BEFORE THE ILLINOIS POLLUTION CONTROL BOARD

IN THE MATTER OF:	)	
	)	
NITROGEN OXIDES EMISSIONS FROM	)	R08-19
VARIOUS SOURCE CATEGORIES:	)	(Rulemaking – Air)
AMENDMENTS TO 35 ILL. ADM. CODE	)	
PARTS 211 AND 217	)	

NOTICE

TO: John Therriault
Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601

SEE ATTACHED SERVICE LIST

PLEASE TAKE NOTICE that I have today filed with the Office of the Clerk of the Illinois Pollution Control Board the ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO PRE-FILED QUESTIONS BY THE ILLINOIS ENVIRONMENTAL REGULATORY GROUP, a copy of which is herewith served upon you.

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________________
Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

DATED: September 30, 2008

1021 North Grand Avenue East
P. O. Box 19276
Springfield, IL 62794-9276
217/782-5544

THIS FILING IS SUBMITTED ON RECYCLED PAPER

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THE ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO PRE-FILED QUESTIONS BY THE ILLINOIS ENVIRONMENTAL REGULATORY GROUP

NOW COMES the Illinois Environmental Protection Agency ("Illinois EPA"), by its attorneys, and pursuant to the Hearing Officer's Order dated June 12, 2008, respectfully submits the Illinois EPA's Answers to the Pre-Filed Questions by the Illinois Environmental Regulatory Group:

1. The Technical Support Document, at page 5, and again at page 38, describes the NOx reductions that could be achieved by switching to other fuels. In formulating its proposed rule, did the Agency intend to force affected sources to switch fuel sources to achieve compliance?

   It is not the intent of the Illinois EPA to force affected sources to switch fuels. The information provided on page 5 of the TSD is general information regarding NOx emissions generated from the combustion of different fuels.

   a. To what extent does the Agency expect fuel switching will be required to achieve compliance?

      Fuel switching is an option for industries to consider. The Illinois EPA believes that industries will determine the most cost effective approach to compliance.

   b. To what extent did the Agency consider the availability of alternative fuels?

      The Illinois EPA considers the fuels mentioned on page 5 to generally be available, although we have not performed a source-specific review.

   c. Does the Agency believe that it is technically and economically feasible for a coal-fired boiler to be converted to used oil or natural gas?

      Such conversions are technically feasible and have been implemented in Illinois. The feasibility of such conversions is an economic issue based on the cost of conversion and the relative costs of coal, natural gas, and oil.

d. Would such a converted boiler then be subject to the more stringent NOx emissions limits applicable to oil and gas boilers?

That is not the Illinois EPA's intent. The converted boiler would be subject to the emission limit based on the fuel used prior to conversion, provided that the conversion occurs after the effective date of this rule.

2. Table 2-la of the Technical Support Document, at page 6, lists the "Emissions Requirements of Proposed Industrial and Small EGU Boilers RACT Rule." Has the Agency made any determination as to whether the Illinois units affected by this proposed rule can achieve the emissions limits listed in this table?

The Illinois EPA believes that control technologies needed to comply with this proposal are reasonably available and cost effective.

3. Did the Agency consider the federally approved NOx RACT emission limits from other states for similar affected units when it formulated its proposal?

Yes.

4. The Agency's Technical Support Document, at page 12, states that circulating fluidized combustion boilers range in size up to 1,075 mmBtu/hour. Is the Agency aware that the largest such boiler affected by this rule is nearly twice that size, and that there are other such boilers which are greater than 1,075 mmBtu/hour?

The number being referred to was intended to describe "typical" sizes for industrial boilers. As noted below on that page, CFBs are larger, especially for utility boilers. The largest CFB boilers in the world currently in operation are on the order of 300 MW, or about 3,000 MMBtu/hr.

a. Were the above mentioned large boilers considered in determining the emission limits contained in the proposal?

Yes. CFBs, even large ones, are capable of achieving under 0.10 lb/MMBtu.

5. Table 2-2: Data from Cleaver-Brooks Study, on page 14 of the Technical Support Document, provides information on NOx emission rates for gas-fired boilers predominately in the size range of 7 to 33 mmBtu/hour (one boiler had a size of 89 mmBtu/hour). It is IERG's understanding that the Agency is not proposing to establish NOx emission limits for gas-fired boilers in the size range of less than, or equal to, 100 mmBtu/hour. Is this correct?

Yes.

a. If so, how was the data in this table used to inform the Agency in the setting of NOx limits for gas-fired boilers larger than 100 mmBtu/hour?

The information on Tables 2-2 and 2-3 (from the same source) was not used *directly* to assist in forming an opinion on the emission limits for boilers larger than 100 MMBtu/hr, because there is other data that refers to boilers larger than 100 MMBtu/hr. However, the data in these tables and in the reference document has implications for such boilers (especially gas and oil fired). Certainly, it demonstrates that the emissions limits of the proposed rule are technically feasible. One of the units on Table 2-2 is of a size approaching 100 MMBtu/hr. And, it is generally more difficult to achieve low emissions on a smaller boiler, as there is often less space available for modification of combustion controls. As shown on the table, the lowest emissions are achieved by the largest boilers. In fact, the reference cited has a longer list of retrofits than shown in the TSD, and includes a retrofit much larger than 100 MMBtu/hr that achieves emissions levels below 0.01 lb/MMBtu on gas (see #23 which is a retrofit of a 184 MMBtu/hr boiler). See, Attachment 8 to the TSD. So, this data certainly demonstrates that the emission limits in the rule are technically feasible. In fact, as cited in this reference document by Mr. Willems, the Vice President of Product Development for Cleaver Brooks, other locations have adopted emission limits far stricter than what is proposed in Illinois:

"Finally, the San Joaquin area air district in CA took this approach about two years ago and reduced their limits to <9 ppm NOx (0.01 lb/MMBtu) for boilers over 20 MM BTU/hr and <15 ppm NOx (0.02 lb/MMBtu) for boilers between 2MM BTU/hr and <20 MM BTU/hr. They mandated that 25% of the boiler population was required to comply with these new regulations each year. They are currently in year two of this program with over (50) units completed and ozone reductions have occurred."

b. What is the averaging time for the emission rates shown in Table 2-2?

These were stack tests.

c. Does the emission data depicted in Table 2-2 represent stack test results? If so, what was the load capacity of the boilers at the time of testing?

Yes. Flowrates for each stack test are shown on the table.

d. How much flue gas recirculation was incorporated into each of the boilers listed in Table 2-2?

As noted in the response to Question 5a, the Table 2-2 information is referenced in the TSD. We do not have unit by unit information on FGR. FGR was likely in use for most or all of the units at or below 12 ppm. But, we cannot be certain of this without additional information.

However, to comply with the emissions levels proposed in the rule on gas units – 0.080 lb/MMBtu (or about 60 ppm) – FGR should not be necessary. The NATCOM burners that are referenced in Attachment 8 to the TSD are

capable of under 0.05 lb/MMBtu without FGR, as shown in the attached brochure (Attachment 1). This is typical of the performance of burners from other manufacturers as well.

e. The paragraph that precedes Table 2-2 (the last paragraph on page 13 of the Technical Support Document) states that Table 2-2 shows that low NOx levels can be maintained through "proper planning of boiler configuration." Since the Agency's proposed rule applies to existing boilers, for which boiler configuration modifications can be somewhat restricted, could you please describe the boiler configuration changes that were incorporated into the boilers shown in Table 2-2?

The retrofits included replacement of the burner. In many cases the burner quarl would need to be replaced or modified. Many of these burners have induced FGR, and therefore, may not require ductwork modifications. As noted in the answer to Question 5d, more detailed information is not available.

6. Table 2-5, on page 18 of the Agency's Technical Support Document, is identified as representing "uncontrolled" NOx emissions. Does the "Uncontrolled NOx Range" include newer boilers with some NOx control incorporated in their design?

The table is from the 1994 Alternative Control Techniques Document, NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers, and represents uncontrolled emissions as stated in that document. Due to the date of that document (over 10 years ago), the "baseline" emissions would not represent the capabilities of current low NOx burner technology even if the burners were called "low NOx burners" at that time.

a. How did the Agency utilize the "uncontrolled" ranges listed in Table 2-5 in establishing its proposed RACT limits?

These are exemplary of "baseline" control levels and might be useful in providing baseline control emission rates when calculating cost of control in $/ton of NOx reduced.

b. Has the Agency relied on a percent reduction target from "uncontrolled" levels in establishing its NOx RACT emission limits?

Yes and no. For post-combustion technologies, these are generally "percent reduction" limited, at least to a point. Combustion controls may be characterized by percent reduction. However, they are probably best characterized by their control level in ppm or lb/MMBtu than in terms of percent reduction. The emission rate targets were established by examining what has been achieved on similar units with technologies that are within the cost range of RACT. In most cases, combustion technology should be adequate. However, it is understood that in some cases post-combustion technology may be determined to be preferable or necessary.

7. Table 2-12b, on page 31 of the Technical Support Document, presents "Statistics Regarding Performance of Industrial Boiler Types Equipped with Ammonia SNCR." Has the Agency evaluated the coal-fired stoker boilers used in Illinois in relation to the stokers included in Table 2-12b in terms of boiler design, fuel type, and ammonia slip in order to evaluate their comparability?

   Detailed review of each boiler in Illinois was not done and was not viewed to be necessary. SNCR has been shown to be effective on a large number of stoker boilers. Therefore, a "case-by-case" review was unnecessary.

8. On page 33 of the Agency's Technical Support Document, the statement is made that "... SCR is viewed as technically feasible for nearly any coal application." Does the Agency believe that SCR is technically feasible for fluid bed boilers?

   SCR is technically feasible on CFB boilers, but would be unnecessary for compliance with this rule. SCR is generally not used on CFB boilers because much less expensive options are available, such as SNCR, to comply with existing regulations. The figure set forth at Attachment 2 is from a brochure by Foster Wheeler – a manufacturer of CFB boilers - that shows SCR installed on an industrial CFB boiler. The complete brochure is provided as Attachment 3.

   a. Does the Agency believe that SCR is feasible on all stoker boilers?

      SCR is technically feasible on stoker boilers. However, it is generally not used because, like CFB boilers, stoker boilers have much less costly options for control.

   b. Do the Agency's proposed NOx emission limits for stoker boilers assume that SCR is a feasible option?

      We do not expect that a stoker boiler would select SCR for compliance with this rule because there are less costly options, such as combustion controls and SNCR. However, as noted in the answer to Question 8a, SCR is technically feasible on stoker boilers.

   c. What information did the Agency rely upon in determining that SCR is technically feasible on a broad range of ICI boiler types and sizes?

      It is important to distinguish between technical feasibility and cost. SCR has been applied to a broad range of boiler types – coal, natural gas, oil. SCR can be applied to any combustion source with an available temperature range (or where the temperature range can be made available). However, the cost of applying SCR technology will vary by source type. The selection of SCR or any other control technology for NOx reduction on a specific source will depend upon the cost of applying SCR to that source and the costs of other options that are available for that source. As a result, because other less-expensive options are available, SCR is not in use on some source types although it is technically feasible to apply it to them,.

9. Has the Agency performed any analyses of Illinois facilities to determine the potential cost of this rule?

A total cost was not estimated for the TSD. However, this rule was developed with the intent of keeping the cost of NOx reductions generally at or below $3000/ton.

10. Has the Agency gathered or reviewed any information from the last 3 years for costs of NOx retrofit controls for facilities in Illinois or similar to those in Illinois?

Yes, in fact escalation was applied to some of the cost estimates, particularly for SCR as described on page 36 of the TSD.

11. The Agency's Technical Support Document includes NOx emission limits for categories of emission units that do not, or likely never will, exist in the area covered by this rule. What is the purpose for including these limits?

There is no basis for the claim that certain emission units "likely never will exist." The TSD acknowledges that there are no cement kilns in the current NAA boundaries, and that the only aluminum melting furnace in the Chicago area is not currently operating. To our knowledge, the aluminum melting furnace has not been dismantled, so it is possible that the current, or a potential future owner, may intend to operate the furnace in the future. Regarding cement kilns, it should be noted that USEPA has indicated that it will designate Massac County, where there is an existing cement kiln, as non-attainment for PM2.5 in December 2008.

12. Does the Agency intend its definition of "industrial boiler" (see Section 211.3 100, and Sections 217.160 to 166 of the proposed rule) to include cogeneration units and/or heat recovery steam generators that capture waste heat from turbines or engines?

Yes.

a. If so, has the Agency performed any analysis to determine the technical feasibility and cost for cogeneration units and/or heat recovery steam generators to comply with its proposed rule?

No.

13. Does the Agency intend its definition of "industrial boiler" (see Section 211.3 100, and Sections 217.160 to 166 of the proposed rule) or "process heater" (see Section 211.5195, and Sections 217.180 to 186 of the proposed rule) to include gas-fired chillers that provide cooling for either processes or occupied spaces?

If refrigerant is heated directly by gas firing, it is a process heater.

a. If so, has the Agency performed any analysis to determine the technical feasibility and cost for such gas-fired chillers to comply with its proposed rule?

No separate analysis was performed, but the Illinois EPA believes that the technical feasibility and cost for gas-fired chillers should be similar to process heaters and industrial boilers.

14. The Statement of Reasons, at pages 7-8, states that the NOx RACT State Implementation Plan was required to be submitted to the USEPA by September 15, 2006. And further, that the date for affected sources to comply with the emissions limitations in the proposed rule is May 1, 2010.

a. Based on the federal requirement for the NOx RACT SIP submittal, when does he USEPA require that NOx RACT be implemented?

USEPA required that NOx RACT be implemented no later than May 1, 2009.

b. What is the basis for the Agency's selection of May 1, 2010 as the compliance date?

Given the delay in developing this proposal, and in response to concerns expressed by stakeholders, the Illinois EPA has proposed to delay implementation for one year after USEPA's required implementation date.

c. In the Agency's deliberations regarding the technical feasibility and cost of compliance for this rule, was any consideration given to the amount of lead-time necessary for various industries to plan, design, construct and test the emission control technologies envisioned by this proposed rule?

The Illinois EPA believes that stakeholders have already had ample time to plan and design the control measures needed to comply with this proposal since they have been aware of it for several years. Depending on the duration of the rulemaking process, there may or may not be sufficient time to obtain the necessary permits and construct the control equipment. The Illinois EPA is willing to discuss specific hardships posed by the compliance deadlines should they, in fact, occur.

d. Does the Agency believe that the amount of time from rule promulgation to the compliance date has a significant bearing on the ultimate cost and feasibility of compliance?

The Illinois EPA does not believe that the compliance date will, in general, impose a significant cost impact to most industries, although the Illinois EPA is willing to discuss options with companies that are unduly impacted by the proposed compliance date.

e. Is the concept of "Reasonably Available" a factor of the compliance date such that the technical options and economic cost for Reasonably Available Control Technology would be dependent on the amount of time between rule promulgation and compliance?

"Reasonably available" is not a factor influenced by the compliance date. The Illinois EPA is willing to discuss compliance options with companies that will have difficulty complying by the proposed compliance date.

15. Section 217.158 of the proposed rule describes the Emissions Averaging Plans. It is IERG's understanding that the Agency is not allowing emission units into an averaging plan if they commenced operation after January 1, 2002, unless they are deemed to be a "replacement unit." Is this correct?

    Yes.

    a. What is the basis for the Agency's determination to exclude such units?

       USEPA has established 2002 as the base year for planning purposes for implementation of the ozone and PM 2.5 NAAQS. USEPA used air quality data from that time period to establish which areas would be designated as nonattainment. Since air quality levels in the Chicago and Metro-East areas violated the NAAQS in 2002, the Illinois EPA must seek emission reductions from emission units that were in existence in 2002. Further, Illinois is required to demonstrate continued progress towards attainment beginning in the base year, 2002. Units that commenced operation after 2002 cause emissions to increase above the levels already existing in 2002. The Illinois EPA must seek reductions from existing sources that yield progress toward attainment and to compensate for any increases due to the operation of new emission units.

    b. Has the Agency attempted to assess the impact that such a restriction might have on environmental decision-making at affected facilities?

       It is the intent of the Illinois EPA that owners and operators of units that were operating on or before January 1, 2002 seek cost effective measures to reduce NOx emissions from those units.

    c. Has the Agency considered how it will make a determination of whether a new unit constitutes a "replacement unit," especially as emphasis is growing to improve energy efficiency and reduce greenhouse gasses, thereby making it unlikely that a "replacement unit" would be exactly the "same" as the unit(s) it replaces?

       For the purposes of emissions averaging under this proposal, a replacement unit must be essentially the same as the unit it replaces.

16. Section 217.154 of the proposed regulation sets forth the performance testing requirements. Both subsections (a) and (b) refer to the date of emission unit construction or modification. Could the Agency please clarify what constitutes "constructed on or before," and similarly "construction or modification occurs after"? That is, is it the

beginning of construction, the completion of construction, the date of issuance of a construction permit?

The definitions contained in 35 Ill. Adm. Code 201 and 211 apply to Part 217. See, 35 Ill. Adm. Code 217.103. Accordingly, Section 201.102 defines the term "construction" as "commencement of on-site fabrication, erection or installation of an emission source or of air pollution control equipment," and "modification" as "any physical change in, or change in the method of operations of, an emission source or of air pollution control equipment which increases the amount of any specified air contaminant emitted by such source or equipment or which results in the emission of any specified air contaminant not previously emitted. It shall be presumed that an increase in the use of raw materials, the time of operation or the rate of production will change the amount of any specified air contaminant emitted. Notwithstanding any other provisions of this definition, for purposes of permits issued pursuant to Subpart D, the Illinois Environmental Protection Agency (Agency) may specify conditions under which an emission source or air pollution control equipment may be operated without causing a modification as herein defined, and normal cyclical variations, before the date operating permits are required, shall not be considered modifications." See, 35 Ill. Adm. Code 201.102.

a. If the terms mean the beginning or completion of construction, please define what constitutes beginning or completion.

See answer to Question 16.

17. On page 6 of James Staudt's pre-filed testimony, the statement is made that SCR has been widely used on boilers at industrial facilities.

a. Could you please provide a representative list of such installations, including the boiler type, and identify those that were retrofits?

According to my testimony,

"It has been widely used on utility boilers, turbines, diesel engines as well as industrial facilities."

So, the question incorrectly characterizes my testimony. SCR has been used in numerous gas-fired industrial boilers and it has been used in refinery process units, especially CO boilers. It has also been retrofit on hundreds of coal fired power plants. But, to my knowledge it has not been retrofit on any solid fuel industrial boilers in the United States because lower cost approaches are available.

b. Also, please identify those that used high-sulfur coal, and those that were stoker fired boilers.

There are numerous high sulfur boilers equipped with SCR in the electric utility industry. In Illinois, the Duck Creek, Dallman, and Marion plants all

have units with SCR and burn high sulfur coal. Numerous other power plants throughout the United States that fire high sulfur coal are also equipped with SCR. USEPA's National Electric Energy Data System (NEEDS) database, that can be downloaded at http://www.epa.gov/airmarkt/progsregs/epa-ipm/past-modeling.html, includes a list of electric utility boilers equipped with both SCRs and scrubbers. It also shows units with SCR without scrubbers – some firing high sulfur coal. Those units with wet scrubbers typically fire high sulfur coal. Therefore, there is extensive experience with SCR on high sulfur fueled coal fired boilers.

I am not aware of any stokers that are equipped with SCR, as stokers generally have less expensive options to control NOx due to the lower baseline NOx level, lower temperature combustion and longer furnace residence time than pulverized coal units. However, if the owner of a stoker boiler chose to use SCR to control NOx, there is no technical reason why they couldn't, even if they burned high sulfur coal. But, as previously mentioned, a stoker boiler owner has other, less-expensive options to reduce NOx and, therefore, would be very unlikely choose to use SCR.

18. Does the Agency believe that a >250 mmBtu/hour coal-fired boiler, using Illinois coal, can meet a NOx limit of 0.18 lbs/MMBtu without SCR?

    Yes, combinations of combustion controls and SNCR have been shown to be capable of providing emissions below 0.18 lb/MMBtu, as described in Section 2.3.6 of the TSD. An example is Ameren's Sioux unit 1, which achieved under 0.18 lb/MMBtu while firing 100% Illinois bituminous coal, as presented at the Electrical Utilities Environmental Conference (EUEC), January 22-25, 2006, in a presentation by Giesmann, Stuckmeyer, Cremer, Chiodo, Adams, and Boyle (See Attachment 4).

19. On page 6 of James Staudt's pre-filed testimony, it is stated that "SCR can and has been installed to provide NOx reductions at costs below $2,500/ton."

    a. What price was used for the cost of ammonia in making this calculation?

       In the estimates in Figures 2-17 and 2-18 of the TSD, $400/ton. Since 17 pounds of ammonia removes 46 pounds of NOx, the effect of ammonia cost is that a change in ammonia cost of $100/ton changes the cost of removing NOx by $37/ton of NOx. In other words, if the cost of ammonia were doubled from $400/ton to $800/ton, the effect on Figure 2-17 would be to increase cost by $150/ton of NOx – a relatively modest shift.

    b. Does this cost include the cost of replacement of the boiler's air pre-heater?

       Yes, the majority of the boilers that have been retrofit with SCR were utility boilers and many of them replaced their air pre-heater.

    c. Does this cost include the cost of a wet electrostatic precipitator?

No, because a wet ESP is not necessary. None of the hundreds of coal-fired SCR retrofits in the United States have required a wet ESP.

20. On page 6 of James Staudt's pre-filed testimony, he describes the SNCR technology. Is the Agency aware of SNCR applications on industrial boilers using high-sulfur coal?

Yes, industrial and utility units that burn high sulfur coal (3 lb/MMBtu of SO_2 or greater) and have used SNCR on a commercial basis include:

- **AES Beaver Valley (PA)**
- **AES Greenidge (NY)**
- **BL England Station (NJ)**
- **Cinergy Miami Fort 6 (OH)**

Also attached is the ICAC SNCR White Paper, as well as Fuel Tech's installation list, to provide additional information regarding where SNCR has been applied (See Attachments 5 and 6).

a. Could you please describe how the formation of ammonium bisulfate is managed, to avoid corrosion problems?

Ammonium bisulfate is primarily a concern for deposition on air preheater surfaces. It is controlled by minimizing ammonia slip into the air preheater.

b. What provisions need to be made to accommodate boilers with frequent load swings?

More than one injection zone would likely be needed to ensure that the reagent is injected into the proper temperature zone, and associated controls would be necessary. This is a commonly included design feature in SNCR systems that are expected to operate over a wide load range.

c. How does SNCR affect the turn down ratio of the boiler?

SNCR should not affect turn down of the boiler if the SNCR system is designed to cover the boiler's operating range. The most difficult load is typically full load because temperatures are highest and gas flow is fastest (treatment time is shortest). And, NOx emissions are often highest at full load. If an owner wishes to operate the SNCR system at lower loads, then he or she would normally design for injection zones and associated controls to inject into the proper temperature location in the furnace at these lower loads.

21. Does the use of SCR or SNCR affect the ability to beneficially re-use ash?

Potentially it does. However, this is normally avoided. The extent to which ammonia slip can impact fly ash reuse will depend upon the level of ammonia slip, the characteristics of the fly ash, the manner in which the fly ash is handled and how

it is reused. But, if ammonia slip is maintained at sufficiently low levels, fly ash will not be impacted.

Respectfully submitted,

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY

By: ______________________

Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

DATED: September 30, 2008

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THIS FILING IS SUBMITTED ON RECYCLED PAPER

STATE OF ILLINOIS	)	
	)	**SS**
COUNTY OF SANGAMON	)	
	)	

CERTIFICATE OF SERVICE

I, the undersigned, an attorney, state that I have served electronically the attached ILLINOIS ENVIRONMENTAL PROTECTION AGENCY'S ANSWERS TO PRE-FILED QUESTIONS BY THE ILLINOIS ENVIRONMENTAL REGULATORY GROUP, upon the following person:

John Therriault
Assistant Clerk
Illinois Pollution Control Board
James R. Thompson Center
100 West Randolph St., Suite 11-500
Chicago, IL 60601

and mailing it by first-class mail from Springfield, Illinois, with sufficient postage affixed to the following persons:

SEE ATTACHED SERVICE LIST

ILLINOIS ENVIRONMENTAL
PROTECTION AGENCY,

Gina Roccaforte
Assistant Counsel
Division of Legal Counsel

Dated: September 30, 2008

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IEPA ATTACHMENT NO. 1

NAT-COM

National Combustion Equipment INC.

a division of aqua-chem Inc.

NEW GENERATION

LOW-NO$_x$

INDUSTRIAL BURNERS

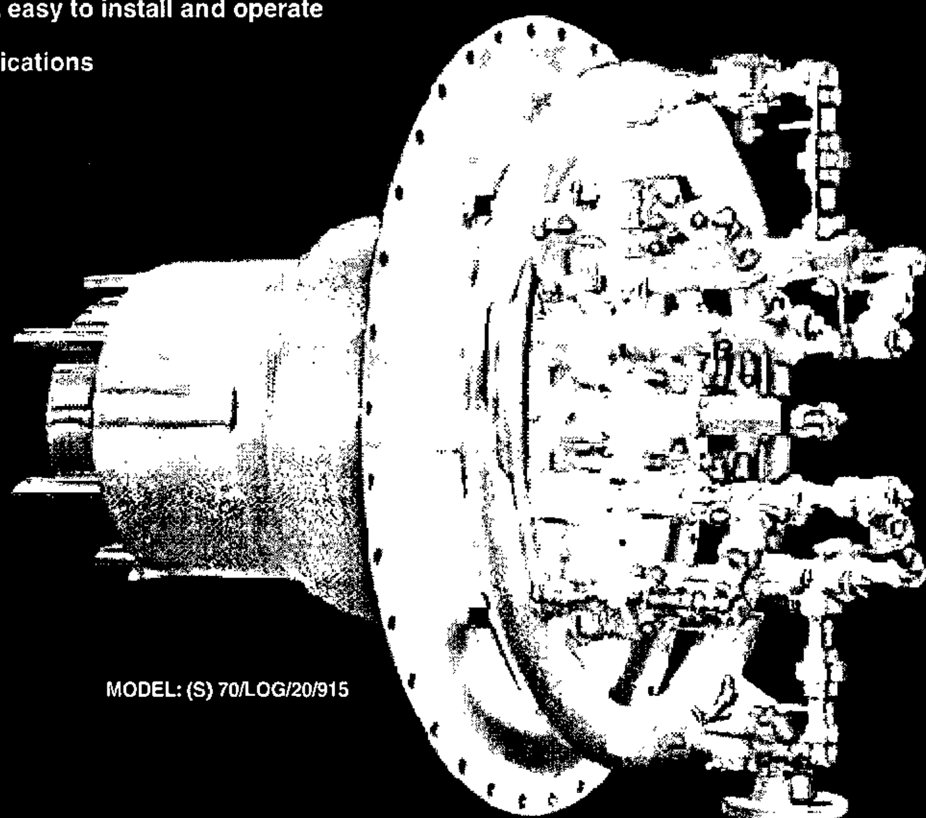
ENGINEERED FOR HIGHEST PERFORMANCE AND LOWEST EMISSIONS

- Lowest operating cost burner available
- Lowest NO_x achievable without FGR
- Adaptable to any furnace/windbox configuration
- Superior quality construction, reliable, easy to install and operate
- Ideal for single or multiple burner applications

Adaptability is NATCOM's response to complexity

NATCOM burners are adaptable to all types of combustion chamber configurations to maximize boiler efficiency and reduce emissions.

A revolutionary system *that permits "on-line" adjustments of the burner components. This maximizes the use of any combustion chamber to reduce emissions down to the lowest achievable NO_x levels without the need for flue gas recirculation.*



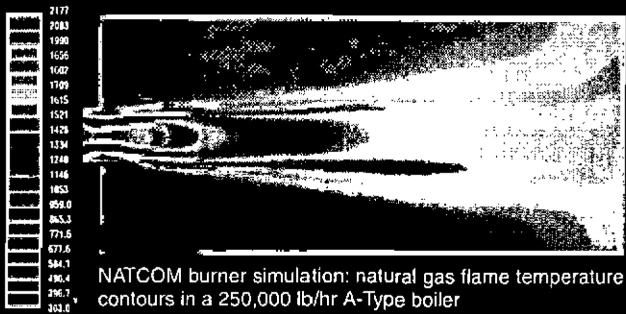
MODEL: (S) 70/LOG/20/915

NATCOM sets New Standards

20 to 400 MMBTU/hr for heavy oils, Natural gas and low BTU gases

ISO-9001

COMPUTER DESIGNED COMBUSTION AERODYNAMICS



NATCOM burner simulation: natural gas flame temperature contours in a 250,000 lb/hr A-Type boiler

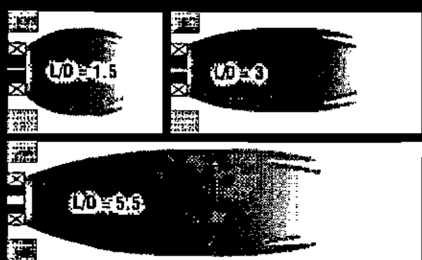
Absolute flame stability

Natcom's dual swirl flame stabilizer uses variable pitch blades to produce strong back-flows of hot gases that sustain a very wide flame front. The result is an absolute flame stability at all boiler loads for a range of excess air from minus 20% to plus 400%.

High fuel-air mixing efficiency

The axial, radial and tangential air flow fields generated at the burner outlet are combined with high momentum fuel jets for maximum diffusion between boundary layers. This results in a stable and well defined mixing pattern that produces very homogeneous fuel-air mixtures.

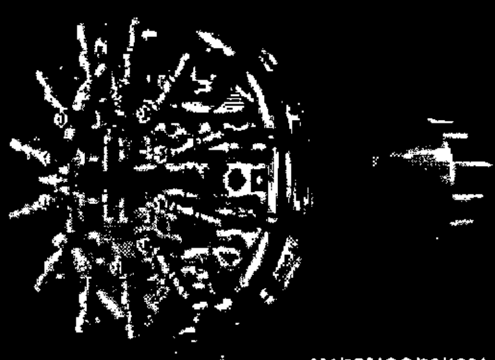
Adaptability



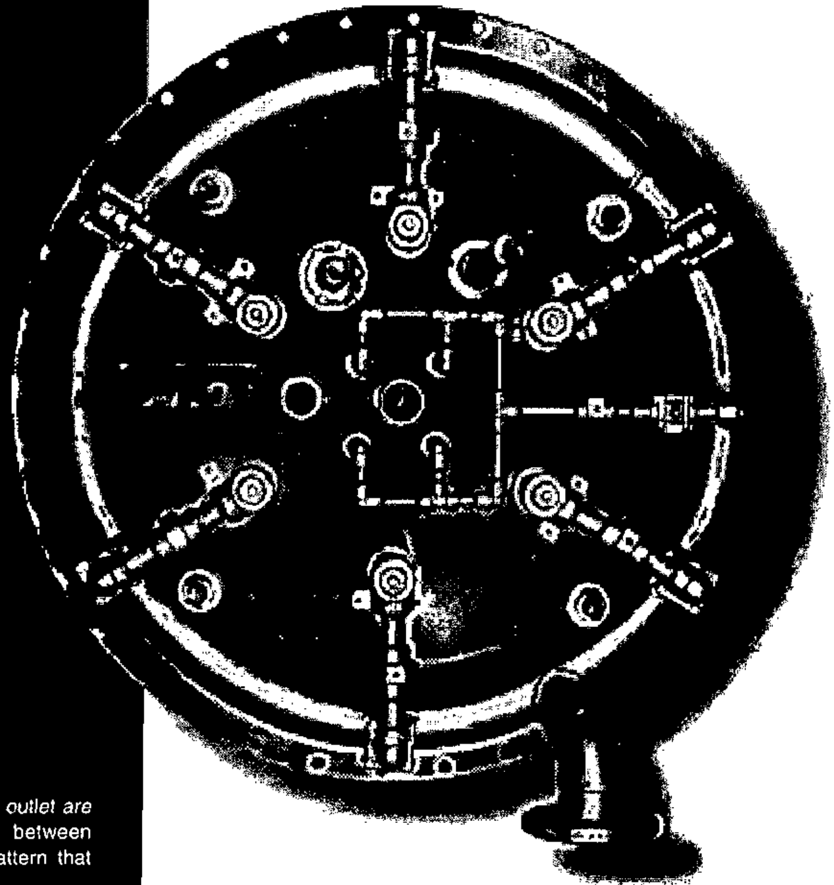
Burner aerodynamics can be adapted to produce either short and wide flames or long and narrow flames. Flame length to diameter ratios from 1.5 to 5.5 will fit any boiler type. Fuel gas flow and injection direction can be adjusted on each individual gas injector in order to match the air flow perfectly. For fuel-oil injection, Natcom uses a proprietary variable-geometry atomizer which is adjustable on line for optimum oil flame shaping.

Low NO_X

Individually adjustable fuel staged gas injectors allow for optimal use of any given combustion chamber configuration, resulting in lowest achievable NO_X emissions without FGR. If necessary, flue gas recirculation may be used to reduce NO_X even further.



M4/85/HOG/26/1321



A TOP PERFORMER: NATCOM score sheet

- O_2 < 1%
- CO < 10 ppm
- **Natural Gas Firing:**
  - NO_X < 0.05 lb/MMBTU (40 ppm)
  - NO_X < 0.01 lb/MMBTU (8 ppm) w / IFGR
- **Heavy Oil Firing:** (< 0.3% N_2)
  - NO_X < 0.20 lb/MMBTU (150 ppm)
  - Particulates < 0.03 lb/MMBTU
- **Turndown ratio**
  - > 40 : 1 (Natural Gas)
  - > 15 :1 (Oil)

NAT-COM

National Combustion Equipment Inc.

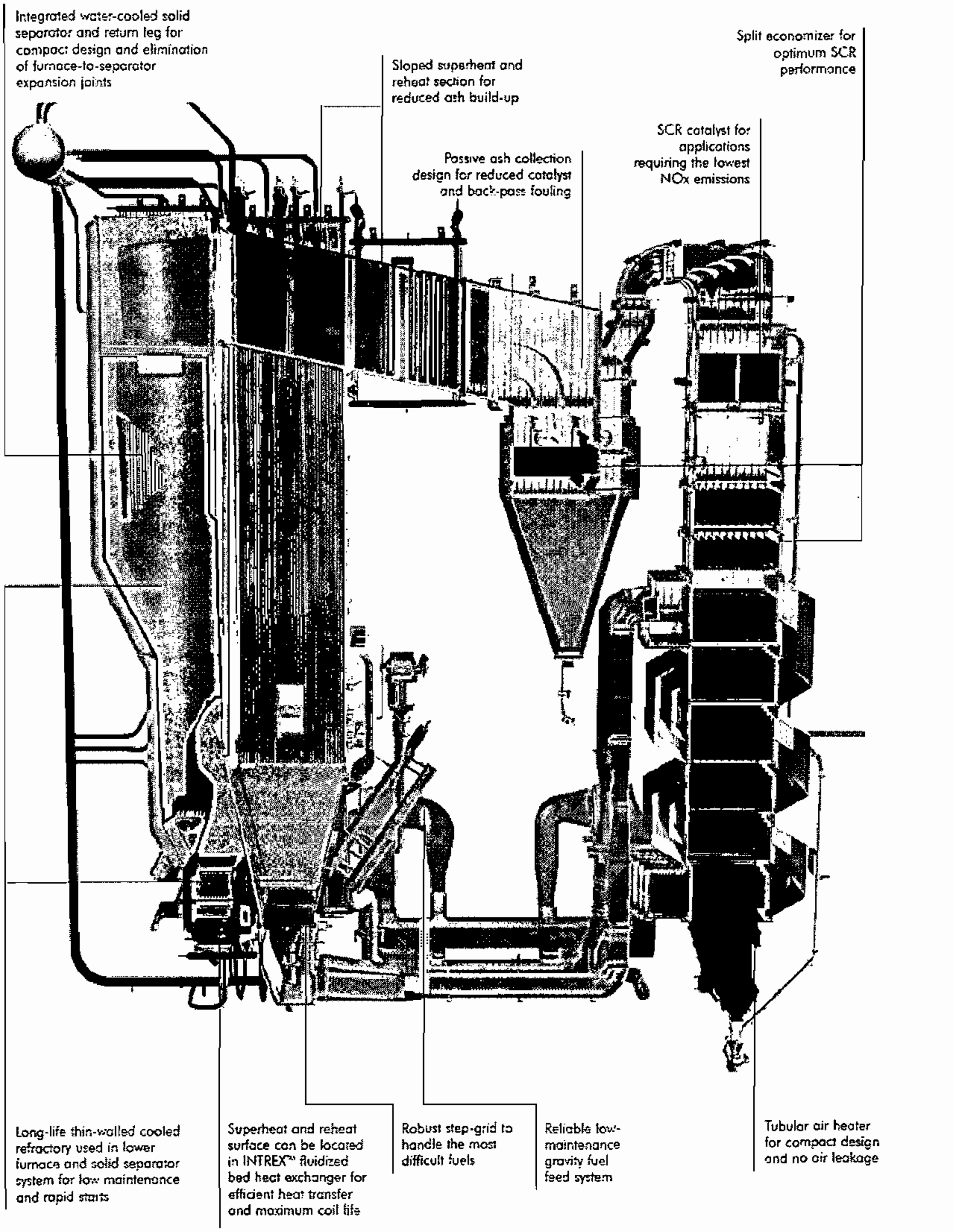
a division of aqua-chem inc.

