ASSESSMENT OF EXISTING EQUIPMENT WHEN CONVERTING TO NATURAL GAS FIRING

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ABSTRACT

Based on recent gas conversion announcements, existing coal units generating a total of approximately 9,000 megawatts (MW) will be converted to natural gas firing. The major drivers of this trend have been Mercury and Air Toxics Standards (MATS) regulations, New Source Review (NSR) settlements, natural gas availability and pricing, and the uniqueness of each project to deliver electricity at the required capacity, making it economically feasible to convert existing coal-fired units to natural gas firing capability. Some facilities are already environmentally compliant and are adding dual-fuel firing capabilities for fuel flexibility and to capitalize on fuel cost savings.

The existing coal-related equipment, material handling systems, and air quality control systems (AQCS) are generally left in place to help drive economic feasibility of firing natural gas. In certain cases, this equipment can be put into long-term layup with the uncertainties of fuel costs and environmental regulations but with higher operations and maintenance (O&M) costs. AQCS equipment, such as electrostatic precipitators, can be de-energized and wet/dry flue gas desulfurization (FGD) systems can be bypassed.

In some cases, retiring and decommissioning of all coal equipment and AQCS equipment may be the more prudent choice to avoid the costs of long-term layup and operating and maintaining the equipment.

Two recent cases studies are presented in this paper: (1) retiring and decommissioning of all coal equipment and AQCS equipment, and (2) implementing dual-firing capabilities for coal and natural gas, in which suggested O&M layup procedures for coal equipment and pollution control are discussed.

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1. INTRODUCTION

This paper provides a general assessment of existing equipment and changes in operations and maintenance (O&M) costs when converting to 100% natural gas firing or dual-fuel firing capabilities. An overview of permitting impacts and variability and availability of fuel is given since these are major parameters when evaluating a fuel switch to natural gas.

1.1 Assessing Permit Impacts

Converting existing coal-fired units to fire natural gas may be subject to environmental review and permitting, including New Source Review (NSR) pre-construction permitting, the applicable New Source Performance Standards (NSPS), and other state emission standards. Typically, the NSR regulations dictate the emission limits and control technologies required for modifications to an existing major source of emissions.

New major stationary sources of air pollution, and major modifications to existing sources, are subject to NSR review. Additional permitting requirements apply to larger installations or installations located in areas that do not meet the national ambient air quality standards. Converting the existing coal-fired boilers to fire natural gas is classified as a modification (i.e., change in the method of operation) of an existing major stationary source. Thus, the natural gas conversion project will be subject to NSR review if it results in a significant net increase in emissions.

A preliminary netting evaluation should be performed to determine if the coal-to-gas conversion project would trigger NSR review. In general, a netting evaluation compares the post-project annual emissions and the respective pre-project (i.e., baseline) emissions. If the change in emissions exceeds the respective Prevention of Significant Deterioration (PSD)/NSR significant emission rates, the project will be subject to NSR review.

Based on Sargent & Lundy's experience with other coal-to-gas conversion studies, the netting evaluation could show that the facility's emissions will increase because the baseline emission rates are very low. The low baseline emission rates are typically based on the following: (1) limited operation of the unit prior to the gas conversion project, or (2) emissions were calculated using EPA's emission factors instead of actual emissions. For example, several facilities report CO emissions from coal-fired units using EPA's AP-42 emission factor thereby underestimating baseline actual CO emission rates. The AP-42 emission factor of 0.5 lb/ton is approximately 0.025 lb/MBtu (30 ppmvd @ 3% O_2) where actual carbon monoxide (CO) emissions from coal-fired boilers typically range from 0.15 to 0.25 lb/MBtu (180 to 300 ppmvd @ 3% O_2). Typical CO emissions after a natural gas fuel switch would be approximately less than 200 ppmvd.

