr to Recommend X
Preferred: Inlet
Outlet

MATERIALS

Plug 416 SS
Seat Ring TFE
Cage --
Guides --
Stem 316 SS

Disk --
Seat 316 SS

Packing Teflon V-Ring

VALVE OPERATOR

Type Pneumatic Diaphragn
Signal Range 6-30 psig
Valve Action
Flow Opening
Spring Closing
Signal Increase Opens

OPERATOR ACCESSORIES

Positioner Yes 4-20 mA input
Limit Switches Open --
Closed
Handjack Yes Stops
Solenoid --
Other --

CONTROLLER

PRESSURE

Type --
Adj Range --
Max Press --
Mounting --
Sig Range --
Reset or Rate --

TEMPERATURE

Type --
Adj Range --
Max Press/Temp --
Mounting --
Capillary Lgth --
Pipe Conn --

LEVEL

Type Electric
Adj Range --
Cage Conn --
Press Class --
Sig Range 4-20 mA
Cooling Ext --
Gage Glasses --
Reset or Rate --

VALVE FEATURES

The control valve shall be furnished complete with stainless steel pressure tubing and isolation valve, Fisher Type 67 AFR yoke mounted air supply filter - regulator, with outlet gauge all factory assembled and mounted. Control signal is 4-20 mA from Owner-furnished DCIS.

CONTROL VALVE SPECIFICATION SHEET

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER, UNIT 2
B&V PROJECT 16805

VALVE DESCRIPTION

Piping & Instrument Diagram 16805-DM-1053B Number Required 2 Valve Tag(s) Later
Service Ammonia Pressure Regulator

Fluid Ammonia Vapor Sp Gr -- Viscosity --

VALVE DESIGN

	DESIGN	LOW	OTHER
Flow Rate	As Required		
Inlet Pressure	Ammonia Vaporizer		
Inlet Temperature			
Outlet Pressure			
Percent Travel Preferred	20 percent to 70 percent		
Predicted			
Inner Valve Type	Self-contained, self-operated, pressure reducing valve		

Maximum Differential Pressure ______ Maximum Temperature ______

VALVE CONSTRUCTION

BODY

Body Type Fisher 95 H or acceptable equal
Body Pressure Class CL 600
Body Material Forged Steel
Body Ends Screwed
Guide Location

Cooling Fins No
Body Size

Mfr to Recommend X
Preferred: Inlet
Outlet

MATERIALS

Plug 416 SS
Seat Ring TFE
Cage --
Guides --
Stem 316 SS

Disk --
Seat --

Packing Teflon V-Ring

VALVE OPERATOR

Type Self-contained
Signal Range
Valve Action
Flow
Spring Closing
Signal Increase

OPERATOR ACCESSORIES

Positioner --
Limit Switches Open --
Closed
Handjack ______ Stops ______
Solenoid --
Other --

CONTROLLER

PRESSURE

Type --
Adj Range --
Max Press --
Mounting --
Sig Range --
Reset or Rate --

TEMPERATURE

Type --
Adj Range --
Max Press/Temp --
Mounting --
Capillary Lgth --
Pipe Conn --

LEVEL

Type --
Adj Range --
Cage Conn --
Press Class --
Sig Range --
Cooling Ext --
Gage Glasses --
Reset or Rate --

VALVE FEATURES

Section 2H - DUCTWORK AND EXPANSION JOINTS

2H.1 GENERAL. Flue gas ductwork, supports and hangers, gas distribution devices, test ports, and instrument connections required for the NO_x Reduction System furnished under these specifications shall be furnished as indicated on the drawings included herein.

Ductwork to be furnished includes all ductwork identified on the drawings included with these specifications as being within the limits of the Contractor's scope of supply.

A model test shall be conducted as specified in Section 2A.

2H.2 ARRANGEMENT. The ductwork shall be arranged as required by the NO_x Reduction System design, model tests, accessibility for monitoring and testing, space utilization and appearance considerations. Unless otherwise accepted by the Engineer, ductwork shall be arranged as indicated on the drawings included herein.

Final ductwork arrangement shall be based on the model test results.

2H.3 DESIGN CRITERIA. Ductwork shall be designed in accordance with the following criteria.

Maximum gas velocity for design flow commensurate with operation at maximum continuous rating of the steam generator as specified in Section 2A	3,000 fpm
Wind load	100 mph
Seismic load	As specified in Section 2A
Insulation load	5 psf
Dust load, floor surface	85 psf
Live load, where applicable	75 psf
Minimum design pressure	
At allowable design stress at continuous operating temperature or maximum transient temperature if applicable	As specified in Section 2A

At yield stress at continuous operating temperature	As specified in Section 2A

Minimum design vacuum

At allowable design stress at continuous operating temperature or maximum transient temperature if applicable	As specified in Section 2A
At yield stress at continuous operating temperature	As specified in Section 2A

Design temperature	Continuous Operating	Maximum Transient
SCR reactor module	As specified in Section 2A	As specified in Section 2A

The maximum transient temperature excursion shall be assumed to have a duration of 30 minutes.

Maximum allowable stresses in the materials shall be in accordance with the AISC Manual, Ninth Edition and its commentary. The value of F_y for material for the design of the ductwork and internal bracing and trusses shall be the 0.2 per cent offset yield strength at the design temperature.

The Contractor's ductwork design calculations shall be available for the Owner's review at the Contractor's facilities. Upon the Owner's request, the Contractor will provide ductwork design calculations for specific components when necessary to resolve a problem.

2H.4 MATERIALS. All materials shall be new and undamaged and shall conform to pertinent AISC and ASTM standard specifications and the following requirements.

Ductwork plates and shapes exposed to flue gas	ASTM A588
External stiffeners not exposed to flue gas	ASTM A588

Steel pipe for interior stiffeners	ASTM A588 Schedule 80 minimum
Shop bolts	ASTM A325
Field bolts	ASTM A325
Expansion joint bolts	IFI-104, Grade 303-A 303-A or 305

2H.5 CONSTRUCTION REQUIREMENTS. All ductwork and gas distribution devices shall be constructed of steel plate not less than 1/4 inch thick. The thickness shall include a minimum of 1/16 inch for corrosion allowance and will be properly stiffened to structurally withstand the specified design pressures for a plate thickness of 3/16 inch.

Internal duct bracing and trusses shall be provided at intervals of approximately 20 feet and shall be constructed of steel pipe with wall thickness sized for the design stresses.

Ductwork shall be designed to prevent pulsations and noise generation.

Gas distribution and mixing devices shall be provided with stiffeners and supports and shall be designed to preclude vibration or flutter in the gas stream under all specified flow conditions. The devices shall be bolted to the ductwork such that they are removable.

External duct stiffeners shall utilize shapes of the same depth to facilitate installation of insulation and lagging. Fabricated shapes made from plates may be substituted for rolled shapes if the properties of the fabricated shapes are equivalent to or better than the rolled shapes.

Access doors shall be provided to permit access to all ductwork sections and between all major items of equipment. The doors shall be not less than 18 inches by 24 inches in size, gastight, with bolted closure.

Ductwork shall be of all welded construction except as specified otherwise herein.

All ductwork materials and accessories shall be shop seal welded with field bolting fit-up and seal welding construction except where bolted connections are indicated on the Contractor's drawings and accepted by the Engineer and shall be shop fabricated subject to shipping limitations.

Where field fit-up and seal welding are required, joints shall be constructed such that the overlap shall be in the direction of the gas flow and the seal weld shall be done on the gas side.

The ductwork shall be fabricated in shipping units. Shipping units shall be designed to require a minimum of field welding within the limits of shipping requirements. Temporary braces and stiffeners shall be installed as required to maintain the true shape of all components during shipping.

Permanent internal bracing and trusses shall be installed in the shop and provisions shall be made for field connection of the bracing and trusses between ductwork sections, where required, by welding.

Fabrication tolerances shall be controlled to permit the ductwork to be erected within the specified erection tolerances. At joints, each edge shall match the adjoining edge in all dimensions within a tolerance of 1/8 inch. Edges and corners which do not fit up within this tolerance shall be reworked or replaced.

2H.6 WELDING. Except as otherwise specified, all shop welding and related operations for the ductwork shall be in accordance with the requirements of Section 1W.

All welded joints exposed in exterior locations or subject to submergence in any location shall be provided with seal welds along all contact edges.

All interior seams and joints of the ductwork shall be seal welded.

2H.7 EXPANSION JOINTS. Leakproof expansion joints shall be provided as required and approved by the Engineer to prevent deformation or failure of structures or equipment as a result of thermal expansion. All expansion joints for ductwork provided under these specifications shall be provided. The expansion joints at the interface of Owner-furnished ductwork with Contractor-furnished ductwork will be provided by the Owner.

#Joints shall be fabricated of corrosion-resistant steel conforming to ASTM A588. Expansion joints shall be designed so that they will not pack with ash and dirt deposits.

#

The decision regarding the design (metallic or nonmetallic) of the expansion joints shall be agreed between the Contractor and Engineer no later than September 1, 1992.

#Addendum 2
Contract Revision

~~Expansion joints shall be sized and designed by the manufacturer of the joints to meet the conditions specified and the arrangement of the duct-work with respect to expansion, contraction and offsets. Each joint shall be sized to accommodate all anticipated ductwork movements without stretching or tearing the joint. Design movements at each joint and drawings of the expansion joints shall be submitted to the Engineer in accordance with the requirements of Section 1C.~~

~~Holes for bolting expansion joints to equipment or ductwork furnished by the Contractor shall be shop drilled and punched.~~

#Addendum 2

#~~2H.7.1 Flexible Expansion Joints. Expansion joints shall be of the flexible belt type designed for the conditions specified in this section and Section 2A.~~

~~The expansion joint belt shall be designed to provide completely sealed sides and shall have no stitching exposed outside the area clamped under the backup bars.~~

~~The manufacturer shall provide a certificate of conformance to these specifications for materials and fabrication. Acceptable manufacturers for the expansion joints are as follows.~~

~~Flow-Flex Engineering Company~~
~~Garlock Incorporated~~
~~Holz Rubber Company~~
~~Pathway Bellows, Inc.~~
~~RM Engineered Products, Inc.~~

~~Low temperature expansion joints shall be constructed of a single sheet not less than 1/4 inch thick consisting of fluoroelastomer and two plies of 35 ounces per square yard plain woven fiberglass cloth.~~

~~The fluoroelastomer shall conform to ASTM D 2000 2HK 715 Z1 containing not less than 70 per cent Du Pont Viton B Polymer. Reclaimed elastomers shall not be used.~~

~~Rounded corners shall be provided in the expansion joints. Splices will not be acceptable in the rounded corners.~~

#2H.8 DUCTWORK SUPPORT. Ductwork ~~may~~ ***shall*** be ~~top supported or~~ bottom supported ~~as required by the Contractor's design~~. Ductwork support shall be in accordance with the following criteria.

