LG&E KU SERVICES COMPANY

REVISION 0 DRAFT NO_x Reduction Study

B&V PROJECT NO. 194176
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PREPARED FOR

LG&E KU Services Company

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1.0 Project Overview

The Mill Creek Generating Station consists of four (4) coal-fueled steam generating units. The peak generating capacity of the station is approximately 1,500 megawatts (MW). The scope of this study is only Unit 1 and Unit 2. Unit 1, which was commissioned in 1972, is currently capable of producing approximately 330 MW (gross); Unit 2 was commissioned in 1974 and is currently capable of producing approximately 356 MW. Each of the steam generators is an indoor, balanced draft, two-pass, corner-fired boiler designed and furnished by Combustion Engineering. Each steam generator is designed to supply steam at a flow rate of approximately 2,326,000 lbs/h at a temperature and pressure of 1,005°F and 2,600 psig, respectively.

Unit 1 and Unit 2 are each equipped with low NO_x burners for NO_x reduction, wet flue gas desulfurization (FGD) systems for sulfur dioxide (SO_2) removal, and electrostatic precipitators (ESP) and Pulse Jet Fabric Filters (PJFF) for fly ash removal. Each unit was designed to fire pulverized coal using sixteen (16) tilt style, corner-located burners.

Each of the steam generators is equipped with two (2) forced draft (FD) fans, one (1) bi sector Ljungstrom air heater, four (4) RPS mills, and four (4) coal feeders, as well as associated piping, valves, instrumentation, ducting, controls, access platforms, support steel, and BRIL (brick, refractory, insulation, lagging).

Louisville Gas & Electric and Kentucky Utilities (LG&E KU) contracted with Black & Veatch to identify potentially available NO_x control strategies and technologies for Unit 1 and Unit 2 of the Mill Creek Generating Station. For each NO_x reduction technology, this study will identify the expected percentage of NO_x reduction, a general description of the control strategy, estimated implementation schedule, and costs. A list of options was developed and reviewed with LG&E KU to determine their applicability to the Mill Creek Generating Station. The results of the study on Mill Creek may also be applied to Ghent 2 and Brown 1 & 2 units.

The NO_x reduction technologies listed in Table 1-1 were identified for evaluation. Details of each of the NO_x reduction techniques are discussed in Section 3 and 4 of this report.

Table 1-1 NOx Reduction Techniques

NO_x REDUCTION TECHNIQUES
Unit Derate
Boiler Tuning
Instrumentation Upgrades
Artificial Neural Network or Advanced Control System
Low NO_x Burner Modifications
Refurbish the Over Fire Air System (if applicable)
Integrated Low NO_x Burner Modifications and Over Fire Air System (Fireside Corrosion Preventive Measures)
Natural Gas Co-Firing
Flue Gas Recirculation System
Selective Non Catalytic Reduction

Table 1-2 contains a list of the abbreviations used in this report.

Table 1-2 Abbreviations

ABBREVIATIONS	DESCRIPTION
ABS	Ammonium Bisulfate
ANN	Artificial Neural Network
BMS	Burner Management System
BOP	Balance of Plant
CIA	Carbon in Ash
CO	Carbon Monoxide
$CO(NH_2)_2$	Urea
FD	Forced Draft
FEGT	Furnace Exit Gas Temperature
FFP	Fabric Filter Plant
FGR	Flue Gas Recirculation
HHV	Higher Heating Value
ID	Induced Draft
LNB	Low NO_x Burners
MBTU	Million British Thermal Units

ABBREVIATIONS	DESCRIPTION
MCR	Maximum Continuous Rating
MW	Megawatt
MWel	Megawatt Electric
MWh	Megawatt-Hour
N_2	Nitrogen
N_2O	Nitrous Oxide
NEC	National Electrical Code
NFPA	National Fire Protection Association
NH_3	Ammonia
NO	Nitric Oxide
NO_x	Oxides of Nitrogen (expressed as total NO_2)
NO_2	Nitrogen Dioxide
O_2	Oxygen
OFA	Over Fire Air
PA	Primary Air
PRB	Powder River Basin
SCR	Selective Catalytic Reduction
SH	Superheat (steam)
SNCR	Selective Non-Catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
UBC	Unburned Carbon

2.0 Executive Summary

LG&E KU contracted with Black & Veatch to identify potentially available NO_x control strategies and technologies for Units 1 and 2 at the Mill Creek Generating Station. For each NO_x reduction technology, this study will identify the expected percentage of NO_x reduction, a general description of the control strategy, estimated implementation schedule, and costs. A list of options was developed and reviewed with LG&E KU to determine their potential applicability to the Mill Creek Generating Station. From this discussion, the following potential options were identified as technically feasible NO_x reduction technologies for the Mill Creek Generating Station. These options are further summarized in Table 2-1 for Unit 1 and Unit 2.

- Instrumentation Upgrades
- Ultra-Low NO_x Burners
- Refurbish the OFA System
- Integrated LNB Modifications and OFA System
- Natural Gas Co-Firing
- Selective Non-Catalytic Reduction (SNCR) System

Other options were reviewed but eliminated from consideration either because they are not well suited for or had not been demonstrated on a unit of this size and type, or because there are outside operating business plan constraints. These non-viable options are further summarized in Table 2-2 for both Unit 1 and Unit 2:

- Unit Derate
- Boiler Tuning
- Artificial Neural Net or Advanced Control System
- Flue Gas Recirculation (FGR) Systems

Table 2-1 Technically Feasible NOx Reduction Options Summary

REFERENCED REPORT SECTION	STRATEGY/TECHNOLOGY TITLE/DESCRIPTION	EXPECTED MODIFICATIONS	POTENTIAL IMPLEMENTATION RISKS/CONCERNS	EXPECTED NO_X REDUCTION	DIFFERENTIAL PLANT IMPACTS	ESTIMATED IMPLEMENTATION SCHEDULE	DIFFERENTIAL OPERATING AND MAINTENANCE COST IMPACT	ROUGH ORDER OF MAGNITUDE INSTALLATION COST
3.1	Instrumentation Upgrades	Install additional instruments to allow measurement of fuel and air flow to each of the burners, to achieve the optimal fuel air ratio at each individual burner.	▪ No potential equipment risks have been identified for this option; however, the possibility of water wall corrosion due to staging of the combustion process should be monitored. The instrumentation will assist in making sure staged combustion is controlled.	**MC1 & MC2:** 5% to 10% **BR1 & BR2:** 5% to10% **GH2:** 5% to 10%	**MC1 & MC2:** Power Usage: 0 kW NPHR: 0 Btu/kW-hr **BR1:** Power Usage: 0 kW NPHR: 0 Btu/kW-hr **BR2:** Power Usage: 0 kW NPHR: 0 Btu/kW-hr **GH2:** Power Usage: 0 kW NPHR: 0 Btu/kW-hr	5 to 6 months **Outage duration – 2 to 4 weeks**	**MC1 & MC2:** $0.04/MWh Maintenance (fixed): $37,500 per unit Operators (fixed): $49,000 per unit Total Annual Fixed Cost: $86,500 ($0.04/MWh) Total Annual Variable Cost: $0 ($0.00/MW) **BR1:** $0.19/MWh Maintenance (fixed): $37,500 Operators (fixed): $19,700 Total Annual Fixed Cost: $57,200 ($0.04/MWh) Total Annual Variable Cost: $0 ($0.00/MWh) **BR2:** $0.14/MWh Maintenance (fixed): $45,000 Operators (fixed): $19,700 Total Annual Fixed Cost: $57,200 ($0.04/MWh) Total Annual Variable Cost: $0 ($0.00/MWh) **GH2:** $0.03/MWh Maintenance (Fixed): $45,000 Operators (Fixed): $49,000 Total Annual Fixed Cost: $94,000 ($0.03/MWh) Total Annual Variable Cost: $0 ($0.00/MWh)	**MC1 & MC2:** $1.0M to $1.25M per Unit **BR1:** $1.0M to $1.25M per Unit **BR2:** $1.25M to $1.5M per Unit **GH2:** $1.25M to $1.5M
3.2	Ultra Low NOx Burners	Replace the existing burners with new ultra low NOx burners. Depending on the throat design, modifications to the burner openings/furnace wall tubes may be required. Some modifications to the coal distribution piping may be required. **MC1 & MC2** - sixteen (16) burners, each unit - concerns with fire-side corrosion **BR1 & BR2** - sixteen (16) burners, each unit **GH2** - twenty-four (24) burners - previous study indicated physical limitations installing an OFA system; structural interferences.	Fuel-rich operation at individual burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is currently a problem. If tube wastage is observed, mitigation measures, such as **weld overly** or **thermal spray** could be employed, yet not monetized in this study. Excessive unburned carbon content in the ash may impact salability.	**MC1 & MC2:** 10% to 20% **BR1 & BR2:** 10% to 20% **GH2:** 10% to 20%	**MC1 & MC2:** Power Usage: 0 kW NPHR: 49 Btu/kW-hr **BR1:** Power Usage: 0 kW NPHR: 51 Btu/kW-hr **BR2:** Power Usage: 0 kW NPHR: 51 Btu/kW-hr **GH2:** Power Usage: 0 kW NPHR: 46 Btu/kW-hr	Approximately 8 to 10 months will be needed for the selected burner Supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a **2 month outage** will be needed to modify the existing burners. Following the outage, 1 month will be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 11 to 13 months from release of a contract through commissioning.	**MC1 & MC2:** $0.23/MWh Coal Cost (Variable): $221,000 per unit Maintenance (fixed): $270,000 per unit Operators (fixed): $0 per unit Total Annual Fixed Cost: $270,000 ($0.13/MWh) Total Annual Variable Cost: $221,000 ($0.10/MWh) **BR1:** $0.94/MWh Coal Cost (Variable): $43,400 Maintenance (Fixed): $240,000 Operators (Fixed): $0 Total Annual Fixed Cost: $240,000 ($0.80/MWh) Total Annual Variable Cost: $43,400 ($0.14/MWh) **BR2:** $0.78/MWh Coal Cost (Variable): $68,600 Maintenance (Fixed): $300,000 Operators (Fixed): $0 Total Annual Fixed Cost: $300,000 ($0.64/MWh) Total Annual Variable Cost: $68,600 ($0.14/MWh) **GH2:** $0.21/MWh Coal Cost (Variable): $305,000 Maintenance (Fixed): $360,000 Operators (Fixed): $0 Total Annual Fixed Cost: $360,000 ($0.12/MWh) Total Annual Variable Cost: $305,000 ($0.09/MWh)	**MC1 & MC2:** $7.0M to $9.0M per Unit **BR1:** $6.0M to $8.0M per Unit **BR2:** $8.0M to $10.0M per Unit **GH2:** $10.0M to $12.0M

