UNIT HEAT RATE IMPROVEMENT STUDY

AT CORONADO GENERATING STATION

SL-012487

November 13, 2014
PROJECT 12113-303

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EXECUTIVE SUMMARY

On June 18, 2014, the United States Environmental Protection Agency (EPA) published the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule" in the *Federal Register*. (79 Fed. Reg. page 34830). The proposed rule does not set emissions standards for individual sources, but provides guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing sources. Specifically, EPA proposed to establish state-specific rate-based (or mass-based) goals for carbon dioxide (CO_2) emissions from the power sector, including existing fossil fuel-fired electric generating units (EGUs). Proposed emission goals vary from state to state.

EPA's proposal includes four building blocks to lower GHG emissions from power plants. To establish each state's rate-based CO_2 emissions goal, EPA concluded "that a six percent reduction in the CO_2 emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost." (79 FR 34861). Heat rate improvements that may be achieved by adopting best practices and equipment upgrades were based in part on EPA's review and interpretation of a report, titled "Coal-Fired Power Plant Heat Rate Reductions" prepared by Sargent & Lundy in 2009 for the EPA (hereafter referred to as the "2009 Report").

The purpose of the 2009 Report was to identify various methods that have been successfully implemented in the industry to improve the heat rate of existing U.S. coal-fired power plants. For each alternative, S&L estimated the potential heat rate improvement that may be achieved at a 200, 500, and 900 MW coal plant. The 2009 Report also provided two conceptual level case studies: one for a 250 MW unit and the second for an 850 MW unit, to provide examples of how heat rate improvement projects would be implemented and to identify some of the site-specific technical issues that would need to be taken into consideration.

Based on information provided in the 2009 Report, "EPA estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh, corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from \$40 to \$150 per kW." (79 FR 34861)[1] However, based

[1] It should be noted that the pre-publication version of the proposed rule published on June 2, 2014 stated that "The [2009 S&L] study estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh,

on a review of the 2009 Report, as well as a review of EPA's Goal Computation Technical Support Document, it appears as though EPA misapplied information presented in the 2009 Report when it calculated heat rate improvements of 415 to 1205 Btu/kWh and 4 to 12 percent.

It appears EPA assumed heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units, when the 2009 Report does not state it would be feasible to implement all of the examined alternatives to achieve the sum total of their heat rate improvements. Furthermore, the 2009 Report does not state any range of overall heat rate improvements that could be expected from implementing any combination of the examined alternatives. Heat rate improvements described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. In addition, verification of actual heat rate improvements was not made to determine whether any of the modifications were implemented and what actual heat rate improvements were realized based on detailed design. Furthermore, the case studies showed that it would not be feasible to apply all of the examined alternatives from the study to an individual generating unit due to a number of factors including plant design, previous equipment upgrades, and operational approaches.

The purpose of this engineering study is to review the potential heat rate improvement strategies identified in S&L's 2009 Report and assess their feasibility to improve heat rate for both units at Salt River Project's (SRP) Coronado Generating Station (CGS).

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corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from $40 to $150 per kW." (See, pre-publication version, page 168 of 645). However, that conclusion was not included in the 2009 Report. The 2009 Report did not state that heat rate improvements were additive, nor did the report conclude that heat rate improvements of 4 to 12 percent would be achievable for a typical coal-fired EGU. In the version of the proposed rule that was published in the *Federal Register*, EPA corrected this statement to make it clear that "EPA estimated" heat rate improvements of 415 to 1250 Btu/kWh, or 4 to 12% may be achievable on existing coal-fired EGUs.

In both the 2009 Report and EPA's proposed regulation for GHG emissions for existing stationary sources, the areas of a power plant where efficiency and heat rate improvement may be possible are:

- Boiler Island
- Turbine Island
- Flue Gas System
- Air Pollution Control Equipment
- Water Treatment System

This study identifies systems and equipment at CGS Units 1 and 2 where efficiency improvements may be realized either through new installations or modifications. This study also provides estimates of the resulting net plant heat rate improvements and the order-of-magnitude costs for implementation. Additionally, S&L reviewed past modifications to the units to estimate the maximum heat rate improvement that has already been achieved. To conduct this evaluation, S&L reviewed equipment data manuals, system description manuals, plant data, test reports, and documents from past projects between SRP and S&L for each of the CGS units.

It should be noted that the scope of this report does not include any detailed design work. Should SRP implement any of the technologies identified as potentially improving heat rate at one or both of their CGS units, detailed design work may reveal limitations in either the applicability of the technology or limitations on the achievable heat rate improvement.

Coronado Generating Station, owned & operated by SRP, is located in St. John's, Arizona and includes two (2) 437 MW_{gross} pulverized coal units with Riley Turbo boilers that were originally designed to fire bituminous fuel and blends of bituminous and sub-bituminous coals. The units switched to a sub-bituminous coal, specifically Powder River Basin (PRB) coal, in 2007. Unit 1 was placed into service in 1979 and Unit 2 in 1980. Each unit was originally equipped with a hot-side electrostatic precipitator (HESP) and horizontal wet limestone scrubbers for emissions control.

In August 2008, a final settlement between the U.S. Environmental Protection Agency (EPA), the Department of Justice, and SRP was issued to resolve alleged Clean Air Act (CAA) violations at the Coronado Generating Station. Under the settlement, SRP was required to install state-of-the-art pollution control technology for the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). According to the Consent Decree, CGS was required to replace the original horizontal scrubbers with new Wet Flue Gas Desulfurization (WFGD) systems to achieve higher SO_2 reductions. The new WFGD systems are open spray tower absorbers and have ancillary equipment including recycle pumps, mist eliminator wash, bleed pumps, oxidation air blowers and primary dewatering hydrocyclones. To account for the increased pressure drop through the flue gas system, new axial flow ID fans were installed. Unit 1 and Unit 2 WFGD's were placed into service in 2012 and 2011, respectively. As required by the Consent Decree to reduce NO_X emissions, the units were both retrofitted with Low-NO_X burners (LNBs), in 2009 on Unit 1 and in 2011 on Unit 2, and a Selective Catalytic Reduction (SCR) system was installed on Unit 2 in 2014.

In addition to the air pollution control systems that were implemented for compliance, other modifications to the units have also been implemented since the units were brought online. The modifications that affected the units' net heat rates were: turbine upgrade in 1999-2000, conversion from wet to dry bottom ash conveying, a neural network and knowledge-based sootblower system. In addition to these modifications for compliance, Coronado Generating Station also began firing Powder River Basin (PRB) coal in 2007. Due to high moisture content in PRB coal, the boiler efficiency of both CGS units is reduced, which results in higher heat rate, or heat rate penalty.

For each unit, two numbers were estimated based on this evaluation: (1) percent change in heat rate from original design based on past modifications, and (2) potential percent change in heat rate. The following tables summarize these changes for Unit 1 and Unit 2. The negative values listed in Table ES-1 are considered to be improvements in the unit's heat rate while a positive value represents a heat rate penalty.

