CONVERSION OF COAL-FIRED ELECTRIC GENERATING UNITS TO NATURAL GAS-FIRED UNITS

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ABSTRACT

An increasingly stringent and uncertain regulatory environment and lower natural gas prices have made converting existing steam generating boilers to natural gas firing increasingly attractive.

This paper provides a general feasibility assessment of projects that have converted coal-fired steam generating units to 100% natural gas firing. We present an approach to assess permitting impacts to the project that dictate the direction and scope in terms of required equipment to achieve the targeted emissions. The project's technical feasibility, including burner technologies for a range of different boiler firing configurations, natural gas effects on thermal performance, American Society of Mechanical Engineers (ASME) and National Fire Protection Association (NFPA) code requirements, and air pollution control equipment are discussed.

A case study is presented which involved the conversion of existing industrial boilers. The implementation of the project is discussed, including the design of the natural gas piping/delivery system on the plant premises, new gas-fired burners, heat absorption impacts with existing heat transfer surfaces, and impact on the balance-of-plant equipment and design. The project was successfully completed in November 2014.

1. INTRODUCTION

This paper provides a general assessment of projects that have converted coal-fired steam-generating units to 100% natural gas firing. We present an approach to assess the projects' technical feasibility, including boiler thermal performance modeling and project planning. Balance-of-plant considerations, such as American Society of Mechanical Engineers (ASME) and National Fire Protection Association (NFPA) code compliance, natural gas piping systems, emissions control equipment, draft systems, and retirement of existing coal equipment are also discussed.

1.1 Quality and Variability of Natural Gas

Historically, natural gas supply has been consistent in quality and heating value throughout the United States. Gas properties have also been consistent, with slight variations, making the risk of a significant error in engineering and design of gas-fired equipment quite low. Table 1offers a representative fuel analysis for natural gas.

Table 1. Sample Natural Gas Fuel Analysis

Parameter	**Value**
Relative density	0.580 lb/ft^3
Higher heating value (HHV)	1002 Btu/ ft^3 22,665 Btu/lb
Constituent (%)	
Nitrogen dioxide (N_2)	0.340
Carbon dioxide (CO_2)	1.690
Methane	96.700
Ethane	1.250
Propane	0.005
N-Hexane	0.003
N-Butane	0.006
Isobutane	0.005
i-Pentane	0.002
Isopentane	0.000
Sulfur compounds	<0.001
Moisture (lb/MCFD)	0.000

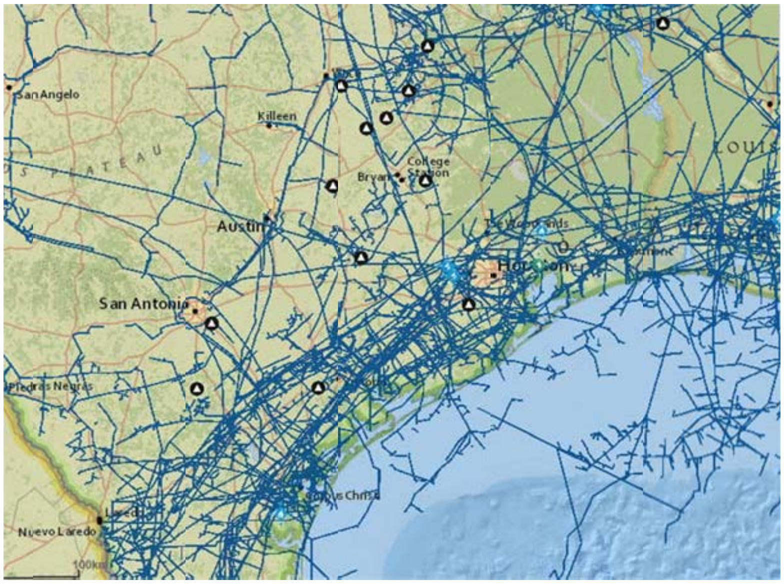
Recent exploration and drilling techniques have led to an increase in the amount of gas discovered and extracted, driving supply up and prices down. Gas is now being recovered from many sources. Biogas and syngas are being manufactured, creating variations in constituents and proportional gas makeup. Recently, we have observed “natural gas” deviating from the norm and affecting the predicted performance of gas-fired boilers and potentially requiring special equipment for emissions control; therefore, it is highly recommended that the makeup of fuel(s) intended to be fired in the boiler be fully understood during the project planning phase.

