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ABSTRACT

This paper presents the successes and lessons learned during recent low NOx burner and SNCR projects on generating units at New England Power's Salem Harbor Generating Station. The principals involved in the project were New England Power Company, New England Power Service Company, Stone and Webster Engineering Corp. and DB Riley, Inc. One unit was retrofitted with 16 DB Riley CCV® burners with an OFA system, the other with 12 low NOx burners only. In addition to the burners, a SNCR system was also installed on three units.

Since each of the burner systems are interdependent (SNCR was treated separately during design phases and optimized along with the burner systems), close cooperation during the design stages was essential to ensuring a successful installation, startup and optimization.

This paper will present the coordinated effort put forth by each company toward this goal with the hope of assisting others who may be planning a similar effort. A summary of the operating results will also be presented. The up front teamwork and advance planning that went into the design stages of the project resulted in a number of successful outcomes e.g. scanner reliability, properly operating oil supply system, compatibility of burners and burner front oil system with new Burner Management System (BMS), reliable first attempt burner ignition and more. Advance planning facilitated pre-outage work and factored into keeping schedules and budgets on track.

The groundwork for the success of these projects was developed during numerous team meetings consisting of the design team from the utility, Architect Engineer, and burner manufacturer. This paper will also present the lessons learned from this joint design effort particularly with respect to burning South American coals. During this project, a significant investigation into the characteristics of these coals was conducted to understand the reasons behind a decrease in combustion efficiency. This paper will summarize the results of this effort and provide data from the application of low NO_X technology using these coals.

BACKGROUND

Multiple NO_X control technologies were required on Units 1 and 3 to meet and maintain the strict NO_X emission levels levied upon them in an agreement between the Massachusetts Department of Environmental Protection and New England Power Company (NEP). The agreement outlined a suggested combination of technologies to meet and maintain a NO_X emission rate of 0.33 lbs/MMBtu, lower than the ACT rate of 0.45 lb/MMBtu. In 1992, the industry had limited experience with NO_X reduction. Therefore, the agreement did not specify which technology to combine or use alone to meet the NO_X goal.

- Current Order (ACO) from Mass DEP .33 lb/MMBtu NO_X
- Technology not specified
- NEP pursued LNB and SNCR as parallel, but separate projects

To minimize large capital expenditures on the relatively small units, SNCR systems were installed, as a first step, on all three coal units at Salem Harbor. Unit 2 *was* able to achieve the strict NO_X limit using SNCR alone and therefore was not equipped with new burners and related controls. Units 1 and 3 were *not* able to achieve the NO_X emission rate and therefore low NO_X burner equipment was required.

NEP and New England Power Services Company (NEPSCO) were given the task of engineering and executing the NO_X reduction projects for all three coal fired boilers at Salem Harbor. The projects were part of a larger, company wide program to modify and/or install appropriate NO_X control equipment to ensure compliance with all emission requirements.

These projects, like other environmentally driven projects, are complex and have schedules established prior to project engineering and development. NEPSCO recognized that proper planning and a team approach would be essential in successfully executing the projects on schedule and within established budgets. To that end, Stone and Webster Engineering Company (SWEC) was retained to perform necessary studies and detailed engineering, and to work as an extension of NEPSCO's engineering department.

PROJECT ORGANIZATION

The study and detailed engineering work was divided into discrete work packages, which, based on the team's prior burner retrofit experiences, would allow for readily measurable progress of the work and would better ensure that sufficient, accurate information would be available to support the project.

As a result of a review of the technologies available for NO_x reduction and the resulting bid specification development, solicitation, review and award, DB Riley (DBR) was awarded the burner work in December 1992. The detailed project engineering fell into four general work packages:

1. Balance of plant engineering, design and procurement
2. Burner management and controls systems engineering, design and procurement
3. Vendor monitoring and design review for specification compliance.
4. Overall engineering coordination.

During the detailed engineering phase of the project, frequent meetings with all project team members (NEPSCO, NEP, SWEC and DBR) were held. These meetings, frequently convened on a weekly basis, often were held at the burner vendor's engineering offices so that design work could be reviewed "in process" rather than waiting for the usual fully completed design review. Mutually identifying and resolving problem areas before the designs were "frozen," ensured a smooth transition from the drawing board to the final installation.

EXISTING EQUIPMENT

Salem Harbor Unit 3 (SH 3) is a Babcock and Wilcox Co. coal/oil fired single reheat regenerative cycle, balanced draft boiler originally placed into service in 1958. The water cooled, dry bottom furnace is vertically partitioned with a division wall and is fired from 16 coal/oil burners located on the front wall in four levels of four burners each. The boiler nominal ratings are 1,000,000 lbs/hr steam flow at 1975 psig/1000°F, reheat at 460 psig/1000°F, for a rating of 155 MW.