REFERENCED REPORT SECTION	STRATEGY/TECHNOLOGY TITLE/DESCRIPTION	EXPECTED MODIFICATIONS	POTENTIAL IMPLEMENTATION RISKS/CONCERNS	EXPECTED NO_X REDUCTION	DIFFERENTIAL PLANT IMPACTS	ESTIMATED IMPLEMENTATION SCHEDULE	DIFFERENTIAL OPERATING AND MAINTENANCE COST IMPACT	ROUGH ORDER OF MAGNITUDE INSTALLATION COST
3.3	Refurbish the OFA System	A refurbishment of the current overfire air (OFA) system or replacement of the current OFA system to provide better mixing of the OFA with the boiler flue gases should allow for a 10 to 20 percent reduction from the current NOx levels. The OFA works by reducing the excess air in the primary combustion (burner) zone, which enhances the combustion staging effect and further reducing NOx emissions. Any residual unburned fuel, such as CO and unburned carbon that escapes the main burner zone, is subsequently oxidized as the OFA is introduced. As with primary NOx control, the performance that can be expected from a given OFA system depends on a number of factors. As the amount of OFA is increased, the stoichiometry in the burner zone decreases, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, particularly if the fuel has characteristics that make it difficult to burn. It would also depend on the balance of flows between individual burners and the fuel fineness. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions and unburned carbon would be formed. Similarly, fuel-rich operation at burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is an ongoing problem. This deeper staging of the combustion process will also lead to a fairly high level of unburned fuel to leave the primary combustion (burner) zone. To minimize the unburned carbon in the ash and CO emissions, the air that is introduced into the upper furnace will need to be thoroughly mixed to complete the combustion process. For the existing system, the amount of OFA that could be introduced in the upper furnace was limited to control CO and UBC. The installation of new OFA ports will allow for a greater percentage of the OFA to be introduced without increasing current CO and UBC levels.	Fuel-rich operation at individual burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is currently a problem. If tube wastage is observed, mitigation measures, such as **weld overly** or **thermal spray**, could be employed, yet not monetized in this study. Excessive unburned carbon content in the ash may impact salability. Annual tuning – costs as well variable performance as the system drifts.	**MC1 & MC2:** 10% to 15% **BR1 & BR2:** 10% to 15% **GH2:** 10% to 15%	**MC1 & MC2:** Power Usage: 20 kW NPHR: 49 Btu/kW-hr **BR1:** Power Usage: 20 kW NPHR: 51 Btu/kW-hr **BR2:** Power Usage: 20 kW NPHR: 51 Btu/kW-hr **GH2:** Power Usage: 20 kW NPHR: 46 Btu/kW-hr	Approximately 7 to 8 months will be needed for the selected OFA Supplier to design, fabricate, and deliver to the components to the site. After receipt of the equipment on site, a **1 month outage** will be needed to modify the existing OFA ports. Following the outage, 1 month will be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 9 to 10 months from release of a contract through commissioning.	**MC1 & MC2:** $0.15/MWh Coal Cost (Variable): $221,000 per unit Auxiliary Power (Variable): $8,000 per unit Maintenance (Fixed): $90,000 per unit Operators (Fixed): $0 per unit Total Annual Fixed Cost: $90,000 ($0.04/MWh) Total Annual Variable Cost: $229,000 ($0.11/MWh) **BR1:** $0.36/MWh Coal Cost (Variable): $43,400 Auxiliary Power (Variable): $3,200 Maintenance (Fixed): $60,000 Operators (Fixed): $0 Total Annual Fixed Cost: $60,000 ($0.20/MWh) Total Annual Variable Cost: $46,600 ($0.16/MWh) **BR2:** $0.34/MWh Coal Cost (Variable): $68,600 Auxiliary Power (Variable): $3,200 Maintenance (Fixed): $90,000 Operators (Fixed): $0 Total Annual Fixed Cost: $90,000 ($0.19/MWh) Total Annual Variable Cost: $71,800 ($0.15/MWh) **GH2:** $0.14/MWh Coal Cost (Variable): $305,000 Auxiliary Power (Variable): $8,000 Maintenance (Fixed): $120,000 Operators (Fixed): $0 Total Annual Fixed Cost: $120,000 ($0.04/MWh) Total Annual Variable Cost: $313,000 ($0.10/MWh)	**MC1 & MC2:** $2.0M to $3.0M per Unit **BR1:** $1.5M to $2.0M per Unit **BR2:** $2.0M to $3.0M per Unit **GH2:** $3.0M to $4.0M

REFERENCED REPORT SECTION	STRATEGY/TECHNOLOGY TITLE/DESCRIPTION	EXPECTED MODIFICATIONS	POTENTIAL IMPLEMENTATION RISKS/CONCERNS	EXPECTED NO_X REDUCTION	DIFFERENTIAL PLANT IMPACTS	ESTIMATED IMPLEMENTATION SCHEDULE	DIFFERENTIAL OPERATING AND MAINTENANCE COST IMPACT	ROUGH ORDER OF MAGNITUDE INSTALLATION COST
3.4	Integrated LNB Modifications and OFA System (requires annual Boiler Tuning)	This option would consist of upgrading (replacing) the existing low NOx burners and overfire air system. A description of what this would entail is described above.	▪ Increased potential for the formation of slagging. ▪ Increased tube wastage rates possibly requiring weld overlay ▪ Excessive unburned carbon content in the ash could prevent sale of ash. ▪ Annual tuning – costs as well variable performance as the system drifts.	**MC1 & MC2:** 15% to 30% **BR1 & BR2:** 15% to 30% **GH2:** 15% to 30%	**MC1 & MC2:** Power Usage: 20 kW NPHR: 49 Btu/kW-hr **BR1:** Power Usage: 20 kW NPHR: 51 Btu/kW-hr **BR2:** Power Usage: 20 kW NPHR: 51 Btu/kW-hr **GH2:** Power Usage: 20 kW NPHR: 46 Btu/kW-hr	Approximately 8 to 10 months will be needed for the selected burner Supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a **2 month outage** will be needed to modify the existing burners. Following the outage, 1 month will be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 11 to 13 months from release of a contract through commissioning.	**MC1 & MC2:** $0.26/MWh Coal Cost (Variable): $221,000 per unit Auxiliary Power (Variable): $8,000 per unit Maintenance (Fixed): $330,000 per unit Operators (Fixed): $0 per unit Total Annual Fixed Cost: $330,000 ($0.15/MWh) Total Annual Variable Cost: $229,000 ($0.11/MWh) **GH2:** $0.23/MWh Coal Cost (Variable): $305,000 Auxiliary Power (Variable): $8,000 Maintenance (Fixed): $420,000 Operators (Fixed): $0 Total Annual Fixed Cost: $420,000 ($0.13/MWh) Total Annual Variable Cost: $313,000 ($0.10/MWh) **BR1:** $1.16/MWh Coal Cost (Variable): $43,400 Auxiliary Power (Variable): $3,200 Maintenance (Fixed): $300,000 Operators (Fixed): $0 Total Annual Fixed Cost: $300,000 ($1.00/MWh) Total Annual Variable Cost: $46,600 ($0.16/MWh) **BR2:** $0.91/MWh Coal Cost (Variable): $68.600 Auxiliary Power (Variable): $3,200 Maintenance (Fixed): $360,000 Operators (Fixed): $0 Total Annual Fixed Cost: $360,000 ($0.76/MWh) Total Annual Variable Cost: $71,800 ($0.15/MWh)	**MC1 & MC2:** $9.0M to $11.0M per Unit **BR1:** $9.0M to $10.0M per Unit **BR2:** $10.0M to $12.0M per Unit **GH2:** $12.0M to $14.0M