~~2H.8.1 Top Supported Ductwork. All necessary hanger assemblies and miscellaneous hanger steel including suitable welding brackets for attachment to the structural support framework shall be furnished. Special attention shall be given to hangers around transition sections, openings and access doors. Hanger assemblies shall be designed for clean appearance. Structural steel angle hangers and brackets shall not be used.~~

~~Hanger rods shall be ASTM A36 steel. The allowable working stress in the hanger rods shall not exceed 9000 psi. Loads to the hanger rods shall take into consideration all ductwork loads including dead load, dust load, live load, snow load, wind load and earthquake loads and any bending stresses introduced during expansion, contraction or offset movements of the ductwork.~~

~~The safety factors allowed for the design of hanger clevises and turnbuckles shall be at least those specified for the hanger rods. Turnbuckles and clevises shall be of forged steel with safe working loads and minimum dimensions as described in the AISC Manual, Ninth Edition.~~

#Addendum 2

#~~Constant or variable spring load hangers may be utilized by the Contractor; however, variable spring hangers will be allowed only with the specific acceptance of the Engineer. Spring hangers shall be VS or CS type as manufactured by Grinnell or Basic Engineering or shall be an acceptable equal hanger.~~

~~2H.8.2 Bottom Supported Ductwork.~~ The ductwork shall be provided with column extensions or stubs to project from the ductwork to the structural support framework.

The Contractor shall provide Merriman "Lubrite" or acceptable equal expansion bearing assemblies for installation between the ductwork free support points and the support structure. Flat expansion plates, radius plates or spherical plates shall be provided as required for the application. All necessary bearing plates and anchorages shall be provided by the Contractor such that the interface between the ductwork stub columns and the tops of the structural support framework columns is a steel plate to steel plate connection requiring only a field weld.

2H.9 ACCESS PROVISIONS. Exterior access provisions necessary to provide complete and convenient access to the ductwork and expansion joints will be provided under separate specifications. Provisions will be made for access to the top (roof) of all horizontal ductwork for inspection and maintenance of flexible expansion joints.

#~~The Contractor shall furnish handrailing for the top (roof) of ductwork. The handrailing shall extend above the insulation and lagging surface to accommodate a slope for drainage of 1/2 inch per foot from the center line of the duct to the vertical duct face.~~

Interior steps or ladders shall be provided by the Contractor where location of inspection doors will not permit access to all areas of the ductwork interior for inspection or maintenance except by ascending or descending inclined ductwork surfaces. Interior handrail shall be provided in all areas where a falling hazard may be present.

Access provisions shall be adequate for all operation, inspection, testing and maintenance activities.

The Contractor-furnished access provisions shall be designed and fabricated as specified in Section 2J and herein.

2H.10 TEST PORTS. Test ports to obtain samples required to conduct the performance tests specified in Section 2B shall be provided at locations acceptable to the Engineer and in accordance with the recommendations derived from the model tests.

Test ports required for flow traversing of ductwork to verify flow model and adjust ammonia injection grid branch flow shall be provided. Test port location shall consider ductwork configuration and accessibility for testing and use of test equipment.

#Addendum 2

2H.11 <u>INSTRUMENT CONNECTIONS</u>. Instrument connections shall be provided as required to permit installation of instrumentation sensing devices required to monitor and control the operation of the NO_x Reduction System in accordance with the requirements of Section 2K.

2H.12 <u>PAINTING</u>. Protective coatings for auxiliary items such as hangers and miscellaneous steel which will be visible after installation shall be in accordance with the requirements of Section 1B.

Ductwork which is to be covered by insulation and lagging shall also be prime painted as specified in Section 1B.

Section 2I - DUCTWORK DAMPERS

2I.1 GENERAL. This section covers the construction requirements for the dampers.

Dampers shall be constructed to withstand the differential pressures encountered when operating under the conditions specified in Section 2A.

All parts shall be serviceable without removing the damper frames from the ductwork.

Dampers shall be provided with a mechanical lockout for use when personnel access to equipment is necessary.

Dampers shall be considered as structural members, and as such shall be designed in accordance with the applicable provisions of the AISC and as specified herein.

> Allowable bending stress in any component shall not exceed 60 percent of yield at design conditions.
>
> The combined axial compressive and bending stress shall not exceed 60 percent of yield at design conditions.
>
> Deflection of frame components shall not exceed the length of the component divided by 360 (L/360).
>
> Damper blade deflection at the maximum design differential pressure across the damper shall be such that it does not interfere with damper operation or sealing capability.

Dampers shall be constructed such that flue gas cannot leak to the atmosphere.

All austenitic stainless steels and high nickel alloy shall be protected with rub blocks in such a way as to avoid contact with steel alloys or free iron.

Dampers shall be manufactured by one of the following manufacturers.

Air Clean Damper Co.
Bachman Industries Inc.
Damper Design Inc.
Effox Inc.
Mosser Damper Co.

All welding shall be in accordance with the requirements of Section 1W.

2I.2 LOUVER DAMPERS. Louver dampers shall be of the parallel blade type.

The damper net areas shall approach, to the maximum extent practical, the inside area of the duct cross section.

2I.2.1 Materials. Dampers shall be constructed of corrosion- and erosion-resistant materials which are equivalent to the following.

SCR Inlet Dampers and Bypass Dampers

Frame	ASTM A588
Blade skin	ASTM A588
Axles	Carbon steel (ASTM A106) if pipe shaft axle; stainless steel (Carpenter Custom 450 or other acceptable stainless steel in accordance with ASTM A564) if solid shaft axle; ASTM A588 if structural shape axle
Axle stub ends	Stainless steel (Carpenter Custom 450 or other acceptable stainless steel in accordance with ASTM A564)
Seals	ASTM B575, Alloy C-276
Seal retainers	ASTM A588
Shop and field bolts for structural connections	ASTM A325, Type 1 bolts, nuts, washers and load indicator washers; 7/8 inch diameter. Install in accordance with manufacturer's written instructions

2I.2.2 Frames. Damper frames shall be fabricated of heavy rolled structural steel shapes or heavy formed plates, or a combination thereof.

Frame designs which use center mullions in the flue gas stream are not acceptable.

Frames shall be rigid and shall be capable of operating under the design conditions without distortion which could affect the operating or leakage characteristics. Damper frames shall be self-supporting structural members not requiring exterior bracing. If required, adjustable alignment bars shall be provided to remove misalignment occurring during shipment and installation. A steel support member shall be furnished between the top and bottom sections of the bypass inlet dampers as required to maintain frame rigidity and provide for independent blade edge-to-frame sealing for the two damper sections. The support members shall be of the same material as the remainder of the damper frame.

Damper frame flange-to-flange dimension shall be equal to or greater than total blade width including seals.

Frames shall be completely welded assemblies and shall be flanged for fit-up bolting and seal welding to the flanges of the ductwork or expansion joint. Bolt hole pattern for all dampers shall be 3/4 inch holes at 1'-6" maximum center-to-center spacing. Frames shall include mounting brackets for control drives and actuators furnished under these specifications.

Damper frame section and thickness shall be determined on the basis of stresses resulting from transit and handling abuse; any combination of pressure, temperature, wind; effects of corrosion and erosion; and the physical size and weight of the damper. Stress at the weakest section of the frame shall not exceed the levels specified in the AISC manual for complete structural members. Minimum thickness shall be 1/2 inch.

Bearing mounting brackets, shaft packing boxes, blade stops, seal strips, alignment bars, and actuator mounting brackets shall be welded to the frame. Continuous welds shall be provided where necessary to prevent flue gas leakage or where required for strength.

Integral lifting lugs shall be provided on the damper frames.

2I.2.3 Blades and Axles. Damper blades shall be horizontal and shall be of the airfoil type. Airfoil blades shall be of bolted or welded construction. Blade edges shall be through bolted or welded. Hemmed blade construction in which one blade skin is folded over the other is not permitted. The blade skin shall be attached to a solid shaft or other suitable axle member which extends the full length of the blade. Stressed skin blade design with stub axles may be provided in lieu of through member axles. Complete calculations illustrating blade stiffness shall be submitted. Techniques for eliminating blade warpage in welded blade construction shall be submitted. Axles shall be provided with machined ends for packing box penetration and support of the blades in the bearings. Welded blade construction shall be provided. The blades shall be suitably reinforced to prevent flutter or vibration.

The blade skin and axle shall have compatible coefficients of thermal expansion. Provisions shall be made to accommodate differential thermal expansion without warping or buckling. The blade ends shall be closed to prevent accumulation of dust or moisture.

Collars shall be provided on the blade axles to fix the blade position relative to the frame on one end and permit controlled expansion of the blade toward the opposite end of the frame. The design shall not be dependent upon maintenance of thermal equilibrium between the blades and frame to maintain the proper clearances.

Axles shall be capable of transmitting full required operating torque without exceeding 33-1/3 percent of the shear yield stress and operator stall torque without exceeding 45 percent of the shear yield stress.

Damper blades shall not exceed 30 inches in width. Dampers shall not block more than 25 percent of the available duct area when in the open position.

Blade stops if required shall be provided as part of the blade linkage assembly for both the open and closed positions. Blade stops shall not be installed internal to the ductwork.

Blade deflection shall be limited as required by the bearing and shaft packing box design but in no case shall deflection at the center of the span exceed 1/4 inch at any operating condition.

Blade axle stub ends shall be pinned or through-bolted to the axle to permit blades to be removed for replacement or repair without removal of the damper frame from the ductwork. The blade axle stub ends and pins or bolting shall be stainless steel as a minimum.

2I.2.4 Bearings. Dampers shall be provided with blade support bearings mounted externally to the flue gas stream and with packing boxes to prevent air or gas leakage through the casings.

Blade support bearings shall be of the self-aligning, sleeve type. Bearings shall be constructed of self-lubricating material suitable for the temperature requirements. All parts of the bearing which contact the blade shaft shall be of noncorrosive materials.

2I.2.5 Linkages. Damper interconnecting linkages and operating levers shall be of heavy-duty construction and shall be fitted with heavy pin connections using closefitting hardened pins in reamed holes. The blade linkage shall permit no independent action of a blade. Single shear type connections shall not be used. All linkage bolts and pins shall be stainless steel or an acceptable or equal material.

At normal torque switch setting for the actuator, all component parts in the linkage shall be rated at 200 percent of actuator torque output. For actuator stall condition, the combined stress in any linkage component, under worst case condition, shall not exceed 75 percent of yield strength. No component shall be loaded in excess of 75 percent of the critical buckling load at stall condition. Components with pins or bushings shall not be loaded in excess of 75 percent of the manufacturer's allowable rating of the component at the actuator stall condition.

Each damper shall be provided with a position indicator and a position lock.

