E.ON US
Coal Fired Fleet Wide

Air Quality Control
Technology Cost Assessment

B&V Project: 167987
B&V File No.: 26.0000

Issue Date and Revision
July 2010
Rev. 0

BLACK & VEATCH
Building a world of difference.

e·on

Table of Contents

Table of Contents (Continued)

Table of Contents (Continued)

Tables

Table of Contents (Continued)

Tables (Continued)

Acronym List

AQC	Air Quality Control
BOP	Balance-of-Plant
CAIR	Clean Air Interstate Rule
CDS	Circulating Dry Scrubber
CO	Carbon Monoxide
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
H_2SO_4	Sulfuric Acid
HCl	Hydrogen Chloride
Hg	Mercury
ID	Induced Draft
LNB	Low NO_x Burners
MACT	Maximum Achievable Control Technology
MBtu	Million British Thermal Unit
NN	Neural Network
NO_x	Nitrogen Oxides
O&M	Operation and Maintenance
OFA	Overfire Air
PAC	Powdered Activated Carbon
PJFF	Pulse Jet Fabric Filter
PM	Particulate Matter
SCR	Selective Catalytic Reduction
SO_2	Sulfur Dioxide

Executive Summary

The purpose of this study was to develop fleet-wide, high-level, capital and O&M costs for recommend air quality control equipment necessary to meet future environmental requirements at 18 coal-fired units located at 6 facilities (E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River) owned and operated by E.ON. The study was conducted at a high-level and under a tight schedule in order to meet E.ON's requirements.

To perform the study, Black &Veatch dispatched two teams of engineers to conduct site visits and walk-downs at each of the 6 facilities over the course of 3 days. Based on information gathered during these site visits, initial air quality control equipment recommendations were prepared for E.ON's review and approval before proceeding with the cost estimate. Following E.ON's approval, high-level capital and O&M costs were determined for each unit and air quality control technology—these scenarios are considered the "base case" air quality control technologies. Table ES-1 summarizes the capital and O&M cost totals rolled up for each facility.

Table ES-1
Summary of Base Case Plant AQC Technology Costs

Plant	**Capital Cost ($/1,000)**	**Operating Cost ($/kW)**	**O&M Cost ($/1,000)**	**Levelized Annual Cost ($/1,000)**
E.W. Brown	263,163	1,391	15,651	47,679
Ghent	772,355	1,475	47,902	141,898
Cane Run	889,000	4,426	49,760	157,953
Mill Creek	2,144,030	5,485	117,530	378,462
Trimble County	135,451	248	10,295	26,780
Green River	171,695	1,922	20,703	41,598
Total	**4,375,694**	**14,947**	**261,841**	**794,370**

This report contains a breakdown of the aforementioned base case costs and summarizes the basis and supporting documentation used to develop them. Additionally, E.ON requested specific air quality control technology alternatives (herein referred to as “options”) for units at the E.W. Brown and Mill Creek plants. The costs for each option are included within the report document. The supporting documentation includes site visit notes, control technology recommendations, design basis, process flow diagrams, equipment layout drawings, and milestone implementation schedules for the selected technologies.

1.0 Introduction

Black & Veatch was tasked by E.ON to provide a high-level cost estimate of air quality compliance expenditures necessary to meet expected future regulatory requirements for budgetary purposes. The following coal fired units were considered in this study:

- E.W. Brown – Units 1, 2, and 3.
- Ghent – Units 1, 2, 3, and 4.
- Cane Run – Units 4, 5, and 6.
- Mill Creek – Units 1, 2, 3, and 4.
- Trimble County – Units 1 and 2.[1]
- Green River – Units 3 and 4.

To accomplish this objective, Black & Veatch personnel collected the necessary unit-specific data and performed onsite observations to prepare this AQC retrofit technology and cost assessment. Based on information gathered during these site visits, initial base case air quality control equipment recommendations were prepared for E.ON's review and approval before proceeding with the cost estimate. To support this process, design basis, process flow diagrams, equipment layout drawings, and milestone implementation schedules for the selected technologies were developed. Additionally, E.ON requested specific air quality control technology alternatives (herein referred to as "options") for units at the E.W. Brown and Mill Creek plants.

Based on B&V experience, technical and economic assumptions were made in order to facilitate rapid development of the technical calculations and costs estimates. Of special note, the capital cost estimates and annual operating cost data for the AQC equipment should be considered as high-level conceptual design estimates and should be confirmed with a more detailed follow-up assessment before initiating an implementation plan.

The assessment identifies AQC technologies for reducing unit-specific air emissions for pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM)[2], carbon monoxide (CO), mercury (Hg), hydrogen chloride (HCl), and dioxin/furans. This report documents the assumptions and findings of the assessment,

---

[1] Unit 2 at Trimble County is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Therefore, this unit was excluded from further analyses.

[2] At the May 10, 2010 kick-off meeting, E.ON indicated that PM should be used as a surrogate for all metal hazardous air pollutants (HAPs) and that metal HAPs would not specifically be addressed in the study. Furthermore, it was reasoned that a fabric filter control device installed for PM control would also control metal HAPs.

including the identification of retrofit AQC technologies to achieve compliance at each unit, as well as order-of-magnitude costs capital and operation and maintenance (O&M) cost estimates, process flow diagrams, summary plot plan drawings, and Level 1 summary schedules to engineer, procure, and install each recommended technology. Additionally, the report identifies potential impacts the AQC technologies may impose on balance-of-plant (BOP) systems as applicable, such as, electric systems, ash handling systems, water supply and wastewater treatment systems.

2.0 Pollutant Emission Targets

The potential impact of future regulations are the primary driver for both the timing and nature of environmental controls planned at the E.ON plants. Among the regulatory drivers are the Utility Maximum Achievable Control Technology (MACT) and the Transport Rule -- Clean Air Interstate Rule (CAIR) replacement to be proposed by the United States Environmental Protection Agency (USEPA) by March 2011 and summer 2010, respectively. These two regulatory drivers and their associated emission levels serve as the primary basis used by Black & Veatch to develop unit-by-unit AQC technology recommendations.

E.ON provided a matrix of estimated requirements under future new environmental regulations, as well as a summary implementation schedule of regulatory programs. This information is provided in Appendix A. From this information, E.ON developed specific pollutant emission limit targets with the intent that the limits would be applied to each unit individually to assess current compliance and the potential for additional AQC equipment. For the purposes of this study, compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) were not considered. Table 2-1 summarizes the future pollution emission targets provided by E.ON for each unit.

Table 2-1
Future Pollution Emission Targets

Pollutant	Future Pollutant Emission Limit (lb/MBtu)
NO_x	0.11
SO_2	0.25
PM	0.03
CO	0.10(a)
Hg	0.000001(b)
HCl	0.002
Dioxin/Furan	15×10^{-18}

(a)E.ON's original emission matrix provided a CO emission level of 0.02 lb/MBtu. It was determined that there was not a feasible and proven control technology available for the type and size of unit being assessed. Therefore, on May 21, 2010, the future pollutant emission limit was modified to reflect 0.10 lb/MBtu, which is considered reflective of potentially achievable CO emissions from coal fired units.
(b)The emission matrix indicated 0.012 lb/GWh or 90 percent reduction.

3.0 Study Basis and Methodology

The following sections discuss the basis and methodology used to make the AQC technology recommendations and cost estimates presented herein. These activities included site visits, development of a design basis, costs estimate methodology development, and economic assumptions.

3.1 Site Visits

During the week of May 10, 2010, E.ON provided Black & Veatch personnel access to each plant site to review existing unit systems and components and discuss current operational issues with appropriate plant personnel. The discussions focused on plant-specific issues that could potentially impact the selection, installation, and operation of future AQC technologies, such as:

- Available space to locate new AQC equipment.
- Availability of auxiliary power.
- Condition assessment of major equipment.
- Identification of BOP issues.
- Constructability issues.

These discussions were followed by plant lead facility tours. Each plant site visit ended with an exit meeting, where the initial recommendations and findings were summarized with the plant team. A brief description of site visit observations and AQC considerations for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble, and Green River are included in Sections 4.1.1, 4.2.1, 4.3.1, 4.4.1, 4.5.1, and 4.6.1, respectively. Table 3-1 identifies team personnel and facilities visited by each Black & Veatch team.

3.2 Design Basis

A design basis was established for each unit based on information provided by E.ON (included in Appendix B) and results from Black & Veatch's internal combustion calculations. Information in the design basis was used as the basis for estimating equipment sizes, performance calculations, cost estimates (capital, operating, and maintenance) and also for estimating resource consumption, auxiliary power requirements, and byproduct disposal volumes. The performance calculations developed were based on the established design basis parameters and served as the basis for estimating capital and annual O&M costs for proven and feasible AQC equipment. The design basis is provided in Appendix C.

Table 3-1
Black & Veatch Team Members

Team No. 1[a]	
Black & Veatch Team Member	**Position**
Anand Mahabaleshwarkar Richard Hooper Mike Ballard	Air Quality Control Engineer Mechanical Engineer Civil/Structural Engineer
Team No. 2[b]	
Black & Veatch Team Member	**Position**
Pratik Mehta Dave Muggli Roger Goodlet	Air Quality Control Engineer Mechanical Engineer Civil/Structural Engineer

(a)Visited Cane Run, Mill Creek, and Green River Stations on May 11, May 12, and May 13, respectively.
(b)Visited Ghent, Trimble County, and E.W. Brown Stations on May 11, May 12, and May 13, respectively.

3.3 Cost Methodology

Capital and annual O&M costs to procure, install, and operate the E.ON approved AQC technologies were developed for each of 17 units[3]. All cost information was produced for unit-specific combinations of new AQC technology components — upgrades to existing AQC equipment were not considered. A brief description of the proven and feasible AQC technologies considered for this study is included in Appendix D.

To support the cost estimate, Black & Veatch performed a high-level fatal flaw analysis of the following for each selected emission control technology for each unit:

- Flue Gas Conditions. Based on design fuel analysis, boiler steaming capacity, and current operating characteristics, Black & Veatch determined the flue gas conditions to be used as the basis for the AQC equipment design basis.
- Draft Fan Analysis. Black & Veatch identified the new fan requirements with high-level approximations for the new or modified ID or booster fans.

---

[3] Unit 2 at Trimble County is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Therefore, this unit was excluded from further analyses.

- Simplified AQCS Mass Balance. Simplified mass balances for the AQC process was completed to determine the level of reagent use and the quantity of byproduct produced.
- Black & Veatch identified new auxiliary electric loads with approximate values for recommended technologies.
- Chimney Analysis. A high-level analysis was performed to evaluate, for each air pollution control equipment option identified, modifications or replacement of the existing chimney.
- Constructability Review. A high-level constructability review was performed to assure that each conceptual site layout considers necessary access for construction without disrupting existing plant and AQC equipment. Construction and schedule are key considerations in the success of any major capital plan.
- Conceptual Equipment Arrangements. Black & Veatch produced overlays of existing site layout drawings supplied by E.ON to identify potential equipment locations (AQC equipment footprint boxes) for the approved AQC technologies. These layouts approximate the footprints and the real estate constraints.
- Schedule. Black & Veatch developed a general high-level project schedule (Level 1) including construction and erection plan of recommended AQC technologies.

The capital cost estimates were factored from recent detailed studies of similar coal fired applications and previous in-house design/build projects, include direct and indirect costs, and are stated in 2010 dollars. These costs also include allowances for auxiliary electric, draft fan upgrades, control system upgrades and other required BOP system upgrades and high-level estimates of capital cost for new stacks, induced draft (ID) and booster fans, and ductwork. Likewise, O&M costs were also estimated for the aforementioned equipment and were similarly based on data from either in-house design/build projects or, as in most case, were estimated based on a factor. The capital and O&M represent order-of-magnitude costs. The following sections briefly describe these costs.

3.3.1 Capital Costs Estimate

Direct costs consist of purchased equipment, installation, and miscellaneous costs including foundation, handling equipment, electrical, demolition, buildings, relocation costs, etc. The purchased equipment costs are the costs for purchasing the equipment, including taxes and freight. An itemized list of key components of the direct capital cost has been included in the costs for each feasible control technology described later in this report. The installation costs include construction costs for installing the new controls. The installation costs take into account the retrofit difficulty of the existing site configuration and condition and the installation requirements of the evaluated technology. Finally, the costs of miscellaneous items such as site preparation, buildings, and other site structures needed to implement the control technology are included.