8515 Lafrenaie, St-Leonard, Qc, Canada H1P 2B3

TEL.: (514) 326-2571 FAX: (514) 326-9347

http://www.natcomonline.com

NAT-1000

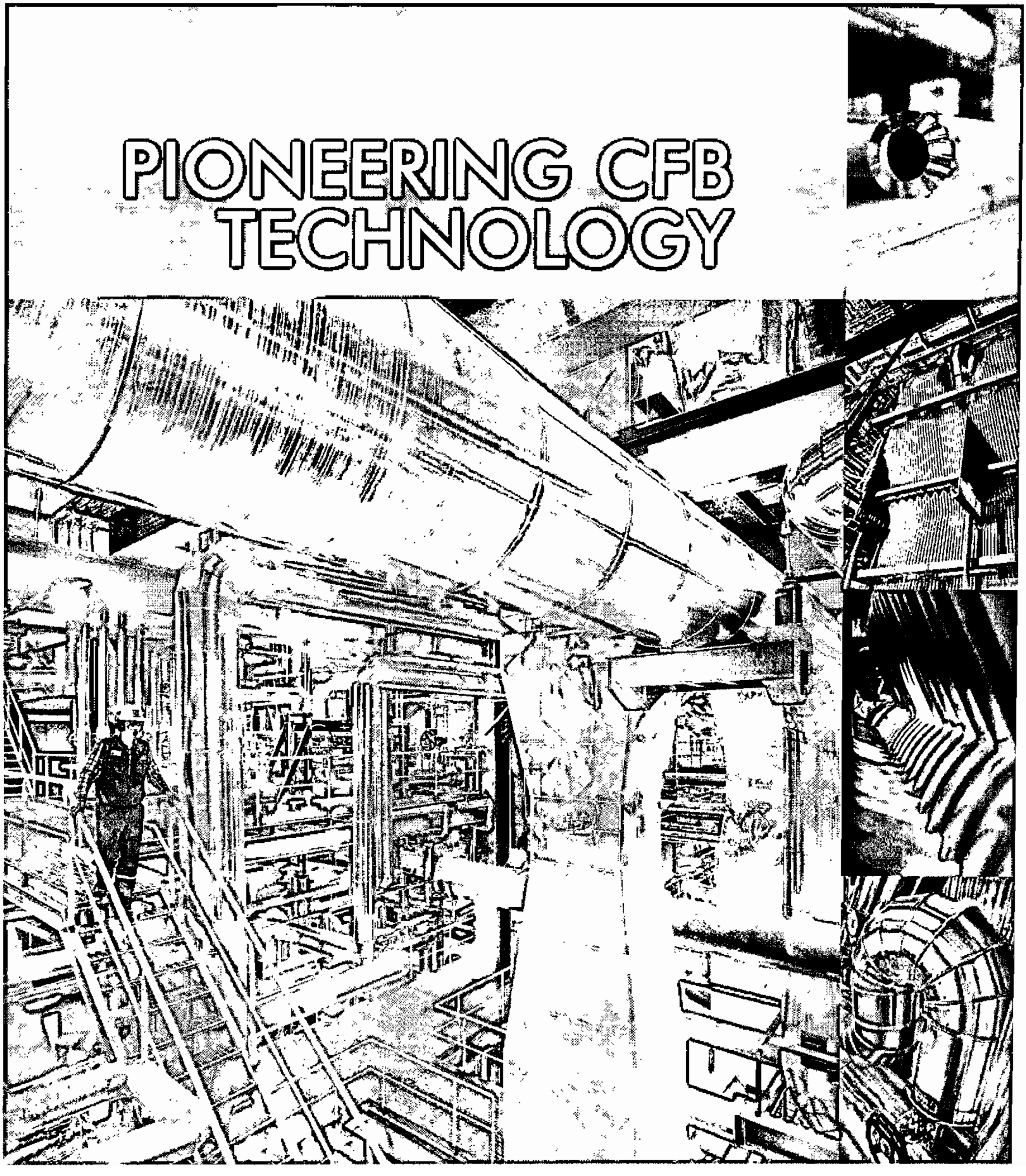


WE OFFER INNOVATIVE AND PROVEN DESIGN FEATURES
IN OUR INDUSTRIAL CFB UNITS

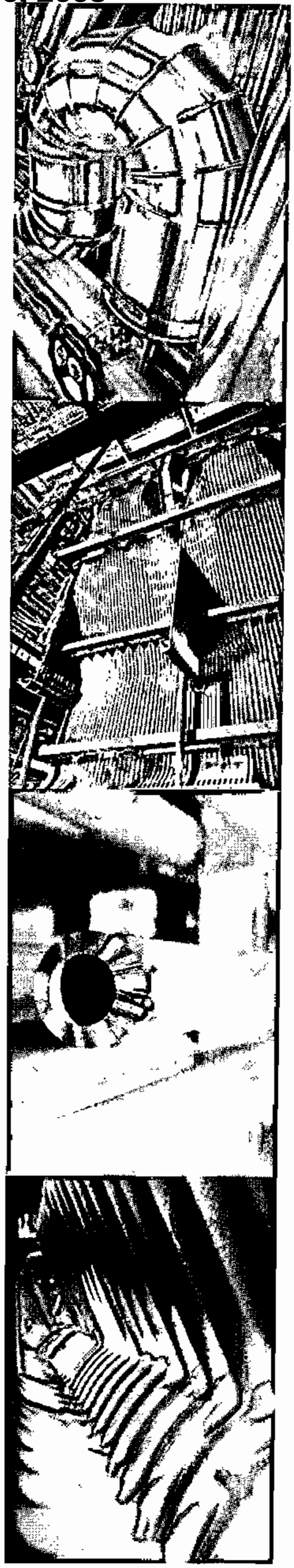
FOSTER WHEELER

IEPA ATTACHMENT NO: 3

PIONEERING CFB TECHNOLOGY



FLUIDIZED BED COMBUSTION IS OUR SPECIALTY - ONE THAT WE HAVE PIONEERED FROM THE VERY START.



PIONEERING CFB TECHNOLOGY

CIRCULATING FLUIDIZED BED (CFB) PIONEERS

We have steadily increased unit size and integrated advanced field-proven design features into our CFB technology. Our CFBs first reached small-scale utility application in 1987 on the 110 MWe Tri-State Nucla power project in the U.S., then went on to the medium utility scale in 2001 with the 2 x 300 MWe units for the Jacksonville Energy Authority. Over the 1998-2004 period we delivered six CFB units totaling nearly 1500 MWe for the largest CFB repowering project ever in history - the Turów project in Poland.

Our success has come from a track record of satisfying clients' reliability, environmental, and efficiency goals with innovative technology for converting economical solid fuels into valuable steam and power. Through our experience of supplying over 400 fluidized bed units to industrial and utility customers worldwide, we have steadily scaled-up and improved our technology. Over 300 of these fluidized bed steam generators have been CFB designs.

Our latest pioneering can be seen in our award for the Lagisza project in Poland, which brings a double first to the utility power industry - the world's first supercritical CFB boiler and the world's largest single CFB unit, rated at 460 MWe.

Looking into the future, our CFB technology can be adapted to capture carbon dioxide to help reduce the threat of global warming. We are currently developing Oxy-Fuel technology to be applied to CFB units operating today as well as, to new more advanced units. Oxy-Fuel technology looks very promising allowing 100% capture of carbon dioxide in a cost-effective and reliable way. We expect Oxy-Fuel CFB technology to be a fuel-flexible, zero-air-emission technology bringing high value to our utility and industrial clients.

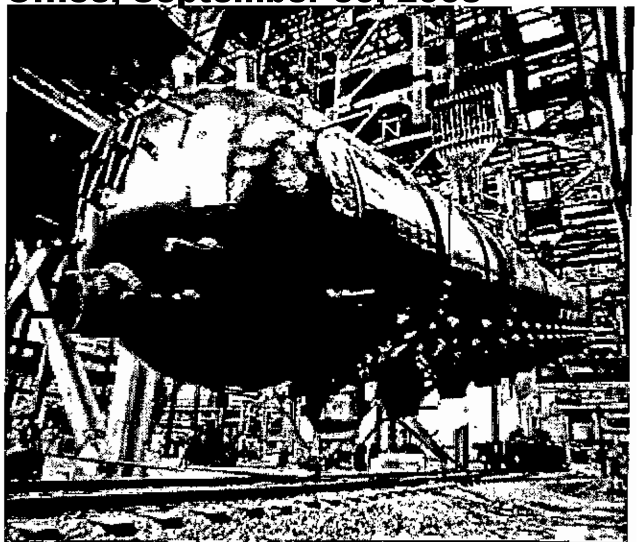
PIONEERING CFB TECHNOLOGY

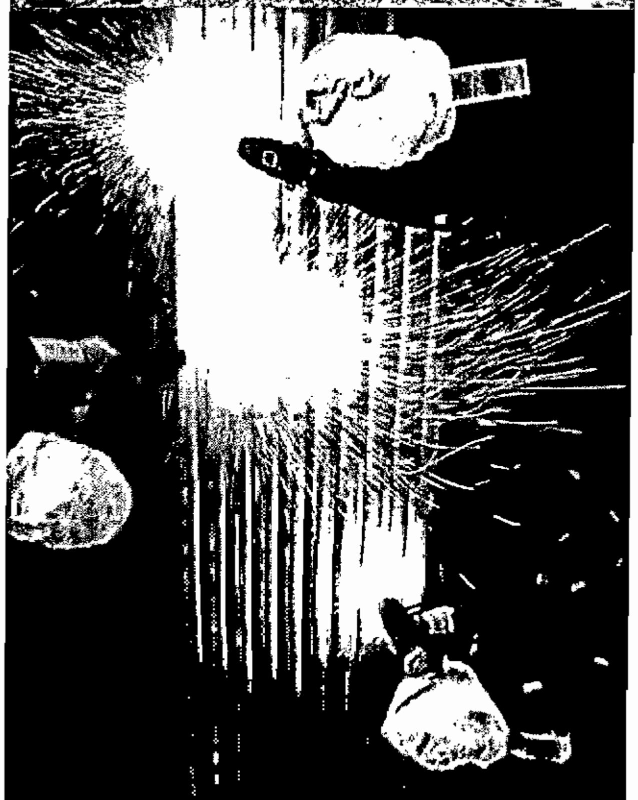
INNOVATIVE TECHNOLOGY SOLUTIONS

THINK GREEN

Low emissions are a key benefit of our CFB technology, allowing them to meet the strictest environmental standards. Our CFBs stage the combustion process and operate at low combustion temperatures while giving the fuel long burning times, resulting in naturally low nitrogen oxide (NOx) formation and high combustion efficiency. They can also capture the fuel's sulfur as the fuel burns by using low-cost limestone and employing selective-non-catalytic-reduction (SNCR) to achieve very low NOx and sulfur oxide (SOx) emissions in the most economical way, and in most cases, avoiding add-on pollution control equipment.

The CFB advantage is particularly highlighted in repowering projects. SOx and particulate emissions can often be cut by over 90% and NOx emissions by over 50%. Carbon dioxide emissions are often cut by 25% or more due to the dramatic improvements in boiler and plant efficiency when older equipment is replaced. For the lowest emissions, our supercritical, once-through-unit (OTU) CFB technology can reduce all these emissions another 5-10%, due to its ability to further increase overall plant efficiency.

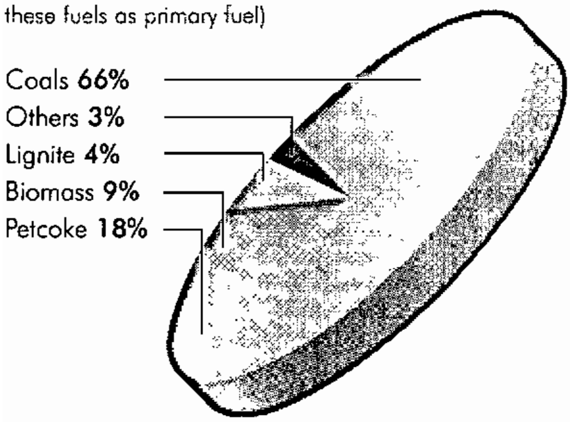




FUEL FLEXIBILITY

Our CFB units are capable of firing nearly all solid fuels - including waste products that otherwise would have been land-filled - while maintaining the lowest levels of emissions, and the highest equipment reliability and efficiency. Our fuel experience is unmatched as proven by our capability to design units for even the lowest-quality fuels. Our CFBs give plant owners the flexibility to source fuel from a number of suppliers and industries, improving their fuel supply security while taking advantage of fuel prices and market conditions.

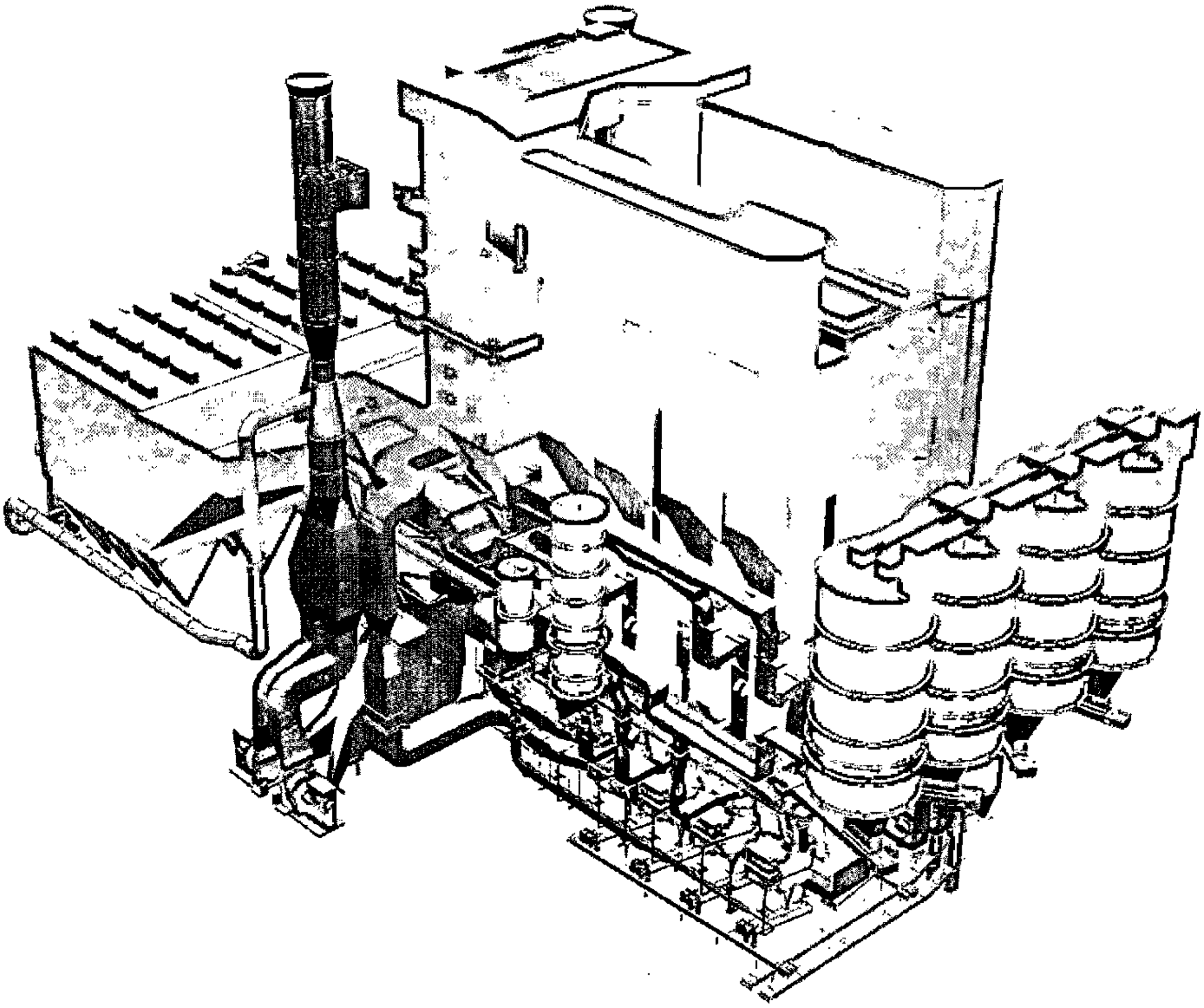
Our CFB Fuel Experience
(% of operating FW CFB capacity utilizing these fuels as primary fuel)



RELIABLITY

Our simple yet advanced CFB designs can achieve the highest plant availability, proven by over twenty million hours of operational experience, even after years of operation. Preventative condition monitoring, expert maintenance, and rapid-response repair work - all supplied by our service teams - help ensure maximum reliability - year after year.

Our long-term operations and maintenance support (O&MS) agreements and our innovative SmartBoiler™ system (an expanding set of intelligent analysis and optimization tools for enhancing plant operation and maintenance) are available to increase your plant's availability even further.



OUR LARGE-SCALE SUPERCRITICAL ONCE-THROUGH CFB DESIGN OFFERED UP TO 800 MWe UNIT SIZES

UTILITY CFBs

WHAT STARTED OFF AS A SOLUTION FOR HARD-TO-BURN FUELS HAS BECOME A MAINSTREAM COMBUSTION TECHNOLOGY AVAILABLE IN EVER-LARGER UNIT SIZES. TODAY, WE OFFER TWO STATE-OF-THE-ART UTILITY CFB DESIGNS, EACH OFFERING HIGH VALUE TO UTILITY CLIENTS.

UTILITY CFBs

GOING SUPERCRITICAL

We have taken the next major step forward in advancing our CFB technology by offering our latest generation of supercritical once-through steam generation technology, which incorporates Siemens' BENSON vertical-tube evaporator technology for units above 300 MWe. This allows us to offer our utility clients all of the benefits of CFB combustion technology, together with the high efficiency of supercritical steam technology. This technology can improve overall plant efficiency by 5-10% compared to conventional natural circulation steam technology, which translates directly into a 5-10% reduction in the plant's air and ash emissions as well as its fuel and water needs. When we say a reduction in air emissions, we mean all air emissions like SOx, NOx, mercury and particulates as well as greenhouse gases, like carbon dioxide.

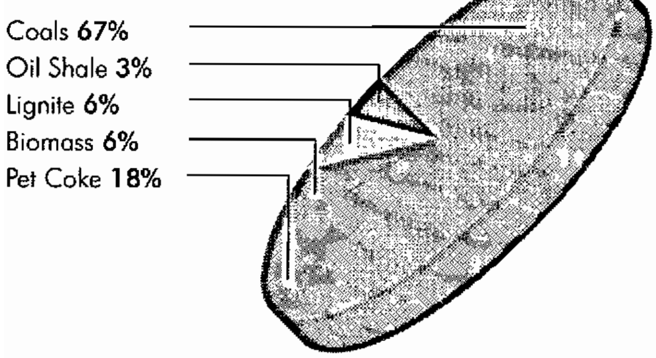
As with our conventional natural circulation CFBs, these highly efficient supercritical units will be equally at home with hard-to-burn fuels, as well as common utility coals. We have developed a modular design approach allowing us to offer units up to 800 MWe in steam capacity.

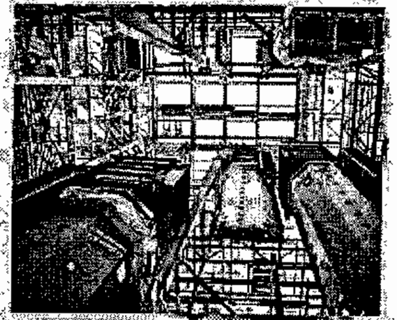
CFB VALUE FOR UTILITIES

Our utility customers have turned to CFBs due to the value they see in our technology: fuel flexibility, low emissions, and reliability. Many are seeing value in petroleum coke, lignite, waste coal, and biomass from both an economic and environmental aspect. Our technology can reliably and cleanly burn these fuels as primary fuels or in combination with other fuels over the life of the plant, giving power generators the flexibility to alter their fuel strategies and to take advantage of fuel market opportunities and changes in environmental regulation.

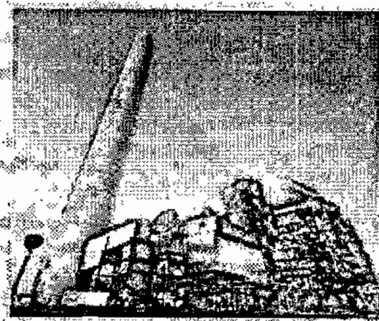
Our Utility Fuel Experience

(% of operating FW utility capacity utilizing these fuels as primary fuel)



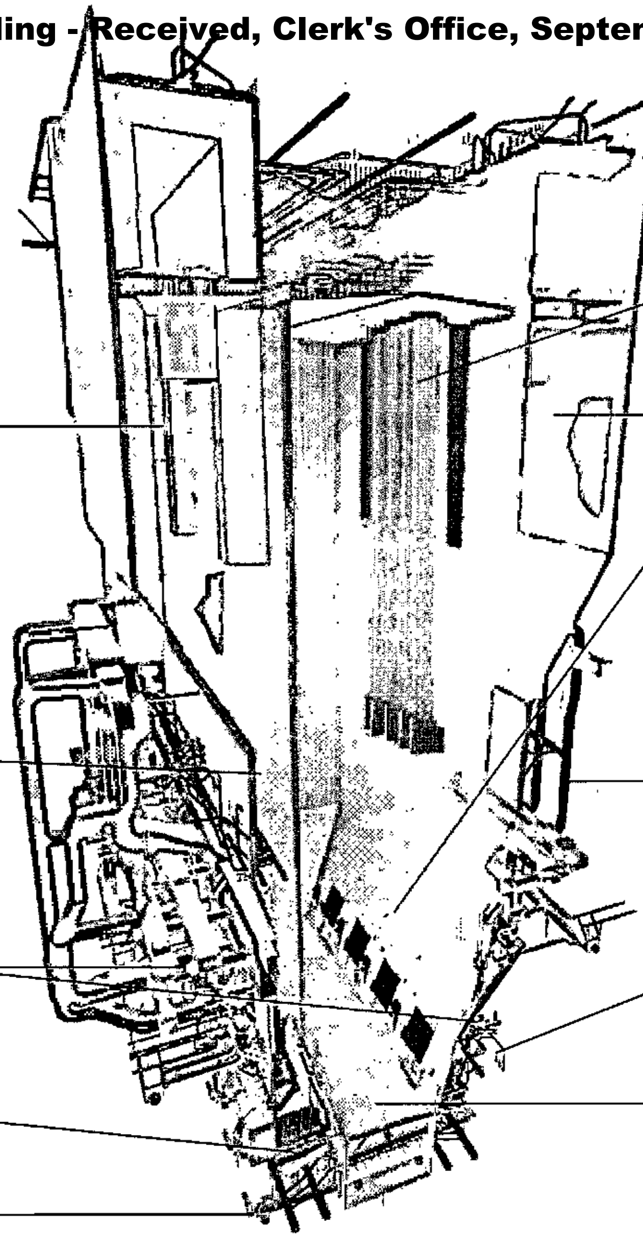


PKE: LAGISZA, POLAND
Location: Bedzin, Poland
Customer: Poludniowy Koncern Energetyczny (PKE) Elektrownia Lagisza
Start-Up Year: 2009
Capacity: 460 MWe
Fuel: Bituminous Coal

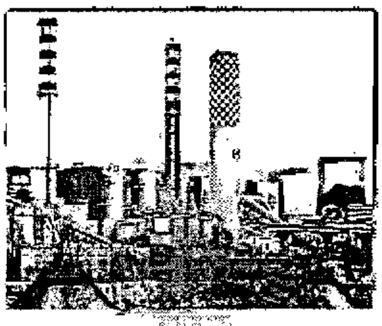


JEA NORTHSIDE REPOWERING PROJECT
Location: Jacksonville, Florida
Customer: Jacksonville Electric Authority
Start-Up Year: 2001
Capacity: 2 x 300 MWe
Fuel: Bituminous coal and petroleum coke

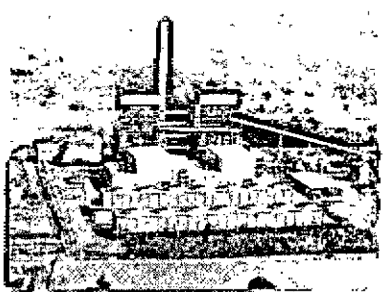
NARVA ELEKTRIJAAMAD
Location: Narva, Estonia
Customer: AS Narva Elektrijaamad
Start-Up Year: 2004, 2005
Capacity: Eesti Block 2 x 100 MWe, Balti Block 2 x 100 MWe
Fuel: Oil Shale



OUR LARGE-SCALE COMPACT SEPARATOR CFB DESIGN OFFERED UP TO 800 MWe UNIT SIZES

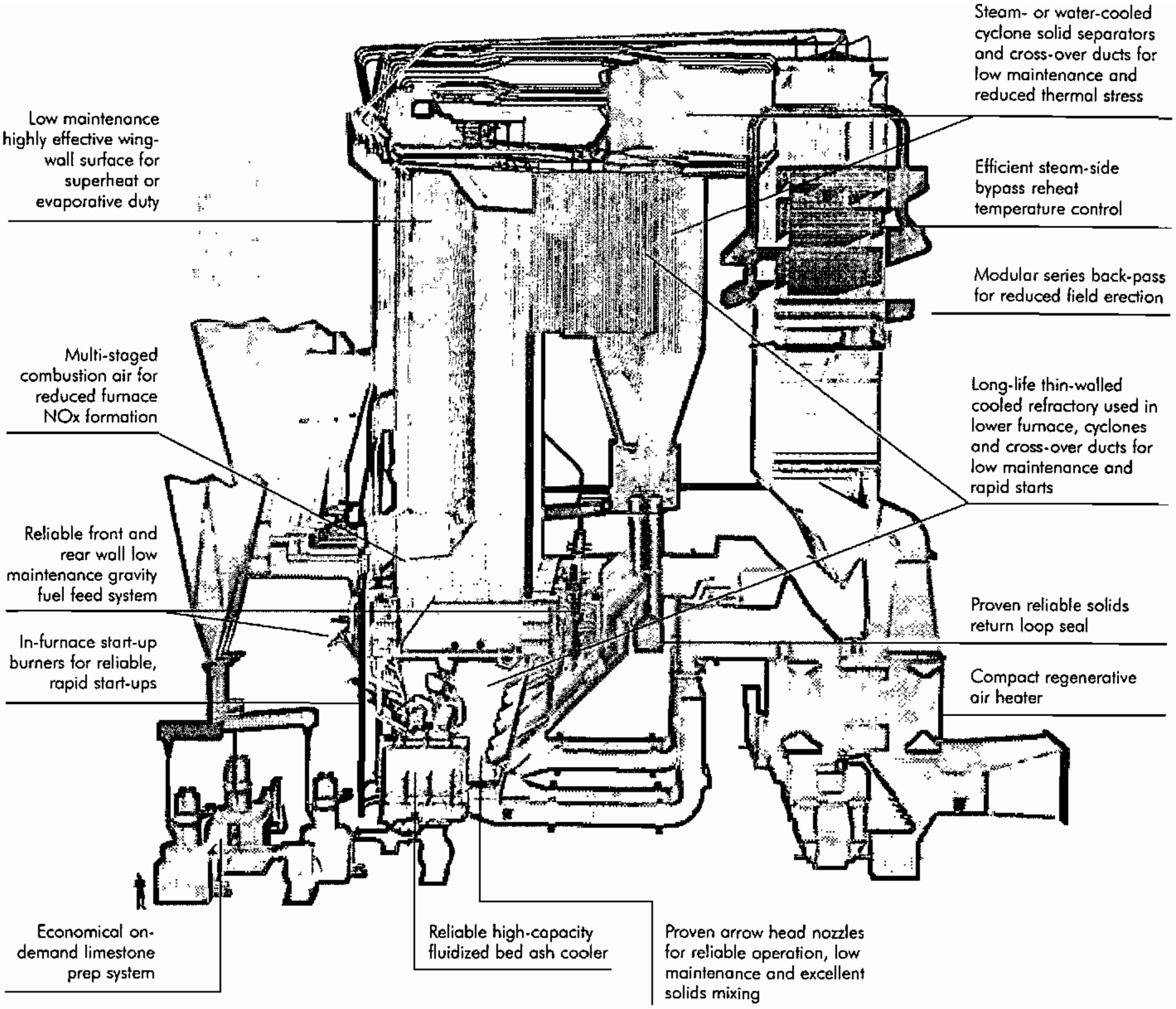


ELEKTROWNIA TUROW
Location: Bogatynia, Poland
Customer: BOT Elktrownia Turow S.A.
Start-up Year: 1998, 2000, 2003, 2004
Capacity: 3 x 235 MWe, 3 x 262 MWe
Fuel: Polish Brown Coal

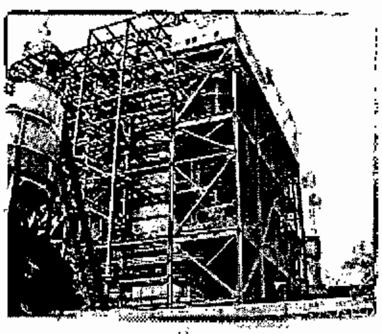


NPS
Location: Tha Toom, Thailand
Customer: National Power Supply Co., Ltd.
Start-Up Year: 1998
Capacity: 2 X 150 MWe
Fuel: Anthracite, Bituminous Coal, Rice Husk, Bark

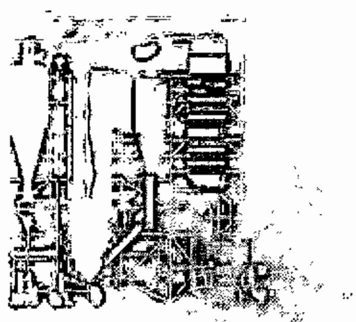
ELCHO
Location: Chorzow, Poland
Customer: EC Chorzow Elcho Sp. z.o.o.
Start-Up Year: 2003
Capacity: 2 X 113 MWe
Fuel: Bituminous Coal



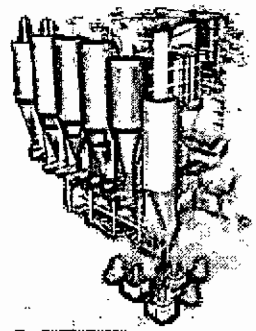
OUR MEDIUM-SCALE CYCLONE CFB DESIGN
OFFERED AT A NOMINAL 300 MWe UNIT SIZE



SOUTHERN ILLINOIS POWER COOPERATIVE
Location: Marion, Illinois
Customer: Southern Illinois Power Cooperative
Start-Up Year: 2003
Capacity: 120 MWe
Fuel: Bituminous Coal Fines



CLECO
Location: Boyce, Louisiana
Customer: Shaw Group/Cleco Power LLC
Start-Up Year: 2009
Capacity: 2 x 330 MWe
Fuel: Petroleum Coke, PRB, Lignite



SANDOW
Location: Rockdale, Texas
Customer: Bechtel/TXU
Start-Up Year: 2009
Capacity: 2 x 315 MWe
Fuel: Texas Lignite

A LEADER IN INDUSTRIAL CFBs

OUR INDUSTRIAL CIRCULATING FLUIDIZED BED (CFB) STEAM GENERATORS ARE WELL KNOWN IN THE INDUSTRY FOR THEIR LOW EMISSIONS, RELIABILITY AND LONG LIFE.

Our history of developing innovative combustion technologies for industry began with our bubbling fluidized bed (BFB) steam generators, from which we have developed our advanced robust CFB technology for a diverse range of industrial fuels and energy needs. We are now a leading supplier of industrial CFB technology, supplying over 210 units, with unit sizes up to 150 MWe, for industrial applications.

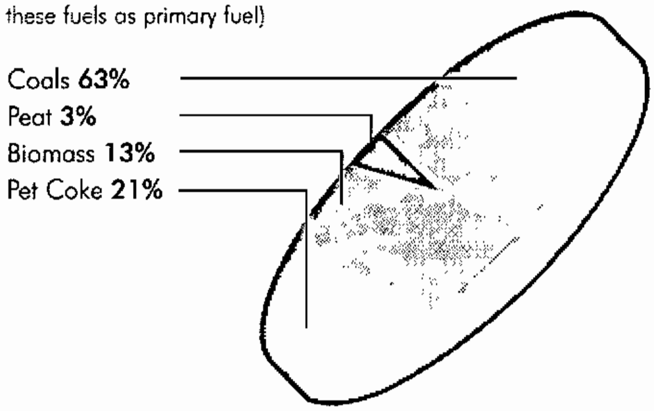
PROVEN EXPERIENCE

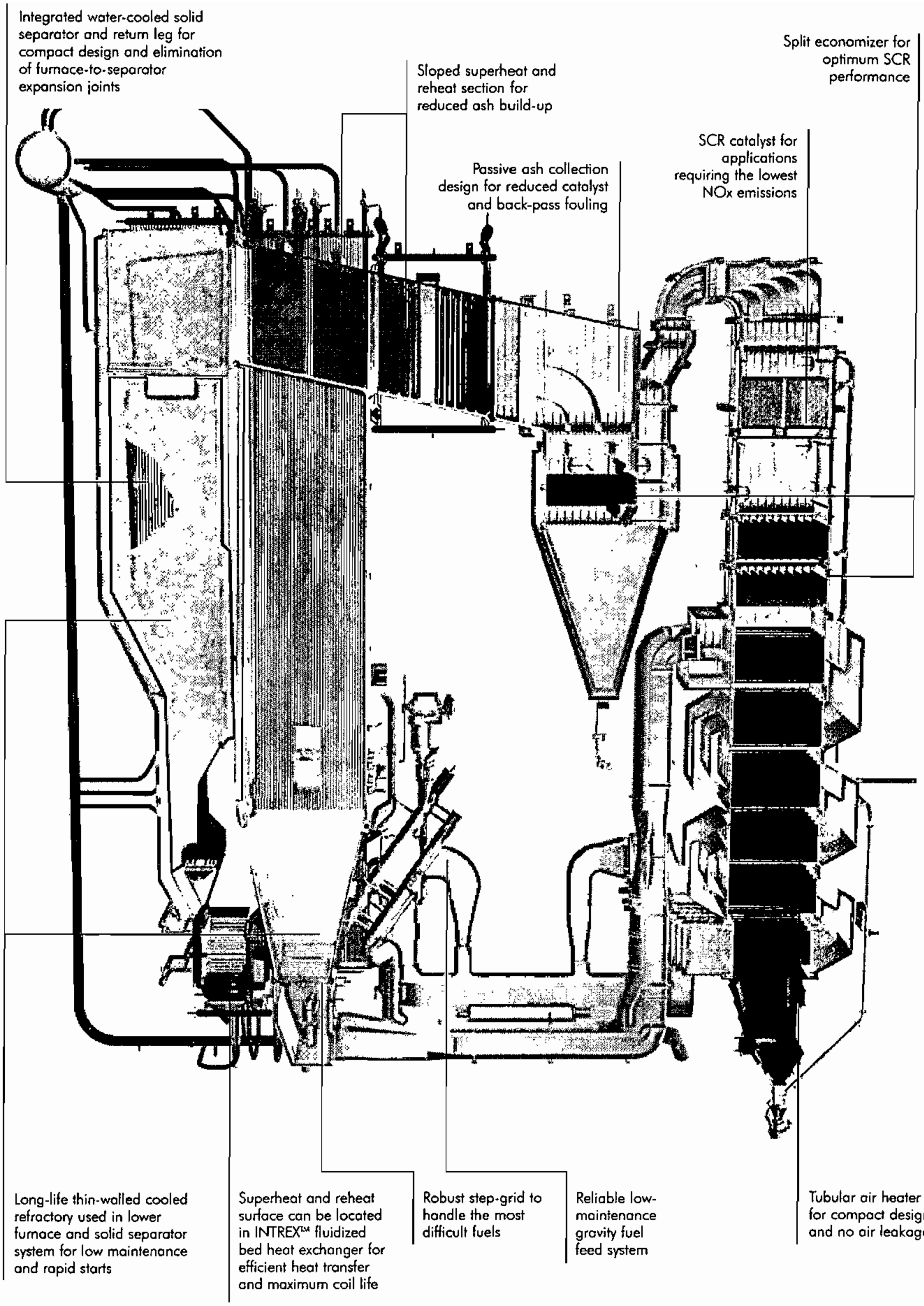
The solutions we have provided have been as diverse as our clients' needs. The CFB we supplied to a Swedish paper mill to convert their waste bark and sludge into useful steam needed by the mill, as well as the 20 petcoke-fired steam generators we delivered to Sinopec in China, demonstrate our ability to customize units to meet clients' needs. Our industrial boiler designs have been proven and advanced based on 30 years of operating experience.

WIDEST FUEL EXPERIENCE

Multi-fuel firing is particularly important in industrial applications, where utilizing on-site waste has a high value. Fuel flexibility is a key factor in unlocking the value of these waste streams since both their quality and volumes can vary on a daily basis. Our CFB technology has proven itself over the widest range of industrial fuels.