It is important to establish the baseline emission rates before concluding whether the project will be subject to PSD, which will require a best available control technology (BACT) evaluation to determine the appropriate emissions control technology (e.g., oxidation catalyst could be required for control of CO emissions) and emissions limits.

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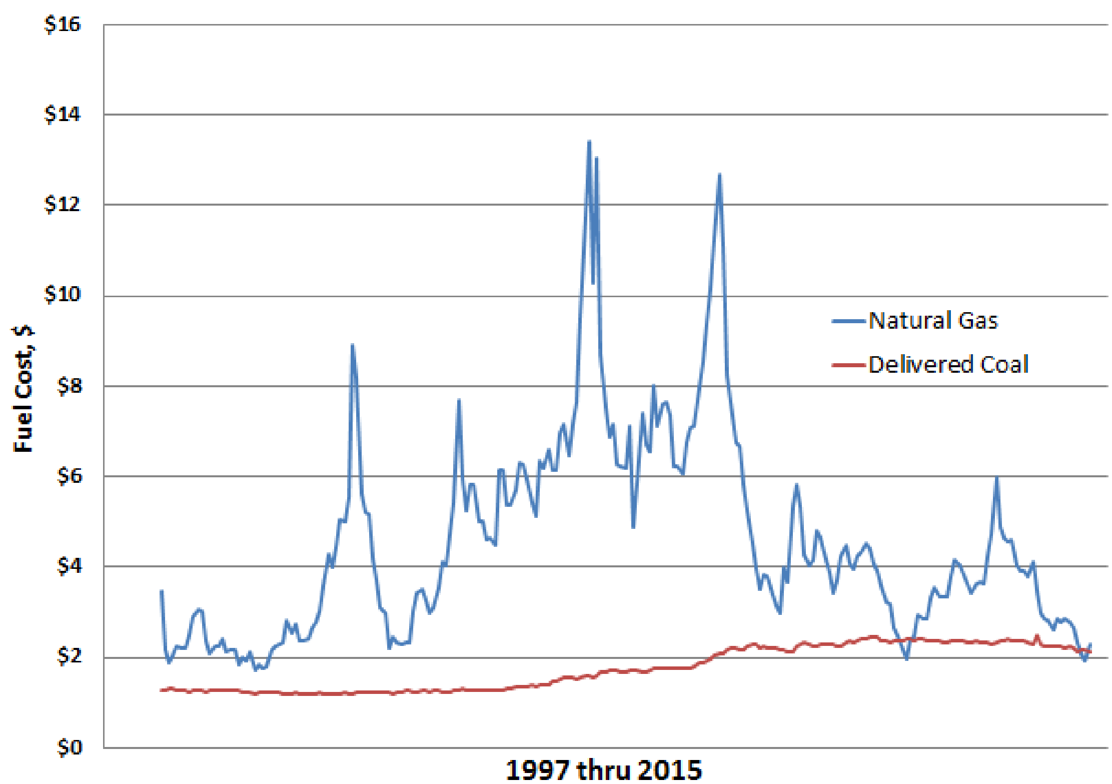
Emission standards and guidelines established for carbon dioxide by the Clean Power Plan (CPP) apply to existing coal-fired electrical generating units (EGUs). Converting an existing coal-fired boiler to natural gas could be a potentially viable non-BSER (best system for emission reduction) CPP compliance option, as coal-to-natural gas conversion would reduce CO_2 emissions from the affected units. A comprehensive evaluation of the station's potential CPP compliance options should be evaluated in the next phase.