1.2 Natural Gas Availability

Low prices and regulatory pressures have created a swell in demand for natural gas, but the domestic distribution system has finite capacity, and in some areas of the country delivery capacity already lags demand. This is an acute problem in the northeastern United States where gas delivery infrastructure is capacity-limited during the winter heating season. Efforts to increase pipeline capacity are complex and contentious because of political, environmental, safety, and other concerns.

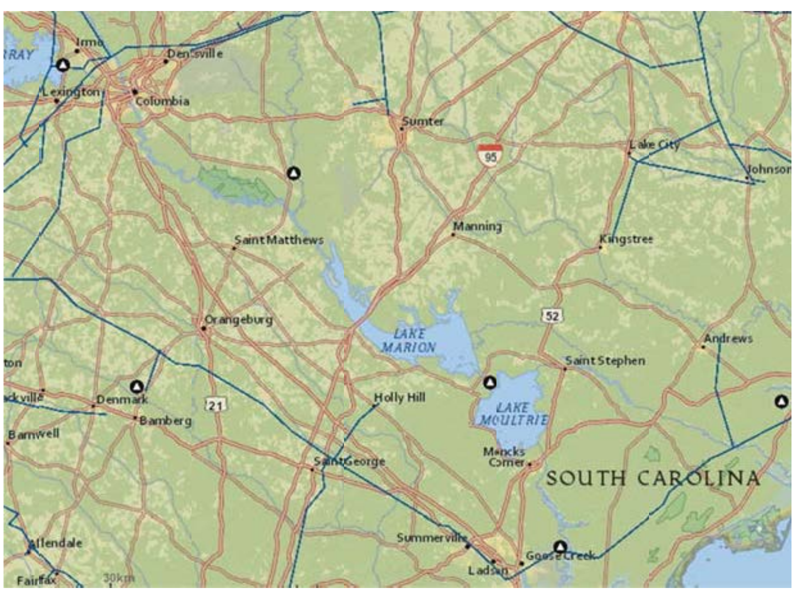
When considering a coal to natural gas conversion it is an obvious advantage if the utility boiler is located close to an existing natural gas supply line with adequate surplus capacity, rather than one located many miles away from a pipeline that is at or near capacity. The locations of existing coal power plants depicted by white triangles inside black circles shown in Figure 1, illustrate the benefit these plants have by their proximity to natural gas fuel sources.

Figure 1. Natural Gas Pipelines in the Texas Gulf Region



Utility generating stations in some areas of the country are distant from available gas pipelines and, thus, fueling the unit may not be feasible and justification for a gas conversion may prove difficult or not possible.

Figure 2. Natural Gas Pipelines in the Carolinas



1.3 Assessing Permit Impacts

Coal to natural gas conversion projects are subject to a number of environmental regulations and permitting requirements. The primary regulation that can dictate the air pollution control technologies required for the new natural gas-fired boiler is the New Source Review (NSR) Prevention of Significant Deterioration (PSD) permitting requirements. For our case study, Domtar was subjected to the final ruling of the Industrial Boiler MACT (Maximum Achievable Control Technology).

EPA issued their Final Industrial Boiler MACT Rule in February 2011, which regulates emissions of pollutants, including acid gases (HCl), filterable particulate matter (PM), mercury (Hg), carbon monoxide (CO) and dioxins/furans. Due to strong criticism and legal opposition, the EPA reopened portions of the clean air standards to public comment in December 2014.

Several key factors with respect to permitting for a coal to gas conversion are discussed later in the Case Study portion of this paper.