2I.2.6 Sealing System. Packing boxes suitable for all pressure and vacuum conditions specified in Section 2A shall be provided on each end of each shaft. Packing boxes shall be welded to the frames. Shaft deflection at the midpoint of the packing shall not exceed 75 percent of the packing manufacturer's recommended maximum operating deflection. Packing shall contain no corrosive materials and shall be designed so that packing may be easily replaced without removing bearings and linkage. High temperature shaft packing for all louver dampers shall be furnished. Packing boxes shall be provided with followers which are adjustable by means of threaded studs and nuts or other arrangement which is not susceptible to exposure to flue gas. Threaded type packing followers shall not be used.

Dampers shall be provided with seals between blade ends and side frame members, seals between blade edges and top and bottom frame members, and blade edge-to-edge seals.

2I.3 MODULATING DAMPER DRIVES. Louver damper motor operators shall be direct coupled to the blade drive shaft and shall actuate blades by means of interconnecting linkages and levers.

#Damper drives shall ~~meet the guaranteed maximum opening and closing time requirements specified in Section 2A~~ ***be designed for a maximum closing time of 45 seconds.***

The electric motor operator, gear reducer, shafts bearings, couplings, and limit switches shall be accessible for inspection and maintenance purposes with the blade in the closed position.

Louver damper operators shall have a rated torque output of at least 300 percent of the maximum required operating torque based on the combination of all live loads and dead loads. The maximum of the breakaway or running torque shall be used for sizing the damper operator. Friction loads shall be based on static coefficients of friction.

Drives for dampers which must be modulated during operation shall be of the modulating electric type. All drives shall be electronically position controlled. The Owner's control system will produce electric drive position demand signals. Control drives shall be compatible with these signals, and shall provide position feedback signals as required by the system. Each drive shall also be furnished with four limit switches, adjustable over the full travel of the drive. These limit switches shall be wired to terminal blocks and shall be available for use by the Owner. Remote power switching equipment required for operation of the drives will be provided by the Owner.

Drives shall be furnished complete with all required mounting bases, connecting linkage, and accessories required for operation. Drives shall be equipped with housings suitable for outdoor installation. All damper

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drives installed outdoors shall be equipped with space heaters, complete with thermostatic control.

Jordan control drives Series SM5000, complete with characterized position feedback, shall be furnished. Control drives shall be compatible with the Owner's DCIS system. The modulating dampers shall be designed such that pulsations at low load do not occur.

Control drives shall be in accordance with the applicable requirements of Section 1F.

Each operator shall be provided with a 1-1/2 inch hexagon nut for a portable air wrench drive.

Electric motor operators shall be in accordance with the requirements of Section 1F.

2I.4 DAMPER SHOP TESTING. Dampers shall be shop tested to determine their compliance with the specified performance and guarantee requirements.

Each damper shall be oriented in its installed position for testing.

Any or all of the shop testing may be witnessed by the Owner or his representative. Notice of the testing shall be submitted in accordance with the requirements of Section 1A.

Testing shall be conducted on the SCR inlet and bypass dampers in accordance with the damper manufacturer's recommendations as accepted by the Engineer. Detailed test procedures shall be submitted to the Engineer and Owner for review in accordance with the schedule included in Section 1A of these specifications. The detailed test procedures shall provide details of the test methods the Contractor plans to use to perform the tests specified herein and shall identify and describe instrumentation used during testing. Testing methodology shall be acceptable to the Engineer.

Shop test reports shall be prepared and submitted in accordance with the schedule in Section 1A.

2I.5 DAMPER FIELD TESTS. The dampers will be tested by the Owner after erection. Field tests will include determination of as-installed opening and closing times and determination of flue gas leakage across dampers in the closed position and flue gas leakage to atmosphere.

The Contractor and the Contractor's damper manufacturer may witness the field tests. The Contractor will be given written notice of field testing at least 10 working days in advance of the scheduled dates.

The tests will be conducted at the Owner's expense with the exception of the expenses incurred by the Contractor's representative or the Contractor's damper manufacturer's representative.

2I.6 PAINTING. Portions of the dampers fabricated from carbon steel or A588 material shall be shop prime painted.

Shop prime painting shall be in accordance with the requirements of Section 1B.

Section 2J - ACCESS PROVISIONS

2J.1 GENERAL. This section covers the design and fabrication of access provisions for the NO_x Reduction System equipment.

Typical details of access provisions shall be in accordance with the requirements indicated on Drawings 16805-DS-0003 and 16805-DS-0004 included as a part of these specifications.

2J.2 SCOPE OF SUPPLY. An arrangement of access stairs, platforms, walkways, handrails and ladders necessary to provide complete and convenient access for operation, inspection, testing, and maintenance shall be developed by the Contractor. The arrangement shall be acceptable to the Engineer. Access provisions included with the equipment shall be indicated on the arrangement drawings.

Except as otherwise specified, the Owner will provide exterior access stairs, platforms, walkways, handrails and ladders under separate specifications.

The Contractor shall furnish access provisions as required in the interior of all equipment. As a minimum, the following access doors shall be provided on the SCR catalyst housing.

Personnel access doors for each layer of catalyst

Catalyst access doors for each row of catalyst blocks (if required) and each layer of catalyst

Personnel access doors for access to catalyst coupons

Personnel access doors for access to ammonia injection grid

Personnel access doors for access to static mixing devices

Personnel access doors for access to ductwork dampers

The Contractor shall furnish all access provisions required on equipment roofs.

***A steel grating personnel access platform shall be provided above the two initial catalyst layers to allow personnel to walk on top of the layers without damaging the catalyst.**

2J.3 DESIGN CRITERIA. Platform, stairway, and walkway supporting steel shall be designed for 75 pounds per square foot live load. Platforms and walkways shall be a minimum of 3'-0" wide. Vertical deflection of steel framing members shall not exceed 1/360 of the span length in inches or a maximum of 3/4 inch. Platforms shall have lateral bracing as required for rigidity and stability.

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All platforms and walkways shall be provided with handrails. The handrails shall consist of a lower rail 21 inches above the floor, an upper rail with the top surface 42 inches above the floor, and vertical posts uniformly spaced at intervals not exceeding 6'-0" on center.

The assembled handrail shall provide continuous unbroken runs, with field connections as required between platform rails and stair rails and at corners of platforms. Handrails for adjacent stairs shall be connected by return bends. Continuity of handrails shall be interrupted only where the railings intersect columns, bracing, or other structural supports.

Stairs shall have a minimum tread width of 3'-0". The riser-to-tread ratio shall not exceed 1:1. Risers shall not exceed 8 inches. Stair stringers shall be not less than 10 inch, 15.3 pound channels.

All stairs shall be provided with stair railing. Stair rails shall consist of a lower rail, an upper rail, and vertical posts uniformly spaced at intervals not exceeding 6'-0" measured parallel to the slope of the stairs as indicated on Drawing DS-0011.

Kickplates shall be provided for all platforms, on equipment roofs as required, and as otherwise necessary for personnel protection and safety. Kickplates shall project 4 inches above the top surface of the grating, roof, or other walking surface. Any kickplates on roofs shall be notched to permit drainage of water.

Walkways, stairs, and platforms shall be fabricated from galvanized rectangular bar grating.

Ladders shall be used in lieu of stairways only in locations specified or where stairways would not be practicable and then only with the specific acceptance by the Engineer after consideration of other alternatives.

2J.4 MATERIALS. The materials used shall be equivalent to or shall exceed the requirements of the following specifications.

Steel framing	ASTM A36 steel, shop prime painted. Minimum yield point of 36,000 psi including appurtenant materials
Connection bolts for steel framing	ASTM A325, Type 1
Rectangular floor grating (interior and exterior)	Fed Spec RR-G-661, Type I, steel, 1-1/2 inches deep, welded rectangular type, galvanized in accordance with ASTM A123 and ASTM A385

Stair tread grating	Same as specified for floor grating
Nosings	Wooster Type 120 Alumogrit or acceptable equal
Reticulated floor grating	Globe "Grip Strut Safety Grating" No. 14 gage steel, serrated, galvanized, 1-1/2 channel height
Handrailings	
Posts and rails	Square steel tubing, ASTM A500 Grade A or B, or ASTM A501, 1-1/2 inches outside dimension, 0.148 inch minimum wall thickness. Square tube rolled from round pipe will not be acceptable. Shop prime painted indoors and galvanized outdoors
Slip joints	R&B Wagner single lock expansion splice locks, galvanized
Bolts	ASTM A307 Grade A hexagon with lock washers and nuts, all galvanized
Kickplates and angles	ASTM A36, shop prime painted indoors and galvanized outdoors
Ladder with safety cage	ASTM A36 ladder and cage shall meet OSHA requirements and be acceptable to the Engineer; galvanized

2J.5 FABRICATION. Access provisions shall be fabricated as specified herein.

2J.5.1 Steel Framing. Steel framing for platforms, walkways, and stairs shall be designed and detailed in accordance with the Ninth edition of the American Institute of Steel Construction (AISC) "Specification for the Design, Fabrication and Erection of Structural Steel for Buildings." Details of field connections to steel furnished under separate specifications shall be coordinated with the Engineer to ensure matching.

Steel framing shall be fabricated to tolerances that will permit field erection within AISC tolerances.

Shop connections shall be all welded. Field connections shall be bolted with high strength bolts. All field connection bolts, including bolts for connecting to steel furnished under other specifications, shall be furnished under these specifications. Bolts shall be 7/8 inch diameter. Both shop and field beam connections shall conform to AISC recommendations for slip-critical connections unless otherwise required by the design conditions. Connection angles or plates shall have a minimum thickness of 3/8 inch. Contact surfaces at field connections shall be clean, smooth, and free of foreign materials that would prevent solid seating of the parts.

All welding of stair stringer miters, closure plates, extension pieces, and similar welding applications shall be continuous welds and shall be ground smooth.

2J.5.2 Rectangular Grating and Stair Treads. All rectangular floor grating and stair treads shall be in accordance with the "Metal Bar Grating Manual" published by the National Association of Architectural Metal Manufacturers (NAAMM), except as modified herein. Maximum span of grating shall be 6'-0".

Rectangular grating bearing bars (main load carrying) shall be 3/16 inch wide by 1-1/2 inches deep. Spacing for bearing bars shall be 1-3/16 inches center-to-center. Spacer bars shall be 9/32 inch hexagonal sections or 1/4 inch twisted square sections and shall be spaced on 4 inch centers. Tops of spacer bars shall be flush with the tops of bearing bars. Unless otherwise accepted, ends of spacer bars shall be cut off and ground flush with the outside face of the bearing bars which form the sides of grating panels.

Grating for stair treads shall be as specified for floor grating, except that bearing (main load carrying) bars shall be not less than 3/16 inch by 1 inch for tread lengths up to and including 3 feet. End carrier plates shall be provided and shall be welded to each bearing bar. Both ends of each bearing bar shall be attached to the carrier plates with a 1/8 inch continuous fillet weld on one side of the bar.

