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THE BABCOCK & WILCOX COMPANY

FULL-SCALE DEMONSTRATION OF LOW-NO_X CELL BURNER® RETROFIT

PROJECT PERFORMANCE SUMMARY
CLEAN COAL TECHNOLOGY DEMONSTRATION PROGRAM

JUNE 1999

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ENVIRONMENTAL CONTROL DEVICES

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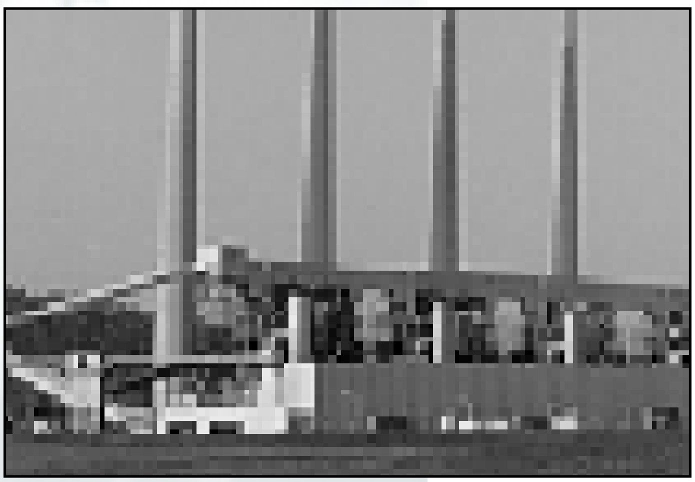
OVERVIEW

B&W's LNCB® offers a cost-effective solution to the NO_x control problem previously posed by the highly efficient, but high NO_x emitting, cell burner boilers.

The Babcock and Wilcox Company (B&W), in close cooperation with a utility user group, successfully completed demonstration of a low-cost, plug-in technology capable of reducing NO_x emissions from cell burner boilers by more than 50 percent. B&Wdemonstrated its low-NO_X cell burner (LNCB®) system at Dayton Power and Light company's 605-MWe J.M. Stuart Plant, Unit No. 4, in Aberdeen, Ohio.

The project is part of the U.S. Department of Energy's Clean Coal Technology Demonstration Program (CCTDP) established to address energy and environmental concerns related to coal use. Cost-shared partnerships with industry were sought through five nationally competed solicitations to accelerate commercialization of the most advanced coal-based power generation and pollution control technologies. The CCTDP, valued at nearly $6 billion, has leveraged federal funding twofold through the resultant partnerships encompassing utilities, technology developers, state governments, and research organizations. This project was one of 13 selected in December 1989 from 48 proposals submitted in response to the Program's third solicitation.



The LNCB® responds to concerns over particularly high NO_x emissions from the class of boilers called cell burners. Cell burner boilers comprise about 7 percent of coal-fired generating capacity existing before implementation of New Source Performance Standards (pre-NSPS). Although highly efficient, cell burner boilers produce a disproportionately high percentage (over 11 percent) of the total NO_x emissions from the pre-NSPS coal-fired boilers. The designed high heat release rate of the cell burner, which causes high NO_x emissions, precludes modification with conventional low-NO_x burner technology approaches.

Installation of the LNCB® can be accomplished without pressure part modification, providing essentially a plug-in assembly, and can reduce NO_x emissions well beyond the design objective of 50 percent. Boiler performance is not compromised. The capital cost for a 600-MWe plant, in 1994 constant dollars, is estimated at $9/kW and levelized cost at 0.284 mills/kWh, or $98.48 per ton of NO_x removed.

Dayton Power and Light has retained the LNCB® for commercial service and as of August 1997 there were seven commercial sales for 144 burners valued at $27 million.

The Project

The state of Ohio and utility industry interest in structuring the project was prompted by increasing concern over the impact of NO_x emissions not only on acid rain but on ozone nonattainment. Cell burner boilers, which represent about 7 percent of the pre-NSPS coal-fired generating capacity, emit a disproportionately high percentage (over 11 percent) of the total NO_x emissions from this pre-NSPS boiler population. Of the 26,700 MWe of cell burner capacity, about 10,000 MWe resides in Ohio. Typically, the NO_x levels associated with standard cell burner boilers range from 1.0–1.8 lb/10^6 Btu heat input.

