Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Ghent

Ghent.xls 6/16/2010

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)	No		
Natural gas line (into the station) capacity (if applicable)	No		
Current Lost on Ignition (LOI)			
Start-up Fuel	# 2 Fuel Oil		
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate		B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		tangential	tangential	ont/back wall fired	ont/back wall fired		
Boiler Manufacturer		CE	CE	FW	FW		
Net MW Rating (specify plant or turbine MW)						MW	
Gross MW Rating		541	517	523	526	MW	
Net Unit Heat Rate		10557	8904	11180	11070	Btu/kWh	
Net Turbine Heat Rate		8733	7565	8404	8439	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		1.50%		1.95%	2.20%	%	
Fly Ash/Bottom Ash Split						%	
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		No	No	No	No		
In operation? (Y/N)		No	No	No	No		
Flue Gas Recirculation (if installed)		No	No	No	No	%	
Type of Air Heater		Lungstrom	Lungstrom	Lungstrom	Lungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)		vertical	vertical	vertical	vertical		
Design Pressure/Vacuum Rating for Steam Generator	+/-	35	26	35	35	in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	35"V	30" V	30" V	30" V	in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Emerson	Emerson	Emerson	Emerson		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Ovation	Ovation	Ovation	Ovation		
Neural Network Installed? (Y/N)		No	No	No	No		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		n/a	n/a	n/a	n/a		
Extra Capacity available in DCS?		yes	yes	yes	yes		
Historian Manufacturer		Emerson	Emerson	Emerson	Emerson		
Additional Controls from DCS or local PLC w/tie-in		yes	yes	yes	yes		
Transformer Rating for Intermediate Voltage Switchgear							
(SUS's) and Ratings of Equipment in These Cubicles							
Auxiliary Electric Limited (Y/N)							
Operating Conditions							
Economizer Outlet Temperature		729	610	731	791	°F	
Economizer Outlet Pressure		-323	-5.07	-5.12	-4.51	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		3	3.5	3.5	3.3	%	
Economizer Outlet Gas Flow		3775	4147	4506	4076	acfm	
						lb/hr	
Air Heater Outlet Temperature		345	309	315	309	°F	
Air Heater Outlet Pressure		-22.4	-18.6	-36.1	-29.4	in wg.	
Particulate Control Equipment Outlet Temperature		361	605	708	770	°F	
Particulate Control Equipment Outlet Pressure		-25.7	-10.8	-0.92	-0.82	in wg.	
FGD Outlet Temperature (if applicable)		125	83	130	128	°F	
FGD Outlet Pressure (if applicable)		1.65	1.45	2	1.56	in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

	Unit 1	Unit 2	Unit 3	Unit 4		Notes
NOx Emissions						
Emissions Limit	0.45	0.4	0.46	0.46	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB/OFA	LNB/OFA	LNB/OFA		
Current NOx Reduction with existing controls	SCR	SCR	SCR	SCR	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	anhydrous	anhydrous	anhydrous	anhydrous		
Reagent Cost					$/ton	
Current Emissions	330	1300	330	330	lb/hr	
	930	850	4800	850	ton/yr	
	0.04	0.35	0.04	0.04	lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side ESP	Hot side ESP	Hot side ESP	Hot side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.025 lbs/mmbtu	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	No	No	No	No		
ESP						
Specific Collection Area (SCA)	153	223	328	328	ft^2/1000 acfm	
Discharge Electrode Type	rigid	wire	wire	wire		
Supplier	PECO	GE	GE	GE		
Efficiency	99.2	99			%	
No. of Electrical Sections	4 in series	4 in series	7 in series	7 in series		
% of Fly Ash Sold	0	0	0	0	%	
Fabric Filter						
Air to Cloth Ratio (net)	N/A				ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	5.67 lbs/mmbtu (24 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	wet FGD	wet FGD	wet FGD	wet FGD		
Current Emissions	600	600	1120	600	lb/hr	
	1400	2100	1400	1400	ton/yr	
	0.15	0.2	0.15	0.15	lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	yes	yes	yes	yes		

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit 3	Unit 4		Notes
ID Fan Inlet Pressure	-22.5	-18.7	-36	-28.9	in wg.	
ID Fan Discharge Pressure	6.08	11.4	5.94	14.6	in wg.	
ID Fan Inlet Temperature	358	309	322	309	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3	3.5	3.5	3.17	%	
ID Fan Motor Voltage (Rated)	4160	6600	13200	4000	volts	
ID Fan Motor Amps (Operating)	990	670	410	1385	A	
ID Fan Motor Amps (Rated)	1113	953	535	1020	A	
ID Fan Motor Power (Rated)	9000	12500	13600	8000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1.15	1.15		
Chimney Information:						
Flue Liner Material	fiber glass	brick	brick	fiber glass		Ghent 2 and 3 share a common stack-each unit is mixed
Flue Diameter	29'6"	34'5"	34'5"	29'6"	ft	into a common exit flue
Chimney Height	660	580	580	660	ft	
Number of Flues	1	2	2	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ______________________ Owner: ______________________