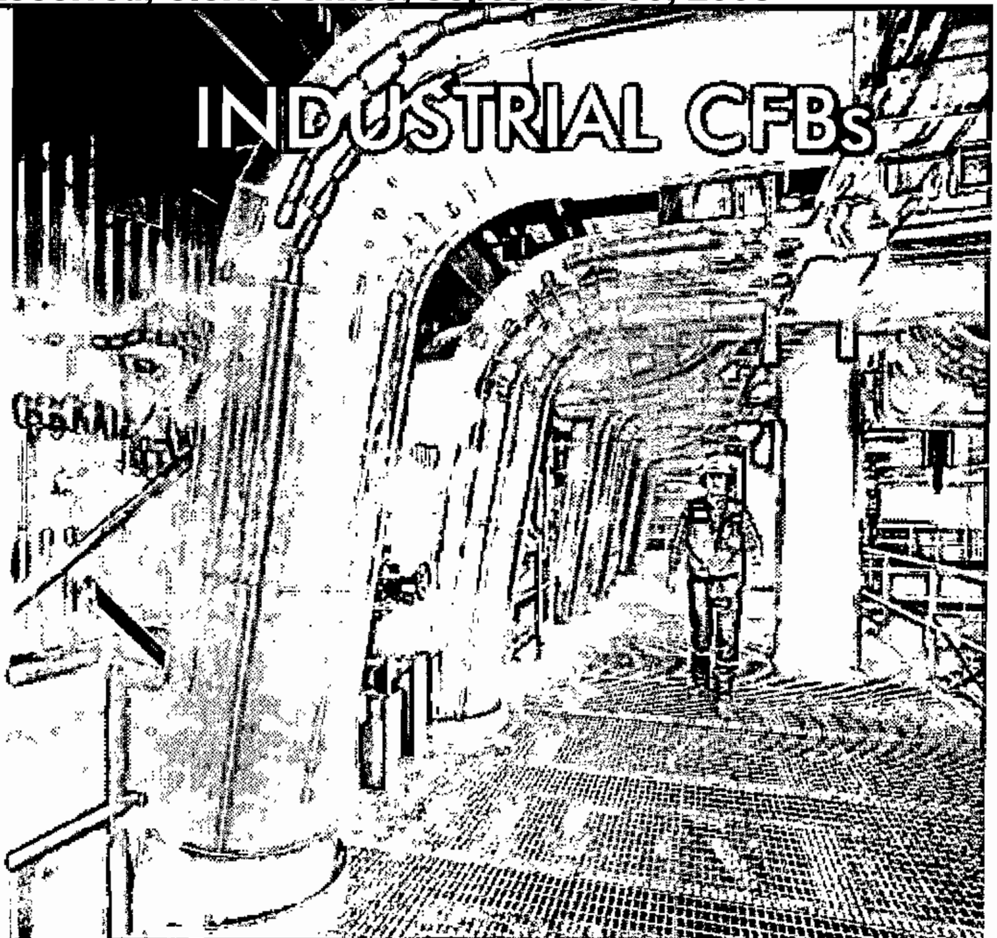
Our Industrial Fuel Experience
(% of operating industrial FW CFB capacity utilizing these fuels as primary fuel)

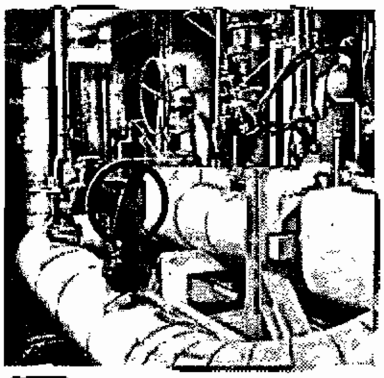




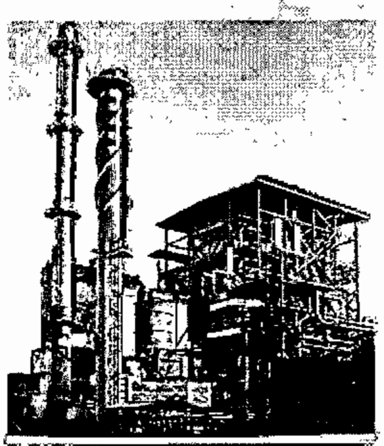
WE OFFER INNOVATIVE AND PROVEN DESIGN FEATURES
IN OUR INDUSTRIAL CFB UNITS

INDUSTRIAL CFBs





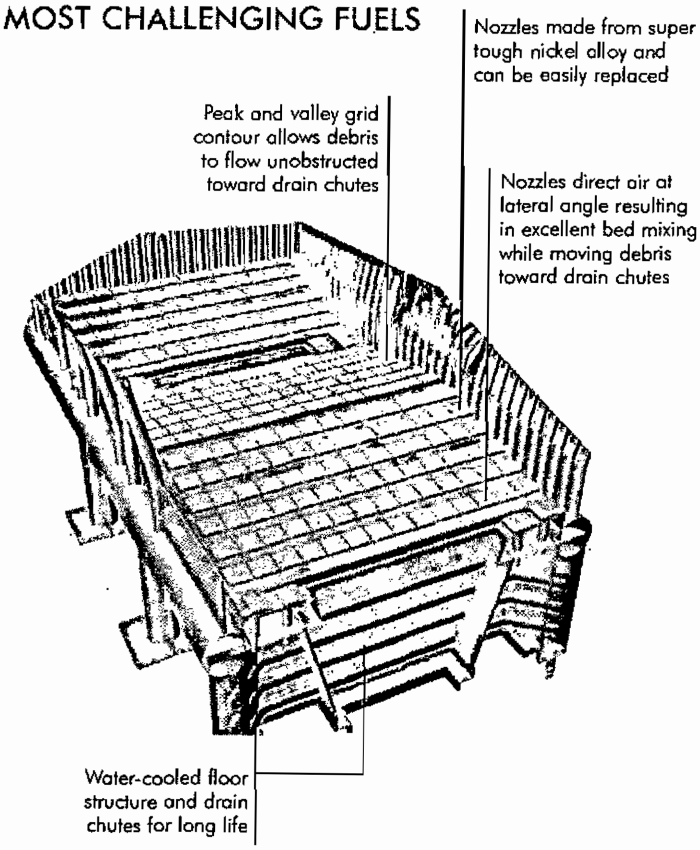
APEC
Location: Pampanga Site, Philippines
Customer: Formosa Heavy Industries, Asian Pacific Energy Company
Start-Up Year: 2006
Capacity: 50 MWe
Fuel: Coal, Mill Sludge



UPPC
Location: Calumpit, Bulacan, Philippines
Customer: United Pulp and Paper Co., Ltd (UPPC)
Start-Up Year: 2006
Capacity: 35 MWe
Fuel: Coal, Mill Sludge, Paper Reject

PETROPOWER
Location: Talcahuano, Chile
Customer: Petropower Talcahuano
Start-Up Year: 1998
Capacity: 67 MWe
Fuel: Petroleum Coke

OUR ROBUST STEPPED FLUIDIZING GRID FOR THE MOST CHALLENGING FUELS

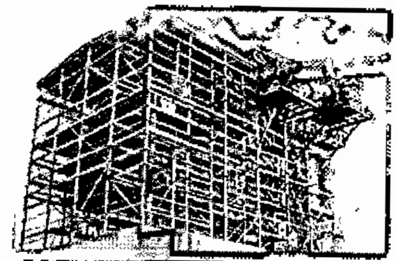


HIGHLY RELIABLE

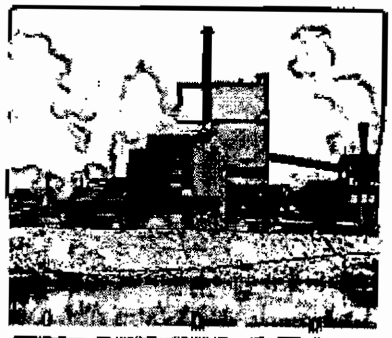
Industry relies on high availability: day in, day out, year round. Our CFBs have a proven track record of being highly reliable.

Our CFBs have excellent load-following capabilities, enabling them to accommodate rapid swings in process steam requirements. Their wide turn-down range means that our units can adapt to temporary or seasonal changes in steam or district heat needs, operating at very low loads of nameplate capacity.

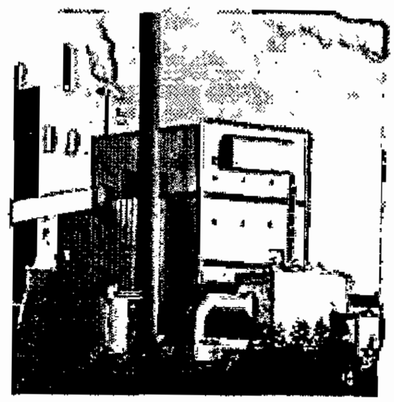
To achieve the highest reliability, we offer SmartBoiler™ to all CFB plant owners and operators. SmartBoiler™ is an intelligent operation and service support tool for monitoring, diagnosing, analyzing and optimizing steam generation and power plant operation. SmartBoiler™ combines our experience and expertise in fluidized bed combustion with advanced information technology.



CORN PRODUCTS
Location: Bedford, Illinois
Customer: Corn Products International
Start-Up Year: 2006
Capacity: 100 MWe
Fuel: Bituminous coal and petroleum coke



STORA ENSO KVARNSVEDEN
Location: Borlänge, Sweden
Customer: Stora Enso Kvarnsveden AB
Start-Up Year: 2005
Capacity: 36 MWe
Fuel: Bark, Sludge, Coal



VATTENFALL SCA
Location: Munksund, Sweden
Customer: Vattenfall SCA
Start-Up Year: 2002
Capacity: 25 MWe
Fuel: Bark, Wood Residue, Paper Rejects

RENEWABLE ENERGY CFBs

BIOFUELS AND WASTE ARE TWO OF THE FUEL GROUPS IDEALLY SUITED FOR OUR CFB TECHNOLOGY. OUR UNITS CAN BE DESIGNED TO FIRE 100% RENEWABLE ENERGY FUELS.

A GREEN TECHNOLOGY

Concern about global warming is a key factor for developing and implementing energy solutions today.

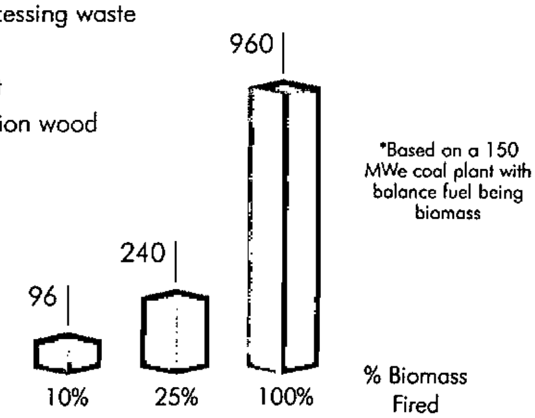
Use of biomass in power generation can contribute significantly to reducing emissions of carbon dioxide - a greenhouse gas. The fuel flexibility of our CFB techology allows them to utilize a wide range of renewable and waste fuels and fuel mixes, helping our world reach a goal of reduced greenhouse gas emissions.

Our CFBs can also divert waste headed for land-fills and instead convert this waste into valuable steam and electricity to support our growing energy needs.

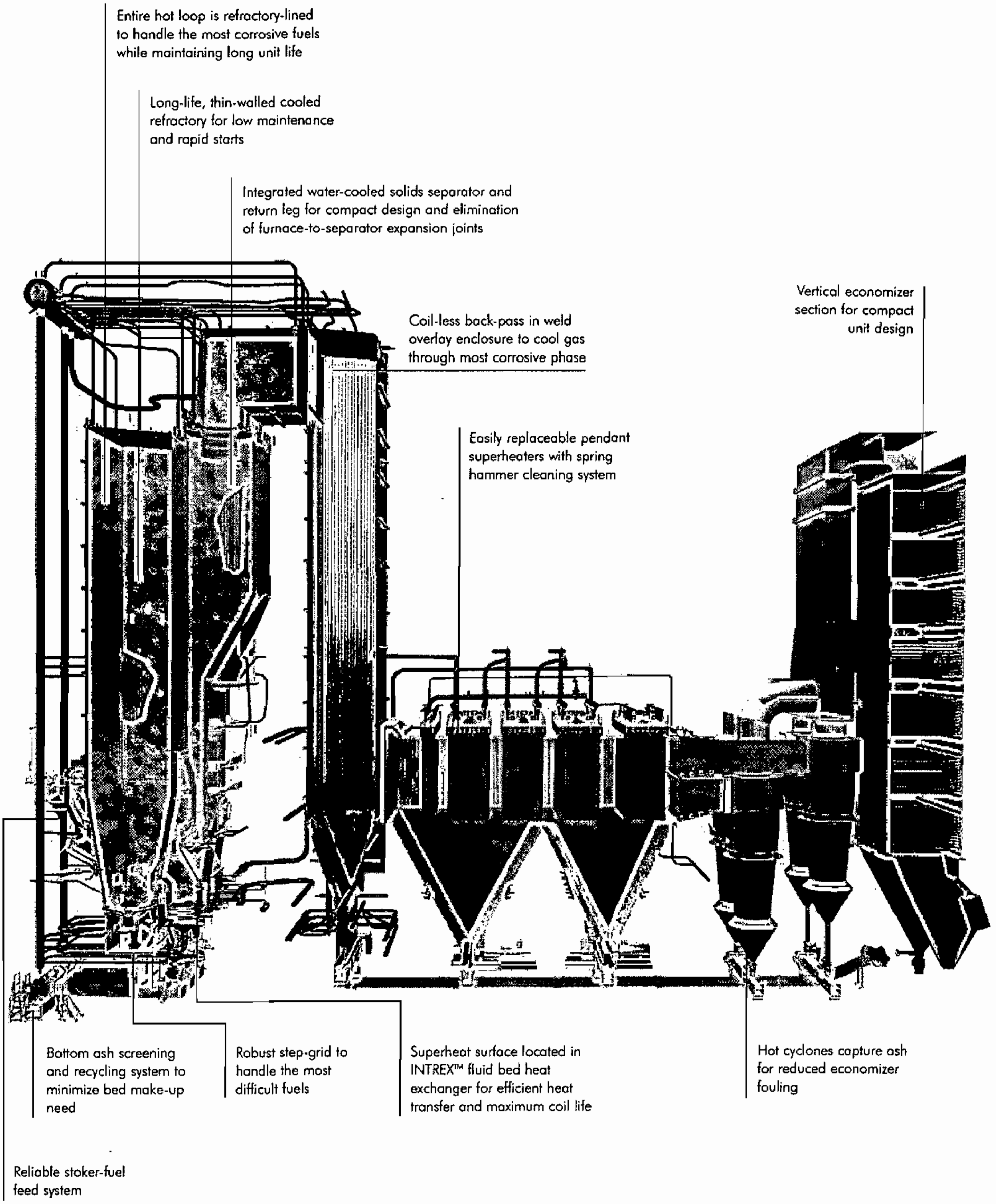
GREEN FUELS

Biofuels include natural materials and waste produced by various industrial or other processes, and include:

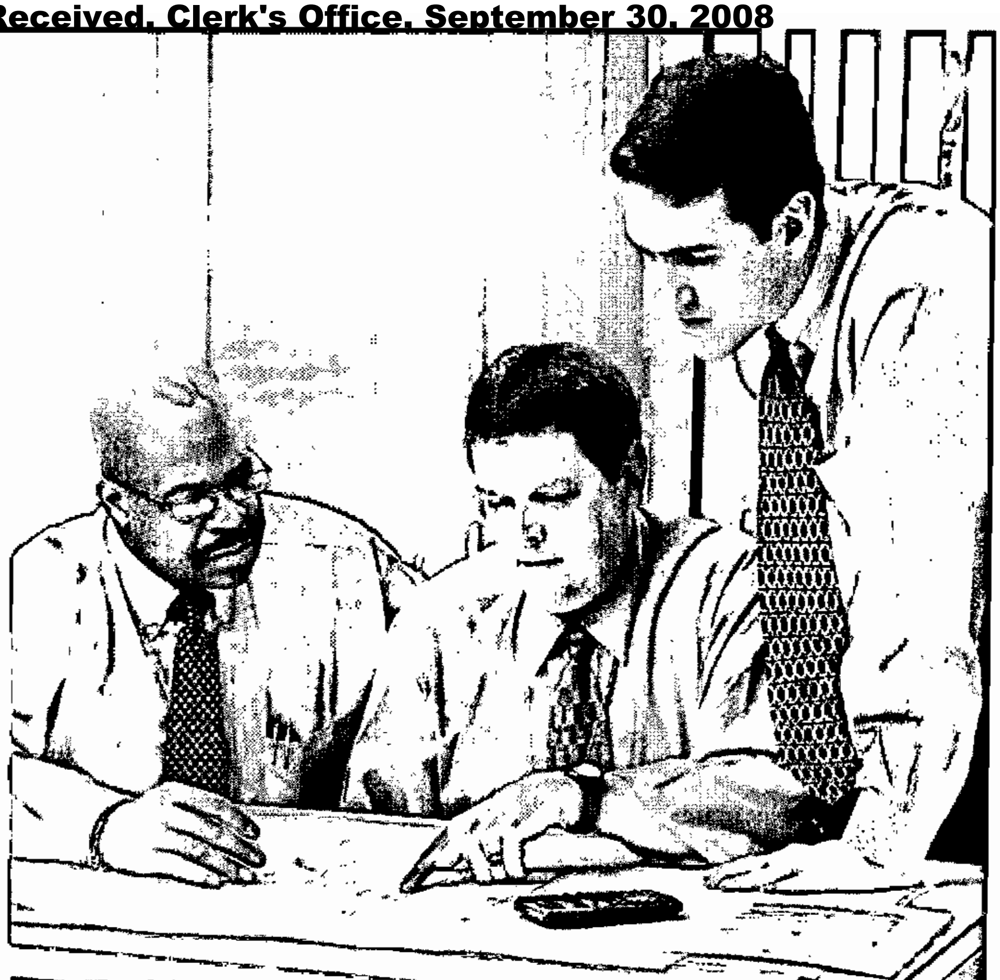
- Material from forestry operations
  - thinnings
  - harvesting waste
  - bark
  - stumps
- Wood processing waste
  - offcuts
  - sawdust
  - demolition wood
- Pulp and papermaking waste
- Fast-growing energy crops
- Agricultural waste
- Industrial waste and municipal refuse-derived fuel (RDF)

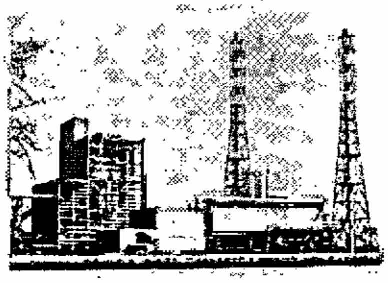


Avoided CO2 Emissions*
(Ktons/yr)

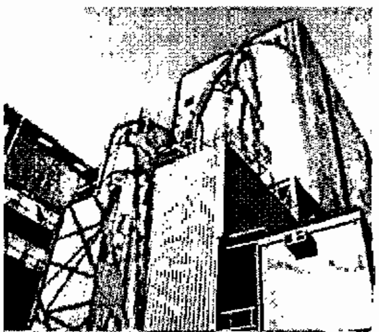


OUR WASTE-TO-ENERGY CFB UNIT DESIGNED
TO FIRE REFUSE-DERIVED FUEL (RDF)

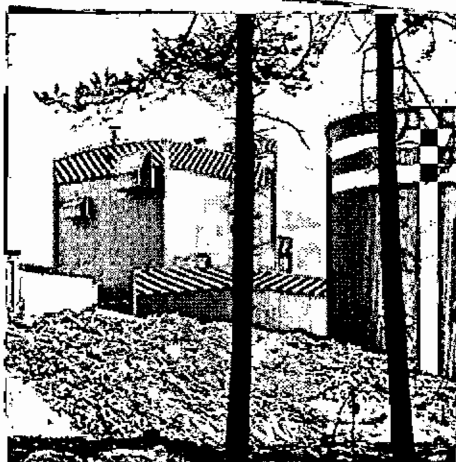


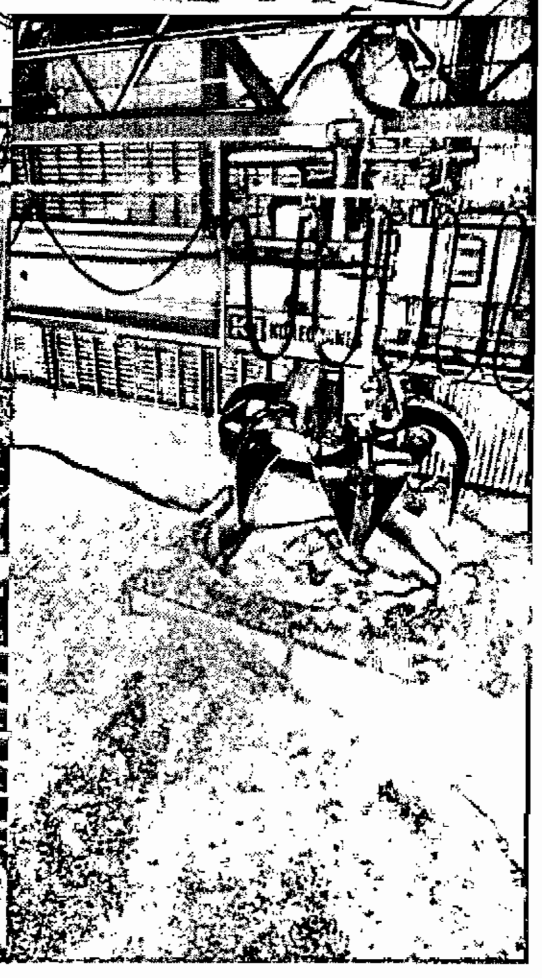


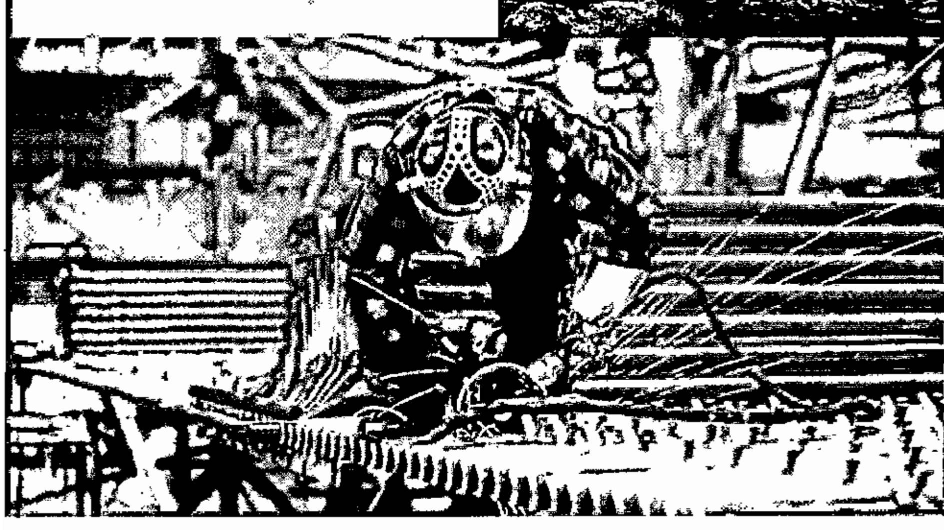
LOMELLINA II
Location: Parona, Italy
Customer: Lomellina Energia S.r.l.
Start-Up Year: 2007
Capacity: 17 MWe
Fuel: RDF (Refuse Derived Fuel)



LOMELLINA ENERGIA
Location: Parona, Italy
Customer: Lomellina Energia S.r.l.
Start-Up Year: 2000
Capacity: 15 MWe
Fuel: RDF (Refuse Derived Fuel)







Our Renewable CFB Fuel Experience
(% of operating FW renewable capacity firing these fuels as primary fuel)

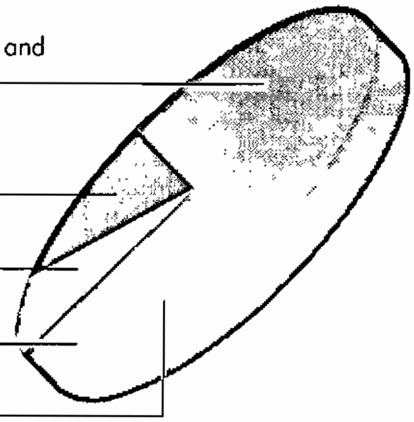
Material from forestry operations and pulp and papermaking 55%

Industrial waste and municipal refuse-derived fuel 14%

Agricultural waste 10%

Pulp & papermaking waste 14%

Wood processing waste 7%



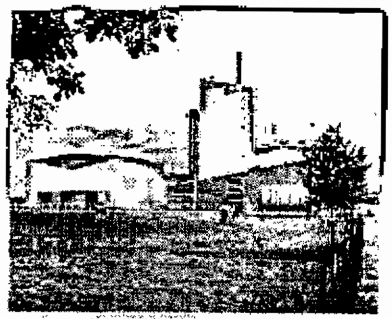
RENEWABLE ENERGY CFBs

OPTIMIZED FOR RDF

Efficient waste recycling and handling, designed to remove reusable fractions and inert materials, is key to producing a refuse-derived fuel (RDF) stream that can be burned efficiently and safely to generate electricity, steam or heat. A waste-to-energy (WTE) power plant based on this concept can achieve a net cycle efficiency of above 28%, substantially higher than conventional incineration plants, resulting in lower emissions and higher energy output per ton of waste destroyed.

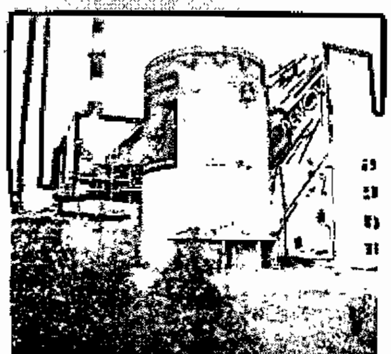
BECOMING MORE GREEN

Co-firing renewable fuels in a CFB plant originally designed for coal is an excellent, cost-effective option for helping our environment. In most cases, our operating coal-fired CFBs can co-fire biomass or waste fuels by simply adding a biomass fuel handling and feeding system, and modifying boiler operating procedures.



PROKON NORD
Location: Emlichheim, Germany
Customer: Prokon Nord Energiesysteme
Start-Up Year: 2006
Capacity: 20 MWe
Fuel: Recycled Wood

HEIZKRAFTWERK KEHL
Location: Kehl, Germany
Customer: Heizkraftwerk Kehl GmbH
Start-Up Year: 2002
Capacity: 9 MWe
Fuel: Recycled Wood



SIMMERING
Location: Simmering, Vienna, Austria
Customer: Siemens AG Austria
Start-Up Year: 2006
Capacity: 23 MWe
Fuel: Forest Chips

CFB SAMPLE REFERENCES

WE HAVE SOLD AND DELIVERED OUR CFBs TO CLIENTS AROUND THE WORLD, SPANNING A WIDE SPECTRUM OF FUELS AND APPLICATIONS. OUR COMPLETE REFERENCE LIST IS QUITE LONG AND IS AVAILABLE BY SIMPLY CONTACTING ANY ONE OF OUR ACCOUNT REPRESENTATIVES. BELOW IS A SAMPLING OF PROJECTS SHOWING THE VERSATILITY AND VALUE OF OUR CFB TECHNOLOGY.

CFBs IN UTILITY APPLICATIONS

Order Date	Start-Up Date	Client	Plant	Country	Steam MWe	Primary Fuel	Secondary Fuel
2006	2009	Harbin Power Engineering Company, Ltd. (HPE)	Cam Pha	Vietnam	2 x 160	Waste Anthracite	Slurry
2006	2009	Bechtel/TXU	Sandow Gen	USA	2 x 315	Texas Lignite	
2006	2009	Shaw Group/CLECO Power LLC	Rodemacher	USA	2 x 330	Petroleum Coke	Illinois 6, PRB, Lignite
2005	2009	PKE – Elektrownia Lagisza	Lagisza	Poland	460	Bituminous Coal	Coal Slurry (option)
2003	2007	PLN Labuhan Angin Sibolga	Labuhan	Indonesia	2 x 100	Coal	
2001	2005	AS Narva Elektrijaamad	Balti	Estonia	2 x 100	Oil Shale	
2000	2004	AS Narva Elektrijaamad	Eesti	Estonia	2 x 100	Oil Shale	
2000	2003-4	BOT Elektrownia Turow S.A. Units 4, 5, 6	Turow	Poland	3 x 262	Polish Brown Coal	
1999	2003	EC Chorzow Elcho Sp. z.o.o.	Elcho	Poland	2 x 113	Bituminous Coal	
1997	2001	JEA Northside Gen. Station	Northside	USA	2 x 300	Petroleum Coke	Bituminous Coal
1996	2000	Bay Shore Power Company	Bay Shore	USA	180	Petroleum Coke	
1994-6	1998-2000	BOT Elektrownia Turow S.A. Units 1, 2, 3	Turow	Poland	3 x 235	Polish Brown Coal	
1995	1999	COCO	Map Ta Phut	Thailand	2 x 110	Coal	
1994	1998	National Power Supply Co., Ltd.	Tha Toom	Thailand	2 x 150	Anthracite	Bit Coal, Rice Husk, Bark
1992	1996	CMIEC/Neijiang Thermal Power Plant	Neijiang	PRC	100	Coal	
1991	1995	Colver Power Project, Inter Power/AhlCon Ptns	Colver	USA	100	Bituminous Gob	
1991	1995	Fortum Engineering Ltd. Oulun Energia	Toppila	Finland	100	Peat	Coal

CFBs IN INDUSTRIAL APPLICATIONS

Order Date	Start-Up Date	Client	Plant	Country	Steam MWe	Primary Fuel	Secondary Fuel
2007	2009	Hanwha International Corporation	Yeosu	South Korea	3 x 100	Coal	
2006	2008	China Petrochemical Corp. SINOPEC Tianjin Company	Tianjin	China	3 x 100	Petroleum Coke	Coal
2006	2008	Votorantim Metais Niquel S.A.	Acampamento Macedo	Brazil	50	Petroleum Coke	Coal, Eucalyptus
2006	2008	Deven JSCo	Devnya	Bulgaria	100	Petroleum Coke	Hard Coal
2004	2008	Abalco S.A.	Alumar alumina refinery	Brazil	2 x 60	Coal	Petroleum Coke
2006	2008	China Petrochemical Corp. SINOPEC	Qingdao	China	2 x 75	Petroleum Coke	
2003	2007	SINOPEC	Guangzhou Petrochemical	China	2 x 115	Coke	
2003	2007	Tornion Voima Oy	Tornio	Finland	45	Peat	Forest Residue, RDF, CO Gas, Coal
2002	2007	Thai Cane Paper Ltd.	Prachinburi	Thailand	35	Coal	Mill Sludge, Paper Reject
2002	2007	Yuen Foong Yu Paper Manufacturing Co., Ltd.	Yangzhou	China	50	Bituminous Coal	Sub-Bituminous Coal, Tires, Sludge
2004	2006	Corn Products Intl, Inc	Argo	USA	100	Bituminous Coal	
2002	2006	United Pulp and Paper Co., Ltd (UPPC)	Pampanga	Philippines	35	Coal	Mill Sludge, Paper Reject
2001-2	2005-6	Maoming Petrochemical Corp.	Maoming	PRC	2 x 100	Coke and Coal	Oil Shale
2001	2005	Zhenhai Refinery	Zhenhai	PRC	3 x 100	Coke and Coal	
1997	2001	Mälarenergi AB	KVV Västerås P5	Sweden	59	Wood Residues	Peat, Coal

CFBs FIRING RENEWABLE FUELS

Order Date	Start-Up Date	Client	Plant	Country	Steam MWe	Primary Fuel	Secondary Fuel
2007	2010	Kaukaan Voima Oy	Kaukas	Finland	125	Biomass	Peat
2006	2008	"NV Huisvuilcentrale Noord-Holland (HVC-NH)"	HVC Bio-energiecentrale, Alkmaar	Netherlands	28	Demolition Wood	
2003	2007	Lomellina Energia S.r.l.	Lomellina	Italy	17	RDF	
2002	2006	Bundersforste Biomasse Kraftwerk GmbH & Co KG	Simmering	Austria	23	Forest Chips	
2004	2006	Prokon Nord Energiesysteme GmbH	BMHKW Emlichheim	Germany	20	Recycled Wood	
2003	2006	Prokon Nord Energiesysteme GmbH	BMHKW Borigstraße, Hamburg	Germany	20	Recycled Wood	
2003	2005	Harpen Energie Contracting GmbH	BMHKW Bergkamen	Germany	20	Recycled Wood	Forest Residue
2002	2005	MVV Energie AG	BMHKW Königswuster hausen	Germany	20	Recycled Wood	
2001	2005	Stora Enso Kvarnsveden AB	Kvarnsveden	Sweden	36	Bark	Bio Sludge, Sediment Sludge, Bituminous Coal
2002	2004	Prokon Nord Energiesysteme GmbH	BMHKW Papenburg	Germany	20	Recycled Wood	
1998	2002	Jämtkraft AB	KVV Lugnvik Östersund	Sweden	45	Wood Residues	Peat, Bark, Wood Dust, Recycled Wood
1998	2002	Vattenfall SCA	Munksund	Sweden	25	Bark	Wood Residues, Paper Reject
1996	2000	Lomellina Energia S.r.l.	Lomellina	Italy	15	RDF	

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- Bubbling Fluidized Bed
- Pulverized Coal
- Supercritical Steam
- Package
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ALTA Achieves Sub 0.15-lb/MBtu NOx Emissions on a 500 MW Cyclone-Fired Boiler

Ameren

C. Giesmann, K. Stuckmeyer

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ENGINEERING
INTERNATIONAL

M. Cremer, A. Chiodo, B. Adams

FUEL TECH™

J. Boyle

The Electrical Utilities Environmental Conference
January 22-25, 2006
Tucson, AZ

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Acknowledgements

- The authors wish to thank the US DOE NETL for providing funding for this program. The authors would also like to acknowledge Bruce Lani, project officer for DOE NETL, and the integral support of AmerenUE Sioux Plant Manager, Bruce Bruzina, and his staff.
- "This presentation was prepared with the support of the USDOE National Energy Technology Laboratory's Innovations for Existing Plants Program, under Award No. DE-FC26-04NT42297. However, any opinions, findings, conclusions, or recommendations expressed herein are those of the author(s) and do not necessarily reflect the views of the DOE."

