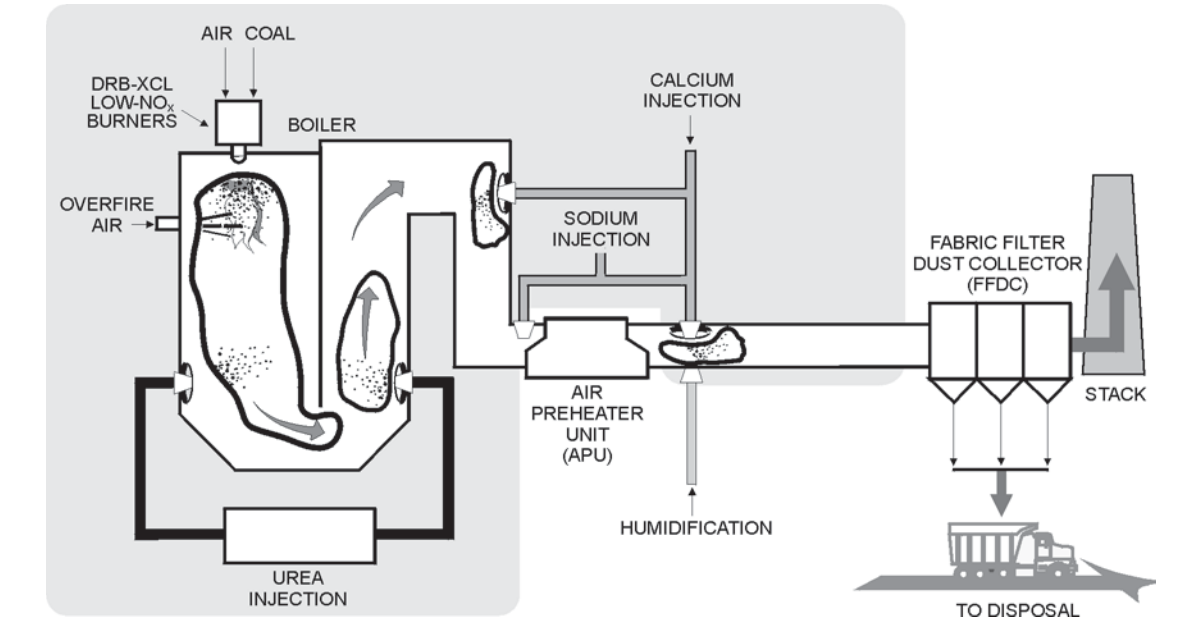
Integrated Dry NO_x/SO_2 Emissions Control System



Project completed

Participant

Public Service Company of Colorado

Additional Team Members

Electric Power Research Institute—cofunder

Stone and Webster Engineering Corp.—engineer

The Babcock & Wilcox Company—burner developer

Fossil Energy Research Corporation—operational tester

Western Research Institute—fly ash evaluator

Colorado School of Mines—bench-scale engineering researcher and tester

NOELL, Inc.—urea injection system provider

Location

Denver, Denver County, CO (Public Service Company of Colorado's Arapahoe Station, Unit No. 4)

Technology

The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners (LNB) with overfire air (OFA), in-duct dry sorbent injection (DSI) with and without flue gas humidification (FGH), and NOELL's urea-based selective non-catalytic reduction (SNCR) injection

Plant Capacity/Production

100 MWe

Coal

Colorado bituminous, 0.4% sulfur
Wyoming subbituminous (short test), 0.35% sulfur

Project Funding

Total	$26,165,306	100%
DOE	13,082,653	50
Participant	13,082,653	50

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.