Unit ______________________ Project: ______________________

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Cane Run

Black & Veatch AQCS Information Needs

Power Plant: Cane Run Owner: Louisville Gas & Electric
Unit: Project:

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum	Notes
Carbon	61.4	59.8	63.14	
Hydrogen	4.3	4.09	4.3	
Sulfur	3.2	2.23	3.2	
Nitrogen	1.3	1.26	1.5	
Oxygen	6.5	6.62	7.44	
Chlorine	0.1			
Ash	10.8	9.13	11.67	
Moisture	12.4	11.92	15.18	
Total	100	95.05	106.43	
Higher Heating Value, Btu/lb (as received)	10921.64	10391	11673	
Ash Mineral Analysis (% by mass):				
Silica(SiO_2)	46.02	42.41	49.07	
Alumina (Al_2O_3)	23.27	20.81	25.64	
Titania (TiO_2)	1.09	0.99	1.21	
Phosphorous Pentoxide (P_2O_5)	0.255	0.16	0.34	
Calcium Oxide (CaO)	1.211	0.88	1.89	
Magnesium Oxide (MgO)	0.98	0.87	1.14	
Sodium Oxide (Na_2O)	0.3	0.22	0.44	
Iron Oxide (Fe_2O_3)	22.97	17.48	27.84	
Sulfur Trioxide (SO_3)	0.95	0.52	1.7	
Potassium Oxide (K_2O)	2.6	2.24	2.93	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium	46.75	%	
Arsenic	15.47	%	
Mercury	0.09	% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)	Y		
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel	Gas		
Ash Fusion Temperature			
Initial Deformation	2025.56	°F	
Softening	2211.44	°F	
Hemispherical	2332.11	°F	
Hardgrove Grindability Index	62		

Black & Veatch AQCS Information Needs

Power Plant: Cane Run Owner: Louisville Gas & Electric
Unit: Project:

Plant Size and Operation Data: (provide for each unit)		CR4	CR5	CR6		Notes
Maximum (Design) Fuel Burn Rate		1601.9	1753.4	2395.7	MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall	Wall	Wall		
Boiler Manufacturer		CE	Riley	CE		
Net MW Rating (specify plant or turbine MW)		155	168	240	MW	
Gross MW Rating		168	181	261	MW	
Net Unit Heat Rate		10340	10458	10789	Btu/kWh	
Net Turbine Heat Rate		8414	8429	8625	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		-	-	-	%	
Fly Ash/Bottom Ash Split		80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)		Y	N	N		
In operation? (Y/N)		Y	N	N		
Flue Gas Recirculation (if installed)					%	
Type of Air Heater		Ljungstrom	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)		Horizontal	Horizontal	Horizontal		
Design Pressure/Vacuum Rating for Steam Generator	+/-	1800/3.5	1800/1.5	2400/3.5	in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	no data	20" H2O/-8.75	no data	in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Honeywell	Honeywell	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		TDC3000/Experion	TDC3000/Experion	TDC3000/Experion		
Neural Network Installed? (Y/N)		Y	Y	Y		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		Neuco	Neuco	Neuco		
Extra Capacity available in DCS?		Y	Y	Y		
Historian Manufacturer		Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear (SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)		N	N	N		
Operating Conditions						
Economizer Outlet Temperature		580.45	630.24	617.2	°F	
Economizer Outlet Pressure					in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)					%	
Economizer Outlet Gas Flow					acfm	
					lb/hr	
Air Heater Outlet Temperature		369.22	299.15	317.59	°F	
Air Heater Outlet Pressure					in wg.	
Particulate Control Equipment Outlet Temperature		132.6	128.4	132.8	°F	Summer design Temperature
Particulate Control Equipment Outlet Pressure					in wg.	ID Fan Suction Pressure
FGD Outlet Temperature (if applicable)		127			°F	
FGD Outlet Pressure (if applicable)					in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Cane Run   Owner: Louisville Gas & Electric
Unit: Project:

NOx Emissions	CR4	CR5	CR6		Notes
Emissions Limit	0.3372	0.3934	0.3276	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB	OFA		
Current NOx Reduction with existing controls				%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	N/A	N/A	N/A		
Reagent Cost				$/ton	
Current Emissions	0.337	0.384	0.286	lb/hr	
				ton/yr	
				lb/MBtu	
Particulate Emissions					
Emissions Limit	0.11	0.11	0.11	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF					
Oxygen Content of Flue Gas @ Air Heater Outlet	5.78	5.82	4.53	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet				%	
Current Emissions	0.041	0.034	0.024	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	N	N	N		
ESP					
Specific Collection Area (SCA)				ft^2/1000 acfm	
Discharge Electrode Type	0.109" Copper Bessemer	0.109" Copper Bessemer			
Supplier	Research-Cottrell	Research-Cottrell	Buell Engineering		Original supplier
Efficiency	99.1	96.1	99.2	%	
No. of Electrical Sections	48		49		
% of Fly Ash Sold	N/A	N/A	N/A	%	
Fabric Filter					
Air to Cloth Ratio (net)				ft/min	
Number of Compartments					
Number of Bags per Compartments					
Efficiency				%	
% of Fly Ash Sold	N/A	N/A	N/A	%	
SO_2 Emissions					
Emissions Limit	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet	Wet	Wet		
Current Emissions	0.411	0.419	0.676	lb/hr	
				ton/yr	
				lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	N	N	N		