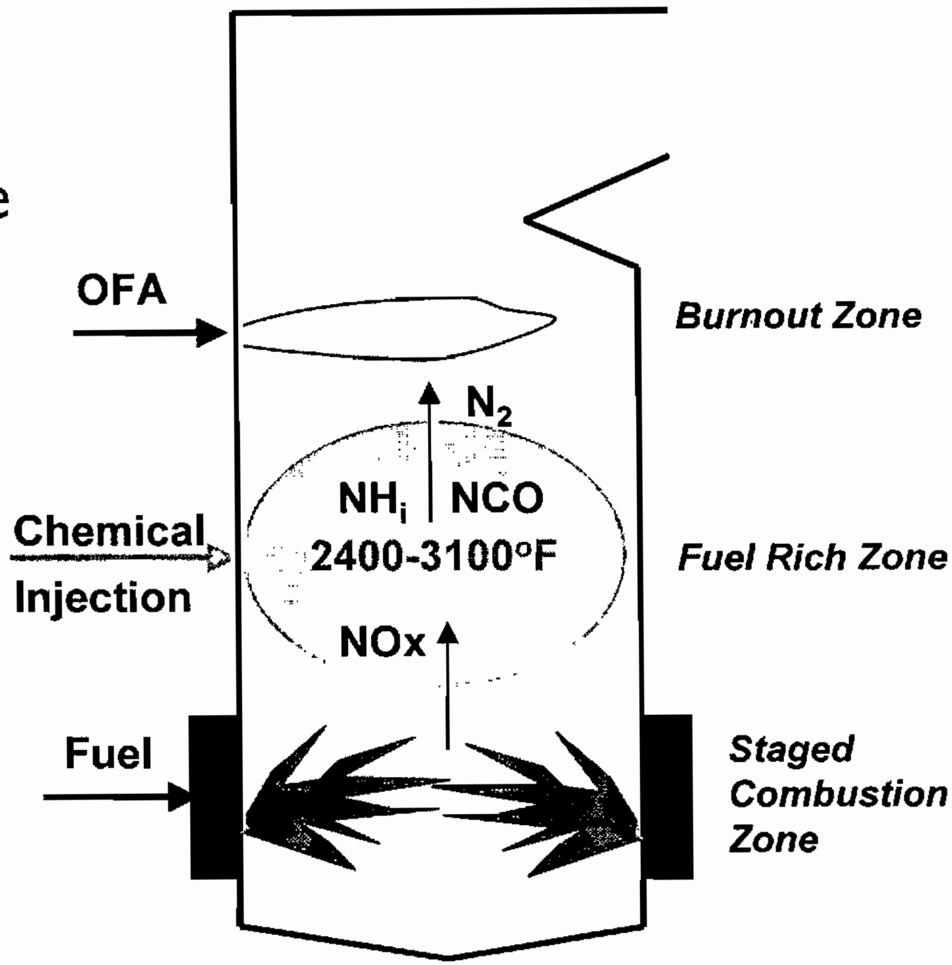
REACTION ENGINEERING INTERNATIONAL

Overview

- Background and Objectives
- Pre-Test Activities
- Test Results
- Conclusions

Rich Reagent Injection

- Staging creates hot, fuel rich lower furnace
- NH_3/urea accelerate the rate of NOx reduction
- Insignificant NH_3 slip
- Developed by REI and EPRI
- CCA and FuelTech are licensed implementers



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ALTA = Advanced Layered Technology Approach

- Deep staging
- Rich Reagent Injection (RRI)
- SNCR

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Project Objectives

- NOx < 0.15 lb/MBtu
- Levelized cost below 75% that of current state-of-the-art SCR
- BOP impacts including LOI, slag tapping, and NH_3 slip

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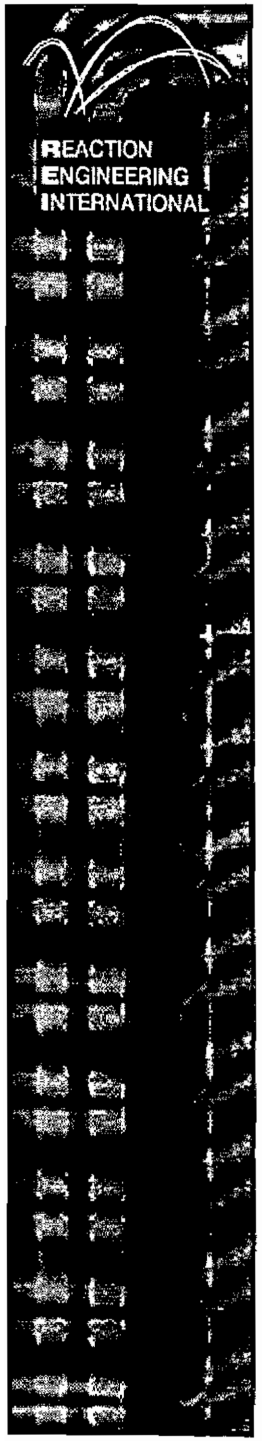
Project Team

- AmerenUE Sioux Plant – Host
- REI – Project Lead
- FuelTech – RRI and NOxOut SNCR equipment supply and testing
- EPRI - Field support and continuous NH_3 monitoring (UC-Riverside)

AmerenUE's Sioux Plant



- Two Units –500 MW each
- Supercritical
- 10 cyclone barrels
- 85% PRB blend with Illinois bituminous

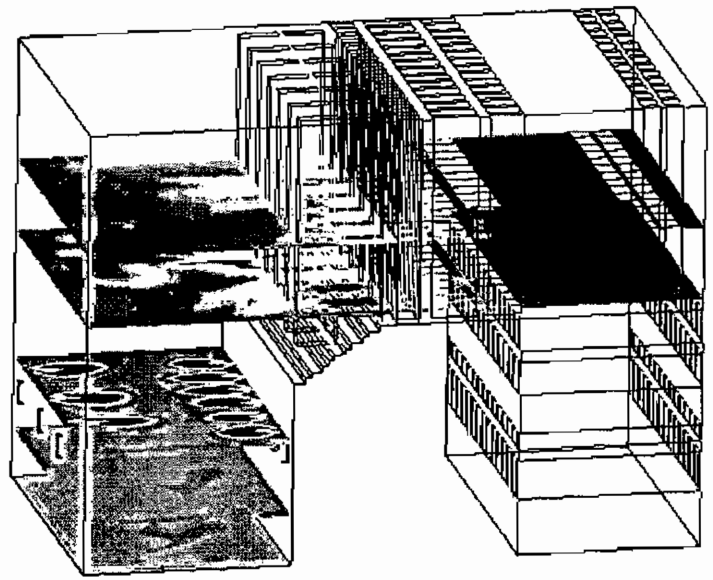
- FGR and GT for steam temperature control
- Fine grind crushers
- First application of OFA on cyclone in unit 2 in 1997

REACTION ENGINEERING INTERNATIONAL

CFD Model Approach
Sioux Unit 1

Lower Furnace Model

Cyclone Barrel Model



Upper Furnace Model

- ALTA Modeling
  - Cyclone barrel model (barrel impacts of staging, coal blend)
  - Lower furnace model (OFA, RRI)
  - Upper furnace model (SNCR)

Electronic Filing - Received, Clerk's Office, September 30, 2008

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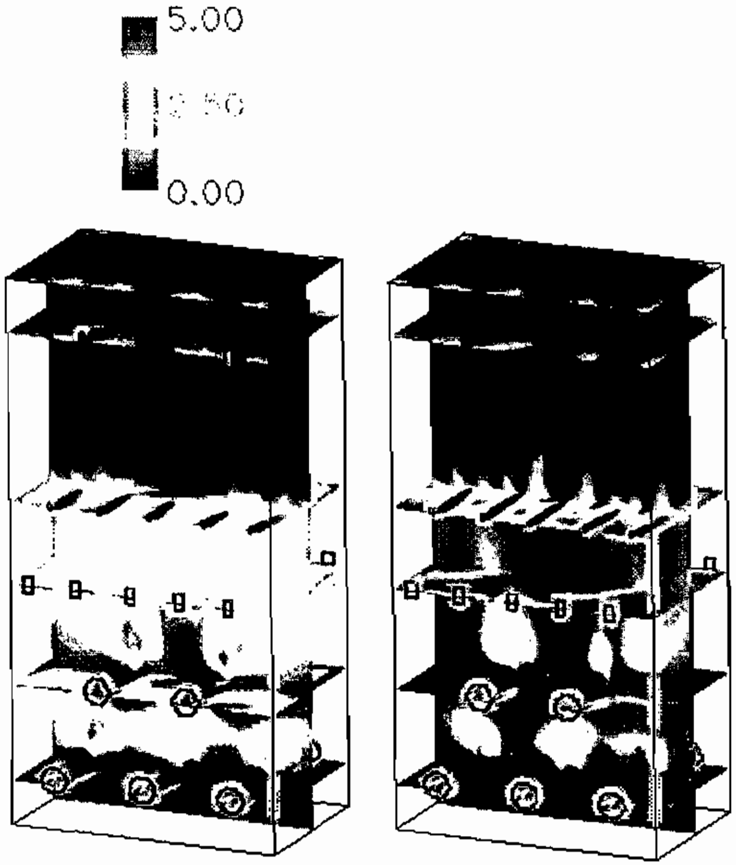
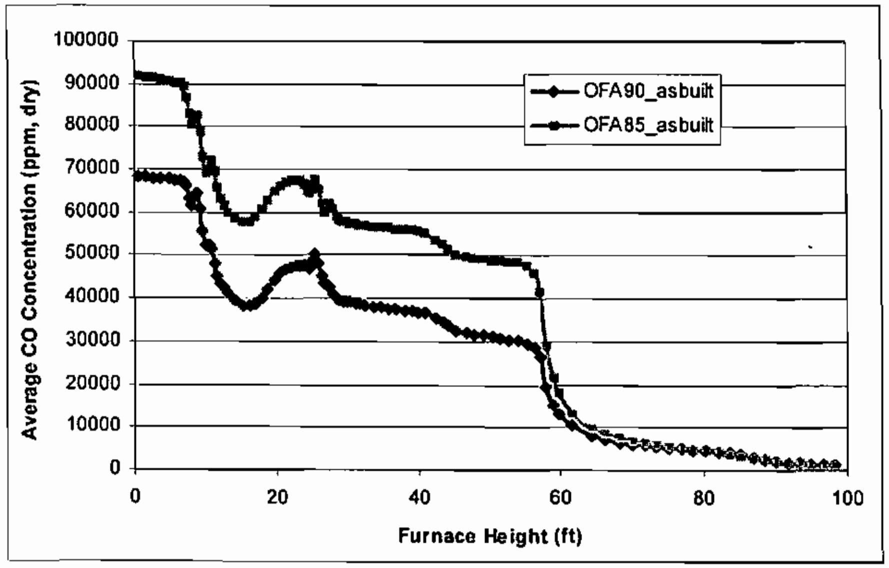
Sioux Unit 1 OFA Modeling



OFA90_asbuilt OFA85_asbuilt



- Interlaced OFA arrangement combined with GT provides good mixing under deeply staged conditions

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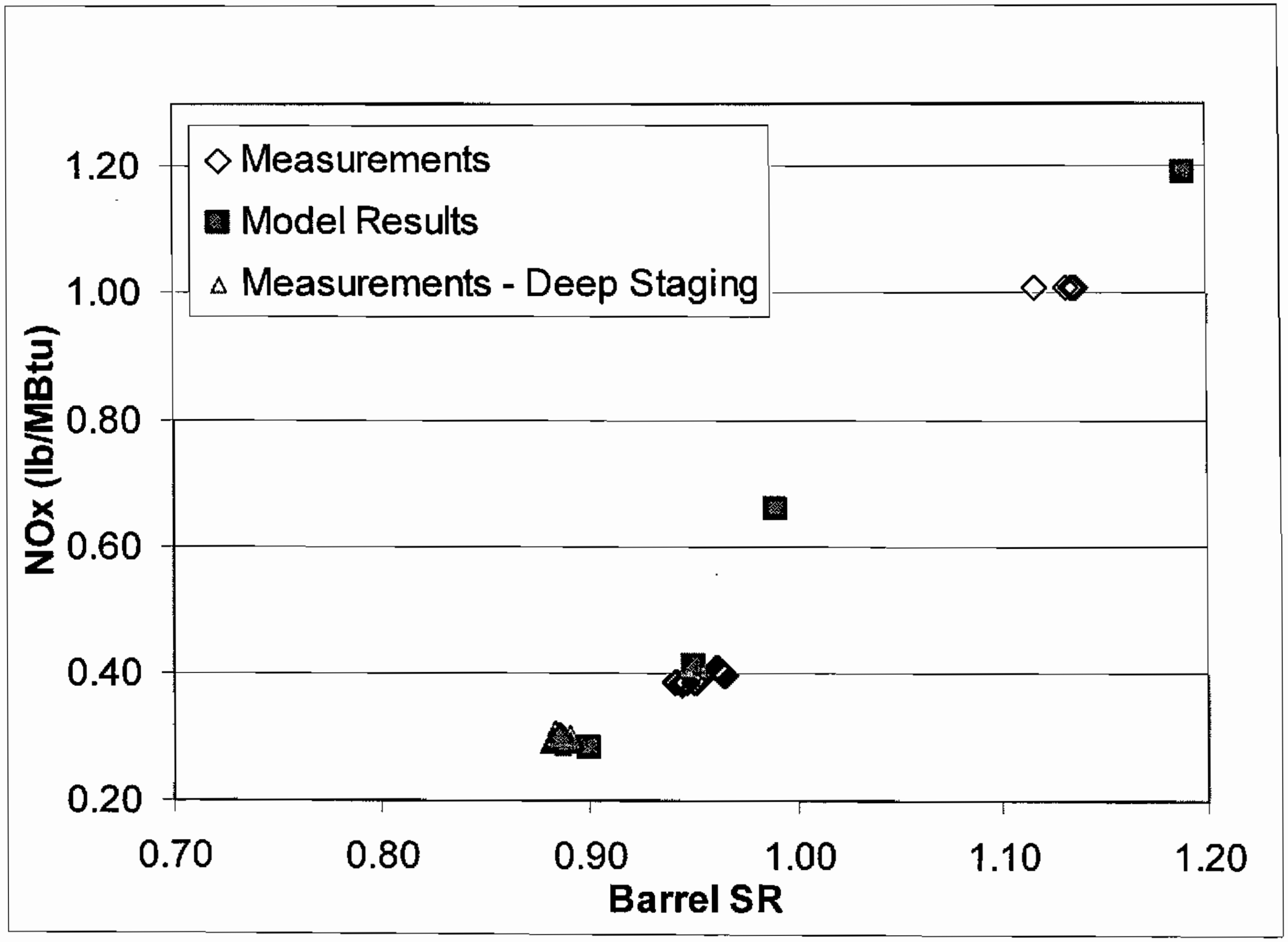
NOx vs Barrel SR

Sioux Unit 1



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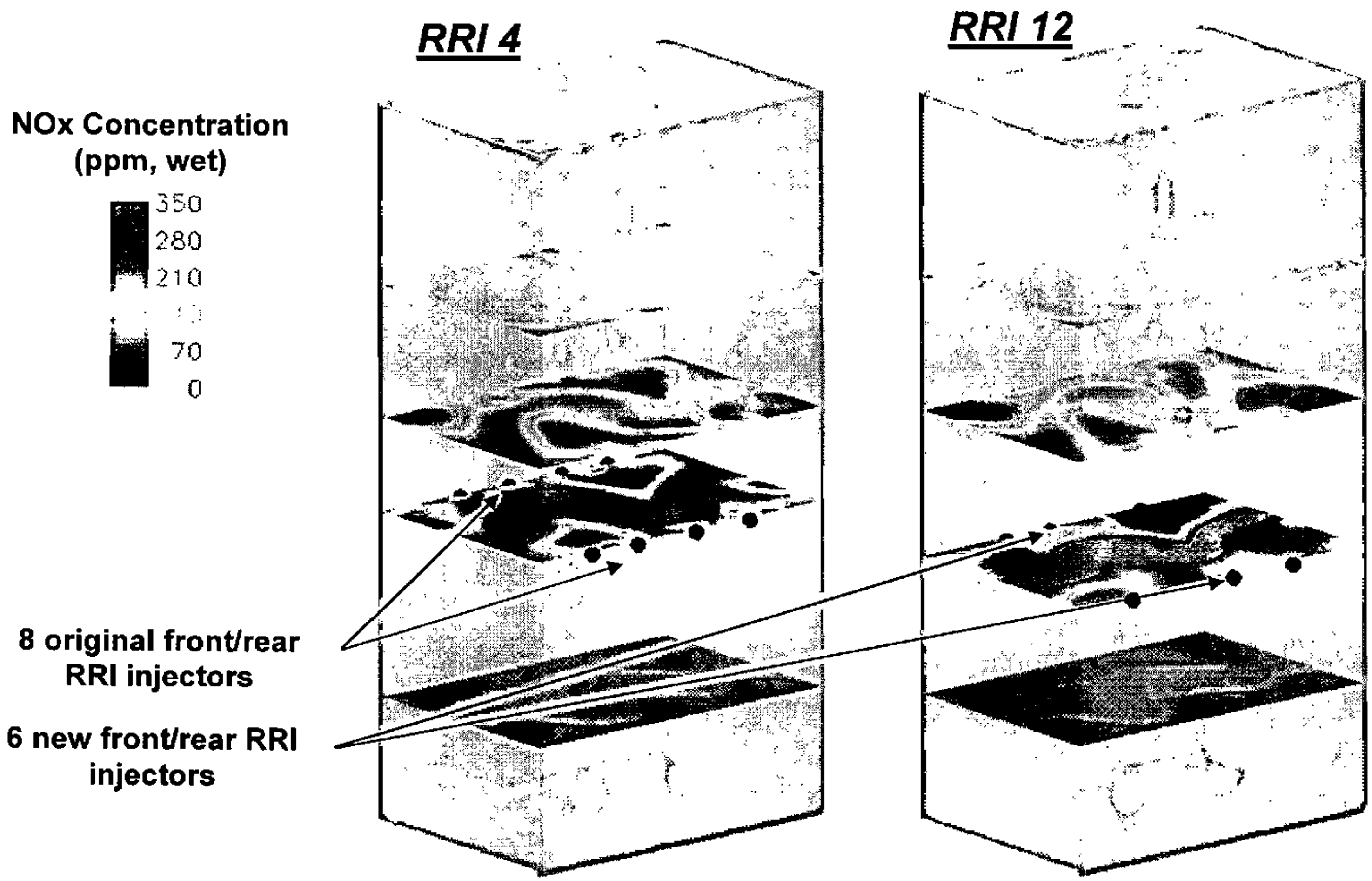
Sioux Unit 1 RRI Modeling



Significant improvement to NOx reduction predicted with addition of six new RRI ports 7' feet below original ports

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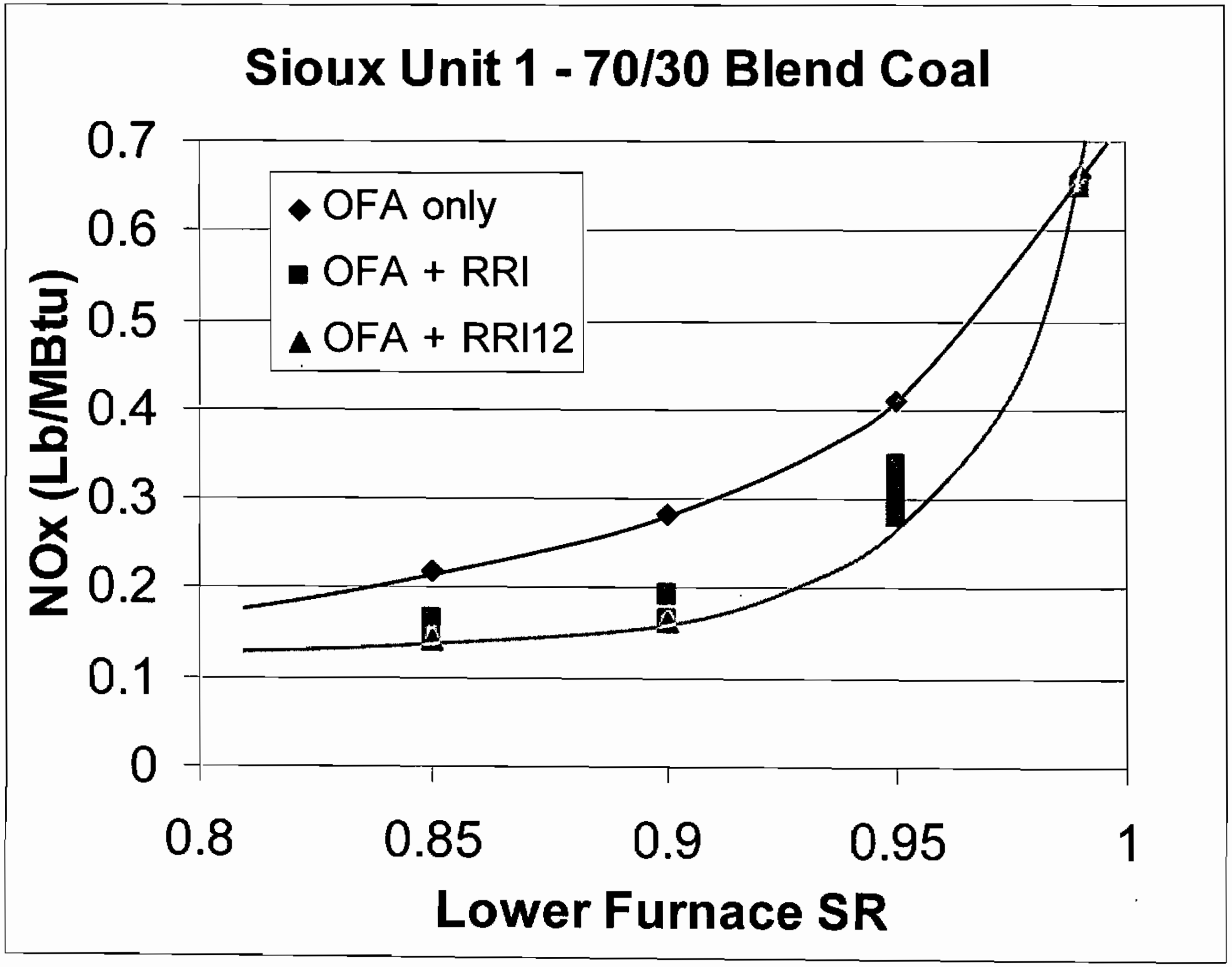
Predicted RRI Performance



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Spring 2005 Outage

Sioux Unit 1

- Installation of 8 new RRI ports
  - 6 on front and rear walls
  - 2 on the side walls

- Installation of 14 new SNCR ports
  - 9 through existing GT ports
  - 5 through upper front wall

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Overview of Tests

- Test Plan
  - RRI only tests
  - SNCR only tests
  - Combined RRI+SNCR tests
- Parametric Testing Conditions
  - 480 MW_g, 80/20 blend ***(10 days)***
  - 530-540 MW_g, 100% Ill. #6 ***(2.5 days)***
  - 530 MW_g, 60/40 blend ***(0.5 days)***
  - 425 MW_g, 80/20 blend ***(1 day)***
- Continuous Tests – 3 days 24 hrs/day

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Overall Results

ALTA in Sioux 1

Coal Blend (PRB/Bit)	Load (MWg)	Baseline NOx w/OFA (lb/Mbtu)	Controlled NOx (w/RRI+SNCR) (lb/Mbtu)	Controlled NOx (w/SNCR) (lb/Mbtu)	50% Urea (gph)	NH3 slip (ppmv)
80/20	480	0.24-0.25	0.12		650 or less	<5
80/20	480	0.20-0.21	0.12		550 or less	<5
80/20	425	0.230		0.156	210	
60/40	530	0.26	0.15		790	<2
0/100	535	0.25	0.165		610	<10
0/100	535	0.25		0.165	360	<10

*Values for the 80/20 blend represent averages for several tests, while values for the 0/100 and 60/40 blends represent single test results

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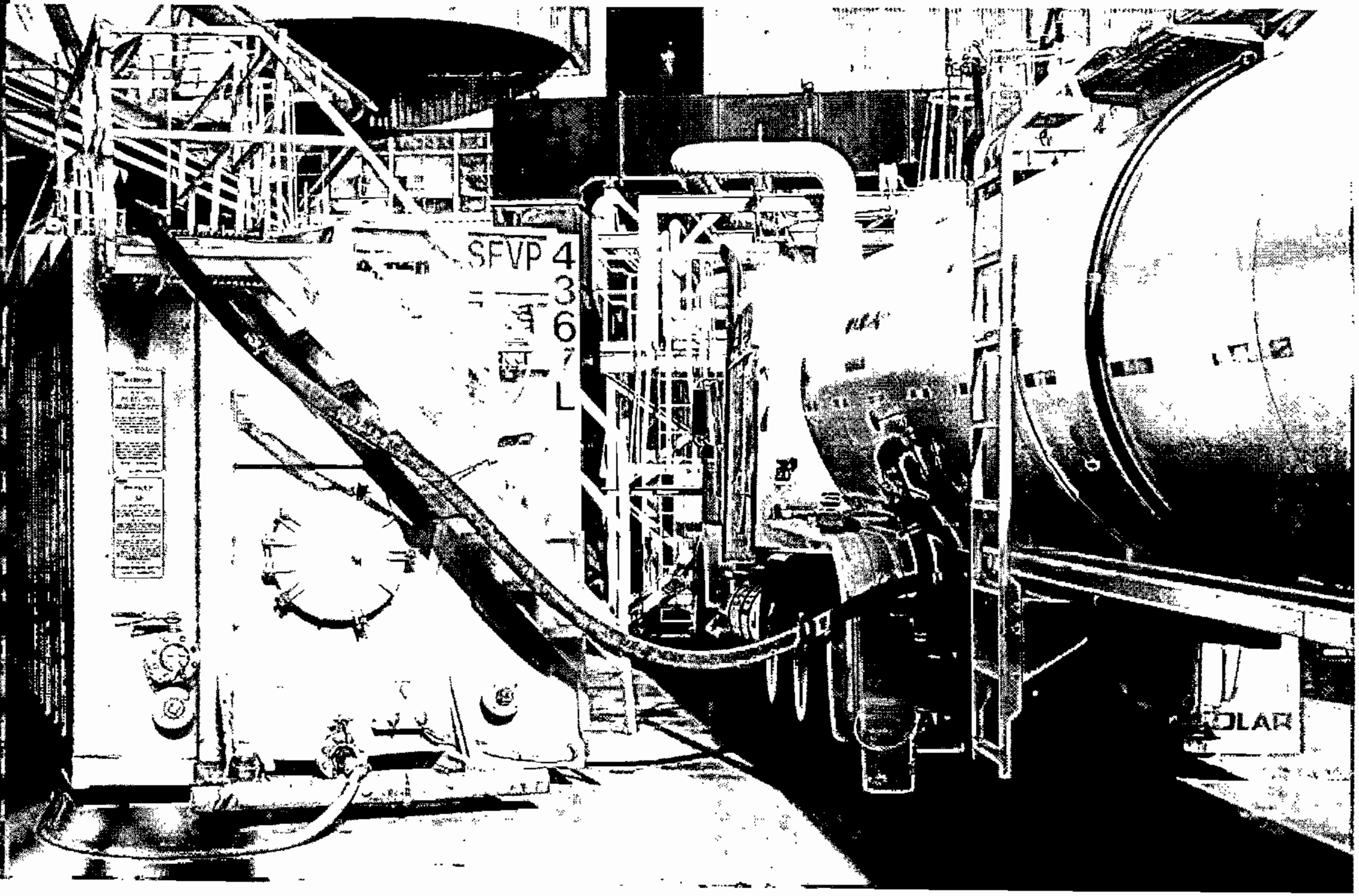
Urea Supply Tank

ALTA in Sioux Unit 1



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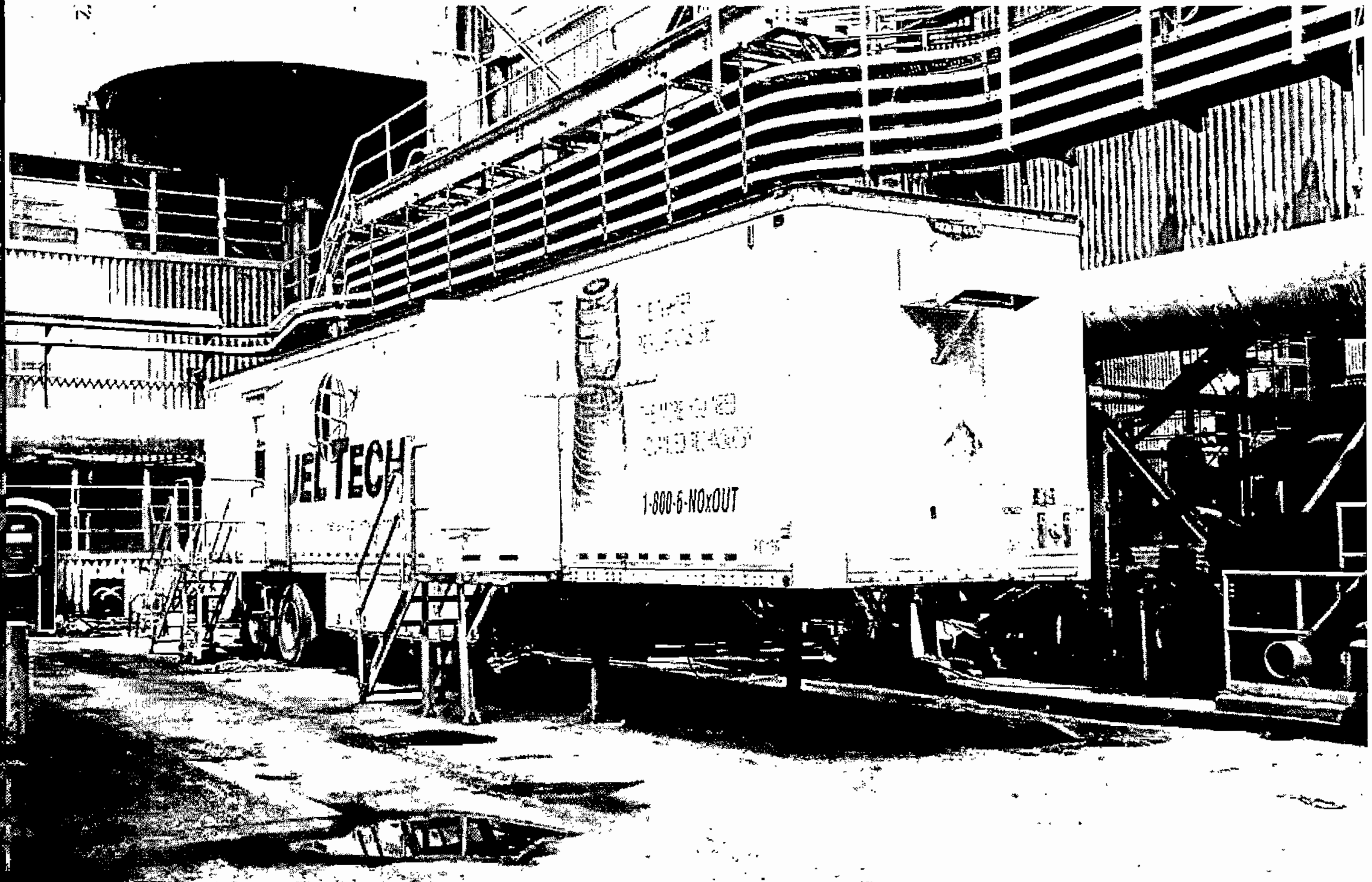
FuelTech MTT

ALTA in Sioux Unit 1



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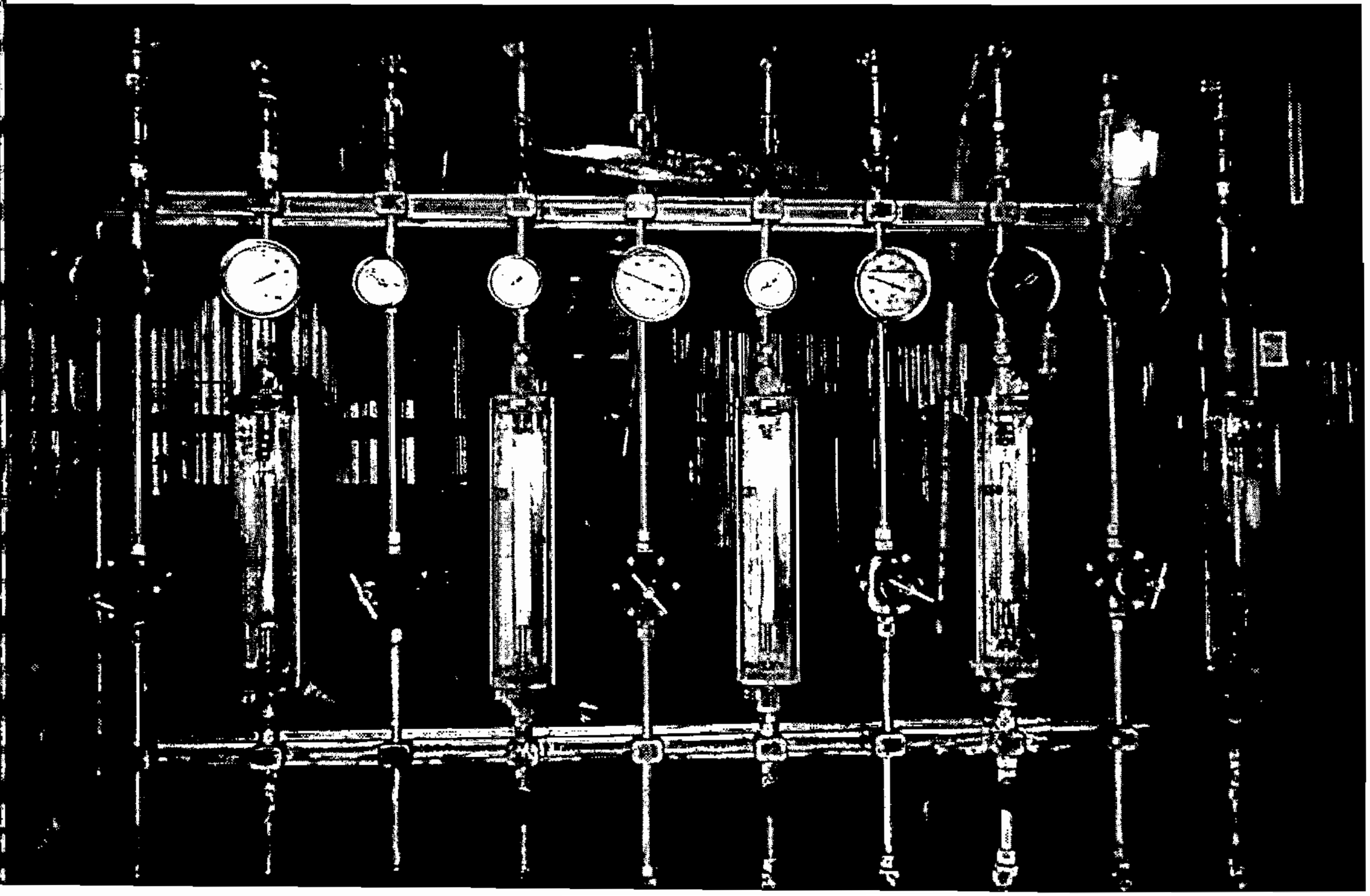
Distribution Module

ALTA in Sioux Unit 1



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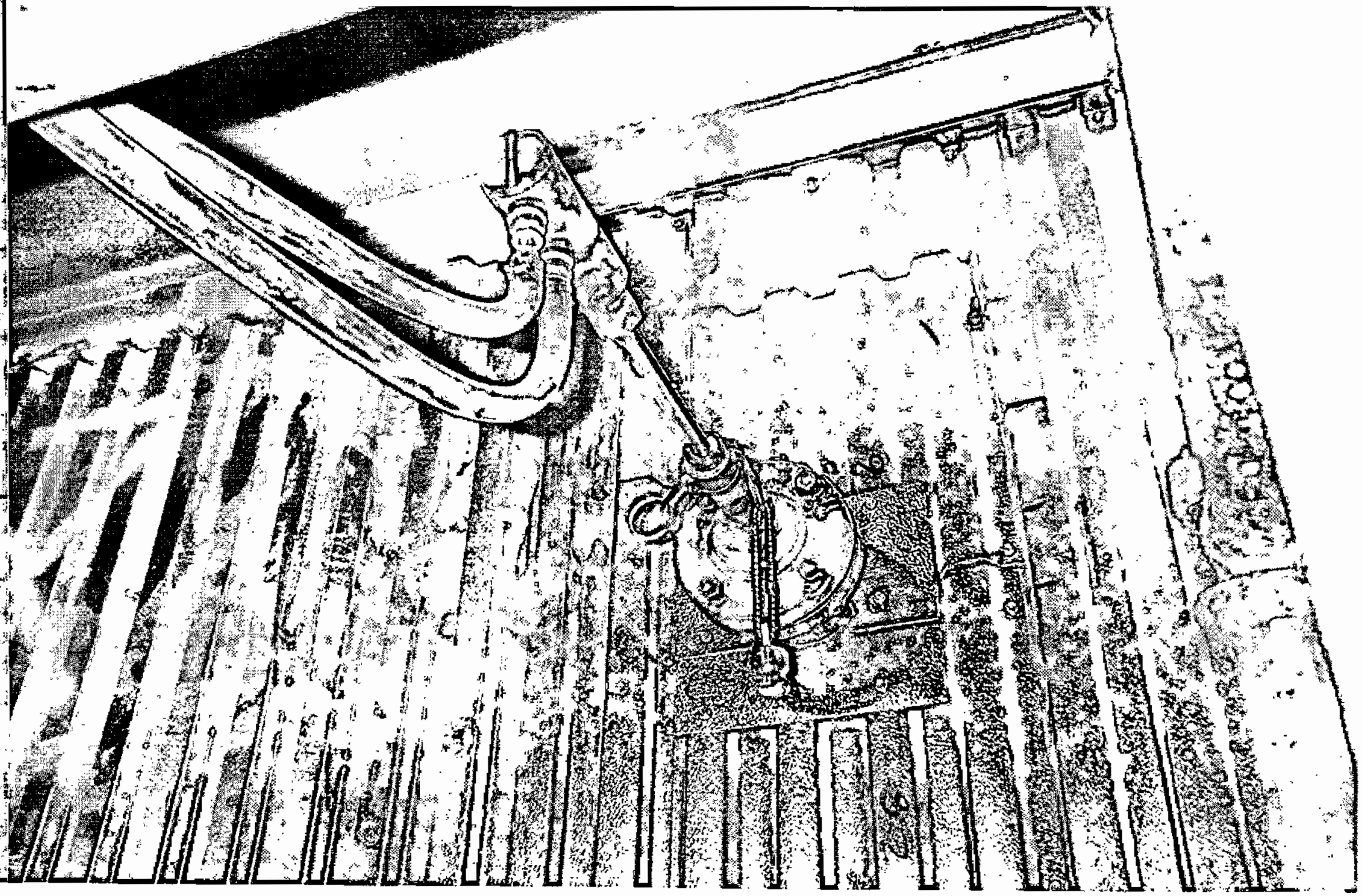
RRI Injector

ALTA in Sioux Unit 1



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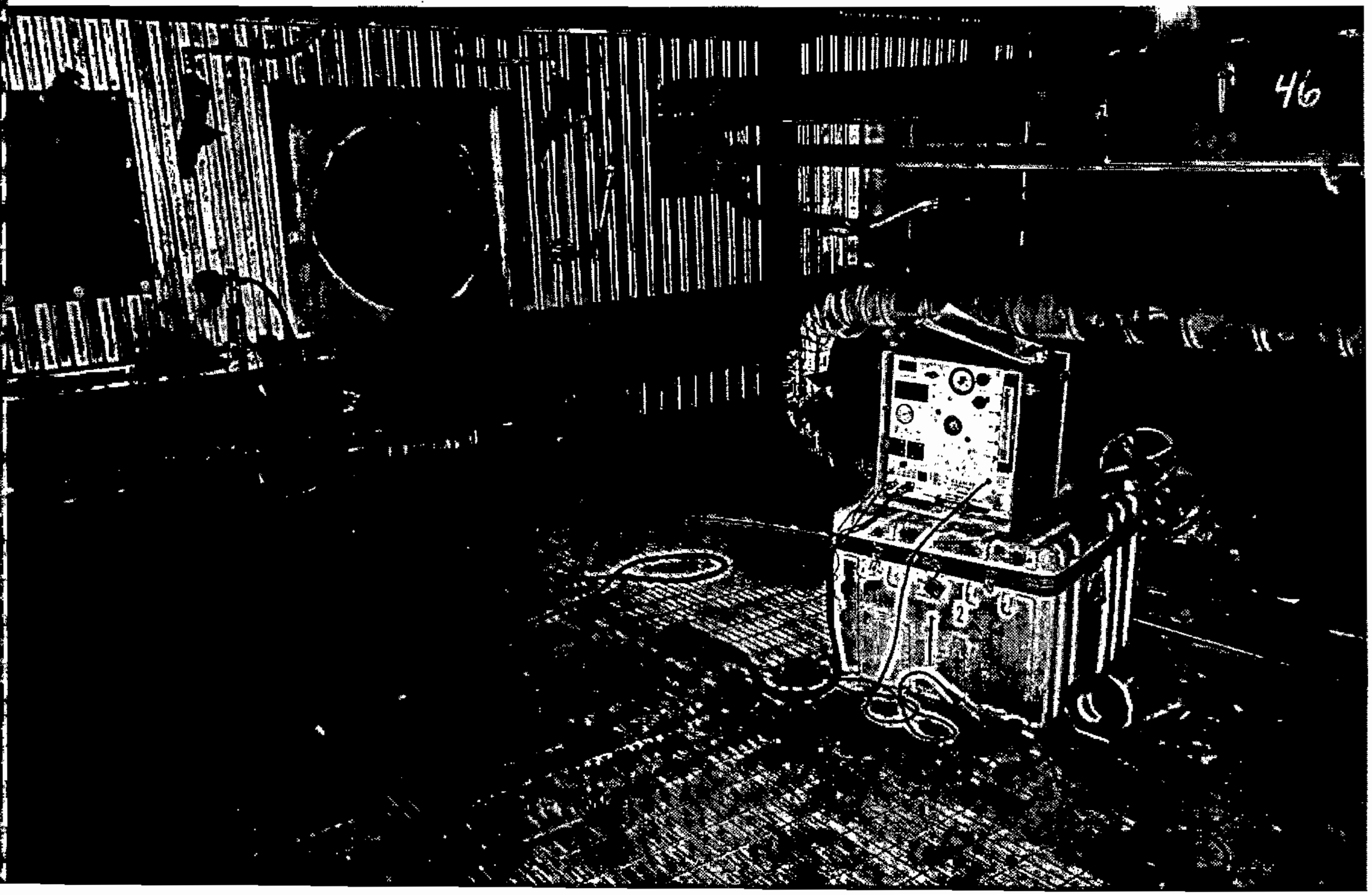
Extractive NH_3 Meas.