Table ES-1 – Summary of Heat Rate Changes for Unit 1 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date Note 3	Potential % Change Note 3
Boiler Island		
Material Handling	-0.10%	N/A
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BMP Note 1
Neural Network & Intelligent Sootblowers	-1.0%	N/A
Air Pre-Heater		
Reduce Air Heater Leakage	-0.05%	BMP
Reduce Flue Gas Acid Dew Point	+0.15%	N/A
Turbine Island		
Turbine Overhaul	-3.8%	-1.0%
Feedwater Heaters	0%	BMP
Condenser	0%	BMP
Boiler Feed Pumps	0%	BMP
Flue Gas System		
FD and ID Fan Efficiency	Note 2	N/A
Primary Air Fans	N/A	N/A
Air Pollution Control Equipment		
FGD System	0%	BMP
SCR System	N/A	N/A
ESP	N/A	N/A
Cooling Towers	N/A	BMP
Large Scale Motors	0%	BMP
TOTAL	**-4.8%**	**-1.0%**
Additional Plant Modifications		
Coal switch to PRB	+1.8%	N/A

Note 1: "BMP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BMP prevents significant degradation of the unit's performance.
Note 2: Change in heat rate due to FD and ID fan efficiency has been included in FGD auxiliary power consumption section as discussed in Section 2.3.1.
Note 3: Negative values listed are considered to be improvements in the unit's heat rate, and a positive value represents a heat rate penalty.

Table ES-2– Summary of Heat Rate Changes for Unit 2 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date Note 3	Potential % Change Note 3
Boiler Island		
Material Handling	-0.10%	N/A
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BMP Note 1
Neural Network & Intelligent Sootblowers	-0.6%	N/A
Air Pre-Heater		
Reduce Air Heater Leakage	-0.05%	BMP
Reduce Flue Gas Acid Dew Point	+0.13%	N/A
Turbine Island		
Turbine Overhaul	-3.8%	-1.0%
Feedwater Heaters	0%	BMP
Condenser	0%	BMP
Boiler Feed Pumps	0%	BMP
Flue Gas System		
FD and ID Fan Efficiency	Note 2	N/A
Primary Air Fans	N/A	N/A
Air Pollution Control Equipment		
FGD System	0%	BMP
SCR System	+0.5%	N/A
ESP	N/A	N/A
Cooling Towers	N/A	BMP
Large Scale Motors	0%	BMP
TOTAL	**-3.9%**	**-1.0%**
Additional Plant Modifications		
Coal switch to PRB	+1.8%	N/A

Note 1: "BMP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design, or a change of 0%. BMP prevents significant degradation of the unit's performance.
Note 2: Change in heat rate due to FD and ID Fan efficiency has been included in FGD and SCR auxiliary power consumption section as discussed in Section 2.3.1.
Note 3: Negative values listed are considered to be improvements in the unit's heat rate, and a positive value represents a heat rate penalty.

As shown in the above table, Unit 1 has improved heat rate by an estimated 4.8%, however the total heat rate improvement including impacts of switching to PRB coal is approximately 3.0%. For Unit 2, the improvement in heat rate is estimated to be 3.9%; however the total improvement including switching to PRB coal is approximately 2.1%. Unit 2 has a lower heat rate improvement due to the SCR that was installed for regulatory compliance with the Consent Decree. The potential improvement in heat rate is estimated to be 1.0% for each unit; this 1% would be attributed to the potential turbine upgrade. The units at CGS have implemented some of the heat rate improvement technologies prior to 2012. SRP should continue to implement good maintenance practices to prevent significant degradation of the units' heat rates.

1. INTRODUCTION

1.1 PURPOSE

On June 18, 2014, the United States Environmental Protection Agency (EPA) published the "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units; Proposed Rule" in the *Federal Register.* (79 Fed. Reg. page 34830). The proposed rule does not set emissions standards for individual sources, but provides guidelines for states to follow in developing plans to address greenhouse gas (GHG) emissions from existing sources. Specifically, EPA proposed to establish state-specific rate-based (or mass-based) goals for carbon dioxide (CO_2) emissions from the power sector, including existing fossil fuel-fired electric generating units (EGUs). Proposed emission goals vary from state to state.

To establish the state-specific rate-based CO_2 emission goals, EPA analyzed potential CO_2 emission reductions associated with various "building blocks" that affect the power generating industry. The building blocks included: (1) reducing CO_2 emissions (i.e., lb CO_2/MW-net) at individual affected EGUs through increased efficiency and heat rate improvements; (2) CO_2 emission reductions achievable through re-dispatch from coal-fired and oil/gas steam-fired units to natural gas combined cycle units; (3) expanded use of renewable and nuclear energy resources; and (4) expanded use of demand-side energy efficiency. Based on this evaluation, and taking into consideration each state's current mix of generation resources, EPA established state-specific rate-based CO_2 emission goals.

The proposed rule does not explicitly require that each state follow the building block approach to achieve the emission guidelines. States will have the flexibility to use any combination of measures, or building blocks, most relevant to their specific circumstances and policy preferences. Although the proposed guidelines do not include CO_2 emission standards for individual sources, states are required to establish them as part of their compliance plan and may require existing coal-fired EGUs to reduce CO_2 emissions through heat rate improvements.

To establish each state's rate-based CO_2 emissions goal, EPA concluded "that a six percent reduction in the CO_2 emission rate of the coal-fired EGUs in a state, on average, is a reasonable estimate of the amount of heat rate improvement that can be implemented at a reasonable cost." (79 FR 34861). The average 6% heat rate improvement (using 2012 as the baseline year) was determined to be a reasonable target based on EPA's evaluation of heat rate improvements that may be achieved at existing coal-fired EGUs through the adoption of best practices (e.g., turning off unneeded pumps, installation of digital controls systems, earlier like-kind replacement of worn components, etc.) and equipment upgrades. Heat rate improvements that may be achieved by adopting best practices and equipment upgrades were based in part on EPA's review and interpretation of a report, titled "Coal-Fired Power Plant Heat Rate Reductions" prepared by Sargent & Lundy in 2009 for the EPA (hereafter referred to as the "2009 Report").

The purpose of the 2009 Report was to identify various methods that have been successfully implemented in the industry to reduce the heat rate of existing U.S. coal-fired power plants. The 2009 Report identified a range of conceptual Btu/kWh heat rate improvement projects, including boiler modifications, steam turbine modifications, control system upgrades, high efficiency motors, and similar modifications known to result in system efficiency gains. For each alternative, S&L estimated the potential heat rate improvement that may be achieved at a 200, 500, and 900 MW coal plant. The 2009 Report also provided two conceptual level case studies: one for a 250 MW unit and the second for an 850 MW unit, to provide examples of how heat rate improvement projects would be implemented and to identify some of the site-specific technical issues that would need to be taken into consideration.

In the preamble to the proposed rule, EPA stated that it "believes that implementation of all identified best practices and equipment upgrades at a facility could provide total heat rate improvements in a range of approximately 4 to 12 percent." (79 FR 34859). Based on information provided in the 2009 Report, "EPA estimated that for a range of heat rate improvements from 415 to 1205 Btus per kWh, corresponding to percentage heat rate improvements of 4 to 12 percent for a typical coal-fired EGU, the required capital costs would range from $40 to $150 per kW." (79 FR 34861)[2] However, based on a review of the 2009 Report, as well as a review of EPA's Goal Computation Technical Support Document, it appears as though EPA misapplied information presented in the 2009 Report when it calculated heat rate improvements of 415 to 1205 Btu/kWh and 4 to 12 percent.