SALEM HARBOR STATION
SALEM, MASSACHUSETTS

UNIT 1	~ 86 MW	COAL/OIL	1951
UNIT 2	~ 86 MW	COAL/OIL	1951
UNIT 3	~ 155 MW	COAL/OIL	1958
UNIT 4	~435 MW	OIL	1972

Salem Harbor units 1 and 2 (SH 1 & 2) are Babcock and Wilcox Co. coal/oil fired single reheat regenerative cycle, balanced draft boilers originally placed into service in 1951. Each water cooled, dry bottom furnace is fired from 12 coal/oil burners located on the front wall in four levels of three burners each. The boiler nominal ratings are 625,000 lbs/hr steam flow at 1500 psig/1000°F, reheat at 470 psig/1000°F, for a rating of 86 MW.

NEW BURNER EQUIPMENT

The basic fuel firing arrangements were not changed with the installation of low NO_X burners. The original burners were replaced with the appropriate number of DB Riley low NO_X CCV® burners on a "plug-in" basis. Pressure part and coal pipe modifications were not required.

DB Riley's Model 90 CCV® burner consists of a patented Venturi coal nozzle, secondary air diverter, low swirl spreader, stainless steel burner barrel with expansion joint, barrel front support, air register/shroud assembly, electric actuator for shroud, register vane operator, burner front plate, and coal head.

An optional, removable center plug is a design feature of the burner. Upon deciding to add gas firing, this plug is easily removed and replaced with new plug consisting of a gas plenum and stainless steel gas canes located inside the windbox and attached to the front plate.

NO_X reduction capability is achieved by the CCV® burner with only a single register resulting in a mechanically simple design. Another advantage of the DB Riley register design is the location of linkages and levers *outside* the windbox. Only the turning vane shaft penetrates the burner front plate into the windbox. This feature permits any burner adjustments to be made while the unit is on line.

The key element of the burner design is the patented Venturi coal nozzle and low swirl coal spreader located in the center of the burner. The Venturi nozzle concentrates the fuel and air in the center of the coal nozzle, creating a very fuel rich mixture. As this mixture passes over the coal spreader, the blades divide the coal stream into four distinct streams which then enter the furnace in a gradual helical pattern producing very gradual mixing of the coal and secondary air.

One of the most important design features of the CCV® burner is the air register/shroud assembly which provides independent control of swirl and secondary airflow. Secondary airflow is controlled by a moveable shroud that slides over the vanes. The complete register/shroud assembly is located away from the waterwall, minimizing adverse radiation effects from the furnace.

Independent control of the shroud and the vanes offers significant flexibility in controlling combustion, particularly at low load. In addition to DB Riley's low NO_X burners for reducing emissions, SH 3, because of its relatively tall furnace, also implemented DB Riley's Overfire Air System to achieve further NO_X reductions.

DB Riley's scope of supply consisted of eight duct/port assemblies located directly above the windbox. The combined burner and OFA system provides the control required to regulate the mixing of combustion air with the fuel, by means of staging, needed for low NO_X and CO emissions operation.

DB Riley performed significant research work for EPRI in the mid-1980's to develop the proper design guidelines for OFA systems. The following key elements are considered to be critical when designing a retrofit OFA system:

1. Adequate separation must be available between the primary and secondary combustion zones to reduce NO_X.
2. Rapid mixing of the OFA with the primary combustion zone products must exist to promote efficient burnout of the remaining fuel.

3. Adequate residence time in the secondary combustion zone must be available for complete burnout.

4. Independent control of OFA from the burner air must be incorporated into the overall combustion system design.

Each OFA port is divided into 1/3 and 2/3 sections. This approach has been used by DB Riley for several years to insure that adequate penetration velocity is maintained throughout the boiler load range when the OFA is being used to control NO_X emissions. The 1/3 and 2/3 sections have dampers which automatically open and close with the boiler load.

Full load oil guns located in the center of the burner are also used as ignitors for the coal, similar to the original operating methodology. Since these new guns were almost a foot longer than the existing guns, removal clearances had to be verified. This was accomplished by using a length of PVC tubing cut to the proper lengths and “mocked up” in the field.

To meet current fire codes, a supervised manual burner management system was installed, including oil safety shut-off valves, numerous safety interlocks, flame scanner equipment and high energy spark ignitors for oil gun ignition.