Project Objective

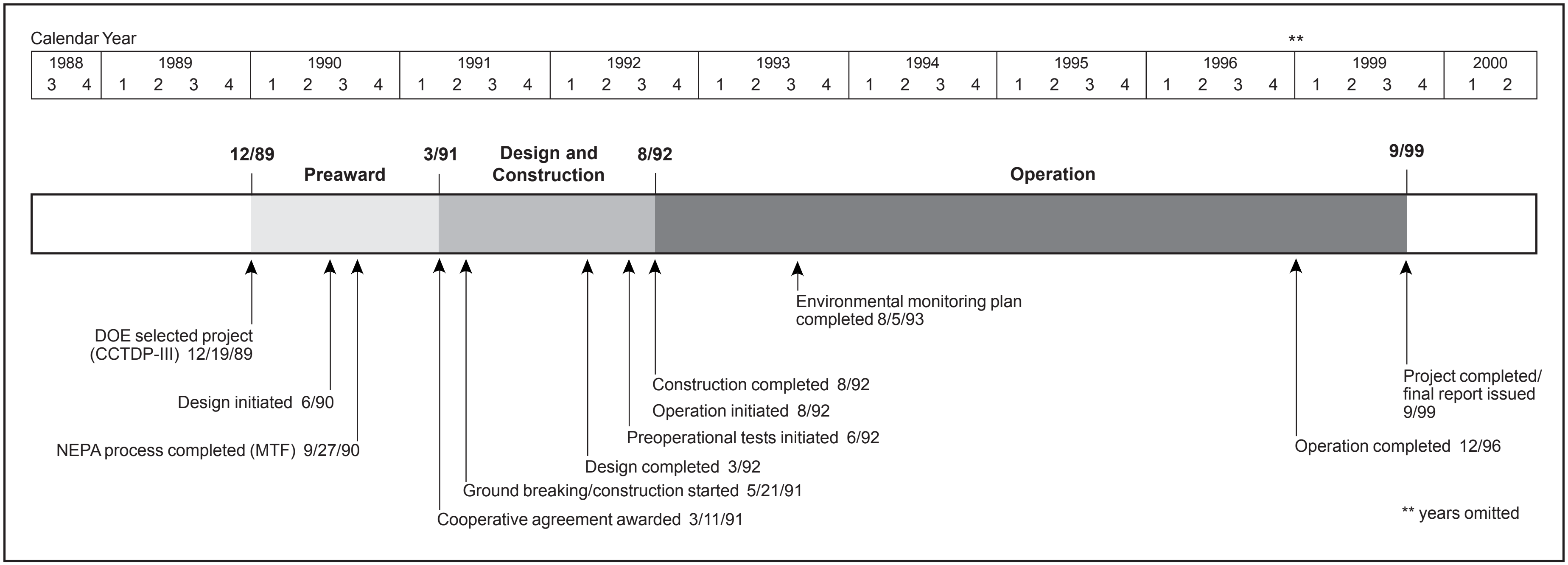
To demonstrate the integration of five technologies (LNB, OFA, DSI, FGH, and SNCR) to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired, low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with humidification for SO_2 removal.

Technology/Project Description

All of the testing used Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with overfire air (12 DRB-XCL® burners and 6 B&W Dual-Zone NO_x ports). These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air is introduced via overfire air ports to complete the combustion process and further enhance NO_x removal. A urea-based SNCR system was tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents were injected into the ductwork downstream of the boiler to reduce SO_2 emissions. Either calcium-based sorbent was injected upstream of the economizer, or sodium-based sorbent downstream of the air heater. Humidification downstream of the dry sorbent injection was incorporated to aid SO_2 capture and lower flue gas temperature and gas flow before entering the fabric filter dust collector (FFDC).

The Integrated Dry NO_x/SO_2 Emissions Control System (IDECS) was installed on Public Service Company of Colorado's Arapahoe Station Unit No. 4, a 100-MWe down-fired, pulverized-coal boiler with roof-mounted burners.



Results Summary

Environmental

- DRB-XCL® burners with minimum OFA reduced NO_x emissions by more than 61% over the load range of 80–100 MWe. With maximum OFA (32% of total secondary air at 50 MWe to 24% at 80 MWe and above), NO_x reduction was 62–69% across the load range of 50- to 110-MWe.
- DRB-XCL® burners with maximum OFA maintained CO below baseline emission levels, reaching a maximum of 50 ppm.
- The SNCR system, using both stationary and retractable injection lances in the furnace, provided NO_x removal of 30–50% at an ammonia (NH_3) slip of 10 parts per million (ppm), thus increasing performance of the total NO_x control system to greater than 80% NO_x reduction. The advanced retractable injection lances (ARIL) system increased NO_x emission reduction at low loads (below 70 MWe) from 11% to 35–52%.
- Hydrated lime injection into the boiler economizer at 950–1,150 °F reduced SO_2 emissions by 5–10%; and hydrated lime injection into the FFDC duct reduced SO_2 emissions by 28–40% at a normalized stoichiometric ratio (NSR) of 2.0 and 25–30 °F approach to saturation temperature.
- A 70% SO_2 removal was achieved by injecting sodium bicarbonate before the AP (650 °F) at an NSR of 1.0; and by injecting sodium sesquicarbonate after the APU (220–280 °F) at an NSR of 1.9.
- At 70% SO_2 removal, both sodium-based sorbents reduced NO_x emissions by approximately 10%.
- Integration of SNCR and sodium-based DSI decreased the level of unwanted nitrogen dioxide emissions by 50% and, in turn, DSI decreased the level of ammonia slip that would occur with SNCR alone.
- IDECS with the FFDC successfully removed 96.9–98.6% of trace metal emissions and 67.5–93.7% of the mercury.