REFERENCED REPORT SECTION	STRATEGY/TECHNOLOGY TITLE/DESCRIPTION	EXPECTED MODIFICATIONS	POTENTIAL IMPLEMENTATION RISKS/CONCERNS	EXPECTED NO_X REDUCTION	DIFFERENTIAL PLANT IMPACTS	ESTIMATED IMPLEMENTATION SCHEDULE	DIFFERENTIAL OPERATING AND MAINTENANCE COST IMPACT	ROUGH ORDER OF MAGNITUDE INSTALLATION COST
3.5	Natural Gas Co-Firing	Modify the existing firing system (currently designed for 100% coal firing) to allow co-firing 30% - 40% (total heat input basis) natural gas up to a percentage where plant infrastructure changes will be required. The coal firing system at Mill Creek Units 1 and 2 utilize natural gas ignitors/warm-up guns. The coal firing systems at Ghent 2 and Brown Units 1 and 2 utilize No. 2 fuel oil warm-up guns. No flue gas recirculation, over fire air, or boiler/economizer modifications.	▪ Potential for overheating convective surfaces (surface or material changes may be required) ▪ Increased attemperator spray water consumption.	**MC1 & MC2:** 15% to 25% **GH2:** 15% to 25%	**MC1 & MC2:** Power Usage: 0 kW NPHR: 99 Btu/kW-hr **BR1:** Power Usage: 0 kW NPHR: 102 Btu/kW-hr **BR2:** Power Usage: 0 kW NPHR: 102 Btu/kW-hr **GH2:** Power Usage: 0 kW NPHR: 92 Btu/kW-hr	Approximately 14 to 16 months will be needed for the selected Supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, the installation will take approximately 4 months (3 month pre-outage / **1 month outage** duration). Following the outage, 1 month will be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 19 to 21 months from release of a contract through commissioning.	**MC1 & MC2:** $3.34/MWh Coal Cost (Variable): -$8,828,000 per unit NG Cost (Variable): $15,826,000 per unit Auxiliary Power (Variable): $0 per unit Maintenance (Fixed): $252,000 per unit Operators (Fixed): $0 per unit Total Annual Fixed Cost: $252,000 ($0.12/MWh) Total Annual Variable Cost: $6,998,000 ($3.12/MWh) **GH2:** $3.09/MWh Coal Cost (Variable): -$12,191,000 NG Cost (Variable): $21,854,000 Auxiliary Power (Variable): $0 Maintenance (Fixed): $270,000 Operators (Fixed): $0 Total Annual Fixed Cost: $270,000 ($0.08/MWh) Total Annual Variable Cost: $9,663,000 ($3.00/MWh) **BR1:** $2.08/MWh Coal Cost (Variable): -$1,737,000 NG Cost (Variable): $2,239,000 Auxiliary Power (Variable): $0 Maintenance (Fixed): $120,000 Operators (Fixed): $0 Total Annual Fixed Cost: $120,000 ($0.40/MWh) Total Annual Variable Cost: $502,000 ($1.68/MWh) **BR2:** $2.08/MWh Coal Cost (Variable): -$2,742,00 NG Cost (Variable): $3,536,000 Auxiliary Power (Variable): $0 Maintenance (Fixed): $189,000 Operators (Fixed): $0 Total Annual Fixed Cost: $189,000 ($0.40/MWh) Total Annual Variable Cost: $794,000 ($1.68/MWh)	**MC1 & MC2:** $7.0M to $9.0M per Unit **BR1:** $3.0M to $4.0M per Unit **BR2:** $5.0M to $7.0M per Unit **GH2:** $8.0M to $10.0M (costs excluding offsite gas pipeline costs of approximately $1.5M/mile)

REFERENCED REPORT SECTION	STRATEGY/TECHNOLOGY TITLE/DESCRIPTION	EXPECTED MODIFICATIONS	POTENTIAL IMPLEMENTATION RISKS/CONCERNS	EXPECTED NO_X REDUCTION	DIFFERENTIAL PLANT IMPACTS	ESTIMATED IMPLEMENTATION SCHEDULE	DIFFERENTIAL OPERATING AND MAINTENANCE COST IMPACT	ROUGH ORDER OF MAGNITUDE INSTALLATION COST
3.6	Selective Non-Catalytic Reduction (SNCR) System	Selective non-catalytic reduction (SNCR) is a method to reduce NOx emissions in coal fired units. The process involves injecting a urea (H2N - CO - NH2) at multiple levels in the boiler. Urea is injected into areas of the boiler where the flue gas temperature ranges from 1500 to 2000 °F. Urea is a non-hazardous reagent if shipped in dry pelletized form with no special shipping, storage, or usage limitations. Urea is stored as 40 to 50 percent urea solution. The urea solution is pumped to the boiler and atomized with compressed air at the injection nozzles. NOx emissions reduction levels of 10 percent up to 40 percent can be achieved with acceptable ammonia slip of less than 10 ppm. Ammonia slip is the ammonia that does not react with NOx and instead “slips” out of the boiler as unreacted ammonia. High levels of ammonia slip can cause several negative operational impacts. Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section. Optimum injector location is mainly a function of temperature, CO concentration, and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances are normally installed. A flue gas residence time of at least 0.3 seconds in the optimum temperature range is desired to ensure adequate SNCR performance. Residence times in excess of one second yield high NOx reduction levels even under less than ideal mixing conditions. Computational fluid dynamics and chemical kinetic modelling can be performed to establish the optimum ammonia injection locations and flow patterns. For an existing boiler, minor water wall reconfigurations are necessary to accommodate installation of SNCR injector lances.	▪ High ammonia slip may require the disposal of the ash (non-saleable) ▪ Increased air heater fouling (maintenance risk not monetized)	**MC1 & MC2:** 20% to 35% **BR1 & BR2:** 20% to 35% **GH2:** 25% to 40%	**MC1 & MC2:** Power Usage: 113 kW NPHR: 0 Btu/kW-hr **BR1:** Power Usage: 74 kW NPHR: 0 Btu/kW-hr **BR2:** Power Usage: 74 kW NPHR: 0 Btu/kW-hr **GH2:** Power Usage: 149 kW NPHR: 0 Btu/kW-hr	Approximately 6 months will be needed for the selected SNCR Supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, the installation of SNCR system will take approximately 4 months (4 month pre-outage / **1 month outage** duration). The pre-outage activities would consist of installing the urea storage, reagent circulation skid, mixing and measurement module, platforms, piping, and supplemental support steel. The outage would consist of installing the boiler penetrations, injection lances, and the balance of the ancillary equipment. Following the outage, 1 month will be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 11 months from release of a contract through commissioning.	**MC1 & MC2:** $1.32/MWh Maintenance (Fixed): $116,000 per unit Operators (Fixed): $39,000 per unit Reagent (Variable): $1,899,000 per unit Auxiliary Power (Variable): $45,000 per unit Total Annual Fixed Cost: $155,000 per unit ($0.97/MWh) Total Annual Variable Cost: $1,944,000 per unit ($0.35/MWh) **GH2:** $1.21/MWh Maintenance (Fixed): $148,000 Operators (Fixed): $39,000 Reagent (Variable): $2,673,000 Auxiliary Power (Variable): $59,000 Total Annual Fixed Cost: $287,000 ($0.30/MWh) Total Annual Variable Cost: $2,732,000 ($0.91/MWh) **BR 1&2:** $2.55/MWh Maintenance (Fixed): $82,000 per unit Operators (Fixed): $39,000 per unit Reagent (Variable): $1536,000 per unit Auxiliary Power (Variable): $12,000 per unit Total Annual Fixed Cost: $121,000 per unit ($1.14/MWh) Total Annual Variable Cost: $133,000 per unit ($1.41/MWh)	Mill Creek Units 1 & 2 $8.0M to $11.0M per Unit Ghent Unit 2 $9.0M to $12.0M Brown Units 1 & 2 $6.0M to $9.0M per Unit

Notes:

1. The expected NO_X reduction was estimated based on the information obtained either from equipment supplier bids or post implementation tests on past projects. The expected benefit could vary based on a more thorough review by the prospective technology Suppliers. The guarantee NO_X reduction percentage would be based on the expected design coal, boiler/burner configuration, performance guarantees (e.g. NO_X versus CO guarantees), modeling, and installation base for the proposed technology.
2. Estimated implementation schedules are on a per unit basis.
3. MC1 & MC2 = Mill Creek Unit 1 and Unit 2; BR1 & BR2 = Brown Unit 1 and Unit 2; GH2 = Ghent Unit 2