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It appears that EPA assumed that heat rate improvements cited in the 2009 Report were additive and applicable to all coal-fired units, when the 2009 Report does not state it would be feasible to implement all of the examined alternatives to achieve the sum total of their heat rate improvements. Furthermore, the 2009 Report does not state any range of overall heat rate improvements that could be expected from implementing any combination of the examined alternatives.

Heat rate improvements described in the 2009 Report case studies were estimated at a conceptual level, and were not based on any site-specific detailed analysis. In addition, verification of actual heat rate improvements was not made to determine whether any of the modifications were implemented and what actual heat rate improvements were realized based on detailed design. Furthermore, the case studies showed that it would not be feasible to apply all of the examined alternatives from the study to an individual generating unit due to a number of factors, including plant design, previous equipment upgrades, and operational approaches.

The purpose of this engineering study is to review the potential heat rate improvement strategies identified in S&L's 2009 report and assess their feasibility to improve heat rate for both units at Salt River Project's (SRP) Coronado Generating Station (CGS).

In both the 2009 Report and EPA's proposed regulation for greenhouse gas (GHG) emissions for existing stationary sources, the areas of a power plant where efficiency and heat rate improvements may be possible are:

- Boiler Island
- Turbine Island
- Flue Gas System
- Air Pollution Control Equipment
- Water Treatment System

This study identifies systems and equipment at CGS Units 1 and 2 where efficiency improvements may be realized either through new installations or modifications. This study also provides estimates of the resulting net plant heat rate improvements and the order-of-magnitude costs for implementation. Additionally, S&L reviewed past modifications to the units to estimate the maximum heat rate improvement that has already been achieved. To conduct this evaluation, S&L reviewed equipment data manuals, system description manuals, plant data, test reports, and documents from past projects between SRP and S&L for each of the CGS units.

1.2 STUDY SCOPE

The following technical alternatives were identified in the 2009 report for efficiency and heat rate improvements in the aforementioned power plant areas:

- Boiler island
  - Coal transport, conveying, and grinding
  - Boiler operation/overhaul with new heat transfer surface
  - Neural network (NN) control systems
  - Intelligent sootblowers (ISB) systems
  - Air heaters
- Turbine island
  - Turbine
  - Feedwater heaters
  - Condenser
  - Turbine drive/motor-driven feed pumps
- Flue gas system
  - Forced draft (FD) and induced draft (ID) fan improvement
  - Variable Frequency Drives (VFDs)
- Air pollution control equipment
  - Flue gas desulfurization (FGD) system
  - Particulate system
  - Selective catalytic reduction (SCR) system
- Water treatment system
  - Boiler water treatment
  - Cooling tower

S&L has evaluated each technical alternative to determine whether they are technically feasible at the CGS units as a means of improving heat rate. For the alternatives that are determined to be technically applicable to CGS, S&L estimated the improvement in unit heat rate specific to the CGS units. This report documents the following:

- Identification of technical alternatives and/or operating practices that would likely improve plant efficiency at CGS
- Estimated improvement in unit heat rate resulting from implementation of the technical alternatives or operating practices determined to be technically feasible at CGS
- Commercial availability and current industry application of the technical alternative or operating practices
- Impacts on balance of plant at CGS

It should be noted that the scope of this report does not include any detailed design work. Should SRP implement any of the technologies identified as potentially improving heat rate at one or both of their CGS units, detailed design work may reveal limitations in either the applicability of the technology or limitations on the achievable heat rate improvement.

1.3 STATION BACKGROUND

Coronado Generating Station, owned & operated by SRP, is located in St. John's, Arizona and includes two (2) 437 MW_{gross} pulverized coal units with Riley Turbo boilers that were originally designed to fire bituminous fuel and blends of bituminous and sub-bituminous coals. The units switched to a sub-bituminous coal, specifically Powder River Basin (PRB) coal, in 2007. Unit 1 was placed into service in 1979 and Unit 2 in 1980. Each unit was originally equipped with a hot-side electrostatic precipitator (HESP) and horizontal wet limestone scrubbers for emissions control.

In August 2008, a final settlement between the U.S. Environmental Protection Agency (EPA), the Department of Justice, and SRP was issued to resolve alleged Clean Air Act (CAA) violations at the Coronado Generating Station. Under the settlement, SRP was required to install state-of-the-art pollution control technology for the reduction of sulfur dioxide (SO_2) and nitrogen oxides (NO_X). According to the Consent Decree, CGS was required to replace the original horizontal scrubbers with new WFGD systems to achieve higher SO_2 reductions. The new WFGD systems are open spray tower absorbers and have ancillary equipment including recycle pumps, mist eliminator wash, bleed pumps, oxidation air blowers and primary dewatering hydrocyclones. To account for the increased pressure drop through the flue gas system, new axial flow ID fans were installed. Unit 1 and Unit 2 WFGD's were placed into service in 2012 and 2011, respectively. As required by the Consent Decree to reduce NO_X emissions, the units were both retrofitted with Low-NO_X burners (LNBs), in 2009 on Unit 1 and in 2011 on Unit 2, and a Selective Catalytic Reduction (SCR) system was installed on Unit 2 in 2014.

1.4 KEY ASSUMPTIONS

The key assumptions included in S&L's analysis are summarized below:

- Although the CGS units are designed to fire 100% bituminous fuel and blends of bituminous and sub-bituminous fuel, since 2007 the plant has fired 100% sub-bituminous, specifically Powder River Basin (PRB) fuel. This report assumes 100% PRB fuel firing will continue to apply in the future. If bituminous fuels are fired, some of the results reported in this analysis would need to be modified.

- For technologies that have already been implemented at CGS this report assumes that plant data available for net plant load and heat input are accurate enough to report relative changes to heat rate before and after a project was implemented. Data ranges analyzed were selected to isolate contributions of specific modifications to the extent possible.

- For technologies that cannot be compared to plant data, the change in auxiliary power was used to estimate the net heat rate change. Since EPA proposed rule uses net heat rate and net generation for its analysis, the change in auxiliary power is compared to the net load rating of the units. The net load rates for Unit 1 and Unit 2 are 380 MW and 385 MW, respectively.

- For some of the analyses data were only available for a single unit. In those cases, this report assumes equivalent performance between the units. This is a reasonable assumption because both units utilize similar, if not the same, equipment, maintenance practices, and fuel, and were brought online within a year of each other.

- Air heater in-leakage for Unit 1 is assumed to be the same as Unit 2 air preheaters. Unit 2 air preheaters were upgraded in 2014, and performance test data was received and analyzed. Unit 1 air preheaters will be upgraded in 2015 the same as was done for Unit 2. Both units' air preheaters are seeing deterioration due to the use of Calcium Bromide.

- The heat rate improvements were evaluated based on full load operation. Increased cycling and long term operation at lower loads will result in heat rate penalties because units are designed to optimize efficiency at full load.