Operational

- LNB/OFA maintained unburned carbon or loss-on-ignition (LOI) at essentially baseline levels.
- DRB-XCL® burners resulted in an approximately 200 °F decrease in furnace exit gas temperature, which impacted the amount of excess air required to maintain steam temperature at reduced load.
- Temperature differential between the top and bottom surfaces of the ARIL caused the lances to bend downward 12–18 inches, making insertion and removal difficult.

Economic

- Total estimated capital cost for IDECS applied to a 100-MWe boiler is $195/kW. Fixed operating costs are estimated at $0.32 million/year and variable operating costs at $1.49 million/year.
- Estimated levelized costs are $1,358/ton of NO_x plus SO_2, or 9.7 mills/kWh (current 1994$s) and $1,044/ton of NO_x plus SO_2, or 7.4 mills/kWh (constant 1994$s).

Project Summary

IDECS was composed of five technologies: LNBs, OFA, SNCR, DSI, and FGH. However, the combinations of the five separate technologies equated to three separate emission control systems for purposes of testing because the LNBs were always used in conjunction with OFA, and FGH was used only with DSI. The three systems—LNB/OFA, SNCR, and DSI with or without FGH—were individually tested using both parametric tests and long-term tests. Individual system tests were followed by testing the technologies as one integrated system.

Environmental Performance

LNB/OFA. The testing of the LNB/OFA system was performed in two phases, parametric testing and long-term testing. The results of LNB/OFA parametric testing are shown in Exhibit 3-41. Parametric testing was conducted with minimum OFA and maximum OFA. Minimum OFA represents 15% of total secondary air. Maximum OFA varies as boiler load, air flow, and fan pressure change. Maximum OFA varied from 32% of total secondary air at a load of 50 MWe to 24% at 80 MWe and above. The LNB/OFA system using minimum OFA reduced NO_x emissions from 61–64% in the 80–100 MWe load range. At maximum OFA, the LNB/OFA system reduced NO_x emissions 61–69% in the 50–100 MWe load range. Maximum OFA kept CO levels lower than the original burners, holding CO levels to a maximum of 50 ppm, as shown in Exhibit 3-42. However, the LNBs required higher than baseline excess air to maintain adequate steam temperature and to stay below 50 ppm CO at boiler loads below 100 MWe.

During long-term testing, the NO_x emissions were 10–20% (30–60 ppm) higher than the parametric tests. These increased NO_x emissions were attributed to higher oxygen (O_2) levels (1.0–1.5% higher) experienced during normal load-following conditions. The NO_x levels increased by about 40 ppm for each % increase in O_2 levels.

SNCR. The SNCR system underwent both parametric and long-term testing. Boiler load was the predominant factor in determining the flue gas temperature at SNCR injection locations and, therefore, had the greatest effect on performance. The original two-row SNCR injector design proved relatively ineffective because one row was in a region where the flue gas temperature was too low for effective operation. This situation was exacerbated by a 200 °F boiler temperature drop resulting from LNB/OFA installation. Thus, installation of the ARIL retractable lance system in the appropriate temperature region was required to bring SNCR performance to an acceptable level. With the ARIL system, NO_x reduction increased from 11% to 35–52% at loads below 70 MWe. The ability to follow the temperature window by rotating the lances proved to be an important feature in optimizing performance. As a result, the SNCR system achieved NO_x removals of 30–50% (at an ammonia slip limited to 10 ppm at the FFDC inlet) over the normal load range. The 30–50% reduction was with LNB/OFA and resulted in total NO_x emission reductions of greater than 80%.