There are 38 pre-NSPS cell burner boilers in the U.S., 33 of which are opposed wall fired with two rows of two-nozzle cell burners on each wall. The host site chosen for the project was one of these 33. The demonstration unit is a supercritical universal pressure, single reheat, Carolina-type boiler.

Because of relatively small burner throat openings, cell burner boilers are not compatible with conventional low-NO_x burner design approaches. The delayed combustion principle underlying most low-NO_x burner designs typically requires low burner air velocity and, therefore, large throat openings.

Project objectives included: (1) Achieving at least 50 percent reduction in NO_x emissions; (2) reducing NO_x with no degradation of boiler performance or life; and (3) demonstrating the technical and economic feasibility of the technology.

The demonstration program was comprised of: (1) baseline testing of the boiler to characterize performance in an unmodified state (October–November 1990); (2) parametric testing to determine optimum LNCB® settings (May 1992); (3) optimization testing at the optimum burner settings under boiler load and excess air conditions identical to those used in baseline testing (June 1992); (4) long term, load following testing (August 1992–April 1993); and (5) corrosion testing of boiler walls/tubes following long term testing. The state of Ohio, EPRI, and eight utilities established the LNCB® Advisory Committee to guide project implementation.

Project sponsor
The Babcock & Wilcox Company

Additional Team Members
Dayton Power & Light Company—cofunder and host
Electric Power Research Institute (EPRI)—cofunder
Ohio Coal Development Office—cofunder
Tennessee Valley Authority—cofunder
New England Power Company—cofunder
Duke Power Company—cofunder
Allegheny Power company—cofunder
Centerior Energy Corporation—cofunder
Cincinnati Gas & Electric Company—cofunder
Columbus and Southern Power company—cofunder

Location
Aberdeen, Adams County, OH (Dayton Power & Light Company's J.M. Stuart Plant, Unit No. 4)

Technology
The Babcock & Wilcox Company's low-NO_x cell burner (LNCB®) system

Plant Capacity
605-MWe

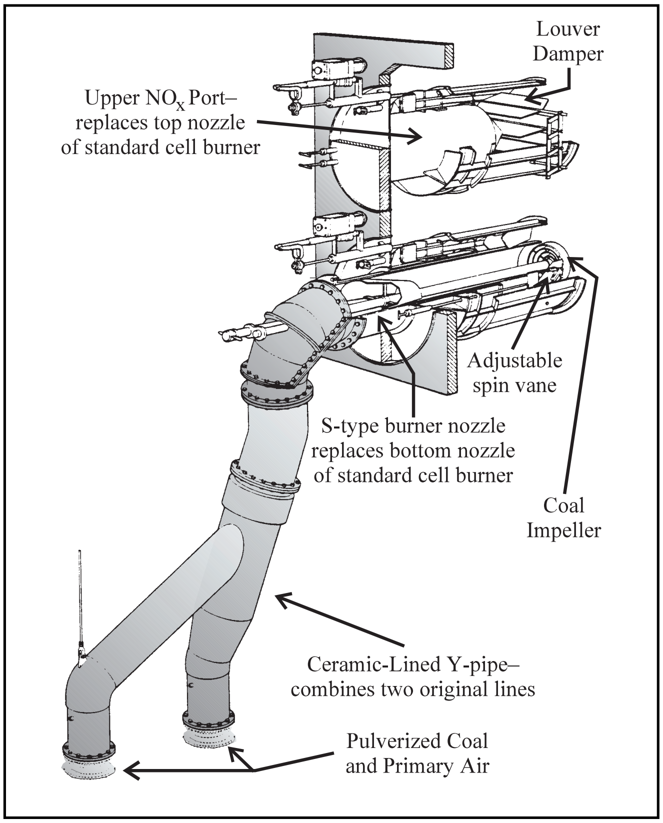
Coal
Bituminous, 1.3% nitrogen (medium volatile) and 1.2% sulfur

Demonstration Duration
May 1992–April 1993

Project funding

Total Project Cost	$11,233,392	100%
DOE	5,442,800	48
Participant	5,790,592	52

The Technology



The LNCB® technology replaces the upper coal nozzle of the standard two-nozzle cell burner with a secondary air port. The lower burner coal nozzle is replaced with an S-type burner designed to accept the same fuel capacity as the original two burners. A y-pipe assembly directs all fuel to the S-type burner. Combustion is staged by providing only about 58 percent of the air theoretically required for complete combustion through the S-type burner and the balance of the air through the secondary air port (NO_x port).