Black & Veatch AQCS Information Needs

Power Plant: Cane Run   Owner: Louisville Gas & Electric
Unit: Project:

ID Fan Information (at Full Load):	Unit X	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-9.11	-6.82	-9.84	in wg.	
ID Fan Discharge Pressure	8	7	8	in wg.	
ID Fan Inlet Temperature				F	
Oxygen Content of Flue Gas @ ID Fan Inlet				%	
ID Fan Motor Voltage (Rated)	4160	4160	4000	volts	
ID Fan Motor Amps (Operating)	104.23	194.37	146.11	A	
ID Fan Motor Amps (Rated)	157	211	265	A	
ID Fan Motor Power (Rated)	1250	3000	2000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1	1.15		
Chimney Information:					
Flue Liner Material	Pre-Krete	Hadite/Pre-krete	Hastalloy C276		
Flue Diameter	14'2"	15'6"	24'41/2"	ft	
Chimney Height	239	239	500	ft	
Number of Flues	1	1	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
Specific burner and overfire air ports arrangement (single wall, opposed fired, total number of burners, number of burner levels, number of overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Cane Run Owner: Louisville Gas & Electric
Unit Project:

Economic Evaluation Factors:	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life	20	20	20	years	
Annual Capacity Factor (over life of study/plant)	65	65	65	%	
Contingency Margin (can be determined by B&V)				%	
Owner Indirects Cost Margin				%	
Interest During Construction				%	
Levelized Fixed Charge Rate or Capital Recovery Factor				%	
Present Worth Discount Rate	6.4	6.4	6.4	%	
Capital Escalation Rate	4%	4%	4%	%	
O&M Escalation Rate	3%	3%	3%	%	
Energy Cost (energy to run in-house equipment)				$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)				$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)				$/MBtu	
				$/ton	
Base Fuel Price				$/MBtu	
				$/ton	
Fuel Price Escalation Rate				%	
Water Cost				$/1,000 gal	
Limestone Cost	N/A	N/A	N/A	$/ton	
Lime Cost	$112.54	$112.54	$112.54	$/ton	Total cost $773,013.3
Ammonia Cost	N/A	N/A	N/A	$/ton	
Fully Loaded Labor Rate (per person)				$/year	
Fly Ash Sales	N/A	N/A	N/A	$/ton	
Bottom Ash Sales	N/A	N/A	N/A	$/ton	
FGD Byproduct Sales	N/A	N/A	N/A	$/ton	
Waste Disposal Cost					
Fly Ash	$2.73			$/ton	Values represent total O&M cost for 2009. Plant Total
Bottom Ash	$8.40			$/ton	Values represent total O&M cost for 2009. Plant total
Scrubber Waste	$3,469.00	$4,989.00	$8,734.00	000$	Values represent total O&M cost for 2009.

Mill Creek

Mill Creek.xls 6/16/2010

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon	64			%	
Hydrogen	4.5			%	
Sulfur	3.5			%	
Nitrogen	1.3			%	
Oxygen	4.62			%	
Chlorine	0.08			%	
Ash	12			%	
Moisture	10			%	
Total	100.00				
Higher Heating Value, Btu/lb (as received)	11471.82			Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ______________ Owner: ______________

Unit ______________ Project: ______________

Plant Size and Operation Data: (provide for each unit)	Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate	B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Tangential fired	Tangential fired	opposed wall	opposed wall		
Boiler Manufacturer	CE	CE	B&W	B&W		
Net MW Rating (specify plant or turbine MW) Winter ratings	303MW	303MW	397MW	492MW	MW	
Gross MW Rating Winter ratings	330MW	330MW	423MW	525MW	MW	
Net Unit Heat Rate	10639	10929	10602	10410	Btu/kWh	
Net Turbine Heat Rate					Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)					%	
Fly Ash/Bottom Ash Split	80/20	80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)	N	N	N	N		
In operation? (Y/N)						
Flue Gas Recirculation (if installed)					%	
Type of Air Heater	Air Preheater Co.	Air Preheater Co.	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)	Vertical Flow	Vertical Flow	Vertical Flow	Vertical Flow		
Design Pressure/Vacuum Rating for Steam Generator +/-					in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-					in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Honeywell	Honeywell	Honeywel	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	TC3000			Experion		
Neural Network Installed? (Y/N)	Y	Y	N	N		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	Neuco	Neuco				
Extra Capacity available in DCS?	minimal	minimal	minimal	minimal		
Historian Manufacturer	Honeywell	Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear						
Capacity of Spare Electrical Cubicles in Existing MCC's and LCUS's (SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)	N	N	N	N		
Operating Conditions						
Economizer Outlet Temperature	760	760	690	640	°F	
Economizer Outlet Pressure	-5	-5	-5	-5	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	5	5	5	5	%	
Economizer Outlet Gas Flow	1524804	1524804	1958726	2239453	acfm	
	2976508	2976508	4056287	4848440	lb/hr	
Air Heater Outlet Temperature	375	375	325	315	°F	
Air Heater Outlet Pressure	-10	-10	-18	-18	in wg.	
Particulate Control Equipment Outlet Temperature	375	375	325	315	°F	
Particulate Control Equipment Outlet Pressure	-14	-14	-23	-21	in wg.	
FGD Outlet Temperature (if applicable)	133	133	130	130	°F	
FGD Outlet Pressure (if applicable)	1	1	1	1	in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