Indirect costs are those costs that are not related to the equipment purchased but are associated with any engineering project, such as the retrofit of an AQC technology. Indirect costs addressed in this evaluation include the following:

- Contingency.
- Engineering.
- Owner’s Cost.
- Construction Management.
- Startup and Spare Parts.
- Performance Tests.
- Construction Difficulty Cost
- Demolition Cost

The following sections briefly describe the indirect capital costs considered for this study.

3.3.1.1 Contingency. Contingency accounts for unpredictable events and costs that could not be anticipated during the normal cost development of a project. Costs assumed to be included in the contingency cost category are items such as possible redesign and equipment modifications, errors in estimation, unforeseen weather-related delays, strikes and labor shortages, escalation increases in equipment costs, increases in labor costs, delays encountered in startup, etc. Contingency assumptions will vary per individual AQC technology and unit and therefore contingency costs were established per AQC technology instead of being combined on a per unit basis in this study.

3.3.1.2 Engineering. Engineering costs include any services provided by an architect/engineer or other consultant for support, design, and procurement of the AQC project.

3.3.1.3 Owner's Cost. Table 3-2 lists possible Owner's costs for this category. The Owner's costs are identified as indirect costs. Some of the categories are not applicable to all of the evaluated technologies, but are representative of the typical expenditures that an Owner would experience as part of an AQC retrofit project.

Table 3-2
Typical Owner's Cost Categories

Project Development:

- Legal assistance
- Environmental permitting/offsets
- Public relations/community development
- Road modifications/upgrades

Financing:

- Debt service reserve fund
- Analyst and engineer

Owner's Project Management:

- Provide project management
- Perform engineering due diligence
- Prepare bid documents and select contractors and suppliers

Plant Startup/Construction Support:

- Owner's site mobilization
- O&M staff training
- Initial test fluids and lubricants
- Initial inventory of chemicals/reagents
- Consumables
- Construction all-risk insurance
- Auxiliary power purchase

Taxes/Advisory Fees/Legal:

- Taxes
- Market and environmental consultants
- Owner's legal expenses:
  - Power purchase agreement
  - Interconnect agreements
  - Contract--procurement and construction
  - Property transfer

3.3.1.4 Construction Management. Construction management services include field management staff such as support personnel, field contract administration, field inspection and quality assurance, project controls, technical direction, and management of startup. It also includes cleanup expense for the portion not included in the direct-cost construction contracts, safety and medical services, guards and other security services, insurance premiums, other required labor-related insurance, performance bond, and liability insurance for equipment and tools.

3.3.1.5 Startup and Spare Parts. Startup services include the management of the startup planning and procedure and the training of personnel for the commissioning of the newly installed AQC technology. Also included are the general low-cost spare parts required for each AQC technology system. High-cost critical spare part components are kept only if recommended by the manufacturer; they are determined and accounted for on a case-by-case basis.

3.3.1.6 Performance Tests. Performance test services are typically required after every AQC technology addition to validate the performance of the emissions reduction system. The results of the performance tests are used to ensure compliance with performance guarantees and emissions limits.

3.3.1.7 Construction Difficulty Cost. The construction difficulty costs assumes a construction difficulty factor in the range of 1.0 - 1.8 depending upon the site specific conditions. The construction difficulty ratio are based on such factors as equipment height restrictions, building at height, complicated ductwork tie in, limited footprint, elevated AQCS equipment, underground utility interferences, difficult construction of foundations for structural steel framework, major existing equipment relocation, limitation of access, etc. Depending upon the site conditions, the construction difficulty costs were estimated for individual AQC technologies for this study.

3.3.1.8 Demolition Cost. The demolition costs include, but are not limited to, support steel and ductwork demolition and relocation, modifying structural steel framework, chimney demolition, relocation of underground utilities, relocation of above ground utilities, demolition and relocation of buildings, demolition of existing AQC technology, relocation of underground water wells, electrical vault, electrical manholes, storm sewer, relocation of pipe racks and above ground or overhead obstructions, demolition of foundations and supports, relocation of power lines, etc. The demolition cost reflects the cost for removing an asset, the tools required, the labor involved, any other equipment required to complete the demolition activity, mobilization and demobilization, etc. Depending upon the site conditions, the demolition costs were estimated for individual AQC technology for this study.

3.3.2 Annual O&M Cost Estimate

Annual O&M costs typically consist of both fixed and variable O&M costs. The following cost categories are a few of the fixed and variable costs considered:

- Reagent costs.
- Electric power costs.
- Makeup water costs.
- Wastewater treatment and byproduct disposal costs.
- Operating labor costs.
- Maintenance materials and labor costs.

The costs of reagent, electric power, makeup water, wastewater, and byproduct disposal are variable annual costs and are dependent on the specific control technology. O&M materials and labor are fixed annual costs.

The following sections briefly discuss some of the fixed and variable O&M costs considered for this study.

3.3.2.1 Reagent Costs. Reagent costs include the costs for the material, delivery of the reagent to the facility, and reagent preparation. Reagent costs are a function of the quantity of the reagent used and the price of the reagent. The quantity of reagent used will vary with the quantity of pollutant removed. Reagent costs were defined for the following reagents:

- Anhydrous ammonia.
- Limestone.
- Lime.
- Trona.
- Powdered Activated Carbon (PAC).

3.3.2.2 Electric Power Costs. Additional auxiliary power will be required to run some of the new AQC technology systems. The power requirements of each system vary, depending on the type of technology and the complexity of the system. Electric power costs include an increase in fan power caused by the flue gas pressure losses through the new equipment. The additional fan power was estimated with a basis of 90 percent fan efficiency and 80 percent motor efficiency.

3.3.2.3 Makeup and Service Water Costs. Makeup water or service water is required for some of the processes in the new control technology systems. Examples of water consumption include water to support AQC activities for the SO_2 scrubber systems.

3.3.2.4 Wastewater and Byproduct Disposal Costs. Some control technologies generate wastewater and/or byproduct that will require treatment or disposal. Examples of wastewater and disposal to support the AQC activities include the SO_2 scrubber systems and the pulse jet fabric filter (PJFF) systems.

3.3.2.5 Operating Labor Costs. Operating labor costs are developed by estimating the number and type of employees that will be required to run the new AQC equipment. This estimate was based on common industry practices. The labor cost was based on a fully loaded labor rate and 40 hours per work week.

Typically, a complex emissions control technology will require a combination of the following personnel:

- Supervisor.
- Control Room Operator.
- Roving Operator.
- Relief Operator.
- Laboratory Technicians.
- Equipment Operators.

3.3.2.6 Maintenance Materials and Labor 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 were estimated to be between 1 and 5 percent of the total direct capital costs. Some initial recommended spare parts were included (assumed) 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. For technologies that replace a similar existing technology at the current plant site, a determination of the additional maintenance requirements was performed. If the required maintenance materials and labor were similar to the existing technology, no additional maintenance costs were credited for the new control technology.

3.4 Economic Data and Assumptions

The following are the economic data and assumptions used in the cost analysis.

3.4.1 Economic Data

Economic data were provided by E.ON for use in development of the annual O&M costs. However, some economic data were not available for some units/plants. Therefore, Black & Veatch assumed the highest value provided by E.ON as representative of the equivalent variable for any plant with missing economic data. The economic data are presented in Table 3-3. The assumed cost data have been denoted in bold-italic font and are summarized below:

- The limestone cost for Cane Run and Green River is $11.54/ton.
- The lime cost for Cane Run and Green River plant is $132.19/ton.
- The ash disposal cost for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $15/ton.
- The selective catalytic reduction (SCR) catalyst replacement cost for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $6,500/m^3.
- The anhydrous ammonia cost for E.W. Brown, Cane Run, and Green River is $530.03/ton.
- The trona cost for Cane Run, Trimble County and Green River is $200.42/ton.
- The halogenated PAC costs for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $1.1/lb.
- The water costs for E.W. Brown, Ghent, Cane Run, Mill Creek, Trimble County, and Green River is $2/1,000 gallons.

Table 3-3
Economic Evaluation Parameters[a]

Economic Parameters	**Economic Criteria**																	
	E.W. Brown			**Ghent**				**Cane Run**			**Mill Creek**				**Trimble County**		**Green River**	
Unit Identification	**1**	**2**	**3**	**1**	**2**	**3**	**4**	**4**	**5**	**6**	**1**	**2**	**3**	**4**	**1**	**2**	**3**	**4**
Remaining Plant Life (years)	30			30				20			30				30		30	
Capacity Factor (percent)	44.00	62.00	57.00	81.00	71.00	78.00	77.00	60.00	62.00	54.00	68.00	70.00	75.00	75.00	85.00	87.00	26.00	32.00
Auxiliary Power Cost ($/MWh)	42.66	36.46	36.24	24.87	24.59	25.44	24.9	28.88	28.35	30.18	21.56	21.69	23.31	22.35	23.25	21.49	34.33	31.87
Limestone Cost ($/ton)	11.54			8.22				***11.54***[b]			7.54				8.24		***11.54***[b]	
Lime Cost ($/ton)	132.19			131.78				***132.19***[b]			118.13				131.78		***132.19***[b]	
Ash Disposal Cost ($/tonne)	***15***[b]			***15***[b]				***15***[b]			***15***[b]				***15***[b]		***15***[b]	
SCR Catalyst Replacement Cost ($/m^3)	***6,500***[b]			***6,500***[b]				***6,500***[b]			***6,500***[b]				***6,500***[b]		***6,500***[b]	
Ammonia Cost for SCR ($/ton)	***530.03***[b]			517.55				***530.03***[b]			530.03				522.7		***530.03***[b]	
Trona Cost ($/ton)	200.42			200.42				***200.42***[b]			195				***200.42***[b]		***200.42***[b]	
Halogenated PAC Cost ($/lb)	***1.1***[b]			***1.1***[b]				***1.1***[b]			***1.1***[b]				***1.1***[b]		***1.1***[b]	
Water Cost ($/1,000 gal)	***2***[b]			***2***[b]				***2***[b]			***2***[b]				***2***[b]		***2***[b]	
Fully-Loaded Labor Rate ($/h)	123,325			121,000				126,882			132,901				132,491		121,547	
Capital Escalation Rate (percent)	2.5																	
O&M Escalation Rate (percent)	2																	
Levelized Fixed Charge Rate or Capital Recovery Factor (percent)	12.17																	
Interest During Construction (percent)	4.5																	

[a] Utilities costs are as delivered costs.
[b] Economic variable was not provided by E.ON and are assumed data based on similar economic data for other E.ON plants.

3.4.2 Economic Assumptions

Based on Black & Veatch's experience technical and economic assumptions were made to appropriately characterize costs for the study. These assumptions are briefly described, but are not limited to, the following:

1. The direct cost estimates reflect the following:
    - Costs for regulatory and environmental permitting were not included.
    - Costs for additional equipment studies were not included.
    - Regular supply of construction craft labor and equipment is available.
    - Normal lead-times for equipment deliveries are expected.
2. Compliance options beyond the addition of new AQC technology (such as fuel switching, shutdown of existing emission units, development of new power generation, and emissions averaging scenarios) and their associated cost were not considered.
3. Costs for loss of generation for construction outage were not included as part of the indirect costs.
4. Annual operating cost estimates are based on operation at full-load conditions utilizing E.ON supplied load factors.
5. Sizing of AQC components and estimates of flue gas flow and pressure drops are developed from calculations based on the coal composition as provided by E.ON.
6. Sizing of AQC components is based on the AQC equipment being capable of achieving Best Available Control Technology emission levels. However, O&M costs were based on achieving the identified pollutant emission rates.
7. The cost estimate includes calculated values for escalation and contingency.
8. Owner's costs (project development, financing, etc.) are estimated as a percentage of the total capital cost.
9. Annual O&M costs associated with the AQC retrofit equipment are differential O&M costs associated with the equipment, rather than with the entire plant O&M costs.
10. Common economic components of each AQC technology are apportioned to the technologies rather than identified separately.