2. TECHNICAL CONSIDERATIONS

2.1 Feasibility

Firing natural gas avoids the slagging and fouling conditions associated with coal combustion, which improves boiler cleanliness and tends to increase heat absorption. However, combustion-zone radiation rates to the furnace walls tend to be lower. Achieving design steam temperatures and full boiler output can be difficult for a boiler originally designed to burn coal. Higher tube-metal temperatures may be experienced when firing natural gas. In some cases, a unit derate of 15% or more may be necessary to reduce flue gas and tube-metal (superheater, reheater) temperatures in the furnace and convection pass unless upgrades are made to tube material or attemperator nozzles are modified. In other cases, steam temperature derates are seen, since a reduction in excess air is needed for natural gas combustion, which reduces the flue gas flow rate and rate of heat transfer. There are several boiler parameters responsible for the unit and steam temperature derates, which include boiler/burner technology and furnace heat input/plan area ratio. Boiler natural gas feasibility studies are necessary to determine the effects of burning natural gas in a coal-fired boiler.

Coal and ash handling equipment is not required for firing natural gas; in most cases, this equipment will be abandoned in place or will be removed to the extent necessary to carry out the conversion. In some circumstances, the owner elects to remove this equipment for maintenance, personnel access, or even for aesthetics.

Original forced draft (FD) and induced draft (ID) fans and other boiler auxiliary equipment are usually adequate for firing natural gas but sometimes need to be modified or replaced entirely.

2.2 Estimated Boiler Performance and Expected Plant Performance

Converting a coal boiler to natural gas typically decreases boiler efficiency because of the large quantity of hydrogen in natural gas. During combustion, the hydrogen is converted to water.

Evaporating this water uses a portion of the flue gas energy, thus, lowering boiler efficiency. This efficiency loss is offset somewhat by the lower amount of excess air required to burn natural gas. Boiler efficiency decreases are to be expected in the 3% to 4% range, depending on the current fuel and boiler design. Auxiliary power demand is reduced with natural gas firing because pulverizers, primary air (PA) fans, precipitators, coal and ash handling systems, sootblowers, and other equipment are no longer required. Instrument air and service water will also decrease accordingly.

There will be a significant difference in plant efficiency results in the conversion of a pulverized coal application versus a stoker grate application. The changes in air flow and decreasing tramp air within the unit will be a critical driver in the implementation and final results.

Net Plant Heat Rate (NPHR) could change ±2% due to the changes in boiler efficiency, power output limitation, and auxiliary power usage. More accurate NPHR estimates can be calculated based on unit-specific design and operating parameters.

2.3 Code Requirements

All natural gas system piping from the property fence line to the boiler burners fronts are in accordance with applicable requirements of:

- ASME B31.1, Power Piping
- NFPA 70, 497, 85

It is common for natural gas supply piping to be installed underground on plant properties, where it can be protected from the elements, vehicular traffic, and tampering; however, this presents some challenges that need to be addressed up front in your project. The new underground pipeline will be designed per NFPA 85 requirements and will transition to above ground before entering the high-pressure PRV, also known as “outside of boiler room,” where the pressure will be reduced. This supply line then branches to igniter and burner supply lines before passing through the individual low-pressure-reducing valves (PRVs), also known as “control valve skid stations,” where the pressure is controlled to the design pressures required by the burner original equipment manufacturer (OEM). The burner and igniter supply lines typically run in parallel, penetrating the boiler building wall, and branch into front and rear wall supply headers.

2.3.1 NFPA 70 and 497

Conversion to natural gas firing will place piping systems containing a combustible gas into various areas of the plant site. NFPA 70, *National Electrical Code* (NEC), specifies requirements for electrical and electronic equipment and wiring in locations where fire or explosion hazards may exist due to flammable gases, flammable liquid–produced vapors, combustible liquid–produced vapors, combustible dusts, or ignitable fibers within the operating environment. Locations are classified depending on the properties of the flammable or combustible materials that may be present, and the likelihood that a flammable or combustible concentration or quantity of the material is present. The NEC further specifies acceptable protection techniques for electrical and electronic equipment in hazardous (classified) locations.

Electrical area classification is the process of determining the existence and extent of hazardous (classified) locations in a facility. NFPA 497, *Recommended Practice for the Classification of Flammable Liquids, Gases, or Vapors and of Hazardous (Classified) Locations for Electrical Installations in Chemical Process Areas,* provides a methodology for determining the combustible material class (material type), group (material properties), and division (likelihood of hazardous atmosphere). Further, NFPA 497 provides a series of generalized classification diagrams to be used to formulate the extent and boundaries of classified locations.