Table 2-2 Non-Viable NOx Reduction Options Summary

REFERENCED SECTION	OPTION	DESCRIPTION	REASON FOR ELIMINATION
4.1	Unit Derate	Reduce the output of the unit to an operating condition where the heat input is such that the resulting mass emissions levels will be below the maximum annual target values.	Derating the unit is not part of the current operating plans for these units.
4.2	Boiler Tuning	For the existing LNBs to reach the lowest achievable NO_X and CO, a proper balance of fuel and airflow to the burners (and from burner to burner) is critical. NO_X reduction would be achieved from the ability to control the location of the flame, the length of the flame, and, to a certain extent, the time of combustion with the optimal fuel fineness. By balancing the fuel and airflow to the burners, an important step is achieved in controlling the flame characteristics and improving the overall combustion process. The improved combustion characteristics should allow for a slight reduction in the current air-to-fuel air ratio thereby resulting in a lower NO_X formation.	Boiler Tuning provides limited removal potential, requires continuous tuning efforts and results will vary over time.
4.3	Artificial Neural Net or Advanced Control System	For optimum combustion, an ideal fuel air mixture has to be delivered to each burner and the overfire air system. This balanced delivery should produce the maximum amount of heat with the minimum amount of waste. However, without the ability to continuously monitor air and fuel flow entering each burner and the resulting burner performance, conditions typically exist where inadequate air is supplied for combustion, creating a fuel-rich or air-rich area. Both conditions reduce boiler efficiency and result in excess carbon monoxide (CO), fly ash loss-on-ignition (LOI) or NO_x emissions. In an attempt to prevent or reduce these effects, plants often turn to the procedure known as “burner balancing.” This entails the monitoring and adjustment of burners so that the fuel/air ratio is equalized across the boiler. Advances in computer hardware and software technology have enabled power generation companies to improve their competitive position by implementing cost-effective optimization solutions that decrease emissions and maximize plant efficiency. This solution, commonly referred to as boiler optimization or neural network systems, provides simultaneous improvements in both fuel efficiency and emissions. Neural network computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time varying, nonlinear relationships. Neural network systems use real-time operational data extracted from a plant Distributed Control System (DCS), "learn" solutions from plant operational experience, and reduce emissions while improving plant performance by continuously adapting to changes in plant operation. Neural network systems also supplement other NO_X reduction strategies. These include LNBs, OFA and post-combustion controls such as SCR and SNCR. These systems are also used to help boiler manufacturers tune boilers with poor combustion characteristics or after an LNB retrofit or other boiler modifications such as OFA modifications.	Artificial Neural Nets or Advanced Control Systems have either been implemented or deemed to not improve NO_X performance.

REFERENCED SECTION	OPTION	DESCRIPTION	REASON FOR ELIMINATION
4.4	Flue Gas Recirculation (FGR) System	Flue gas recirculation is used for superheat temperature control as well as to reduce NOx emissions in coal fired units. For temperature control, a portion of the flue gas is typically extracted downstream of the economizer and introducing it into the furnace. For NOx control the extracted flue gas is re-injected at or near the burner combustion zone. This location allows for a reduction in excess combustion air (excess combustion air is provided to allow for adequate quantities of oxygen and to promote mixing of the fuel and the oxygen). However, excess air contributes more nitrogen which can form NOx. The recirculated flue gas replaces the mixing function of the excess air, thereby reducing the amount of excess air. Recirculated flue gas can also lower NOx formation by lengthening the flame in pulverized coal units which reduces maximum flame combustion temperature. This reduction in flame temperature reduces NOx formation because NOx formation is increased at elevated temperatures. A side benefit of reduced excess air is an improvement in the efficiency of the system. A reduction is lost heat (the greatest loss of heat is up the stack) also improves efficiency.	▪ Limited industry experience of FGR systems on large units. ▪ FGR fan and ductwork maintenance.

3.0 Technically Feasible NOx Reduction Techniques

Mill Creek Units 1 and 2 currently fire a bituminous coal with higher heating values ranging from 10,000 to 12,000 Btu/lb. The fuel contains constituents such as nitrogen, oxygen, sulfur, carbon, and ash. Firing this fuel creates emissions such as nitrogen oxides (NO_x), carbon monoxide (CO), and sulfur dioxide (SO_2). Since commencing commercial operation of the units, combustion control techniques have emerged which are designed to reduce fossil fuel emissions. These techniques generally focus on the reduction of NO_x (while optimizing combustion to avoid high CO). This section of the Report discusses the technically feasible and proven NO_x reduction techniques for LG&E-KU, including predicted NO_x reduction, potential risks, estimated engineering/construction costs, and implementation schedule. Note that all estimated engineering and installation costs and implementation schedules discussed are on a per unit basis.

The results of this report are based on the fuel analysis indicted in Table 3-1.

Table 3-1 Fuel Analysis Used in the Report

CONSTITUENT	UNITS (BY WEIGHT)	VALUE (AS-RECEIVED)		
		Average	Minimum	Maximum
Proximate				
Residual Moisture	percent	4.03		
Moisture	percent	12.51	5.80	17.19
Ash	percent	8.86	7.19	13.15
Volatile	percent	36.01	30.04	39.40
Fixed Carbon	percent	42.90	39.21	47.50
Higher Heating Value	Btu/lb	11,381	10,582	12,004
Sulfur	percent	2.71	1.89	3.74
Ultimate				
Carbon	percent	62.98	58.30	66.46
Hydrogen	percent	4.38	3.66	4.74
Nitrogen	percent	1.36	1.21	1.56
Oxygen	percent	7.48	4.94	9.26

3.1 INSTRUMENTATION UPGRADES

A review of the current instrumentation would be required to determine if additional air and fuel flow devices are necessary. Additional instruments would allow for more accurate balancing of the air and fuel flows to each of the burners. The goal would be to achieve a more optimum NO_x reduction and CO control. The expected NO_x reduction is between 5 percent and 10 percent, but the units would need to be tuned on an annual basis to maintain these NO_x reduction values.

3.1.1 Modifications

Instrumentation upgrades would include both windbox air flow measurement for each of the sixteen (16) burners and burner line coal flow measurements in each of the sixteen (16) burner lines. Additionally, controllers would be added to the existing coal line balancing valves, and a diagnostics grid for obtaining CO measurement would be installed at the economizer outlet.

3.1.2 Potential Risks

No potential equipment risks have been identified for this option. However, the possibility of water wall corrosion due to staging of the combustion process should be monitored.

3.1.3 Engineering/Installation Cost Estimate

It is estimated that the cost of installing the air and fuel flow instruments, controllers, and the diagnostics grid is $1,000,000 to $1,500,000 per unit and that it would take 5 to 6 months lead time to obtain and to install the new components. Any such installation would have to be done at the next regularly scheduled outage after the equipment is obtained.

3.1.4 Estimated Operation and Maintenance (O&M) Costs

Table 3-2 summarizes the operating and maintenance costs associated with the instrumentation upgrades. The economic evaluation criteria which were utilized are described in Appendix A.

Table 3-2 Operation and Maintenance Costs for Instrumentation Upgrades

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Maintenance	$37,500	$45,000	$37,500	$45,000
Operators	$49,000	$49,000	$19,700	$19,700
Notes: Per Unit costs.				

3.2 ULTRA LOW NOX BURNER MODIFICATIONS

In a conventional fossil fuel-fired boiler, nitric oxide (NO) and nitrogen dioxide (NO_2), collectively referred to as NO_x, are formed in the high temperature region both in and around the burner zone. NO_x in the flue gas is a result of either oxidizing nitrogen in the fuel (fuel NO_x) or in the combustion air (thermal NO_x). It is estimated that less than 25 percent of the NO_x formation is thermal NO_x; the remaining 75 percent is due to the amount of nitrogen in the fuel, which is greatly influenced by the oxygen concentration in the combustion region. The use of air- and fuel-staging techniques to control O_2 availability and establish early ignition can minimize volatile nitrogen conversion to NO_x.

LNBs in coal fired boiler applications control the formation and emissions of NO_x through staged combustion by controlling and balancing the fuel and air flow to each burner in order to create larger and more branched flames. The results are a reduction in the peak flame temperature and less NO_x formation. Burner efficiency is improved because the upgraded flame structure reduces the amount of oxygen available in the hottest part of the flame.

In a conventional LNB, combustion, reduction, and burnout are achieved in three stages. NO_x is formed in the initial stage where combustion occurs in a fuel rich, oxygen deficient zone. In the reducing atmosphere (2nd stage), hydrocarbons are formed which react with the NO_x formed from the combustion stage. Additional NO_x may be formed in the burnout stage where internal air staging completes the combustion. The additional NO_x can be minimized by completing the combustion in an air-lean environment.

The basic NO_x reduction principles for LNBs are to control and balance the fuel and airflow to each burner and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high temperature zones are not oxygen rich. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen deficient conditions, while the mixing of a portion of the combustion air is delayed along the length of the flame. The burner zone stoichiometry for the desired levels of NO_x reduction is typically in the range of 0.85 to 0.90.

The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, and force it to form molecular nitrogen rather than be oxidized to NO_x. Any nitrogen escaping the initial fuel-rich region has a greater opportunity to be converted to NO_x as the combustion process is completed. Staged combustion would increase the potential for higher levels of unburned carbon (UBC) in ash and higher CO emissions. This is particularly true of wall-fired boiler systems where, compared to tangential firing, the combustion process must be confined to well-defined flame zones and is less able to make maximum use of the available burner zone volume.

For LNBs to reach their maximum benefit, the proper balance of fuel and airflow to the burners (and from burner to burner) is critical. NO_x reduction is achieved from the ability to control the location of the flame, the length of the flame, and, to a certain extent, the time of combustion.

By balancing the fuel and airflow to the burners, an important step is achieved in controlling the flame characteristics and improving the overall combustion process. Balanced fuel flow ensures that each burner is operated with a similar air-to-fuel ratio. This allows the burners to operate as a NO_x control system rather than as individual burners.