11. Neural networks (NNs) were assumed for all units as the proven and feasible control technology to reduce emissions of CO from the coal fired units[4]. For units less than 300 MW, a capital and O&M cost of $500,000 and $50,000, respectively, was assumed. For units greater than 300 MW, a capital and O&M cost of $1,000,000 and $100,000, respectively, was assumed.
12. H_2SO_4 (SO_3) emissions were not an identified pollutant in E.ON's emission matrix. However, due to generation of sulfuric acid mist[5] (H_2SO_4) (SO_3) from SO_2 to SO_3 conversion across the SCR technology catalyst, Black & Veatch included costs for a H_2SO_4 (SO_3) mitigation system for units with approved SCR AQC technologies.
13. Costs estimates have been included in the unit specific AQC equipment costs for AQC equipment that requires new reagent preparation systems, dewatering systems, or byproduct handling systems.
14. Contingency costs were established per AQC technology instead of being combined on a per unit basis in this study.
15. Construction difficulty and demolition costs were estimated for individual AQC technology in this study.

---

[4] Neural networks are proven and feasible technologies to reduce CO emissions. However, CO emission reductions due to installation of NN vary from unit to unit based on each unit's specific equipment configuration and operation. It is recommended that detailed studies be performed to determine the potential benefit from NN installation.

[5] Emissions of H_2SO_4 (SO_3) were not included in the emission matrix as a primary pollutant requiring assessment for new AQC technology.

4.0 Control Cost Estimate (Capital and O&M)

The following sections describe the existing conditions, site visit observations, AQC recommendations, cost estimates, special considerations, and implementation schedules for each unit.

4.1 E.W. Brown - Units 1, 2, and 3

The E.W. Brown Station is located on Herrington Lake in Mercer County, Kentucky, between Shakertown and Burgin, off of Hwy 33. The station was constructed on the west side of Herrington Lake, the impoundment behind Dix Dam. The plant began commercial operation in 1957. The station includes three coal fired electric generating units with a total nameplate capacity of 747 MW gross. The electrical power from the E.W. Brown Station units is used to provide both load and voltage support for the 138 kV transmission systems.

Unit 1 has a gross capacity of 110 MW and is equipped with old generation LNBs and cold side dry ESP for NO_x and PM control, respectively. Unit 2 has a gross capacity of 180 MW and is equipped with LNBs, OFA, and cold-side dry ESP for NO_x and PM control. Unit 3 has a gross capacity of 457 MW and is equipped with LNBs, OFA, and cold-side dry ESP for NO_x and PM control. E.ON is in the process of installing an SCR (in-service date, 2012) on Unit 3 to control NO_x and a common wet FGD scrubber for Units 1, 2, and 3 (in-service date, late 2010).

4.1.1 Site Visit Observations and AQC Considerations

At the E.W. Brown Generating Station, the Black & Veatch team met Brad Pabian (Mechanical Engineer), Barry Carman (Results Coordinator), and Ronald Gregory (Plant Manager) from E.ON. The following text is a narrative summary of the site visit conducted on May 13, 2010.

The installation of SCR on Unit 1 will require significant demolition and relocation of the circulating water system, service water piping, and soot blower air compressors tanks and modification of secondary air heater duct in the boiler building. This would require a significant outage time and is generally thought to be a difficult and expensive alternative. In order to achieve plantwide NO_x emission compliance with future regulatory requirements, it was decided by E.ON to install new generation low NO_x burners (LNBs) and overfire air (OFA) instead of SCR on Unit 1. An option for installing SCR on Unit 1 was also considered for NO_x emissions compliance.

Installing SCR on Unit 2 will require demolishing the abandoned Unit 2 chimney, relocation of the storage tank, relocation of auxiliary transformer, demolition of the dust collector and associated ductwork and support steel, and relocation of underground utilities. The new SCR duct tie-ins to the existing Unit 2 air heater inlet duct will require boiler building structural steel bracing and girts to be modified to accommodate ductwork. The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR structures to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR modules.

Installing individual PJFF on Unit 1 and Unit 2 will require some demolition of ductwork and structural steel and relocation of ductwork and associated support steel for tie-in. Crane access around the footprint of the ID fans for Unit 1 and Unit 2 is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations. There is no real estate available for construction of PJFF on Unit 2, and the PJFF on Unit 2 will be elevated above the grade level and constructed above (downstream) the existing cold-side dry electrostatic precipitators (ESPs). An option for installing a combined PJFF for Unit 1 and Unit 2 was also considered.

For Unit 3, the new PJFF will be installed downstream of the existing cold-side dry ESP. Installing individual PJFF on Unit 3 will require some demolition of ductwork and structural steel and relocation of ductwork and associated support steel for tie-in. It will also require relocation of underground utility lines.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.1.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, PM, CO, Hg, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 1. These AQC technologies include installation of new generation LNBs, OFA, and PAC injection coupled with a new PJFF located downstream of the existing ESP. The new generation LNB and OFA system can reduce NO_x emissions to 0.30 lb/MBtu. The new PJFF will be installed downstream of the existing cold-side dry ESP. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 2. These AQC technologies include the installation of new SCR and PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be into the new ductwork upstream of the PJFF. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

As previously noted, E.ON is in the process of installing an SCR (in-service date, 2012) on Unit 3 that will be capable of reducing NO_x emissions to 0.11 lb/MBtu or lower. To meet the identified pollutant emission limits, new AQC technologies are required for Brown Unit 3. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

Also noted, a common wet FGD scrubber for Units 1, 2, and 3 is in the process of being built (in-service date, late 2010) at E.W. Brown. This wet FGD will serve to meet or exceed the SO_2 target emission of 0.25 lb/MBtu and the HCl target emission of 0.002 lb/MBtu. Therefore, no new SO_2 or HCl emission control technologies are proposed for these units.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.1.2.1 E. W. Brown Unit 1 - Option 2. AQC technology Option 2 for Brown Unit 1 includes installation of SCR in lieu of LNB and OFA to meet unit specific NO_x emission compliance. Based on the base case information contained in Section 4.1.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Brown Unit 1 include installation of new SCR, and PAC injection coupled with a new PJFF located downstream of the existing ESP. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu. The new PJFF will be installed downstream of the existing cold-side dry ESP. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.1.2.2 E. W. Brown Unit 1 - Option 3. AQC technology Option 3 for Brown Unit 1 includes installation of a combined PJFF for Units 1 and 2 in lieu of individual PJFF for Unit 1. Based on the base case information contained in Section 4.1.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Brown Unit 1 include installation of new generation LNBs, OFA, and PAC injection coupled with a new combined PJFF for Units 1 and 2 located downstream of the ID fans for Units 1 and 2. The new generation LNB and OFA system can reduce NO_x emissions to 0.30 lb/MBtu. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of

0.1 lb/MBtu. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.1.2.3 E. W. Brown Unit 2 - Option 2. AQC technology Option 2 for Brown Unit 2 includes installation of a combined PJFF for Units 1 and 2 in lieu of individual PJFF for Unit 2. Based on the base case information contained in Section 4.1.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Brown Unit 2 include installation of new SCR and PAC injection coupled with a new combined PJFF for Units 1 and 2 located downstream of the ID fans for Units 1 and 2. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be into the new ductwork upstream of the PJFF. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.1.3 Capital and O&M Costs

The total estimated capital cost to upgrade E.W. Brown Unit 1, Unit 2, and Unit 3 with recommended technologies are $44,000,000 ($400/kW), $152,000,000 ($843/kW), and $67,000,000 ($148/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-1, 4-2, and 4-3. Detailed cost summaries are included in Appendix H.

Table 4-1
Capital and O&M Cost Summary – E.W. Brown Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Overfire Air	$767,000	$7	$132,000	$225,000
Low NO_x Burners	$1,156,000	$11	$0	$141,000
Fabric Filter	$40,000,000	$364	$1,477,000	$6,345,000
PAC Injection	$1,599,000	$15	$614,000	$809,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	**$44,022,000**	**$400**	**$2,273,000**	**$7,631,000**

Table 4-2
Capital and O&M Cost Summary – E.W. Brown Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
SCR	$95,000,000	$528	$3,373,000	$14,935,000
Fabric Filter	$51,000,000	$283	$1,959,000	$8,166,000
Lime Injection	$2,739,000	$15	$1,155,000	$1,488,000
PAC Injection	$2,476,000	$14	$1,090,000	$1,391,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$151,715,000**	**$843**	**$7,627,000**	**$26,091,000**

Table 4-3
Capital and O&M Cost Summary – E.W. Brown Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
Fabric Filter	$61,000,000	$133	$3,321,000	$10,745,000
PAC Injection	$5,426,000	$12	$2,330,000	$2,990,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$67,426,000**	**$148**	**$5,751,000**	**$13,957,000**

4.1.3.1 E. W. Brown Unit 1 - Option 2 Capital and O&M Costs. The total estimated capital cost to upgrade E.W. Brown Unit 1 (Option 1), Unit 2 (Base Case), and Unit 3 (Base Case) with recommended technologies are $103,000,000 ($939/kW), $152,000,000 ($843/kW), and $67,000,000 ($148/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-4, 4-5, and 4-6. For illustration purposes, costs for the unit specific AQC technology option along with the remaining units and base case AQC technologies have been summarized. Detailed cost summaries are included in Appendix H.

Table 4-4
Capital and O&M Cost Summary – E.W. Brown Unit 1 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$59,000,000	$536	$2,075,000	$9,255,000
Fabric Filter	$40,000,000	$364	$1,477,000	$6,345,000
PAC Injection	$1,599,000	$15	$614,000	$809,000
Lime Injection	$2,181,000	$12	$624,000	$889,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	**$103,280,000**	**$939**	**$4,840,000**	**$17,409,000**

Table 4-5
Capital and O&M Cost Summary – E.W. Brown Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
SCR	$95,000,000	$528	$3,373,000	$14,935,000
Fabric Filter	$51,000,000	$283	$1,959,000	$8,166,000
Lime Injection	$2,739,000	$15	$1,155,000	$1,488,000
PAC Injection	$2,476,000	$14	$1,090,000	$1,391,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$151,715,000**	**$843**	**$7,627,000**	**$26,091,000**

Table 4-6
Capital and O&M Cost Summary – E.W. Brown Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
Fabric Filter	$61,000,000	$133	$3,321,000	$10,745,000
PAC Injection	$5,426,000	$12	$2,330,000	$2,990,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$67,426,000**	**$148**	**$5,751,000**	**$13,957,000**

4.1.3.2 E. W. Brown Unit 1 - Option 3 and Brown Unit 2 – Option 2 Capital and O&M Costs. The total estimated capital cost to upgrade E.W. Brown Unit 1 (Option 3), Unit 2 (Option 2), and Unit 3 (Base Case) with recommended technologies are $30,000,000 ($273/kW), $143,000,000 ($793/kW), and $67,000,000 ($148/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-7, 4-8, and 4-9. It should be noted that the costs for combining the Unit 1 and 2 PJFF have been proportioned between the units base on unit size (i.e., MW). For illustration purposes, costs for the unit specific AQC technology option along with the remaining unit and base case AQC technologies have been summarized. Detailed cost summaries are included in Appendix H.

Table 4-7
Capital and O&M Cost Summary – E.W. Brown Unit 1 (Option 3)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$26,000,000	$236	$1,057,000	$4,221,000
PAC Injection	$1,599,000	$15	$614,000	$809,000
Overfire Air	$767,000	$7	$132,000	$225,000
Low NOx Burners	$1,156,000	$11	$0	$141,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	**$30,022,000**	**$273**	**$1,853,000**	**$5,507,000**

Table 4-8
Capital and O&M Cost Summary – E.W. Brown Unit 2 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
SCR	$95,000,000	$528	$3,373,000	$14,935,000
Fabric Filter	$42,000,000	$233	$1,689,000	$6,800,000
Lime Injection	$2,739,000	$15	$1,155,000	$1,488,000
PAC Injection	$2,476,000	$14	$1,090,000	$1,391,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$142,715,000**	**$793**	**$7,357,000**	**$24,725,000**

Table 4-9
Capital and O&M Cost Summary – E.W. Brown Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost,$	Levelized Annual Cost,$
Fabric Filter	$61,000,000	$133	$3,321,000	$10,745,000
PAC Injection	$5,426,000	$12	$2,330,000	$2,990,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$67,426,000**	**$148**	**$5,751,000**	**$13,957,000**

4.1.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirements will need to be considered for booster fan or upgraded ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.
- **Ash Handling**--Additional new ash handling system will be needed for Units 1, 2, and 3 PJFF.
  - For Brown Unit 1 – Option 3 and Brown Unit 2 – Option 2, additional new ash handling system will be needed for Units 1 and 2 combined PJFF, and Unit 3 individual PJFF.
- **Ammonia Storage**--Ammonia storage for Unit 3 can be utilized to supply Unit 2 ammonia for new SCR.
  - For Brown Unit 1 – Option 1, ammonia storage for Unit 3 can be utilized to supply Unit 1 and Unit 2 ammonia for new SCR
- **H_2SO_4 (SO_3) Emissions**--Consideration was given to Unit 3's H_2SO_4 (SO_3) emissions although these emissions were not a primary focus for this study.