1.2 Cost Variability of Natural Gas and Coal

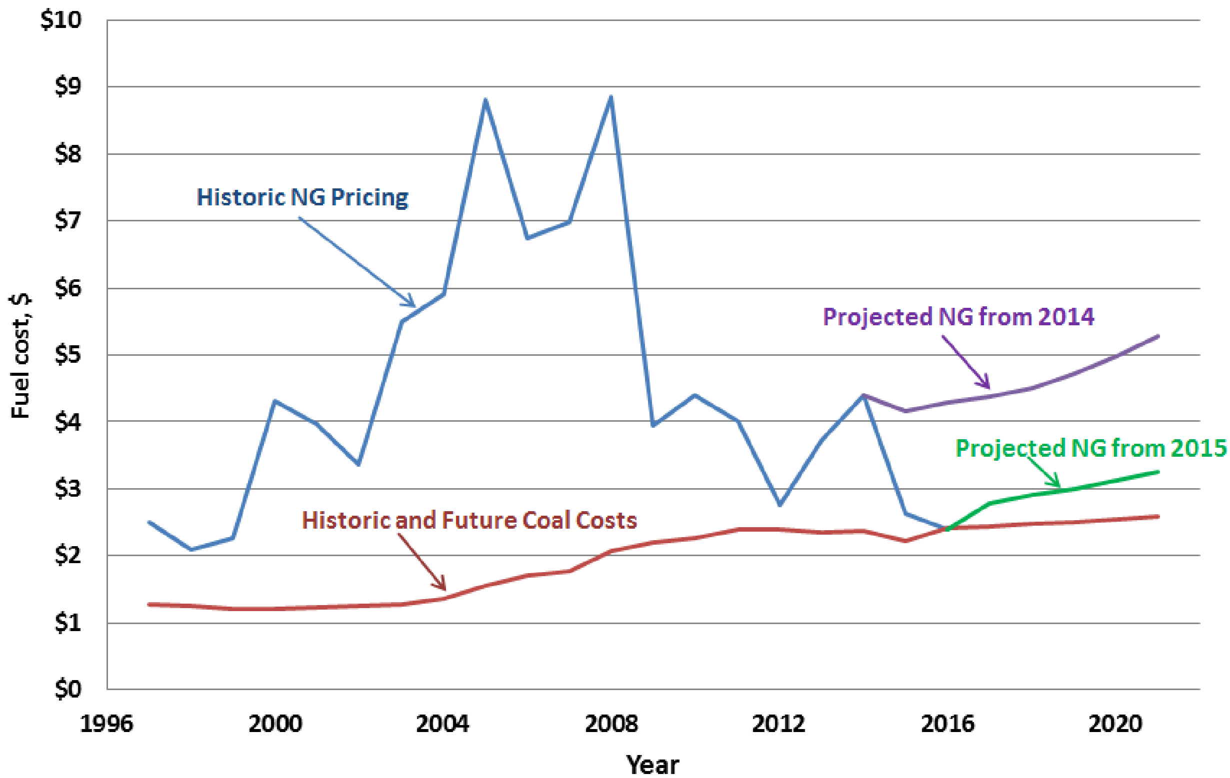
Historically, delivered coal prices have been consistently lower than for natural gas. Figure 1 offers historical monthly fuel costs for coal and natural gas between 1997 and 2015. Since April 2009, monthly natural gas fuel costs have not exceeded $6 per MBtu, but have dipped below coal costs for a few months in 2012 and 2015. With natural gas costs being historically low since the late 1990s, and due to the uncertainty in environmental regulations, fuel switching has become an increasingly attractive solution.

Figure 1: Historical Monthly Fuel Cost Averages for Coal and Natural Gas



From the graph, it is clear that natural gas prices can fluctuate drastically. Since 2005, fuel costs have ranged anywhere between $2 per MBtu to $13.5 per MBtu. Large fluctuations in fuel costs make it difficult to determine an approach to comply with environmental regulations. For facilities already environmentally compliant, adding natural gas firing capability provides fuel flexibility and potential fuel savings when natural gas prices dip below coal costs, and avoids variable operating costs associated with coal. Figure 2 provides a historical and projected outlook for natural gas and coal costs from 1997 through 2021 based on Henry Hub pricing. Natural gas price projections from 2014 and 2015 are shown in the graph and highlight a significant future assessment on fuel forecasting. Although future natural gas prices are expected to slightly increase to approximately $3 per MBtu by 2021, future costs are mere projected/estimated costs, and therefore can change in magnitude as the Henry Hub projected in 2014.