ALTA in Sioux Unit 1



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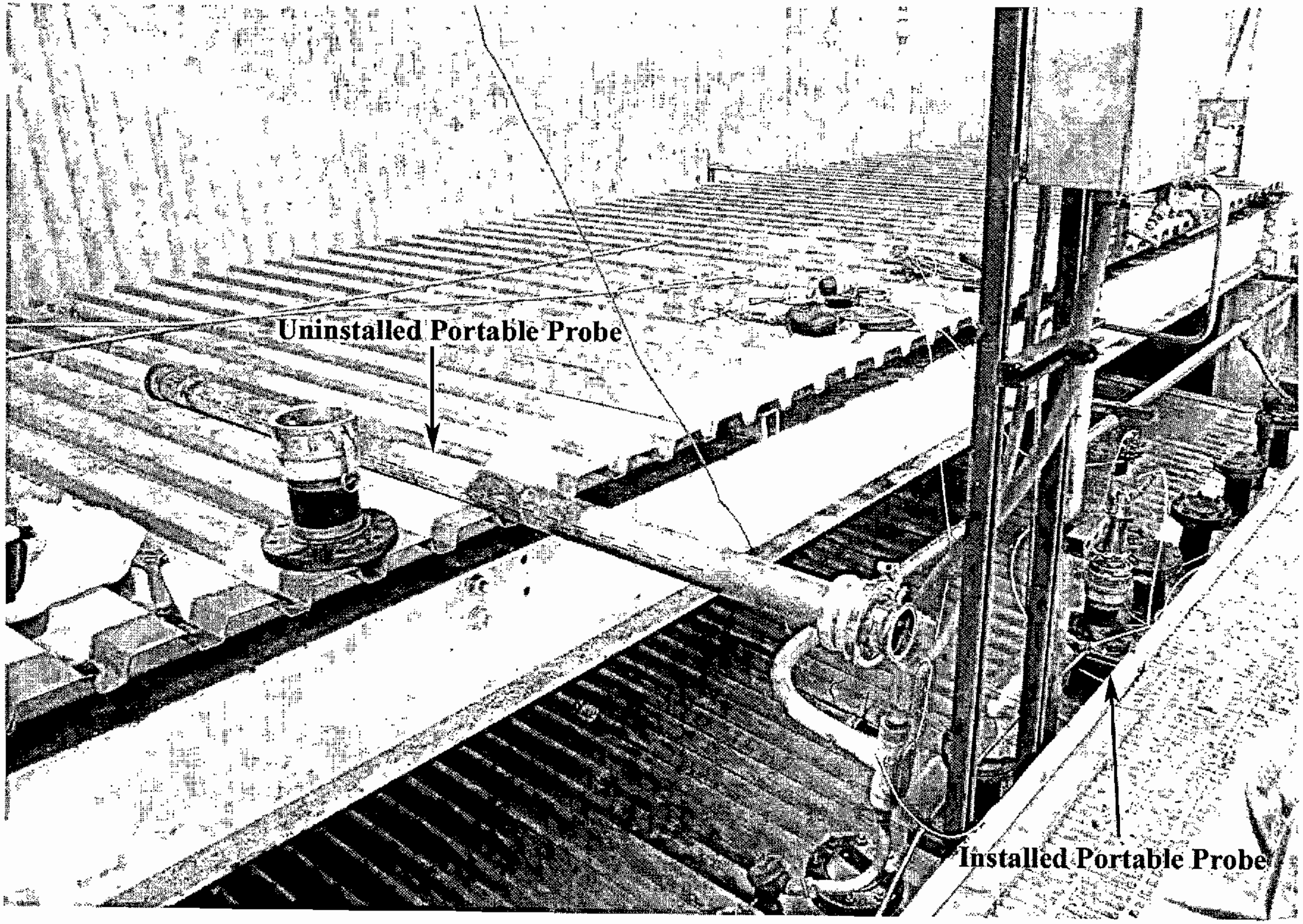
Continuous NH_3 Meas.

ALTA in Sioux Unit 1



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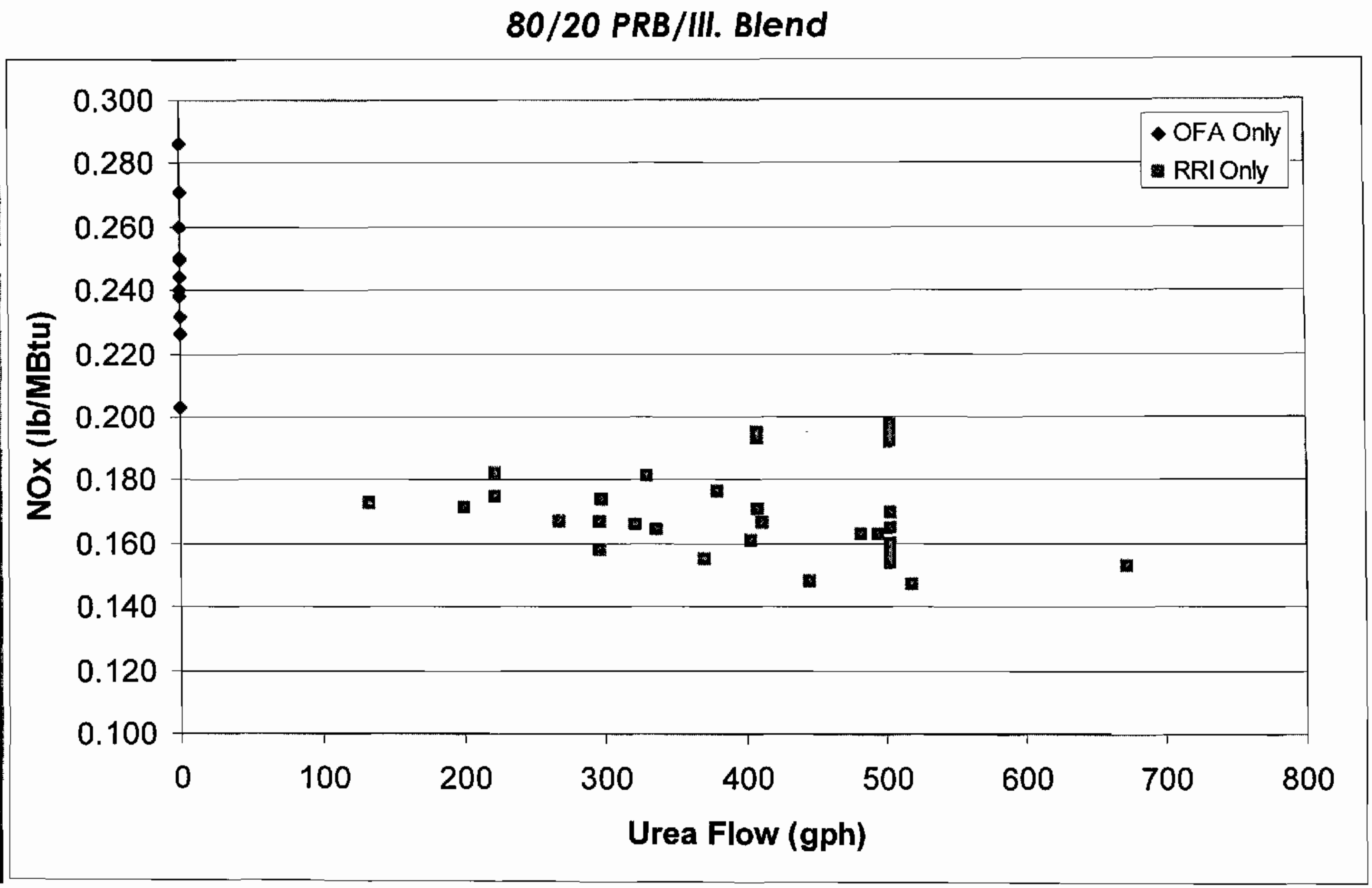
RRI Performance

RRI in Sioux Unit 1



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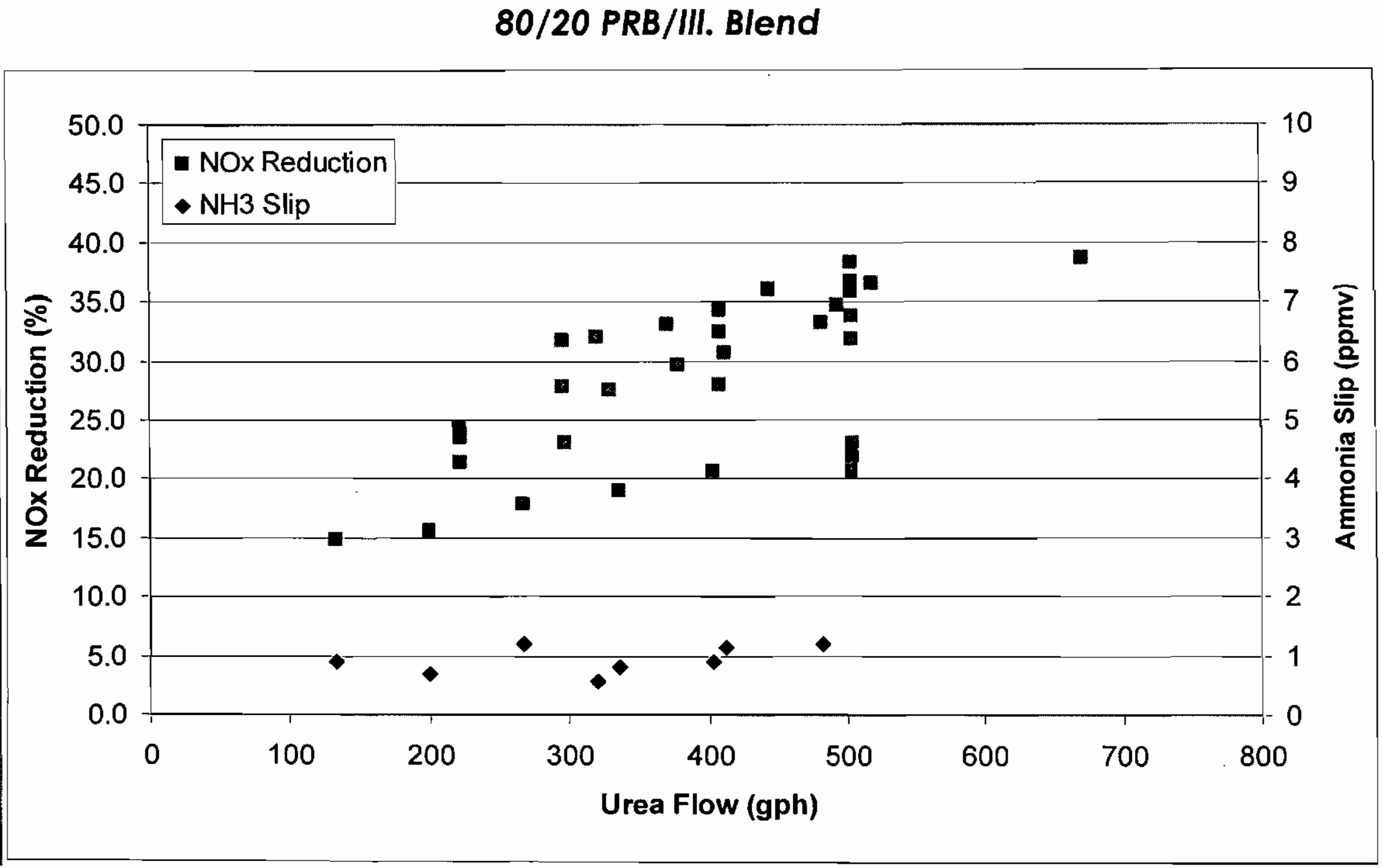
RRI Performance

RRI in Sioux Unit 1



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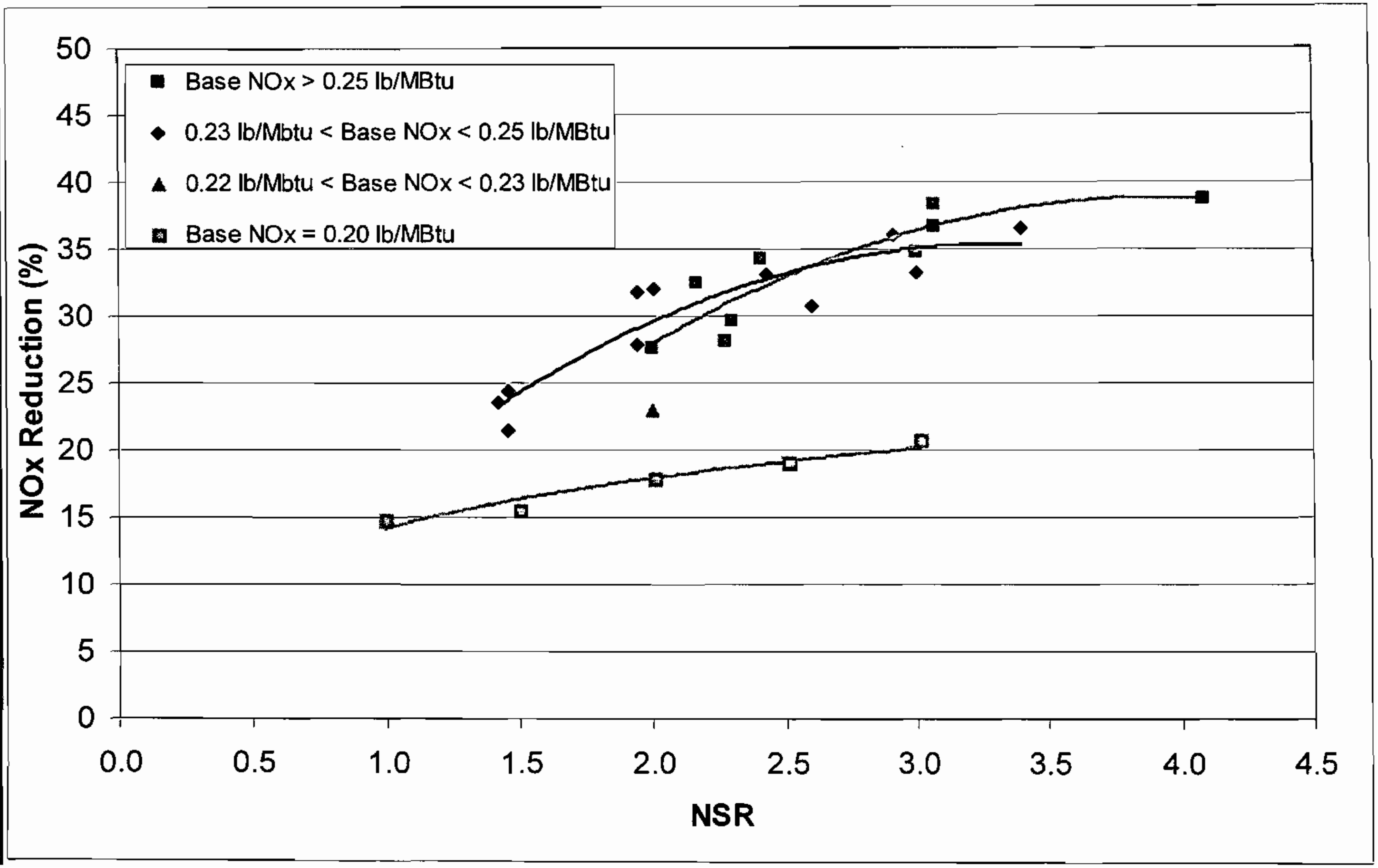
RRI Performance

Dependence on level of staging



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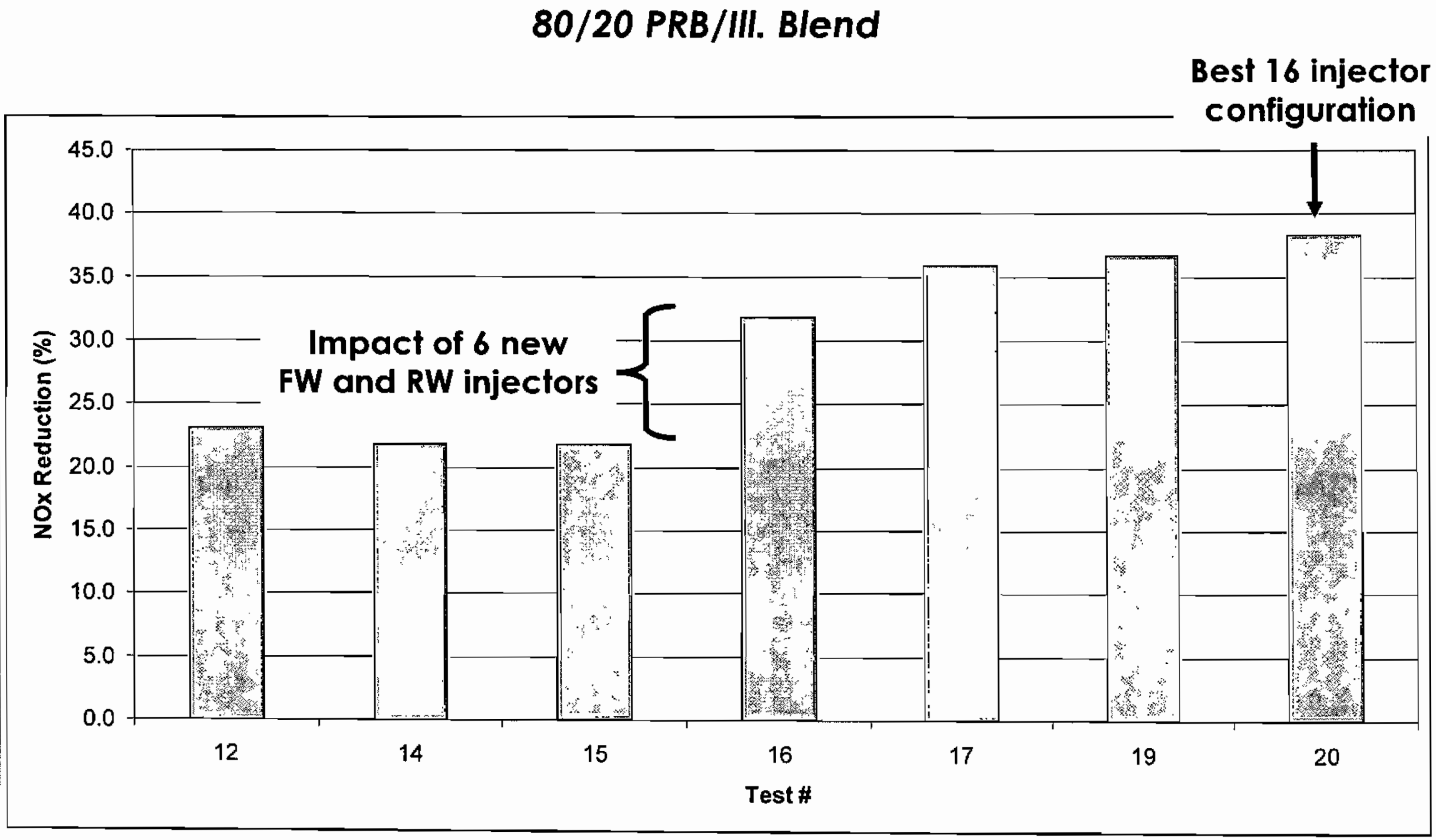
Injector Location Impacts

RRI in Sioux Unit 1



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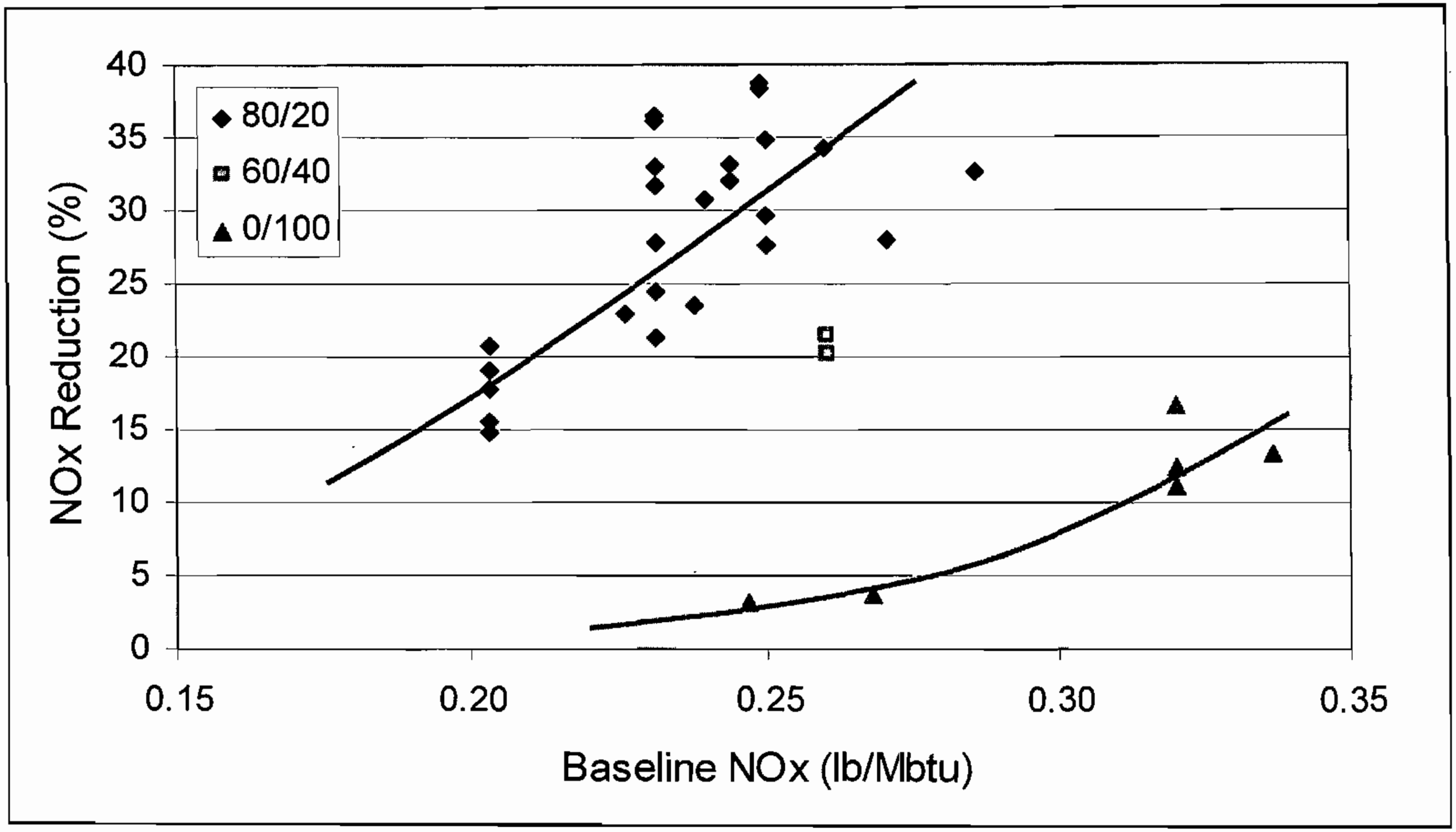
Fuel Blend & NOx Conc. Impacts

RRI in Sioux Unit 1



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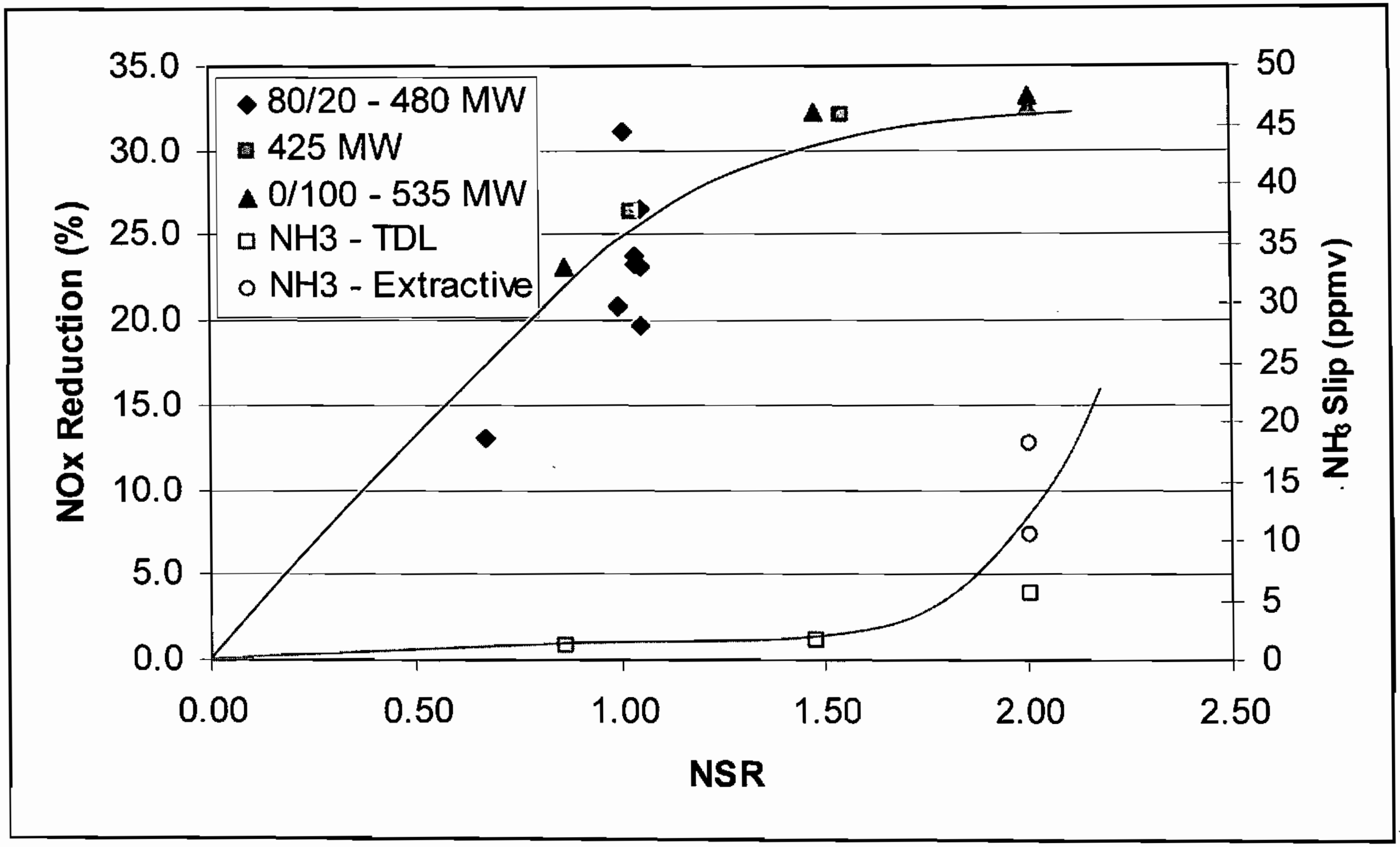
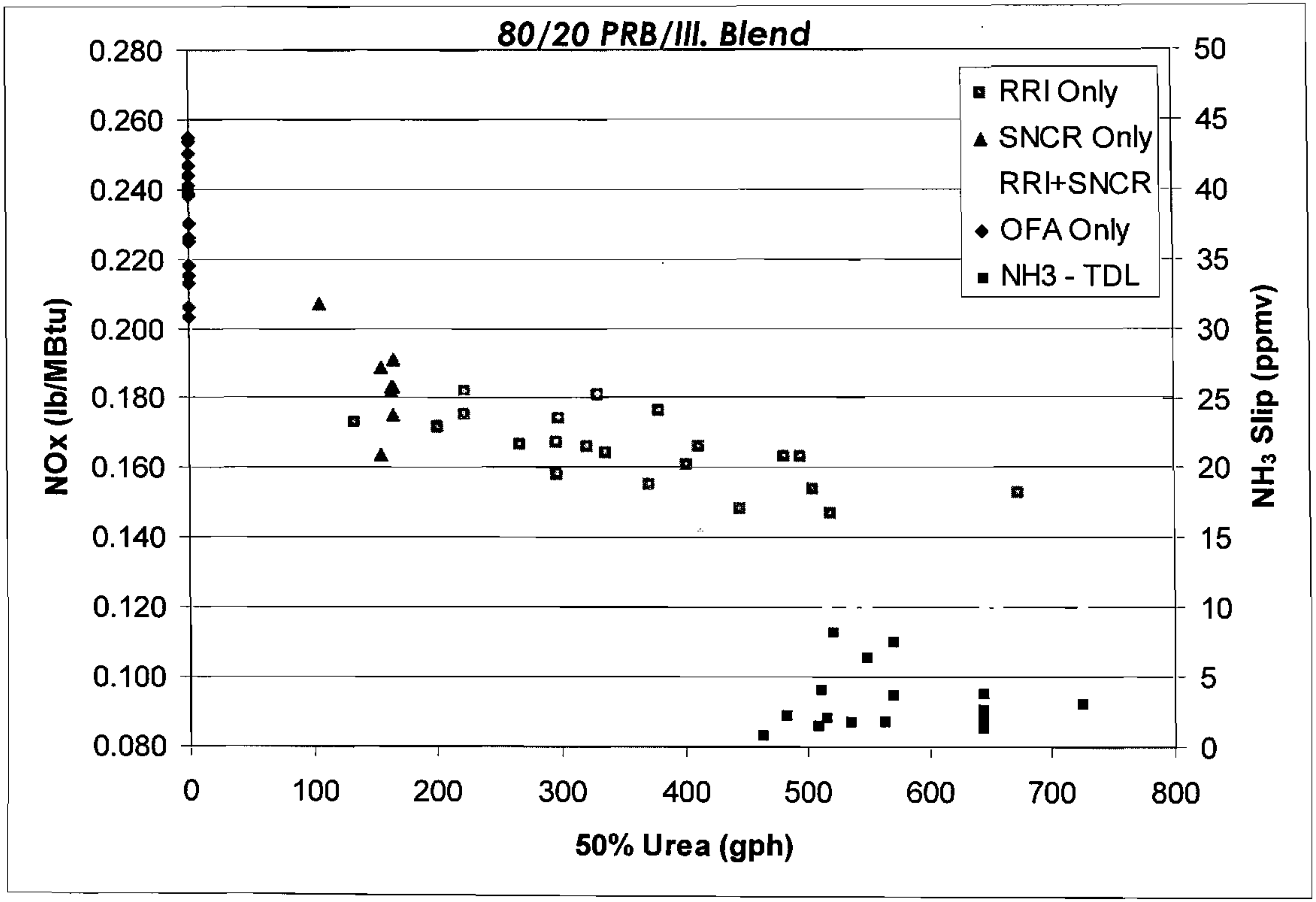
NOxOut SNCR Results

ALTA in Sioux Unit 1



ALTA Results
Sioux Unit 1



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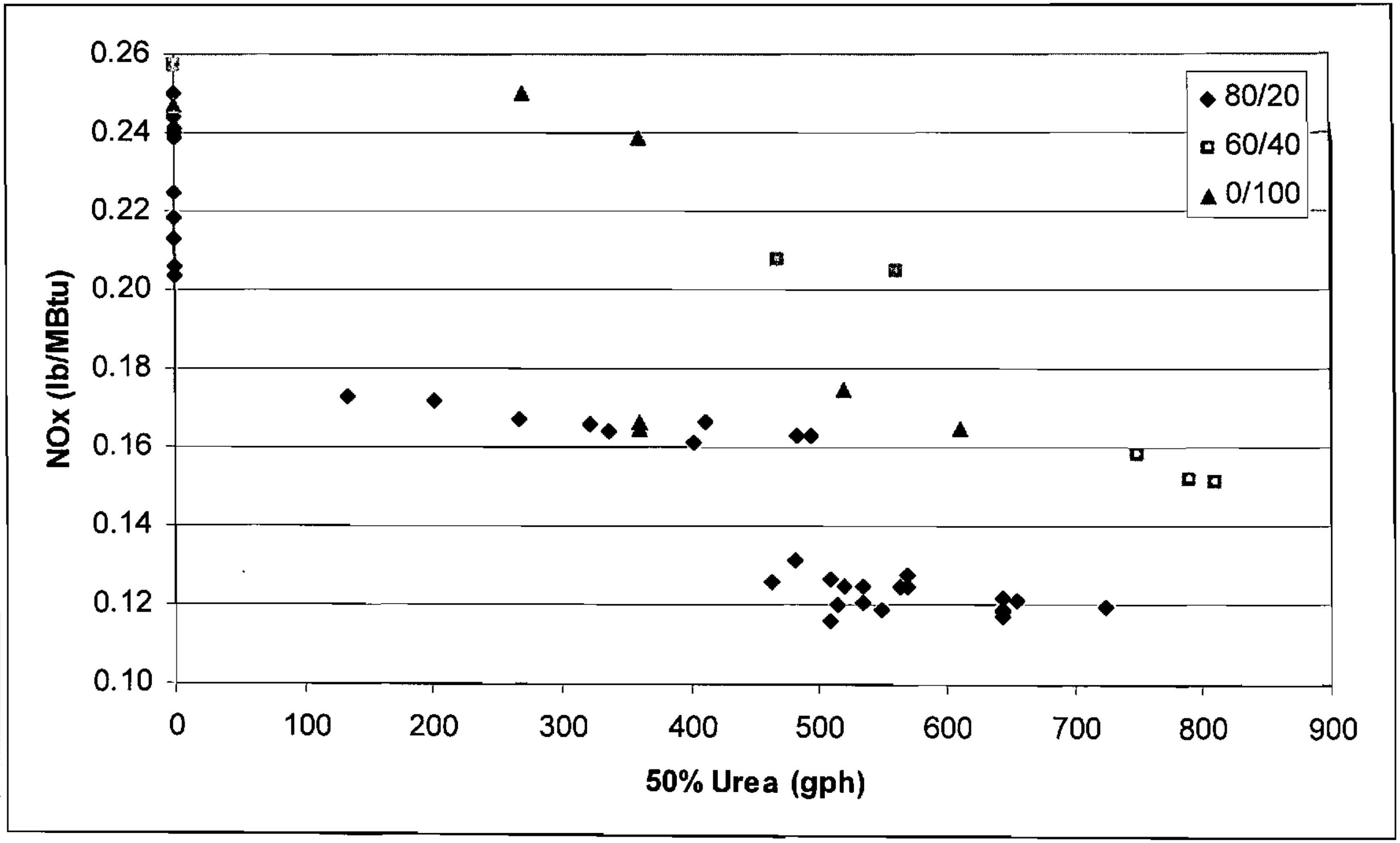
Fuel Impacts

ALTA in Sioux Unit 1



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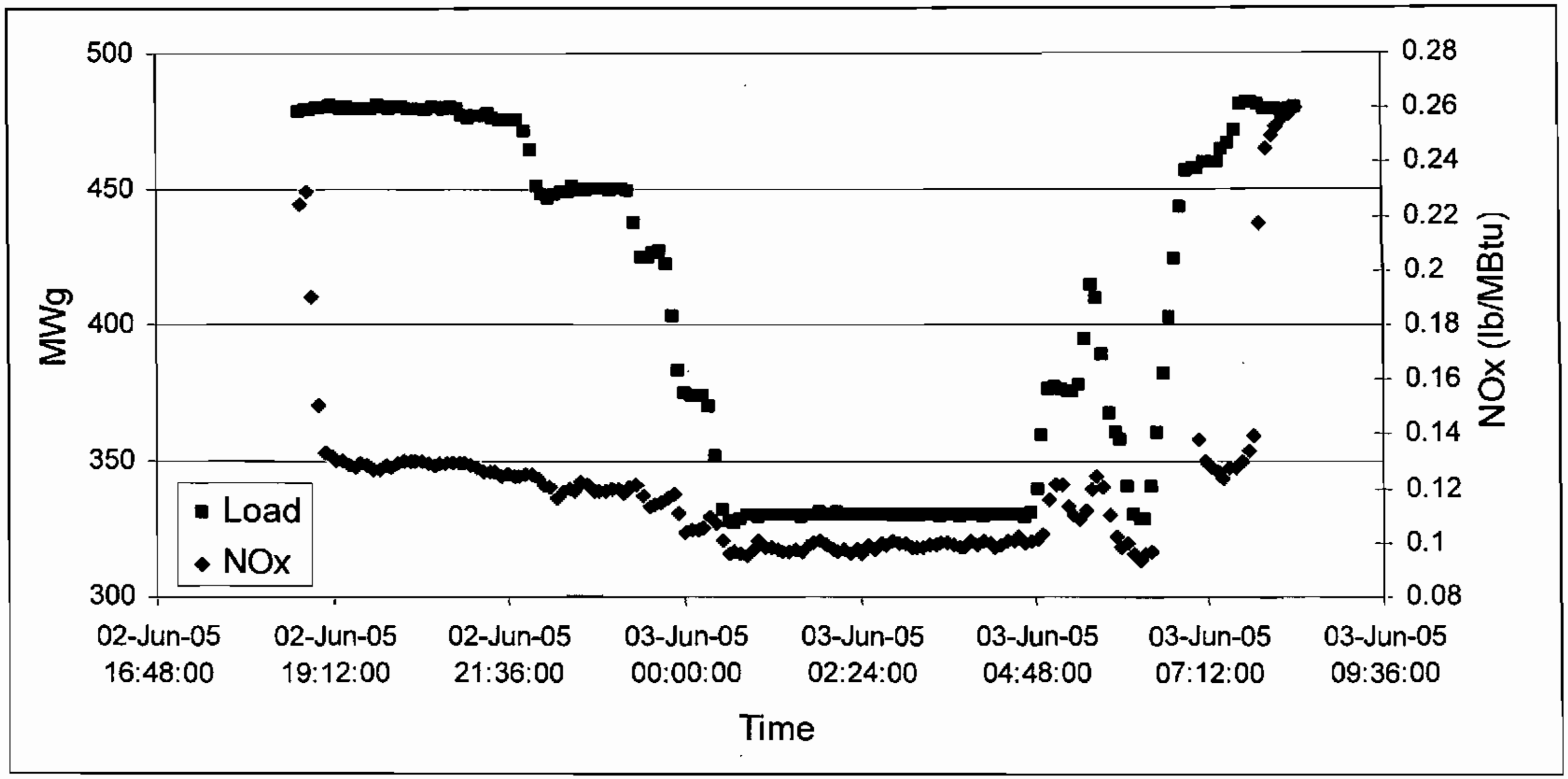
Reduced Load Testing