- **Footprint**:
  - There is very limited space to install a new SCR on Unit 2. Therefore, the SCR will be located between the existing plant wall and the original Unit 2 stack. To achieve this, it will be necessary to demolish the existing mechanical dust collector and demolish the abandoned Unit 2 stack.
  - Because of the limited available footprint, the PJFF on Unit 2 will be located above the existing dry ESP.
  - For Brown Unit 1 – Option 3 and Brown Unit 2 – Option 2, the combined PJFF for Units 1 and 2 will be elevated above ground and installed above the existing combined Units 1 and 2 ductwork upstream of the common WFGD system.
- **Constructability Challenges**:
  - The new SCR duct tie-ins to the existing Unit 2 air heater inlet duct will require boiler building structural steel bracing and girts to be modified to accommodate ductwork.
  - The new Unit 2 SCR support structure and reactor structure will require extensive relocation/demolition of existing plant components.
  - The relocation or protection of field fabricated tank located in base of abandoned Unit 2 chimney shell.
  - The demolition of Unit 2 chimney.
  - The demolition of the dust collection ductwork located along the northeast exterior wall of Unit 2 boiler building.
  - The relocation of Unit 2 auxiliary transformer located outside of the northeast exterior wall of Unit 2 boiler building.
  - Extensive underground investigation will be required to identify operating utilities prior to installing new foundations for Unit 2 fabric filter structural steel support frame.
  - The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR and fabric filter structures to be constructed using a large tonnage crane with extended reach capabilities, or by extending the structural support frame system to the east and using a pick and slide execution method to erect the SCR and fabric filter modules.

- For Brown Unit 1 – Option 1, the new SCR duct tie-ins to the existing Unit 1 Air Heater inlet duct will require extensive modifications of existing plant components which includes rotation of secondary air heater duct.
- For Brown Unit 1 – Option 1, the new Unit 1 SCR will require extensive modification of boiler building structural steel and bracings to accommodate new ductwork.
- For Brown Unit 1 – Option 1, the new Unit 1 SCR will require relocation of switchgear in the boiler building.

4.1.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.1.5.1 Unit 1. The Unit 1 arrangement (Appendix G) will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF and the installation of the LNBs and OFA will require a plant outage.

For Brown Unit 1 – Option 2, an additional outage will be required for modifying the air heater duct and final outage will be required for tie-in of SCR and PJFF

4.1.5.2 Unit 2. Because of the tight space constraints, particularly for the installation sequencing of the SCR and somewhat for the PJFF, the construction efforts for Unit 2 will likely require an extended single outage or two shorter outages with the pre-dust collector being demolished during the first outage. This allows for the major construction of the SCR and PJFFs with the plant in operation and requiring another shorter outage for the tie-in of SCR and PJFF.

4.1.5.3 Unit 3. The Unit 3 arrangement shown on the drawing will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF will require a plant outage.

4.1.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at E.W. Brown is nominally $263,000,000 ($1,400/kW). The O&M and levelized annual costs of new AQC equipment at E.W. Brown is nominally $15,700,000 and $47,700,000, respectively.

4.1.6.1 Brown Unit 1 - Option 2 Summary. The cost of new AQC equipment to meet or exceed defined future emission targets at E.W. Brown for this optional scenario is nominally $322,000,000 ($1,900/kW). The O&M and levelized annual costs of new AQC equipment at E.W. Brown for this optional scenario is nominally $18,200,000 and $57,500,000, respectively.

4.1.6.2 Brown Unit 1 - Option 3 and Brown Unit 2 - Option 2 Summary. The cost of new AQC equipment to meet or exceed defined future emission targets at E.W. Brown for this optional scenario is nominally $240,000,000 ($1,200/kW). The O&M and levelized annual costs of new AQC equipment at E.W. Brown for this optional scenario is nominally $15,000,000 and $44,200,000, respectively

4.2 Ghent - Units 1, 2, 3, and 4

The Ghent Generating Station is located approximately 9 miles northeast of Carrolton, Kentucky. Ghent, which began commercial operations in February 1, 1974, is situated on approximately 1,670 acres.

The plant is a four unit pulverized coal fired electric power plant with gross capacity of 2,007 MW. Two of the boilers are manufactured by Combustion Engineering and two by Foster Wheeler. The Combustion Engineering boilers are tangential-fired, balanced draft forced circulation boilers, and Foster Wheeler boilers are balanced draft natural circulation boilers. Unit 1 has a gross capacity of 541 MW and is equipped with LNBs and SCR for NO_x control; cold-side dry ESP for PM control; wet FGD system for SO_2 control, and lime injection system for H_2SO_4 or SO_3 control. Unit 2 has a gross capacity of 517 MW and is equipped with LNBs, OFA for NO_x control; hot-side dry ESP for PM control; and wet FGD system for SO_2 control. Units 3 and 4 have a gross capacity of 523 MW and 526 MW, respectively, and are equipped with LNBs, OFA, and low-dust SCR for NO_x control; hot-side dry ESP for PM control; wet FGD system for SO_2 control, and trona injection system for H_2SO_4 (SO_3) control.

4.2.1 Site Visit Observations and AQC Considerations

At the Ghent Generating Station, the Black & Veatch team met David Pennybaker (Project Engineer), Carla Piening (Senior Scientist), Stephen Nix (Lead Engineer), and Jeff Joyce (Plant Manager) from E.ON. The following text is a narrative summary of the site visit conducted on May 11, 2010.

Installing PJFF for Units 1 and 2 requires significant site preparation and demolition. Crane access is difficult at Units 1 and 2 because of a low overhead piperack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or relocated. Lattice boom crawler crane booms will need to be final assembled and reeved at the working location. Access lanes around Units 1 and 2 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area. Current arrangement for Unit 2 fabric filters require a section of bypass ductwork to be installed in order to isolate/demolish existing ductwork/duct supports and provide the required footprint for the new equipment. Tie-in portions of this work scope must be accomplished during early plant outages. The new PJFF will be elevated aboveground. Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.

Installing PJFF on Units 3 and 4 requires removal of underground utility lines. Current arrangement for Unit 3 fabric filters requires an extensive length of inlet/outlet ductwork to be routed above and across the existing Unit 3 and 4 ESPs. Access around the footprint of the dry ESPs is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations. Existing underground electrical manholes, water wells, storm sewer boxes and piping, and circulating cooling water piping all run in the proposed footprint for Unit 4 fabric filter. The electrical manholes, water wells, and storm sewer piping will need to be relocated in order to install the foundations for the Unit 4 fabric filter structural frame.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.2.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, PM, CO, Hg, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Unit 1. These AQC technologies include installation of a new PAC injection system coupled with a new PJFF located downstream of the existing dry ESP. The new PJFF will be elevated aboveground. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Unit 1 has an existing SCR to control NO_x emissions to the future NO_x emission target of 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on this unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Unit 2. These AQC technologies include installation of new SCR system, new PAC injection system coupled with a new PJFF located downstream of the existing ID fans. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New sorbent (lime/trona) injection for H_2SO_4 abatement needs to be installed and will be into the ductwork upstream of the hot-side dry ESP. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Ghent Units 3 and 4. These AQC technologies include installation of new PAC injection system coupled with a new PJFF located downstream of the existing ID fans of Units 3 and 4. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Units 3 and 4 have existing SCRs to control NO_x emissions to the future NO_x emission target of 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on these units.

All four Ghent units have existing individual wet FGDs that will meet the SO_2 target emission of 0.25 lb/MBtu or lower and the HCl target emission of 0.002 lb/MBtu or lower. No new SO_2 or HCl emission controls are considered for this study, and there is no need to replace existing stacks.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.2.3 Capital and O&M Costs

The total estimated capital costs to upgrade Ghent Unit 1, Unit 2, Unit 3, and Unit 4 with recommended technologies are $138,000,000 ($256/kW), $365,000,000 ($705/kW), $145,000,000 ($278/kW), and $124,000,000 ($236/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-10, 4-11, 4-12, and 4-13. Detailed cost summaries are included in Appendix H.

Table 4-10
Capital and O&M Cost Summary – Ghent Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$131,000,000	$242	$5,888,000	$21,831,000
PAC Injection	$6,380,000	$12	$4,208,000	$4,984,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$138,380,000**	**$256**	**$10,196,000**	**$27,037,000**

Table 4-11
Capital and O&M Cost Summary – Ghent Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$232,000,000	$449	$7,234,000	$35,468,000
Fabric Filter	$120,000,000	$232	$5,002,000	$19,606,000
Lime Injection	$5,483,000	$11	$2,775,000	$3,442,000
PAC Injection	$6,109,000	$12	$2,880,000	$3,623,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$364,592,000**	**$705**	**$17,991,000**	**$62,361,000**

Table 4-12
Capital and O&M Cost Summary – Ghent Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$138,000,000	$264	$6,122,000	$22,917,000
PAC Injection	$6,173,000	$12	$4,134,000	$4,885,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$145,173,000**	**$278**	**$10,356,000**	**$28,024,000**

Table 4-13
Capital and O&M Cost Summary – Ghent Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$117,000,000	$222	$5,363,000	$19,602,000
PAC Injection	$6,210,000	$12	$3,896,000	$4,652,000
Neural Networks	$1,000,000	$2	$100,000	$222,000
Total	**$124,210,000**	**$236**	**$9,359,000**	**$24,476,000**

4.2.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirements will need to be considered for booster fan or upgraded ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.

- **Ash Handling**--Additional new ash handling system will be needed for Units 1, 2, 3, and 4 PJFF. It is understood that a new byproduct ash system is currently being studied at the plant. Contingent on the final determination of installed AQC technology, further investigation and coordination of ash handling systems will be required.
- **H_2SO_4 (SO_3) Emissions**-- Consideration was given to Unit 1, 2, 3, and 4 3's H_2SO_4 (SO_3) emissions although these emissions were not a primary focus for this study.
- **Ammonia Storage**--Ammonia storage for Unit 3 can be utilized to supply Unit 2 ammonia for new SCR.
- **Footprint**:
  - Unit 1 and Unit 2 PJFF do not have any real estate available on the grade elevation for construction. Hence these PJFF will be elevated above the ground level.
  - The Unit 3 PJFF could be installed between boilers of Units 2 and 3, adjacent to the new Unit 2 SCR. However, plant personnel want to keep this area clear for staging and equipment lay-down purposes. Hence, Unit 3 PJFF will be installed on the south side of the Unit 4 dry ESP, with booster fan or ID fan upgrades because there is very limited space available between the ID fan outlet and wet scrubber inlet on the west side.
- **Constructability Challenges**:
  - Crane access is difficult at Units 1 and 2 because of low overhead piperack on the roadways around the cooling towers. Some piping bridges on the northeast side of the cooling tower and access roads to Unit 1 will need to be temporarily taken down or relocated. Lattice boom crawler crane booms will need to be final assembled and reeved at the working location.
  - Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.
  - Access lanes around Units 1 and 2 are also the maintenance lanes for the cooling towers. Cranes and construction equipment will block access on these roads at various periods during project execution. Careful crane placement will be required in order to provide operations access to the cooling tower area.