2. POTENTIAL MODIFICATIONS BASED ON 2009 REPORT

This section of the report addresses the potential for implementing heat rate improvements identified in the 2009 Report. For technologies that have already been installed at the CGS units, the sections below identify what year the technologies were installed, what heat rate changes were observed, and if additional improvements would achieve further improvements in heat rate. For technologies that have not been installed at the CGS units, the sections below identify whether the technology is feasible at CGS and estimate the heat rate improvements for those applicable technologies.

2.1 BOILER ISLAND

This section of the report discusses equipment within the CGS Unit 1 and Unit 2 boiler islands that offer potential improvements in plant heat rate:

- Material Handling
- Boiler operation/overhaul with new heat transfer surface
- Neural network system and intelligent sootblowers
- Air pre-heaters

2.1.1 Material Handling

Material handling systems include coal, bottom ash, and fly ash handling. With respect to coal handling systems, the use of more efficient motors can improve efficiency. Motor efficiency improvements are discussed in Section 2.6 of this report. With respect to ash handling systems, heat rate improvements can often be realized by converting wet handling systems to dry handling systems by eliminating equipment and auxiliary power loads associated with the transport of water. The original bottom ash systems at CGS were wet handling systems, and the systems for both Units 1 and 2 were converted to a dry submerged drag chain conveyor in 2009 and 2011, respectively. The auxiliary power savings from the modifications were reviewed on both units and used to estimate heat rate improvements. The auxiliary power consumption of the wet ash handling system was estimated to be 0.5 MW while auxiliary power consumption for the dry ash handling system was estimated to be 0.09 MW. Based on the net load rate of the units, the heat rate improvement was estimated to be approximately 0.10% per unit. No further modifications to these systems can be made to improve heat rate.

The units were originally equipped with dry fly ash handling systems, which are considered to be most efficient; therefore, no further modifications to these systems can be made to improve heat rate beyond utilizing more efficient motors, which is discussed in Section 2.6 of this report.

2.1.2 Boiler Operation/Overhaul with New Heat Transfer Surface

Adding heat transfer area to boiler surfaces is a possible methodology for improving plant heat rate. Superheater and reheater tubes were replaced in-kind in 2009 at Unit 1 and in 2014 at Unit 2. The replacement of superheater and reheater tubes is part of general maintenance and recovers the degradation of the heat transfer surface that occurs over time. Because no modifications to surface area were included, the replacement of these surfaces allows the units to maintain heat rate, or 0% change as compared to the original design. Adding surface to increase the steam temperatures beyond the original design values would require a major evaluation of all affected pressure parts and typically is not economical. Therefore it is assumed for this report no further modifications can be economically made to the superheater or reheater tubes to improve heat rate.

For some units, the economizer has been degraded to such an extent that it requires replacement. Units that have installed Selective Catalytic Reduction (SCR) reactors sometimes need to add surface area to economizer tubes because the flue gas temperature to the SCR reactor was higher than the maximum temperature than the SCR catalyst can handle. However, this was not the case for the CGS units due to the sufficient heat transfer across the economizer tube. The SCR project for Unit 2 did not require additional heat transfer area on the economizer tubes, and no further modification to the economizer tubes can be made to improve heat rate. Therefore, there is no change in heat rate achieved to date or potential change in heat rate due to economizer tubes. In 2014, a pegging steam system was installed on Unit 2 to raise flue gas temperatures to the minimum operating temperature for the SCR at low loads. This system does utilize main steam from the unit, which can increase, or penalize, the heat rate even further at low loads. However, Unit 2 is currently a base load operated unit so there would be small impact to the annual average heat rate of the unit. Therefore, the pegging steam system impact has not been included in this evaluation of Unit 2's heat rate.

2.1.3 Neural Network and Intelligent Sootblower System

Computer models, known as neural networks (NNs) simulate the power plants at various static and dynamic loads, with the predicted performance results correlated to several real-time process measurements. Neural network control systems can be used to optimize emissions such as NO_X and CO, as well as help optimize boiler efficiency.

The use of intelligent soot blower (ISB) systems for improving system efficiency also enhance the performance of the furnace and longevity of the tubing material, while minimizing cycling effects to the steam turbine. In April 2013, new sootblower management systems were installed on CGS Unit 1 and Unit 2. The sootblower systems are referred to as “knowledge-” or “rule-” based and are used to target known places for slagging and temperature differences. Additionally, a new neural network system was installed on each of the CGS units. The NNs were installed in January 2014 in order to optimize NO_X and CO. An observed heat rate improvement occurred as a byproduct.

S&L analyzed the net MW and heat input from the supplied plant data during two time periods: January through March 2013 (before NN and ISB) and January through March 2014 (after NN and ISB) in order to estimate the relative change in heat rate resulting from these projects. The cutoff date for “after NN and ISB” of March 2014 was selected to encompass data prior to commissioning of the SCR on Unit 2, which resulted in a heat rate penalty (See Section 2.4.2). To be consistent, three months of data were also analyzed to estimate heat rate prior to the installation of these projects.

Based on the units’ plant data, the improvement in heat rate after the NN/ISB installation was approximately 1.0% for Unit 1 and 0.6% for Unit 2. While further heat rate improvements could be realized with additional studies, testing, and optimization, it is assumed for the purposes of this report these additional heat rate improvements would be negligible.

2.1.4 Air Pre-Heaters

Air pre-heaters are an important component of maintaining efficiency at a power plant. Such systems provide heat recovery to the unit by cooling the flue gas counter-currently with cool incoming pre-combustion air. Cooling of the flue gas transfers contribute to increased efficiency by recovering heat that raises combustion air temperatures and minimizes moisture in the coal prior to its combustion. With respect to air pre-heaters’ contributions to plant heat rate, two possible methods to improve their performance are:

- Minimizing air pre-heater leakages from the air-side to the flue-gas side. This raises auxiliary power requirements due to processing higher volumes of gas in downstream equipment.
- Lowering air pre-heater outlet temperatures by controlling acid dew point, which allows for recovery of additional heat into the combustion air.

2.1.4.1 Minimizing Air Pre-Heater Leakage

Unit 2 has two regenerative air pre-heaters that are referred to as APH 2A and APH 2B. In 2010, the air in-leakage prior to maintenance was measured to be 9.0% in APH 2A and 6.2% in APH 2B, or an average of 7.6%. In April 2014, the air heater baskets and seals were upgraded on CGS Unit 2. Engineering and design of a similar upgrade are in progress for Unit 1. Air pre-heater OEMs typically guarantee improvements to seals on regenerative air pre-heaters in-leakage at approximately 6%. (Ref. 1, 2) Based on Unit 2 air in-leakage test reports, the leakage was reduced to 6%. To estimate the heat rate improvement due to reduction in air pre-heater leakage, S&L calculated the change in flue gas volume from the air in-leakage observed during the 2010 testing to the typical guarantee value provided by OEMs, or from 7.6% to 6%.

The decrease in flue gas volume reduces the FD and ID fan auxiliary power consumption rates and slightly improves heat rate. Table 2-1 shows the estimated changes in flue gas volume, auxiliary power consumption, and heat rate due to the reduction in leakage.