For a natural gas piping system, a proper electrical area classification assessment must consider a large number of variables, some of which are dependent on identification of the placement of potential release points, such as flanged connections, valve stems, vents, and safety valve discharges, and on determination of the applicable extent of the associated classified area. These can only be determined as detailed design of the piping system evolves. The results of this classification assessment and the plant owner's interpretations of NFPA requirements are subject to acceptance by the Authority Having Jurisdiction.

2.3.2 NFPA 85 Furnace Implosion Considerations

When boiler trips occur, flame collapse causes furnace negative pressure excursions. With gas firing, fuel cutoff is much faster than when firing coal, which may result in a change to the pressure excursion throughout the draft system.

A strict interpretation of NFPA 85 would require a furnace transient design of −35 in WC, which is often more negative than what the existing boilers, ducts, and precipitators were originally designed to handle.

NFPA 85 states:

> **"6.5.1.3.2.2* Negative Transient Design Pressure.** The negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, -8.7 kPa (-35 in. of water).
>
> Exception: If the test block capability of the induced draft fan at ambient temperature is less negative than -8.7 kPa (-35 in. of water), for example, -6.72 kPa (-27 in. of water), the negative transient design pressure shall be at least as negative as, but shall not be required to be more negative than, the test block capability of the induced draft fan."

However, NFPA 85 does allow the use of alternative design approaches as described below:

> "**1.2.3** This code shall not be used as a design handbook.
>
> **1.2.3.1** A designer capable of applying more complete and rigorous analysis to special or unusual problems shall have latitude in the development of such designs."

Reinforcing boilers, air heaters, ducts, and precipitators can be expensive and require long outages. For this reason, many plant owners have decided not to reinforce their furnaces to −35 in WC.

Some of the common transient conditions that cause the most problematic negative furnace and draft system pressures are described in Table 2.

Table 2. Common Transient Conditions to Evaluate

Transient Conditions	Description
1	Operating problems during fan startup and furnace purge – The ID fans can produce a higher pressure when handling cold air or cold flue gas than when operating with hot flue gas. Several plants have experienced high negative pressure under these conditions; however, the potential transients during startup of the fans and furnace purge will most likely be similar for natural gas as for coal firing.
2	Runaway ID fan at low load – This is a common case that is evaluated in transient studies and considers that at low load, the ID fan(s) increase in speed (or the inlet vanes open for constant-speed fans) due to a control system failure. This will cause a high negative furnace pressure that will result in a master fuel trip (MFT).
3	FD fan trip and MFT – A trip of the FD fans will cause the ID fan(s) to trip (except the last ID fan) and an MFT.
4	MFT based on turbine generator or other major problems.

The distributed control system (DCS) will require reprogramming to ensure that the natural gas conversion complies with the current NFPA 85 requirements and triple-redundant pressure transmitters are installed, which are auctioneered using a median-select methodology. In the control system, the furnace pressure signal and a feed-forward demand signal will be inputs to the furnace pressure control subsystem, which modulates the furnace pressure regulating control element to maintain a desired setpoint. A furnace pressure control protection system will be applied after an auto/manual transfer station to minimize furnace pressure excursions under both operating modes. The furnace pressure protection system will include a feed-forward override action that will be initiated by an MFT in anticipation of a furnace pressure excursion due to flame collapse, and will work in conjunction with logic to minimize furnace pressure excursions.

2.4 Burner Technologies and Boiler Types

2.4.1 Low-NO_X Natural Gas Burners

Low-NO_X burners (LNBs) limit NO_X formation by controlling both the stoichiometric and temperature profiles of the combustion flame in each burner flame envelope. This control is achieved with design features that regulate the aerodynamic distribution and mixing of the fuel and air, yielding reduced oxygen (O_2) in the primary combustion zone, reduced peak flame temperature, and reduced residence time at peak combustion temperatures. The combination of these techniques produces lower NO_X emissions during the combustion process.

NFPA 85 classifies igniters in three ways (Class 1, 2, and 3). Class 3 igniters typically are provided for natural gas conversions due to cost considerations.