All openings in grating panels shall be provided with a kickplate of formed 1/4 inch steel plate or standard weight steel pipe welded to the bearing bars. Kickplates shall extend a minimum of 4-1/2 inches above the top of the grating.

Two galvanized steel saddle-clip fasteners shall be provided for each section of grating at each supporting member. Galvanized 3/8 inch diameter bolts, nuts, and lock washers shall be provided for attaching treads to stair stringers.

Cast aluminum abrasive nosings shall be provided on grating at stair heads and for each stair tread. Nosings shall be securely attached.

Grating panels shall be fabricated in sizes that can be easily handled. Warped, bent, or twisted panels or treads will not be acceptable.

Grating panels and stair treads shall be galvanized after fabrication.

2J.5.3 Reticulated Grating and Stair Treads. Each unit of reticulated floor grating shall consist of a horizontal reticulated area of short span, not to exceed 11-3/4 inches wide, supported between formed side channels. Arrangement of the individual pieces shall be such that all longitudinal and transverse joints shall be continuous from adjacent sections.

All grating shall lie flat with no tendency to rock when installed. Grating shall be galvanized after fabrication and straightened after galvanizing.

Five Globe "Grip Strut Anchoring Device No. 12262" fasteners shall be provided for each section of grating, except six fasteners shall be provided for each cantilevered section. Galvanized 3/8 inch diameter bolts, nuts, and lock washers shall be provided for attaching stair treads to stair stringers.

2J.5.4 Handrailings. Handrailings shall be smooth, with all projecting joints and sharp corners around smooth. Welded joints shall be of the flush type. Members shall be neatly fitted and continuously welded at all junctions of posts and rails. Flattening of the rail or post ends at junctions of posts and rails will not be permitted. Fittings or other connectors shall not be used at junctions of posts and rails.

All angles, offsets, and other changes in alignment of railings shall be made with accurately mitered joints.

When assembled, all posts shall be vertical. Longitudinal members shall be parallel with each other and with the floor surface or slope of stairs, or other supporting members. In any section or run of railing, the center line of all members shall be in true alignment, lying in the same vertical plane. Top rails shall run continuously over the posts and the posts shall be continuous through the lower rail.

All welding shall be done neatly and substantially, with all fillets dressed to uniform radius, all excess metal removed, and with all welds ground smooth and flush.

A drain hole shall be provided at the base of each post.

Slip joints for expansion and contraction shall be provided in all straight runs exceeding 50 feet. Set screw holes shall be provided on the underside of the rails. Slip joints shall be shipped loose for field installation.

All exterior handrail shall be galvanized after fabrication. All interior handrail shall be shop prime painted after fabrication.

2J.5.5 Ladders. Ladders, if required, shall not be less than 20 inches wide, with 3/4 inch diameter solid steel rungs spaced 12 inches center-to-center. Ladder side rails shall be steel bars not smaller than 2-1/2 inches by 3/8 inch. Ladder side rails shall be punched for the rungs.

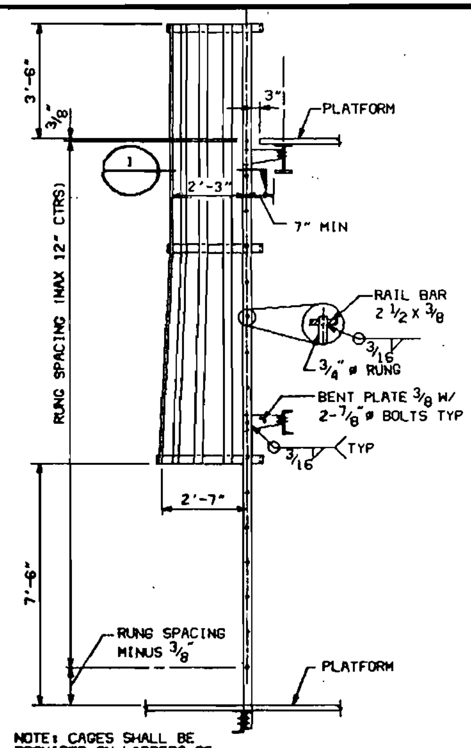
Rungs shall extend to within 1/8 inch of the outside rail surface, and the remaining 1/8 inch recess shall be filled with plug welds. Ladder supports shall be steel brackets, not less than 2-1/2 inches by 3/8 inch, spaced not more than 5'-0" vertically center-to-center. The center of the rung shall be no more than 9 inches (horizontal measure) from the surfaces supporting the brackets. Ladders more than 20 feet high shall be provided with safety cages.

All ladders and cages shall be galvanized after fabrication.

2J.6 SHOP PAINTING. All ungalvanized structural steel materials furnished under these specifications, unless specifically exempted, shall be painted in accordance with the requirements of Section 1B.

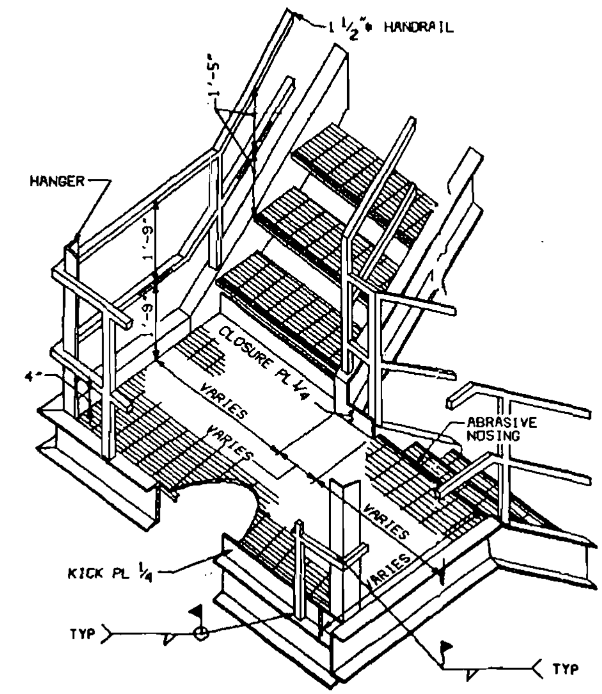
2J.7 GALVANIZING. Steel materials which are to be galvanized shall be hot-dip galvanized in accordance with the requirements of Section 1B.

2J-7

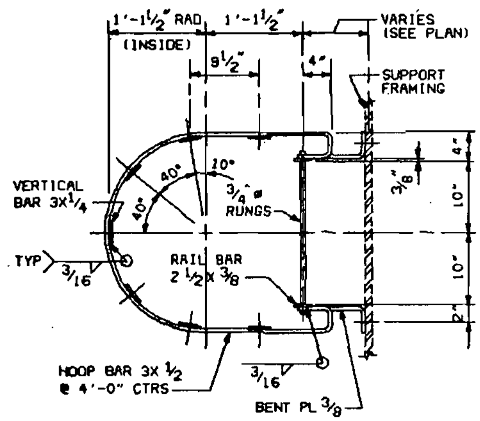


NOTE: CAGES SHALL BE PROVIDED ON LADDERS OF MORE THAN 20'-0" LENGTH.

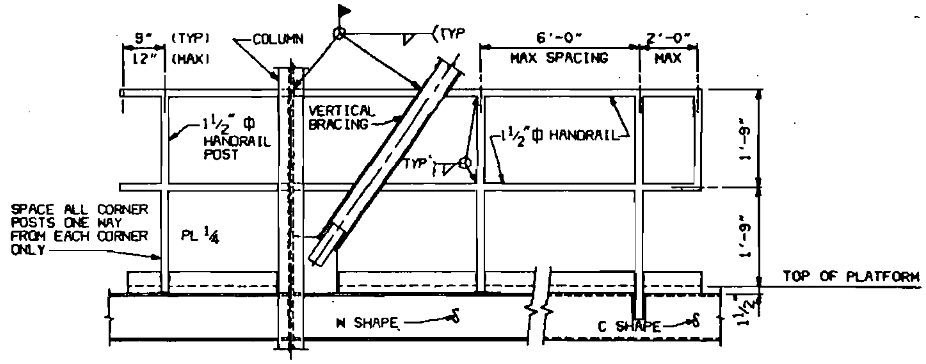
TYPICAL LADDER & CAGE



TYPICAL STAIR LANDING DETAIL



SECTION 1



ELEVATION

TYPICAL HANDRAIL DETAIL

NO	DATE	REVISIONS AND RECORD OF ISSUE	BY	CHK	APP	FLN
0	8-10-90	INITIAL ISSUE				

A-G NO. EA004

I HEREBY CERTIFY THAT THIS DOCUMENT WAS PREPARED BY ME OR UNDER MY DIRECT SUPERVISION AND THAT I AM A DULY REGISTERED PROFESSIONAL ENGINEER UNDER THE LAWS OF THE STATE OF ______
SIGNED ______
DATE ______ REG NO. ______

BLACK & VEATCH CONSULTING ENGINEERS

ENGINEER VFD DRAWN AGG
CHECKED DATE

ORLANDO UTILITIES COMMISSION
STANTON ENERGY CENTER - UNIT 2

STRUCTURAL STEEL
HANDRAIL AND LADDER DETAILS

PROJECT 16805 DRAWING NUMBER DS-0011 REV 0
CODE
AREA

2K.1 GENERAL. This section covers the control and instrumentation requirements for control of the NO_X Reduction System. Except as specifically noted, the intent of this section is that the Contractor provide the primary input and output field devices and documentation indicating the recommended control logic. The NO_X Reduction System control system will be software based and will be programmed by the Engineer.

The Contractor shall ship loose instruments to the jobsite or to the Owner's instrument enclosure supplier as directed by the Engineer. The Engineer will provide notification to the Contractor by February 1, 1993, if the instruments are to be shipped to the instrument enclosure supplier.

2K.2 NO_X REDUCTION SYSTEM CONTROL SYSTEM DOCUMENTATION. The Contractor shall provide documentation indicating the recommended method of NO_X Reduction System operation, alarms, automatic trips, sequence functions, operator information, and modulating control functions to be provided. This information shall be submitted in a format acceptable to the Engineer. The preferred format for documenting digital (on-off) control is the ISA Binary Logic Diagram method. The preferred format for documenting modulating control is the SAMA logic method. The format to be provided shall be as stated in the Proposal Data. System descriptions and input/output (I/O) lists shall be provided.

The Contractor shall also submit documentation in equation format and written descriptions for all performance calculations recommended by the Contractor. The device tag numbers assigned by the Engineer shall be used in the equations.

The Engineer will be responsible for programming the Contractor's recommended control system. Control system hardware, including I/O cabinets, control consoles, CRTs, and annunciation system, will be provided by the Owner under a separate specification.

All interlocks required for proper operation of the equipment shall be indicated on the Contractor's logic diagrams.