Table 2-1 Unit 2 Changes due to Reduction in AH In Leakage

	Δ between 7.6% and 6% AH In Leakage
Unit 2 Air Inlet Volume at FD Fan Inlet	-1.7%
Unit 2 FD Fan Auxiliary Power Consumption	-62 kW
Unit 2 Flue Gas Volume at ID Fan Inlet	-1.5%
Unit 2 ID Fan Auxiliary Power Consumption	-127 kW
Total Unit 2 Heat Rate Change from FD and ID Fans	-0.05% [Note 1]

Note 1: This is a calculated value.

Although there are no test data for Unit 1, Unit 1 is in the process of upgrading air heater baskets and seals by May 2015. The air heater in-leakage is estimated to be similar to Unit 2, and the estimated heat rate improvement for Unit 2 is assumed to be the same as Unit 1.

When estimating heat rate, the margin of error can be considered to be ±0.1%. The improvement in heat rate in Table 2-1 is small and may be considered to be insignificant based on the margin of error for heat rate adjustments. However, past performance tests have shown that the CGS units typically operate at low air in leakage rates. As part of good maintenance practice, the units should continue to replace air heater baskets and seals to maintain the air in-leakages. Based on the typical guarantees provided by air heater OEMs, further reductions in air in-leakage are not anticipated to be feasible at CGS.

2.1.4.2 Lower Air Pre-Heater Outlet Temperature by Controlling Acid Dew Point

The air heater outlet temperature typically is controlled at 20-30°F above the sulfuric acid dew point to minimize corrosion of cold-end baskets. To enable lower air heater outlet temperatures, dry sorbent injection (DSI) can be installed in order to remove SO_3 and lower the acid dew point temperature. This technology is generally applied to medium- to high- sulfur fuel applications. The CGS units fire low sulfur PRB coal; so both the SO_3 concentration and the acid dew point are low compared to higher sulfur bituminous coals.

Because Unit 1 does not have an SCR, SO_3 is formed only by oxidizing SO_2 in the boiler. Assuming SO_2 oxidation in the boiler of 0.5% while firing PRB, flue gas concentrations of SO_3 upstream of the air pre-heater are estimated to be 2 ppmvd at 3% O_2 (Ref. 13). DSI equipment vendors do not guarantee SO_3 emissions below 5 ppmvd at 3% O_2; therefore, this technology is not feasible for Unit 1.

The oxidative properties of SCR catalyst on Unit 2 result in slightly higher SO_3 concentrations due to SO_2 to SO_3 oxidation that occurs across the SCR catalyst. Based on the catalyst design of 0.5% SO_2 oxidation across the SCR, and assuming all future layers installed, flue gas concentrations of SO_3 upstream of the air pre-heater are estimated to be 5 ppmvd at 3% O_2. DSI equipment vendors do not guarantee reductions in SO_3 emissions to below 5 ppmvd at 3% O_2; therefore, this technology is not feasible for Unit 2.

Although this small potential improvement in heat rate is theoretically possible, it is not technically feasible at CGS because of Calcium Bromide (CaBr) injection used to oxidize mercury as part of SRP's Mercury and Air Toxic Standards (MATS) compliance program. The Calcium Bromide injection system was installed in 2011 as part of a state rule that required calcium bromide injection to control mercury beginning on or before January 1, 2012. Prior to 2011, air heater basket corrosion was never observed. After injecting Calcium Bromide in the fuel, minimal air heater basket corrosion was observed and is thought to be due to HBr in the flue gas. Further reductions in air pre-heater operating temperatures that are permitted by reducing sulfuric acid dew point through DSI injection would exacerbate HBr corrosion in the air pre-heater and are not considered technically feasible at CGS.

Additionally, SRP noted that the units have increased the use of the air preheater steam coils in order to increase the air side outlet temperatures. Based on the plant data for Unit 1 and Unit 2, the outlet temperature for the combustion air was raised. The effects of the rise in combustion air temperature can also be observed in the rise in flue gas temperatures at the air preheater outlet. A rise of 40°F in air pre-heater outlet temperature decreases boiler efficiency by approximately 1%. The estimated rise in temperature on Unit 1 was approximately 6°F in flue gas temperature during full load operation, which can be estimated to result in a heat rate penalty of approximately 0.15%. After the installation of the SCR on Unit 2, the average cold end temperature control set point was programmed to be based on recommendations from the manufacturer. S&L evaluated the temperature rise after the modifications were implemented, and the estimated rise in flue gas outlet temperature was 5°F. This rise in temperature can be estimated to result in a heat rate penalty of approximately 0.13%. Similar modifications to the cold end temperature control set point will be implemented on Unit 1 in May 2015. For purposes of this evaluation, the increase in heat rate due to the rise in flue gas temperature for Unit 1 and Unit 2 is estimated to be approximately 0.15% and 0.13%, respectively, but may be higher during the winter months. Due to the potential corrosion from CaBr injection, the flue gas temperatures cannot be lowered. Since CaBr injection is part of SRP's regulatory compliance strategy, this system must be maintained online and no other improvements can be made regarding controlling the acid dew point.

2.2 TURBINE ISLAND

This section of the report discusses modifications that have been or could be made to the CGS units' equipment within the turbine island that offer potential improvements in plant heat rate:

- Turbine overhaul
- Feedwater heaters
- Condenser

2.2.1 Turbine Overhaul

Technological advancements have improved the efficiency and longevity of steam turbines compared to the turbines that were originally installed in many older units. Advanced design tools, such as computational fluid dynamics (CFD) have significantly enhanced turbine design capabilities that have lead to increases in turbine efficiency. Additionally, the fabrication of increasingly complex geometric components has been developed to streamline design and efficiency. (Refs. 3, 4, 5, 6, 7, 8, 9, 10, 11, 12)

Both CGS Units replaced HP & IP turbines between 1998 and 2000. Although plant data is not available from this time to demonstrate the impact on heat rate, the original and upgraded heat balances were reviewed to substantiate the heat rate improvement of 3.8%. It shall be note this heat rate improvement is “clean and new” and will deteriorate from this value until the next planned major turbine overhaul. Overhauls are typically performed every 7 to 10 years. The new and old station heat balances provided calculated net turbine heat rate values for each operating point. These before and after values were reviewed and the value provided above is based on an average capacity. Based on discussions between OEMs and SRP, further heat rate improvements may be possible through more advanced turbine upgrades that were not available at the time of the original upgrade work. Based on the information provided by SRP from a 2013 analysis, the estimated heat rate improvement for each unit is up to 1.0%. SRP also provided an estimated capital cost for the turbine upgrade of approximately $11.3 million per unit (2013 dollars), which includes engineering, materials, project management and installation costs.

2.2.2 Feedwater Heaters

Feedwater heaters are used within a power plant’s thermal cycle to improve overall efficiency by recovering as much heat as possible into the boiler feedwater. The number and placement of feedwater heaters are determined during the original plant design and are highly integrated with the overall performance of the steam turbine. The heat used to increase the feedwater temperature is supplied directly from the thermal cycle in the form of steam extracted at various turbine sections.