2.4.2 Converting Cyclone Burners to Natural Gas Firing

The gas fuel burners/nozzles typically are composed of three flat spuds located in the existing secondary air dampers. The cyclone burner can be supplied with a manifold, having individual piping to each spud. The refractory can be removed for 100% natural gas operation but the studs could remain in place. Whether to remove the refractory studs is determined by the OEM's boiler assessment. Minor modifications might be required to the cyclone re-entrant throats/slag tap direction to facilitate the flue gas properly exit the cyclone burner.

2.4.3 Converting Tangentially Fired Burners to Natural Gas Firing

The gas fuel nozzles are composed of two spuds located in the existing coal compartments. Each new gas fuel compartment would feature two gas-spud elements and gas supply piping that will manifold together and terminate at a single butt-weld connection at the exterior of the windbox. A single flanged inlet pipe would protrude from the header through the windbox to connect to the gas supply flex hose. All air tips within the main windbox typically are replaced.

2.5 Emission Control Equipment

2.5.1 NO_X Control

The formation of NO_X is determined by the interaction of chemical and physical processes occurring within the boiler. There are two primary forms of NO_X: *thermal* NO_X and *fuel* NO_X.

Due to the characteristically low nitrogen content of natural gas, NO_X formation through the fuel NO_X mechanism is normally insignificant. Therefore, the principal mechanism of NO_X formation in natural gas combustion is thermal NO_X, which results from the oxidation of nitrogen in the combustion air contained in the inlet gas in the high-temperature, post-flame region of the combustion zone.

The major factors influencing thermal NO_X formation are temperature, the concentration of oxygen in the inlet air, and residence time within the combustion zone. LNB technology can affect thermal NO_X formation by regulating the distribution and mixing of the fuel and air to reduce flame temperatures and residence times at peak temperatures.

Several methods are available to effectively limit NO_X formation during combustion, as summarized below.

- Increase the size of the furnace
- Control peak flame temperatures below 2800°F
- Add flue gas recirculation to the combustion air to lower flame temperature
- Reduce excess air

2.5.1.1 Flue Gas Recirculation

Flue gas recirculation (FGR) controls NO_X by recycling a portion of the flue gas from the economizer outlet and back into the primary combustion zone in the windbox. The recycled air lowers NO_X emissions by (1) lowering the combustion temperature; and (2) reducing the O_2 content in the primary flame zone. The amount of recirculation is based on flame stability requirements and is normally in the 15% range at 100% MCR to minimize NO_X formation and maintain proper tube metal temperatures and attemperation. However; in some cases the amount of FGR can be as high as 30%.

Our experience also suggests that the mixed flue gas/combustion air flow supplied to the windbox should be not lower than approximately 16% O_2 because lower O_2 content impacts flame stability and could promote the formation of excess CO and volatile organic compound (VOC) emissions.

An FGR system may also increase heat absorption in the convection pass, resulting in increased boiler tube temperatures and attemperation rates. Increased flue gas flow rates would be a concern regarding boiler tube-metal temperatures; however, lower excess combustion air with natural gas firing will tend to reduce the overall flue gas flow increase. In most cases, steam temperatures and attemperation feedwater flows assist in maintaining design steam temperatures. Existing attemperators, valves, and piping often include design margins allowing these components to work on a gas-converted boiler without modification.

NFPA 85 requires that an FGR system be provided with either the ratio of flue gas to air or to the oxygen content of the mixture. Oxygen analyzers typically are supplied downstream of the FGR mixing area in the windbox since duct space is limited for a flow measurement system. These analyzers will monitor the oxygen content of combustion air and alert the operator if oxygen is being overly diluted, which may cause the flames to become unstable.

FGR increases hot reheat steam temperatures at control load (low-load/low maximum continuous rating [MCR]) improving superheat/reheat steam temperature control.

2.5.1.2 Selective Catalytic Reduction

In the event that NO_X cannot be adequately controlled with an LNB and FGR, it may be necessary to use a selective catalytic reduction (SCR) system. SCR is a process in which ammonia reacts with NO_X in the presence of a catalyst to reduce the NO_X to nitrogen and water. The catalyst enhances the reactions between NO_X and ammonia, according to the following reactions:

$$4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$$

$$4\ NO_2 + 8\ NH_3 + 2\ O_2 \rightarrow 6\ N_2 + 12\ H_2O$$

The location for this process is normally downstream of the economizer and upstream of the air heater. SCR technology can be applied at *full scale*, which is an independent reactor vessel with inlet and outlet ducting or *in-line*, whereby the SCR uses the current ductwork, modified to expand the dimensions of the duct to hold the catalyst.