All burner front oil piping was completely removed, redesigned in cooperation with SWEC and replaced. To verify the final layout, full size cardboard models of the valves were constructed and “mocked up” in the field.

BURNER SYSTEM ENGINEERING AND INSTALLATION

The engineering effort involved some unique approaches by the team to assure that plant staff “bought in to” the conceptual designs prior to engineering release. This approach included:

1. A full scale, functional burner was presented at the plant for review by operators and maintenance prior to burner contract award.

2. The oil safety shutoff valve locations were critical due to limited operating and maintenance space. Full scale models and racks were built and installed at the desired locations for concurrence by the plant and engineering. This also assisted in locating interferences and finalizing the design without multiple drawing revisions.

3. Spare burners were purchased to provide training aids as well as reference points for trouble-shooting, construction and future modifications.

The concern for potential problems with flame scanner sighting and reliability on reduced stoichiometric firing, resulted in the following actions:

1. The low NO_X burner vendor would provide and properly locate the scanners and retain the full responsibility for scanner performance.

2. To provide the ability to use different flame scanners and/or different sensitivity settings for coal and oil flames, the burner equipment was specified with two separate scanners, one for oil and one for coal. Different scanners and setting for the different fuels were not required. The BMS logic was successfully developed to utilize both scanners when firing coal to eliminate the sporadic occurrence of nuisance burner trips due to random movement of the coal flame.

The result is a reliable, nearly trouble free scanner system design. On Unit 1, the coal flame scanners needed to be aimed at very sharp angles due to the narrow coal flame shape. One scanner would not be able to sight both the oil and coal flames.

Based on previous experience, direct ignition of No. 6 fuel oil was chosen rather than the conventional approach of using dedicated No. 2 oil ignitors on all burners. Two of the heavy oil burners on Unit 3 (one on Unit 1) were designed to fire No. 2 fuel oil for cold start up and boiler warm up. This design improved the reliability of the light offs and fired clean using No. 6 oil guns and tips. As a result, *all* oil guns for both boilers have the same tips for both fuels reducing the complexity of the oil system design and operation.

A key factor in successful light off of all fuels is the oscillation of the spark ignitor. This feature ensures that the "sweet spot" in the oil stream is found each time the ignitor is used.

The project team held weekly meetings prior to preparing for the installation outages to review all aspects of the design including constructability. As a result, the Unit 1 OFA design was eliminated due to the minor NO_X reduction predictions and the difficulty and cost of building OFA ports internal to the windbox. Other enhancements to the overall design included:

1. A non-standard "keyhole" burner front plate and angles for the burner attachment to the existing windbox minimized field work and stud welding.
2. Piping designs were modified for easier installation and maximized pre-outage work, e.g. No. 2 fuel oil tie in, plant air tie in, and scanner air skid location.

Almost all aspects of the project construction were handled by the in house construction forces of New England Power Service Company. The SNCR system was installed in each unit prior to the combustion system retrofit. Due to the advance planning, construction forces were mobilized two months prior to the outages and installed stab "tie-ins" and isolation to:

- No. 2 fuel oil
- Plant air system
- Instrument air system

Valve racks for the burner valves were pre-fabricated, thus avoiding construction activities during the outage. Also pre-installed were cable trays, conduit, and cables as well as major equipment including scanner air fan skids, burner management cabinets, and the uninterruptible power supply system. The existing fuel oil piping insulation was also removed prior to the outage. The amount of work accomplished in this period was an important contribution toward completion of the project on schedule and within budget with minimal overtime.

Pre-assembly of a portion of the Unit 3 overfire air system, out of position, prior to the outage, was a significant factor in the trouble free installation of the system. Minor problems with the linkage arrangement and assembly were uncovered and resolved without the typical construction pressures which are present during an outage.

Extensive use of pre-assembled cables and electrical equipment made the electrical construction portion of the project go smoothly. Not only was critical outage time saved by factory testing cables and equipment prior to shipment, assembly mistakes were uncovered and corrected without resorting to expensive and time consuming in-the-field troubleshooting and repair.

Consistent with the project direction to keep the burner front as uncluttered as possible, all burner fuel oil safety shutoff valves, scanner amplifiers, ignitor power packs and burner local control stations were mounted away from the burner front. The somewhat remote locations for these items allowed piping and wiring to take place independently of actual burner installation, thereby reducing construction sequencing problems and congestion. The arrangement greatly simplified the burner front piping and permitted the standardization of piping and valve locations thereby minimizing operator confusion and promoting safe operation. The deleterious effects of heat and potential fire damage to high dollar value equipment such as safety shutoff valves, ignitor power packs, scanner amplifiers and control panels was also greatly reduced.