More than 75 percent of NO_x comes from oxidation of fuel bound nitrogen as it is volitalized in the coal combustion process. To mitigate this, the S-type burner severely restricts the amount of air available. Oxidation of nitrogen remaining in the char is less of a concern because there is a lesser amount, and oxygen availability is less. Char burnout occurs upon mixing with the air from the NO_x port. Reduced flame temperature from staging of the combustion mitigates thermal NO_x formation (which accounts for the remaining 25 percent or less of NO_x formation in coal combustion).

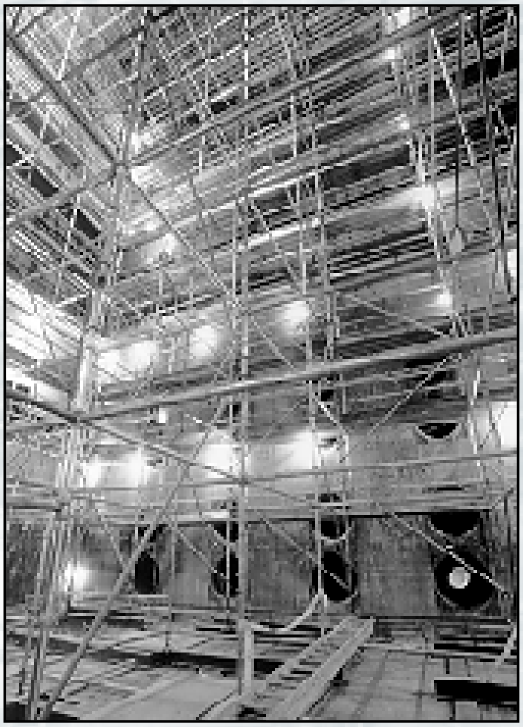
Stoichiometry in the S-type burner, critical to NO_x control, is controlled by positioning of adjustable spin vanes and sliding disk dampers in both the S-type burner and NO_x port. A pitot tube grid ensures uniform distribution of secondary air to all the burners. Each burner has a pitot tube located in the barrel before the spin vanes.

The flame shape, important to NO_x reduction because of the need to stretch out combustion (increase flame length), is controlled by a number of LNCB® components. Primary control of flame shape is afforded by adjustable spin vanes within the burner barrel, an impeller near the burner exit, and the NO_x port louver dampers. The impeller (adjustable to some extent along the barrel) disperses the coal/air mixture into the boiler in a manner determined by the angle of the vanes (steeper angles produce shorter flame lengths but better mixing). The adjustable spin vanes establish the secondary air swirl for flame shaping. NO_x port louver dampers affect flame shape by the angle of impingement on the burner flame.

The S-type burner and NO_x port fit within the existing throat openings in the boiler wall, averting expensive modifications to the windbox and water wall.

Demonstration Results

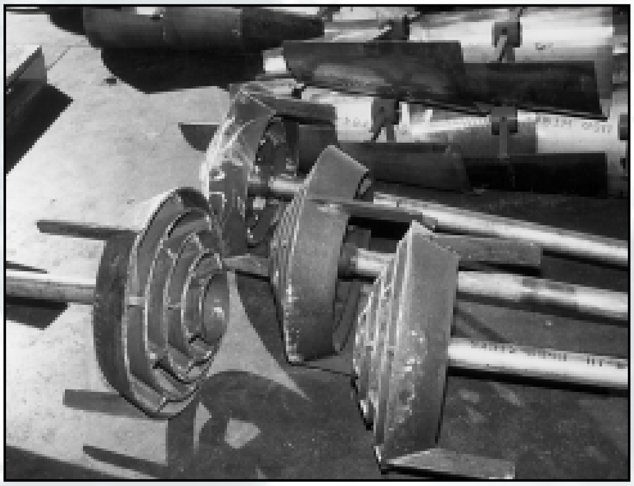
- Short-term optimization testing (all mills in service) showed NO_x reductions in the range of 53.0–55.5 percent, 52.5–54.7 percent, and 46.9–47.9 percent at loads of 604-MWe, 460-MWe, and 350-MWe respectively.
- Long-term testing at full load with all mills in service showed an average NO_x reduction of 58 percent (over 8-months).
- Long-term testing at full load with one mill out of service showed an average NO_x reduction of 60 percent (over 8-months).
- CO emissions averaged 55 ppm at full load with all mills in service compared to 26 ppm for the same conditions during baseline testing (based on the more conservative of two sets of tests conducted).
- Flyash increased, ash deposition on boiler components decreased relative to baseline operation, and ESP performance remained virtually unchanged.
- Unit efficiency remained essentially unchanged.
- Unburned carbon loss (UBCL) increased by approximately 28 percent for all tests, but boiler efficency loss was offset by a decrease in dry gas energy loss due to lower boiler economizer outlet gas temperature.
- Boiler tube corrosion with LNCB® was roughly equivalent to boiler tube corrosion rates prior to retrofit.
- Capital cost to reduce baseline NO_x emissions of 1.2 lb/10^6 Btu by 50 percent for a 600-MWe plant, in 1994 constant dollars, is estimated at $9/kW. Levelized costs for the same conditions are estimated at 0.284 mills/kWh and $96.48/ton of NO_x removed.