In the case of SRP’s Coronado Generating Station, SRP replaced the feedwater heaters in order to maintain overall unit performance. Over the past ten years, four of the six feedwater heaters on both units have been replaced in-kind. The HP and IP feedwater heaters were replaced due to an excessive number of plugged tubes. Other feedweater heaters have been replaced due to flow accelerated corrosion (FAC) on the shells. Replacement of the feedwater heaters maintains unit performance with the original design. With no reduction or increase in duty, the change to heat rate is considered to be 0%.

The subject of increasing the thermal performance of the feedwater heaters has been brought up in past studies; however, it is more appropriate to discuss this application on a new unit. Although the option may be technically feasible to retrofit, major modification would impact the entire steam cycle, including the steam turbine extraction points, extraction line sizing and heater drains piping. Therefore, it is not considered to be a reasonable approach for a small improvement in heat rate. The units already perform regular maintenance on the feedwater heaters, and no other modifications are considered to be feasible for future heat rate improvement.

2.2.3 Condenser

By lowering the condensing temperature, the backpressure on the turbine is lowered, which increases its efficiency. A condenser degrades primarily due to fouling of the tubes and air in-leakage. Tube fouling leads to reduced heat transfer rates, while air in-leakage directly degrades the quality of the water. However, if a closed cooling system is used, cooling water quality can be controlled to a much higher degree.

CGS's maintenance practices are to routinely inspect and clean the condenser tubes in the spring or fall planned outages in order to maintain condenser performance. The condenser tube material was changed in November 2004 for Unit 1 and in January 2006 for Unit 2 from 90/10 Cu-Ni to Seacure Stainless to minimize corrosion; heat transfer capabilities are identical to the original design. Reverse Osmosis systems are used to control water quality. By including routine maintenance, upgrading materials to prevent corrosion, and by controlling water quality to minimize fouling, CGS has incorporated all technologies that can improve and maintain system performance. A review of the recent plant data indicates that the back-pressures are close to the original design values, and as such, any modifications made to the condenser will not produce appreciable heat rate improvements.

2.2.4 Boiler Feed Pumps

Boiler feed pumps consume a large fraction of the auxiliary power used internally within a power plant. Overhauling the boiler feed pumps can yield heat rate improvements depending on the size of the unit and the original design of the pumps.

The existing boiler feed pumps at CGS are motor-driven feed pumps with a motor-driven booster. There are two motor driven boiler feed pumps per unit which have fluid couplings for speed control, 8 stages, and 8500 hp motors. Based on the equipment data sheets, the fluid couplings are 90% efficient. CGS performs routine maintenance and continually monitors performance of the boiler feed pumps and their motors. These pumps are configured with fluid drives that improve overall operating efficiency when operating at part loads. Due to best maintenance practices and operation with fluid couplings a heat rate improvement is not considered to be feasible.

2.3 FLUE GAS SYSTEM

2.3.1 FD and ID Fan Efficiency

As previously mentioned in Section 1.3, the units were required by a Consent Decree to replace their existing horizontal scrubbers with new tower absorbers to improve SO_2 removal. Unit 2 also was required to install SCR technology for additional NO_X control. The original centrifugal ID fans were replaced with new variable pitch blade axial fans to account for the additional differential pressure added by the new emission control equipment. The original FD fans for both units are also axial fans. Since axial fans run closer to their best efficiency point during turndown than do centrifugal fans, (Ref. 14) and since variable frequency drive (VFD) control is not applicable to axial fans, no further modifications to fan design can be incorporated to improve plant heat rate at the CGS units.

Because the modifications to the ID fans occurred during major emission control technology retrofits, the overall heat rate impact must consider the total changes installed for each unit. Details regarding the FGD retrofits at both Units 1 and 2 are provided in Section 2.4.1 of this report, and details regarding the SCR retrofit at Unit 2 are provided in Section 2.4.2.

2.3.2 Primary Air (PA) Fans

The primary air fans supply the air required to transport the pulverized coal to the burners. The primary air fans at CGS are the original fans. The PA fans are damper controlled. In 1985, the PA fan rotors were reduced from 115" to 110" to increase the range of operation of the rating air dampers. Fuel flow was difficult to control prior to the modification because the fans were not sized adequately. Fuel input was controlled by the amount of air the rating air damper allowed to pass through the mills. The PA fan rotor was modified to increase the range of the rating damper and gain better fuel control because the original rating air damper has a narrow range of travel. No other modifications to the PA fans have been made. The changes above position the PA fans to be set-up to operate efficiently based on the current fuel characteristics. Due to the rotor modification in 1985 the fan is running near critical speed; consequently a VFD is not practical. Because regular maintenance is performed and a VFD is not practical, a heat rate improvement is not considered to be feasible.

2.4 AIR POLLUTION CONTROL EQUIPMENT

2.4.1 Flue Gas Desulfurization (FGD) System

As mentioned earlier in Section 1.3, SRP was required to install state-of-the-art WFGD systems on the CGS units. The original system was a horizontal scrubber type that was designed to scrub 80% of each unit's flue gas. The new FGD systems are spray tower absorbers and are designed to scrub 100% of each unit's flue gas. The original ID and booster fans were replaced with the new axial ID fans.

The auxiliary power consumption for the new WFGD system, including the new axial ID Fans, is approximately the same as the original horizontal scrubber system, and therefore no overall heat rate change for the CGS units.

2.4.2 Selective Catalytic Reduction System

As part of the Consent Decree, for Coronado Generating Station, SCR technology was installed on Unit 2 in 2014. With the addition of the SCR reactor and ancillary equipment, the auxiliary power consumption increased. The increase in auxiliary power consumption is due to (1) increase ID fan power due to pressure drop across the new ductwork and SCR reactor and (2) ancillary equipment including catalyst cleaning equipment and equipment associated with ammonia injection. Although steam consumption due to the sootblower catalyst cleaning system also increases plant heat rate for Unit 2, the sootblowers operate intermittently and the consumption of steam was assumed to have a negligible impact on plant heat rate.

To reduce auxiliary power consumption on the SCR system, either the ancillary equipment would need to be operated less frequently or pressure drop in the system would need to be reduced. Operating catalyst cleaning equipment and ammonia injection equipment less frequently or at lower rates are not feasible options because these systems are required to keep the catalyst from plugging and to provide sufficient reagent to remove NO_X from the flue gas. To reduce pressure drop in the system, either ductwork modifications or a lower degree of mixing would be required. The SCR ductwork and mixing were designed with state-of-the art modeling technologies to optimize pressure drop while providing the degree of mixing required to achieve sufficient NO_X reduction. Changes in ductwork design and mixing to reduce pressure drop would have a detrimental impact on SCR performance and are not considered feasible options at CGS. Because neither auxiliary power reductions nor pressure drop reductions are feasible at CGS Unit, there are no further opportunities to improve heat rate associated with the SCR system.

The auxiliary power consumption due to the new SCR system is approximately 2 MW for Unit 2, and results in a heat rate penalty of approximately 0.5%.

