

DUAL FUEL/LOX NO_x CONVERSION OF THREE OIL FIRED BURNERS AT COMMONWEALTH EDISON'S COLLINS STATION

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History and Schedule

During August 1991, Commonwealth Edison Company (CECo) committed to a "Dual Fuel" Conversion, of Collins Units 1, 2 & 3. The conversion of the three units with combined capacity of nearly 1700 MW was the largest conversion project known to CECo. It was justified based on the savings associated with the differential fuel costs of oil and gas. Prior to the project, these units burned No.6 fuel oil for main fuel and No.2 distillate oil for ignition fuel. The project enabled Collins to burn either natural gas or No.6 fuel oil as a main fuel and natural gas as ignition fuel.

In addition to the cost savings, the project provided an opportunity to incorporate existing low NO_x combustion technology which will assist CECo in meeting any future NO_x emissions caps. The NO_x emissions limits specified by CECo were 27% and 30% lower than the New Source Performance Standard (NSPS) requirements for oil and gas respectively.

CECo began the process of designing this fuel conversion during January of 1992. Completion was aggressively targeted for July of 1993. The project cost was approximately \$18/KW.

The units involved are three (3) Babcock & Wilcox El Paso type radiant boilers described by the following parameters:

Continuous High Pressure Steam Output:
4,000,000 pounds/hour

Steam Conditions at Superheater Outlet:
1005°F, 2,410 PSIG

Steam Conditions at Reheater Outlet:
1005°F, 615 PSIG

Boiler Heating Surface:
35,375 ft²

Furnace (waterwall) Heating Surface:
22,930 ft²

Turbine Generator outputs:
572 MW (Units 1 & 2), 550 MW (Unit 3)

Scope

The project included the following work:

1. A gas supply station was provided and installed by the contracted natural gas supplier on Collins Station property. This facility meters, heats, reduces pressure of, and odorizes the gas. Additionally, CECo installed overpressure protection and filter/separators adjacent to the gas supplier's facility.
2. Each unit was provided with separate pressure reduction and metering stations for both main and ignition gas. Pressure reduction is accomplished in two (2) stages.
3. The Burner Management System (BMS) was replaced. The boiler combustion controls were modified. Fully integrated BMS/Combustion Controls were provided.
4. The burners were replaced with Low NO_x burners. Ignitors were replaced. Main flame scanners and ignitor flame scanners were replaced. New overfire air port dampers and drives were installed. The boiler windbox was cold flow modeled and modified in order to balance airflow between burners.
5. The boiler tube water walls were replaced to accommodate the larger burner openings. The

larger openings were required because of the higher airflow requirements when burning gas. Eight (8) waterwall panels were installed in each boiler, each consisting of three (3) elevations of burner openings.

6. The existing superheater attemperators were modified. The spray head orifices were enlarged 25%.
7. The atomizing steam system was modified. The supply was changed from the auxiliary steam system to the secondary superheater inlet header to provide superheated steam.
8. The boilers were retrofitted with high speed induced draft fan damper drives to alleviate high negative draft excursions, experienced on gas main fuel trips.

Project Team Concept

Primary responsibility for engineering and construction activities was assigned to CECo's Fossil Engineering and Construction Department (FECD). This centralized department manages projects for all CECo's fossil generating stations. Because of the size and scope of the Collins dual fuel conversion retrofit, key personnel from the Collins Station staff were assigned to work closely with the FECD project team. This group was actively involved in reviewing and commenting on equipment specifications; developing control system user interface graphics; developing and implementing training programs for all station personnel; participating in vendor factory acceptance tests; coordinating construction and maintenance activities during the unit outages; and developing the pre-operational testing program to verify proper equipment operation prior to set-up. The upfront involvement by station personnel fostered ownership and acceptance of the new system and equipment.

Studies

CECo recognized the implications that a fuel switch would have on full load Unit capability and anticipated some elevation in gas path temperatures associated with natural gas as a fuel. To address the significance of these issues, an architect/engineering firm was contracted to supply a boiler model. The model, suggested that the fuel switch would not negatively affect full load capability on the units. The model did indicate, however, that the superheater attemperator capabilities would need to be increased.

Additionally, studies to model airflow distribution to the burners and furnace implosion dynamics were performed. Both of these studies are discussed in more detail later in this paper.