Construction of each unit was completed within the budget and scheduled maintenance overhaul outage. Start up of all aspects of the project was accomplished without major problems. The units returned to service on schedule.

TRAINING, START-UP, AND TESTING

Training, startup and testing were unique since the project was supported mainly by the project team rather than the supplier's service engineers. Maintenance training on the new burner equipment was held prior to startup. During the outage, the project team and the plant reviewed all instrument installations and checked out all loops. Test loop diagrams were drawn and checked out, and settings made prior to the first fire.

The No. 6 oil burners and mills were tested and "dry fired" (no fuel was admitted to the furnace, mills or oil valves) with limited logic jumpering, by using simulated fires (drop lights in close proximity) of each flame scanner. Oil valves were stroked and burner shrouds were repositioned to satisfy the logic. This basic testing easily identified wiring problems and, as a result, the first oil burner was fired and ignited on the first attempt.

Based on a pre-planned matrix, many adjustments were made to the burner shrouds, registers, and OFA (Unit 3). The South American coal worked well for NO_X reduction but the LOI was higher than expected. The burners were set to optimize NO_X emissions against increased LOI.

PERFORMANCE

The following section provides an overview of the startup and optimization of the CCV® burners and overfire air system for Unit 3. The installation of the burners and OFA system was completed in January of 1994. Burner setup and optimization began in February 1994 and continued through to November, 1994.

The project team performed the initial CCV® burner setup and optimization in February 1994. The boiler met the specified NO_X and CO emission levels. However, unburned combustibles in the flyash were higher than anticipated when compared with other CCV® burner performance data.

Diagnostic testing to determine the cause of the high LOI began with fineness and coal distribution testing. Results from these tests indicated that adjustments to the coal fineness and balance were required and resulted in a small improvement in combustion efficiency.

In parallel, mutual investigations into coal reactivity showed that South American coal reactivity is significantly less than that of domestic bituminous coals. As coal reactivity decreases, longer retention times are needed to insure complete combustion. In an existing furnace, residence time is essentially fixed. If the available retention time is insufficient for complete combustion of low reactivity coal, the obvious consequence will be an increase in LOI levels. The project team believes the coal characteristics are the primary factor creating the higher than expected LOI at this facility.

COAL CHARACTERISTICS

DB Riley performed a series of different laboratory analysis and techniques on differing samples of each coal burned:

1. Maceral distribution analysis
2. Scanning electron microscopy
3. Drop tube furnace studies
4. Thermogravimetric analysis of size fractions.

Each type of maceral in coal has different optical characteristics. This analysis (performed on raw coal samples) provides the volume or number percent of the macerals in a coal sample (Figure 1). This data indicates that South American coals have a greater tendency to form unburned carbon under the same combustion conditions than standard domestic coals of the same rank.

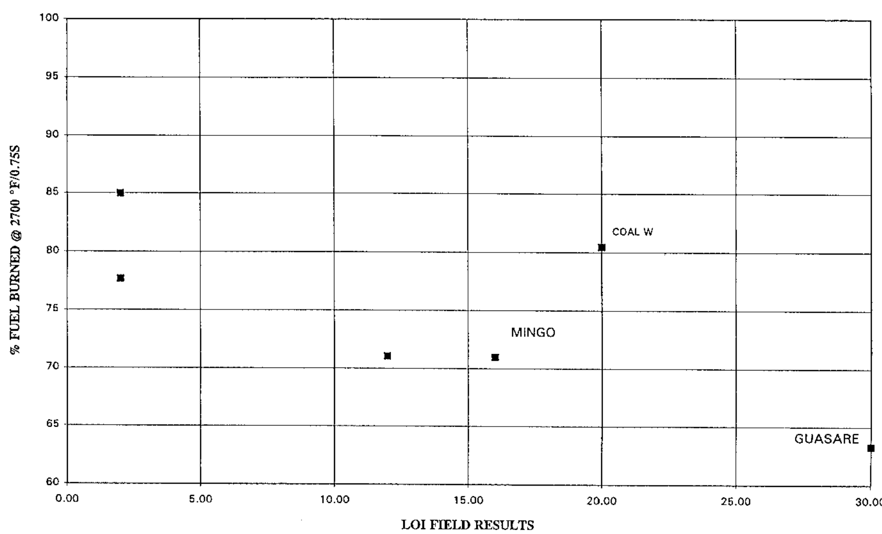

Figure 1 % Fuel Burned versus LOI Field Results

Further microscopic examination of the coal indicated that the two South American coals appeared to have less mineral matter inherently associated with the pulverized coal particles than the domestic fuel. Minerals in the coal particles can act as nucleation sites for combustion. During heating the minerals can undergo thermal and chemical degradation. If this occurs within the coal particle the reactions can break up the particle thereby increasing net surface area as well as act as nucleation sites on the surface of the particle and increase the overall reaction rates. The relative lower level of inherent mineral matter may result in overall lower combustion efficiency.