NOx Emissions	Unit 1	Unit 2	Unit 3	Unit 4		Notes
Emissions Limit			0.7	0.7	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA etc.	LNB/OFA	LNB/OFA	LNB/SCR	LNB/SCR		
Current NOx Reduction with existing controls			90%	90%	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)			Anhydrous	Anhydrous		
Reagent Cost			500	500	$/ton	
Current Emissions	0.32	0.32	0.05	0.05	lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit	0.115	0.115	0.105	0.105	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold Side ESP	Cold Side ESP	Cold Side ESP	Cold Side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet	4	4	4	4	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	4	4	4	4	%	
Current Emissions	0.36	0.48	0.05	0.04	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	Y	Y	Y	Y		Very minimal at this point in time
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	1.2	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet FGD	Wet FGD	Wet FDG	Wet FGD		
Current Emissions	0.47	0.47	0.58	0.47	lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit 3	Unit 4		Notes
ID Fan Inlet Pressure	-16	-16.5	-22	-23	in wg.	
ID Fan Discharge Pressure	-2	-1			in wg.	
ID Fan Inlet Temperature	340	340	330	330	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	4	4	4	4	%	
ID Fan Motor Voltage (Rated)	4160	4160	4160	4160	volts	
ID Fan Motor Amps (Operating)	275	275	920	1115	A	
ID Fan Motor Amps (Rated)	320	320	1176		A	
ID Fan Motor Power (Rated)	2500	2500	9000	9500	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1	1.15		
Chimney Information:						
Flue Liner Material	C276	C276	C276	C276		
Flue Diameter	15' 6"	15' 6"	19' 6"	19' 6"	ft	top of liner
Chimney Height	623	623	630	630	ft	
Number of Flues	1	1	1	1		1&2 share a common stack

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ______________ Owner: ______________

Unit ______________ Project: ______________

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Trimble County

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit TC1 and TC2 Project:

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit: TC1 and TC2 Project:

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit X	Unit X		Notes
Maximum (Design) Fuel Burn Rate		B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Tangential	Wallfired				
Boiler Manufacturer		Combustion Engineering	Doosan				
Net MW Rating (specify plant or turbine MW)		turbine 512	760			MW	
Gross MW Rating		547	509			MW	
Net Unit Heat Rate		10372	8662 guarentteed			Btu/kWh	
Net Turbine Heat Rate		gross 8362.53	7066 turbine guarenteed			Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		NA	0.068 lb/MMBtu less than this at Econ outlet			%	
Fly Ash/Bottom Ash Split		80/20	80/20			%	
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		N	N				
In operation? (Y/N)		N	NA				
Flue Gas Recirculation (if installed)		NA	NA			%	
Type of Air Heater		Regenerative	Regenerative				
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical 2 layer	Vertical 2 layer				
Design Pressure/Vacuum Rating for Steam Generator	+/-	26.5	24/35 +/- 24 on continuous +/-35 on transient basis			in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	42 at 100%	25/-6 +/-35 for DESP, PJFF +25/-6			in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Emerson	Emerson				
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Ovation	Ovation				
Neural Network Installed? (Y/N)		N	N				
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		N/A	N/A				
Extra Capacity available in DCS?		Y	Y				
Historian Manufacturer		Emerson	Emerson				
Additional Controls from DCS or local PLC w/tie-in		Y	Y				
Transformer Rating for Intermediate Voltage Switchgear		100.8 MVA? Need better definintion					
(SUS's) and Ratings of Equipment in These Cubicles		NA					
Auxiliary Electric Limited (Y/N)		N					
Operating Conditions							
Economizer Outlet Temperature		700	586			°F	
Economizer Outlet Pressure		-6				in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		3	3.2/8.15 25%			%	
Economizer Outlet Gas Flow		N/A	3200333			acfm	
		N/A				lb/hr	
Air Heater Outlet Temperature		600	324			°F	
Air Heater Outlet Pressure		diff 6.5				in wg.	
Particulate Control Equipment Outlet Temperature		N/A	313			°F	
Particulate Control Equipment Outlet Pressure		-0.3				in wg.	
FGD Outlet Temperature (if applicable)		130	12.9 diff			°F	
FGD Outlet Pressure (if applicable)						in wg.	stack draft