Dual Fuel Combustion Equipment - Performance

Dual fuel combustion equipment was competitively bid based on a performance specification. The specified performance requirements took into account the pre-retrofit unit performance data and the available technology in order to determine practical limits for the Collins boilers.

Burner capacity was specified as follows:

Main gas - 252 Mbtu/hr each to allow full load with one pair out of service (22/24), 5:1 turndown
Main oil - 243 Mbtu/hr to allow full load with one pair out of service (22/24), 5:1 turndown
Gas ignitors - 25 Mbtu/hr (Class 1), 5:1 turndown

Available technology allowed guaranteed NO_x limits to be specified lower than New Source Performance Standard (NSPS) requirements. NSPS NO_x emission limits for Collins are:

- 0.2 lb/Mbtu firing natural gas
- 0.3 lb/Mbtu firing No. 6 fuel oil

Specified guaranteed NO_x emission limits are:

- 0.14 lb/Mbtu firing natural gas
- 0.22 lb/Mbtu firing No. 6 fuel oil

Specified carbon monoxide (CO) emission limits were 150 ppm (dry corrected to 3% excess O₂) based on an average of 24 sampling points measured in the flue gas duct economizer outlet and 300 ppm at any single sample point.

Opacity was specified not to exceed 15% during light-off of main burners and start-up operations up through auxiliary boiler mode and not to exceed 10% during normal operation (auxiliary boiler mode to full load). Auxiliary boiler mode consists of firing the boiler at very low firing rates to provide steam to the auxiliary steam system (primarily for station heating).

Dual Fuel Combustion Equipment - Deliverables

The combustion equipment specification scope included design, manufacture, testing and delivery of burners, ignitors, flame detectors, NO_x port assemblies and cold flow modeling.

The burners purchased incorporate an axial flow venturi design. Six (6) manifold gas spuds are located around a central swirler and oil gun. The

burner design incorporates Class 1, continuous duty ignitors. Two (2) flame scanners are provided for each burner, one (1) for main flame scanning and one (1) for ignitor flame scanning.

Pre-retrofit testing (firing oil) proved that existing manually operated NO_x ports had a dramatic effect in reducing NO_x emissions. Since their operation would be required to meet the NO_x emission limits, the combustion equipment specification also included replacement or modification to increase their operational reliability and to allow NO_x port airflow to be modulated remotely.

Cold flow modeling was performed by the burner manufacturer. The purpose of the modeling was three-fold:

- 1) To model the mixing effectiveness of the flue gas recirculation (introduced through the airfoils) with windbox combustion air
- 2) To perfect the mixing quality of the overfire air (OFA) with the bulk furnace flow in the post retrofit condition.
- 3) To predict airflow to each burner (post retrofit) and aid in balancing, if necessary

The results of the modeling indicated that the existing ductwork and furnace configuration provides good flue gas recirculation (FGR) mixing and OFA mixing. The modeling also indicated, however, that windbox modifications were required to balance airflow between burners to within +/- 2% to ensure burner combustion stability. The modifications consisted of installation of deflection baffles adjacent to burners. Additionally, piezometric rings were incorporated into the burner design to provide relative airflow measurement to confirm balanced airflow.

Burner Management System / Combustion Control System / Instrumentation

The project scope included replacement of original burner management system (BMS) hardware with distributed control based equipment. The existing combustion control system (CCS) was modified to interface with the new BMS and with the natural gas supplier's equipment. The interface with the natural gas supplier's equipment allowed acquisition of natural gas flow and fuel composition signals for logging and accounting purposes. A remote trip signal, which can be activated from the control room, allows the operator to shut down the natural gas supply station in the event of a major gas system malfunction.

The requirement for natural gas for ignition and natural gas and/or oil for main fuel required that the BMS logic independently monitor and control each

fuel system. Additionally, the existing CCS was modified to provide natural gas pressure and flow regulation for both the ignition and main gas systems. BMS logic was specified to function in accordance with NFPA Standard 85C-1991 regarding prevention of furnace explosion and implosion in multiple burner boiler-furnaces.

The common BMS and CCS operator interface is via color touch-screen/keyboard CRT consoles. Hardwired trip pushbuttons are also provided. The CRT consoles are driven by independent electronics to ensure high reliability and to allow on-line troubleshooting.

The BMS system is designed to provide complete status and control of all fuel delivery systems. Alarms and trip conditions are displayed in a first-out condition, enabling the operator to quickly recognize the primary cause of the trip or malfunction and take the appropriate corrective action.