Similarly, the different distribution of mineral matter in the coals may result in a difference in performance or particle behavior within the pulverizer and classifiers. The coal preparation and delivery system is based on sizing by density differences. When the generally smaller (but denser) mineral matter is separated from the coal, the aerodynamic classification of the fuel is significantly different than anticipated and would not be able to catalyze the combustion process.

Drop tube studies were used to further investigate the characteristics described above and the relative reactivity of bituminous coals under low NO_X firing conditions. Figure 2 shows the results of field experience with these coals, all classified as bituminous.

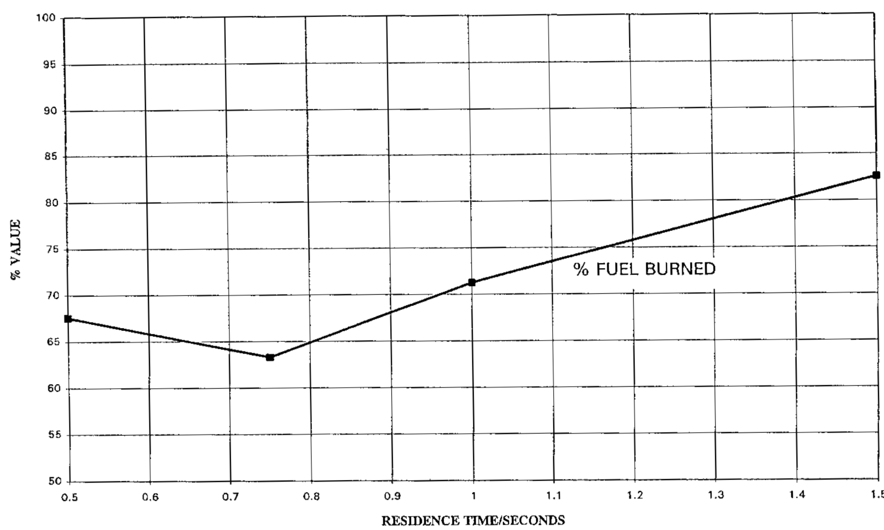

Figure 2 Drop-Tube Furnace Tests
Gusare Coal as Function of Residence Time @ 2700°F

This drop tube furnace was designed to operate at isothermal conditions and controlled atmospheres with selected particle residence times. The atmospheric condition used was that of a stoichiometry of 1.0. One set of experiments was performed with a set of six coals (a combination of South American coals and known domestic coals) with a residence time of 0.75 seconds at 2700°F. Another set of experiments focused specifically on Gusare coal and was designed to ascertain the effect of flame temperature and residence time on carbon burnout. These additional test matrices included the following (all at a stoichiometry of 1.0):

1. Residence times of 0.5, 1.0, 1.3 1.5 seconds at 2700°F

2. Temperatures of 2600°F, 2800°F, and 2850°F at a residence time of 0.75 s.

The data shows the lowest reactivity was observed with the Gusare and Mingo Logan coals. The laboratory test results compare favorably with the field results with one exception. Coal "W" (not from NEPCO) is inconsistent with the drop tube furnace results and other measured parameters, i.e. TGA, maceral analysis. This coal is under further investigation at this time.

The results of the laboratory tests to quantify the effects of residence time and temperature are shown in Figures 2 and 3. Reference to Figure 2 shows that there is a discernable increase on percent fuel burned with increasing residence time. The graph shows that reasonable carbon burnout with Gusare coal can be achieved with residence times of 1.5 seconds or greater at 2700°F. Varying temperatures, see Figure 3, showed no significant effect in the ranges studied.