3.2.1 Modifications

All of the existing 16 burners for Mill Creek Unit 1and Unit 2 would be replaced with a new ‘generation’ of LNBs such as those offered by Babcock & Wilcox (DRB-4Z), Babcock Power (Controlled Combustion Venturi [CCV®]), or Hitachi. Some modifications to the existing burner throat openings may be required as well as some modifications to the coal piping connecting to the inlet of the burners. The scope of the modifications would be dependent upon the selected burner. A review of the combustion air, primary air system components (fans, motors, dampers, controls, etc.), and burner ignition system would be required to determine if the existing systems are adequate or if modifications would be required.

A LNB retrofit for Units 1 & 2 can achieve a NO_x reduction on the order of 10 percent to 20 percent, but the unit would need to be tuned on an annual basis to maintain these NO_x reduction values.

3.2.2 Potential Risks

Fuel-rich operation at individual burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is currently a problem. If tube wastage is observed, mitigation measures, such as weld overly, could be employed. Observance for tube wastage should be performed during extended outages, and mitigation measures discussed should findings be present.

UBC in the ash may also increase, potentially preventing the salability of the ash. The carbon content is not expected to increase by more than 3 to 4% (worst case). If there is presently a high carbon content in the ash this could change the classification and storage of these waste byproducts.

3.2.3 Engineering/Installation Cost Estimate

It is estimated that the cost to replace the existing sixteen (16) burners with new generation LNBs is $7,000,000 to $9,000,000 per unit. Approximately 8 to 10 months would be needed for the selected burner supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a 2 month outage would be needed to install the new burners. Following the outage, 1 month would be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be about 11 to 13 months from release of a contract through commissioning. Installation would have to be done at the next regularly scheduled outage after the equipment has been obtained.

3.2.4 Estimated Operation and Maintenance (O&M) Costs

Table 3-3 summarizes the operating and maintenance costs associated with the LNB modifications. The economic evaluation criteria which were utilized are described in Appendix A.

Table 3-3 Operation and Maintenance Costs for LNB Modifications

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Fuel Costs	$221,000	$305,000	$43,400	$68,600
Maintenance	$270,000	$360,000	$240,000	$300,000
Operators	$0	$0	$0	$0
Notes: Per Unit costs.				

3.3 REFURBISH THE OVER FIRE AIR SYSTEM

Two-staged combustion is a method of achieving a significant reduction in NO_x. Combustion airflow is directed to the burner zone in quantities (70 percent to 90 percent) that are less than that required to theoretically burn the fuel. The remainder of the combustion air (10 percent to 30 percent) is directed to OFA ports which are generally located above the top row of burners. The additional air nozzles are installed to spread the release of heat over a larger volume by controlling where air is introduced into the furnace.

In the burner zone (first stage), the fuel and air mixture produce an oxygen-deficient, fuel-rich zone in which the formation of NO_x is minimized and the fuel is partially combusted. The remainder of the combustion air is injected into the OFA nozzles/ports and the combustion stage is completed.

OFA works by reducing the excess air in the primary combustion (burner) zone and thereby enhancing the combustion staging effect and further reducing NO_x emissions. Any residual unburned material, such as CO and UBC that inevitably escapes the main burner zone, is subsequently oxidized as the OFA is added.

As with primary NO_x control, the expected performance from a given OFA system depends on a number of factors. The stoichiometry in the burner zone decreases (0.85 to 0.90) as the amount of OFA is increased, and a point is reached where CO emissions reach high levels and become uncontrollable. The point at which this occurs varies, particularly if the fuel has characteristics that make it difficult to burn. For example, low volatility, low oxygen, or high moisture content make fuels more difficult to burn. It would also depend on the balance of flows between individual burners and the fuel fineness. As the OFA amount approaches 10 to 15 percent, the probability for individual burners to be operating under fuel-rich conditions increases so that pockets of very high CO emissions and UBC would be formed. Similarly, fuel-rich operation at burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is an ongoing problem. A fairly high level of unburned material leaving the burner zone can be accommodated by proper OFA port design, where requirements call for rapid and complete mixing of the OFA with the boiler flue gases.

The OFA ports must be designed to allow thorough mixing of the air and the combustion gases. The existing OFA ports were designed to limit the amount of combustion air to control CO and UBC. The existing OFA ports would be replaced with a new design that would provide better mixing and penetration of the combustion air being introduced into the upper furnace while not increasing CO and UBC above current values.

3.3.1 Modifications

The existing four (4) sets of OFA ports would be replaced with four (4) new OFA ports of a new design. The new OFA ports would be designed to provide a better mixing of the air with the flue gas in the upper furnace.

OFA technology alone can achieve NO_x reduction on the order of 10 percent to 15 percent, but the units would need to be tuned on an annual basis to maintain these NO_x reduction values.

3.3.2 Potential Risks

Fuel-rich operation at individual burners close to the water walls can lead to local slag formation and increased tube wastage rates, particularly if slagging is currently a problem. If tube wastage is observed, mitigation measures, such as weld overly, could be employed. Due to the current fuel characteristics, including low sulfur content, tube wastage is not anticipated. Observance for tube wastage should be performed during extended outages, and mitigation measures discussed should findings be present.

UBC in the ash may also increase, potentially preventing the salability of the ash. The carbon content is not expected to increase by more than 3 to 4% (worst case). If there is presently a high carbon content in the ash this could change the classification and storage of these waste byproducts.

3.3.3 Engineering/Installation Cost Estimate

It is estimated that the cost to replace the existing four (4) sets of OFA ports with new, redesigned OFA ports is $2,000,000 to $3,000,000 per unit. Approximately 7 to 8 months would be needed for the selected OFA port supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a 1 month outage would be needed to install the new OFA ports. Following the outage, 1 month would be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be about 9 to 10 months from release of a contract through commissioning. Installation would have to be done at the next regularly scheduled outage after the equipment has been obtained.

3.3.4 Estimated Operation and Maintenance (O&M) Costs

Table 3-4 summarizes the operating and maintenance costs associated with the OFA modifications. The economic evaluation criteria which were utilized are described in Appendix A.

Table 3-4 Operation and Maintenance Costs for OFA Modifications

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Fuel Costs	$221,000	$305,000	$43,400	$68,600
Auxiliary Power	$8,000	$8,000	$3,200	$3,200
Maintenance	$90,000	$120,000	$60,000	$90,000
Operators	$0	$0	$0	$0
Notes: Per Unit costs.				

3.4 INTEGRATED LOW NOX BURNER MODIFICATIONS AND OVER FIRE AIR SYSTEM

This option would combine the replacement of the existing burners with new LNBs discussed in Section 3.5 and replacement of the existing OFA ports with newly designed OFA ports as described in Section 3.6.

3.4.1 Modifications

The existing sixteen (16) burners and four (4) sets of OFA ports would be replaced with new generation LNBs and newly designed OFA ports. The control system, specifically the burner management system (BMS), may require minor modifications to incorporate any differences in the logics for the new burners and OFA ports. Some modifications of the fuel inlet piping to the new burners, startup guns and OFA ports may be required. The scope of the modifications would be dependent on the differences between the existing OFA ports and burners and the new OFA ports and burners. The expected NO_x reduction is 15 percent to 30 percent, but the units would need to be tuned on an annual basis to maintain these NO_x reduction values.

3.4.2 Potential Risks

Fuel-rich operation at individual burners close to the water walls can lead to local slag formation and increased tube wastage rates (metal loss) from sulfidation (fire-side) corrosion associated with operation under a reducing atmosphere in the furnace. If tube wastage is observed, mitigation measures such as weld overly or thermal spray could be employed to maintain a longer water wall tube operating service life. Due to the current fuel characteristics, including low sulfur content, tube wastage is not anticipated. Observance for tube wastage should be performed during extended outages, and mitigation measures discussed should findings be present.

UBC in the ash may also increase, potentially preventing the salability of the ash. The carbon content is not expected to increase by more than 3 to 4% (worst case). If there is presently a high carbon content in the ash this could change the classification and storage of these waste byproducts.

3.4.3 Engineering/Installation Cost Estimate

It is estimated that the cost to replace the existing sixteen (16) burners and four (4) sets of OFA ports with new LNBs and redesigned OFA ports is $9,000,000 to $11,000,000 per unit. Approximately 10 to 12 months would be needed for the selected OFA port supplier and LNBs to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a 2 month outage would be needed to install the new OFA ports and burners. Following the outage, 1 month would be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 13 to 15 months from release of a contract through commissioning. Installation would have to be done at the next regularly scheduled outage after the equipment has been obtained.

3.4.4 Estimated Operation and Maintenance (O&M) Costs

Table 3-5 summarizes the operating and maintenance costs associated with the LNB and OFA modifications. The economic evaluation criteria which were utilized are described in Appendix A.

Table 3-5 Operation and Maintenance Costs for LNB and OFA Modifications

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Fuel Costs	$221,000	$305,000	$43,400	$68,600
Auxiliary Power	$8,000	$8,000	$3,200	$3,200

Maintenance	$330,000	$420,000	$300,000	$360,000
Operators	$0	$0	$0	$0
Notes: Per Unit costs.				

3.5 NATURAL GAS CO-FIRING

The existing Mill Creek Unit 1 and 2 coal burners are equipped with eight (8), two (2) MMBtu/h natural gas fired ignitors and four (4) warm-up guns which provide a total of 8 percent to 10 percent of the full load heat input. The existing natural gas fired ignitors and warm-up guns can be replaced with natural gas-fired guns to increase the potential natural gas capability to approximately 30 to 40 percent. If a higher level of natural gas co-firing is required, natural gas firing capability would need to be incorporated into the main burner system along with boiler heat transfer modifications to maintain main steam and reheat steam temperatures. Potential modifications include installation of gas rings around the existing coal burners, installation of gas spuds in the annulus or center of the burner, or other means to allow for inserting natural gas into the existing burner.