2.4.3 Electrostatic Precipitator

Approximately 75% of the coal-fired electric generating units in the U.S. use electrostatic precipitators (ESPs) to control particulate emissions. ESPs operate by routing the particulate laden flue gas through a vessel that is divided into multiple, vertical sections. Each section is energized with an applied voltage that creates an electric field between a discharge electrode (DE) and a collection electrode (CE). The electric field ionizes the particles entrained in the flue gas and enables their capture on the CE plates. At specific intervals, the plates are shaken and the particles are dislodged and fall into hoppers for collection and removal.

In order to improve the ESP performance, utilities have increasingly made use of ESP energy management system (EMS) upgrades. The EMS enables the ESP to be optimized for varying load conditions by adjusting T/R set power consumption to optimize particle collection efficiency. The EMS also enables fine tuning of each T/R set such that if a unit is exceeding its particulate removal requirements, one of the T/R sets can be deactivated to save on auxiliary power consumption. The CGS units are equipped with hot-side ESPs, which have not been modified to include an EMS. Theoretically, an EMS system could be installed at the CGS units to reduce auxiliary power costs. However, the MATS rule requires controlling non-mercury metals, for which most affected facilities, including SRP, will use filterable particulate matter (FPM) as a surrogate, as permitted by the rule. Because the FPM limits prescribed by the MATS rule are relatively low (0.03 lb/MMBtu), an EMS system may not be able to significantly lower auxiliary power. No data are currently available to quantify the impacts of an EMS system in conjunction with the low FPM limits required by MATS since the MATS emission rates do not take effect until April 2015. Because of a lack of data, at this time, an EMS system cannot be evaluated and is not being considered further in this analysis.

2.5 WATER SYSTEMS

2.5.1 Boiler Water Treatment

Heat rate improvement as related to water treatment primarily involves maintaining the proper water chemistry to reduce boiler scale and the amount of boiler water blowdown needed to control solids and impurities. Boiler scale lowers heat transfer by lowering thermal conductivity. Heat transfer may be reduced significantly by the presence of scale. More important than the heat loss is that scale can cause overheating of the boiler tube metal and can result in subsequent tube failures, leading to costly repairs and boiler outages.

High-purity water reduces water and energy losses because less scale is formed and less water must be discarded in the blow down. By reducing the blowdown amounts, more steam is available in the thermal cycle, thereby improving overall power plant efficiency and improving heat rate.

The station was originally designed with a demineralizer and evaporator, but the evaporator was replaced with two polishing reverse osmosis (RO) systems in 1993. During normal operating conditions CGS does not utilize boiler blowdown. Boiler blowdown is not required due to the high quality water chemistry. The plant practices careful monitoring and maintenance of the water treatment systems for optimal water quality. Since the station already has advanced water treatment systems installed and high-quality water chemistry, there is no opportunity for further improvements regarding additional treatment technologies to reduce boiler scale, reduce boiler blowdown and improve plant heat rate.

2.5.2 Cooling Towers

Coronado Generating Station is equipped with cross-flow cooling towers. The objective of the rebuild that was performed in 2011 was to maintain structural integrity of the cooling towers, and not for performance of the cooling towers. Currently, the plant schedules to replace cooling tower fill every 10 years. The cooling towers currently have a stainless steel grid with Kelly v-bar with the exception of Unit 1 cells 1-3 and Unit 2 cells 1-2, which have a plastic integrid with optibar fill. SRP currently plans to change these cells to be the same as the others. The current fill is not considered to be a high performance fill. The change to Kelly v-bar fill was part of a maintenance change out to a fill that reduces the risk of damage from various operating conditions. To improve the plant heat rate, advanced packing could be installed to increase the overall thermal efficiency of the tower by increasing mass transfer efficiency. This would result in a lower condenser operating pressure and increase the net power generation. This effect would primarily be noticed during summer operation since during the rest of the year, the condenser is operating at or near pressures achieving optimum turbine efficiency. However, recent experience at other power plants have shown that high efficiency fills are more susceptible to fouling than are older style splash fill towers. When selecting more efficient fills, the cooling tower water chemistry must be appropriately managed to limit fouling. Fouling degrades the effectiveness of the fill, so an increase in efficiency gained by the use of high-efficiency film fill may actually be lost over time if the appropriate water chemistry is not maintained. The installation of this high efficiency fill has resulted in operating issues affecting reliability of the units. Since the units' condensers are currently operating at or near design pressures for the majority of an operating year, high efficiency fill would not significantly improve the units' heat rate.

Based on the review of plant operating data, the cooling tower and cooling system are operating effectively and are achieving back pressures at or near design values. The condenser pressure is operating at pressures between 1.5 and 2.5 inches HgA for most of the year (excluding the summer months). Based on the turbine design conditions, this is near the optimum turbine back pressure. Therefore, little or no efficiency can be gained for most of the year by lowering the condenser operating pressure. However, based on review of the plant operating data, there is a potential for heat rate improvement in the summer months by adding additional cells to the cooling tower. In the summer months, the condenser operating pressure ranges between 2.7 and 3.5 inches HgA. These are not optimum back pressures for the turbine, and therefore leave room for improvement. Adding additional cells to the cooling tower would lower the cooling tower approach temperature, therefore allowing the turbine to achieve a lower back pressure and thus increasing the cycle efficiency. However, as mentioned, this improvement would only be observed during the summer months. Adding cells would require major construction on the existing cooling towers, and the incremental improvement to heat rate that would be realized would only be present during three to four months of the year. Since the cooling tower and cooling system are already operating effectively, there is no opportunity for further improvement regarding modifications to the cooling tower systems. However, regular maintenance of the fill and water chemistry must be continued to prevent degradation of cooling tower performance.

2.6 VARIOUS LARGE MOTORS

In addition to the various methods of improving plant performance that have been discussed, there are other areas that can provide improvements on a plant-wide basis. Two additional methods that will be discussed in this section are VFDs and upgrade of large electric motors.

Due to current electricity market conditions, many units no longer operate at base-load capacity and, therefore, VFDs, also known as variable-speed drives (VSDs) on fans can greatly enhance plant performance at off-peak loads. Additionally, because utilities are phasing in their environmental equipment upgrades, new fans are oversized and operated at lower capacities until all additional equipment has been added. Under these scenarios, VFDs can significantly improve the unit heat rate. VFDs as motor controllers offer many substantial improvements to electric motor power requirements. With unit loads varying throughout the year, the benefits of using VFDs on large-size equipment, such as FD or ID fans, boiler feedwater pumps, and condensate pumps can have significant impacts.

As mentioned previously, the CGS Units are already equipped with axial fans and VFDs cannot be implemented on axial fans. The boiler feed pumps are equipped with fluid drives so VFDs would also not be implemented. The condensate pumps are 5-stage vertical centrifugal pumps. For CGS, the units are base-load operated so the gains from adding VFDs would not be expected to be as much as a cycling unit.

The other potential area for heat rate improvements is the upgrade of large electric motor (>450 hp) by replacing older electric motors with new, energy efficient motors. The primary problems with implementing more efficient motors are the cost of the materials and the cost of training plant personnel on the proper maintenance procedures. All electric motors in the range of 1-200 hp sold today in the U.S. must meet high-efficiency standards as mandated by the federal government in the Energy Policy Act of 1992 (EPAct). Therefore, replacing older, failing motors will necessarily entail the inclusion of a more efficient motor.