Figure 2: Historical and Projected Yearly Coal and Natural Gas Fuel Costs from 1997-2021



1.3 Natural Gas Availability

Low prices and regulatory pressures have increased the 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. Using the Texas Gulf Region as an example, the locations of the existing coal power plants represented as white

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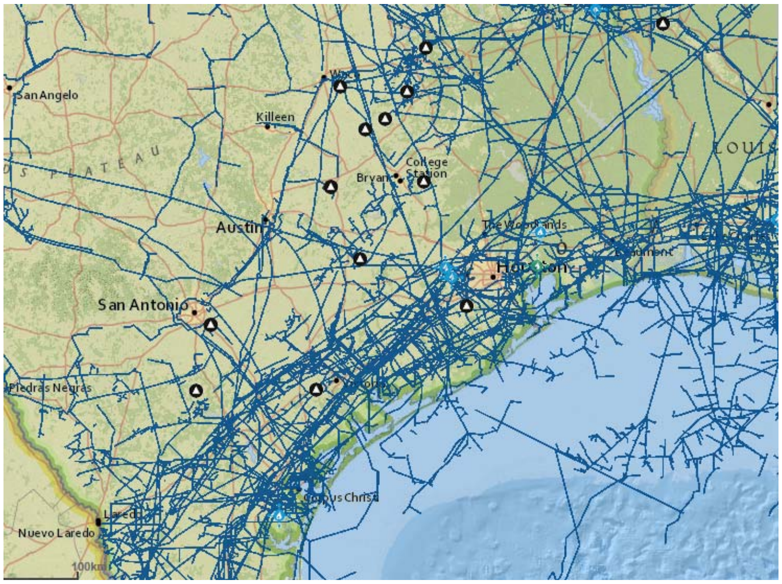
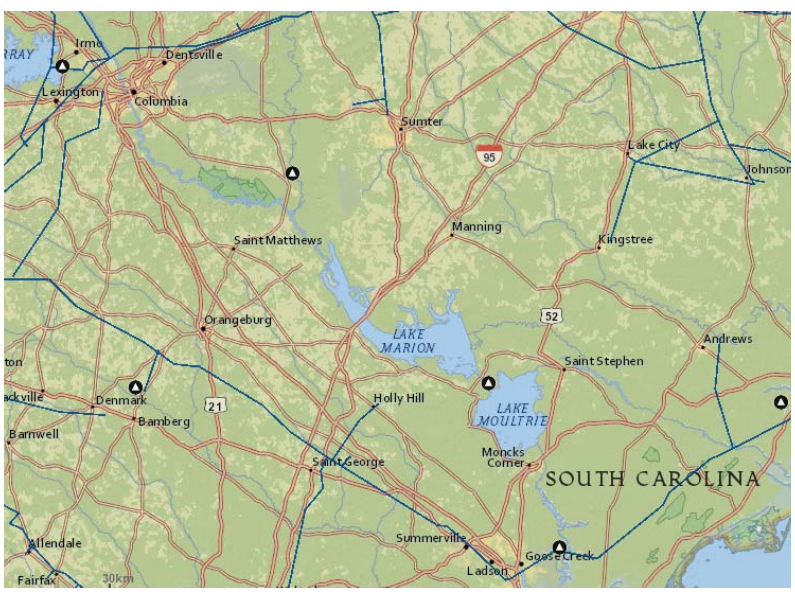
triangles inside black circles shown in Figure 3 illustrate the advantages these plants have by their proximity to natural gas fuel sources.