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit TC1 and TC2 Project:

NOx Emissions	Unit 1	Unit 2	Unit X	Unit X		Notes
Emissions Limit					lb/MBtu	
Type of NOx Control (if any) - LNB, OFA etc.						
Current NOx Reduction with existing controls					%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)						
Reagent Cost					$/ton	
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF						
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions					lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section						
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)						
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit TC1 and TC2 Project:

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-0.3	-23.08			in wg.	
ID Fan Discharge Pressure	-0.3	15.77			in wg.	
ID Fan Inlet Temperature	300	313			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3-6%	4.2-9.2			%	
ID Fan Motor Voltage (Rated)	6600	13200			volts	
ID Fan Motor Amps (Operating)	535	NA			A	
ID Fan Motor Amps (Rated)	740	790			A	
ID Fan Motor Power (Rated)	9000	20241			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15				
Chimney Information:						
Flue Liner Material	FRP	FRP				
Flue Diameter	18'	18' & 10'			ft	
Chimney Height	754'	754'			ft	
Number of Flues	1	2				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant:	Trimble	Owner:	
Unit	TC1 and TC2	Project:	

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Green River

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)			Notes
Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

Plant Size and Operation Data: (provide for each unit)		Unit 3	Unit 4	Unit X	Unit X		Notes
Maximum (Design) Fuel Burn Rate		880	1.2			MBtu/hr	Original Design
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall Fired	Wall Fired				
Boiler Manufacturer		B&W	B&W				
Net MW Rating (specify plant or turbine MW)		71	102			MW	
Gross MW Rating		75	109			MW	
Net Unit Heat Rate		11942	11278			Btu/kWh	
Net Turbine Heat Rate						Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		Unknown	Unknown			%	
Fly Ash/Bottom Ash Split		80/20	80/20			%	
Flue Gas Recirculation (FGR)		NA	NA				
Installed? (Y/N)							
In operation? (Y/N)		NA	NA				
Flue Gas Recirculation (if installed)		NA	NA			%	
Type of Air Heater		Tubular	Lungstrom				
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical	Vertical				
Design Pressure/Vacuum Rating for Steam Generator	+/-	-18	-13.3			in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	-18	-13.3			in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Honeywell	Honeywell				
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Experion	Experion				
Neural Network Installed? (Y/N)		N	N				
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		NA	NA				
Extra Capacity available in DCS?		Y	Y				
Historian Manufacturer		Honeywell	Honeywell				
Additional Controls from DCS or local PLC w/tie-in		Y Rockwell	Y Rockwell				
Transformer Rating for Intermediate Voltage Switchgear		7.5 MVA	9.375 MVA				
(SUS's) and Ratings of Equipment in These Cubicles		N/A	N/A				
Auxiliary Electric Limited (Y/N)		N	N				
Operating Conditions							
Economizer Outlet Temperature		475	610			°F	
Economizer Outlet Pressure		-5	-6			in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		25%	25%			%	
Economizer Outlet Gas Flow						acfm	
		510	687			Klb/hr	
Air Heater Outlet Temperature		243	363			°F	
Air Heater Outlet Pressure		-9	-135			in wg.	
Particulate Control Equipment Outlet Temperature		230	600			°F	
Particulate Control Equipment Outlet Pressure		-11	-8.1			in wg.	
FGD Outlet Temperature (if applicable)		NA	NA			°F	
FGD Outlet Pressure (if applicable)		NA	NA			in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

NOx Emissions	Unit 3	Unit 4	Unit X	Unit X		Notes
Emissions Limit	0.46	0.5			lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB				
Current NOx Reduction with existing controls	NA	NA			%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	NA	NA				
Reagent Cost	NA	NA			$/ton	
Current Emissions					lb/hr	
					ton/yr	
	0.398	0.384			lb/MBtu	
Particulate Emissions						
Emissions Limit	0.29	0.14			lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side	Hot side				
Oxygen Content of Flue Gas @ Air Heater Outlet	~5%	~5%			%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	~5%	~5%			%	
Current Emissions	Compliance	Compliance			lb/MBtu	Indirectly measured by Opacity
Fly Ash Sold (Y/N) - See Economic Section	N	N				
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type	Weighted Wire	Weighted Wire				
Supplier	Buell	Buell				
Efficiency	98.50%	99%			%	
No. of Electrical Sections	6	7				
% of Fly Ash Sold	0	0			%	
Fabric Filter						
Air to Cloth Ratio (net)	NA	NA			ft/min	
Number of Compartments	NA	NA				
Number of Bags per Compartments	NA	NA				
Efficiency	NA	NA			%	
% of Fly Ash Sold	NA	NA			%	
SO_2 Emissions						
Emissions Limit	4.57	4.57			lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	NA	NA				
Current Emissions					lb/hr	
	5448	9276			ton/yr	2009 data
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