The addition of the natural gas system is expected to improve the unit turndown capability and is expected to be lower than the steam turbine minimum operating capability. A single level of gas burners operating will have a turndown ratio of 5 to 1 so it will be capable of providing less than 10 percent full load heat input to each boiler. Prior to determining the actual minimum unit load operating point, the OEMs should also be consulted to determine the minimum safe operating condition for all major equipment.

Modifications to the boiler and boiler auxiliary equipment are often minimal or not required if the natural gas fuel heat input is limited to 40 percent but this would have to be studied further to determine the exact fuel gas heat input that could be supported but unit should be capable of operating solely on natural gas at loads up to 20 percent without requiring any major alterations to the boiler. DCS modifications would be required to incorporate additional burners and natural gas into the plant’s operating system. As long as the BMS is of a newer vintage, the existing system can be modified and reused. Updates to the combustion control system would also be required.

The radiant heat transfer characteristic of natural gas is less than that of coal. Due to this, less radiant heat is transferred in the boiler furnace and tube bundles which “see” the furnace flame. The problem is also compounded by the fact that coal slag and fly ash accumulation would result in a dirty boiler and the accumulation would act as insulation on the boiler heat transfer surfaces. An overall reduction in heat transfer would result in a lower steaming capacity; though, steaming capacity can be brought up by increasing the boiler heat input. With a reduced heat transfer and increased heat input in the furnace, a higher exit flue gas temperature is often experienced. A higher exit flue gas temperature can result in higher finishing steam temperatures and at times can deplete the capability of the steam attemperators. Higher exit flue gas temperatures can also exceed the original operating design temperatures of back end tube bundles. In the past these issues have been handled by operating with higher excess air, flue gas recirculation (Note: Generally, no FGR is required with up to 40 percent co-firing. Beyond 40 percent, FGR may be required to meet a lower NOx emission), and/or boiler heat transfer surface modifications. As part of future efforts, a thermal model and combustion and heat transfer study would be required to define any specific issues with co-firing natural gas, along with solutions to resolve those issues.

FD fans may operate at a lower point because of the lower excess air requirements of natural gas. However, primary air normally provided by the PA fans through the coal mill would need to be made up by the FD fans to provide the overall net air required to combust natural gas.

Primary air would be reduced with the reduction in coal flow. Mass flow through the induced draft (ID) fans would also be reduced. The net result of co-firing natural gas would be an overall reduction in fan horsepower from baseline levels.

The air heaters would not be adversely affected when co-firing natural gas. Although moisture content in the flue gas increases during co-firing, the amount of sulfur trioxide (SO_3) that is formed would be lower. This would result in a slightly lower acid gas condensation (dew point) temperature, which is still expected to be below the air heater gas outlet temperature.

3.5.1 Modifications

The existing gas ignitors would be replaced with Class I (per NPFA) ignitors. If required, the existing main flame scanners would also be replaced with new dual infrared/ultraviolet (IR/UV) flame scanners to provide proper flame discrimination.

The existing natural gas piping systems would be evaluated to determine if larger piping systems are required as necessary to transfer the increase in gas flow required by the Class I ignitors. If larger piping is required, the routing of the new piping system will follow the routing of the current small system as much as possible. If required, new gas valve trains, venting, new BMS and logic would be integrated into the existing DCS. New electrical equipment would be required and must adhere to National Fire Protection Association (NFPA) 497 hazardous area classification requirements when dealing with flammable or combustible liquids, combustible gases, or combustible dusts. The National Electrical Code (NEC), as defined by NFPA 70, defines the requirements for electrical equipment and associated installation methods within the boundaries of hazardous areas defined by NFPA 497. In many cases, this requires vendors to provide equipment in explosion proof enclosures, the installation of purge air systems, or the use of intrinsically safe barrier systems. Electrical installation methods include the use of raceway systems specifically rated for the hazardous area and the use of seal-offs in raceways that cross the hazardous area boundary. Assuming that the existing boiler building meets the definition of being well-ventilated, NFPA 497 requires that 15 foot spheres around each potential leakage point be classified as a Class I, Division II hazardous area. Long sections of welded natural gas piping without any flanges, valves, or instruments would not require a hazardous area classification. The 50 psig fuel gas piping to the burners would include flanged connections; stem packing on the control and shutoff valves, and fittings on instrument connections that represent potential leakage points. As a result, all existing electrical components and raceway within the 15 foot sphere of potential leak points not rated for a Class I, Division II environment would require replacement with appropriately rated equipment and materials. Many clients are concerned about the impacts to maintenance and cost associated with classification of a burner front. In some cases, clients consult with their insurance carrier and/or steam generator supplier regarding these risks and choose to not classify the burner front area. Black & Veatch standards require that its detailed designs adhere to the NFPA 497 and NEC requirements for hazardous area classification. However, with the appropriate documentation and direction from the client, a client's design criteria could be utilized if desired.

3.5.2 Potential Risks

The combustion of fuel and heat transfer dynamics are different when comparing 100 percent coal firing versus natural gas co-firing with coal in a boiler originally designed to fire 100 percent coal. The emissivity (transfer of radiant heat) characteristic of natural gas is less than that of coal. Due to this, less radiant heat is transferred in the boiler furnace and tube bundles which "see" the furnace flame. The problem is also compounded by the fact that coal slag and fly ash accumulation would result in a dirty boiler and the accumulation would act as insulation on the boiler heat transfer surfaces. An overall reduction in heat transfer would result in a lower steaming capacity; though, steaming capacity can be brought up by increasing the boiler heat input. With a reduced heat transfer and increased heat input in the furnace, a higher exit flue gas temperature is often experienced. A higher exit flue gas temperature can result in higher finishing steam temperatures and at times can deplete the capability of the steam attemperators. Higher exit flue gas temperatures can also exceed the original operating design temperatures of the heat surfaces in the boiler back pass. In the past these issues have been handled by operating with changes in excess air, flue gas recirculation, or boiler heat transfer surface modifications.

If this option were viable and were pursued, a thermal model and combustion and heat transfer study would be required to define any specific issues with co-firing natural gas, along with solutions to resolve those issues.

3.5.3 Engineering/Installation Cost Estimate

The estimated cost, excluding pipeline costs, is between $7,000,000 and $9,000,000 per unit. The cost per mile of natural gas pipeline is approximately $1,000,000 to $1,500,000, excluding purchase of property, obtaining rights of way, legal fees, etc. The estimated implementation schedule for boiler modifications would be 19 to 21 months from release of a contract through commissioning for the on-site work. Approximately 14 to 16 months would be needed for the selected supplier to design, fabricate, and deliver the components to the site. The installation would take approximately 4 months – 3 months pre-outage, 1 month outage. Following the outage, 1 month would be needed for commissioning activities (tuning/testing).

3.5.4 Estimated Operation and Maintenance (O&M) Costs

Table 3-6 summarizes the operating and maintenance costs associated with natural gas co-firing. The economic evaluation criteria which were utilized are described in Appendix A.

Table 3-6 Operation and Maintenance Costs for Natural Gas Co-Firing

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Fuel Costs				
Coal	-$8,828,000	-$12,191,000	-$1,737,000	-$2,742,000
Natural Gas	$15,826,000	$21,854,000	$2,239,000	$3,536,000
Auxiliary Power	$0	$0	$0	$0

Maintenance	$252,000	$270,000	$120,000	$189,000
Operators	$0	$0	$0	$0
Notes: Per Unit costs.				

3.6 SELECTIVE NON CATALYTIC REDUCTION

Selective non-catalytic reduction (SNCR) is a method to reduce NO_x emissions in coal fired units. The process involves injecting urea (H_2N - CO - NH_2) at multiple levels in the boiler. Urea is injected into areas of the boiler where the flue gas temperature ranges from 1,600 to 2,100 °F. Urea is a non-hazardous reagent if shipped in dry pelletized form with no special shipping, storage, or usage limitations. Urea is stored as 40 to 50 percent urea solution. The urea solution is pumped to the boiler and atomized with compressed air at the injection nozzles.

When injecting urea into the boiler, NO_X reduction should be balanced with ammonia slip for optimal performance. Ammonia slip is the ammonia that does not react with NO_X and instead "slips" out of the boiler as unreacted ammonia. High levels of ammonia slip can cause several negative operational impacts.

Ammonia can be used in lieu of urea for the SNCR but the main SNCR vendor (FuelTech) does not use ammonia. Ammonia reacts extremely fast making it very difficult to achieve good distribution across the boiler resulting in low performance. Urea on the other hand takes time to convert from Urea to ammonia, delaying the vaporization of the ammonia and allowing better distribution and performance. For these reasons, Black & Veatch recommends against using ammonia for SNCR.