Figure 3. Natural Gas Pipelines in the Texas Gulf Region



Utility generating stations in some areas of the United States, such as the Carolinas, 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 4. Natural Gas Pipelines in the Carolinas



2. CASE STUDY 1: RETIRING AND DECOMMISSIONING OF COAL-RELATED EQUIPMENT

2.1 Case Study 1 Background

Case 1 is a 150-MW gross steam electric, multi-fueled unit designed to fire natural gas, oil, and coal. The boiler has an original maximum continuous rating (MCR) of 1,000,000 lb/hr main steam flow with outlet conditions of 1875 psig and 1010°F. A reverse air (RA) baghouse is used for particulate matter (PM) control. The facility recently switched to burning 100% natural gas to diversify its energy profile and to be compliant with Regional Haze and future CPP CO_2 requirements.

2.2 Boiler Performance Summary

The major conclusions of the Case 1 study of reverting to firing natural gas only were:

- Original steam output of 1,000,000 lb/hr can be achieved when firing natural gas. The original steam output when firing coal is 700,000 lb/hr.
- Boiler efficiency decreased approximately 4%, which also saw degradation in net plant heat rate of 3%.

2.3 Retiring and Decommissioning of Coal-Related Equipment

A study performed by Sargent & Lundy provided recommendations on all coal-related equipment, including all major boiler long-term plant modifications required for the decommissioning of the unused equipment and facilities. These modifications would be implemented during the first major unit outage in the 2017. Table 1 summarizes Sargent & Lundy's major findings and recommendations.

Table 1. Summary of Case 1 Conclusions

System, Equipment, or Component	Extent
Coal handling equipment (coal yard)	*Tripper Room and Dumper House / Tunnel*: Continue use of ventilation system for proper air circulation and continued use of sump pumps in tunnels. *Reclaim Hopper*: The reclaim hopper required a secured cover to help prevent storm water intrusion when no coal is present. *Conveyor Systems*: Tension was released on each belt and the idlers were left in place. Counterweights were secured in a no tension position for safety.
All motors, gearboxes, and electrical equipment	Prior to disconnecting power or instrumentation cables, the current combustion control and burner management systems were reviewed to confirm that no permissives in the logic were tied to the coal system when firing natural gas. All electrical cable connections were removed back to a junction box or cable tray and breakers were "spared" and leads pulled. All gearboxes were drained.

Air sootblowers	Air compressors were abandoned in place and air connections to each sootblower were disconnected and capped. All sootblowers were removed from service with new wall plates and refractory on each boiler wall opening.
Boiler coal equipment (in plant)	Pulverizers, coal feeders, and silos were retired and left in place. All shutoff dampers were closed and isolated from service. Tempering and hot air system isolation dampers were closed and de-energized.
Primary air heater system	Primary air steam coils were removed and steam source was capped and removed from service. The primary air system had its own air heater in which the inlet and outlet ducts on the air and flue gas side were blanked and demolished. The primary air heater was taken out of service.
Reverse air (RA) baghouse	Pressure losses were assessed when evaluating its bypass system versus removal of fabric filters from the baghouse. Due to the uncertainty with the bypass dampers and duct, it was decided to remove the fabric filters to reduce pressure drop from the ID fan and reduce auxiliary power consumption.
Coal feeders, pulverizers, and exhausters	Coal feeders, pulverizers, and exhausters were removed from service, cleaned, de-energized and retired in place.
Cooling water supply/return for pulverizers	Supply and return lines to pulverizer lube oil coolers will be isolated by closing isolation valves.
Bottom and fly ash	Portions of the bottom ash and fly ash systems were isolated and removed from service. The bottom ash hoppers and water seal at the bottom of the furnaces were retained to provide for the thermal expansion of the boiler, boiler access for outages, and to reduce the negative transient fuel trip furnace pressures. The service water supply for ash hopper tap cooling, water seal makeup, and overflow remain in operation. All conveyor belts and drag chains were removed from service. Recirculation and sluice pumps were decommissioned and left in place.
Water and steam balance- of-plant (BOP) piping	All water and steam piping systems were drained and capped, and piping dead legs were removed. This mitigated the risk of pipes rupturing during freezing conditions in the winter months.
Forced draft (FD) and induced draft (ID) fan performance	The unit was originally designed as a pressurized boiler until coal firing capabilities and balanced-draft operations were implemented in the 1980s. FD fan and air/flue gas draft systems were evaluated for pressurized operation. It was believed that auxiliary power could be reduced significantly with the elimination of the ID fan and improvements in ramp rates could be achieved. Our assessment indicated limited fan capacity, minimal improvements to ramp rates, and additional modifications were needed to the bottom ash system and access doors if pressurized operations were elected. It was recommended to continue balanced-draft operations and to install new variable frequency drives (VFDs) on the FD and ID fans if the unit continued to cycle.