ALTA in Sioux Unit 1



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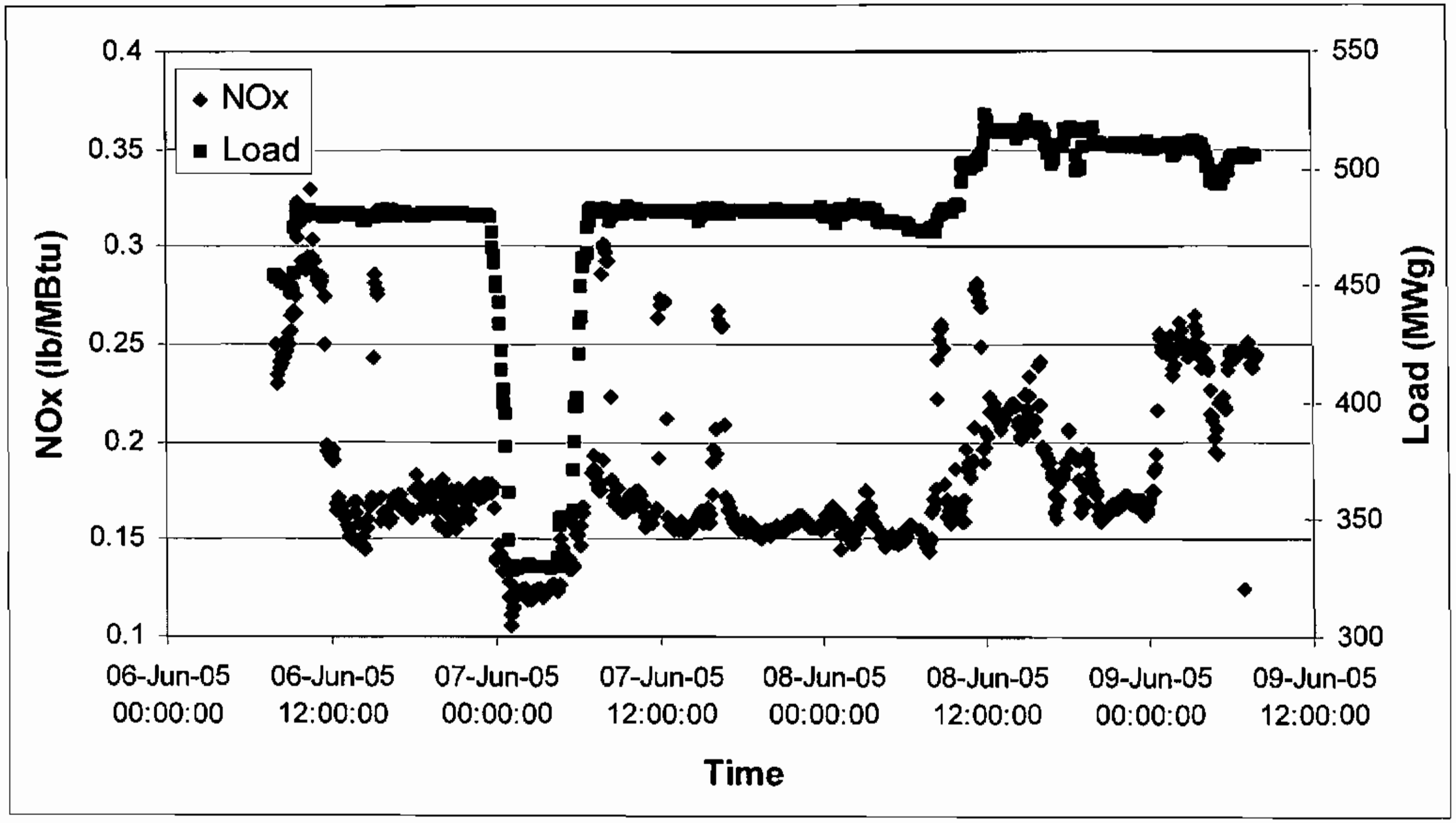
Continuous Testing

ALTA in Sioux Unit 1



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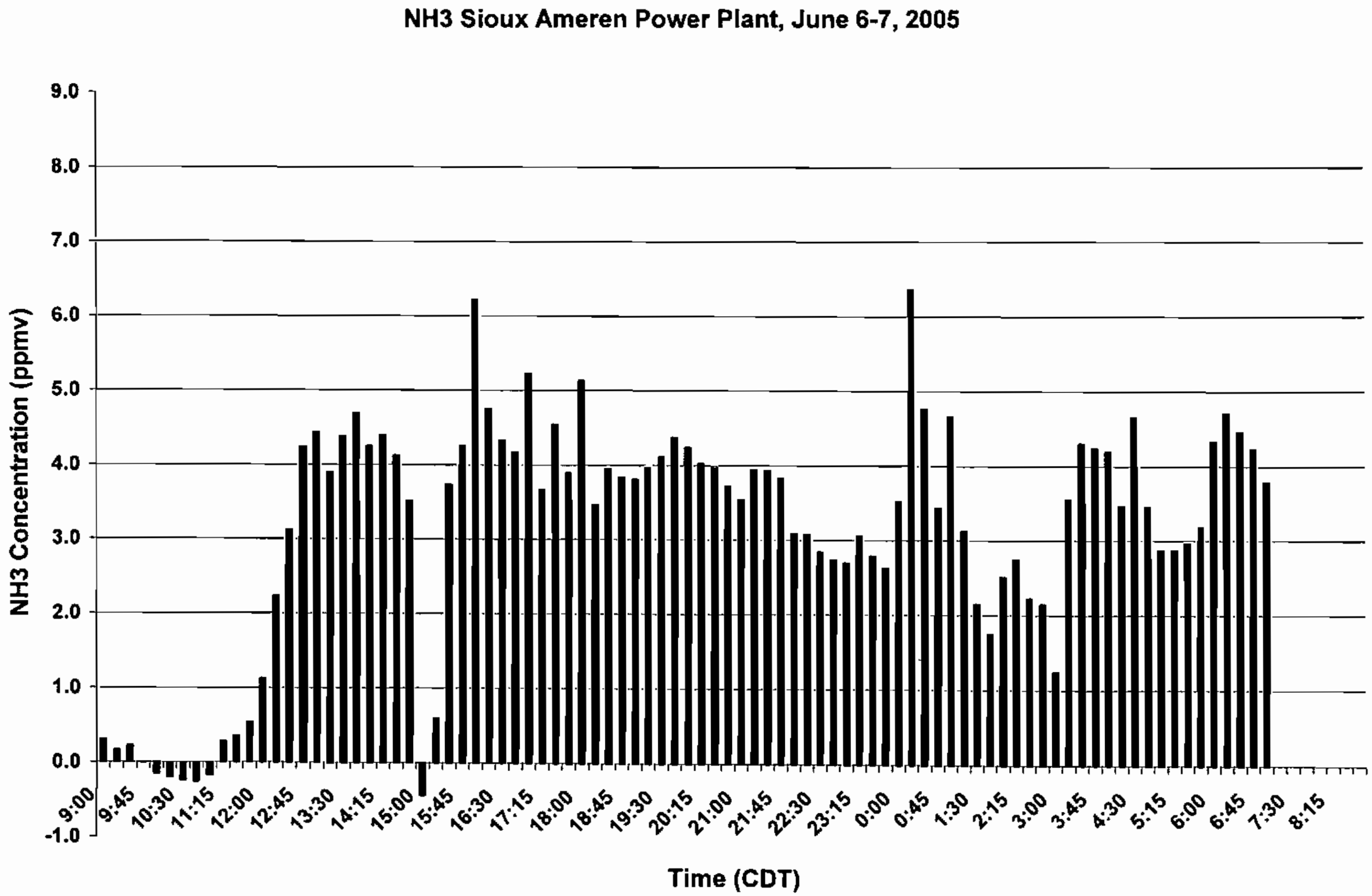
Continuous Tests – NH_3 Slip

ALTA in Sioux Unit 1



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Summary of Testing
ALTA in Sioux

- 0.12 lb/MBtu with 80/20 blend
  - As low as 0.15 lb/MBtu with RRI alone
  - 90% NOx reduction from uncontrolled baseline
- Decreased RRI performance with increasing Ill. 6 blends
  - 0.165 lb/MBtu with ALTA
  - Initial NOx/staging level dependence
- ALTA test results consistent with model predictions
- Sioux is proceeding with engineering for commercial ALTA systems in both units

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Thank You

cremer@reaction-eng.com

 IEPA ATTACHMENT NO. 5

INSTITUTE OF CLEAN AIR COMPANIES

WHITE PAPER

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO_x EMISSIONS

PREPARED BY:

SNCR COMMITTEE

INSTITUTE OF CLEAN AIR COMPANIES, INC.

MAY 2000

INSTITUTE OF CLEAN AIR COMPANIES

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The Institute's mission is to assure a strong and workable air quality policy that promotes public health, environmental quality, and industrial progress. As the representative of the air pollution control industry, the Institute seeks to evaluate and respond to regulatory initiatives and establish technical standards to the benefit of all.

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PURPOSE

To comply with federal, state, and local acid rain and ozone non-attainment rules, both regulators and regulated industry seek nitrogen oxide (NO_x) controls which offer the greatest reliability and effectiveness at the least cost. One such NO_x control technology is selective non-catalytic reduction (SNCR). Although SNCR will not be universally applicable, or always the most cost effective control strategy, in many cases it will meet the dual requirements of high performance and low cost, and so should be considered by affected sources and permitting authorities. To date, SNCR technology has been installed on 32 units in the power generation industry and on more than 250 industrial units (see Appendix 1 for a partial installation list).

The SNCR Committee of the Institute of Clean Air Companies, Inc. (ICAC) prepared this white paper to educate all interested parties on the capabilities, limitations, and cost of SNCR.

ICAC is the nonprofit national association of companies which supply stationary source air pollution monitoring and control systems, equipment, and services. Its members include suppliers of SNCR systems, and of competing NO_x control technologies.

EXECUTIVE SUMMARY

Selective non-catalytic reduction (SNCR) is a chemical process for removing nitrogen oxides (NO_x) from flue gas. In the SNCR process, a reagent, typically urea or anhydrous gaseous ammonia, is injected into the hot flue gas, and reacts with the NO_x, converting it to nitrogen gas and water vapor. No catalyst is required for this process. Instead, it is driven by the high temperatures normally found in combustion sources.

SNCR performance depends on factors specific to each source, including flue gas temperature, available residence time for the reagent and flue gas to mix and react, amount of reagent injected, reagent distribution, uncontrolled NO_x level, and CO and O_2 concentrations. However, reductions in emissions of 30-75% are common. Using appropriately designed SNCR systems, these levels of control are not accompanied by excessive emissions of unreacted ammonia (ammonia slip) or of other pollutants, particularly using recent design upgrades demonstrated on commercial systems. Further, SNCR does not generate any solid or liquid wastes.

SNCR also may be combined with a selective catalytic reduction (SCR) system or with gas reburn technologies to provide deeper emissions reductions for moderate capital investment. A combined SNCR/SCR systems uses substantially less catalyst (typically installed "in-duct") than a conventional SCR, allowing higher overall NO_x reduction than SNCR alone and lower ammonia slip, but with a relatively small increase in capital cost.

SNCR is a proven and reliable technology. SNCR was first applied commercially in 1974, and significant advances in understanding the chemistry of the SNCR process since then have led to improved NO_x removal capabilities as well as better ammonia slip control. As a result, approximately 300 SNCR systems have been installed worldwide. Applications include utility and industrial boilers, process heaters, municipal waste combustors, and other combustion sources.

SNCR is not a capital-intensive technology. Low capital costs, ranging from \$5-15/kWe on power generation units, make SNCR particularly suitable for use on lower capacity factor units, on units with short remaining service lives and for seasonal control. SNCR also is well suited for NO_x "trimming" and for use in combination with other NO_x reduction technologies. SNCR can provide 10-25 % reductions in power generation boiler NO_x emissions for total costs below 1 mill/kWh. Removal cost effectiveness values for SNCR center around \$1000 per ton of NO_x removed.

The performance and cost of SNCR make this technology attractive for export, including to developing and former Communist countries.

SELECTIVE NON-CATALYTIC REDUCTION (SNCR) FOR CONTROLLING NO_x EMISSIONS

What is SNCR?

Selective non-catalytic reduction (SNCR) is a chemical process that changes nitrogen oxides (NO_x) into molecular nitrogen (N_2), carbon dioxide (CO_2) (if urea is used), and water vapor. A reducing agent, typically anhydrous gaseous ammonia or liquid urea, is injected into the combustion/process gases. At suitably high temperatures (1,600 - 2,100 F)1[1], the desired chemical reactions occur. Other chemicals can also be added to improve performance, reduce equipment maintenance, and expand the temperature window within which SNCR is effective.

Conceptually, the SNCR process is quite simple. A gaseous or aqueous reagent of a selected nitrogenous compound is injected into, and mixed with, the hot flue gas in the proper temperature range. The reagent then, without a catalyst, reacts with the NO_x in the gas stream, converting it to harmless nitrogen gas, carbon dioxide gas (if urea is injected), and water vapor. SNCR is "selective" in that the reagent reacts primarily with NO_x,. A schematic depicting the SNCR process is shown in Figure 1.[2]

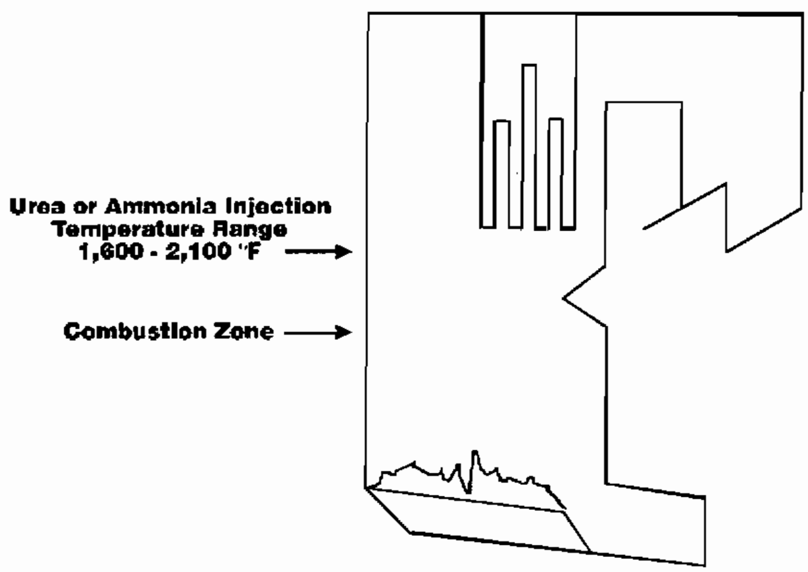

Figure 1

No solid or liquid wastes are created in the SNCR process.

While either urea or ammonia can be used as the reagent, for most commercial SNCR systems, urea has become the prevalent reagent used. Urea is injected as an aqueous solution while ammonia is typically injected in either its gaseous or anhydrous form using carrier air as a dilutive and support medium.

The principal components of the SNCR system are the reagent storage and injection system, which includes tanks, pumps, injectors, and associated controls, and often NO_x continuous emissions monitors. Given the simplicity of these components, installation of SNCR is easy relative to the installation of other NO_x control technologies. SNCR retrofits typically do not require extended source shutdowns.

How much NO_x can SNCR remove?

While SNCR performance is specific to each unique application, NO_x reduction levels ranging from 30% to more than 75% have been reported.

Temperature, residence time, reagent injection rate, reagent distribution in the flue gas, uncontrolled NO_x level, and CO and O_2 concentrations are important in determining the effectiveness of SNCR.[3] In general, if NO_x and reagent are in contact at the proper temperature for a long enough time, then SNCR will be successful at reducing the NO_x level.

SNCR is most effective within a specified temperature range or window. A typical removal effectiveness curve, as a function of temperature within this window, is shown in Figure 2. At temperatures below the window, reaction rates are extremely low, so that little or no NO_x reduction occurs. As the temperature within the window increases, the NO_x removal efficiency increases because reaction rates increase with temperature. Residence time typically is the limiting factor for NO_x reduction in this range. At the plateau, reaction rates are optimal for NO_x reduction. A temperature variation in this range will have only a small effect on NO_x reduction.

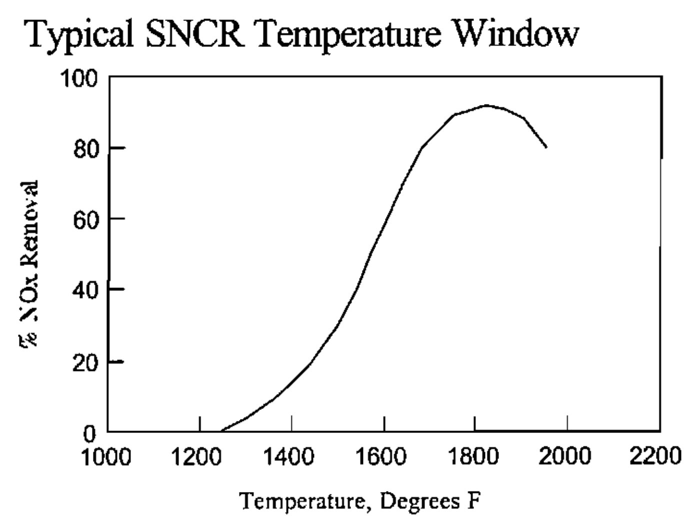

Figure 2

A further increase in temperature beyond the plateau decreases NO_x reduction. On the right side of the curve, the oxidation of reagent becomes a significant path and competes with the NO_x reduction reactions for the reagent. Although the efficiency is less than the optimum, operation on the right side is practiced and recommended to minimize byproduct emissions. On the left side of the curve, there is also greater potential for ammonia slip for a given NO_x removal and residence time.

The effective temperature window becomes wider as the residence time increases, thus improving the removal efficiency characteristics of the process. Long residence times (>0.3 second) at optimum temperatures promote high NO_x reductions even with less than optimum mixing.

Normal stoichiometric ratio (NSR) is the term used to describe the N/NO molar ratio of the reagent injected to the uncontrolled NO_x concentrations. In general, one mole of ammonia species will react with one mole of NO in the reduction reaction. If one mole of anhydrous ammonia is injected for each mole of NO_x in the flue gas, the NSR is one, as one mole of ammonia will react with one mole of NO_x. If one mole of urea is injected into the flue gas for each mole of NO_x, the NSR is two. This is because one mole of urea contains two ammonia radicals and will react with two moles of NO_x.[3] For both reagents, the higher the NSR, the greater the NO_x reduction. Increasing NSR beyond a certain point, however, will have a diminishing effect on NO_x reduction with a resultant increase in ammonia slip and reagent cost.

Is SNCR a new technology?

No. Commercial installations using SNCR have been in existence for more than 20 years.

The first commercial application of SNCR was in Japan in 1974.[4] This installation used anhydrous ammonia. At about the same time, the anhydrous ammonia injection process was patented in the U.S. by Exxon Research and Engineering Co. This process is commonly known as the Thermal $DeNO_x$ process.

Fundamental thermodynamic and kinetic studies of the NO_x-urea reaction occurred during 1976-1981 under the direction of the Electric Power Research Institute (EPRI). Patents granted to EPRI for this process were licensed to Fuel Tech which, with its implementors and sub-licensees, has marketed the urea-based NOxOUT[R] process with improvements to the original patents.

Is SNCR commercially demonstrated?

SNCR systems are in commercial operation in the United States, as well as in Europe and Asia.

SNCR is a fully commercial NO_x reduction technology, with successful application of the urea- and ammonia-based processes at approximately 300 installations worldwide (see Appendix 1 and 2), covering a wide array of stationary combustion units firing an equally large number of fuels.

In the U.S., commercial installations or full-scale demonstrations include virtually every boiler configuration and fuel type, as well as other major NO_x emitting process units, such as cement kilns and incinerators. Urea-based SNCR has been applied commercially to sources ranging in size from a 60 MMBtu/hr (gross heat input) paper mill sludge incinerator to a 640 MWe pulverized coal-fueled, wall-fired electric utility boiler. The longest running commercial urea-based SNCR system in the U.S. was installed in early 1988 on a 614 MMBtu/hr CO boiler in a Southern California oil refinery. This SNCR system reduces NO_x emissions 65% from a baseline of 90 ppm.

Industrial boilers, process units, municipal and hazardous waste combustors, and power boilers make up the largest share of commercial SNCR installations in the U.S. This distribution is determined more by NO_x control regulations than by SNCR process limitations. Examples of commercial installations include:

- Two 75 MWe pulverized coal tangentially fired power boilers in California equipped with low NO_x burners and overfire air required the installation of SNCR to meet a 165 ppm permit limit.[5]

- SNCR systems installed on the coal-burning, wall-fired New England Power Company's Salem Harbor Station Units 1, 2 (84 MWe each) and 3 (156 MWe) in 1993, together with LNBs, can reduce NO_x emissions 50-75 % from a baseline of 0.85-1.12 lb/MMBtu.

- Commercial SNCR systems retrofit on 320 MWe wet-bottom, twin furnace boilers in New Jersey provide 30-35% NO_x reductions.[6]

- Commercial SNCR systems retrofit on cyclone-fired boilers in New Jersey reduce NO_x emissions by 35-40%.

- SNCR is achieving compliance with RACT limits at coal-fired boilers in Massachusetts[7] and Delaware.[8]

- An SNCR system installed on a circulating fluidized bed boiler designed to produce 350,000 lb/hr of steam can reduce NO_x emissions from a baseline of 0.2-0.35 lb/MMBtu to below 0.15 lb/MMBtu over a load range of 40-100%.[9]

- Among significant demonstrations in the U.S.:

- An SNCR system on a 600 MW coal-fired boiler reduced NO_x by 30 % across the load range while maintainging ammonia slip near 5 ppm. The unit experienced very few operational difficulties.[10]

- SNCR, in conjunction with combustion tempering, is achieving NO_x reductions of nearly 60 % on a 244 MWe gas-fueld cyclone boiler.[11]

- SNCR, in conjunction with burner optimizations, reduced NO_x on coal over 70 % on coal fired boilers.[12]

- SNCR provided an 80+ % reduction from uncontrolled emissions of 3.5-6.0 b NO_x per ton of clinker in a demonstration at a West Coast cement kiln.

- A SNCR system in combination with a modified reburn process is meeting 0.2 lb/MMBtu on a 600 MW boiler firing Powder River Basin coal.

SNCR also has been commercially installed and demonstrated in Asia. For example, an SNCR system installed on a 331 MMBtu/hr pulverized coal-fired industrial boiler in Kaohsuing, Taiwan, in 1992 reduced NO_x emissions from this front-fired boiler from 300 to 120 ppm.

In addition, SNCR has been commercially installed throughout Europe. Installations include coal-fueled district heating plant boilers, electric utility boilers, municipal waste incinerators, and many package boilers.

In Germany, commercial SNCR systems installed on municipal waste incinerators in Hamm, Herten, and Frankfurt reduce NO_x emissions 40-75 % from baselines of 160-185 ppm. SNCR also has been installed on more than 20 heavy oil-fired Standardkessel package boilers.

In Sweden, a commercial SNCR system on a 275 MMBtu/hr coal-fueled, stoker-fired boiler at the Linkoping P1 district heating plant reduces NO_x emissions 65 % from a baseline of 300-350 ppm. At the Nykoping demonstration on a 135 MMBtu/hr coal-fueled circulating fluidized-bed boiler, SNCR achieves a 70 % NO_x reduction from a 120-130 ppm baseline. Demonstrations of SNCR, in addition to municipal waste incinerators and wood- and coal-fueled district heating plant boilers, included a pulp and paper mill kraft recovery boiler, where a 60 % reduction from uncontrolled emissions of 60 ppm was attained. [13]

To meet new environmental demands in Eastern Europe, SNCR systems were installed on five coal-fired industrial boilers in the Czech Republic since 1992.

Are there applications for which SNCR is particularly suited?

Yes. Some applications have combinations of temperature, residence time, unit geometry, and uncontrolled NO_x level, and operating modes which make them especially well-suited for cost-effective reduction of NO_x by SNCR.

Certain applications are technically well-suited for the use of SNCR. These include combustion sources with exit temperatures in the 1550-1950 °F range and residence times of one second or more, examples of which are many municipal waste combustors, sludge incinerators, CO boilers, and circulating fluidized bed boilers. Furnaces or boilers with high NO_x levels or which are not suited to combustion controls, e.g., cyclone-type or other wet bottom boilers and stokers and grate-fired systems, also are good candidates for SNCR.

Other applications are well-suited to the use of SNCR for economic reasons. For these applications, controls with reduced capital cost, even at the expense of somewhat higher operating costs, may be the least expensive to operate. Applications meeting these criteria include units with lower capacity factors, such as peaking and cycling boilers, units requiring limited control, e.g., additional "trim" beyond combustion control or seasonal control.

How much does SNCR cost?

The capital cost of a selective non-catalytic reduction system is among the lowest of all NO_x reduction methods. Recent innovations in the control of reagent injection make SNCR operating costs also among the lowest of all NO_x reduction methods.

SNCR is an operating expense-driven technology, so that the absolute cost of applying SNCR varies directly with the NO_x reduction requirements.

Typical SNCR capital costs (including installation) for utility applications are \$5-15/kW, vendor scope, which corresponds to a maximum of \$20/kW if balance-of-plant capital requirements are included. For example, the total capital requirement for the commercial installation of SNCR at New England Electric's Salem Harbor Station (three pulverized coal-fired boilers) was \$15/kW. [14] Similarly, total capital requirements for Public Service Electric and Gas' Mercer Station Unit 2 and B.L. England Station Unit 1 were \$10.6/kW and \$15/kW, respectively. [15] Southern California Edison reported an even lower capital requirement of \$3/kW for installing "urea injection" on 20 units totaling 5600 MW[16].

In the industrial sector, SNCR capital costs have been on the order of \$900/MMBtu/hr (equivalent to \$9/kWe on an electric utility boiler) for CO boilers, industrial power boilers, and waste heat boilers. Waste-to-energy plants and process heaters typically require \$1,500/MMBtu/hr (equivalent to \$15/kWe).

For similar type sources, the installed capital cost per unit of output (e.g., \$/kWe) decreases as the source size increases, i.e., due to economy of scale, total capital outlay increases less than linearly with increasing boiler capacity.

Given such low capital requirements, most of the cost of using SNCR will be operating expense. A typical breakdown of annual costs for utilities will be 25 % for capital recovery and 75 % for operating expense. For industrial sources, annual costs will be 15-35 % for capital recovery and 65-85 % for operating expense. For an operating expense-driven technology, little cost will be incurred if the source is not operating, and cost effectiveness (the cost per ton of NO_x removed) will be relatively insensitive to capacity factor or duty cycle. This makes SNCR attractive for seasonal control of NO_x emissions. (For capital-intensive technologies, cost effectiveness becomes worse with decreasing capacity factor.)

Demonstrated cost-effectiveness values for SNCR are low, ranging from \$400 to \$2,000 per ton of NO_x removed, depending upon site-specific factors. For example, the cost effectiveness of SNCR at New England Electric's Salem Harbor Station unit 2 is \$670/ton.[17] The wide range exists because of differeing conditions found across different facilities, even with in the same industry. For utility boilers alone, cost effectiveness varies with factors such as uncontrolled NO_x level, required emission reduction, unit size, capacity factor (or duty cycle), heat rate (or thermal efficiency), degree of retrofit difficulty, and economic life of the unit.

Of primary interest to electric utilities is the cost of pollution controls per unit of electricity generated, expressed on a busbar basis (mills/kWh). For SNCR, the busbar cost varies directly with the amount of NO_x to be removed. Costs range from less than 1.0 mill/kWh for "trim reduction" on a coal-fired unit or RACT-level reduction on an oil-fired unit, to 3.5 mills/kWh for a 75 % reduction on a unit with uncontrolled emissions greater than 1 lb NO_x/MMBtu. A commercial installation of urea-based SNCR on a New England Electric unit has a busbar cost of 2.7 mills/kWh, and a cost effectiveness of approximately \$1,000/ton. (To convert the busbar costs of SNCR to a cost increment relative to fuel price, 0.5-3.5 mills/kWh is roughly equivalent to \$0.05-\$0.35/MMBtu.)

Innovations in SNCR control systems and continued system optimization during operation have reduced reagent usage at commercial installations, thus decreasing operating costs further. At one coal-fired utility boiler, a control upgrade, including continuous ammonia and temperature monitors, improved control hardware and software, and additional injector pressure controls, allow over a 50 % decrease in reagent use from baseline levels.[18] At a second coal- and oil-fired unit, system optimization after start-up has lowered reagent consumption 35 % below predicted levels.[19] Given that the reagent dominates SNCR operating cost, such large reductions in reagent use translate to significant reductions in operating cost.

What about ammonia slip?

Ammonia slip, or emissions of ammonia which result from incomplete reaction of the NO_x reducing reagent, typically can be limited to low levels.

Ammonia slip may result in one or more problems, including:

- Formation of ammonium bisulfate or other ammonium salts which can plug or corrode the air heater and other downstream components;
- Ammonia absorption on fly ash, which may make disposal or reuse of the ash difficult;
- Formation of a white ammonium chloride plume above the stack; and,
- Detection of an ammonia odor around the plant.

Ammonia slip is controlled by careful injection of reagent into regions of the furnace or other sources where proper conditions (temperature, residence time, and NO_x concentration) for the SNCR reaction exist. If the reagent reacts in a region where the temperature is too low for the NO_x-reducing reaction to occur in the available residence time, then some unreacted ammonia will be emitted. Further, if reagent is injected in such a way that some regions of the furnace are over treated, the excess reagent can lead to ammonia slip. Thus, it is critical that the SNCR injection system be designed to provide the appropriate reagent distribution.

The difficulty in controlling ammonia slip will vary from application to application. At many commercial installations, particularly in electric utilities, units have operated with ammonia slip levels of equial to or less than 5 ppm upstream of the air heater to meet the requirements of owners or permitting authorities. This is a far more stringent criterion than stack emissions. In any case, ammonia concentrations at ground level will be well below thresholds for both odor and toxicity.

Control system upgrades and process optimization after installation can lower slip below guaranteed levels. Thus, at a commercial SNCR system on a coal-fired boiler, improved controls have lowered ammonia slip from 10-15 ppm to below 5 ppm, and have reduced ammonia on the fly-ash by half.

Use of an SCR downstream of a SNCR also optimizes the integration to ammonia-sensitive units.

Does SNCR have other limitations?

As do all pollution control technologies, SNCR has limitations which must be understood in order to use it properly to optimize the control of NO_x emissions.

High temperature and critical NO_x concentration. As temperature increases, the "critical" or equilibrium NO_x concentration at a given oxygen concentration increases. At high enough temperatures, any reduction of NO_x to below the critical level by SNCR or other means will be counteracted by the rapid oxidation of nitrogen to re-form NO_x. For this reason, at sufficiently high temperatures and baseline NO_x levels below the critical concentration, injection of ammonia or urea into the flue gas will result in *increased* NO_x levels. If, however, the baseline NO_x concentration is above the critical level, NO_x reduction will result. For typical coal- and oil-fired steam boilers, critical NO_x levels are 70-90 ppm (ca. 0.1 lb/MMBtu) in the upper furnace.

High furnace carbon monoxide concentration. High CO concentrations can shift the temperature window of the SNCR process. When CO concentrations in the region of reagent injection are above 300 ppm, the critical NO_x level and SNCR reaction rate will increase above what they would have been had little CO been present, as if the temperature were slightly higher. Therefore, in some furnaces with high CO levels, it is preferable to inject reagent at lower temperatures to effect good NO_x control.

Carbon monoxide emissions. In a well-controlled urea-based SNCR system, the carbon contained in the urea is fully oxidized to carbon dioxide. Normally, steps taken to control ammonia slip impose sufficient restrictions on reaction temperature to prevent substantial emissions of CO.

Nitrous oxide (N_2O) emissions. Nitrous oxide is a by-product of the SNCR process, with urea-based systems typically producing more nitrous oxide than ammonia-based systems. At most, about 10 % of the NO_x reduced in urea-based SNCR is converted to nitrous oxide. With proper control, the nitrous oxide production rate may be limited to significantly lower levels. Nitrous oxide contributes to neither ground level ozone nor acid rain formation, and biogenic sources dominate the atmospheric budget of N_2O.

What are common misconceptions regarding SNCR?

Several common misconceptions have slowed the acceptance of SNCR by utilities.

Misconception: As boiler size increases, SNCR efficiency decreases. As long as reagent can be distributed, there is no technical limitation to the size of boilers on which SNCR will be effective. This misconception arose in part from the earliest experiences at large utility boilers in California. These boilers were equipped with low NO_x combustion systems, had high furnace exit gas temperatures, and very rapid cooling of the gases in the boiler convective regions. Low baseline NO_x levels resulting from these natural gas-fired boilers and rapid cooling led to low NO_x control efficiencies and high ammonia slips using SNCR. Increased technical knowledge and experience have allowed better delineation of the limitations of the SNCR process, which since then has been used to achieve over 60 % NO_x reductions on some electric utility boilers.

The commercial development of retractable multi-nozzle lances as well as advances in feed-forward controls has extended the applicability of urea-based SNCR technology. These advances enable delivery of reagent across the boiler, as has been demonstrated both in the U.S. and abroad. Recently, three utility units (each with a different type of combustion system) with capacity in excess of 600 MW each have successfully implemented the SNCR technology. The combustion systems for these units include opposed wall-, cell- and turbo-fired technologies.

Misconception: SNCR cannot be used on boilers equipped with low NO_x combustion controls. SNCR has been installed commercially on boilers equipped with low NO_x burners, overfire air, and flue gas recirculation, and has been shown to operate effectively with all of these technologies.[20]

Misconception: Use of SNCR on coal-fired plants results in fly ash which cannot be sold and the disposal of which is expensive. The tendency of fly ash to absorb ammonia is a function of many factors in addition to the amount of ammonia slip. Ash characteristics such as pH, alkali mineral content, and volatile sulfur and chlorine content help to determine whether or not ammonia will be absorbed readily by the fly ash. In most applications, properly designed SNCR systems will keep the ammonia slip levels low enough so that the salability of the ash should be unaffected.

Can SNCR be used in combination with selective catalytic reduction (SCR)?

Hybrid SNCR-SCR systems have been demonstrated at a number of utility plants, and are being commercially installed to meet post-RACT NO_x limits.

SNCR may be combined with selective catalytic reduction (SCR). While achievable NO_x reductions using SNCR normally are limited by ammonia slip requirements, in a combined SNCR/SCR system, ammonia slip is generated intentionally as the reagent feed to the SCR catalyst, which provides additional NO_x removal. The quantity of catalyst required in a hybrid system is reduced from that in an SCR-only application, so that the hybrid system will have lower capital requirements. This hybrid approach has been demonstrated in several full-scale utility applications.

For example, at two gas-fired utility boilers in Southern California, hybrid systems gave emissions reductions of 72-91%.[21] At a wet bottom coal-fired boiler in New Jersey, a hybrid system reduced NO_x emissions by up to 98%. A utility in Pennsylvania is installing a full-scale SCR/SNCR hybrid system on an 148 MW coal-fired boiler. A SNCR system currently operating at that boiler reduces emissions from 0.78 lb/MMBtu to 0.45 lb/MMBtu. With the installation of in-duct SCR catalyst, the utility expects to further reduce NO_x emissions to below 0.35 lb/MMBtu, with less than 2 ppm ammonia slip.[22]

What developments in SNCR technology are expected?

Efforts are in progress to optimize the combination of SNCR with other technologies for controlling NO_x and other air pollutants.

SNCR Combination with Gas Reburn. Reburning under fuel-rich conditions converts NO_x to reduced nitrogen-containing compounds. During burnout, which occurs at lower temperatures than normal combustion, a substantial fraction of these compounds are converted to N_2 (with the remainder oxidized back to NO_x). Pilot scale demonstrations have shown that conditions in the burnout zone are appropriate for SNCR.[2] Thus, reburn and SNCR may be combined to achieve NO_x reductions of over 70 %, and a full-scale demonstration with the electric utilities is underway. Recently, Fuel Lean Gas Reburn (FLGR) has reached commercial status and in combination with SNCR is known as Amine Enhanced Fuel Lean Gas Reburn (AE-FLGR). The first full-scale installation of this combined technology is achieving 60% NO_x control.[23]

SNCR Combinations for Control of Other Pollutants. Many sources must control flue gas constituents other than NO_x, such as SO_2, chlorides, heavy metals, and dioxins and furans. It has been found that co-injection of a lime slurry with aqueous urea provides effective control of SO_2 and chlorides, in addition to NO_x.[24] With a reduction in chlorides, there is an associated reduction in dioxin and furan emissions.[25] In-furnace lime injection has also been shown to reduce emissions of heavy metals. Thus, the combination of SNCR and lime injection has the potential for simultaneous control of NO_x, SO_2, HCl, heavy metals, and dioxins and furans.

SNCR and Wastewater Disposal. In many cases, the ability to discharge wastewater into local streams, rivers, and sewers is restricted, with no discharge allowed in sensitive locations. As an accessory pollution control program to SNCR using aqueous reagents, wastewater can be disposed of by injection into a furnace or other combustion source with simultaneous control of NO_x. The dilution or "motive" water needed to inject urea reagent ranges from 100-500 % of the reagent flow. For larger sources, such as utility plants where 500-1000 gallons per hour reagent could be used, typical dilution water use is 1000-5000 gallons per hour or 20-85 gallons per minute, thus offering a significant opportunity for maintenance of plant water balance or wastewater minimization.