DSI/FGH. DSI testing examined two sodium-based sorbents (sodium-sesquicarbonate and sodium-bicarbonate) and hydrated lime. Objectives of the sodium-based DSI test extended beyond SO_2 removal to evaluating the effects on NO_x removal and NO_2 emissions. Variables investigated included sorbent type, boiler load, injection location, sorbent particle size, humidification/approach-to-saturation temperature, and NSR. NSR is a molar ratio of sorbent to SO_2 that has a value of 1.0 for the theoretical removal of all SO_2. For calcium-based sorbents only 1.0 mole of calcium is needed to remove 1.0 mole of sulfur, whereas 2.0 moles of sodium are needed. Percent utilization is the ratio of percent SO_2 removal divided by NSR.

Boiler load had little, if any, effect on SO_2 removal. SO_2 removals of 70% were achieved with sodium-bicarbonate at an NSR of 1.0, while sodium-sesquicarbonate required an NSR of 1.9 for the same removal efficiency. The sodium-bicarbonate was injected before the air preheater unit (APU) at 650 °F to correct for slow response times in reaching steady-state conditions. The sodium-sesquicarbonate was injected after the APU at 220–280 °F, but had equal effect when injected before the APU.

Particle size proved to be a major factor influencing SO_2 removal efficiency for sodium-sesquicarbonate, ranging from 28% at a 28 microns mean particle diameter to 48%

Exhibit 3-41
Boiler Load Parametric Testing of LNB/OFA System

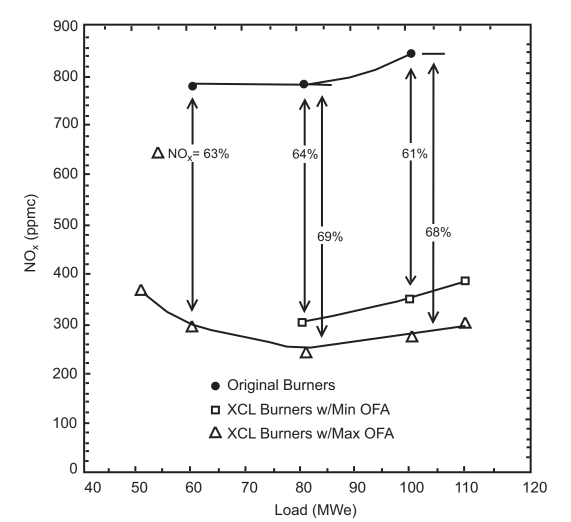
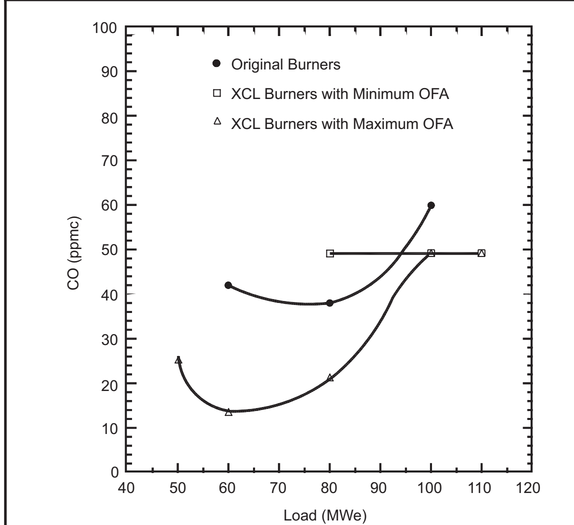


Exhibit 3-42
CO Emissions During Parametric Testing



at 15 microns (both measurements at an NSR of 0.9). The SO_2 removal efficiency with sodium-bicarbonate showed less dependence on particle size. Humidification at a 60 °F approach-to-saturation temperature increased sodium-sesquicarbonate SO_2 removal efficiency by 20% at an NSR of 2.0, but had little effect at an NSR of 1.0.

Both sodium sorbents reduced NO_x emissions by approximately 10% at injection levels comparable to 70% SO_2 removal, but oxidized NO to NO_2. However, sodium-sesquicarbonate produces only half a much NO_2 as sodium-bicarbonate at comparable SO_2 removal efficiencies.