Scaffolding and cell burner penetration into boiler wall from the inside of the boiler.

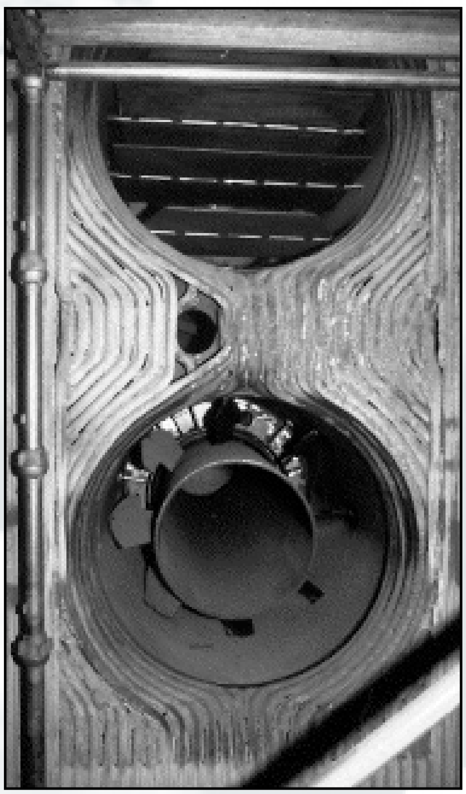
Operational Performance

Retrofit of the boiler with the LNCB® was completed during a 6-week outage. This included incorporation of 48 new sliding damper drives (with 3 pre-set positions–out-of-service/light-off/normal operation). In order to minimize installation costs and achieve a high degree of reliability, a programmable logic was used to interface an old push button system with the new drive position switches, reducing control selection possibilities from 13 to 4.



Shown here are the modified, shallow-angle coal impellers that disperse coal at the burner exit.

Preliminary post-retrofit testing identified two problems that warranted design changes. Inability to achieve more than 35 percent NO_x reduction was attributed to too steep a burner impeller angle. As a result, all 24 impellers were replaced with those having a shallower angle. The angle chosen was steep enough to maintain good coal/air dispersion and avoid flame impingement on the opposing boiler wall (which could lead to slagging and corrosion).



This shows the boiler side of the LNCB® without the coal impeller, exposing the adjustable spin vanes

The other problem was the presence of high levels of carbon monoxide (CO) and hydrogen sulfide (H_2S) in the furnace hopper. This posed both a safety hazard and a threat of accelerated corrosion to the hopper wall tubes. Leaks of these toxic gases were possible because the boiler was a pressurized unit. The acidic nature of the gases represented corrosion potential for the SA-213T2 (T2) alloy steel boiler tube material. To determine an optimum solution, B&W used their numerical flow (FORCE) and combustion and heat transfer (FURMO) models. The corrective measure taken was to invert alternating LNCB® burners in the lower row of 12 burners (leaving the upper row of 12 burners alone).

Both the burner impeller change and LNCB® repositioning proved to be effective as the test program unfolded. LNCB® repositioning and burner optimization generally reduced H_2S in the lower furnace to lower detection limits.

Operational performance met or exceeded all objectives. As to boiler performance, efficiency changed little from baseline testing, actually increasing somewhat as shown in *Table 1*. This was despite unburned carbon and CO emission increases which represented efficiency losses. These losses were offset by the decrease in dry gas energy loss due to lower economizer gas outlet temperature and ensuing lower air heater outlet temperature. Also, performing pulverizer maintenance before LNCB® testing may have mitigated unburned carbon loss (UBCL) somewhat by increasing coal fineness.