The BMS equipment delivery schedule was such that a complete hardware/software factory acceptance test could not be performed prior to the required equipment delivery dates. Since the BMS system design was identical for each of the three (3) units, the hardware for the first unit was shipped after a hardware checkout. The software for the first unit to be placed in service was then acceptance tested on the identical second unit's hardware at the manufacturer's factory. The tested software was then installed in the on-site equipment prior to start-up testing. This approach resulted in a timely hardware delivery for pre-outage installation work and allowed the BMS logic development/testing and troubleshooting schedule to be performed without the constraint of the hardware delivery milestone.

It was recognized early in the new control system design that the operator interface for the new system was a key element to its success. This was especially true since the control room operators at Collins had no experience with CRT-based controls. The existing BMS was operated from a hardwired panel of status lights and switches, while the CCS was operated exclusively from hardwired manual/auto and digital logic stations. The decision to install a touch-screen CRT interface, therefore, was accompanied by a decision to actively involve representative control room operators in the design of the graphical interface.

A small team of operators, operating supervisors and a plant controls engineer worked together to lay out all the graphic screens which would be used to operate the new system. Members of this team also participated in the factory checkout/testing. This allowed them to use the control graphics they had

designed with simulated boiler operation. It also provided an opportunity to correct graphic and control logic during the logic checkout so that the final delivered system met the intentions of the operators who had assisted in its design. These efforts paid off with a very smooth control system start-up.

During start-up, the controls engineers from Collins Station, working together with the control manufacturer's field service personnel, set about the task of tuning and optimizing the control system performance. This work led to substantial improvement in unit ramp rates and control accuracy

Prior to the conversion, maximum unit ramp rates were in the range of 8 MW per minute. The modified units now operate routinely on automatic generation control (AGC) at ramp rates of 10 to 15 MW per minute on natural gas fuel. In addition to the improved ramp rates, the units also excel in other measures of AGC performance, such as turnaround time and deadband. These enhancements allow Collins Station to contribute to improved regulation for the entire CECo system.

The ignition and main gas flow measurements are performed by a differential pressure device called a V-Cone. The V-Cone works under the same principle as a flow nozzle, except it provides inherent flow straightening, high turndown capabilities and excellent repeatability (for control purposes) and accuracy (for accounting purposes). In order to achieve the high accuracy desired, the V-Cone systems were laboratory calibrated prior to shipment. The flow calculation being performed by the combustion control system includes pressure and temperature compensation.

The gas pressure and flow control valves are positioned via electro-hydraulic actuators. These actuators were chosen due to their extremely precise positioning accuracy (0.1%), speed of response, small size and low installation costs. These actuators interface directly to the combustion control system for control and position feedback indication.

The main gas and oil flame scanners are based upon fiber optic sighting. A two (2) channel amplifier is used to set the scanner for the selected fuel. The BMS switches the amplifier to scan for oil or gas flame based upon the main fuel being used in the burner. The ignition flame scanner is a line of sight ultraviolet system. Flame scanner settings were adjusted during start-up to provide reliable flame scanning under various operating conditions.

Boiler Implosion

The negative pressure excursions in a draft system following a Master Fuel Trip (MFT) are predominantly caused by the rapid collapse of the flame envelope and a sudden drop in furnace gas temperature and density. This phenomenon can result in furnace implosion. It is common experience that the flameout time on a gas fired boiler is usually quicker than on an oil or coal fired boiler. Consequently, the draft system transients are expected to be more severe than those on oil or coal fired boilers.

An architect/engineering firm was contracted to generate a computer model of the boiler/draft system to predict the impact of the fuel conversion on negative pressure excursions following an MFT. The model initially predicted the minimum transient pressure would be -28.6° W.G. firing oil and -33.2° W.G. firing gas. The predicted minimum firing oil exceeded the furnace design pressure of $\pm 20^{\circ}$ W.G. and did not align with known boiler draft system performance. Subsequently, CECo performed a full load unit trip firing oil which resulted in a furnace pressure minimum of -15.3° W.G. Data from this trip test was used to calibrate the model.

Due to the large deviation between the model's predictions and the data taken during the tests CECo elected to install the most recent furnace draft control logic and perform MFT testing at increasing load points following the gas conversion of Unit 3. This would provide the station and opportunity to tune existing draft controls for maximum effectiveness in mitigation draft excursions based on actual data and it would provide data to help tune the computer model. Additionally, the testing would better define the need, if any, to replace the damper actuators with faster acting ones.