How can SNCR be used to best advantage?

The features of being a low hazard, low capital cost, expense-driven technology that requires little space and little unit down-time to implement suggests various appropriate uses to comply with U.S. clean air regulations.

Beyond-RACT Controls for Ozone Attainment. States not meeting the ozone National Ambient Air Quality Standard after application of RACT controls will require greater NO_x reductions from sources within their borders. Many states presume that these reductions will be based on the addition of post-combustion controls, including SNCR. In some cases, SNCR could be retrofit to units that already have implemented combustion modifications. Where SNCR has been used to meet RACT limits, the reagent use rate could be increased to meet new, lower limits.

Seasonal Controls for Ozone Attainment. In a seasonal approach, NO_x reductions beyond RACT would be required only during the "ozone season" (May through September) when exceedances normally occur. For example, the states of the northeast Ozone Transport Region have committed to a plan calling for control of ozone precursors only during the May-September ozone season to help meet regional ozone attainment goals. SNCR is particularly well-suited for seasonal control in that it may provide deep reductions in NO_x emissions, but incurs little cost when the system is not in use. For urea-based SNCR, the incremental cost of control during the ozone season would be on the order of $0.30/MMBtu on a unit without low-NO_x burners, expressed as a fuel cost adder relative to the "off" season.

Acid Rain Control. Under the acid rain provisions (Title IV) of the Clean Air Act Amendments, NO_x limits for Group 2 coal-fired utility boilers, which include cyclones, wet-bottom wall-fired boilers, cell-burner-fired boilers, stoker-fired units, and roof-fired boilers were promulgated in 1996 based upon the capabilities and costs of available control technologies.

SNCR technology has been successfully installed on cell-, pulverized-coal wet bottom-, cyclone-, and stoker-fired units as well as on circulating fluidized bed boilers.

Overcontrol. The low capital cost and ease of retrofit of SNCR suggest its use as an add-on to other NO_x control technologies to provide overcontrol, or control to below permit limits. Overcontrol can be useful where the marginal cost of control on one unit is lower than on other units, and where averaging or trading emissions or emissions reductions is permitted. Trading provisions of the proposed NO_x SIP Call regulation, the Regional Clean Air Incentives Market (RECLAIM) instituted by the California South Coast

Air Quality Management District, the acid rain NO_x rule, and proposed rules for generation of emissions reduction credits all authorize strategies based on overcontrol.

In an overcontrol strategy, a second SNCR system may be used to provide insurance: If the overcontrolled unit in the averaged group is forced out of service, the insurance system is available to provide the requisite emissions reductions on a second unit. When the overcontrolled unit is in service, the cost of the insurance SNCR system is limited to a relatively low capital charge.

BACT/New Source Controls. SNCR has been utilized to fulfill best achievable control technology (BACT) requirements for new stoker units in Maine, Vermont, Massachusetts, Connecticut, and Virginia, among other states. In North Carolina, a new pulverized coal-fired unit was permitted recently with SNCR to meet a 0.17 lb/MMBtu NO_x emission limit.

APPENDIX 1: Selected Applications of Urea-Based SNCR, by Industry

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
Wood-Fired IPP/Co-Gen Plants					
ABB Okeelanta Okeelanta, FL	Grate-fired Stoker	660	Bagasse, Wood, Coal	0.2-0.4 (4)	40-60
ABB Osceola Osceola, FL	Grate-fired Stoker	660	Bagasse, Wood, Coal	110-200	40-60
Alternative Energy, Inc. Ashland, ME	Zurn Stoker	500	Wood	128	50
Alternative Energy, Inc. Cadillac, MI	Zurn Stoker	500	Wood	128	50
Alternative Energy, Inc. Livermore Falls, ME	Zurn Stoker	500	Wood	128	50
Black & Veatch Genessee, MI	ABB-CE Stoker	473	Wood	0.47 (4)	60
Black & Veatch Grayling, MI	Zurn Stoker	440	Biomass	150	60
Georgia Pacific Brookneal, VA	Wellons 4-Cell	236	Mixed Wood	0.33 (4)	38
Georgia Pacific Mt. Hope, GA	Cell-fired	240	Bark/Dust	144.00	20
I.P. Masonite Towanda, PA	B&W	242.5	Sludge/Wood Waste, Coal	0.404 (4)	48
Kenetech Energy Fitchburg, MA	Riley Stoker	225	Wood	210	47
LFC Hillman, MI	Grate-fired	190	Biomass, Tires	170	35
McMillan Bloedel Clarion, PA	EPI Fluid Bed Combustion	291,000 #/hr steam	Wood Waste, Hog Fuel	100	42
Ridge Generating Aubumdale, FL	Zurn Stoker	550	Wood	0.35 (4)	57
Ryegate Power Station Ryegate, VT	Riley Stoker	300	Wood	0.2-0.3 (4)	30-50
Sierra Pacific Lincoln, CA	Cell-fired	2@130	Biomass	200	46-57
Zachry Energy Hurt, VA	Riley Stoker	3@390	Wood	0.20 (4)	50
Utility Boilers					
American Electric Power Cardinal Station Unit #1	B&W Universal Press.	5347	Coal	0.57 (4)	30
Atlantic Electric (3 units) Mays Landing, NJ	Cyclone Cyclone T-fired	138 MWe 160 MWe 160 MW3	Coal Coal #6 Oil	1.31 (4) 1.40 (4) 0.31 (4)	31 36 35
Carolina Power & Light Asheville #1 (AEFLGR)	Riley Front Wall-Fired	2173	Coal	426	50 – AEFLGR 25 - SNCR
Cinergy Miami Fort Unit #6 Northbend, OH	Tangential Fired C.E.	1490	Coal	0.55 (4)	35
Delmarva Power Wilmington, DE	T-fired	84 MWe	Coal	0.54 (4)	30
Eastern Utilities Somerset, MA	Tilting T-Fired Boiler	410-1120	Coal, Oil	0.49-0.89 (4)	28 - 60
First Energy Unit #3 East Lake, OH	T-fired CE with Division Wall	1470	Emerald or Powhatan Coal	255	20 – 32.5
First Energy Unit #2 Sammis, OH	FW Steam Generator	1735	Coal	0.450 (4)	25 - 30
GPU Genco Seward Station	Tangential Fired	1457	Coal	0.78 (4)	55

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
Seward, PA (Cascade)	C.E.				
Korean Electric Power Company Honam Station, Korea	Front & Rear Wall-Fired	2474	Coal	0.654 (4)	40
LILCO Port Jefferson, NY (D)	T-fired	185 MWe	Oil	250	50
LILCO Port Jefferson, NY (D)	T-fired	108 MWe	#6 Oil	0.354 (4)	35-60
Middletown Unit #3 Middletown, CT	Cyclone-Fired	2455	Gas	0.34 (4)	25
NEPCO Unit 1 Salem Harbor, MA	Front-fired	84 MWe	Coal	1.0±0.1 (4)	~ 66 (5)
NEPCO Unit 2 Salem Harbor, MA	Front-fired	84 MWe	Coal	1.0±0.1 (4)	~ 66 (5)
NEPCO Unit 3 Salem Harbor, MA	Front-fired	156 MWe	Coal	1.0±0.1 (4)	~ 66 (5)
NYSEG Milliken (DOE) Milliken, NY (D)	CE T-Fired, LNCFS III	150 MWe	Coal, Oil	0.37-0.4 (4)	30
Northeast Utilities Norwalk Harbor Station Norwalk Harbor, CT	CE Twin T-fired	172 MW 182 MW	Oil	<0.4 (4)	<0.25 (4)
Penelec Seward #15 Seward, PA	CE T-fired	1147	Coal	0.78 (4)	<0.45 (4)
PSE&G of New Jersey Mercer Station (SNCR)	Front Wall-Fired Wet Bottom	2@320 MWe Twin Furnace	Pulverized Coal, Gas	2 (4)	35
PSE&G Hudson Station, Unit #2 Jersey City, NJ	Foster Wheeler Opposed Wall	6017 6000	Coal Natural Gas	0.65 (4) 0.35 (4)	2,525.00
PSE&G Mercer Station Unit 1 Furnace #11 & #12	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.4 (4)	60
PSE&G Mercer Station Unit 1 Furnace #21 & #22	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.4	60
Pennsylvania Electric Company Comby Station	B&W Divided Furnace	1480	Coal	0.5 (4)	25
PSNH, Schiller (SNCR)	Wall-Fired	80 MW	Oil	0.40 (4)	50
WEPCO Valley Power Plt. Milwaukee, WI (D)	Wall-fired	70 MWe	Coal	725	60
Wisconsin Electric Power Company Pleasant Prarie Unit #1 (AEFLGR)	Riley Turbo	6260 (620 MWg)	Coal	0.45 (4)	56
Tire Burners					
Chewton Glen Energy	Grate-fired	240.00	Shredded Tires	0.195 (4)	60
Oxford Energy Modesto, CA (D)	Moving Grate Incinerator	75	Tires	85	40
Oxford Energy Sterling, CT	Grate-fired	2@170	Tires	80	50
Pulp and Paper Industry					
Boise Cascade International Falls, MN (D)	Hydrogate Stoker	395	Bark, Gas	117-136	35
Energy Products of Idaho Italy	BFB	70.2	Paper/Landfill Sludge	0.587 (4)	60.5
Garden State Paper Garfield, NJ	Front-fired Ind. Boiler	72	Paper	355	50
Garden State Paper Garfield, NJ	Front-fired Ind. Boiler	172	Fiber Waste	374	50

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
I.P. Masonite Towanda, PA	Towerpak Boiler	204	Wood Waste	0.404 (4)	53
Jefferson Smurfit Jacksonville, FL	CE Grate-Fired	540	Coal, Bark, Oil	0.55-0.70 (4)	<0.45 (4)
Minergy Fox Valley Neenah, WI	B&W Cyclone	350	Paper Sludge, Natural Gas	0.8 (4)	62
P. H. Glatfelter Neenah, WI	Sludge Combustor	60	Paper Sludge	570	50
P. H. Glatfelter Neenah, WI	Sludge Combustor	60	Paper Sludge	570	50
Potlach Bemidji, MN	Wellons 4-Cell Boiler	242	Wood Waste	0.30 (4)	57
S. D. Warren Skowhegan, ME	CE Grate-fired	900	Oil, Bark, Biomass	235	50
Sodra Skogsagarna Sweden (D)	Recovery Boiler	900	Black Liquor	60	60
Refinery Process Units and Industrial Boilers					
ARCO CQC Kiln Los Angeles, CA (D)	Calciner HRSG		Petroleum Coke	25	34
Babcock and Wilcox Bowater, Calhoun, TN	BFB	821	Wood/Sludge	0.35 (4)	62
Chambers Medical Waste, Incinerators (2 units) Chambers County, TX	Simonds Incinerator	221	Medical and Municipal	0.48 (4)	67.8
Corn Products North Carolina	Gasifier	262	Wood	163	20
MAPCO Petroleum Memphis, TN	Bottom-fired Process Htr.	177	Refinery Gas, NG	75	60
MAPCO Petroleum Memphis, TN	Bottom-fired Process Htr.	50	Refinery Gas, NG	65	50-75
Mobil Oil Paulsboro, NJ	GT - HRSG	630	Refinery Gas	75	50
Mobil Oil Torrance, CA	CO Boiler	614	Refinery Gas	90	65
Mobil Oil/Macchi Yanbu, Saudi Arabia	Package Boiler	3@265	Vac. Tower Bottoms, Propane		
Pennzoil Shreveport, LA	CO Boiler Thermal Oxidizer		CO, Refinery Gas		
Pennzoil Shreveport, LA	CO Boiler Thermal Oxidizer	243	Natural Gas & Regen. Gas	0.27 (4)	74
Powerine Santa Fe Springs, CA	Package Boiler	31-62	Refinery Fuel Gas	105	60
Powerine Santa Fe Springs, CA	CO Boiler	31-62	Refinery Fuel Gas	105	60
Shell Oil Martinez, CA	CO Boiler	3@222	Refinery Gas	230	65
Total Petroleum Alma, MI	CO Boiler	247	Refinery and Natural Gas	1.2 (4)	67
UNOCAL Los Angeles, CA (D)	CO Boiler	400	Refinery Gas	140	68
UNOCAL Santa Maria, CA (D)	Calciner HRSG		Petroleum Coke	45	53
Chemical Industry					
BP Chemicals	AOG Incin.	34	Waste	330	80+

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
Green Lake, TX (D)	HRSG		Gas		
BP Chemicals (3 units) Green Lake, TX	AOG Incin. HRSG	399 399 238 (lb flue gas/hr)	Absorber Off Gas	238 238 150	50 50 50
Formosa Plastics Kaohsiung, Taiwan	Front-fired	331	Coal	200	60
Miles, Inc. Kansas City, MO	Carbon Furnace Afterburner	16	Chemical Waste	150	35
North American Chemical Corp. Trona, CA	T-fired	2@75 MWe	Coal	200	40
Coal-Fired Industrial and IPP Co-Generation Boilers					
Cogentrix Richmond, VA	CE Stoker	8@28 MWe	Coal	350	40
Far East Textiles Hsihpu, Taiwan	Stork Boiler	190	Coal	550 @ 6% O_2	50.00
General Electric Lynn, MA (D)	B&W Packaged D-Type	236	#6 Oil, Gas	0.28-0.31 (4)	40-60
Michigan State Univ. East Lansing, MI	CFB	460	Coal	247	57
NFT GmbH	Fire Tube Package Boilers	5@10-20 MWe	Heavy Oil	700-800 mg/Nm^3	40-50
Nykoping, Sweden	CFB	135	Coal	120-130	70
Riley Ultrasystems II Weldon, NC	Riley Front-Fired	505	Pulverized Coal	0.33 (4)	50
Sonoco Huntsville, SC	Foster-Wheeler/ Pyropower CFB	145	Coal	195	67.00
Standardkessel, Germany	Packaged Firetube	31@ 10-20 MWe	Heavy Oil	700-800 mg/Nm^3	40-50
Strakonice Czech Republic	Wall Fired, Grate Fired	2@36-40	Lignite, Brown Coal	600 mg/Nm^3	50
Tekniskaverken Linkoping P1, Sweden	Stoker	275	Coal	300-350	65
Tekniskaverken Linkoping P3, Sweden (D)	Stoker		Wood	200	50
Municipal Waste Combustors					
American Ref-Fuel Niagara Falls, NY	Riley Grate	2@414	RDF, MSW	300	50
Baltimore/Resco/WAPC (3 units) Baltimore, MD	Burning Grate Stoker Fired	325	MSW	0.50 (4)	30
City of Berlin Berlin, Germany (D)	Moving Grate		MSW	160	69
City of Berlin Berlin, German (D)	Zurn Stoker	167	MSW	275	75
CRRA – Units 11 & 12 Hartford, CT	CE VU 40	326	RDF	0.52 (4)	40
De Canderas Cremona, Italy	MWC		MSW, RDF	250 @11% O_2	60
DB Riley, Central Wayne (3 units) Dearborn, MI	Municipal Waste Combustor	115 138	MSW	0.47 (4) 0.48 (4)	50
Dong Bu (2	Municipal Waste	150 tpd	MSW	0.59 (4)	65

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
units) Kwang Myong, Korea	Combustor				
Emmenspitz Zuchwil, Switzerland (D)	Moving Grate	121	MSW	200	68
Emmenspitz Zuchwil, Switzerland (D)	Detroit Stoker	137.5	MSW	110	60
Falls Township Falls Township, PA	B&W Stoker	325 (2)	MSW	330 Max 285 Typ	50 Max 40 Tpy
Fort Lewis	MWC	60 tons/day	MSW	230 @7% O_2	65
Frankfurt Germany	Moving Grate	4@660	MSW	170	70
Hamm Germany	Moving Grate	3@528	MSW	170	41
Herten Germany	Moving Grate	2@242	MSW	185	60
Kwang Myung Korea	Steinmuller MWC	2@58	MSW	200	65
Montenay Resource Recovery Facility Montgomery, PA	Steinmuller MWC	2@260		0.385 (4)	50
New Hanover County Wrightsville Beach, NC	Volund MWC	108	MSW	300	60
North Andover, MA		351	750 tpd	300	32
Pinellas County/WAPC	Municipal Waste Combustor	200 tpd	MSW	0.53 (4)	65
Ravenna, Italy	MWC	45,000 Nm^3/hr	MSW	400	62.5
Regional Waste Systems Units 1 & 2 ME	Steinmuller	120	MSW	0.40 (4)	33 43 - Design
Robbins Resource Recovery Facility Robbins, IL	Foster-Wheeler CFB	2@309		0.39 (4)	48.72
SEMASS Rochester, MA	Riley Stoker	375	MSW	220	50
Seoul Metro Gov't Mok-Dong – Seoul, Korea	Municipal Waste Combustor	62	MSW	100 – 150	50 - 67
Tekniskaverken Garstad (D)	Moving Grate		MSW		
Process Units					
Alcan (2 units) Berea, KY	Decoater/ Afterburner	30,000 lb cans/hour	Gas	90-130	50-80+
Allis Minerals Oak Creek, WI	Rotary Kiln Incinerator	60	Paper Sludge	0.48 (4)	57
Fort Lewis	MWC	60 tons/day	MSW	230 @ 7 % O_2	65
Rollins Environmental Deer Park, TX (D)	Hazardous Waste Incinerator	185	Chlorinated Chemical Waste, Soil	60-250	35-50
Industrial/Steel Industry					
China Steel Units 7&8 Republic of China (Taiwan)	C.E. VU 40	156.8	Coal	0.568 (4)	42.9
MHIA National Steel Portage, IN (Cascade)	Direct Fired Furnace	47.9	Natural Gas	0.3 (4)	85
NKK Steel Engineering National Steel Ecorse, MI (SCR)	Cont. Galv. Line				
NKK Steel Engineering National Steel CGL #1 (SCR)	Radiant Tube Furnace	117	Natural Gas	0.26 (4)	90

COMPANY/LOCATION (1),(2)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (3)
Nucor Steel Hickman, Arkansas (SNCR & SCR)	Preheat Radiant	46.7 14.6	Natural Gas	0.32 (4) 0.46 (4)	75.5 78.9
Nucor Steel Hugor, SC (SNCR & SCR)	Preheat Radiant	50.8 20	Natural Gas	0.44 (4) 0.31 (4)	82 89
Protec/US Steel, CGL #2 Leipsic, OH (SCR)	Radiant	76.8	Natural Gas	0.253 (4)	90
Selas/BHP Rancho Cucamonga, CA	Cont. Galv. Line	29	Natural Gas	105 (4)	65
WAPC Iron Dynamics Butler, IN	Rotary Hearth	435	Natural Gas	0.374 (4)	30
Cement Kilns					
Ash Grove Cement Seattle, WA (D)	Precalciner	160 tons solids/hr	Coal, Gas	350-600 lb/hr	>80
Korean Cement Demonstration Dong Yang Cement, Korea	New Suspension Calciner		Coal	1.27 (4)	45
Taiwan Cement Units #3, #5, #6	Cement Kiln/ Precalciner	260 697 658	Coal Coal Coal	1.29 (4) 1.58 (4) 0.92 (4)	50 45 25
Wulfrath Cement Germany (D)	Cement Kiln	140	Lignite	1000 ng/Nm^3 500	90

(1) All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.

(2) Company/Locations which are not named are requirements of Confidentiality Agreements. (D) Denotes "Demonstration."

(3) NO_x Reduction values are not necessarily the limit of the technology. These values may be the guaranteed limits.

(4) lb/MMBtu

(5) Actual limit = 0.33 lb/MMBtu

APPENDIX 2: Selected Applications of Ammonia-Based SNCR, by Industry

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Stoker-Fired and Pulverized Coal-Fired Boilers					
Atavista, VA	Stoker Fired	2@380	Wood/Coal	321	50-65
Buena Vista	Stoker Fired	2@385	Coal	324	54-66
Hopewell, VA	Stoker Fired	2@385	Coal	324	54-66
KMW Mainz, Germany	Pulverized Coal	2@450	Coal	600	83
Modesto, CA	Stoker Fired	2@204	Tires	N/A	78
STEAG Herne, Germany	Pulverized Coal	4500	Coal	250	55
Showa Denko Oita, Japan	Pulverized Coal	1000	Coke	315	57
Coal-Fired Boilers					
Kraftwerke Mainz Wiesbaden/Deutsche Babcock Anlagen AG Germany	Cyclone	2@433	Coal		83
Northeast Utilities Merrimack Station Unit 1 Bow, New Hampshire	Cyclone		Coal		
Rio Bravo Jasmin Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Rio Bravo Poso Rio Bravo, CA	Circulating Fluid Bed	391	Coal		80
Stockton Cogen Stockton,CA	Circulating Fluid Bed	620	Coal		N/A
Veba Kraftwerke A.G. Gelssenkirchen, Germany	Cyclone	730	Coal		38
Stoker-Fired Wood-Fueled Boilers					
Brawley, CA	Stoker Fired	250	Wood	400	60
Burney, CA	Stoker Fired	2@478	Wood	116	52
Long Beach, CA	Stoker Fired	200	Wood	325	60
Sacramento, CA	Stoker Fired	164	Wood	220	59
Shasta, CA	Stoker Fired	3@903	Wood	75-90	40-52
Susanville, CA	Stoker Fired	500	Wood	130	58
Terra Bella, CA	Stoker Fired	158	Wood	100	50
Tracy, CA	Stoker Fired	275	Wood	310	75
Circulating Fluidized and Bubbling Bed Boilers					
Chinese Station, CA	Bubbling Bed	315	Wood	125	80
Chowilla, CA	Bubbling Bed	152	Wood		
Colmac, CA	Fluidized Bed	590 total [2 units]	Coal		
Combustion Power, CA	Fluidized Bed		Coal, Coke		
El Nido, CA	Bubbling Bed	175	Wood		
Fresno, CA	Fluidized Bed	350	Wood	120	76
Jasmine, CA	Fluidized Bed	394	Coal	150	80
Madera, CA	Bubbling Bed	384	Wood		
Mendota, CA	Fluidized Bed	349	Wood	120	80
Poso, CA	Fluidized Bed	394	Coal	150	80
Rocklin, CA	Fluidized Bed	340	Wood	120	76
Stockton, CA	Fluidized Bed	620	Coal		
Woodland, CA	Fluidized Bed	330	Wood	120	76
Municiple Solid Waste Incinerators					
Commerce		300 (3)		200	60
Bremerhaven, Germany					
Essex County		3@770 (3)		190	60

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Huntington, Long Island		3@480 (3)		350	60
Long Beach, CA		3@470 (3)		200	70
Minneapolis		2@600 (3)		240	60
Munich, Germany		930 (3)		190	70
Spokane		2@400 (3)		300	45
Stanislaus County		2@400 (3)		200	67
Union County		3@480 (3)		350	70
Unit "M"		750 (3)		320	65
Vapor, Sludge, and Hazardous Waste Incinerators					
Carson, CA		2@204	Sludge	350	65
Deepwater, NJ		2@103	Sludge	265	77
Gaviota, CA		20	Vapor	112	70
Germany			Vapor		
Gladstone, Australia		57	Vapor	2000	91
Gas- and Oil-Fired Industrial Boilers					
Champlin Petroleum Wilmington, CA			Oil/Gas		65
Chanselor-Western Oil Santa Fe Springs, CA		50	Crude		65
Getty Oil California			Crude		
Golden West Refinery Santa Fe Springs, CA		60	CO		75
Mitsui Petrochemical Japan		340	Oil		53
Mohawk Petroleum Bakersfield, CA		[2 units]	Oil/Gas		60-70
Oxnard Refinery Oxnard, CA		18.5	Crude		30
Santa Fe Energy Santa Fe Springs, CA		3@150	Crude		
Tonen Kawasaki, Japan		400	CO/Gas		50
TSK Kawasaki, Japan		215	Oil/Gas		55
TSK Kawasaki, Japan		574	Oil/Gas		65
TSK Kawasaki, Japan		1135	Oil/Gas		57
TSK Kawasaki, Japan		1135	Oil/Gas		55
Glass Melting Furnaces					
AGF Industries Los Angeles, CA		125	Gas		61
LOF Glass Lathrop, CA		200	Gas/Oil		51
PPG Industries Fresno, CA		150	Gas		60
SHOTT Germany					
Sierra Envr. & GAF Irwindale, CA		29	Gas		70
Oil- and Gas-Fired Heaters					
Champlin Petroleum Wilmington, CA		627 total [13 units]	Oil/Gas		50 to 60
Chevron Research San Francisco, CA		315	Gas		69

COMPANY/LOCATION (1)	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NO_x BASELINE (ppm)	REDUCTION (%) (2)
Fletcher Oil and Refining Wilmington, CA		47 total [2 units]	Gas		45 to 65
Independant Valley Energy Bakersfield, CA		165 total [4 units]	Gas		65 to 75
Kyokuto Petroleum Chiba, Japan		2@250	Oil/Gas		51 to 53
LOF Glass Stockton, CA	Glass Furnace	200	Gas/Oil		51
Mendota Biomass Mendota, CA	Circ. Fluid Bed	349	Wood		72
Mohawk Petroleum Bakersfield, CA		349 total [4 units]	Oil/Gas		60 to 70
Monsanto Carson, CA		23	Oil		43
PPG Industries Fresno, CA	Glass Furnace	150	Gas		60
Rocklin Rocklin, CA	Circ. Fluid Bed	340	Wood		76
SHOTT Germany	Glass Furnace		Gas		
Sierra Envr. and GAF Irwindale, CA	Glass Furnace	29	Gas		70
Tonen Kawaski, Japan		515 and 190	Gas		63

(1) All units listed are commercial installations, unless otherwise indicated. Commercial includes units in the design and installation phases.
(2) NO_x Reduction values are the guarantees.
(3) Tons/day.

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FUEL TECH
Technologies to enable clean efficient energy™

FUEL TECH NO_XOUT® PROCESS EXPERIENCE LIST

Legend

- All units listed are commercial installations, unless otherwise indicated.
- Commercial includes units in the design and installation phases.
- [D] Denotes "Demonstration".
- % NOx Reduction and Ammonia Slip values are not necessarily the limit of the technology.
- These values may be the guaranteed or permitted limits structured to easily meet permit conditions.
- (CP) Denotes an agreement has been reached, however, the "Contract is Pending".
- Companies/Locations which are not named are requirements of Confidentiality Agreements.

FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm. * lb/MMBtu)	REDUCTION %
Utility	NOxOUT® [D]	USA	AEP - Southwestern Electric Power Pirkey Station Unit 1 Hallsville, TX	1	B&W Opposed Wall Fired	6900 MMBtu/hr 710 MW	Coal	0.19 lb/MMBtu	20
Utility	NOxOUT CASCADE®	USA	AES - Greenidge Unit 4 Dresdon, NY	1	T-Fired	107 MW	Coal	0.25 lb/MMBtu	60
Utility	NOxOUT®	USA	AES / Indianapolis Power and Light Harding Street Station Units 5 and 6	2	C.E. T-Fired	110 MWg each	Coal	0.96 lb/MMBtu	30-40
Utility	NOxOUT®	USA	AES Beaver Valley 2, 3, 4, & 5 Monaca, PA	4	Multiple Units	125 MW Total	Coal	-	-
Utility	NOxOUT®	USA	Allegheny Power Hatfield's Ferry Unit 3 Mason Town, PA	1	Cell-Fired	550 MW	Coal	0.35 lb/MMBtu	18-20
Utility	NOxOUT® + RRI	USA	Ameren Energy Sioux Units 1 & 2 Alton, MO	2	Cyclone	510 MW	PRB Coal	0.25 lb/MMBtu	50
Utility	NOxOUT® + RRI [D]	USA	Ameren Sioux Station Unit 1	1	Cyclone	510 MW	PRB Coal	0.25 lb/MMBtu	50
Utility	NOxOUT® [D]	USA	American Electric Power Cardinal Station Unit #1 Brilliant, OH	1	B & W Universal Press.	5347 600 MW	Coal	0.57 lb/MMBtu	30
Utility	NOxOUT®	USA	Atlantic Electric B.L. England Station Mays Landing, NJ	3	Cyclone Cyclone T-Fired	138 Mwe 160 MWe 160 Mwe	Coal Coal #6 Oil	1.31 lb/MMBtu 1.40 lb/MMBtu 0.31 lb/MMBtu	31.3 36 35
Utility	NOxOUT®	Slovak Republic	Austrian Energy Vojany Power Station	1	Utility	1146	Pulverized Coal	789 mg/Nm^3 @ 11% O_2 1.53 *	32
Utility	NOxOUT®	USA	Cinergy Miami Fort Unit #6 Northbend, OH	1	Tangential Fired C.E.	1490	Coal	0.53 lb/MMBtu	35
Utility	NOxOUT®	USA	Dominion Generation Clover Station, Units 1 & 2 Clover, VA	2	CE T-Fired	465 MW each	Coal	0.32 MMBtu	25
Utility	NOxOUT®	USA	Dominion/NEPCO Unit 1 Salem Harbor, MA	1	Front-Fired	84 MWe	Coal	1.00 ± 0.10 *	~ 66 **
Utility	NOxOUT®	USA	Dominion/NEPCO Unit 2 Salem Harbor, MA	1	Front-Fired	84 MWe	Coal	1.00 ± 0.10 *	~ 66 **
Utility	NOxOUT®	USA	Dominion/NEPCO Unit 3 Salem Harbor, MA	1	Front-Fired	156 MWe	Coal	1.00 ± 0.10 *	~ 66 **
Utility	NOxOUT®	USA	Duke Energy Allen Station Unit 1 Belmont, NC	1	CE T-Fired	1751 MMBtu/hr 185 MW	Coal	0.22 lb/MMBtu	25
Utility	NOxOUT®	USA	Duke Energy Allen Station Unit 2 Belmont, NC	1	CE T-Fired	1751 MMBtu/hr 185 MW	Coal	0.22 lb/MMBtu	TBD
Utility	NOxOUT®	USA	Duke Energy Allen Station Unit 3 Belmont, NC	1	CE Twin Furnace	2546 MMBtu/hr 270 MW	Coal	0.22 lb/MMBtu	23
Utility	NOxOUT®	USA	Duke Energy Allen Units 4 & 5 Belmont, NC	2	CE Twin Furnace	2546 MMBtu/hr 270 MW	Coal	0.22 lb/MMBtu	23
Utility	NOxOUT®	USA	Duke Energy Buck Station Units 5 & 6 Salisbury, NC	2	CE T-Fired	1230 MMBtu/hr 142 MW	Coal	0.20 lb/MMBtu	20
Utility	NOxOUT®	USA	Duke Energy Marshall Station Unit 3 Terrell, NC	1	CE 8-Corner	6130 MMBtu/hr 660 MW	Coal	0.267 lb/MMBtu	20
Utility	NOxOUT®	USA	Duke Energy Marshall Station Units 1 & 2 Terrell, NC	2	CE 8-Corner	3367 MMBtu/hr 350 MW	Coal	0.245 lb/MMBtu	20
Utility	NOxOUT®	USA	Duke Energy Marshall Unit 4 Terrell, NC	1	T-Fired	720 MW	Coal	0.25 lb/MMBtu 0.215 lb/MMBtu	20 15
Utility	NOxOUT®	USA	Duke Energy Riverbend Station Units 4 & 5 Salisbury, NC	2	CE T-Fired	937 MMBtu/hr 100 MW	Coal	0.25 lb/MMBtu	TBD
Utility	NOxOUT®	USA	Duke Energy Riverbend Station Units 6 & 7 Salisbury, NC	2	CE T-Fired	1318 MMBtu/hr 133 MW	Coal	0.20 lb/MMBtu	TBD
Utility	NOxOUT® [D]	USA	Dynegy NE Generation Danskammer Unit 4 Newburgh, NY	1	T-Fired	239 MW	Coal	0.25 lb/MMBtu	20
Utility	NOxOUT®	USA	Exelon Philadelphia Electric Co. Cromby Station, Unit 1 Phoenixville, PA	1	B&W Divided Furnace	1480	Coal	0.50 lb/MMBtu	25
Utility	NOxOUT®	USA	Exelon Eddystone Station Units 1-2 Eddystone, PA	2	T-Fired Twin Furnace	318 MWg 333 MWg	Coal	0.26 lb/MMBtu	~ 30%

MWC = Municipal Waste Combustor
[D] Denotes Demonstration

FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
Utility	NOxOUT®	USA	First Energy East Lake Unit 3 East Lake, OH	1	CE 8-Corner	1470 MMBtu/hr 120 MW	Coal	0.34-0.40 lb/MMBtu	20 - 32.5
Utility	NOxOUT®	USA	First Energy East Lake Unit 5 East Lake, OH	1	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 1 Sammis, OH	1	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 2 Sammis, OH	1	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 3 Sammis, OH	1	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 4 Sammis, OH	1	FW Front Wall Fired	180 MW	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 5 Sammis, OH	1	B&W Wall Fired	300 MW	Coal	0.45 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 6 Sammis, OH	1	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	USA	First Energy Sammis Unit 7 Sammis, OH	1	B & W Universal Press.	620 MWg	Coal	0.38 lb/MMBtu	25
Utility	NOxOUT®	Korea	Korean Electric Power Co. Honam Station, Units 1 & 2 Korea	2	Front & Rear Wall-Fired	2474	Coal	0.654 lb/MMBtu	40
Utility	NOxOUT®	USA	Northeast Utilities Schiller Station Units 4, 5 & 6 Portsmouth, NH	3	Foster Wheeler Front Fired	50 MW each	Coal	0.45 lb/MMBtu	50
Utility	NOxOUT ULTRA®	USA	Northern Indiana Public Service Schahfer Station #14	1	Cyclone-Fired	520 MW	Coal	SCR Reagent Requirement 1200 lb/hr	
Utility	NOxOUT ULTRA®	USA	Northern Indiana Public Service Bailly Station #8	1	Cyclone-Fired	360MW	Coal	SCR Reagent Requirement 1100 lb/hr	
Utility	NOxOUT ULTRA®	USA	Northern Indiana Public Service Bailly Unit 7 Chesterton, IN	1	Cyclone	175 MW	Coal	SCR Reagent Requirement 720 lb/hr	N/A
Utility	NOxOUT ULTRA®	USA	Northern Indiana Public Service Michigan City Station #12 Michigan City, IN	1	Cyclone-Fired	520 MW	Coal	SCR Reagent Requirement 1200 lb/hr	
Utility	NOxOUT®	USA	NRG/Eastern Utilities Somerset, MA	1	Tilting T-Fired Boiler	410-1120	Coal, Oil	0.89 – 0.49 lb/MMBtu	28 – 60
Utility	NOxOUT®	USA	NRG/Northeast Utilities Middletown Unit 3 Middletown, CT	1	Cyclone-Fired	2455 MMBtu/hr	Gas	0.34 lb/MMBtu	25
Utility	NOxOUT®	USA	NRG/Northeast Utilities Norwalk Harbor Station, Units 1&2 S. Norwalk, CT	2	CE Twin T-Fired	172 MWg 182 MWg	Oil	< 0.40 *	< 0.25
Utility	FLGR™ + NOxOUT®	USA	Progress Energy Carolinas Asheville Unit 1 Skyland, NC	1	Riley Front Wall-Fired	2179 MMBtu/hr 200 MW	Coal	0.58 lb/MMBtu	50
Utility	FLGR™ +NOxOUT®	USA	PSE&G Mercer Station Unit 1 Furnace #11 & #12 Trenton, NJ	1	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.40 lb/MMBtu	60
Utility	FLGR™ +NOxOUT®	USA	PSE&G Mercer Station Unit 2 Furnace #21 & #22 Trenton, NJ	1	Front Wall-Fired Wet Bottom	320 MW Twin Furnace	Pulv. Coal	1.40 lb/MMBtu	60
Utility	FLGR™ +NOxOUT®	USA	PSE&G Hudson Station, Unit #2 Jersey City, NJ	1	Foster Wheeler Opposed Wall	660 MWg	Coal Natural Gas	0.65 lb/MMBtu 0.35 lb/MMBtu	40 40
Utility	NOxOUT®	USA	PSE&G Hudson Station, Unit #2 Jersey City, NJ	1	Foster Wheeler Opposed Wall	660 MWg	Coal Natural Gas	0.65 lb/MMBtu 0.35 lb/MMBtu	25 25
Utility	NOxOUT®	USA	PSE&G Mercer Station, Unit #2 Trenton, NJ	1	Front Wall-Fired Wet Bottom	320 MWe Twin Furnace	Pulv Coal Gas	2.00 lb/MMBtu 0.60 lb/MMBtu	35 40%
Utility	NOxOUT® [D]	USA	Reliant Energy Shawville Unit 2 Shawville, PA	1	Front Wall-Fired	127 MW	Coal	0.55 lb/MMBtu	30
Utility	NOxOUT CASCADE®	USA	Reliant Energy/Penelec Seward Unit 15	1	Tangential Fired C.E.	1457	Coal	0.78 lb/MMBtu	55
Utility	NOxOUT®	USA	Reliant Energy/Penelec Seward Unit 15	1	CE-T-Fired	1457 MMBtu/hr	Coal	0.78 lb/MMBtu	35
Utility	NOxOUT®	USA	Rochester Gas & Electric Russell Station, Units 1-4	4	CE T-Fired	265 MW Total	Coal	0.28 - 0.42 lb/MMBtu	15 - 27.5