Table 1. Boiler Efficiency-All Mills in Service (%)

Load	Baseline	LNCB®
Full	89.43	89.59
Intermediate	89.73	90.12
Low	90.18	90.38

UBCL generally increased by approximately 28 percent for all of the tests. The largest measured increase in UBCL of 52 percent resulted in a boiler efficiency loss of 0.69 percent.

Furnace exit gas temperature (FEGT), analytically determined, was as much as 100 ^{o}F lower during the initial stages of optimization testing, but eventually increased and stabilized to within 10 ^{o}F of baseline FEGT. This was attributed to ash buidup on the boiler walls or changes in thermal emissivity. Very few changes in cleanliness factors, a measure of heat transfer performance of each unit component, from baseline to optimized test conditions were found for the primary superheater, reheater, and economizer.

With LNCB®, the amount of flyash increased, while bottom ash decreased. Flyash from LNCB® operation appeared finer than the baseline flyash. Even though the dust loading entering the electrostatic precipitator (ESP) increased, resistivity remained unchanged as did ESP performance. Maintaining resistivity was attributed to the SO_3 injection system already in place on the J.M. Stuart No. 4 boiler. LNCB® was found to greatly reduce a baseline condition of agglomerated "popcorn" ash buildup and associated tube erosion in the convection pass of the boiler (particularly the economizer).

Corrosion panel testing showed that boiler tube wall metal wastage rates were not significantly higher with LNCB® than with standard cell burner operation. Both were determined to be somewhat high. Testing involved installation of a 12-foot high by 14-foot wide corrosion panel covering half of one side-wall in the lower burner zone. Four coatings, listed below, were evaluated along with bare T2 tube material. Wastage rates were determined from destructive examination of panel samples as well as predictive equations developed from extensive laboratory analysis. Physical analysis showed a corrosion rate of 17 mils per year; and predictive models calculated a corrosion rate of 15 mils per year. Predictive equations were based on metal temperature, H_2S concentration, and chromium concentration of the alloys. H_2S concentration and tube temperature data were obtained during the long-term testing. Ultrasonic test (UT) surveys showed significant scatter and were inconclusive. All the test panel coatings exhibited excellent resistance to corrosion.

- Aluminized spray coating on T2 tube material
- 309L stainless weld overlay on T2 tube material
- 308L stainless weld overlay on T2 tube material
- Chromizing on T2 tube material

Environmental Performance

Parametric Testing

The first step in the test program established the optimum burner settings to minimize NO_x emissions while maintaining acceptable boiler performance. *Table 2* outlines the test parameters examined and optimum burner settings adopted for subsequent optimization and long-term testing.

Table 2. Burner Parameters and Optimized settings

Parameter	Setting
Burner spin vanes	60^{o} from fully closed
Burner throat stoichiometry	0.58 stoichiometric air flow
NO_x port louver	20^{o} divergent from flame
Coal impellers	Standard position (not retracted)
Primary air flow	Normal level

NO_x port louver settings were -20^{o} for the lower inverted burners to direct air into the furnace hopper and mitigate buildup of CO and H_2S.

Optimization Testing

Optimization testing was performed with the above burner settings and at the same conditions existent during the baseline tests. Measurements were taken both by B&W and an independent test group, Acurex Environmental. The following summarizes the findings:

- At full load (604-MWe) with all mills in service, average NO_x emission rates were 0.517 lb/ 10^6 Btu (B&W) and 0.551lb/10^6 Btu (Acurex), corresponding to removal efficiencies of 55.5 percent and 53.0 percent respectively. (Baseline emission rates measured by B&W and Acurex were 1.150 lb/ 10^6 Btu and 1.217 lb/ 10^6 But respectively.)