In-line SCR systems differ from full-scale SCR systems because they are installed within the existing flue gas flow path, as opposed to a separate reactor structure. Such SCR systems are usually installed to achieve +90% NO_X reduction for gas-fired units. Installation requires "ballooning" the ductwork to reduce the normal 60 feet per second (fps) flue gas velocities to the required 20- to 25-fps range. Thus, physical space must be available around the existing ductwork to accommodate the larger duct dimensions.

Static mixers typically are not installed in gas units, as high ammonia slip of 5-10 ppm can be tolerated. An injection grid can be used to distribute reagent uniformly across the entire flue gas path.

We find that most existing SCR systems on coal-fired boilers can be reused when the unit is converted to gas firing without extensive modifications.

2.5.2 Carbon Monoxide Control

CO emissions result from incomplete combustion of the fuel. The formation of CO can be minimized by providing adequate fuel residence time and high temperatures in the combustion zone. However, these factors also tend to increase the formation of NO_X. Conversely, reducing NO_X emissions using low-NO_X combustion tends to increase the formation of CO. Therefore, good combustion design typically attempts to minimize NO_X formation while also keeping CO emission rates at acceptable levels.

Catalytic oxidation systems consist of a passive reactor vessel fitted with a honeycomb grid of metal panels coated with a precious-metal catalyst (usually platinum, palladium, or rhodium). Exhaust gas passes over the catalyst surface, promoting the oxidation reaction of $CO + ½O_2 \rightarrow CO_2$. This reaction occurs spontaneously, without the need to inject reactants such as ammonia into the exhaust gas. Optimal catalytic control of CO/VOC generally is achieved within an exhaust gas temperature range of 700°F to 900°F. A detailed engineering evaluation of the catalytic oxidation control system on a specific boiler is needed to ensure technical feasibility and to exclude the control system from consideration due to technical infeasibility.

Adverse air quality impacts can be associated with the use of a catalytic oxidation system. For example, sulfur dioxide (SO_2) in the exhaust gas may be oxidized to sulfur trioxide (SO_3), and the SO_3 can then react with water in the exhaust gas or in the atmosphere to form sulfuric acid (H_2SO_4) mist. However, these impacts are a function of the fuel sulfur content, and are generally inconsequential on units that fire natural gas exclusively.

2.5.3 Expected Carbon Dioxide Emissions

Natural gas firing offers a strategy to reduce CO_2 emissions. The CO_2 emission factor will vary depending on the carbon content and heating value of the fuel fired, but the typical CO_2 emission factor for natural gas is approximately 40% less than the coal emission factor.

2.6 Cycling

Cycling operation might be desired when switching to natural gas because of cost and availability considerations. Cycling of units that were originally designed for baseload operation typically requires modifications to the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components.

Cycling operation increases boiler header and tube stress cycling. During a warm restart, the superheater and reheater tubing and headers will experience differential surface temperatures as compared to the interface surface at wall and roof penetration sealing points, which will remain near the steam saturation temperature. The headers will retract as temperatures decrease during a load reduction or shutdown “bottled” condition and they will expand as the temperatures increase during a restart. This differential expansion will increase the magnitude and number of stress cycles on the tube-to-header connections, particularly at the end points, where the differential movements will be greatest. A flexible header connection design is often necessary to accommodate this extra movement and prevent undue stresses from being transferred to the header and tube attachment points.

Determining the requirements for cycling operation requires analysis of the boiler, turbine, water treatment system, controls, large motors, piping systems, and other plant components. A boiler/turbine bypass startup system and control system modifications may be required to reduce unit startup costs and to minimize thermal stresses. A detailed study would be required on a unit-specific basis to determine the limitations and changes that would be required for cycling operation.

Other needed changes to accommodate cycling could include those associated with “winterizing” the unit for long shutdown periods. Modifications could include additional drains, unit heaters, heat tracing, and other measures, e.g., a new auxiliary boiler, to prevent freezing and delay in unit restart.