As part of the regular maintenance plan at CGS, the large electrical motors are consistently refurbished and have not been replaced. As shown in Table 2-2, most of the motors at CGS have 92 to 95% efficiency. S&L reviewed the data sheets of the large scale (>450 hp) equipment motors to determine their efficiencies and have included them in Table 2-2.

Table 2-2 Efficiency of Large Scale Motors (>450 hp)

Type of Equipment Note 1	Motor Horse Power (hp)	Efficiency, %
FD Fan	3000	95.5
PA Fan	1250	95.0
Coal Mills	1750	93.6
Circulating Water Pumps	2000	94.9
Boiler Feed Pumps	8500	96.7
Conveyor Belt	700	94.3
BFP Booster Pump	1500	95.8
Condensate Pump	600	92.0
Coal Crusher	600	95.1

Note 1: ID fans and wet FGD equipment were recently installed and are considered to be equipped with a high efficiency motors.

All of the large scale motors have motor efficiency greater than 90% so replacing the motors would not yield significant improvement in heat rate. As mentioned in the 2009 Report, motor efficiency gains of 5-25% can be achieved by replacing older motors. However, all of the large scale motors at CGS cannot be improved by more than 5%. For CGS, continuous maintenance of these large scale motors would be the best option for maintaining the plant's original heat rate. As mentioned previously, CGS already conducts this routine maintenance so the overall change in heat rate is estimated to be 0%, or no change in heat rate.

3. ADDITIONAL PLANT MODIFICATIONS

After reviewing the modifications already implemented on the CGS units, S&L evaluated potential areas of heat rate improvement that could be implemented.

3.1 COAL SWITCHING TO PRB

As previously mentioned, the units switched to 100% PRB fuels in 2007. The switch to PRB coal was a part of the station's effort to reduce SO_2 emissions. PRB coal typically has sulfur content in the 0.5 wt% range compared to bituminous coal that can be as high as 1-2 wt%. Even though CGS switched to PRB coal in order to reduce SO_2 emissions, the coal switch also led to a decrease in the units' boiler efficiencies. Compared to bituminous coal, PRB also has much higher moisture content. The higher moisture content in the fuel lowers boiler efficiency because of the heat lost to evaporating the moisture in the coal.

S&L reviewed the coals fired at CGS to determine the change in boiler efficiency due to the switch to PRB coal. Based on the design basis of the SCR retrofit project, there were two coal analyses used for design (1) 100% El Segundo bituminous coal and (2) a blend of PRB coals (80% Jacobs Ranch and 20% Spring Creek). The reduction in boiler efficiency from firing 100% bituminous coal compared to firing 100% blend of higher moisture PRB coals was estimated to be approximately 1.8% due to differences in fuel moisture. The differences in fuel moisture content and resultant efficiencies correspond to a heat rate penalty of approximately 1.8%.

4. SUMMARY AND CONCLUSION

The changes to the units' heat rates based on the modifications implemented at CGS as well as the potential improvements that can be implemented are summarized in the tables below.

Table 4-1 Summary of Heat Rate Changes for Unit 1 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date Note 3	Potential % Change Note 3
Boiler Island		
Material Handling	-0.10%	N/A
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BMP Note 1
Neural Network & Intelligent Sootblowers	-1.0%	N/A
Air Pre-Heater		
Reduce Air Heater Leakage	-0.05%	BMP
Reduce Flue Gas Acid Dew Point	+0.15%	N/A
Turbine Island		
Turbine Overhaul	-3.8%	-1.0%
Feedwater Heaters	0%	BMP
Condenser	0%	BMP
Boiler Feed Pumps	0%	BMP
Flue Gas System		
FD and ID Fan Efficiency	Note 2	N/A
Primary Air Fans	N/A	N/A
Air Pollution Control Equipment		
FGD System	0%	BMP
SCR System	N/A	N/A
ESP	N/A	N/A
Cooling Towers	N/A	BMP
Large Scale Motors	0%	BMP
TOTAL	**-4.8%**	**-1.0%**
Additional Plant Modifications		
Coal switch to PRB	+1.8%	N/A

Note 1: "BMP" is defined as "Best Maintenance Practices" and incorporates consistent maintenance to sustain the unit's heat rate at its original design. BMP prevents significant degradation of the unit's performance.
Note 2: Change in heat rate due to FD and ID fan efficiency has been included in FGD auxiliary power consumption section as discussed in Section 2.3.1.
Note 3: Negative values listed are considered to be improvements in the unit's heat rate, and a positive value represents a heat rate penalty.

Table 4-2 Summary of Heat Rate Changes for Unit 2 (Achieved to Date and Potential)

Heat Rate Improvement	% Change Achieved to Date Note 3	Potential % Change Note 3
Boiler Island		
Material Handling	-0.10%	N/A
Boiler Operation/Overhaul with New Heat Transfer Surface	0%	BMP Note 1
Neural Network & Intelligent Sootblowers	-0.6%	N/A
Air Pre-Heater		
Reduce Air Heater Leakage	-0.05%	BMP
Reduce Flue Gas Acid Dew Point	+0.13%	N/A
Turbine Island		
Turbine Overhaul	-3.8%	-1.0%
Feedwater Heaters	0%	BMP
Condenser	0%	BMP
Boiler Feed Pumps	0%	BMP
Flue Gas System		
FD and ID Fan Efficiency	Note 2	N/A
Primary Air Fans	N/A	N/A
Air Pollution Control Equipment		
FGD System	0%	BMP
SCR System	+0.5%	N/A
ESP	N/A	N/A
Cooling Towers	N/A	BMP
Large Scale Motors	0%	BMP
TOTAL	**-3.9%**	**-1.0%**
Additional Plant Modifications		
Coal switch to PRB	+1.8%	N/A

Note 1: “BMP” is defined as “Best Maintenance Practices” and incorporates consistent maintenance to sustain the unit’s heat rate at its original design, or a change of 0%. BMP prevents significant degradation of the unit’s performance.
Note 2: Change in heat rate due to FD and ID Fan efficiency has been included in FGD and SCR auxiliary power consumption section as discussed in Section 2.3.1.
Note 3: Negative values listed are considered to be reductions in the unit’s heat rate, and a positive value represents an increase in heat rate.

As shown in the above tables, Unit 1 has improved heat rate by an estimated 4.8%, however the total heat rate improvement including impacts of switching to PRB coal is approximately 3.0%. For Unit 2, the improvement in heat rate is estimated to be 3.9%, however the total improvement including switching to PRB coal is approximately 2.1%. Unit 2 has less of an improvement to heat rate due to the SCR that had to be installed for regulatory compliance with the Consent Decree. The potential improvement in heat rate is estimated to be 1.0% for each unit based on the potential for turbine upgrades. The units at CGS have implemented some of the heat rate improvement technologies prior to 2012. SRP should continue to implement good maintenance practices to prevent significant degradation of the units' heat rates.

5. REFERENCES

5.1 TECHNOLOGY VENDORS

Discussions were held with the following vendors during this study. Additionally, many useful case studies were obtained from the vendors listed below.

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2. Paragon

5.2 SURVEYED LITERATURE

The various literature listed below were surveyed as part of this study.

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