- The current arrangement for Unit 2 fabric filters requires a section of bypass ductwork to be installed in order to isolate/demolish existing ductwork/duct supports and provide the required footprint for the new equipment. Tie-in portions of this work scope must be accomplished during early plant outages.
- The current arrangement for Unit 3 fabric filters requires an extensive length of inlet/outlet ductwork to be routed above and across the existing Unit 3 and 4 dry ESPs. Access around the footprint of the dry ESPs is restricted, and it will be difficult to stage the construction equipment necessary to erect the ductwork support frame and associated foundations.
- Crane access will be restricted around the tie-in for Unit 3 fabric filter inlet/outlet ductwork.
- Existing underground electrical manholes, water wells, storm sewer boxes and piping, and circulating cooling water piping all run in the proposed footprint for Unit 4 fabric filter. The electrical manholes, water wells, and storm sewer piping will need to be relocated in order to install the foundations for the Unit 4 fabric filter structural frame.

4.2.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.2.5.1 Units 1, 2, 3, and 4. The arrangement shown on the drawing will allow for the majority of the construction of the PJFF to occur without taking a plant outage. The tie-in of the PJFF will require a plant outage. Unit 2 arrangements shown on the drawing will allow for the majority of the construction of the SCR to occur without taking a plant outage. The tie-in of the SCR will require a plant outage.

4.2.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Plant Ghent is nominally $772,400,000 ($1,500/kW). The O&M and levelized annual costs of new AQC equipment at Ghent is nominally $47,900,000 and $141,900,000, respectively.

4.3 Cane Run - Units 4, 5, and 6

The Cane Run Generating Station is located at 5252 Cane Run Road (State Highway 1849), about 8 miles southwest of Louisville, Kentucky. The facility includes approximately 500 acres between Cane Run Road and the Ohio River. The pulverized coal fired electric power plant began commercial operation in 1954 in response to the demand for electricity by industries that were located in Louisville during World War II. Three of its six units are now retired. Units 4, 5, and 6 are currently active and have a gross capacity of 610 MW. Unit 4 was placed in service in 1962, Unit 5 in 1966, and Unit 6 in 1969.

Units 4, 5, and 6 have a gross capacity of 168 MW, 181 MW, and 261 MW, respectively, and are equipped with LNBs or OFA (Units 4 and 5 have LNBs but no OFA, Unit 6 has OFA but no LNBs) for NO_x control; cold-side dry ESP for PM control; and wet FGD system for SO_2 control.

4.3.1 Site Visit Observations and AQC Considerations

At the Cane Run Station, the Black & Veatch team met Keron Miller, Mike Hensley, and Chuck Hance from E.ON. The following text is a narrative summary of the site visit conducted on May 11, 2010.

Cane Run Units 4, 5, and 6 have existing LNBs and FGD emission control devices. Performance of the aging FGD scrubbers is sufficient to meet the current stack emission limit, and NO_x emissions are currently controllable to the existing limits using only LNBs. Current PM emissions are controlled by the combination of the efficient ESPs and FGD designs. In general, the plant is capable of maintaining the current emissions levels but requires new AQC technologies to meet the future pollutant emission limits and have operational flexibility. According to plant personnel, upgrades to the existing scrubber towers are currently being considered that would increase scrubbing efficiency to meet the future emission standards. However, due to space constraints, upstream control devices (e.g., SCR, fabric filter) require real estate that precludes use of the existing FGD vessels. Plant personnel also pointed out that maintenance of boiler tubes is considerably exacerbated because of lower oxygen combustion zone to minimize NO_x emissions.

New AQC technologies for each unit will be identical except for the sizing of components. Each unit will need new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, PJFF, and wet FGD. A new single chimney will house three lined wet stacks; one liner for each unit. The SCR will increase the H_2SO_4 (SO_3) concentration in the flue gas and exacerbate the potential for corrosion on the cooler surfaces downstream of the air heater. Lime will be added downstream of the air heater (upstream of the PJFF) to minimize the impact of acid components in the flue gas on downstream surfaces. Injection of PAC is also recommended upstream of the PJFF.

Installation of SCR on Units 4, 5, and 6 would become a constraining factor from a construction perspective. There is not sufficient room to successfully install the connections from and back into the ductwork after the economizer section on any of the units. Any attempt to do so would compromise the performance of the SCR and would also be an operational challenge over the life of the plant. This decision alone leads to the difficult alternative of selectively demolishing the existing back end AQC equipment one unit at a time. This means that for an extended period of time only two of the three units would be operational. Scheduled outages on the remaining units will reduce plant availability even more.

Installation of SCR technology requires access to the hopper/ductwork exiting the economizer sections of each boiler. The hot fly ash laden flue gas must be transported to the SCR and ducted from the SCR to the air heater inlet. The existing equipment at this plant is too close-coupled in this area to allow adequate access for attaching these new ducts. The space required to install new AQC technologies is currently occupied by the existing wet FGD components and stacks. Any new technologies should be installed directly in lieu of the existing equipment. This requires a complete demolish and removal of existing equipment prior to installation of the new equipment. This will cause an extended outage as shown in the AQC replacement schedule in Subsection 4.3.5. Demolition of the existing and construction of new AQC equipment is planned in series for each unit. This lengthens the unit outage time and increases the cost associated to meet new emission standards.

Due to lack of available space to add the new equipment, the new AQC technologies required for the three units will need to use the existing footprint. Demolition of existing equipment will need to be completed prior to construction of new equipment to provide space for installation of the new equipment. Demolition of all existing AQC equipment one unit at a time from the economizer section back is proposed to minimize outage time (at least 24 month outages are estimated). Power lines above each unit will need to be moved for safe demolition and construction. There appear to be adequate areas available for equipment laydown during construction.

Demolition and construction of each unit will be in series. For example, Unit 5 could be taken out of service and demolished from the economizer to the FGD equipment. The common stack and other common equipment (ammonia storage area, common reaction tank) could be built prior to the outage. Moving of transmission lines could also be accomplished prior to the outage along with preparation of lay-down areas and moving of needed underground utilities.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.3.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x, SO_2, PM, CO, Hg, HCl and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Cane Run Units 4, 5, and 6. The AQC technologies identified for each of the three units are the same and include installation of a new SCR system to reducing NO_x to 0.11 lb/MBtu or lower, new PJFF to reduce PM emissions to 0.03 lb/MBtu or lower; a new wet FGD system to reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower; a new halogenated PAC injection to reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu, new sorbent (lime) injection system for H_2SO_4 abatement, and New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.3.3 Capital and O&M Costs

The total estimated capital costs to upgrade Cane Run Unit 4, Unit 5, and Unit 6 with recommended technologies are $261,000,000 ($1,556/kW), $275,000,000 ($1,518/kW), and $353,000,000 ($1,352/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-14, 4-15, and 4-16. Detailed cost summaries are included in Appendix H.

Table 4-14
Capital and O&M Cost Summary – Cane Run Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$63,000,000	$375	$2,219,000	$9,886,000
Wet FGD	$160,000,000	$952	$8,666,000	$28,138,000
Fabric Filter	$33,000,000	$196	$1,924,000	$5,940,000
Lime Injection	$2,569,000	$15	$983,000	$1,296,000
PAC Injection	$2,326,000	$14	$1,087,000	$1,370,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$261,395,000**	**$1,556**	**$14,929,000**	**$46,741,000**

Table 4-15
Capital and O&M Cost Summary – Cane Run Unit 5

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$66,000,000	$365	$2,421,000	$10,453,000
Wet FGD	$168,000,000	$928	$9,056,000	$29,502,000
Fabric Filter	$35,000,000	$193	$2,061,000	$6,321,000
Lime Injection	$2,752,000	$15	$1,089,000	$1,424,000
PAC Injection	$2,490,000	$14	$1,120,000	$1,423,000
Neural Networks	$500,000	$3	$50,000	$111,000
Total	**$274,742,000**	**$1,518**	**$15,797,000**	**$49,234,000**

Table 4-16
Capital and O&M Cost Summary – Cane Run Unit 6

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$86,000,000	$330	$2,793,000	$13,259,000
Wet FGD	$214,000,000	$820	$10,816,000	$36,860,000
Fabric Filter	$45,000,000	$172	$2,672,000	$8,149,000
Lime Injection	$3,873,000	$15	$1,367,000	$1,838,000
PAC Injection	$3,490,000	$13	$1,336,000	$1,761,000
Neural Networks	$500,000	$2	$50,000	$111,000
Total	**$352,863,000**	**$1,352**	**$19,034,000**	**$61,978,000**

4.3.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new wet FGD is required. There will be a significant change in the amount of wastewater produced by the wet FGD. A new or a possible upgrade in wastewater treatment facility is required.
- **Wet FGD Byproduct Handling**--There will be a significant change in the amount of byproduct produced by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in byproduct handling system is required.
- **Wet FGD Reagent Preparation System**--There will be a significant change in the amount of reagent required by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in reagent preparation system is required.
- **Ash Handling**--Cane Run has limited new space available for landfill of waste (ash and scrubber solids). Onsite landfill space is expected to be consumed in less than 20 years. Additional new ash handling system or a possible upgrade in the ash handling system will be required.

- **Ammonia Storage**--A new ammonia storage facility will be required for new SCRs. Detailed investigation or study will be required to identify the site location for ammonia storage and supply.
- **Footprint**--The new AQC equipment will be installed where the existing AQCS equipment is currently operating.
- **Constructability Challenges**:
  - Ingress from highways - Multiple power lines need to be raised to accommodate high loads.
  - Barge unloading is not economically feasible.
  - Existing overhead power lines are routed over each unit and must be relocated for crane access.
  - 4 kV building and CT switchyard needs to be relocated.
  - Entire Unit 5 "back-end" must be dismantled prior to starting any work on Unit 4.
  - There is a need for multiple mob/de-mob/outages for tie-ins and access to build new AQC equipment.
  - Underground utility interferences/relocations.
  - Aboveground utility interferences/relocations.
  - Need for areas to build ammonia storage, ash handling systems, limestone handling, reagent preparation dewatering (ancillary systems).
  - Extended outages (entire plant) needed to accommodate construction of new AQC systems.
  - Demolition must be performed in multiple phases followed by extensive earthwork activities to bring existing site up to proper elevation.
  - Soils must be tested and stabilized for heavy lift crane operations.
  - Space is very limited around units; the most efficient use of modularization will be compromised.

4.3.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.3.5.1 Units 4, 5, and 6. Plant life is restricted at Cane Run because of the amount of available land required for landfill of waste products. Installation of new AQC equipment is made particularly difficult by the close-coupling of existing equipment. B&V proposes to demolish the existing dry ESP and FGD equipment one unit at a time to make room for the new equipment. B&V estimates that this will require an extended construction outage of approximately 24 months per unit. One time-saving benefit is provided by construction of a single chimney with three liners.

4.3.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Cane Run is nominally $889,000,000 ($4,400/kW). The O&M and levelized annual costs of new AQC equipment at Cane Run is nominally $49,800,000 and $158,000,000, respectively.

4.4 Mill Creek - Units 1, 2, 3, and 4

The Mill Creek Station is located in southwestern Jefferson County, approximately 10.5 miles southwest of the city of Louisville, Kentucky, on a 509 acre site. Mill Creek Station includes four coal fired electric generating units with a gross total generating capacity of 1,608 MW. Mill Creek Station Unit 1 was placed in service in 1972, Mill Creek Station Unit 2 was placed in service in 1974, and Mill Creek Station Units 3 and 4 were each placed in service at 4 year intervals afterward in 1978 and 1982, respectively.

The Mill Creek Station consists of four coal fired electric generating units. All four boilers fire high sulfur bituminous coal. Each Mill Creek Station unit is composed of one GE reheat tandem compound, double-flow turbine with a condenser and hydrogen-cooled generator. Units 1 and 2 each consist of one Combustion Engineering subcritical, balanced draft boiler and have a gross capacity of 330 MW each and are equipped with LNBs and OFA for NO_x control; a cold-side dry ESP for PM control, and a wet FGD for SO_2 and HCl control. Units 3 and 4 each consist of one Babcock & Wilcox (B&W) balanced draft, Carolina type radiant boiler and have a gross capacity of 423 MW and 525 MW, respectively, and are equipped with LNBs and SCR for NO_x control; a cold-side dry ESP for PM control and a wet FGD for SO_2 and HCl control.