- At full load (604-MWe) with one mill out of service, average NO_x emission rates were 0.496 lb/10^6 Btu (B&W) and 0.505 lb/10^6 Btu (Acurex), corresponding to removal efficiencies of 53.3 percent and 54.5 percent respectively. (Baseleine emission rates measured by B&W and Acurex were 1.053 lb/10^6 Btu and 1.186 lb/10^6 Btu respectively.)
- At intermediate load (460-MWe) with one mill out of service, average NO_x emission rates were 0.418 lb/10^6 Btu (B&W and Acurex), corresponding to removal efficiencies of 54.7 percent (B&W) and 52.5 percent (Acurex). (Baseline emission rates measured by B&W and Acurex were 0.921 lb/10^6 Btu and 0.964 lb/10^6 Btu respectively.)
- At low load (350-MWe) with two mills out of service, average NO_x emission rates were 0.372 lb/10^6 Btu (B&W) and 0.370 lb/10^6 Btu (Acurex), corresponding to removal efficiencies of 46.9 percent and 47.9 percent respectively. (Baseline emission rates measured by B&W and Acurex were 0.703 lb/10^6 Btu and 0.922 lb/10^6 Btu respectively.)
- At full load (604-MWe) with all mills in service, average CO emissions, corrected to 3 percent O_2, were 55 ppm versus 26 ppm for baseline conditions. (Only B&W data is presented here for CO emissions because there was a major discrepancy between B&W and Acurex data and B&W data was the more consistent and conservative.)
- At full load (604-MWe) with one mill out of service, average CO emissions, corrected to 3 percent O_2, were 38 ppm versus 30 ppm for baseline conditions.
- At low load (350-MWe) with two mills out of service, average CO emissions, corrected to 3 percent O_2, were 27 ppm versus 20 ppm for baseline conditions.
- The mass mean diameter of LNCB® flyash, which ranged from 13.5–25 microns, was 67 percent lower than the baseline flyash mass mean diameter. LNCB® flyash mass mean diameter remained unchanged by boiler load and mills out of service, unlike the baseline test experience.
- As shown in *Table 3*, electrostatic precipitator performance remained essentially unchanged with LNCB®. This was attributed to little change in flyash resistivity.

Long-Term Testing

The average NO_x emission rate achieved for the eight month, long-term test period was 0.49 lb/10^6 Btu at an average load of 604-MWe and 3.2 percent excess O_2 level. This corresponded to a 58 percent removal efficiency. For the same load conditions, but various single mills out of service and an average 3.7 percent excess O_2 level, the average NO_x emission rate was 0.47 lb/10^6 Btu, or a 60 percent removal efficiency.

Superior NO_x reduction resulted when mills fueling the upper burners were out of service. This was attributed to deeper staging of lower burners, which are fired harder with one mill out of service, and higher secondary air availability with a burner out of service.

Economic Performance

An economic assessment was made for a commercial LNCB® installation on a 600-MWe boiler. This size was deemed representative because 23 of the 38 total cell burners fall in the range of 480–800-MWe. A location in the midwest United States (where most of the units are located) was assumed with the unit burning a medium sulfur, medium volatile bituminous coal. Key boiler and fuel attributes in the evaluation include:

- Nominal net boiler output — 600-MWe
- Boiler baseline efficiency — 89.5 percent
- Coal flow — 248 ton/hr
- Coal higher heating value — 11,900 Btu/lb
- Coal ash — 13 percent
- Unit capacity factor — 65 percent
- Fuel cost delivered — $39/ton

Table 3: Precipitator Performance

Test #	Test Description	Optimized Testing			Baseline
		Dustloading @ Econo. Outlet EPA Method 17	Dustloading @ Stack EPA Method 5	Collection Efficiency	Collection Efficiency
1	Full Load - All Mills In Service	57,000 lbs/hr	325 lbs/hr	99.43%	99.50%
8	Full Load - "A" Mill Out-of-Service	42,000 lbs/hr	367 lbs/hr	99.12%	99.49%
5	Intermediate Load - "A" Mill Out-of-Service	34,000 lbs/hr	222 lbs/hr*	99.35%	99.81%

* Corresponding baseline value unusually low (69lbs/hr)

- Initial NO_x emission rate — 1.2 lb/10^6 Btu
- NO_x reduction — 50 percent
- Forced draft fan motor efficiency — 60 percent
- Unburned carbon in ash (baseline) — 1 percent

Capital Costs

The capital costs estimated for a 20 burner installation were broken down into three major areas as shown in *Table 4*. The unit costs were determined by preparing a complete site material cost estimate and then dividing by the number of cell burners. They are not true unit costs. Therefore, simply multiplying the number of burners needed in a retrofit by these numbers will not necessarily provide accurate estimates. Numerical modeling and start-up service engineering support costs were included. All costs are in 1994 constant dollars unless otherwise indicated.