2K.3 CONTROL SYSTEM DESIGN CONFERENCES. The Contractor shall attend *design conferences to be held in the Engineer's ***or Contractor's*** offices ***as determined by the Engineer***. It is expected that periodic design conferences will be required to discuss the status of the project. Several of the design conferences will cover the following general aspects of the control system design.

Field instrumentation
Control system logic
Control system information and alarms
Emergency shutdown requirements
Operator interfaces

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In addition to the above, the Contractor's control system design engineers shall attend the factory checkout of the NO_x Reduction System Control System. It is anticipated that one trip of 2 days duration will be required at the Owner's control system manufacturer's factory. This trip is in addition to the manufacturer's service time included in Article 1A.5.2.

2K.4 CONTROL SYSTEM FUNCTIONAL REQUIREMENTS. The Contractor's recommended control system shall include provisions for the following general requirements.

These general requirements are the minimum control capability requirements of the system. The Contractor's recommended control system shall include and coordinate the capabilities described in the following articles as a minimum and may include additional capability as required by the Contractor's design.

2K.4.1 Ammonia Vaporization Control. The ammonia vaporization system shall be designed for either manual control or automatic control.

In the manual mode, the following equipment shall be opened, closed, started, or stopped through individual CRT control screens on the main control panel.

Ammonia vaporizers
All air- or motor-operated valves

In the automatic mode, the control system shall automatically control the operation of the ammonia vaporizers to maintain the preset ammonia delivery pressure. The ammonia storage tank liquid outlet valves and vaporizer inlet valves shall automatically provide ammonia from the tank in service to the operating vaporizer.

On low tank level, the storage tank liquid outlet valve shall automatically close. The vapor crossover valve shall open, the vapor return valve to the operating tank shall close, and the tank liquid outlet valve on the standby tank shall open.

On failure of an operating vaporizer or during automatic shutdown of a vaporizer, the vaporizer inlet valve shall automatically close. At the appropriate point during the startup sequence for the standby vaporizer, the crossover valve shall open, and the vaporizer inlet valve on the standby vaporizer shall open.

2K.4.2 Conveying Air Fan Control. The conveying air fan system shall be designed for either manual control or automatic control.

In the manual mode, the following equipment shall be opened, closed, started, or stopped though individual CRT control screens on the main control panel.

Conveying air fans
All air or motor-operated flow control dampers

In the automatic mode, the control system shall automatically control the operation of the conveying air fans. The conveying air fans shall automatically provide dilution air at the required flow rate to the air/ammonia mixing chamber.

2K.4.2.1 Flow Control Damper Operation. The flow of conveying air shall be controlled to provide the dilution of ammonia specified in Section 2E - AMMONIA INJECTION EQUIPMENT, by automatic operation of a flow control damper in the common outlet of the conveying air fans based on the required ammonia injection rate. The flow control dampers shall be furnished in accordance with Article 2I.3.

2K.4.3 Ammonia Injection Control. The ammonia injection system shall be designed for either manual control or automatic control.

In the manual mode, the following equipment shall be opened, closed, started, or stopped through individual CRT control screens on the boiler control console.

Damper drives
All air- or motor-operated valves

In the automatic mode the control system shall automatically control the conveying, mixing, and injection of ammonia and the operation of the SCR inlet and bypass flue gas dampers. The control system will receive Owner-furnished input signals for unit load, NO_x, concentration at the inlet to the SCR catalyst, and NO_x concentration at the outlet of the SCR catalyst. Optionally, the Owner may also elect to provide an input signal for the ammonia concentration at the outlet of the SCR catalyst.

2K.4.3.1 Ammonia Injection Rate Determination. The rate of ammonia injection shall be determined from the inlet NO_x concentration and the unit load signal, based on the preset NH_3/NO_x molar ratio and the desired outlet NO_x concentration input by the operator. The unit load signal shall be used to indicate inlet flue gas flow rate. The rate of ammonia injection shall be adjusted downward to maintain the required outlet NO_x concentration at the lowest possible ammonia injection rate. The rate of ammonia injection shall be adjusted upward if the outlet NO_x concentration exceeds the target NO_x emission rate.

If the outlet ammonia concentration signal is provided, the ammonia injection rate shall be adjusted downward to maintain the preset ammonia slip limit. If the desired outlet NO_x concentration cannot be achieved without exceeding the preset ammonia slip limit, the ammonia slip shall be alarmed and shall be minimized while maintaining the desired outlet NO_x concentration.

2K.4.3.2 Ammonia Injection Rate Control. The flow of ammonia to the air/ammonia mixing chamber shall be controlled by automatic modulation of the control valve in the ammonia storage tank outlet manifold. The actual flow of ammonia shall be measured downstream of the ammonia control valve and used to automatically adjust the control valve position.

During startup, injection of ammonia shall not be initiated until the following conditions have been met.

The flue gas temperature at the inlet to the SCR is at SCR operating conditions

The SCR inlet damper is fully open

The SCR bypass damper is fully closed

The flue gas temperature at the outlet of the SCR catalyst is at SCR operating conditions

The ammonia injection control valve shall stop flow of ammonia to the SCR under any of the following conditions.

The SCR bypass damper is open or the SCR inlet damper is closed

The flue gas temperature at the SCR reactor outlet is below the precipitation temperature for ammonium bisulfate for the fuel being fired

The flue gas flow rate is below the minimum low load operation level

The ratio of ammonia and conveying airflow signals is greater than the maximum value specified in Section 2E - AMMONIA INJECTION EQUIPMENT

2K.4.3.3 Injection Shutoff Valve Control. The injection shutoff valve shall automatically close when the conveying airflow is less than the preset minimum operating flow.

2K.4.4 Soot Blowing Control. The soot blowers shall operate in an automatic, selective, sequential, variable group mode. The system logic shall include all interlocks, alarms, and devices required to protect the soot blowing system from damage due to malfunction within the system. The system logic shall provide for selection of the soot blowers by groups or individually, with repetitive blowing with a sequence.

The control system shall conduct the operations of pressurizing and isolating the appropriate soot blower steam headers as part of specific operating sequences commanded by the operator. These operations shall include warm-up of the headers. The control system shall enable or isolate the header drains to prevent exposing the header system to condenser vacuum. The control system shall operate all valves necessary to perform these operations, including motor-operated valves.

2K.4.5 SCR Inlet Damper Control. The SCR inlet damper shall open when the flue gas temperature at the SCR inlet reaches SCR operating temperature. The SCR inlet damper shall not close when the SCR bypass damper is closed. The inlet damper shall be provided in accordance with Article 2I.3.

2K.4.6 SCR Bypass Damper Control. The SCR bypass damper shall close when the flue gas temperature at the SCR inlet reaches SCR operating temperature and the SCR inlet damper is fully open. Automatic inching control of the bypass damper shall be included to control the warmup rate of the catalyst. The SCR bypass damper shall not close when the SCR inlet damper is closed. The bypass damper shall be provided in accordance with Article 2I.3.

2K.5 CONTROL AND INSTRUMENTATION DEVICES. The Contractor shall furnish all primary control and instrumentation required by the NO_x Reduction System control system. Primary instruments shall be provided for monitoring, alarming, and verification of performance in order to assure reliability of the NO_x Reduction System and associated equipment. Equipment to be furnished shall include, but not be limited to, the following.

- Control valves
- Transmitters
  - Level transmitters
  - Pressure transmitters
  - Flow transmitters
- Signal converters
- Flow measurement devices
- Accessory items
  - Limit switches
  - Pressure switches
  - Temperature switches
  - Level switches
  - Pressure gauges
  - Thermometers

Temperature detectors

Thermowells

Test wells

Vibration transducer mountings

Flow indicators

Flow switches

Valve positioners

Diaphragm seals

Solenoid valves

Local instrumentation shall be furnished where required for maintenance and periodic inspection. As a minimum, the Contractor shall provide local instrumentation and test taps at all locations where a pressure or temperature process tap has been made.

Instrumentation shall be suitable for the environment and shall be corrosion resistant. All devices shall have a NEMA 4X rating. All instrument devices shall be designed for easy access and maintainability.

2K.5.1 Control Valves. Control valves shall be furnished in accordance with the requirements of Section 2G - VALVES.

2K.5.2 Transmitters. Transmitters shall be of the electronic type and furnished as required by the design of the control and instrument systems furnished. Transmitters shall be as specified in Section 1B or acceptable equal. Transmitters shall be equipped with mounting brackets suitable for attachment to a mounting rack structure by bolting or welding.

#The transmitter system pressure ratings and ~~a description of all~~ transmitter temperature characteristics shall be ***as*** stated in the Proposal Data.

The signal output for electronic transmitters shall be 4-20 mA dc.

2K.5.3 Signal Converters. Electric-to-pneumatic signal converters shall be furnished as required. These shall be of a design suitable for operation in the conditions described in Section 2A. Converter output signal shall be 3-15 psi. An air supply filter regulator equipped with a pressure gauge shall be supplied with each converter.

Electronic trip devices, voltage to current, current to voltage or any other electronic signal converter of this type shall be as manufactured by Rochester Instrument Systems, Inc. or acceptable equal.

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2K.5.4 Flow Measurement Devices. Flow measurements of clear fluids shall be made using orifice plates, venturi tubes, or rotameters as required by the Contractor's design.

2K.5.5 Accessory Items. Limit switches, pressure switches, temperature switches, level switches, pressure gauges, thermometers, temperature detectors, thermowells, test wells, and vibration transducer mountings shall be provided as required and shall conform to the requirements of Section 1B.

Other accessory items shall be provided as specified herein.

2K.5.5.1 Flow Indicators. Local flow indicators shall be provided as required by the NO_x Reduction System manufacturer's design. Flow indicators shall be as manufactured by Fischer and Porter, Schutte and Koerting, Wallace & Tiernan or acceptable equal.

2K.5.5.2 Flow Switches. Flow switches shall be provided as required by the Contractor's design. Flow switches for clear fluids shall be of the indicating type as manufactured by Universal Filters, Inc., or acceptable equal.

2K.5.5.3 Valve Positioners. All valve positioners shall be as manufactured by Fischer Controls Company or acceptable equal.

2K.5.5.4 Diaphragm Seals. Diaphragm seals shall be Hyatt Model 25F.

2K.5.5.5 Solenoid Valves. Solenoid valves shall conform to the requirements of Section 1B and shall be constructed of stainless steel bodies.

2K.6 INSTRUMENT ACCURACY. All instruments shall be constructed to perform normally and meet all guarantees when subjected to vibration and the range of ambient temperatures listed in Section 2A.

Flowmeter secondary devices shall produce signals which are linear with respect to flow within plus or minus 1 percent of full scale flow value when operating between 25 and 100 percent of full scale value. The accuracy guarantee shall include the effect of errors in the differential head measuring device, square root converter, and signal generator, but not the primary device.

Pressure transmitters shall transmit a signal which is linear with respect to the measured pressure within plus or minus 1/2 of 1 percent of the measured range span.