4.4.1 *Site Visit Observations and AQC Considerations*

At the Mill Creek Station, the Black & Veatch team met Mike Kirkland, Michael Buckner, Marc Blackwell, Alex Betz, Tiffany Koller, and Bill Moehrke from E.ON. The following text is a narrative summary of the site visit conducted on May 12, 2010.

Mill Creek Units 1 and 2 require a complete new set of AQC system equipment. Units 3 and 4 have existing SCR to control NO_x emissions to 0.11 lb/MBtu or lower. No further new NO_x emission control technology is needed on Units 3 and 4 based on the identified emission levels. Units 3 and 4 have an existing cold-side dry ESP which will be retained and used for pre-filtration and fly ash sales.

The option to modify the existing wet FGD equipment and use of additives was considered plausible to meet the new emission target. However, Black & Veatch concluded that new limestone scrubbing technology would provide a more reliable long-term emission control technology to meet and exceed the study's SO_2 emission target considering the current state of the existing scrubbers and also the impact on the wastewater treatment facility. Additionally, there is no need to replace the existing wet stacks, and these stacks will be reused for all the four units.

Installation of SCR on Units 1 and 2 would require demolition of the existing dry ESPs to allow space for installation of a new SCR reactor and ductwork. Black & Veatch engineers believe that there is not sufficient room to successfully install the connections from and back into the air heater after the economizer section on either of the units. The new pre-filter dry ESP could be designed for minimal efficiency (~ 90 percent) to reduce size and allow fly ash to help build cake on the downstream bags of the new PJFF. The new PJFF will be stacked above the pre-filter dry ESP. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be routed into the new ductwork upstream of the new cold-side dry ESP. The existing dry ESP will be demolished and a new cold-side dry ESP will be installed for pre-filtration and fly ash sales. These new components could be installed on-line prior to demolition of the existing dry ESP. Once the tie-in to the new PM control devices is completed (New ID fan required), the units can be brought back online for demolition of the existing dry ESP and installation of the new SCR. Segments of the new FGD could begin construction during this period. Tie-in of the new SCR, ductwork, and new FGD would then allow demolition of existing FGD components, if needed. Units 1 and 2 will require new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, cold-side dry ESP, PJFF, and wet FGD. A phased construction approach as described above is necessary for Units 1 and 2 due to site real estate constraints and to reduce the 'loss of generation' aspect of the capital project. This study also considered an option for combining Units 1 and 2 wet FGD absorber modules and is described in greater detail below.

Units 3 and 4 are particularly challenging with respect to finding a footprint for the new AQC equipment that did not require extremely long outages for demolition of existing equipment. Units 3 and 4 have limited space available for construction. The existing rail road tracks and the coal conveyors are the biggest challenges for these units. The new equipment will occupy land currently used as a roadway and historically used for rail. The roadway will need to be moved to provide future plant access. One set of inner tracks will remain for trains to continue to move coal throughout the plant.

Installation of AQC equipment for Units 1 and 2 requires phased installation and demolition activities. Installation of new PJFF and new Wet FGD on Units 3 and 4 will require the scrubber towers to be split to 2 x 50-60 percent capacity absorbers and the PJFFs be stacked and will be installed downstream of the existing cold-side dry ESP. This will avoid the expensive elevated construction option to create a tunnel over the road and rail. New sorbent (lime) injection for H_2SO_4 abatement needs to be installed and will be into the ductwork upstream of the existing cold-side dry ESP. The existing dry ESP will remain in service for pre-filtration and fly ash sales. Units 3 and 4 will require new booster fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, PJFF, and wet FGD systems. Existing power transmission lines would need to be moved for construction. There appears to be space available for addition of another tank to the existing ammonia tank farm if needed. It may be possible to simply increase the number of deliveries of anhydrous ammonia to account for the added demand of the new SCRs on Units 1 and 2. An option of using a single larger absorber module for Unit 3 and Unit 4 Wet FGDs was also considered in this study.

The most imperative site constraint relating to the selection of post-combustion emission control technologies at Mill Creek is that greater than 80 percent of all solid waste is trucked offsite for use in other applications. Offsite transportation of solid waste minimizes onsite landfill needs and thereby helps extend plant life expectations. Therefore, because of the landfill issues, pre-filter dry ESPs are necessary for all units to mitigate the landfill challenge at Mill Creek as the collected ash will be disposed off to another location off site as a possible recycle material. Otherwise the use of a dry ESP for pre-filtration is not required for PM emissions control as new PJFFs are designed as full size PJFFs and not polishing filtration technology. Another option for Units 1 and 2 in this study was removing the existing dry ESPs on these units and not replacing these equipment for pre-filtration.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON’s approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.4.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit. The pollutants that require new control technologies to be installed that will meet target emission levels are NO_x (only on Units 1 and 2), PM, SO_2, CO, Hg, HCl, and dioxin/furan. New sorbent (lime) injection control technology may be required for H_2SO_4 abatement where SCR is installed.

To meet the identified pollutant emission limits, new AQC technologies are required for Mill Creek Units 1 and 2. These AQC technologies include installation of new SCR and PAC injection coupled with a new PJFF located downstream of the new dry ESP. Also a new wet FGD system will be required. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To meet the identified pollutant emission limits, new AQC technologies are required for Mill Creek Units 3 and 4. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. Also, a new wet FGD system will be required. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.4.2.1 Mill Creek Unit 1 - Option 2 and Mill Creek Unit 2 - Option 2. AQC technology Option 2 for Mill Creek Units 1 and 2 includes installation of new combined WFGD absorber modules in lieu of individual WFGD absorber modules. Based on the base case information contained in Section 4.4.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Mill Creek Units 1 and 2 include installation of new SCR and PAC injection coupled with a new PJFF located downstream of the new dry ESP. Also a new combined wet FGD system for Units 1 and 2 will be required. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new combined wet FGD system for Units 1 and 2 will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.4.2.2 Mill Creek Unit 1 - Option 3 and Mill Creek Unit 2 - Option 3. AQC technology Option 3 for Mill Creek Units 1 and 2 includes removal of the new dry ESPs from the base case. Note, the removal of the existing dry ESPs is included as part of the base case and new dry ESPs were included in the base case to continue ash sales. The revenue lost in fly-ash sales is not considered in this study. Based on the base case information contained in Section 4.4.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Mill Creek Units 1 and 2 include installation of new SCR and PAC injection coupled with a new PJFF located downstream of the existing air heater. Also a new wet FGD system will be required. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.4.2.3 Mill Creek Unit 3 - Option 2 and Mill Creek Unit 4 - Option 2. AQC technology Option 2 for Mill Creek Units 3 and 4 includes installation of new larger individual WFGD absorber modules in lieu of two smaller WFGD absorber modules. Based on the base case information contained in Section 4.4.2, the following text briefly describes the inclusion of the AQC technology option. The AQC technologies for Mill Creek Units 1 and 2 include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. Also, a new wet FGD system will be required. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new wet FGD system will reduce SO_2 emissions to 0.25 lb/MBtu or lower and HCl emissions to 0.002 lb/MBtu or lower. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.4.3 Capital and O&M Costs

The total estimated capital cost to upgrade Mill Creek Units 1 and 2 with recommended technologies are is $518,000,000 ($1,569/kW) each. The total estimated capital costs to upgrade Mill Creek Units 3 and 4 with recommended technologies are $513,000,000 ($1,212/kW) and $596,000,000 ($1,135/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-17, 4-18, 4-19, and 4-20. Detailed cost summaries are included in Appendix H.

Table 4-17
Capital and O&M Cost Summary – Mill Creek Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,366,000	$15,171,000
Wet FGD	$297,000,000	$900	$14,341,000	$50,486,000
Fabric Filter	$81,000,000	$245	$3,477,000	$13,335,000
Electrostatic Precipitator	$32,882,000	$100	$3,581,000	$7,583,000
Lime Injection	$4,480,000	$14	$2,024,000	$2,569,000
PAC Injection	$4,412,000	$13	$2,213,000	$2,750,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,102,000**	**$92,116,000**

Table 4-18
Capital and O&M Cost Summary – Mill Creek Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,401,000	$15,206,000
Wet FGD	$297,000,000	$900	$14,604,000	$50,749,000
Fabric Filter	$81,000,000	$245	$3,518,000	$13,376,000
Electrostatic Precipitator	$32,882,000	$100	$3,664,000	$7,666,000
Lime Injection	$4,480,000	$14	$2,117,000	$2,662,000
PAC Injection	$4,412,000	$13	$2,340,000	$2,877,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,744,000**	**$92,758,000**

Table 4-19
Capital and O&M Cost Summary – Mill Creek Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$392,000,000	$927	$18,911,000	$66,617,000
Fabric Filter	$114,000,000	$270	$4,923,000	$18,797,000
PAC Injection	$5,592,000	$13	$3,213,000	$3,894,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$512,592,000**	**$1,212**	**$27,147,000**	**$89,530,000**

Table 4-20
Capital and O&M Cost Summary – Mill Creek Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$455,000,000	$867	$21,775,000	$77,149,000
Fabric Filter	$133,000,000	$253	$5,804,000	$21,990,000
PAC Injection	$6,890,000	$13	$3,858,000	$4,697,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$595,890,000**	**$1,135**	**$31,537,000**	**$104,058,000**

4.4.3.2 Mill Creek Unit 1 - Option 2 and Mill Creek Unit 2 – Option 2 Capital and O&M Costs. The total estimated capital cost to upgrade Mill Creek Units 1 (Option 2) and 2 (Option 2) with recommended technologies is $475,000,000 ($1,439/kW) each. The total estimated capital costs to upgrade Mill Creek Units 3 (Base Case) and 4 (Base Case) with recommended technologies are $513,000,000 ($1,212/kW) and $596,000,000 ($1,135/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-21, 4-22, 4-23, and 4-24. It should be noted that the costs for combining the Unit 1 and 2 wet FGD have been proportioned between the units base on unit size (i.e., MW). For illustration purposes, costs for the unit specific AQC technology option along with the remaining units and base case AQC technologies have been summarized. Detailed cost summaries are included in Appendix H.

Table 4-21
Capital and O&M Cost Summary – Mill Creek Unit 1 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,366,000	$15,171,000
WFGD	$254,000,000	$770	$13,279,000	$44,191,000
Fabric Filter	$81,000,000	$245	$3,477,000	$13,335,000
Electrostatic Precipitator	$32,882,000	$100	$3,581,000	$7,583,000
Lime Injection	$4,480,000	$14	$2,024,000	$2,569,000
PAC Injection	$4,412,000	$13	$2,213,000	$2,750,000
Neural Networks	$1,000,000	$3	$100,000	$222,000
Total	**$474,774,000**	**$1,439**	**$28,040,000**	**$85,821,000**

Table 4-22
Capital and O&M Cost Summary – Mill Creek Unit 2 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,401,000	$15,206,000
WFGD	$254,000,000	$770	$13,542,000	$44,454,000
Fabric Filter	$81,000,000	$245	$3,518,000	$13,376,000
Electrostatic Precipitator	$32,882,000	$100	$3,664,000	$7,666,000
Lime Injection	$4,480,000	$14	$2,117,000	$2,662,000
PAC Injection	$4,412,000	$13	$2,340,000	$2,877,000
Neural Networks	$1,000,000	$3	$100,000	$222,000
Total	**$474,774,000**	**$1,439**	**$28,682,000**	**$86,463,000**

Table 4-23
Capital and O&M Cost Summary – Mill Creek Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$392,000,000	$927	$18,911,000	$66,617,000
Fabric Filter	$114,000,000	$270	$4,923,000	$18,797,000
PAC Injection	$5,592,000	$13	$3,213,000	$3,894,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$512,592,000**	**$1,212**	**$27,147,000**	**$89,530,000**

Table 4-24
Capital and O&M Cost Summary – Mill Creek Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$455,000,000	$867	$21,775,000	$77,149,000
Fabric Filter	$133,000,000	$253	$5,804,000	$21,990,000
PAC Injection	$6,890,000	$13	$3,858,000	$4,697,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$595,890,000**	**$1,135**	**$31,537,000**	**$104,058,000**

4.4.3.3 Mill Creek Unit 1 - Option 3 and Mill Creek Unit 2 – Option 3 Capital and O&M Costs. The total estimated capital cost to upgrade Mill Creek Units 1 (Option 3) and 2 (Option 3) with recommended technologies is $476,000,000 ($1,442/kW) each. The total estimated capital costs to upgrade Mill Creek Units 3 (Base Case) and 4 (Base Case) with recommended technologies are $513,000,000 ($1,212/kW) and $596,000,000 ($1,135/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-25, 4-26, 4-27, and 4-28. For illustration purposes, costs for the unit specific AQC technology option along with the remaining units and base case AQC technologies have been summarized. Detailed cost summaries are included in Appendix H.