Reagent injection lances are usually located between the boiler soot blowers in the pendent superheat section. Optimum injector location is mainly a function of temperature, CO concentration, and residence time. To accommodate SNCR reaction temperature and boiler turndown requirements, several levels of injection lances are normally installed. A flue gas residence time of at least 0.3 seconds in the optimum temperature range is desired to ensure adequate SNCR performance. Residence times in excess of one second yield high NO_X reduction levels even under less than ideal mixing conditions. Computational fluid dynamics and chemical kinetic modelling can be performed to establish the optimum ammonia injection locations and flow patterns. Additionally, detailed testing including temperature mapping and NO_x and CO levels across the boiler cross section will be performed prior to finalization of the SNCR design. For an existing boiler, minor water wall reconfigurations are necessary to accommodate installation of SNCR injector lances.

The NO_x levels for each unit were estimated based on reviewing operating data. These values are presented in Table 3-7. CO emissions were not available in the CEMS data so we have assumed the CO levels are below the level that would significantly impact SNCR performance. Low CO levels are key to good SNCR performance. The CO emissions need to be below 250 ppm at the injection location in order to assure SNCR performance. Boiler testing would be required to verify the CO emissions levels in the furnace.

Table 3-7 Estimated NO_x Levels

ESTIMATED NOX LEVELS			
Pollutant	**Mill Creek 1 & 2**	**Ghent 2**	**Brown 1 & 2**
NO_x	0.3 lb/MMBtu	0.3 lb/MMBtu	0.4 lb/MMBtu

3.6.1 Modifications

The system would consist of the following:

- Urea Storage and Mixing Tanks
- Reagent Recirculation System: A reagent recirculation skid would be installed to provide sufficient pressure to deliver the reagent to the mixing and measurement module which would be used to meter and control the rate of reagent that would be delivered to each reagent injector level.
- Injection lances: The optimum injector location is mainly a function of flue gas temperature and residence time. To accommodate SNCR reaction temperature, boiler turndown requirements, multiple injection levels would need to be installed at different places in between the superheater bundles or platens.
- Boiler Modifications: Water wall penetrations would be installed to accommodate installation of SNCR injector lances.
- Balance of Plant: Piping would be installed to provide compressed air and water from the existing Plant Systems.
- Controls: To maximize the effectiveness of the feedback control system, the control and monitoring system for the system would consist of NO_X monitors located in the ductwork downstream of the SNCR prior to the air heater. The monitor would measure emissions from a portion of the ductwork cross section. The concentrations measured by the monitors would be converted to 4 to 20 milliamp signals for feedback to the reagent injection control system.

3.6.2 Potential Risks

As mentioned previously, the temperature and distribution of NO_x and CO in the boiler have significant effects on the performance of the SNCR. Temperature mapping would need to be completed on each unit to ensure there are suitable locations to inject the urea for both full and part loads. Variations in temperature over the load range can be somewhat mitigated by having multiple injection levels which can be put in and out of service depending on the operating loads. Temperature mapping would need to be completed after any other boiler modifications that may affect the temperature profile within the boiler. Temperature mapping is a very important part of the design process. Injection at higher temperatures would contribute additional NO_x production whereas injection at lower temperatures would reduce achievable NO_x reduction.

Localized high levels of CO in the boiler could be a problem. CO has been found to limit the NO_x removal efficiency of a SNCR system. Although the exact impact is not quantifiable, the removal efficiency would be adversely affected.

The potential impact of the ammonia slip could be seen on the air heaters. Ammonium bisulfate (ABS) forms when excessive ammonia slip from the SNCR combines with the SO_3 and moisture in the flue gas. Formation and deposition of ABS on the air heater surface cause an increase in pressure drop and decrease in plant efficiency. For this reason, it is recommended that the ammonia slip be maintained below 5 ppmvd.

Negative impact on the fly ash would occur at these ammonia slip levels, which could impact the sale of the ash if it is currently not disposed of in a landfill.

Due to the direct injection of urea into the furnace, annual chemical costs are directly related to the number of hours on-line, load, and size of the boiler.

3.6.3 Estimated Engineering/Installation Costs

It is estimated that the cost to engineer and install a SNCR system would be $8,000,000 to $11,000,000 per unit. Approximately 7 to 9 months would be needed for the selected SNCR supplier to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, the installation of a SNCR system would take approximately 4 months (3 month pre-outage / 1 month outage duration). The pre-outage activities would consist of installing the urea storage, reagent circulation skid, mixing and measurement module, platforms, piping, and supplemental support steel. The outage would consist of installing the boiler penetrations, injection lances, and the balance of the ancillary equipment. Following the outage, 1 month would be needed for commissioning (tuning/testing) activities. The total project duration is estimated to be 12 to 14 months from release of a contract through commissioning.

Ghent Unit 2 is slightly larger than the Mill Creek Units. The larger furnace and increased NO_x mass rate would result in additional SNCR lance and a larger reagent preparation system. As a result we would expect the cost to be between $9,000,000 and $12,000,000 to supply, engineer and install an SNCR system. Brown Units 1 & 2 are smaller than Mill Creek so the cost to install an SNCR system is estimated to be between $6,000,000 and $9,000,000 per unit. Lead times and installation durations would be expected to be the same.

3.6.4 Estimated Operation and Maintenance (O&M) Costs

The operating costs for the SNCR system include cost for the urea regent and auxiliary power, as well as, ongoing system maintenance. Operator costs were also included.

The maintenance cost was estimated as 3 percent of the direct cost of the SNCR system. The operator costs were assumed to be ¼ of a full time equivalent. For the purpose of this study an operator was assumed to cost $75 per hour. Reagent costs were estimated to $300 per short ton of 50% urea solution. Historical data has shown costs for the urea solution can vary from $200 to $450 per short ton of solution. Urea costs will vary greatly with many factors including delivery costs. NO_x removal was assumed to be 25% for estimating reagent usage.

The capacity factor was assumed to be 75 percent for Mill Creek Units 1 and 2 and Ghent Unit 2 and 30 percent for Brown Units 1 and 2 to calculate the annual costs for reagent and auxiliary power. Auxiliary power costs were assumed to be $0.06 per kW.

Table 3-8 summarizes these operating and maintenance costs.

Table 3-8 Operation and Maintenance Costs for SNCR

	MILL CREEK 1 & 2	GHENT 2	BROWN 1 & 2
Maintenance	$116,000	$148,000	$82,000
Operators	$39,000	$39,000	$39,000
Urea	$1,899,000	$2,673,000	$536,000
Auxiliary Power	$45,000	$59,000	$12,000
Notes: Per Unit costs.			

4.0 Non-Viable NOx Reduction Techniques

The following technologies were identified but eliminated from consideration because they had limited effectiveness, had already been implemented at some of the units, would require ongoing maintenance or were prohibitive to unit operation.

4.1 UNIT AVERAGE OUTPUT OF 90 PERCENT

This option reduces the output of the unit to an operating condition where the heat input is at a point where the resulting NO_x emissions levels are below the required levels.

4.1.1 Modifications

No equipment modifications are required. The unit control system would be modified to limit the unit output to maintain operation below the established emissions thresholds.

The expected NO_x reduction at an average output of 90 percent is between 5 percent and 10 percent.

4.1.2 Potential Risks

The reduction in MW output might have an overall effect on the distribution grid. There is a risk of loss to revenue from lost generation opportunities.

4.1.3 Estimated Engineering/Installation Costs

This option could be implemented in a relatively short time frame after discussions with the plant staff and dispatch have taken place. There are no capital costs associated with this option, and the operational costs are relatively small. The main cost of this option is associated with lost generation opportunities.

4.1.4 Conclusions

Derating the unit is not part of the current operating plans for these units.

4.2 BOILER TUNING

To utilize the existing burners and OFA system to reach the optimal NO_x levels (while minimizing CO formation), a proper fuel and combustion ratio (mixture) would be required at each burner. The burners would need to be adjusted to achieve the proper air/fuel ratio, flame length, and time of combustion. This effort would involve performing fineness tests, and clean air flow and dirty air flow tests on the coal feed system from the pulverizers to the burners. From these tests, proper fuel flow balancing (pipe-to-pipe) and fineness requirements for each burner can be obtained. Tests on the combustion air flow would allow for biasing the air to the inner and outer sections of the burners and would assist in minimizing the formation of NO_x and CO.

A permanent CO grid installed in the economizer outlet duct would allow operations to monitor the CO being produced and make online adjustments as necessary to achieve an optimal balance between CO and O_2 in order to minimize NO_x formation, while optimizing CO at a level consistent with good combustion practices across the operating load range. Such optimization is not possible using the current test grid and existing instrumentation.

NO_X reduction is expected to be in the 0 percent to 10 percent range.

4.2.1 Modifications

The services of an outside contractor would be required to conduct clean air and dirty air flow tests and fineness tests on the coal feed piping to each of the burners. Testing would also be required to adjust the secondary air flows to each windbox compartment to obtain the optimum settings on the individual windbox compartment dampers as well as inner and outer sections of the burners to achieve efficient burner operation. A CO monitoring grid would have to be installed, as mentioned above.

4.2.2 Potential Risks

The tests may need to be repeated every year or so depending on how well the NO_x and CO emissions are being held at or below the targeted values. Over the course of the year, adjustments to the firing system may be required in order to maintain the current NO_x levels, especially when operating at reduced loads. These adjustments would not be possible without the installation of a permanent CO monitoring system or utilization of third party testing services.