Level transmitters shall transmit a signal which is linear with respect to the measured level within plus or minus 1 percent of the metered level range span based on a specific gravity of 1.00.

Resistance temperature detector elements shall have a resistance characteristic which is linear with respect to temperature within plus or minus 1/2 of 1 percent of the top range value.

2K.7 MISCELLANEOUS ITEMS. Miscellaneous items shall be provided in accordance with the following requirements.

2K.7.1 Support Hardware. All brackets, supports, and other miscellaneous hardware required for mounting devices as specified herein shall be provided.

2K.7.2 Control and Instrument Piping. Control and instrument piping will be in accordance with the requirements of Section 2F - PIPING.

2K.8 INSTRUMENT INSTALLATION. The Contractor shall ship all instruments to be rack mounted including pressure transmitters, flow transmitters, differential pressure switches, flow switches, level transmitters, etc., to the Owner's instrument rack supplier for installation by others. The number of transmitters to be rack mounted shall be as stated in the Proposal Data.

APPENDIX

Noell, Inc.
(Bidder's Name)

#

C.7.1 Catalyst.	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
Catalyst type	Plate	
Catalyst active compounds	TiO_2	
	V_2O_5	
	WO_3	
Catalyst manufacturer	Siemens	
Catalyst identification (model number)	SP350	
Catalyst pitch, mm	6	
Catalyst cell width, mm		
Catalyst cells/in.^{2}		
Catalyst substrate material	metal	
Catalyst block shell material	ceramic	
Dimensions of each catalyst block, inches (L x W x H)	78.3 x 37.4 x 51.6	x x
Weight of each individual catalyst block, lb	3320	
Flue gas velocity within catalyst layer, ft/sec	18	
Flue gas velocity between catalyst layers, ft/sec	15	
Space velocity, l/h	4921	
Number of active catalyst layers in initial charge	2	
Number of catalyst blocks installed per layer	95	

(Trim Line)

#Addendum 1

Noell, Inc.
(Bidder's Name)

	2 ppm NH_3 *Design Basis* Slip	5 ppm NH_3 *Design Basis* Slip
Number of test elements per catalyst layer	Each plate can be randomly used in lieu of coupons.	
Initial catalyst volume, ft^3	11283	
Specific catalyst area, ft^2/acfm	0.58	
Catalyst depth/layer, ft	3.28	
Number of spare layers for future catalyst addition	2	
Future catalyst volume, ft^3	11283	
Minimum catalyst operating temperature, F	650	
Maximum catalyst operating temperature, F	750	
Ammonia grade classification requirement	standard	
Ammonia purity requirement, percent NH_3	99.5% NH_3	
Description of dummy layer	ceramic honeycomb cell opening 10 mm depth 7.87 in.	

C.7.2 Catalyst Housing (Reactor).

Housing fabricator: Titan or equal

Overall dimensions of catalyst housing

Height	53 feet	0 inches
Width	65 feet	0 inches
Depth	35 feet	0 inches

Housing shell plate thickness, in.: 1/4

(Trim Line)

*Addendum 1

Noell, Inc.
(Bidder's Name)

Distance between tops of adjacent catalyst layers, ft	10
Complete weight of catalyst housing including initial catalyst charge without external insulation, lb	1,300,000
Additional weight of future additional catalyst layers, each, lb	320,477
Complete weight of catalyst housing including initial catalyst charge and external insulation and lagging	1,412,000
Soot blowing system	
Number of soot blower elements per layer	4 (12 total)
Number of nozzles per element	TBD
Travel distance of soot blower lances	7 feet 2 inches
Manufacturer	Diamond Power Specialty Co.
Model number	1K-525-SL
Pressure regulator	
Manufacturer	Diamond Power Specialty Co.
Model number	Series 900 chrome moly with externally adjustable pressure control
Motors	
Reversing or nonreversing	Reversing
Manufacturer	GE
Model number	5K47UG8382R
Rating, hp/rpm	2 / 1725

(Trim Line)

	NOELL, INC. (Bidder's Name)
Access provisions	
Design live load for stairs, platforms, and walkways, lb/ft^2	N/A
Grating	
Total floor area, ft^2	N/A
Total stair tread, ft^2	N/A
Manufacturer	N/A
Access door size for personnel access to catalyst layers, feet	3'-0" x 4'-4"
Access door size for personnel access to catalyst coupons, feet	Same x
Access door size for catalyst installation and removal, feet	6'-8" x 4'-0"
Access door size for personnel access to ammonia injection grid, feet	2'-0" x 2'-0"
Access door size for personnel access to static mixing device, feet	2'-0" x 2'-0"
Access door size for personnel access to ductwork dampers, feet	2'-0" x 2'-0"

(Trim Line)

Noell, Inc.
(Bidder's Name)

Describe door seal provisions	
# *Maximum catalyst block dimensions accommodated by housing, inches (L x W x H)*	79 x 38 x 60 for 2 ppm NH_3 slip
Minimum catalyst block dimensions accommodated by housing, inches (L x W x H)	x x
Maximum catalyst weight per catalyst layer accommodated by housing, lb	349,000

C.7.3 Ductwork Dampers.

C.7.3.1 SCR Inlet Dampers.

	SCR Inlet Dampers
Number	Qty 2 LCH/BYI
Type	LOUVER
Manufacturer	DAMPER DESIGN, INC.
Damper frame inside dimensions, in.	
Parallel to blade axis	156
Perpendicular to blade axis	321
Damper net flow area when open, sq ft	Approx. 284.83
Weight, total, lb	Approx. 19,098

(Trim Line)

#Addendum 2

NOELL, INC.
(Bidder's Name)

SCR Inlet Dampers

Materials of construction (ASTM No.)	
Frame	A588
Blade skin	A588/A242
Blade stiffeners	N/A
Axles	N/A
Axle stub ends	17-4 PH S.S. (A564)
Seals	B575 - C276

(Trim Line)

Addendum 2

NOELL, INC.
(Bidder's Name)

SCR Inlet Dampers

Frame	
Structural member dimensions, in.	
Length of frame members parallel to blades (top and bottom)	156
Length of blade support frame members (sides)	APPROX. 340
Flange-to-flange length	30
Structural members characteristics	
Nominal size if standard ANSI shape; if not, provide drawing and list drawing number here	Formen Channel/.5" Plate
Weight per foot, lb	APPROX. 70
Cross-sectional area, in.^{2}	20.5
Depth, in.	.5 inch
Flange	
Width, in.	6
Average thickness, in.	.5
Web thickness, in.	.5

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Inlet Dampers

Frame member moment of inertia, $in.^4$	
Top and bottom	
Weak axis	50.4
Strong axis	2321.7
Sides	
Weak axis	50.4
Strong axis	2321.7
Total weight of frame excluding bearing and operator support brackets, lifting lugs, and other appurtenant items, lb	APPROX. 5658
Blades and axles	
Number of blades	11
Blade width, in.	APPROX. 29
Damper blade skin thickness, in.	.375
Blade axle diameter if solid or pipe shaft, in.; if not, provide drawing and list drawing number here	STUB SHAFT - 3"Ø
Axle pipe shaft wall thickness, in.	N/A
Cross-sectional area of axle, $in.^2$	N/A
Axle stub end diameter, in.	3" Dia.

(Trim Line)

NOELL, INC.

(Bidder's Name)

SCR Inlet Dampers

Center-to-center span distance between blade support bearings, in.	161.5
Center-to-center span distance between blade shaft packing boxes, in.	159.5
Blade cross-section moment of inertia about principal axis parallel to blade chord, $in.^4$	40.49
Blade cross-section polar moment of inertia, $in.^4$	1,291.4
Deflection at center of blade span with damper closed and 52.0 in. wg differential, in.	.52 @ 52" w.c .06 @ 6" w.c.
Deflection at midpoint of blade shaft packing box with damper closed and 52.0 in. wg differential, in.	0.017 @ 52" w.c. .002 @ 6" w.c.
Method of attachment of blade skin to axle	PINNED
Percent of duct area blocked when damper is in open position	18%

Bearings

Type	Grafoil Sleeve
Manufacturer and Model No.	DDI Style "A"
Bearing housing material	Carbon Steel
Bearing surface material	Carbon Steel

(Trim Line)

	NOELL, INC. (Bidder's Name)
	SCR Inlet Dampers
Maximum permissible continuous operating temperature of bearing, F	1000°F
Distance of bearing mount from frame web exterior surface, in.	APPROX. 1"
Recommendation concerning insulating and lagging over bearings and linkage	The DDI Style A Bearing will allow coverage by the insulation lagging. Linkage should remain exposed.
Linkages	
Linkage material	Carbon Steel
Linkage pin material	450 S.S.
Linkage bolt material	N/A
Linkage pivot bearing type and material	N/A
Method of adjusting linkage	N/A Linkage is dual shear Conneoting Link System, - Adjusting Knuckee is located @ actuator connecting link.
Sealing system	
Packing box material	Carbon Steel
Packing follower material	Carbon Steel

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Inlet Dampers

Packing	
Material	J.C. 287I, Coraphite Imp.
Manufacturer and type	" Rope
Maximum temperature rating, F	1200°
Depth of material in packing box, in.	1
Maximum permissible deflection of packing recommended by packing manufacturer, in.	.017
Describe blade edge-to-frame seal provisions	DDI Blade Tip Seals used w/cartridge design and Multiply C276 Flexible Leaves (see attached drawing)
Describe blade end-to-frame seal provisions	A DDI Jamb seal will be used on the blades' stub end, wing flexible, multi-ply seals of C276 (see attached drawing).
Describe blade edge-to-edge seal provisions	The DDI blade tip seals use a cartridge design w/ a flexible, multi-ply seal of C276 (see attached drawing).

(Trim Line)

NOELL, INC.