2.7 Conceptual Design and Technical Considerations

The major equipment necessary to implement a coal to natural gas conversion may include:

- Utility gas supply
- Utility metering, regulating and custody station
- Natural gas burners and igniters
- Flame scanners and electronics
- Pressure reducing valve (PRV) station
- Foundations
- Natural gas distribution piping
- Vent piping
- Instrument air system modifications
- Scanner cooler air modifications

Additional design considerations that may be required include:

- Windbox modifications
- Cathodic protection system modifications
- Grounding system modifications
- FD and ID fan control modifications

- FGR fans, motors, and ductwork
- BMS, CCS, and DCS modifications
- Demolition and de-termination of coal and ash equipment
- Switchgear modifications
- Hazardous area reclassification and related upgrades
- Continuous emission monitoring systems (CEMS) upgrades
- Access galleries for operation and maintenance
- Freeze protection
- Plant heating system addition/modification

3. DOMTAR NEKOOSA PAPER MILL BOILERS 1, 2, AND 10

3.1 General Description

To comply with the latest Industrial Boiler MACT emission requirements, Domtar initiated efforts to convert three boilers at its Nekoosa, Wisconsin paper mill from coal firing to 100% natural gas firing in 2012. The boilers generate the steam used in Domtar's papermaking process and operate a generator for auxiliary power requirements. In 2012, Sargent & Lundy conducted a study to help Domtar assess the feasibility of the multi-boiler fuel conversions. This work was carried out in multiple phases. The Phase 1 study scoped the overall project, estimated the capital costs, and developed an overall implementation schedule. In 2013, Domtar subsequently hired Sargent & Lundy to provide the Phase 2 detailed engineering and design, and construction management assistance services to implement the conversion of all three boilers to 100% natural gas firing.

Domtar's Nekoosa paper mill has three coal-fired boilers (Boilers 1, 2, and 10) that are impacted by the Industrial Boiler MACT environmental standards. Stack testing was performed at the Nekoosa paper mill on the three boilers in August and September 2010 and in March 2011 to determine current emission levels of the regulated pollutants. The results of these stack tests were used to determine if Nekoosa would be in compliance with the regulations and, if not, to determine a path forward toward compliance. The study included development of screening-level capital and operating costs for the technologies required to provide compliance with the Industrial Boiler MACT.

A review of the available emissions test data concluded that:

- Boilers 1, 2, and 10 were not capable of consistently meeting the Industrial MACT filterable PM limit of 0.039 lb/mmBtu, likely resulting in the need for electrostatic precipitator (ESP) upgrades.
- Boilers 1, 2, and 10 were capable of meeting the Industrial MACT HCl limit 0.035 lb/mmBtu with the chlorine content of the coal supply being controlled.

- Boilers 1, 2, and 10 were not capable of meeting the Industrial MACT Hg limit of 4.6 lb/TBtu without the addition of a mercury reduction technology such as activated carbon injection (ACI). Further, ACI would increase particulate loading, which may necessitate upgrades to the existing ESPs.
- Boiler modifications were anticipated to be required on Boiler 10 to reduce back end flue gas temperatures to the range in which activated carbon is effective. Use of ACI at the current high flue gas temperatures on Boiler 10 would require much higher carbon injection rates.
- Natural gas conversion of Boilers 1, 2, and 10 was feasible and provided the economical solution for complying with Industrial Boiler MACT.

Domtar initiated efforts to convert three boilers at its Nekoosa, Wisconsin paper mill from coal to natural gas firing in 2012 to comply with Industrial Boiler MACT.

3.2 Detailed Work Scope

Domtar's Nekoosa Boilers 1 and 2 were front-wall-fired Combustion Engineering (CE) pulverized coal boilers. Boiler 10 was a CE stoker coal-fired boiler. Boilers 1 and 2 burned bituminous coal with rated boiler heat inputs of 182 mmBtu/hr each and 110 mlb/hr steam at 700°F and 400 psig. Boiler 10 was a stoker unit firing bituminous coal and up to 10% bark (on a Btu basis). Boiler 10 was rated at 303 mm Btu/hr heat input and 225 mlb/hr steam at 950°F and 1500 psig. Each of the boilers had a mechanical dust collector and an ESP for control of particulate matter, and operated in a balanced draft. There was an existing natural gas supply for igniters on Boilers 1 and 2 plus miscellaneous plant users.