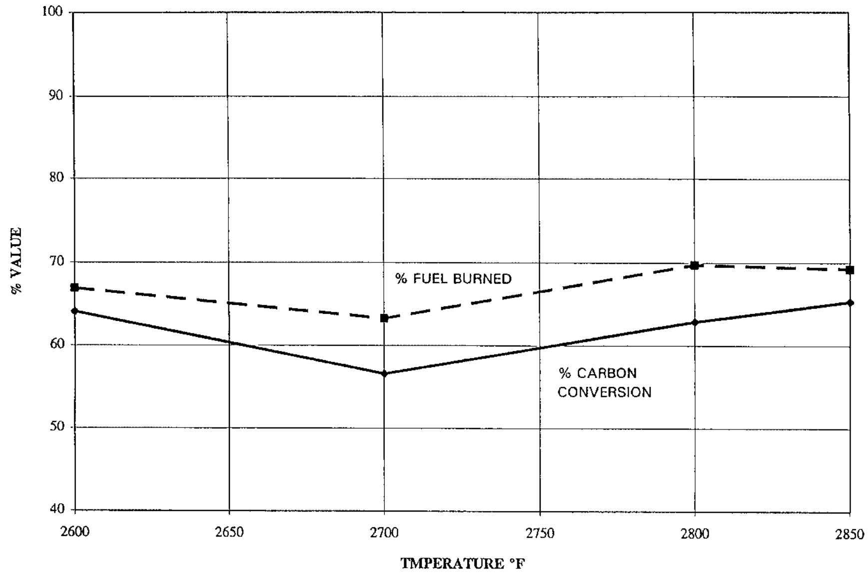

Figure 3 Drop-Tube Furnace Test Results Gusare Coal at Different Temperatures

A final set of tests were conducted to quantify differences, if any, between different size fractions of Gusare coal. Pulverized coal samples (shown in Figure 4) were obtained from the station and sieved to provide five different samples. The samples were subjected to thermogravimetric analysis in the as-sieved condition, i.e. no further grinding was performed. Figure 5 illustrates a typical TGA curve with the results summarized in the table.

	As Pulv	*50 Mesh*	*50-100 Mesh*	*200-100 Mesh*	*<200 Mesh*
Max. Combustion Rate, Wt%/Min	9.0	11.0	10.0	10.5	10.5
Initiation Temperature, °F	747.6	670.8	761.7	761.5	680.9
Temp of Max Combustion Rate, °F	1,076.0	914.0	1032.8	977.0	842.0
Temp for 50% Burnout of FC, °F	968.0	860.0	932.0	896.0	1040.0
Time for 50% Burnout of FC, Min.	26.0	23.0	25.0	24.0	28.0
ASH	6.0	6.6	9.8	13.1	25.3

Figure 4 Summary Chart

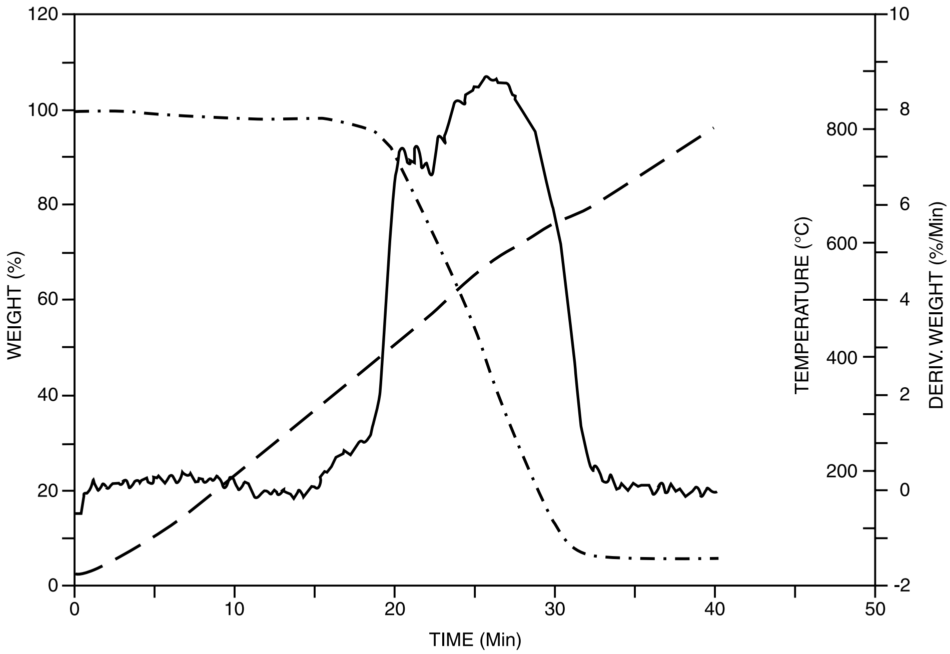

Figure 5 TGA Curve

A number of features were noted from the study of the various curves. As deduced from earlier techniques, differing size fractions had increasing ash concentrations with decreasing particle size. Furthermore, the smaller size fraction (<200 mesh) took much longer to burn the 50% of the fixed carbon than the other samples (28 minutes compared to 23 minutes for the +50 mesh sample) in spite of similar initiation temperatures.