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2.4 O&M Costs

Fixed O&M costs were estimated to decrease by approximately 45% when converting to operation on natural gas. The cost savings would be achieved by elimination of the ash handling and coal handling systems and a reduction in water treatment and other expenses. Variable O&M costs for this unit were estimated to be reduced by approximately 15%, based on eliminating the need for fly and bottom ash disposal, auxiliary power reductions, and the associated fuel costs.

3. CASE STUDY 2: DUAL-FIRING CAPABILITIES

3.1 Case Study 2 Background

Case 2 is a 900-MW gross steam electric, coal-fired unit with an original MCR rating of approximately 6,300,000 lb/hr main steam flow and outlet conditions of 3800 psig and 1005°F. The boiler has a tangentially firing configuration with new low-NO_X combustion upgrades consisting of burners, closed-coupled overfire air, and separated overfire air ports. The plant currently burns Eastern bituminous coal and has a selective catalytic reduction (SCR), electrostatic precipitator (ESP), and wet flue gas desulfurization (FGD) system for NO_X, PM, and sulfur emission control, respectively.

The natural gas addition design goals were the following:

- Adding natural gas firing capabilities to the unit.
- Retaining coal firing capabilities (cofiring).
- No major pressure part modification and no flue gas recirculation.
- Eliminating distillate oil igniters and replacing with natural gas.
- Fuel flexibility.

3.2 Boiler Thermal Performance Summary

The major conclusions of the Case 2 study of converting to cofire natural gas were:

- Firing 100% natural gas at 20% excess air with 975ºF reheat steam results in an estimated decrease of 7 MW to 20 MW in gross generation.
- An increase of approximately 1% to 2% steam flow at full load is needed to offset the predicted megawatt reduction. The steam flow increase is within the operating capability experienced by the plant.
- To increase reheat steam temperature when firing 100% natural gas to match the reheat temperature when firing coal, reheat pendant surface can be added or excess air can be increased to 28% with modifications made to the FD fans for increased capacity.

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3.3 Balance-of-Plant and Equipment Layup Challenges

3.3.1 Balance-of-Plant Considerations

Since coal firing will be retained, coal equipment and instrumentation and controls would need to be left in place. Installing new natural gas equipment and instrumentation and controls to an already congested coal burner front area is challenging and typically increases material and labor costs. In addition, new operating conditions are presented to environmental equipment, which will affect overall performance. Table 2 summarizes the major considerations when designing for dual-fuel firing capabilities.