ID Fan Information (at Full Load):	Unit 3	Unit 4	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-7	-15.5			in wg.	
ID Fan Discharge Pressure	0	-0.24			in wg.	
ID Fan Inlet Temperature	230	365			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	~5%	~5%			%	
ID Fan Motor Voltage (Rated)	2300	2300			volts	
ID Fan Motor Amps (Operating)	105	230			A	
ID Fan Motor Amps (Rated)	98.3	224			A	
ID Fan Motor Power (Rated)	450	1000			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1				
Chimney Information:						
Flue Liner Material	Brick	Brick				
Flue Diameter	12	11			ft	
Chimney Height	198	247			ft	
Number of Flues	1	1				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
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Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Appendix C
Project Design Memorandum (Design Basis)

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	EW Brown			Ghent				Cane Run			Mill Creek				Trimble County		Green River		Reference
	1	2	3	1	2	3	4	4	5	6	1	2	3	4	1	2	3	4	
Ultimate Coal analysis, wet basis																			
Carbon, %	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	65.41	65.41	Data from E-ON
Hydrogen, %	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.46	4.46	Data from E-ON
Sulfur, %	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	2.60	2.60	Data from E-ON
Nitrogen, %	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.34	1.34	Data from E-ON
Chlorine, %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	Data from E-ON
Oxygen, %	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.69	6.69	Data from E-ON
Ash, %	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	Data from E-ON
Moisture, %	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	10.50	10.50	Data from E-ON
Higher Heating Value, Btu/lb	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,600	11,600	Data from E-ON
Trace Metal Analysis, ppm																			
Antimony (Sb)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.07	1.07	Data from E-ON
Arsenic (As)	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	10.00	10.00	Data from E-ON
Barium (Ba)	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	49.00	49.00	Data from E-ON
Cadmium (Cd)	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.30	0.30	Data from E-ON
Chlorine (Cl)	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1845.00	1845.00	Data from E-ON
Chromium (Cr)	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	17.00	17.00	Data from E-ON
Fluorine (F)	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	71.00	71.00	Data from E-ON
Lead (Pb)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	Data from E-ON
Magnesium (Mg)	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	509.00	509.00	Data from E-ON
Mercury (Hg)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.10	0.10	Data from E-ON
Nickel (Ni)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	14.00	14.00	Data from E-ON
Selenium (Se)	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	1.93	1.93	Data from E-ON
Strontium (Sr)	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	30.00	30.00	Data from E-ON
Vanadium (V)	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Data from E-ON
Zinc (Zn)	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	50.00	50.00	Data from E-ON
Ash Analysis, % by mass																			
Alumina (Al2O3)	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	19.45	19.45	Data from E-ON
Barium Oxide (BaO)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	Data from E-ON
Lime (CaO)	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.89	2.89	Data from E-ON
Iron Oxide (Fe2O3)	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	19.90	19.90	Data from E-ON
Magnesia (MgO)	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	Data from E-ON
Manganese Oxide (MnO)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	Data from E-ON
Phosphorous Pentoxide (P2O5)	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.21	0.21	Data from E-ON
Potassium Oxide (K2O)	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.41	2.41	Data from E-ON
Silica (SiO2)	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	49.65	49.65	Data from E-ON
Sodium Oxide (Na2O)	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.77	0.77	Data from E-ON
Strontium Oxide (SrO)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	Data from E-ON
Sulfur Trioxide (SO3)	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.47	2.47	Data from E-ON
Titania (TiO2)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.08	1.08	Data from E-ON
Undetermined	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	Data from E-ON
Unit Characteristics																			
Gross Turbine Generator Load, MW	110	180	457	541	517	523	526	168	181	261	330	330	423	525	547	760	75	109	Data from E-ON
Boiler Efficiency, % (HHV)	85.32	86.73	86.53	85.74	86.83	86.31	86.77	85.12	87.14	87.09	85.40	85.40	86.51	86.51	86.88	86.92	89.02	85.25	Data from E-ON
Boiler Heat Input, MBtu/hr (HHV)	999.80	1,665.50	4,120.43	5,369	4,327	5,496	5,473	1,603	1,757	2,589	3,224	3,311	4,209	5,122	5,310	6,583	848	1,150	Data from E-ON
Coal Flow Rate, lb/hr	89,268	148,705	367,895	479,375	386,339	490,714	488,661	143,125	156,875	231,161	287,857	295,625	375,804	457,321	474,107	587,768	73,103	99,138	Data from E-ON
Capacity Factor, %	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	Data from E-ON
Fly Ash Portion of Total Ash, %	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	Data from E-ON
Air Heater Leakage, %	10.0	10.0	10.0	10.0	10.0	10.0	10.0	16.7	17.0	7.8	10.0	10.0	10.0	10.0	10.0	6.0	6.8	6.8	Data from E-ON
Excess Air, %	34.352	18.258	16.848	18.258	21.926	21.926	20.433	20.00	20.00	20.00	20.00	20.00	20.00	20.00	18.258	19.700	25.000	25.000	Data from E-ON
Economizer Outlet Conditions																			
Flue Gas Temperature, F	650	730	730	729	610	731	791	580	630	617	760	760	690	640	700	586	475	610	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-8.0	-3.7	-5.0	-3.2	-5.1	-5.1	-4.5	-4.0	-3.0	-4.0	-5.0	-5.0	-5.0	-5.0	-6.0	-6.0	-5.0	-6.0	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,090,927	1,615,221	3,952,267	5,206,933	4,316,060	5,482,104	5,397,559	1,575,668	1,727,042	2,544,856	3,169,029	3,254,545	4,137,234	5,034,667	5,149,714	6,455,853	886,785	1,202,598	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	509,072	796,739	1,955,176	2,563,081	1,922,533	2,718,161	2,805,958	680,015	779,254	1,137,376	1,608,445	1,651,849	1,979,343	2,303,938	2,490,348	2,816,034	345,095	536,927	B&V Combustion Calculations