4.2.3 Engineering/Installation Cost Estimate

It is estimated that the cost of the testing will be less than $200,000 per unit per year and take 3 to 4 weeks to complete once the purchase order with the contractor has been released. It is estimated that the cost of installing a permanent CO monitoring system is $400,000 per unit and that it would take 5 to 6 months lead time to obtain and install the new components. Any such installation would have to be done at the next regularly scheduled outage after the equipment has been obtained.

4.2.4 Conclusions

Boiler Tuning provides limited removal potential, requires continuous tuning efforts and results will vary over time.

4.3 ARTIFICIAL NEURAL NETWORK OR ADVANCED CONTROL SYSTEM

For optimum combustion, an ideal fuel air mixture has to be delivered to each burner and the OFA system. This balanced delivery should produce the maximum amount of heat with the minimum amount of waste. However, without the ability to continuously monitor air and fuel flow entering each burner and the resulting burner performance, conditions typically exist where non-optimum air is supplied for combustion, creating a fuel-rich or air-rich area. Both conditions reduce boiler efficiency and result in excess CO, fly ash loss-on-ignition (LOI) or NO_x emissions. In an attempt to prevent or reduce these effects, plants often turn to the procedure known as “burner balancing.” This entails the monitoring and adjustment of burners so that the fuel/air ratio is equalized across the boiler.

Advances in computer hardware and software technology have enabled power generation companies to implement optimization solutions that decrease emissions and maximize plant efficiency. This solution, commonly referred to as boiler optimization or ANN systems, provides simultaneous improvements in both fuel efficiency and emissions. ANN computing differs from traditional computing in that engineering, statistical, and first-law principles have been replaced by complex, time varying, nonlinear relationships. ANN systems use real-time operational data extracted from a plant Distributed Control System (DCS), "learn" solutions from plant operational experience, and reduce emissions while improving plant performance by continuously adapting to changes in plant operation.

ANN systems also supplement other NO_x reduction strategies. These include LNBs, OFA and post-combustion controls such as SCR and selective non-catalytic reduction (SNCR). These systems are also used to help boiler manufacturers tune boilers with poor combustion characteristics or after a LNB retrofit or other boiler modifications such as OFA modifications.

4.3.1 Modifications

Additional NO_x reduction can be realized by implementing an advanced control neural net system to allow for adjustments to be made while the unit is in operation. Currently, all burners and burner line controls are manually adjusted at full load baseline conditions. With the installation of additional instrumentation (secondary air flow measurement at each windbox [4] and burner line flow measurement [16]) and controllers (burner air flow registers [16] and coal pipe restrictors [16]), plus a CO and O_2 profile grid at the economizer outlet, the control system could continuously tune the burners to reduce NO_x, O_2, and CO. There are differences in firing system designs between the two units which could require additional modifications to provide the same functionality in terms of control to maintain the proper air/fuel ratio over the operating load range.

The expected NO_x reduction is 5 percent to 15 percent, but the units would need to be tuned on an annual basis to maintain these NO_x reduction values.

4.3.2 Potential Risks

No potential risks have been identified at this time.

4.3.3 Engineering/Installation Cost Estimate

It is estimated that the cost of installing the advanced control system, related hardware, instrumentation, and controllers is $1,500,000 to $2,500,000 per unit and that it would take 11 to 12 months to obtain and install the new hardware and software. Any such installation would have to be done at the next regularly scheduled outage after the equipment has been obtained.

4.3.4 Conclusions

Artificial Neural Nets or Advanced Control Systems have either been implemented on these units or deemed to not improve NO_X performance.

4.4 FLUE GAS RECIRCULATION SYSTEM

FGR is useful in reducing NO_x when the contribution of fuel nitrogen to the total NO_x formation is small. Typically, a portion of the flue gas is extracted from the discharge of the economizer (gas side) and introduced into the combustion air flow stream which lowers the burner peak flame temperatures. FGR has been successfully used for gas-fired boilers. Its effectiveness is very uncertain and relatively small for coal-fired boilers, where the contribution of fuel nitrogen is dominant.

The typical design of an FGR system requires the installation of a FGR fan, ducting, duct supports, and controls. The FGR system utilizes air foils to mix the recirculated flue gas with the combustion air downstream of the FD fan. This design ensures that the flue gas and combustion air are thoroughly mixed before reaching the burners. Note that the operation of the air foils is not affected by this design.

In general, a significant increase in flue gas recirculation to the burners would produce a large reduction in NO_x emissions. The amount of FGR increase would be dictated by the emissions levels that are being attempted as well as limitations on equipment size and boiler components. For safe and reliable operation of the combustion equipment, the oxygen content must be maintained at or above 17 percent (dry basis). To the maximum NOx Reduction but still maintain stable combustion, the amount of the flue gas recirculation would be limited to 15 percent (17.85 percent oxygen)

4.4.1 Modifications

With the FGR and technology, a pre-determined amount of flue gas would be redirected from the economizer flue gas outlet to the outlet of the FD fans upstream of the windboxes. At a minimum, this would require the addition of ducting, duct supports, dampers, damper controls, and expansion joints at the outlet of the FD fans upstream of the windboxes.

4.4.2 Potential Risks

The boilers are not well-suited for FGR because of the limited industry experience with units of this size, limited removal efficiency, personnel risks from fan failures, increased auxiliary loads, high maintenance costs associated with fan maintenance, and high capital costs.

Most FGR systems were originally installed for steam temperature control and without regard for NO_x control. There is limited industry experience using FGR systems for NO_x control on large coal fired boilers, so expected NO_x reduction is uncertain. For coal fired units, it has been Black & Veatch's experience that other NO_x reduction technologies are able to achieve actual NO_x reduction rates comparable to the theoretical NO_x reduction rates for the FGR but with a lower installed cost.

The NO_x reduction capability of these systems varies drastically by unit size, firing system configuration, and unit load. Most FGR systems installed in the past on coal-fired units have been removed because they are susceptible to component failures from exposure to the heavily dust-laden flue gas stream. In some instances, catastrophic failures have occurred where the FGR fan rotor has failed resulting in significant damage to the facility, and in isolated instances loss of life. These issues are more common on larger units due to the higher fan tip speeds that are required to recirculate the flue gas back to the furnace. These issues, along with the additional impact to auxiliary load, warrant removal of the FGR systems from further consideration.

4.4.3 Estimated Engineering/Installation Costs

It is estimated that the cost to engineer and install a FGR system would be $7,000,000 to $9,000,000 per unit. Approximately 9 to 10 months would be needed for the selected suppliers to design, fabricate, and deliver the components to the site. After receipt of the equipment on site, a 3 month outage would be needed to install the supplemental support steel, foundations, gas recirculation fan and motor, dampers, expansion joints, insulation and lagging. Following the outage, 1 month would be needed for commissioning (tuning/testing) activities. From release of a contract through commissioning, the total project duration is estimated to be 13 to 14 months.

4.4.4 Estimated Operation and Maintenance (O&M) Costs

Table 4-1 summarizes the operating and maintenance costs associated with the installation of a flue gas recirculation system. The economic evaluation criteria which were utilized are described in Appendix A.

Table 4-1 Operation and Maintenance Costs for Flue Gas Recirculation

	MILL CREEK 1 & 2	GHENT 2	BROWN 1	BROWN 2
Fuel Costs	$0	$0	$0	$0
Auxiliary Power	$242,000	$333,000	$85,000	$134,000
Maintenance	$270,000	$360,000	$210,000	$240,000
Operators	$99,000	$99,000	$99,000	$99,000
Notes: Per Unit costs.				

4.4.5 Conclusions

The ability to accurately predict NO_x reduction for FGR systems on units of this size is limited to theoretical evaluation. Given that other NO_x reduction technologies have proven reductions of similar or better levels to the calculated, or theoretical, NO_x reduction of FGR systems for units of this size, and considering the proven technologies are more cost effective, this option was eliminated from further consideration.

Appendix A

Economic Evaluation Criteria

Appendix A

Economic Evaluation Criteria

A.1 Capacity Factor

The annual capacity factor was assumed to be 75 percent for Mill Creek Units 1 and 2 and Ghent Unit 2 and 30 percent for Brown Units 1 and 2.

A.2 Coal Cost

The average annual coal cost on $/MBtu basis was assumed to be as follows:

- Mill Creek: $2.05/MBtu
- Ghent: $2.05/MBtu
- Brown: $2.85/MBtu

A.3 Natural Gas Cost

The average annual natural gas cost was assumed to be $3.50 per MBtu for Mill Creek Units 1 and 2, Ghent Unit 2, and Brown Units 1 and 2.

A.4 Auxiliary Power Cost

Additional auxiliary power will be required to run the new control technology systems applied to the facility. The power requirements of each system vary, depending on the type of technology and the complexity of the system. The 2016 annual energy costs which are composed of fuel costs and variable O&M costs were assumed to be $60/MWH.

A.5 Labor Costs

The hourly burdened wage rate for labor for operation and oversight of the equipment is assumed to be $75.

A.5 Maintenance Costs

The annual maintenance materials and labor costs are typically estimated as a percentage of the total equipment costs of the system. Based on typical electrical utility industry experience, maintenance materials are estimated to be between 1 and 5 percent of the total direct capital costs according to the retrofit technology. Some initial recommended spare parts are included in the capital costs. An annual maintenance value of 3 percent of the total direct capital costs was used as the basis for the yearly maintenance materials and labor cost.