The natural gas utility's metering and regulating (M&R) station was upgraded and a new natural gas line was run from there to a common pressure-regulating valve (PRV) station, which was located outdoors on an existing building roof. Gas supply lines were routed from the roof-mounted PRV station to the boilers, which were fitted with new low-NO_X natural gas burners and igniters, flame scanners, and cooling air blowers.

The existing ABB distributed control system (DCS) was modified to include a new burner management system (BMS) and master fuel trip (MFT) cabinets and the associated programming.

A single burner design proved feasible for all boilers, which limited the amount of spare parts the plant required in their maintenance inventory. For Boilers 1 and 2, new low-NO_X natural gas burners were installed in the existing two lower burner openings. The upper two burners were replaced with shroud assemblies, i.e., overfire air (OFA), to control the amount of air flow through the openings relative to unit load, and to supply supplemental combustion air.

For Boiler 10, four new low-NO_X natural gas burners were installed in the four existing biomass chute openings, avoiding the need to make costly pressure-part modifications and minimizing the outage time. A new windbox with additional ductwork was provided to supply the required combustion air for the new burner assemblies.

Figure 3 shows befo e and after photographs of the Boiler 10 coal to natural gas conversion.

Figure 3. Before and After Boiler Conversion on Boiler 10

Before

After

3.3 Thermal Performance

Performance and emissions criteria were developed for the project, which met state and federal regulatory requirements. This included operation at 100% MCR of the unit's post conversion, environmental requirements for Boiler MACT, and state boiler licensing regulations. These items were established with the equipment supplier as guaranteed performance criteria for the project execution.

3.4 Schedule

The project execution phase spanned just 16 months, concluding with three consecutive outages between July and December 2014. This was one year ahead of the January 31, 2016, Industrial Boiler MACT deadline.

3.5 Key Recommendations for Successful Project

3.5.1 Project Development and Implementation

- Observe the accuracy range of the project estimate. Fund the project based on the appropriate estimate class and contingency level.
- Obtain regulatory approvals as far ahead of project execution as feasible to mitigate unforeseen issues.
- Decide on a contracting strategy up front to improve the accuracy of the estimate. This also impacts the project duration and schedule.
- Perform boiler thermal and transient analyses. Among other aspects, the amount (and cost) of fuel, heat rate, and extent of pressure-part modifications can vary widely based on the results of this effort.

- Plan the fuel supply and vent piping corridors early in your project. This is especially important with underground gas lines, where disturbed soil will necessitate special permitting or environmental impact studies, either of which can significantly impact the project cost and schedule.
- Labor wage rates must be local to the project site and can vary widely on geography, fluctuating construction market conditions, union/non-union or open shop, and seasonality.

3.5.2 Engineering and Design

- Gather existing equipment drawings and system documentation early in the process. These will be essential to the project's progress and technical soundness.
- Identify the location and condition of the gas being supplied by your gas supplier.
- Obtain a fuel analysis for all of the possible natural gases being considered.
- Determine if individual gas meters are needed for each boiler or on each igniter and boiler train, or if the gas suppliers' commercial meter will be sufficient for records purposes and to comply with permit requirements.
- Avoid onerous requirements that will be difficult or not possible for suppliers to provide. Specify standard equipment where possible.
- Furnace implosion considerations should be addressed very early in the engineering and design phase.
- Perform a Hazard and Operability Study (HAZOP).
- Provide adequate isolation, e.g., double block and bleed valves, to major redundant components in the PRV skid design to facilitate maintenance, startup, and commissioning.

3.5.3 Project Startup

- Have specialty and brass tools available.
- Use an ultra-probe to identify leaking valves.
- Have detailed procedures and system-specific meetings before a system startup.
- Burner/igniter timers may need adjustment to allow for proper tuning of flame scanner(s).

3.6 Acknowledgment

The authors recognize and give their warm thanks to the many individuals and organizations who contributed to the success of this project. Many months, days and hours were expended to study, plan, and execute this coal to natural gas conversion project.