Data from this testing was incorporated into the model which then predicted -19° W.G. ($\pm 2^{\circ}$) at 70% load. Subsequent trip tests confirmed the computer model results. Based on that information a decision was made to procure and install faster induced draft fan inlet damper drives. They have been installed on the Unit 2 dampers and additional MFT testing/tuning is underway.

Performance Experience

One of the first problems experienced during start-up was that of burner stability. The main gas burner flames had a tendency to detach and reattach from the gas pokers, as gas pressure increased. The flame

scanning equipment could not be adjusted to reliably sight these flames, and burner trips (due to loss of detected flame) were commonly experienced. The problem was worsened by the fact that, as soon as one burner would trip, the gas pressure to the remaining operating burners would increase, leading to instability and loss of detected flame on the remaining burners. This scenario led to several cascading burner and boiler trips during the initial start-up period.

To address this problem, the burner manufacturer dispatched design personnel to the site to observe and correct the burner stability issue. Flame appearance and stability were carefully observed under a variety of combinations of fuel and air flow. It was determined that the cause of the problem was improper mixing of fuel and air in the vicinity of the burner exit. The gas pokers nozzle, which were designed to be removable and adjustable, were re-oriented. The result was a much more stable, attached gas flame which the scanning equipment could reliably detect.

The Class 1 gas ignitors also exhibited signs of instability. At high gas throughput, the flame detached from the ignitor and the flame front "walked in and out" from the ignitor. The burner manufacturer and the subcontracted ignitor manufacturer worked together producing several modified/prototype ignitors. CECO, together with the burner and ignitor manufacturers, is in the process of evaluating the performance of the modified/prototype ignitors.

Atomizer performance is another area which did not meet CECO's expectations. Atomizers supplied with the burners are skew-jet design and operate with constant steam pressure (100 psig) and variable oil pressure to provide variable capacity. The flame front "walks away" from the oil gun tip/swirler as oil pressure increases above steam pressure. The burner manufacturer is in the process of evaluating the atomizer's performance.

Oil gun coking was another area of concern. The oil guns consist of an interlocking coupling block and two (2) concentric tubes to carry the oil and steam. Oil is carried in the center tube surrounded by steam. Although the guns were provided with pneumatic retracts, coking problems have still been observed following a burner shutdown. This has been mitigated to a large degree, by the addition of a small cooling steam flow through the gun while the burner is shut down. In addition, CECO is experimenting with air cooling of the annular space between the oil gun and its guide tube to eliminate the need for cooling steam. This effort is also ongoing.

Flow induced noise in the gas supply system was a problem which, although specifically addressed during the design/specification phase, was realized during initial operation. Specification limited noise levels to 90 dba. Field measurements in the vicinity of the pressure reduction/flow control valve station exceeded 115 dba at 80% load. Both the control valve manufacturer and A/E firm responsible for the piping layout were contacted about the problem. Both performed site inspections and took sound data. The A/E analyzed the data and issued a detailed study. The study attributed the high noise levels to a combination of high local gas velocities resulting from the piping layout and flow induced noise from the valves which carried throughout the piping system.

The first step taken to alleviate the noise problem was to rotate the valves to reverse the flow through the control valves. This resulted in significant improvement in the noise levels, however, they still exceeded the 90 dba.

The next step which is being taken is the replacement of the cage-style valve internals with disc-stack style internals. It is anticipated that the resulting lower exit velocities will lower the noise level even further.

Another problem which appeared during start-up was intermittent binding of the burner air register sliding sleeves. Careful inspection during an outage revealed that the drive rod, which pushes the air register sliding sleeve open, tipped when opening, resulting in an interference between part of the moving drive rod and the stationary burner frame. This problem was corrected by removing a portion of the frame which was being struck by the drive rod. Once this work was completed on all burners, the registers operated reliably.

Another related problem was that the overfire air dampers, which had been fitted with sliding sleeves and electric actuators, were unable to open with a boiler airflow greater than about 50%. The actuators provided insufficient force to overcome the windbox/furnace differential pressure. In addition, the sliding sleeves, which are similar in design to the burner air registers, also experienced binding. Both problems appear to have been solved through a series of on-site modifications.

Parametric testing of the modified boilers is now in progress. The goal of this testing is to determine how the various boiler operating parameters (excess air, gas recirculation, overfire air, etc.) affect emissions and operational performance.