The estimated control upgrade costs assumed that original equipment was still in use. Systems upgraded to control air flow to individual burners need only minimal control revisions. Corrosion protection was deemed prudent and included. Medium to high sulfur coals and temperatures associated with supercritical boilers pose a threat of corrosion. Sulfidation is the primary corrosion mechanism in substoichiometric combustion of sulfur-containing coal. But, the many supercritical cell burners already having corrosion protection require no further protection.

No provision was included for upgrading the forced draft fan. The assumption was made that systems have sufficient excess capacity to accomodate the 0.5–2.5 inch water gage pressure increase associated with the LNCB®.

Table 5 shows total estimated capital costs. Costs include general facilities presented in *Table 4*. A project contingency of only 5 percent reflects the fact that multiple commercial units have been constructed and costs well established. Allowance for funds during construction was negligible because the period of time from

Table 5: Total Capital Requirement

Area No.	Total Installed Equipment Cost*	$\$10^6$	\$/kW
(A)	**Total process Capital (sum of process areas)**	4.678	7.80
(B)	General Facilities (0% of A)	0	0
(C)	Engineering and home office fees (10% of A)	0.468	0.78
(D)	Project contingency (5% of A+B+C)	0.234	0.39
(E)	**Total Plant Cost (A+B+C)**	5.380	8.97
(F)	Allowance for funds during construction (0% of E)	0	0
(G)	**Total Plant Investment (E&F)**	5.380	8.97
(H)	Royalty allowance (0.4% of A)	0.018	0.03
(I)	Preproduction costs (months of startup)	0	0
(J)	Inventory capital	0	0
(K)	Initial catalyst and chemicals	0	0
(L)	Subtotal Capital (G+H+I+J+K)	5.398	9.00
(M)	Cost of construction downtime	0	0
(N)	**Total Capital Requirement (L&M)**	5.398	9.00

* From Table 4. Includes retrofit costs and process contingencies

Table 4: Major Equipment Costs

Item No.	Item name	Cost/Unit							No. of Units	Total Cost
		F.O.B. Equipment	Sales Tax	Freight	Field Material	Field Labor	Indirect Field	Total		
1	LNCB® Burners	103,370	Incl.	750	**	105,000	**	209,120	20	4,182,400
2	Controls	150,000	Incl.	Incl.	**	150,000	**	300,000	1	300,000
3	Furnace Prot.	0	0	0	**	196,000	**	196,000	1	196,000

** Field material separate from FOB equipment is small. Indirect Field Labor and small Field material costs are included in Field Labor.

Table 6: Levelized Costs

Power Plant Attributes		Units		Value	
Plant capacity, net		MWe		600	
Power produced, net		10^9 kWh/yr		3.416	
Capacity factor		%		65	
Plant life		yr		15	
Coal feed		10^6 tons/yr		248	
Sulfur in coal		wt %		N/A	
Emissions Control	**Units**	**SO_2**	**NO_x**	**TSP**	**PM_{10}**
Removal efficiency	%	—	50%	—	—
Emissions standard	lb/10^6 Btu	—	—	—	—
Emissions w/ocontrols	lb/10^6 Btu	—	1.20	—	—
Emissions with controls	lb/10^6 Btu	—	0.60	—	—
Amount removed	tons/yr	—	10,047	—	—
		Current Dollars		**Constant Dollars**	
Levelized Cost of Power		**Factor**	**Mills/kWh**	**Factor**	**Mills/kWh**
Capital Charge		0.160	0.253	0.124	0.196
Fixed O&M Cost		1.314	0.017	1.000	0.013
Variable Operating Cost		1.314	0.098	1.000	0.075
Total Cost		—	*0.368*	—	*0.284*
Levelized Cost		**Factor**	**$/ton removed**	**Factor**	**$/ton removed**
Capital Charge		0.160	85.96	0.124	66.62
Fixed O&M Cost		1.314	5.89	1.000	4.48
Variable Operating Cost		1.314	33.35	1.000	25.38
Total cost		—	*125.20*	—	*96.48*

Table 7: Alternate Cost Estimate

	Base Case	Alternate Case
Capital ($/kW)	9.00	8.05
Capital (Mills/kWh)	0.196	0.175
O&M (mills/kWh)	0.088	0.016
Total (mills/kWh)	0.284	0.191
$/ton NO_X removed	96.48	64.89

first payment to commercial operation is short (less than 12-months in most cases). Preproduction start-up costs were zero because it is done during scheduled outages and engineering costs are embedded in the *Table 4* costs. Cost of construction downtime was zero for the same reason.