Overall, the results of these TGA tests on the different sieve fractions of Gusare coal showed different sizes burn at different rates with different initiation temperatures (Figure 6). It appears from this data that the 50-100 mesh size fraction is the most difficult to burn based on the temperature for maximum combustion rate, initiation temperature, and maximum combustion rate. The contribution of surface area of the particles to this data requires further investigation.

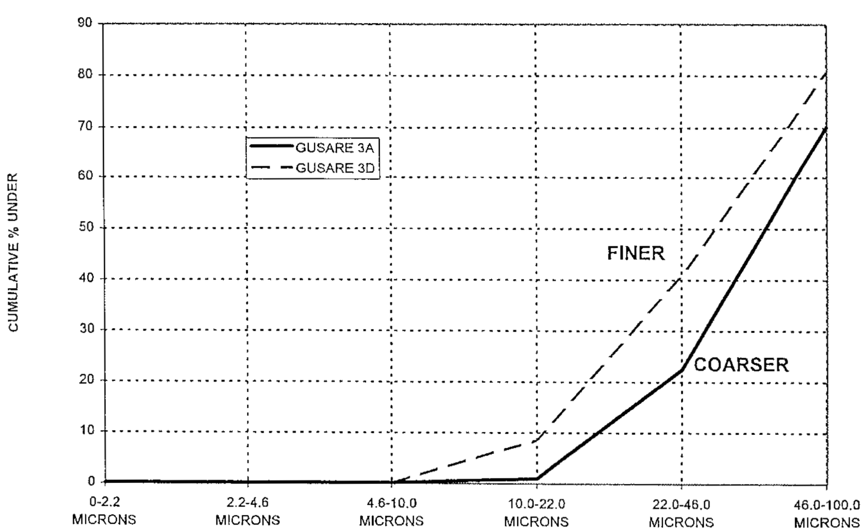

Figure 6 Coal Particle Size Distribution, Salem Harbor #3

From this independent work, it is clear that standard proximate and ultimate analysis is not sufficient for evaluating foreign coals. The following are typical analysis of the coals used at Salem, each with significant differences in UBC.

Proximate	*Coal G*	*Coal C*	*Coal M*
Ash	6.02	3.1	9.0
Vol	34.59	35.09	30.23
Fixed C	52.24	51.68	53.78
Moisture	7.15	10.13	7.00
HGI	48	43	52
Soft Temp	2640	2700	2700
HHV (Btu)	12965	12761	12750

SNCR SYSTEM DESCRIPTION

The SNCR systems were supplied by NALCO/Fuel Tech and installed by NEP. The test contractor, Fossil Energy Research Corp. was responsible for collecting data, operating the test equipment, analyzing the data with NEP and documenting the test programs.

The SNCR process is conceptually simple. An aqueous solution of urea is injected into, and mixed, with the flue gas at the correct temperature. Once the mixing is complete, the reagent reacts selectively to remove NO_X, converting it mainly to nitrogen and carbon dioxide. In practical applications, however, the SNCR process can be complicated. Non-uniformities in velocity, temperature and NO_X and CO concentrations at the injection points pose difficult questions because of the inherent sensitivity of SNCR processes to these parameters. The physical location of the effective process temperature range within the boiler changes, depending on operating factors such as load, fuel type, mills in service and loading, and length of time operating at a given load.

The urea injection systems installed at Salem Harbor, each include a circulation pump skid, metering pump skid, and injector level distribution panels to modulate the solution flow to individual injectors as required. Each boiler is equipped with four injection levels. The location of the levels were determined by computer modeling. However, the modeling was conducted prior to the installation of the LNB and the actual injection scheme differed from the original to accommodate the changes in flue gas temperatures and composition at the injection points. The original injection points were maintained.

Initial SNCR tests on Units 1 and 3, prior to the LNB, were not successful in controlling NO_X to the low levels required by local regulatory agencies. The decision was made to install

LNB on Unit 1 and LNB and OFA on Unit 3. Prior to each of the LNB installations, the SNCR systems were optimized to operate throughout the load range at a configuration to reduce NO_X while limiting the level of ammonia slip to below 20 ppm.

A detailed parametric test plan was conducted on units 1 and 3 following the installation of the LNB and OFA (Unit 3 only) with the SNCR systems off line. The test program was designed to determine the optimum operating configuration of the combustion system(s) that allowed continuous operation of the unit throughout the load range and maintain the highest degree of efficiency as possible. Once the LNB/OFA optimization programs were completed, a similar detailed parametric test program was conducted to optimize the SNCR systems along with the new combustion characteristics of the boilers resulting from the new burners. The SNCR parametric testing included evaluation of the following parameters:

1. Injection locations
2. Reagent flow rate
3. Dilution water flow rate
4. Load
5. Oxygen levels
6. Mills in service and loading
7. Ammonia slip

A series of detailed tests were conducted at the conclusion of the SNCR testing to determine the dynamic effects of operating the LNB (OFA) and SNCR system as an integral NO_X control strategy.