Table 2. Summary of Case 2 Conclusions

System, Equipment, or Component	Extent
Natural gas piping, and valving	Existing coal pipe bays will not be available for natural gas fuel pipe routing. Since most burner fronts are congested, additional natural gas piping is generally needed and may cause additional pressure drop in the system. Locating burner and igniter double-block-and-bleed valves and vent piping/valves also becomes a concern.
Instrumentation and controls	Modifications to the distributed control system (DCS) combustion control logic and burner management system (BMS) would be needed, consistent with the physical and operational changes being implemented in the plant. Input/output (I/O) signals, logic, and graphics will be added. New instruments and equipment would be added to the existing software and graphics. Additional control cabling, cabinets and cards would be required. The existing igniter flame detectors and furnace flame scanners would be replaced with new burner flame scanners.
Wet FGD bypass system	A new wet FGD bypass system would be required when operating natural gas. Sulfur removal is no longer required, but the wet FGD system is typically lined with rubber or fiberglass, which has temperature limitations of 180°F. Options to continue water injection on the wet FGD was discussed, but would have a variable O&M impact.
SCR	Continued use of the SCR is expected, but variable O&M costs will reduce since NO_X emissions rates when firing natural gas will be lower than when firing coal.
ESP	Continued use of the ESP is expected with no modifications needed.
Stack/chimney	Continued use of the chimney is expected since it was brick-lined. If there is a liner in the chimney, water injection in the wet FGD would be required due to temperature limitations of the liner.

3.3.2 Equipment Layup Considerations

Sargent & Lundy evaluated various pieces of equipment associated with the coal burning operation that would be affected by the coal-to-gas conversion project. As part of the conversion, 100% natural gas firing and coal firing capability was to be retained.

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The equipment associated with coal cofiring was kept in place and maintained by recommended procedures outlined by Sargent & Lundy. This includes all coal yard handling equipment, pulverizers, and their associated primary air fans and seal air systems.

Overall plant housekeeping should be performed to remove coal dust from all plant areas, with special attention given to the coal handling systems. Coal cleanup should be performed prior to starting any layup procedure and after all coal operations at the plant have stopped.

With the uncertainty of when coal will be fired, short-term layup and monthly operation were recommended for most coal handling equipment, including pulverizers, to support coal firing operations. Some equipment was also recommended to be left in service and continuously operated, while the rest of the coal equipment was recommended to be operated for approximately 30 minutes every month.

It is strongly encouraged to maintain records of these monthly inspections to assess degradation and any modifications made to the equipment. This will help facilitate any inquiries to the original equipment manufacturer (OEM) on replacement parts and any upgrades required in the event either unit cofires coal in the future. Special attention should be given to dry rot, moisture, and corrosion. In the event that substantial dry rot or corrosion is detected, it is recommended to consult with the OEM for recommendations on corrective action.

All motors, gearboxes, and electrical equipment need additional attention. Motor space heaters were to be energized at any time the equipment was not running. Measuring and recording motor resistance of the winding insulation is also recommended. Gearboxes required monthly inspections for moisture or oxidation. Grease-lubricated bearings must be inspected once a month for moisture and oxidation by purging a small quantity of grease through the drain. If contamination is present, the grease must be completely removed and replaced.

3.4 O&M Costs

Estimating O&M costs for a dual-fuel boiler is challenging. Fixed O&M costs would reduce when firing natural gas, but continued O&M is required on existing coal equipment. Ash and coal handling personnel may be transferred to other facilities within the fleet, since original coal staffing would need to be retained when the unit returns to coal firing. Sargent & Lundy estimates that fixed O&M costs would be reduced by approximately 20% when fuel switching to natural gas, but unused resources would transfer to other facilities in the fleet. The cost savings would be achieved by fewer staff in ash handling and coal handling and a reduction in water treatment and other expenses. Support is still necessary for the coal yard and increase O&M on idle coal equipment.

Variable O&M costs for this unit were estimated to reduce by approximately 20%. Variable O&M costs would include fly and bottom ash disposal, auxiliary power consumption reductions, limestone cost, fuel costs, and ammonia. It was assumed that the derated lost power would be purchased from the grid since the unit is expected to be derated when firing natural gas.

4. SUMMARY

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. Facilities that are already environmentally compliant have expressed great interest in adding dual-firing capabilities, which provides for fuel flexibility and fuel diversity in power generating unit portfolios. Understanding fuel costs and availability and the uniqueness of each case study in the early project stages will lead to a successful conversion to natural gas firing.

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