Operating and Maintenance Costs

The incremental operating and maintenace (O&M) costs for the LNCB® were estimated at $300,000 per year. There are no incremental operators required. No additional maintenace is associated with the burners. But provision was made for recoating the tube walls every five years (chromized coating) —20 percent of the installed cost of $196,000, or about $40,000. Also, a general budget provided for $5,000 per year for miscellaneous maintenance. The only incremental variable operating costs were for additional fan power and additional fuel costs for unburned carbon loss. For increased fan power demand, 2.3 inches of water gage pressure loss was assumed and translated to an incremental power cost of $153,000. Additional coal requirements of 2,611 tons per year as make-up for unburned carbon loss were estimated (a highly conservative estimate), which translated to $102,000.

Table 6 shows the levelized costs estimated for the commercial unit.

Based on a review of the cell burner population, an alternate cost scenario for the same commercial unit was developed, which included the following assumptions:

- Furnace corrosion protection already used prior to retrofit (net $0/kW)
- Combustion system and controls already upgraded (net $0/kW)
- UBCL minor and compensated for by lower O_2 operation, less slagging and lower air heater outlet temperature.

Table 7 shows the results on a constant 1994 dollar basis.

Commercial Applications

The market for LNCB® technology is 33, two-nozzle type cell burner boilers in the U.S. (5 cell burners are three-nozzle types) with a total generating capacity of 25,200 MWe. The LNCB® system insalled at the Dayton Power & Light Company's J.M. Stuart Plant unit No. 4 has been retained for commercial service. In addition, seven commercial contracts had been awarded as of August 1997 for 144 LNCB® units valued at $27 million. Impetus for further LNCB® retrofits comes from: (1) Phase II of the Clean Air Act Amendments of 1990, requiring cell burner NO_x controls (which come into effect in 2000); and (2) an EPA ruling which severely restricts NO_x emissions in ozone nonattainment areas (affecting cell burner locations).

Commercial success to date, and likely to come, is owed largely to the establishment of the LNCB® Advisory Committee composed of most of the cell burner equipped boiler owners. The Committee participated in the demonstration, becoming familiar with the technology, supporting numerical models, providing inputs to the demonstration, and reviewing field data.

Site Specific Implications

NO_x emission results from LNCB® installation will be impacted by application specific burner zone heat release rates, furnace configuration, and coal type (e.g., volatility, fixed carbon level, bituminous versus subbituminous, nitrogen content, and oxygen content). Boilers with higher burner zone heat release rates than the J.M. Stuart Station will generally have higher baseline NO_x levels. LNCB® technology can be expected to reduce emissions by 50 percent from baseline levels, but not necessarily to the same absolute levels achieved at the J.M. Stuart Station. There is some degree of uncertainty regarding NO_x reduction levels possible with low volatility coals.

The demonstration unit had not been upgraded from its original configuration. The air registers on most of the pre-retrofit burners had been welded in an open position, and no recent work had been performed to balance air and fuel flows. Therefore, some combustion related items such as furnace exit gas temperature, surface cleanliness, and unburned carbon results were improved by the mechanical improvements and air balancing capability of the LNCB® equipment. Where mechanical improvements such as "per burner air control" and/or burner fuel/air balancing have been made on prospective units, then:

- FEGT may be slightly higher than baseline. Numerical modeling indicated that in a balanced configuration, a 10 ^{o}F increase in FEGT may result.
- Surface cleanliness will not show as dramatic an improvement because combustion efficiency will have already been improved.
- Unburned carbon losses may be slightly higher. The impact was minimized during the demonstration program because the inital J.M. Stuart Station unit fuel/air flow was not balanced.

Preliminary results from the first commercial LNCB® application (Allegheny Power System's Hatfield Ferry Unit No. 2) revealed NO_x reductions at the 50 percent level with no significant impact on unburned carbon efficiency loss. Also, an upgraded design of the NO_x port to reduce resistance to air flow proved effective in lowering pressure drop.

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