(Bidder's Name)

SCR Inlet Dampers

Damper leakage area, in.^{2}	
Blade edge to frame	3.12
Blade end to frame	38.52
Blade edge to edge	15:36
Other	-
Total	57.00
Damper operating torque requirements, lb-ft	
Aerodynamic	774
Bearing friction	1097
Packing friction	526
Seal torque	1411
Obstruction from fly ash deposits in duct	-
Total	3034
Damper operators	
Manufacturer	JORDAN
Model No.	SM-5480
Frame size	N/A
Voltage/phase	180 VDC from servo amp.
Horsepower/service factor	2.0 / Less than 1

(Trim Line)

	NOELL, INC.
	(Bidder's Name)
	SCR Inlet Dampers
Space heater rating, watts	150 Watts
Motor torque, lb-ft	
Start	4.5 Ft lb / 1750 RPM
Stall	Motor is stall protected
Operator maximum torque capability, lb-ft	
Start	15,155 Ft lbs
Stall	Stall protected @ 7500Ft lbs @ mid stroke
Does the damper operator (excluding external gear units) have self-locking gears?	Yes - Scotch Yoke Mech.
C.7.3.2 **SCR Bypass Dampers.**	**SCR Bypass Dampers**
Number	Qty - 2 #LCH/BYI
Type	LOUVER
Manufacturer	Damper Design, Inc.
Damper frame inside dimensions, in.	
Parallel to blade axis	84
Perpendicular to blade axis	321.25
Damper net flow area when open, sq ft	155.62
Weight, total, lb	10,600

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Bypass Dampers

Materials of construction (ASTM No.)	
Frame	A588
Blade skin	A588
Blade stiffeners	-
Axles	
Axle stub ends	A564
Seals	B575
Frame	
Structural member dimensions, in.	
Length of frame members parallel to blades (top and bottom)	APPROX. 96
Length of blade support frame members (sides)	APPROX. 333.25
Flange-to-flange length	30
Structural members characteristics	
Nominal size if standard ANSI shape; if not, provide drawing and list drawing number here	Formed Channel of Plate
Weight per foot, lb	69.6
Cross-sectional area, in.^{2}	20.5

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Bypass Dampers

Depth, in.	0.5" Thick
Flange	
Width, in.	6
Average thickness, in.	0.5
Web thickness, in.	0.5
Frame member moment of inertia, $in.^4$	
Top and bottom	
Weak axis	50.4
Strong axis	2321.7
Sides	
Weak axis	50.4
Strong axis	2321.7
Total weight of frame excluding bearing and operator support brackets, lifting lugs, and other appurtenant items, lb	10,600
Blades and axles	
Number of blades	11
Blade width, in.	29.2
Damper blade skin thickness, in.	0.25
Blade axle diameter if solid or pipe shaft, in.; if not, provide drawing and list drawing number here	Stub Shaft - 2-1/2" Diam.

(Trim Line)

NOELL, INC.

(Bidder's Name)

SCR Bypass Dampers

Axle pipe shaft wall thickness, in.	N/A
Cross-sectional area of axle, $in.^2$	N/A
Axle stub end diameter, in.	Stub Shaft - 2-1/2" Diam.
Center-to-center span distance between blade support bearings, in.	88.74
Center-to-center span distance between blade shaft packing boxes, in.	86.24
Blade cross-section moment of inertia about principal axis parallel to blade chord, $in.^4$	19.59
Blade cross-section polar moment of inertia, $in.^4$	892.71
Deflection at center of blade span with damper closed and 52.0 in. wg differential, in.	0.08 @ 52" w.c 0.01 @ 6" w.c.
Deflection at midpoint of blade shaft packing box with damper closed and 52.0 in. wg differential, in.	0.008 @ 52" w.c. 0.001 @ 6" w.c.
Method of attachment of blade skin to axle	Pinned
Percent of duct area blocked when damper is in open position	15
Bearings	
Type	Grafoil Sleeve

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Bypass Dampers

Manufacturer and Model No.	DDI Style A - See CVT sheet
Bearing housing material	Carbon Steel
Bearing surface material	Grafoil Sleeve
Maximum permissible continuous operating temperature of bearing, F	1000°
Distance of bearing mount from frame web exterior surface, in.	APPROX. 1"
Recommendation concerning insulating and lagging over bearings and linkage	The DDI style "A" bearing design will allow coverage of the Ins. Lagging. Linkage should remain exposed.

Linkages

Linkage material	Carbon Steel
Linkage pin material	450 SS
Linkage bolt material	N/A
Linkage pivot bearing type and material	N/A
Method of adjusting linkage	N/A - Dual Shear type proposed. Adjusting device located on actuator connecting link.

(Trim Line)

NOELL, INC

(Bidder's Name)

SCR Bypass Dampers

Sealing system	
Packing box material	Carbon Steel
Packing follower material	Carbon Steel
Packing	
Material	Graphite impregnated rope
Manufacturer and type	John Crane 287I
Maximum temperature rating, F	1200°
Depth of material in packing box, in.	1.0
Maximum permissible deflection of packing recommended by packing manufacturer, in.	0.17
Describe blade edge-to-frame seal provisions	DDI Blade Tip Seals used w/ cartridge design and multi-ply C-276 flexible leaves (see attached drawing)
Describe blade end-to-frame seal provisions	~~A DDI Jamb Seal will be used on the blade's stub end using flexible~~ multi-ply seal of Hast. C-276 (See attached drawing)

(Trim Line)

SCR Bypass Dampers

Describe blade edge-to-edge seal provisions	The DDI Blade Tip Seals use a cartridge design w/ a flexible multi-ply seal of hast. C-276 (see attached drawing)
Damper leakage area, in.^{2}	
Blade edge to frame	1.68
Blade end to frame	38.55
Blade edge to edge	8.2
Other	-
Total	48.43
Damper operating torque requirements, lb-ft	
Aerodynamic	3781
Bearing friction	408
Packing friction	438
Seal torque	1091
Obstruction from fly ash deposits in duct	-
Total	1937
Damper operators	
Manufacturer	Jordan
Model No.	SM-5480
Frame size	N/A

(Trim Line)

NOELL, INC.
(Bidder's Name)

SCR Bypass Dampers

Voltage/phase	180 VOC from seryo AMP.
Horsepower/service factor	2.0 / Less than 1
Space heater rating, watts	150
Motor torque, lb-ft	
Start	4.5 Ft lbs / 1750 RPM
Stall	Motor is stall protected
Operator maximum torque capability, lb-ft	
Start	15,155 Ft lbs (breakaway)
Stall	stall protected @ 7500 Ft lbs at mid stroke.
Does the damper operator (excluding external gear units) have self-locking gears?	Yes - Scotch Yoke Mechanism

C.7.4 Anhydrous Ammonia Receiving and Storage.

Ammonia storage tanks	
Number	Two Required
Manufacturer	USS Chemicals Division or equivalent
Capacity, gal (nominal)	30,000 Gal
Effective capacity, gal	28,000 Gal
Total days of storage at ammonia usage rate at MCR conditions	One month
Diameter	12'

(Trim Line)

	NOELL, INC. (Bidder's Name)
Length	44'
Weight, each tank, lb	
Empty	91,000 lb.
Operating	375,110 lb.
Ammonia vaporizers	
Number furnished	1 per storage vessel
Manufacturer	Richard M. Armstrong
Model number	N/A
Storage capacity each, gal	N/A
Maximum kW input at 480 volts, 3-phase, each	65 kW
Thermostat	
Manufacturer	By Vendor
Model number	By Vendor
Temperature range, F to F	By Vendor
Maximum capacity, lb/h of ammonia	416 lb/hr
Ammonia vapor supply pressure to pressure reducing station, psig	93 PSI @ 60°F
Pressure reducing station pressure regulating valves	
Manufacturer	Fisher
Model number	EZ
Size	1"

(Trim Line)

	NOELL, INC. (Bidder's Name)
Ammonia vapor transport pressure from pressure reducing station, psig	36 PSIG
Tank relief valves	
Manufacturer	REGO - Opo Action
Model number	AA3135UA265
Relief valve manifold	
Manufacturer	REGO
Model number	4" Multiport A8573G
Pressure switches	
Manufacturer	ASHCROFT
Model number	B7-65 SXTMX07-200
Level indicators	
Manufacturer	Rochester
Model number	Magnatel Model 6342
Pressure gauges	
Manufacturer	ASHCROFT
Model number	DURAGAUGE
Ammonia leak detector	
Manufacturer	SENSYDINE
Model number	7011782-1
Power requirement	4-20 MA DC

(Trim Line)

Noell, Inc.
(Bidder's Name)

C.7.5 Ammonia Injection System.

Conveying air fans	
Manufacturer	Chicago Blower or engineer acceptec equal
Model number	33 AH
Capacity and head, cfm/in. wg	20,000 / 24
Motors	
Manufacturer	US Motor
Model number	455TS
Rating, hp/rpm	150 / 1200
Voltage/phase	460 / 3
Ammonia dilution, percent ammonia by volume, typical	0.6 Vol%
Ammonia dilution, percent ammonia by volume, range	0 - 0.7 Vol%
Air/ammonia flow to injection grid, acfm at the following steam generator load points	
100 percent of MCR	20,000
90 percent of MCR	20,000
80 percent of MCR	20,000
60 percent of MCR	20,000
40 percent of MCR	20,000
25 percent of MCR	20,000
Air/ammonia transport pressure	20 inch H_2O
Air/ammonia transport duct size, in.	30

(Trim Line)

Noell, Inc. (Bidder's Name)	
Ammonia injection grid	
Piping material	Stainless Steel
Piping sizes, in.	10
Nozzles	
Manufacturer	Noell
Model number	N/A
Material	Stainless Steel
Internal diameter, in.	1.4
Design flow, cfm	143
Total number installed	140
Removal provisions	yes
Injection grid branch flow control valves	
Manufacturer	Adams (or equal)
Size	10 inch
Model number	Type MAK Series 316
Injection grid branch flow measurement device type	Orifice
Describe provisions for optimizing reagent distribution	See Description

(Trim Line)

	Noell, Inc. (Bidder's Name)
Support system, describe	Internal fixed supports and support at penetration of ductwork ductwork walls
Static mixing device	
Number of devices	2
Number of stages per device	1
Material	Carbon Steel
Description	2 Mixers for two directions
Location in ductwork	See drawing
Pressure drop per device	0.6 inch H_2O
Test ports	
Number at each location	
Ammonia injection grid	15
Reactor inlet	30
Between catalyst layers	2
Reactor outlet	20
Size, in.	4

(Trim Line)

	Noell, Inc.
	(Bidder's Name)

C.7.6 Model Test.

Model test contractor	NELS Consulting Services or FERCo	
Proposed scale for model	1/12	
#	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip

C.7.7 Performance Guarantees.

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
Catalyst life, hours, as ##defined in Article ~~2B.2.1~~ *2B.1*	24,000	
Rated capacity of SCR system, flue gas flow rate, lb/h	4,273,145	
Minimum load capability, percent of MCR flue gas flow rate	25%	
SCR inlet damper		
Maximum flue gas leakage across closed damper based on flue gas pressure differential as specified in Section 2A, acfm	20800	
## ~~Opening time, seconds~~		
## ~~Closing time, seconds~~		
SCR bypass damper		
Maximum flue gas leakage across closed damper based on flue gas pressure differential as specified in Section 2A, acfm	20800	
## ~~Opening time, seconds~~		
## ~~Closing time, seconds~~		

(Trim Line)

#Addendum 1
##Addendum 2

Noell, Inc.

(Bidder's Name)

/

C.7.7.1 System Initial Performance (At Initial Formal Performance Guarantee Test).

100 percent of MCR

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥70%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	≤1 Mol %	
System pressure drop, in. wg	3.42	
Pressure drop across second catalyst layer, in. wg	1.085	
Ammonia usage rate at design point, lb/h	344	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	

Maximum operating power requirements, kVA/kW/ voltage/phase

	kVA / kW / voltage / phase
Ammonia vaporizer	/ * / 480 / 3
Injection blowers	/ 67 /480 / 3

(Trim Line)

*Vaporizer is not required for normal process. It is used only as a storage vessel heater during prolonged and lengthy cold condition.