Uncontrolled Sulfur Dioxide Concentration, lb/MBtu	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	4.48	4.48	= % Sulfur in Coal x 20,000 / HHV
Uncontrolled Sulfur Dioxide Mass Flow Rate, lb/hr	5,993	9,983	24,697	32,161	25,936	32,942	32,805	9,608	10,531	15,518	19,324	19,846	25,228	30,701	31,828	39,458	3,798	5,150	B&V Combustion Calculations
Uncontrolled PM Concentration, lb/MBtu	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	6.334	6.334	B&V Combustion Calculations
Uncontrolled PM Mass Flow Rate, lb/hr	8,744	14,566	36,037	46,957	37,844	48,068	47,867	14,020	15,367	22,643	28,197	28,958	36,812	44,797	46,441	57,575	5,371	7,284	= Uncontrolled PM (lb/MBtu) x Heat Input (MBtu/hr)
Uncontrolled Mercury Concentration, lb/TBtu	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	8.62	8.62	= Hg in Coal (ppm) x Coal Flow Rate (lb/hr) / Heat Input (MBtu/hr)
Uncontrolled HCl Mass Flow Rate, lb/hr	147	244.63	605.21	789	636	807	804	235	258	380	474	486	618	752	780	967	139	188	= HCl in Coal (ppm) / 1,000,000 x Coal Flow Rate (lb/hr) x MW of HCl / MW of Cl
Uncontrolled HCl Concentration, lb/MBtu	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	= HCl Flowrate (lb/hr) / Heat Input (MBtu/hr)
Hot-Side ESP Outlet Conditions																			
Flue Gas Temperature, F	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	605	708	770	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	600	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.					-10.80	-10.90	-10.8											-8.1	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr					4,531,863	5,756,209	5,667,437											1,262,728	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm					2,041,027	2,843,960	2,947,083											562,236	B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu					0.0565	0.0451	0.0248											0.08	B&V Combustion Calculations
Controlled PM Mass Flow Rate, lb/hr					244	248	135.73											92	= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %					99.35	99.48	99.72											98.74	= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
SCR Outlet Conditions																			
Flue Gas Temperature, F	No SCR	No SCR	New SCR Planned for 2012	729	No SCR	708	770	No SCR	No SCR	No SCR	No SCR	No SCR	690	640	700	586	No SCR	No SCR	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.				-13.2		-20.90	-20.8						-13.0	-13.0	-16.0	-11.0			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr				5,311,071		5,871,333	5,780,786						4,219,979	5,135,360	5,252,708	6,584,970			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm				2,682,371		2,977,658	3,085,629						2,061,162	2,399,175	2,606,716	2,910,365			B&V Combustion Calculations
Controlled NOx Concentration, lb/MBtu				0.0639		0.0479	0.0627						0.0584	0.0589	0.076	0.076			Data from E-ON
Controlled NOx Mass Flow Rate, lb/hr				343		263	343						246	302	404	500			= Controlled NOx (lb/MBtu) x Heat Input (MBtu/hr)
Air Heater Outlet Conditions																			
Flue Gas Temperature, F	350	330	340	361	309	322	309	369	299	318	375	375	330	330	320	324	243	363	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-14.00	-8.00	-18.00	-22.4	-18.60	-36.10	-29.4	-8.0	-6.0	-8.0	-10.0	-10.0	-18.0	-18.0	-22.5	-16.0	-9.0	-13.5	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,200,020	1,776,743	4,347,494	5,842,179	4,985,049	6,458,467	6,358,865	1,839,262	2,021,310	2,744,081	3,485,932	3,580,000	4,641,976	5,648,896	5,777,979	6,980,068	947,426	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,851	589,646	1,498,187	2,091,568	1,657,754	2,288,309	2,175,592	641,787	642,552	896,674	1,229,416	1,262,592	1,581,582	1,924,653	1,965,750	2,345,528	280,496	473,593	B&V Combustion Calculations
Cold-Side ESP Outlet Conditions																			
Flue Gas Temperature, F	340	320	330	358	No Cold-side ESP. Unit has a Hot-side ESP	No Cold-side ESP. Unit has a Hot-side ESP	No Cold-side ESP. Unit has a Hot-side ESP	369	299	318	340	340	330	330	320	324	230	No Cold-side ESP. Unit has a Hot-side ESP	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-18.00	-12.00	-19.00	-25.7				-9.1	-6.8	-9.8	-14.0	-14.0	-23.0	-21.0	-25.5	-18.0	-11.0		B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288				1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797		B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	436,197	618,296	1,559,510	2,209,920				676,568	676,855	947,034	1,250,977	1,284,735	1,684,442	2,039,199	2,082,968	2,502,995	290,916		B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu	0.241	0.1	0.1	0.023				0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.31	0.063		Data from E-ON
Controlled PM Mass Flow Rate, lb/hr	241	166.55	412.04	123				66	60	62	124	147	218	181	90	2041	53		= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %	97.24	98.86	98.86	99.74				99.53	99.61	99.73	99.56	99.49	99.41	99.60	99.81	96.46	99.01		= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
Fabric Filter Outlet Conditions																			
Flue Gas Temperature, F	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	313	No Fabric Filter	No Fabric Filter	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																-23.1			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr																7,398,872			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																2,500,664			B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu																0.015			Data from E-ON
Controlled PM Mass Flow Rate, lb/hr																99			= Controlled PM from fabric Filter (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %																95.16			= { 1- FF Controlled PM (lb/MBtu) / ESP Controlled PM (lb/MBtu) } x 100
ID Fan Outlet Conditions																			
Flue Gas Temperature, F	356.05	332.17	346.44	376.94	325.52	346.34	333.60	379.03	306.39	327.81	354.85	355.15	348.83	348.83	340.08	334.60	235.91	371.55	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	10.00	10.00	10.00	6.10	11.40	5.90	14.60	8.00	7.00	8.00	10.00	10.00	10.00	10.00	10.00	15.77	1.00	1.00	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288	4,985,049	6,458,467	6,358,865	1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,059	594,805	1,481,211	2,086,965	1,571,913	2,119,437	2,010,799	656,526	660,654	917,824	1,200,841	1,233,697	1,588,066	1,932,543	1,954,644	2,334,113	284,775	461,503	B&V Combustion Calculations