Hydrated lime achieved only 5–10% SO_2 removal when injected into the economizer at 950–1,150 °F and an NSR of 2.0. This performance was attributed in large part to poor sorbent distribution. Humidification failed to significantly improve the performance. Hydrated lime injection downstream of the APU at a 25–30 °F approach-to-saturation temperature and NSR of 2.0 achieved only 28–40% SO_2 removal, short of the 50% target.

SNCR/DSI Synergy. Operation of the SNCR with sodium-based DSI reduced the NO_2 emissions that occur with sodium-based DSI alone by approximately 50%. Sodium-based DSI reduces ammonia slip by an estimated 50% by inducing precipitation onto the fly ash. At 8 ppm NH_3 slip, fly ash NH_3 ranged from 400–700 ppm versus 100–200 ppm with SNCR alone. Adjusting NH_3 slip to 4 ppm returned fly ash NH_3 levels to 100–200 ppm.

Air Toxics. The IDECS project included a comprehensive investigation into many potential air toxics. Tests show that the use of a FFDC was very effective for controlling nearly all air toxic emissions. Overall particulate removal was greater than 99.9%, and trace metal emission removal ranged from 96.9–98.6%. Mercury removal across the FFDC was 67.5% with dry sodium-based DSI, 77.9%, with SNCR, and 93.7% with calcium-based DSI/FGH.

Operating Performance

The Arapahoe Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. The availability factor during the period was over 91%.

LNB/OFA. The new LNBs resulted in an approximately 200 °F decrease in furnace exit temperature, which required more excess air than baseline to maintain steam temperature at low loads. The LOI essentially remained the same between the new and original burners, except at 50 MWe. High LOI at this low load was attributed to an uneven distribution of coal and a coarser grind as the number of mills in service dropped from three to two.

SNCR. The ARIL lances proved to be effective NO_x control devices, but experienced some operational problems. A large differential heating pattern between opposite sides of the lance caused a differential in thermal expansion and bending of the lance approximately 12–18 inches, making insertion and retraction difficult. The problem was partially resolved by adding cooling slots at the end of the lance. An alternative design, provided by Diamond Power Specialty Company, was tested and found to have less bending due to evaporative cooling, but NO_x reduction and ammonia slip performance dropped relative to the ARIL system.

DSI/FGH. During the operation of the DSI system with hydrated lime and FGH under load-following conditions, the FFDC pressure drop significantly increased as a result of buildup of a hard ash cake on the fabric bags that could not be cleaned under normal reverse-air cleaning. The FGH system caused the heavy ash cake, but it was not determined whether the problem was due to operation at 30 °F approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

When the SNCR and DSI systems were operated concurrently, an ammonia odor problem was encountered around the ash silo due to the rapid change in pH attributable to the presence of sodium in the ash and the wetting of the fly ash to minimize fugitive dust. This problem was resolved by transporting the ash in enclosed tanker trucks and by not adding water.

Economic Performance

The technology is an economical method of obtaining SO_2 and NO_x reduction on low-sulfur coal units. Total estimated capital costs range from 125–281 $/kW (1994$) for capacities ranging from 300–50 MWe. Comparably, wet scrubber and SCR capital costs range from 270–474 $/kW for the same unit size range. On a levelized cost basis, the demonstrated system costs vary from 12.43–7.03 mills/kWh (1,746–987 $/ton of SO_2 and NO_x removed) compared to wet scrubber and SCR levelized costs of 23.34–12.67 mills/kWh (4,974–2,701 $/ton of SO_2 and NO_x removed) based on 0.4% sulfur coal. The integrated system is most efficient on smaller low-sulfur coal units. As size and sulfur content increase, the cost advantages decrease.

Commercial Applications

The IDECS system was developed to meet the site-specific requirements of some of the more difficult boiler emission-control situations. A market analysis indicated that 65 down-fired boilers, totaling 6,400 MWe, and 29 wet bottom boilers, totaling 3,800 MWe, could be candidates for the IDECS system. Because of their age and design, these units generate high levels of NO_x and because of lack of plot area, they are difficult to retrofit. The plants also tend to be relatively small. As a result of these considerations, utilities will be reluctant to make major capital investments in these units. However, IDECS provides an economic alternative that can extend plant life.

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