/Addendum 1

Noell, Inc.
(Bidder's Name)

Soot blowing system	/ 1.5 / 480 / 3
Other (describe)	Instrumentation
	/ 10KW* / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/h steam consumption during sootblowing
Number of elements in service at the same time	1
Intermittent average	2 x per week sootblowing

(Trim Line)

*For all other loads, the same maximum power is required for instrumentation.

Noell, Inc.
(Bidder's Name)

/

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
90 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$70%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	<2	
System pressure drop, in. wg	3.28	
Pressure drop across second catalyst layer, in. wg	1	
Ammonia usage rate at design point, lb/h	310	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

*See note page C-31.

/Addendum 1

	Noell, Inc. (Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	2 x per week

(Trim Line)

Noell, Inc.

(Bidder's Name)

/

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
80 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥70%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	<2	
System pressure drop, in. wg	2.79	
Pressure drop across second catalyst layer, in. wg	0.9	
Ammonia usage rate at design point, lb/h	276	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	

Maximum operating power requirements, kVA/kW/voltage/phase

	kVA	kW	voltage	phase
Ammonia vaporizer		*	480	3
Injection blowers		67	480	3
Soot blowing system		1.5	480	3

*See note page C-31.

(Trim Line)

/Addendum 1

	Noell, Inc.
	(Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	3 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
60 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥70	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	<2	
System pressure drop, in. wg	1.93	
Pressure drop across second catalyst layer, in. wg	0.7	
Ammonia usage rate at design point, lb/h	208	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

*See note page C-31

/Addendum 1

	Noell, Inc.
	(Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	4 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

#	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
40 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$70%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	<2	
System pressure drop, in. wg	1.53	
Pressure drop across second catalyst layer, in. wg	0.5	
Ammonia usage rate at design point, lb/h	149	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

*See note on page C-31.

(Trim Line)

#Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	1 x per day

(Trim Line)

Noell, Inc.

(Bidder's Name)

	2 ppm NH_3 Design Basis Slip	*5 ppm NH_3 Design Basis Slip*
25 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$70%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	<2	
System pressure drop, in. wg	1.13	
Pressure drop across second catalyst layer, in. wg	0.3	
Ammonia usage rate at design point, lb/h	105	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.01	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

Addendum 1

	Noell, Inc. (Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr
Number of elements in service at the same time	1
Intermittent average	1 x per day

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

C.7.7.2 System Initial Performance (At Interim Formal Performance Guarantee Test).

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
100 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$ 2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	$\leq$ 1	
System pressure drop, in. wg	3.42	
Pressure drop across second catalyst layer, in. wg	1.085	
Ammonia usage rate at design point, lb/h	232	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	

Maximum operating power requirements, kVA/kW/voltage/phase

	kVA	kW	voltage	phase
Ammonia vaporizer		*	480	3
Injection blowers		67	480	3

(Trim Line)

/Addendum 1

* See note Page C-31

Noell, Inc.
(Bidder's Name)

Soot blowing system	/ 1.5 / 480 / 3
Other (describe)	
	/ / /
Other (describe)	
	/ / /

Soot blowing steam requirements, lb/h

Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	2 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

†

90 percent of MCR	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	3.28	
Pressure drop across second catalyst layer, in. wg		
Ammonia usage rate at design point, lb/h	209	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

†Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	____________
	___/___/___/___
Other (describe)	____________
	___/___/___/___
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	2 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

80 percent of MCR	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3-slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	2.79	
Pressure drop across second catalyst layer, in. wg	0.9	
Ammonia usage rate at design point, lb/h	186	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	

Maximum operating power requirements, kVA/kW/voltage/phase

	kVA	kW	voltage	phase
Ammonia vaporizer		*	480	3
Injection blowers		67	480	3
Soot blowing system		1.5	480	3

(Trim Line)

* See note Page C-31

/Addendum 1

	Noell, Inc. (Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	3 x per week

(Trim Line)

	Noell, Inc. (Bidder's Name)	
/	*2 ppm NH_3 Design Basis Slip*	*5 ppm NH_3 Design Basis Slip*
60 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.93	
Pressure drop across second catalyst layer, in. wg	0.7	
Ammonia usage rate at design point, lb/h	141	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ *	/ 480 / 3
Injection blowers	/ 67	/ 480 / 3
Soot blowing system	/ 1.5	/ 480 / 3

(Trim Line)

* See note Page C-31

/Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	4 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

#

40 percent of MCR	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.53	
Pressure drop across second catalyst layer, in. wg	0.5	
Ammonia usage rate at design point, lb/h	101	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	

Maximum operating power requirements, kVA/kW/voltage/phase

	kVA	kW	voltage	phase
Ammonia vaporizer		*	480	3
Injection blowers		67	480	3
Soot blowing system		1.5	480	3

(Trim Line)

* See note Page C-31

#Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe) ____________________

____ / ____ / ____ / ____

Other (describe) ____________________

____ / ____ / ____ / ____

Soot blowing steam requirements, lb/h

Maximum intermittent per element: 8800 lb/hr steam

Number of elements in service at the same time: 1

Intermittent average: 1 x per day

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

25 percent of MCR	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.13	
Pressure drop across second catalyst layer, in. wg	0.3	
Ammonia usage rate at design point, lb/h	71	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	

Maximum operating power requirements, kVA/kW/voltage/phase

Ammonia vaporizer		*	480	3
Injection blowers		67	480	3
Soot blowing system		1.5	480	3

(Trim Line)

/Addendum 1

* See note Page C-31

Noell, Inc.
(Bidder's Name)

Other (describe)	______
	/ / /
Other (describe)	______
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	1 x per day

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

C.7.7.3 System Performance (At Formal Performance Guarantee Test).

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
100 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	≤ 1 Mol%	
System pressure drop, in. wg	3.42	
Pressure drop across second catalyst layer, in. wg	1.085	
Ammonia usage rate at design point, lb/h	232	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	

(Trim Line)

/Addendum 1

* See note Page C-31

Noell, Inc.
(Bidder's Name)

Soot blowing system	/ 1.5 / 480 / 3
Other (describe)	
	/ / /
Other (describe)	
	/ / /

Soot blowing steam requirements, lb/h

Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	2 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

#

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
90 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	3.28	
Pressure drop across second catalyst layer, in. wg		
Ammonia usage rate at design point, lb/h	209	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

#Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	______________
	/ / /
Other (describe)	______________
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	2 x per week

(Trim Line)

Noell, Inc.
(Bidder's Name)

/

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
80 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$ 2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	2.79	
Pressure drop across second catalyst layer, in. wg	0.9	
Ammonia usage rate at design point, lb/h	186	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

/Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	3 x per week

(Trim Line)

	Noell, Inc. (Bidder's Name)	
#	*2 ppm NH_3 Design Basis Slip*	*5 ppm NH_3 Design Basis Slip*
60 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	< 2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.93	
Pressure drop across second catalyst layer, in. wg	0.7	
Ammonia usage rate at design point, lb/h	141	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

#Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	4 x per week

(Trim Line)

	Noell, Inc. (Bidder's Name)	
#	*2 ppm NH_3 Design Basis Slip*	*5 ppm NH_3 Design Basis Slip*
40 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	≥ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	≤ 2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.53	
Pressure drop across second catalyst layer, in. wg	0.5	
Ammonia usage rate at design point, lb/h	101	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

#Addendum 1

	Noell, Inc. (Bidder's Name)
Other (describe)	
	/ / /
Other (describe)	
	/ / /
Soot blowing steam requirements, lb/h	
Maximum intermittent per element	8800 lb/hr steam
Number of elements in service at the same time	1
Intermittent average	1 x per day

(Trim Line)

Noell, Inc.
(Bidder's Name)

#

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
25 percent of MCR		
NO_x reduction efficiency ~~at 2 ppmvd (3% O_2) NH_3 slip (design point)~~	$\geq$ 47%	
NH_3 slip at design NO_x reduction efficiency, ppmvd (3% O_2)	$\leq$ 2 ppm	
~~NO_x reduction efficiency at 5 ppmvd (3% O_2) NH_3 slip~~		
Oxidation rate of SO_2 to SO_3 at 706 F, percent	< 2	
System pressure drop, in. wg	1.13	
Pressure drop across second catalyst layer, in. wg	0.3	
Ammonia usage rate at design point, lb/h	71	
Stoichiometric ratio, mols NH_3 per mol NO_x removed	1.02	
Maximum operating power requirements, kVA/kW/voltage/phase		
Ammonia vaporizer	/ * / 480 / 3	
Injection blowers	/ 67 / 480 / 3	
Soot blowing system	/ 1.5 / 480 / 3	

(Trim Line)

* See note Page C-31

#Addendum 1

Noell, Inc.
(Bidder's Name)

Other (describe) ______

______ / ______ / ______ / ______

Other (describe) ______

______ / ______ / ______ / ______

Soot blowing steam requirements, lb/h

Maximum intermittent per element: 8800 lb/hr steam

Number of elements in service at the same time: 1

Intermittent average: 1 x per day

(Trim Line)

	Noell, Inc. (Bidder's Name)	
#	**2 ppm NH_3 Design Basis Slip**	**5 ppm NH_3 Design Basis Slip**
C.7.7.4 Expected Performance (Not Guarantee Values).		
Expected catalyst life (initial charge), as de- #fined in Article ~~2B.2.1~~ *2B.1*	5	
Expected catalyst replacement cycle with all layers installed, years	3	
Typical operation system pressure drop, in. wg		
Two catalyst layers installed		
100 percent of MCR	3.1	
90 percent of MCR	2.9	
80 percent of MCR	2.5	
60 percent of MCR	1.7	
40 percent of MCR	1.4	
25 percent of MCR	1.1	
Three catalyst layers installed		
100 percent of MCR	4.2	
90 percent of MCR	4.0	
80 percent of MCR	3.4	
60 percent of MCR	2.3	
40 percent of MCR	1.9	
25 percent of MCR	1.4	

(Trim Line)

#Addendum 2

Noell, Inc.
(Bidder's Name)

#

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
Four catalyst layers installed		
100 percent of MCR	5	
90 percent of MCR	4.5	
80 percent of MCR	4	
60 percent of MCR	3	
40 percent of MCR	2	
25 percent of MCR	1.4	

#C.7.8 Optional Performance Program.

	2 ppm NH_3 Design Basis Slip	5 ppm NH_3 Design Basis Slip
Number of installed catalyst layers		
Year number 1	2	
Year number 2	2	
Year number 3	2	
Year number 4	2.5	
Year number 5	2.5	
Year number 6	2.5	
Year number 7	3.0	
Year number 8	3.0	
Year number 9	3.5	
Year number 10	3.5	

(Trim Line)

#Addendum 2