The results of the testing allow units 1 and 3 to continuously operate throughout their load range while achieving a continuous NO_X limit of 0.33 lbs/MMBtu as agreed upon between NEP and DEP. This is achieved while balancing the ability to safely operate the boilers with urea consumption, CO, LOI, ammonia slip and efficiency. A normalized stoichiometric ratio (NSR) range of 0.8 to 1.5 is sufficient to maintain NO_X compliance. NSR is defined as the ratio of moles of nitrogen injected from the urea to the moles of inlet NO_X to the SNCR system. This is used to compare the effect of urea flow on a non-dimensional basis. This allows comparison at different loads, varying inlet NO_X levels and all other variables associated with a boiler. Ammonia slip levels on Unit 1 ranged from 3 ppm to 9 ppm over the range of NSR's evaluated. Ammonia slip levels on Unit 3 are 5 ppm or less at full load and increase as load decreases to a high of 31 ppm.

Subsequent adjustments to the LNB which increased the barrel diameter and reduced the spreader angle required slight SNCR configuration changes. The overfire air system programming was changed to reduce the flow at all loads. For each load, the overfire air dampers, split between 1/3 and 2/3 dampers were reduced by 1/3 compared to operating with the high angle spreaders. The reduction in OFA led to approximately a 50° to 75°F increase in the furnace exit gas temperatures. This increase in gas temperature did not lead to an increase in NO_X levels, NO_X actually decreased by 5-10% as a result of greater staging of the combustion at the burner tip.

The slight reduction in NO_X generated from the LNB adjustments led to a reduction in the required urea flow for each of the loads. The reduction in urea flow and the increased flue gas temperatures are believed to have lead to lower ammonia slip levels, especially at intermediate and low loads. The ammonia levels have not yet been documented.

	Unit 1 (88 MW)			Unit 2 (86 MW)		
	NO_X	LOI	Urea Consumption	NO_X	LOI	Urea Consumption
Pre LNB SNCR*	.45	16	100%	.33	16	100%
LNB Only	.45	25-30	0%	–	–	–
SNCR and LNB	.33	25-30	55%	.33	25-28	33%

* For comparison SNCR alone, Unit 2 flow was 176% of Unit 1

Ammonia slip was reduced by the addition of LNB's.
Unit 1 - dropped 75%
Unit 2 - dropped 60%

Performance Summary – Gusare

CONCLUSIONS

The following were some of the significant lessons learned from these startups:

1. When evaluating foreign coals, in any application, standard proximate and ultimate analysis are not adequate. Drop tube tests provide more relevant data for evaluating performance in a given furnace.

COAL CHARACTERIZATION STUDIES

1. **Maceral Distribution Analysis**
   - Inertinite on SA coals approximately 10-12%
   - Inertinite on domestic coal approximately 6%
2. **Scanning Electron Microscopy**
   - SA coal has less inherent mineral matter
   - Minerals act to “break up” particles
   - Mineral matter smaller than coal particles
3. **Drop Tube Furnace Studies**
   - Increase residence time - Increase amount of fuel burned
   - Varying temperatures - No significant impact on amount of fuel burned
4. **Thermogravimetric Analysis of Size Fractions**
   - 50-100 mesh most difficult to burn
   - Ash/mineral content of fuel increases with decrease in size (see 2 above)

2. Tuning of the systems took longer than anticipated partly due to the fact that this is the first aspect of the project not completely in the control of the project team. Issues such as balance of plant equipment problems, unit dispatch, fuel problems, etc. contribute to extending the tuning period.

3. The presence of a portable LOI analyzer on site significantly reduced the turn around time for flyash analysis. Although the method may not be laboratory accurate, the relative measures of changes in flyash composition gave valuable, immediate feedback to the testing efforts.

4. The initial optimization efforts should consist mainly of experienced personnel optimizing each burner through visual examination. Using portable NO_X instruments at the initiation of testing bogs down the gross adjustments necessary to get to reasonable burner settings.

5. At this specific installation, low NO_X burners with SNCR provided lower NO_X values than could be obtained with either technology alone. However, NO_X levels with either technology alone was slightly different between units 1 and 2 which are “duplicate” units.

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