MWC – Municipal Waste Combustor
[D] Denotes Demonstration

FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
Utility	NOxOUT® [D]	USA	San Miguel Electric Cooperative Christine, TX	1	Opposed Wall	440 MW	Lignite Coal	0.178 lb/MMBtu	25
Utility	NOxOUT®	USA	Southern Company / Alabama Power Barry Units 1-4 Bucks, AL	4	T-Fired T-Fired Twin Furnace T-Fired	155 MW 153 MW 272 MW 400 MW	Coal Coal Coal Coal	0.49 lb/MMBtu 0.46 lb/MMBtu 0.40 lb/MMBtu 0.29 lb/MMBtu	27.5 27.5 25 25
Utility	NOxOUT® [D]	USA	Southern Company / Alabama Power Gaston Station Unit 5 Wilsonville, AL	1	B&W Opposed Wall Fired	2474 MMBtu/hr 250 MW	Coal	0.44 lb/MMBtu	25
Utility	NOxOUT®	USA	Southern Company / Gulf Power Crist Units 4 & 5 Pensacola, FL	2	T-Fired	82MW	Coal	0.36 lb/MMBtu	25
Utility	NOxOUT®	USA	Southern Company / Gulf Power Crist, Unit 6 Pensacola, FL	1	FWEC	320 MW	Coal	0.35 lb/MMBtu	~ 30
Utility	NOxOUT®	USA	Tennessee Valley Authority Johnsonville Unit 1 Waverly, TN	1	CE T-Fired	125 MW	Coal	0.44-0.46 lb/MMBtu	25
Utility	NOxOUT®	USA	Tennessee Valley Authority Shawnee Unit 1 Paducah, KY	1	B&W Front Wall-Fired	145 MW	Coal	0.43 lb/MMBtu	25
Utility	FLGR™	USA	Wisconsin Electric Power Co. Pleasant Prairie Unit #1 Kenosha, WI	1	Riley Turbo	6260 (620 MWg)	Coal	0.45 lb/MMBtu	20
Utility	FLGR™ +NOxOUT® [D]	USA	Wisconsin Electric Power Co. Pleasant Prairie Unit #1 Kenosha, WI	1	Riley Turbo	6260 (620 MWg)	Coal	0.45 lb/MMBtu	56
Steel	NOxOUT® [D]	USA	AK Steel Furnace No. 1 Rockport, IN	1	Annealing Furnace	110 MMBtu/hr	Natural Gas	0.12 lb/MMBtu	35 - 45
Steel	NOxOUT®	Taiwan	China Steel Unit 6	1	CE T-Fired w/CCOFA	535	Coal	410 mg/Nm³ @ 11% O_2	43
Steel	NOxOUT®	Taiwan	China Steel Units 7 & 8 Taiwan - Republic of China	2	C.E. VU 40	156.8	Coal	0.568 lb/MMBtu	42.9
Steel	NOxOUT®	Italy	Demag Italimpianti S.p.A. Trieste, Italy	1	Steel plant	6200		1200 mg/Nm³ @ 11% O_2	70
Steel	NOxOUT Cascade®	USA	MHIA National Steel Portage, IN	1	Direct Fired Furnace	47.9	Natural Gas	0.50 lb/MMBtu	85
Steel	SCR	USA	NKK Steel Engineering National Steel CGL #1 Portage, IN	1	Radiant Tube Annealing Furnace	117	Natural Gas	0.26 lb/MMBtu	90
Steel	SCR	USA	NKK Steel Engineering National Steel Ecorse, MI	1	Cont. Galv. Line	117	Natural Gas	0.34 lb/MMBtu	90
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Crawfordsville, IN	1	Reheat/ Radiant	58.8 14.5	Natural Gas	0.227 lb/MMBtu 0.581 lb/MMBtu	76
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Hickman, AR	1	Preheat/ Radiant	46.7 14.6	Natural Gas	0.52 lb/MMBtu 0.46 lb/MMBtu	76 79
Steel	NOxOUT® Plus Urea SCR	USA	Nucor Steel, Hugor, S.C.	1	Preheat/ Radiant	50.8 20	Natural Gas	0.44 lb/MMBtu 0.51 lb/MMBtu	82 89
Steel	SCR	USA	Protec/US Steel, CGL #1 Leipsic, OH	1	Radiant Tube Annealing Furnace	99	Natural Gas	0.589 lb/MMBtu	90
Steel	SCR	USA	Protec/US Steel, CGL #2 Leipsic, OH	1	Radiant Tube Furnace	76.8	Natural Gas	0.253 lb/MMBtu	90
Steel	NOxOUT®	USA	Selas/BHP Rancho Cucamonga, CA	1	Cont. Galv. Line	29	Natural Gas	105	65
Steel	NOxOUT®	USA	WAPC Iron Dynamics Butler, IN	1	Rotary Hearth	435	Natural Gas	0.374 lb/MMBtu	30
Refinery	NOxOUT®	USA	ARCO CQC Kiln Los Angeles, CA	1	Calciner HRSG	651	Petroleum Coke	86	30
Refinery	NOxOUT®	USA	BP Toledo, OH	1	CO Boiler	518	Refinery Gas	95	22-35
Refinery	NOxOUT®	USA	MAPCO Petroleum Memphis, TN	1	Bottom-Fired Process Htr	177	Refinery Gas, Natural Gas	75	60
Refinery	NOxOUT®	USA	MAPCO Petroleum Memphis, TN	1	Bottom-Fired Process Htr.	50	Refinery Gas, Natural Gas	65	50 - 75
Refinery	NOxOUT®	USA	Mobil Oil Paulsboro, NJ	1	GT - HRSG	630	Refinery Gas	75	50

MWC = Municipal Waste Combustor
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INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
Refinery	NOxOUT®	USA	Mobil Oil Torrance, CA	1	CO Boiler	614	Refinery Gas	90	65
Refinery	NOxOUT®	Saudi Arabia	Mobil Oil/Marchi Yanbu, Saudi Arabia	1	Package Boiler	(3) 265	Vacuum Tower Bottoms Propane	0.40 lb/MMBtu	25
Refinery	NOxOUT®	USA	Pennzoil Shreveport, LA	1	CO Boiler/ Thermal Oxidizer		CO, Refinery Gas		
Refinery	NOxOUT®	USA	Pennzoil Shreveport, LA	1	CO Boiler/ Thermal Oxidizer	245	Natural Gas & Regen. Gas	0.27 lb/MMBtu	74
Refinery	NOxOUT®	USA	Powerine Santa Fe Springs, CA	1	CO Boiler	31 - 62	Refinery Fuel Gas	105	60
Refinery	NOxOUT®	USA	Powerine Santa Fe Springs, CA	1	Package Boiler	31 - 62	Refinery Fuel Gas	105	40
Refinery	NOxOUT®	USA	Shell Oil Martinez, CA	1	CO Boiler	(3) 222	Refinery Gas	250	65
Refinery	NOxOUT®	USA	Total Petroleum Alma, MI	1	CO Boiler	197	CO, Refinery Gas	1.20 lb/MMBtu	67
Refinery	NOxOUT® [D]	USA	UNOCAL Los Angeles, CA	1	Calciner HRSG		Petroleum Coke	45	53
Refinery	NOxOUT® [D]	USA	UNOCAL Los Angeles, CA	1	CO Boiler	400	Refined Gas	140	68
Pulp & Paper	NOxOUT®	USA	Babcock and Wilcox Bowater, Calhoun, TN	1	BFB	821	Wood/Sludge	0.55 lb/MMBtu	62
Pulp & Paper	NOxOUT® [D]	USA	Boise Cascade Intl. Falls, MN	1	Hydrograte Stoker	395	Bark, Gas	0.14-0.19 lb/MMBtu	25 - 35
Pulp & Paper	NOxOUT®	Italy	C.C.T. Verzuolo, Italy	1	Paper Sludge	28.8 t/h		400 mg/Nm^3 @ 11% O_2	50
Pulp & Paper	NOxOUT®	Italy	Energy Products of Idaho Italy	1	BFB	70.2	Paper/Landfill Sludge	0.587 lb/MMBtu	60.5
Pulp & Paper	NOxOUT®	USA	Garden State Paper, Unit #3 Garfield, NJ	1	Front-Fired Ind. Boiler	110	Fiber Waste	0.30 lb/MMBtu	50
Pulp & Paper	NOxOUT®	USA	Garden State Paper, Unit #4 Garfield, NJ	1	Front-Fired Ind. Boiler	172	Fiber Waste	0.20 lb/MMBtu	30
Pulp & Paper	NOxOUT®	USA	Jefferson Smurfit Jacksonville, FL	1	CE Grate-Fired	540	Coal, Bark, Oil	0.55-0.70 lb/MMBtu	20 - 35
Pulp & Paper	NOxOUT®	USA	McBurney Corp. Koda Energy, LLC Shakopee, MN	1	Biomass Cogen	23 MW	Biomass	0.45 lb/MMBtu 0.55 lb/MMBtu	55 64
Pulp & Paper	NOxOUT®	USA	Minergy Fox Valley Aggregate Plant Neenah, WI	1	B & W Cyclone	350	Paper Sludge/ Natural Gas	0.80 lb/MMBtu	62
Pulp & Paper	NOxOUT®	USA	P. H. Glatfelter Neenah, WI	1	Sludge Combustor	60	Paper Sludge	570	50
Pulp & Paper	NOxOUT®	USA	Potlatch Bemidji, MN	1	Wellons 4-Cell Burner	232	Wood Waste	0.30 lb/MMBtu	50
Pulp & Paper	NOxOUT®	USA	S. D. Warren Skowhegan, ME	1	CE Grate-Fired	900	Oil, Bark, Biomass	0.30 lb/MMBtu	46
Pulp & Paper	NOxOUT®	USA	Schenectady International Schenectady, NY	1					
Pulp & Paper	NOxOUT® [D]	Sweden	Sodra Skogsagarna Sweden	1	Recovery Boiler	900	Black Liquor	60 mg/Nm^3 @ 3% O_2	60
Pulp & Paper	NOxOUT®	USA	Temple-Inland Orange, TX	1	B&W Grate-Fired Boiler	548	Bark Natural Gas	0.25 lb/MMBtu	40
Pulp & Paper	NOxOUT®	USA	Westvaco Phase I (Lukemill) #24 Luke, MD	1	B & W Cyclone	550	Coal	1.15 lb/MMBtu	50
Process Unit	NOxOUT®	USA	Alcan Berea, KY	2	Decoater/ Afterburner	30,000 lbs of aluminum cans/hr	Gas	90 - 150	50 - 80 +
Process Unit	NOxOUT®	USA	Allis Minerals Oak Creek, WI	1	Rotary Kiln Incinerator	60	Paper Sludge	0.48 lb/MMBtu	57

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INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
Process Unit	NOxOUT®	USA	Chambers Medical Waste Incinerator Chambers County, TX	2	Simonds Incinerator	21	Medical and Municipal	0.48 lb/MMBtu	67.8
Process Unit	NOxOUT®	USA	Dow Chemical Midland, MI	1	Rotary Kiln w/Afterburner	145	Haz Waste	720 - 740	40 - 55
Process Unit	NOxOUT®	USA	Eli Lilly Lafayette, IN	1	Haz Waste Incinerator	59	Haz Waste	290	70
Process Unit	NOxOUT® [D]	USA	Rollins Environmental Deer Park, TX	1	Haz Waste Incinerator	165	Chlorinated Chemical Waste, Soil	60 - 250	35 - 50
Process Unit	SCR	Taiwan	Shinkong Synthetic Fiber	3	Engine Generator	5.7 MW each	#6 Fuel Oil	1520 ppm @ 15% O_2	85
MWC	NOxOUT®	Sweden	Hallstehammer	1					
MWC	NOxOUT®	USA	Wheelabrator West Millbury, MA	2	Incinerator	351 / 750 TPD	MSW	300	32
MWC	NOxOUT®	Italy	AGEA MSW Ferrara, Italy	1	Incinerator	1 - 5 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	Italy	Alstom Power Daneco Pisa, Italy	1	Incinerator	2 - 8 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	SNCR	Italy	Ambiente Porto Marghera #1	1	Incinerator	109 t/h	Process Gas	204 mg/Nm^3 @11% O_2 0.28 *	60
MWC	NOxOUT®	Italy	Ambiente S.p.A. Porto Marghera, Italy	1	Incinerator	2 - 7 t/h		450 mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	Italy	Ambiente S.p.A. Ravenna, Italy	1	Incinerator	1 - 12 t/h		500 mg/Nm^3 @ 11% O_2	60
MWC	SNCR	Italy	Ambiente S.p.A. Scarlino, Italy	1	Incinerator	5 - 7 t/h		500 mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	USA	American Ref-Fuel (CP) Hempstead Long Island, NY	3	Deutshe Babcock Grate-Fired	320	MSW 768 T/D	0.44 lb/MMBtu	25
MWC	NOxOUT®	USA	American Ref-Fuel Niagara Falls, NY	2	Riley Grate	(2) 414	RDF, MSW	300	50
MWC	NOxOUT®	Italy	Ansaldo Arrezo Italy	1	Incinerator	31 t/h	MSW	460 mg/Nm^3 @11% O_2 227 *	56
MWC	NOxOUT®	Italy	Aster, R.S.U. Cremona 2ª linea, Italy	1	Incinerator	1 - 8 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	USA	Baltimore/Resco/WAPC Baltimore, MD	3	Burning Grate Stoker Fired	325	MSW	0.50 lb/MMBtu	30
MWC	NOxOUT® [D]	Germany	Bewag	1	Tower	150 MWe	Heavy Oil	200-225 mg/Nm^3 @ 11% O_2	60 - 70
MWC	NOxOUT®	Germany	Bremen, Germany	3	Grate Fired	15 t/h		350 mg/Nm^3 @ 11% O_2	35
MWC	NOxOUT®	Germany	Bremen, Germany	1	Grate Fired	20 t/h		350 mg/Nm^3 @ 11% O_2	35
MWC	NOxOUT® [D]	Germany	Bremen, Germany	1	Grate Fired	15 t/h		350 mg/Nm^3 @ 11% O_2	45
MWC	NOxOUT®	Italy	C.C.T. Airasca, Italy	1	Biomass	40000		400 mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	Italy	C.C.T. Massafra, Italy	1	Biomass	95000		558 mg/Nm^3 @ 11% O_2	71
MWC	NOxOUT®	Italy	C.C.T. Termoli, Italy	1	Biomass	40000		400 mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	Martinique	CAECEM Fort France, Martinique	1	Incinerator	2 - 7		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT® [D]	Germany	City of Berlin Berlin, Germany	1	Moving Grate		MSW	160	69
MWC	NOxOUT® [D]	Germany	City of Berlin Berlin, Germany	1	Zum Stoker	167	MSW	275	75

MWC = Municipal Waste Combustor
[D] Denotes Demonstration

FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY/LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
MWC	NOxOUT®	USA	City of Harrisburg Harrisburg WTE Facility Harrisburg, PA	3	Grate-Fired	267 TPD 141 MMBtu/hr	MSW	300 ppmv	58
MWC	NOxOUT®	Spain	CNIM Spain	1	Grate Fired	50 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	Italy	Compagnia Energetica Bellunese Castellavazzo, Italy	1		8 t/h		800 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	USA	Connecticut Resource Recovery Authority - Unit 13 Hartford, CT	1	CE VU 40	325	RDF, Coal	0.33-0.52 lb/MMBtu	35 - 40
MWC	NOxOUT®	USA	Covanta Energy Babylon MSW NY	2	Zurn Grate-Fired	142	MSW	320	53 - 66
MWC	NOxOUT®	USA	Covanta Lee County WTE Fort Myers, FL	1	Grate-Fired	636 TPD 265 MMBtu/hr	MSW	350 ppmd	68
MWC	NOxOUT®	USA	Covanta Warren County Oxford, NJ	2	Grate-Fired	240 TPD	MSW	250 ppmv	28
MWC	NOxOUT®	USA	CRRA - Units 11 & 12 Hartford, CT	2	C.E. VU 40	326	RDF	0.52 lb/MMBtu	40
MWC	NOxOUT®	UK	Cyclerval UK Grimsby, England	1	Incinerator	1 - 7 t/h	MSW	300 mg/Nm^3 @ 11% O_2	40
MWC	NOxOUT®	USA	DB Riley, Central Wayne Dearborn, MI	3	Municipal Waste Combustor	115 138	MSW	0.47 lb/MMBtu 0.48 lb/MMBtu	50
MWC	NOxOUT®	Italy	De Canderas Cremona, Italy	1	Municipal Waste Combustor		MSW/RDF	250 @ 11% O_2	60
MWC	NOxOUT®	Czech Republic	Deza Vitkovice	1	Wall Fired Boiler	362	Oil/Mazut	700 mg/Nm^3 @ 11% O_2	36
MWC	NOxOUT®	Korea	Dong Bu Ansan Proj	2	Steinmuller Incinerator Grate-Fired	281	MSW	200	75
MWC	NOxOUT®	Korea	Dong Bu Kwang Myong	2	Municipal Waste Combustor	150 TPD	MSW	0.59	65
MWC	NOxOUT®	Italy	Ecoespanso S.Croce sull'Arno, Italy	1	Incinerator	52000 Nm^3/hr		350 mg/Nm^3 @ 11% O_2	45
MWC	NOxOUT® (D)	Switzerland	Emmenspitz Zuchwil, Switzerland	1	Detroit Stoker	157.5	MSW	110	60
MWC	NOxOUT® (D)	Switzerland	Emmenspitz Zuchwil, Switzerland	1	Moving Grate Incinerator	121	MSW	200	68
MWC	NOxOUT®	USA	Falls Township Falls Township, PA	1	B&W Stoker	(2) 325	MSW	330 Max 285 Typ	50% Max 40% Typ
MWC	NOxOUT®	USA	Fort Lewis Fort Lewis, WA	1	Municipal Waste Combustor	60 tons/day	MSW	230 @ 7% O_2	65
MWC	NOxOUT®	Germany	Frankfurt Germany	4	Moving Grate	660	MSW	170mg/Nm^3 @ 11% O_2	70
MWC	NOxOUT®	Italy	G.E.A (P) Pisa, Italy	1	Incinerator	1 - 7,5 t/h		350 mg/Nm^3 @ 11% O_2	43
MWC	NOxOUT®	Germany	Haindl Schwedt	1	Fluidized Bed Incinerator	150	Pulp & Paper Waste	400-600 mg/Nm^3 @ 11% O_2	50 - 66
MWC	NOxOUT®	Germany	Hamm Germany	3	Moving Grate	528	MSW	170mg/Nm^3 @ 11% O_2	41
MWC	NOxOUT®	Italy	Hamon Research Cottrell Italia Filago, Italy	1	Incinerator	93000		400 mg/Nm^3 @ 11% O_2	55
MWC	NOxOUT®	France	Hamon Research Cottrell Italia Lagny, France	1	Incinerator	8.80 t/h		450 mg/Nm^3 @ 11% O_2	55
MWC	NOxOUT®	Germany	Herten Germany	2	Moving Grate	242	MSW	185mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	Germany	Homitex	1	Incinerator	125	Wood	750 mg/Nm^3 370	43
MWC	NOxOUT®	Taiwan	Keelung	2	Steinmuller	142	MSW	240 mg/Nm^3 @ 10% O_2	56

MWC = Municipal Waste Combustor
(D) Denotes Demonstration

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
MWC	NOxOUT®	Korea	Kwang Myung Seoul, Korea	2	Steinmuller MWC	58	MSW	200	65
MWC	NOxOUT®	UK	Lerwick Shetland Islands, UK	1	Incinerator	1 - 4 t/h	MSW	350 mg/Nm³ @ 11% O_2	45
MWC	NOxOUT®	Portugal	LIPOR II Porto, Portugal	1	Incinerator	2 - 24,6 t/h		450 mg/Nm³ @ 11% O_2	56
MWC	NOxOUT®	Germany	Meuselwitz	1	Incinerator	45.2	Sludge	450 mg/Nm³ 222	56
MWC	NOxOUT® (D)	USA	Montenay Pacific Power Long Beach, CA	1	Steinmuller Grate-Fired	172 MMBtu/hr	MSW	280 ppm	60
MWC	NOxOUT®	USA	Montenay Resource Recovery Facility Montgomery, PA	1	Steinmuller MWC	(2) 260		0.385 lb/MMBtu	50
MWC	NOxOUT®	USA	Montenay, Units 1-4 Dade County, Miami, FL	4	Zurn	302 / 623 TPD	RDF	170 - 250	14946
MWC	NOxOUT®	USA	New Hanover County Wrightsville Beach, NC	1	Volund MWC	108	MSW	300	60
MWC	NOxOUT®	Italy	Nuova Romano Bolzicco S.p.A. Manzano, Italy	1	Biomass	55000		400 mg/Nm³ @ 11% O_2	50
MWC	NOxOUT®	USA	Pinellas County/WAPC Tampa, FL	3	Municipal Waste Combustor	420	MSW	0.576 lb/MMBtu	33
MWC	NOxOUT®	Italy	Pisa Demonstration Italy	1	Incinerator	64.9 t/h	MSW	350 mg/Nm³ @11% O_2 0.45 *	43
MWC	NOxOUT®	Korea	Pyeng Chun Pyung Chon City, Korea	1	Municipal Waste Combustor	220 (200 TPD)	MSW	0.53 lb/MMBtu	65
MWC	NOxOUT®	Italy	R.S.U. Arrezzo Arezzo, Italy	1	Incinerator	1 - 6,5 t/h		460 mg/Nm³ @ 11% O_2	57
MWC	NOxOUT®	Italy	R.S.U. Cremona Cremona, Italy	1	Incinerator	1- 8 t/h		500 mg/Nm³ @ 11% O_2	60
MWC	NOxOUT®	Italy	Ravenna Italy	1	Municipal Waste Combustor	45,000 Nm³/hr	MSW	400	62.5
MWC	NOxOUT®	USA	Regional Waste Systems ME, Units 1 & 2	2	Steinmuller	120	MSW	0.40 lb/MMBtu	33% 43% Design
MWC	NOxOUT®	USA	Robbins Resource Recovery Facility Robbins, IL	1	FW CFB	(2) 509		0.39 lb/MMBtu	48.72
MWC	NOxOUT® (D)	Germany	RWE	1	T-Fired	150 MWe	Brown Coal	200-250 mg/Nm³ @ 11% O_2	50
MWC	NOxOUT®	Germany	RWE - C2	1	T-Fired	75 MWe	Brown Coal	150-175 mg/Nm³ @ 11% O_2	40
MWC	NOxOUT®	USA	Savannah Energy Systems Savannah, GA	2	Municipal Waste Combustor	115	MSW	0.71 lb/MMBtu	50
MWC	NOxOUT®	USA	SEMASS Rochester, MA	1	Riley Stoker	375	MSW	220	50
MWC	NOxOUT®	Korea	Seoul Metro Gov't Mok-Dong - Seoul, Korea	1	MWC	62 150 TPD	MSW	100-150mg/Nm³ @ 11% O_2	50-67
MWC	NOxOUT®	France	SETRAD La Rochelle, France	1	Incinerator	2 - 4 t/h		300 mg/Nm³ @ 11% O_2	35
MWC	NOxOUT®	France	SILA Annecy, France	1	Incinerator	1 - 4 & 2 - 6 t/h		350 mg/Nm³ @ 11% O_2	50
MWC	Urea SCR	France	Sirtec Nigi spA Le Havre, France	1	Waste Incinerator SCR	63,571 Nm³/h		350 mg/Nm³ @ 11% O_2	82
MWC	Urea SCR	France	Sirtec Nigi spA Nimes, France	1	Waste Incinerator SCR	77,000 Nm³/h		400 mg/Nm³ @ 11% O_2	87
MWC	SNCR	France	SIVOM Metz, France	1	Incinerator	2 - 8 t/h		350 mg/Nm³ @ 11% O_2	45
MWC	SNCR	France	SMITOM Vaux le Pénil, France	1	Incinerator	2 - 8 t/h		350 mg/Nm³ @ 11% O_2	43

MWC = Municipal Waste Combustor
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FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY/LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
MWC	NOxOUT® [D]	Sweden	Sydkraft	1	PC Front-Fired	500	Coal	650 mg/Nm^3 @ 11% O_2	80
MWC	NOxOUT® [D]	Sweden	Tekniskaverken Garstad, Sweden	1	Moving Grate		MSW		
MWC	NOxOUT®	Italy	Termomeccanica Ecologia Cagliari, Italy	1	Incinerator	1 - 8.75 t/h		450 mg/Nm3 @ 11% O2	60
MWC	NOxOUT®	Italy	Termomeccanica Ecologia Taranto, Italy	1	Incinerator	16 t/h		400 mg/Nm^3 @ 11% O_2	60
MWC	NOxOUT®	Italy	Termomeccanica S.p.A. Brindisi, Italy	1	Incinerator	1 - 8 t/h		450 mg/Nm^3 @ 11% O_2	66
MWC	NOxOUT®	Czech Republic	Trmice	2	Wall-Fired	490	Lignite	341 ppvd	57
MWC	NOxOUT®	Italy	TTR s.r.l. Busto Arsizio, Italy	1	Incinerator	2 - 5 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	Italy	TTR s.r.l. Trieste, Italy	1	Incinerator	2 - 5 t/h		400 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	Taiwan	Tuntex Kaohsiung MSW	3	Deutsche Babcock Incinerator	120 each	MSW	183 mg/Nm^3 @ 10% O_2	42
MWC	NOxOUT®	Germany	Ulm	1	Bubbling Bed Sludge Incinerator		Sludge		
MWC	NOxOUT®	Czech Republic	Vitkovice	1	Front Wall-Fired	250	Hard Coal	600 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	USA	Westchester County/WAPC New York, NY	3	Municipal Waste Combustor	325	MSW	0.50 lb/MMBtu	30
MWC	NOxOUT®	USA	Wheelabrator North Broward, FL	3	Incinerator	351 / 750 TPD	MSW	300	32
MWC	NOxOUT®	USA	Wheelabrator South Broward, FL	3	Incinerator	351 / 750 TPD	MSW	300	32
MWC	NOxOUT®	USA	Wheelabrator RESCO Bridgeport, CT	3	Grate-Fired	281	MSW	300	50
MWC	NOxOUT®	USA	Wheelabrator RESCO Saugus, MA	2	Incinerator	351 / 750 TPD	MSW	300	32
MWC	NOxOUT®	USA	Wheelabrator Concord, NH	2	Incinerator	110 / 250 TPD	MSW	300	32
MWC	NOxOUT®	USA	Wheelabrator Gloucester, NJ	2	Incinerator	109 / 250 TPD	MSW	300	32
MWC	NOxOUT®	USA	Wheelabrator McKay Bay, FL	4	Incinerator	108 / 250 TPD	MSW	306	31
MWC	NOxOUT®	USA	Wheelabrator North Andover, MA	2	Incinerator	351 / 750 TPD	MSW	300	32
MWC	NOxOUT®	Germany	Wilrijk, Germany	2	Grate Fired	9.6 t/h		350 mg/Nm^3 @ 11% O_2	50
MWC	NOxOUT®	Switzerland	Winterthur (1)	1	Sludge Incinerator	8.34	Sludge	200-300 mg/ Nm^3	60 - 73
MWC	NOxOUT®	Taiwan	Yilan	2	Steinmuller	142	MSW	240 mg/Nm^3 @ 10%	56
MWC	NOxOUT® [D]	Korea	Yukong Ulsan, Korea	1	Package Boiler	34 TPH	#6 Oil	260-330 mg/Nm^3 @ 11% O_2	16 - 47
IPP/Co-Gen	NOxOUT®	USA	ABB Okeelanta Okeelanta, FL	1	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT®	USA	ABB Osceola Osceola, FL	1	Grate-Fired Stoker	660	Bagasse Wood, Coal	0.40-0.20 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT®	Puerto Rico	AES Guyama, Puerto Rico	2	CFB	230 MWe	Coal	0.13 lb/MMBtu	23
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Ashland, ME	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50

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FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY/LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Cadillac, MI	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Alternative Energy, Inc. Northeast Empire Livermore Falls, ME	1	Zurn Stoker	500	Wood	0.30 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Black & Veatch Genessee, MI	1	ABB CE Stoker	473	Wood	0.47 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Black & Veatch Grayling, MI	1	Zurn Stoker	440	Biomass	0.26 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Celanese Narrows, VA	1	Front Wall-Fired	315	Coal	.360 lb/MMBtu	35 - 40
IPP/Co-Gen	NOxOUT®	USA	Chewton Glen Energy Ford Heights, IL	1	Grate-Fired	240	Shredded Tires	0.195 lb/MMBtu	60
IPP/Co-Gen	NOxOUT®	USA	Cogentrix Richmond, VA	8	CE Stoker	(8) 25 MWe	Coal	350	40
IPP/Co-Gen	NOxOUT ULTRA® [D]	USA	Combustion Turbine West Coast Location	1	HRSG	100 MW	Gas	SCR Reagent Requirement 100 lb/hr	
IPP/Co-Gen	NOxOUT®	Taiwan	Far East Textiles Hsihpu	1	Stoker Boiler	190	Coal	550 @ 6% O_2	50
IPP/Co-Gen	NOxOUT®	USA	Fibrominn, LLC Benson, MN	1	Grate-Fired	802 MMBtu/hr	Poultry & Natural Gas	0.92 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	Germany	FT GmbH Germany	5	Fire Tube Pkg. Boilers	10 - 20 MWe	Heavy Oil	700-800mg/ Nm^3	40 - 50
IPP/Co-Gen	NOxOUT® [D]	USA	General Electric Lynn, MA	1	B&W "D" Type Pkg. Boiler	236	#6 Oil, Gas	0.28-0.31 lb/MMBtu	40 - 60
IPP/Co-Gen	NOxOUT®	USA	Georgia Pacific Brookneal, VA	1	Wellons 4-Cell	236	Mixed Wood	0.33 lb/MMBtu	38
IPP/Co-Gen	NOxOUT®	USA	Georgia Pacific Mt. Hope, WV	1	Cell-fired	240	Bark/Dust	0.25 lb/MMBtu	20
IPP/Co-Gen	Urea SCR	Turkey	Hamon Research Cottrell Italia	7	Diesel SCR				
IPP/Co-Gen	NOxOUT® [D]	USA	Honey Lake Power Susanville, CA	1	Stoker-Fired	480	Wood	0.21 lb/MMBtu	52
IPP/Co-Gen	NOxOUT®	Korea	Hyundai Korea Kumho Petrochemical	1	CFB	926	Pulv. Coal	275	56
IPP/Co-Gen	NOxOUT®	USA	I.P. Masonite Towanda, PA	1	B & W	250	Sludge/Wood Waste, Coal	0.4 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Kenetech Energy Fitchburg, MA	1	Riley Stoker	225	Wood	0.26 lb/MMBtu	47
IPP/Co-Gen	NOxOUT®	Korea	Korea ICC Units 1 - 3 Kumi Heat & Power Station Korea	3	Front Wall-Fired	530 330 530	Pulv. Coal Pulv. Coal Pulv. Coal	710 700 710	53 53 40
IPP/Co-Gen	NOxOUT®	USA	LFC Hillman, MI	1	Grate-Fired	190	Wood	0.22 lb/MMBtu	30
IPP/Co-Gen	NOxOUT®	USA	McMillan Bloedel Clarion, PA	1	EPI Fluid Bed Combustor	500	Wood Waste/ Hog Fuel	100	42
IPP/Co-Gen	NOxOUT®	USA	Michigan State Univ., Unit #4 East Lansing, MI	1	CFB	460	Coal	247	57
IPP/Co-Gen	NOxOUT®	USA	Michigan State Univ., Units #1-3 East Lansing, MI	3	Wall Fired Boiler	320 320 420	Coal	0.38-0.40 lb/MMBtu	34-38
IPP/Co-Gen	NOxOUT®	Sweden	Nykoping, Units 1-3 Gotaverken Energy	3	CFB	135	Coal	120-150mg/ Nm^3 @ 1% O_2	70
IPP/Co-Gen	NOxOUT® [D]	USA	Oxford Energy Modesto #2, Wesley, CA	1	Moving Grate Incinerator	90	Tires	0.13 lb/MMBtu	40
IPP/Co-Gen	NOxOUT®	USA	Oxford Energy Sterling, CT	1	Grate-Fired	(2) 170	Tires	0.15 lb/MMBtu	50
IPP/Co-Gen	NOxOUT ULTRA®	USA	Peerless Manufacturing MATEP - Boston, MA	2	HRSG	15 MW	Gas	SCR Reagent Requirement 2 @ 15 lb/hr	

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FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY/LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
IPP/Co-Gen	NOxOUT®	USA	Ridge Generating Polk County, FL	1	Zurn Stoker	550	Wood	0.35 lb/MMBtu	57
IPP/Co-Gen	NOxOUT®	USA	Riley Ultrasystems II Weldon, NC	1	Riley Front-Fired Boiler	505	Pulv. Coal	0.33 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Ryegate Power Station Ryegate, VT	1	Riley Stoker	300	Wood	0.20 lb/MMBtu	30
IPP/Co-Gen	NOxOUT®	USA	Sierra Pacific Bohemia Plant Lincoln, CA	1	Cell-Fired	(2) 130	Biomass	0.42 lb/MMBtu	50
IPP/Co-Gen	NOxOUT®	USA	Solvay Chemicals Units 1 & 2 Green River, WY	2	Stoker	155 MMBtu/hr	Coal	0.45 lb/MMBtu	35
IPP/Co-Gen	NOxOUT®	USA	Sonoco Huntsville, SC	1	FW/ Pyropower CFB	145	Coal	195	67
IPP/Co-Gen	NOxOUT®	Germany	Standardkessel Germany	31	Fire Tube Pkg. Boilers	10 - 20 MWe	Heavy Oil	700-800 mg/Nm³	40 - 50
IPP/Co-Gen	NOxOUT®	Czech Republic	Strakonice	2	High Front Wall-Fired & Low Grate Fired	36-40	Lignite Brown Coal	600 mg/Nm³	50
IPP/Co-Gen	NOxOUT®	Sweden	Tekniskaverken Linkoping P1 Sweden	1	Stoker	275	Coal	300-350mg/Nm³ @ 4% O_2	65
IPP/Co-Gen	NOxOUT® [D]	Sweden	Tekniskaverken Linkoping P3 Sweden	1	Stoker		Wood	800mg/Nm³ @ 11% O_2	50
IPP/Co-Gen	NOxOUT®	USA	Trigen Cinergy St. Paul, MN	1	Front Wall Grate-Fired	355	Wood Waste	0.34 lb/MMBtu	36
IPP/Co-Gen	NOxOUT® SNCR	USA	U.S. Sugar Corp. Clewiston, FL	1	Grate-Fired	856	Bagasse	0.28 lb/MMBtu	50
IPP/Co-Gen	NOxOUT® [D]	USA	Ultrasystems Fresno, CA	1	CFB	280	Wood	150	70
IPP/Co-Gen	NOxOUT® ULTRA	USA	University of CA - Irvine Irvine, CA	1	Co-Gen Unit	14 MW	Natural Gas	SCR Reagent Requirement 11 lb/hr	N/A
IPP/Co-Gen	NOxOUT® [D]	USA	Yankee Energy Dinuba, CA	1	CFB	190	Wood Waste	0.10-0.18 lb/MMBtu	40 - 73
IPP/Co-Gen	NOxOUT®	USA	Zachry Energy Hurt, VA	1	Riley Stoker	(3) 390	Wood	0.20 lb/MMBtu	46
Chemical	NOxOUT®	USA	BP Chemicals Green Lake, TX	3	AOG Incin. HRSG	398,757 lb/hr Flue Gas 398,757 lb/hr Flue Gas 238,361 lb/hr Flue Gas	Absorber OFF Gas	238 238 150	50 50 50
Chemical	NOxOUT® [D]	USA	BP Chemicals Green Lake, TX	1	AOG Incin. HRSG	34	Waste Gas	350	80 +
Chemical	NOxOUT®	Taiwan	Far East Textile	1	Front-Fired		Coal		50
Chemical	NOxOUT®	Taiwan	Formosa Plastics Kaohsiung	1	Front-Fired	331	Coal	500	60
Chemical	NOxOUT®	Taiwan	Formosa Plastics Kaohsiung	1	Front-Fired	331	Coal	500 mg/Nm³ @ 11% O_2	60
Chemical	NOxOUT®	USA	Miles, Inc. Kansas City, MO	1	Carbon Furnace Afterburner	16	Chemical Waste	150	35
Chemical	NOxOUT®	USA	N American Chem. Corp. Trona, CA	1	T-Fired	(2) 73 MWe	Coal	200	40
Cement Kiln	NOxOUT® [D]	USA	Ash Grove Cement Seattle, WA	1	Cement Kiln/ Pre-Calciner	160 tons solids/hr	Coal, Gas	350 - 600#/hr	> 80
Cement Kiln	NOxOUT®	USA	Cemex, Inc. Knoxville, TN	1	Pre-Calcining Kiln	317 MMBtu/hr	Coal & Pet Coke	370 ppmd	40
Cement Kiln	NOxOUT® [D]	Korea	Korean Cement Dong Yang Cement, Korea	1	New Suspension Calciner		Coal	1.27 lb/MMBtu	45
Cement Kiln	NOxOUT® [D]	USA	Lehigh Portland Cement Mason City, IA	1	Cement Kiln/ Pre-Calciner	368	Coal, Gas	0.95-1.35 lb/MMBtu	25 - 35
Cement Kiln	NOxOUT®		Plant Name & Location Confidential					1500 mg/Nm³ @ 11% O_2	45

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[D] Denotes Demonstration

FUEL TECH NOxOUT® PROCESS EXPERIENCE LIST

INDUSTRY	PRODUCT TYPE	COUNTRY	COMPANY / LOCATION	# of UNITS	UNIT TYPE	SIZE (MMBtu/hr)	FUEL	NOx BASELINE (ppm, * lb/MMBtu)	REDUCTION %
Cement Kiln	NOxOUT®	Taiwan	Taiwan Cement Units #3, #5, & #6	3	Cement Kiln/ Pre-Calciner	260 697 658	Coal Coal Coal	1.29 1.58 0.92	50 45 25
Cement Kiln	NOxOUT® [D]	Germany	Wulfrath Cement Germany	1	Cement Kiln	140	Lignite	1000 mg/Nm³ 500	90
			Total # of Units	424					