Table 4-25
Capital and O&M Cost Summary – Mill Creek Unit 1 (Option 3)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,366,000	$15,171,000
WFGD	$297,000,000	$900	$14,341,000	$50,486,000
Fabric Filter	$72,000,000	$218	$4,462,000	$13,224,000
Lime Injection	$4,480,000	$14	$2,024,000	$2,569,000
PAC Injection	$4,412,000	$13	$2,213,000	$2,750,000
Neural Networks	$1,000,000	$3	$100,000	$222,000
Total	**$475,892,000**	**$1,442**	**$26,506,000**	**$84,422,000**

Table 4-26
Capital and O&M Cost Summary – Mill Creek Unit 2 (Option 3)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,401,000	$15,206,000
WFGD	$297,000,000	$900	$14,604,000	$50,749,000
Fabric Filter	$72,000,000	$218	$4,575,000	$13,337,000
Lime Injection	$4,480,000	$14	$2,117,000	$2,662,000
PAC Injection	$4,412,000	$13	$2,340,000	$2,877,000
Neural Networks	$1,000,000	$3	$100,000	$222,000
Total	**$475,892,000**	**$1,442**	**$27,137,000**	**$85,053,000**

Table 4-27
Capital and O&M Cost Summary – Mill Creek Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$392,000,000	$927	$18,911,000	$66,617,000
Fabric Filter	$114,000,000	$270	$4,923,000	$18,797,000
PAC Injection	$5,592,000	$13	$3,213,000	$3,894,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$512,592,000**	**$1,212**	**$27,147,000**	**$89,530,000**

Table 4-28
Capital and O&M Cost Summary – Mill Creek Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$455,000,000	$867	$21,775,000	$77,149,000
Fabric Filter	$133,000,000	$253	$5,804,000	$21,990,000
PAC Injection	$6,890,000	$13	$3,858,000	$4,697,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$595,890,000**	**$1,135**	**$31,537,000**	**$104,058,000**

4.4.3.4 Mill Creek Unit 3 - Option 2 and Mill Creek Unit 4 – Option 2 Capital and O&M Costs. The total estimated capital cost to upgrade Mill Creek Units 1 (Base Case) and 2 (Base Case) with recommended technologies is $518,000,000 ($1,569/kW) each. The total estimated capital costs to upgrade Mill Creek Units 3 (Option 2) and 4 (Option 2) with recommended technologies are $456,000,000 ($1,077/kW) and $531,000,000 ($1,011/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-29, 4-30, 4-31, and 4-32. For illustration purposes, costs for the unit specific AQC technology option along with the remaining units and base case AQC technologies have been summarized. Detailed cost summaries are included in Appendix H.

Table 4-29
Capital and O&M Cost Summary – Mill Creek Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,366,000	$15,171,000
Wet FGD	$297,000,000	$900	$14,341,000	$50,486,000
Fabric Filter	$81,000,000	$245	$3,477,000	$13,335,000
Electrostatic Precipitator	$32,882,000	$100	$3,581,000	$7,583,000
Lime Injection	$4,480,000	$14	$2,024,000	$2,569,000
PAC Injection	$4,412,000	$13	$2,213,000	$2,750,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,102,000**	**$92,116,000**

Table 4-30
Capital and O&M Cost Summary – Mill Creek Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$97,000,000	$294	$3,401,000	$15,206,000
Wet FGD	$297,000,000	$900	$14,604,000	$50,749,000
Fabric Filter	$81,000,000	$245	$3,518,000	$13,376,000
Electrostatic Precipitator	$32,882,000	$100	$3,664,000	$7,666,000
Lime Injection	$4,480,000	$14	$2,117,000	$2,662,000
PAC Injection	$4,412,000	$13	$2,340,000	$2,877,000
Neural Network	$1,000,000	$3	$100,000	$222,000
Total	**$517,774,000**	**$1,569**	**$29,744,000**	**$92,758,000**

Table 4-31
Capital and O&M Cost Summary – Mill Creek Unit 3 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$335,000,000	$792	$17,199,000	$57,969,000
Fabric Filter	$114,000,000	$270	$4,923,000	$18,797,000
PAC Injection	$5,592,000	$13	$3,213,000	$3,894,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$455,592,000**	**$1,077**	**$25,435,000**	**$80,882,000**

Table 4-32
Capital and O&M Cost Summary – Mill Creek Unit 4 (Option 2)

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Wet FGD	$390,000,000	$743	$19,826,000	$67,289,000
Fabric Filter	$133,000,000	$253	$5,804,000	$21,990,000
PAC Injection	$6,890,000	$13	$3,858,000	$4,697,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$530,890,000**	**$1,011**	**$29,588,000**	**$94,198,000**

4.4.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID/booster fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new wet FGD is required for all the Units. There will be a significant change in the amount of waste water produced by the wet FGD. A new or a possible upgrade in wastewater treatment facility is required.
- **Wet FGD Byproduct Handling**--There will be a significant change in the amount of byproduct produced by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in byproduct handling system is required.
- **Wet FGD Reagent Preparation System**--There will be a significant change in the amount of reagent required by the wet FGD because of the high amount of sulfur removal from the coal. A new or a possible upgrade in reagent preparation system is required.
- **Ash Handling**--Additional new ash handling system or a possible upgrade in the ash handling system will be required.
- **Ammonia Storage**--Detailed investigation or study will be required to identify if a new ammonia storage facility is required or an existing ammonia storage facility can be upgraded for accommodating Units 1 and 2 ammonia supply.
- **Biomass Utilization**--Black & Veatch is currently completing a biomass utilization study for Mill Creek. Should it be determined that biomass will be considered as a fuel source in one or more units at the plant, a detailed investigation or study will be required to identify potential affect to the approved AQC equipment and how these many affect the aforementioned costs.
- **Footprint—**For units 1 and 2 the SCR will be installed where the existing dry ESP equipment is currently operating. For units 1, 2, 3, and 4 existing scrubbers can be retired in place to save costs or demolished to create access.

- **Constructability Challenges**:
  - Barge unloading is not economically feasible.
  - Overhead power lines and at least two transmission towers must be moved.
  - Numerous underground utility interferences/relocations.
  - Numerous aboveground utility interferences/relocations.
  - Very limited access around units due to existing AQC systems.
  - Multiple mobilization/demobilization (very selective) dismantling operations are needed to ensure tie-in work is accomplished efficiently.
  - Building between Units 1 and 3 from Unit 1 work will present logistical problems for both plant work and construction.
  - Access/height restrictions will dictate the magnitude of modularization that can be utilized.
  - Warehouse and loading dock on Unit 2 side must be relocated.
  - High complexity of ancillary systems routing to avoid interference with existing AQC systems.
  - Ground stability will need to be verified and modified to accommodate heavy lift cranes.
  - Multiple plant outages will be needed for tie-ins because of utilizing existing scrubbers, etc., throughout project.
  - Ductwork routing is more extensive due to the layout of the existing plant and existing AQC systems in use.
  - Space will be a premium for excavations/foundations/duct steel erection.
  - Large existing concrete foundations will need to be removed to accommodate equipment.
  - Outage windows are very short and limited.
  - Site constraints due to the existing railroad and roadway exist.
  - Selective demolition more complex due to ductwork routing.
  - For Mill Creek Unit 1 - Option 2 and Mill Creek Unit 2 – Option 2, Units 1 and 2 combined WFGD will have more ductwork but simple straight forward routing.

- For Mill Creek Unit 1 - Option 3 and Mill Creek Unit 2 – Option 3, Units 1 and Unit 2 PJFF will not be elevated.
- For Mill Creek Unit 3 - Option 2 and Mill Creek Unit 4 – Option 2, Units 3 and 4 WFGD will have less ductwork and simple straight forward routing.

4.4.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.4.5.1 Units 1 and 2. The new dry ESP, PJFF, and ID fans on Units 1 and 2 can be installed with temporary ductwork to connect back to the air heater and to the existing wet FGD during a short outage. This will allow the existing dry ESPs to be demolished and the new SCRs and new wet FGD equipment to be constructed with the units remaining online. The remainder of the new equipment can then be tied into existing ductwork during a normal outage period.

4.4.5.2 Units 3 and 4. The new AQC equipment for these units can be installed without extensive off-line construction related outages. The tie-in of new ductwork can be scheduled to occur during planned unit outages.

4.4.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Mill Creek is nominally $2,100,000,000 ($5,500/kW). The O&M and levelized annual costs of new AQC equipment at Mill Creek is nominally $117,500,000 and $378,500,000, respectively.

4.4.6.1 Mill Creek Unit 1 - Option 2 and Mill Creek Unit 2 – Option 2 Summary. The cost of new AQC equipment to meet or exceed defined future emission targets at Mill Creek for this optional scenario is nominally $2,058,000,000 ($5,200/kW). The O&M and levelized annual costs of new AQC equipment at Mill Creek for this optional scenario is nominally $115,400,000 and $365,900,000, respectively.

4.4.6.2 Mill Creek Unit 1 - Option 3 and Mill Creek Unit 2 – Option 3 Summary. The cost of new AQC equipment to meet or exceed defined future emission targets at Mill Creek for this optional scenario is nominally $2,060,000,000 ($5,200/kW). The O&M and levelized annual costs of new AQC equipment at Mill Creek for this optional scenario is nominally $112,300,000 and $363,000,000, respectively.

4.4.6.3 Mill Creek Unit 3 - Option 2 and Mill Creek Unit 4 – Option 2 Summary. The cost of new AQC equipment to meet or exceed defined future emission targets at Mill Creek for this optional scenario is nominally $2,022,000,000 ($5,200/kW). The O&M and levelized annual costs of new AQC equipment at Mill Creek for this optional scenario is nominally $113,900,000 and $360,000,000, respectively.

4.5 Trimble County - Units 1 and 2

Trimble County Generating Station Unit 1 is a pulverized coal fired power plant located approximately 5 miles west of Bedford, Kentucky. Unit 1 began commercial operation in December 23 1990. Unit 2, a 760 MW coal plant, is under construction on the site and is due to be completed on June 15, 2010. Unit 1 consists of one Combustion Engineering (CE) tangential balanced draft, forced circulation boiler and one General Electric (GE) reheat double-flow steam turbine with a hydrogen-cooled generator.

Unit 1 has a gross capacity of 547 MW and is equipped with LNBs, OFA, and SCR for NO_x control; a cold-side dry ESP for PM control and a wet FGD for SO_2 and HCl control. Unit 2 is a new coal fired unit, has a gross capacity of 750 MW, and is equipped with LNBs, OFA, and SCR for NO_x control; boiler combustion optimization and NNs for CO control; a cold-side dry ESP for PM control, a PJFF with PAC injection for Hg and dioxin/furan control, a wet FGD for SO_2 and HCl control and a wet ESP for H_2SO_4 (SO_3) control.

4.5.1 Site Visit Observations and AQC Considerations

At the Trimble County Station, the Black & Veatch team met Kenny Craigmyle (Project Engineer) and Haley Turner (Chemical Engineer) from E.ON. The following text is a narrative summary of the site visit conducted on May 12, 2010.

The Trimble County plant is the newest plant in the E.ON fleet and Unit 1 has AQC technologies already exceeding operation capabilities of other E.ON coal fired units. Unit 2 is a new unit currently in startup and tuning before becoming commercially operational and has new AQC equipment assumed to be sufficiently designed to meet the target emissions in this study. Thus, the Trimble County plant is already generally capable of meeting nearly all the defined pollutant emission targets. However, it has been determined that Unit 1 will need to add AQC technology to control emissions of Hg and dioxin/furan.

Installing a PJFF on Unit 1 will require demolition of an existing abandoned tower crane foundation and multiple runs of electrical duct bank which covers a large percentage of the area within the footprint proposed to install foundations for the Unit 1 fabric filter support frame. Extensive underground investigation will be required to identify operating utilities prior to installing new foundations.

Plant personnel indicated that the variable speed controller for the existing ID fans has been replaced and has additional capacity beyond what is currently required. This should be verified during any preliminary engineering for a PJFF installation project.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.5.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Trimble County Unit 1. These AQC technologies include installation of new PAC injection coupled with a new PJFF located downstream of the existing dry ESP. The existing cold-side dry ESP is capable of meeting the future PM emission limit of 0.03 lb/MBtu or lower; however, for Hg and dioxin/furan removal and to continue fly ash sales, a new PJFF would be required. The PJFF will reduce PM emissions to 0.03 lb/MBtu or lower. The new PJFF will be elevated above the grade level and will be installed downstream of the existing cold-side dry ESP. The existing dry ESP will be kept in service for pre-filtration and fly ash sales. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the new PJFF, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15 x 10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu.

As previously discussed, Unit 2 is currently in startup mode to test the unit's systems prior to becoming commercially operational. It has been assumed that this unit, and its existing AQC equipment, will meet the identified pollutant emission limits, and no new AQC technologies will be required.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.5.3 Capital and O&M Costs

The total estimated capital cost to upgrade Trimble County Unit 1 with recommended technologies is $136,000,000 ($248/kW). Capital, O&M, and levelized annual costs are shown in Table 4-33. Detailed cost summaries are included in Appendix H.

Table 4-33
Capital and O&M Cost Summary – Trimble County Unit 1

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
Fabric Filter	$128,000,000	$234	$5,782,000	$21,360,000
PAC Injection	$6,451,000	$12	$4,413,000	$5,198,000
Neural Network	$1,000,000	$2	$100,000	$222,000
Total	**$135,451,000**	**$248**	**$10,295,000**	**$26,780,000**

4.5.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for upgrading the ID fans to accommodate the additional pressure drop of the new PJFF.
- **Water**--New wet FGD is not required. No significant change in water supply is needed.
- **Wet FGD Byproduct Handling**--No new wet FGD byproduct handling system will be needed.
- **Ash Handling**--Additional new ash handling system will be needed for PJFF.
- **Ammonia Storage**--No new ammonia storage is required.
- **Footprint**--The new PJFF will be elevated and installed above the existing cold-side dry ESP.

- **Constructability Challenges**--An existing abandoned tower crane foundation and multiple runs of electrical duct bank cover a large percentage of the area within the footprint proposed to install foundations for the Unit 1 fabric filter support frame. Extensive underground investigation will be required to identify operating utilities prior to installing new foundations.

4.5.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.5.5.1 Unit 1. The new PJFF can be installed without extensive construction related outages. The tie-in of new ductwork can be scheduled to occur during planned unit outages.

4.5.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Trimble County is nominally $135,500,000 ($250/kW). The O&M and levelized annual costs of new AQC equipment at Trimble County are nominally $10,300,000 and $26,800,000, respectively.

4.6 Green River - Units 3 and 4

The Green River Generating Station is located 3 miles north of Central City in Muhlenberg County. The station is a four unit, coal fired electric generating station with a total nameplate capacity of 168 MW net. Units 3 and 4 are pulverized coal fired generating units. Units 1 and 2 were placed in service in 1948 and have been decommissioned in 2003 and are, therefore, not included within this review. Units 3 and 4 have a gross capacity of 71 MW and 109 MW, respectively, and are equipped with LNBs for NO_x control; and dry ESP (cold-side dry ESP for Unit 3 and hot-side dry ESP for Unit 4) for PM control.

4.6.1 Site Visit Observations and AQC Considerations

At the Green River Station, the Black & Veatch team met Travis Harper, Jim Edelen, and Eileen Saunders from E.ON. The following text is a narrative summary of the site visit conducted on May 13, 2010.

The Green River plant is the oldest and most uncontrolled coal fired plant in the E.ON fleet. Green River Units 1 and 2 have been retired in place since 2003. Units 3 and 4 were put into service in 1954 and 1959, respectively. Both remaining Units 3 and 4 are load following. Low load is approximately 40 MW for each unit, and (according to plant personnel) it is not unusual for both units to sit at low loads for extended periods just to support line voltage drop.

This low load operating issue for Units 3 and 4 impacts the flue gas temperature at the economizer outlet of both units. To properly operate a new SCR, significant economizer bypass will be needed to keep the SCR inlet temperature from dropping below design limits. The Installation of new AQC systems on Units 3 and 4 would require relocation of overhead power lines and one tower for Unit 4 AQC Equipment. Underground and aboveground utility interferences need to be relocated for Unit 3 AQC equipment. The existing Unit 3 tubular air heater will be replaced with a new regenerative type air heater. Flue gas will be diverted from the economizer section to the SCR inlet duct and will flow vertically upward to the top of the SCR. The SCR will be located above the new air heater and will require economizer bypass to control the flue gas temperature to the SCR inlet. Flue gas flow from the new air heater to the bottom of the new CDS vessel where the bed will be kept fluidized across the load range using recirculated gas from the PJFF outlet. The scrubbed flue gas will be drawn through the CDS and PJFF with a new ID fan that will direct clean flue gas to the new Unit 3 carbon steel stack. Solids collected in the PJFF (fly ash + unreacted reagent) will be recycled back to the CDS inlet to optimize reagent utilization.

The existing Unit 3 cold-side dry ESP and Unit 4 hot-side dry ESP were put into service in 1974. The Unit 4 hot-side dry ESP outlet duct will be connected to the new SCR by new ductwork. Flue gas will travel upward to the top of the SCR and be routed back to the existing regenerative air heater flue gas inlet. Flue gas will travel out from the air heater to the bottom of the CDS. Scrubbed gas will then travel into two new PJFF housings located on each side of the CDS vessel. New ID fans will draw flue gas through the PJFF housings and deliver the clean flue gas to the new Unit 4 stack located between the new AQC equipment and the existing building wall. The hardware and footprint for PAC injection equipment is minimal and will be located near the air heater outlet ductwork before it splits into two PJFF inlet ducts.

Green River Units 3 and 4 require a complete new set of AQC system equipment along with two new carbon steel dry stacks.

Following the site visits, Black & Veatch developed recommendations for specific AQC technology for each unit based on the air emission levels provided by E.ON. The AQC technology recommendations were provided to E.ON for review and approval. Following E.ON's approval of the recommended AQC technologies, costs estimates were developed. The approved AQC technology options selection sheets are provided in Appendix E. The following sections describe the recommended AQC technologies and associated costs.

4.6.2 Control Technology Summary

The following discussion summarizes the approved AQC technologies and considerations for installation of these technologies on each unit.

To meet the identified pollutant emission limits, new AQC technologies are required for Green River Units 3 and 4. These AQC technologies include installation of a new SCR and PAC injection coupled with a new circulating dry scrubber (CDS) and PJFF located downstream of the air heater. The new SCR system can reduce NO_x emissions to 0.11 lb/MBtu or lower. The CDS and PJFF will reduce PM emissions to 0.03 lb/MBtu or lower, SO_2 emissions to 0.25 lb/MBtu or lower, and HCl emissions to 0.002 lb/MBtu or lower. The existing cold-side dry ESP on Unit 3 will be retired in place/demolished and existing hot-side dry ESP on Unit 4 will be kept in service for pre-filtration of fly ash. Halogenated PAC injection for Hg and dioxin/furan removal will be into the new ductwork upstream of the CDS, and it will reduce Hg emissions to 1 lb/TBtu or lower and dioxin/furan emissions to 15×10^{-18} lb/MBtu. New NN systems are recommended as a technology option for consideration to meet the future CO compliance limit of 0.1 lb/MBtu. Units 3 and 4 will require new ID fans (2 x 50 percent) to overcome the added pressure drop of the new ductwork, SCR, CDS, and PJFF.

To support the costs analyses described in the next section, Black & Veatch developed process flow diagrams for the approved AQC technologies to illustrate the potential equipment locations and better understand the retrofit issues with the existing system, as well as potential constructability issues. Additionally, high-level control technology equipment arrangement drawings indicating one possible layout of new equipment for each plant were developed. The equipment arrangement drawings are preliminary and are not meant to replace a detailed engineering study. The drawings illustrate high-level box sketches indicating locations of new ductwork (noted in green) and new AQC equipment (noted in red). The drawings also indicate gas flow paths and include a brief description of the constructability issues considered. The process flow diagrams and equipment arrangements are included in Appendices F and G, respectively.

4.6.3 Capital and O&M Costs

The total estimated capital cost to upgrade Green River Units 3 and 4 with recommended technologies are $71,000,000 ($995/kW) and $101,000,000 ($927/kW) respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-34 and 4-35. Detailed cost summaries are included in Appendix H.

Table 4-34
Capital and O&M Cost Summary – Green River Unit 3

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$29,000,000	$408	$1,040,000	$4,569,000
CDS-FF	$40,000,000	$563	$6,921,000	$11,789,000
PAC Injection	$1,112,000	$16	$323,000	$458,000
Neural Network	$500,000	$7	$50,000	$111,000
Total	**$70,612,000**	**$995**	**$8,334,000**	**$16,927,000**

Table 4-35
Capital and O&M Cost Summary – Green River Unit 4

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$42,000,000	$385	$1,442,000	$6,553,000
CDS-FF	$57,000,000	$523	$10,362,000	$17,299,000
PAC Injection	$1,583,000	$15	$515,000	$708,000
Neural Network	$500,000	$5	$50,000	$111,000
Total	**$101,083,000**	**$927**	**$12,369,000**	**$24,671,000**

4.6.4 Special Considerations

To arrive at the aforementioned cost estimates, BOP and ancillary operations, available space at the plant, and constructability issues were considered. The following highlight several of these issues considered for the development of the AQC equipment costs:

- **Auxiliary Power**--Additional auxiliary power requirement will need to be considered for new ID fans to accommodate the additional pressure drop of the new AQC equipment.
- **Water**--A new CDS-PJFF is required for all the Units. The makeup water system may require a possible upgrade.
- **CDS Byproduct Handling**--There will be a significant amount of byproduct produced by the CDS because of the high amount of sulfur removal from the coal. A new byproduct handling system is required.
- **CDS Reagent Preparation System**--There will be a significant amount of reagent required by the CDS because of the high amount of sulfur removal from the coal. A new reagent preparation system is required.
- **Ammonia Storage**--A new ammonia storage facility will be required for new SCRs. Detailed investigation or study will be required to identify the site location for ammonia storage and supply.
- **Footprint**--The new AQC equipment will be installed in the new location as shown on the equipment layout drawing included in Appendix G.

- **Constructability Challenges**:
    - Relocation of some existing transmission lines and one tower will be needed for safe installation of new AQC equipment.
    - Relocation of the existing generator set will be needed to make space available for the new AQC equipment.
    - Some underground utility interferences/relocations.
    - Some aboveground utility interferences/relocations.

4.6.5 AQC Equipment Implementation Schedule

AQC equipment implementation schedules for each unit are included in Appendix I. These schedules include milestones in months for the conceptual design, and construction and can help to identify critical path considerations for the approved AQC technologies. While these schedules represent a sequence of events to minimize site outages required for installation of the new AQC equipment, consideration of unit-specific outages outside the scope of this study, have not been included. The following highlight scheduling related issues that were considered in the development of the implementation schedules.

4.6.5.1 Unit 3 and 4. The plant has available space for the new AQC equipment, and the new AQC equipment can be installed without extensive off-line construction related outages.

4.6.6 Summary

The cost of new AQC equipment to meet or exceed defined future emission targets at Green River is nominally $172,000,000 ($1,900/kW). The O&M and levelized annual costs of new AQC equipment at Green River are nominally $20,700,000 and $41,600,000 respectively.

Appendix A

E.ON Environmental Matrix

Appendix B
E.ON Unit Specific Data

Appendix C
Project Design Memorandum (Design Basis)

Appendix D
Air Quality Control Technology Descriptions

Appendix E
Approved Air Quality Control Technology Options

Appendix F
Process Flow Diagrams

Appendix G

Air Quality Control Equipment Arrangement Drawings

Appendix H
Air Quality Control Technology Costs

Appendix I
Level 1 Schedules