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	EW Brown			Ghent				Cane Run			Mill Creek				Trimble County		Green River		Reference
	1	2	3	1	2	3	4	4	5	6	1	2	3	4	1	2	3	4	
Scrubber Outlet Conditions	(For 3 units combined to a common/shared scrubber)																		
Flue Gas Temperature, F	129.64			131.74	128.04	129.28	128.50	131.19	125.96	128.80	130.30	130.32	129.60	129.60	129.24	129.43	No Scrubber	No Scrubber	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	2.00			1.70	1.50	2.00	1.60	2.00	2.00	2.00	1.00	1.00	1.00	1.00	2.00	6.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	8,136,097			6,534,149	5,252,980	6,834,132	6,711,801	2,056,206	2,226,116	3,036,144	3,879,298	3,984,228	5,157,618	6,277,442	6,413,722	7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	2,029,766			1,643,977	1,306,064	1,705,743	1,671,656	517,157	550,120	754,452	972,502	998,878	1,291,025	1,571,359	1,598,535	1,927,087			B&V Combustion Calculations
Controlled Sulfur Dioxide Mass Flow Rate, lb/hr	679			805	865	824	821	659	736	1,750	1,515	1,556	2,441	2,407	441	546			B&V Combustion Calculations
Controlled Sulfur Dioxide Concentration, lb/MBtu	0.10			0.150	0.200	0.150	0.150	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083			= Controlled SO_2 (lb/hr) / Heat Input (MBtu/hr)
Sulfur Dioxide Removal Efficiency, %	98.33			97.50	96.67	97.50	97.50	93.15	93.02	88.73	92.17	92.17	90.33	92.17	98.62	98.62			= { 1- Controlled SO_2 (lb/MBtu) / Uncontrolled SO_2 (lb/MBtu) } x 100
Wet ESP Outlet Conditions																			
Flue Gas Temperature, F	No WESP			No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	129.43	No WESP	No WESP	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																2.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr																7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																1,945,943			B&V Combustion Calculations
Stack Outlet Emissions[1]																			
Sulfur Dioxide Emission Concentration, lb/MBtu	0.10	0.10	0.10	0.15	0.20	0.15	0.15	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083	4.48	4.48	Data from E-ON
Sulfur Dioxide Emission Rate, lb/hr	100	167	412	805	865	824	821	659	736	1,750	1,515	1,556	2,441	2,407	441	546	3,798	5,150	= SO_2 Emission (lb/MBtu) x Heat Input (MBtu/hr)
PM Emission Concentration, lb/MBtu	0.241	0.1	0.1	0.023	0.0565	0.0451	0.0248	0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.015	0.063	0.08	Data from E-ON
PM Emission Rate, lb/hr	241	167	412	123	244	248	136	66	60	62	124	147	218	181	90	99	53	92	= PM Emission (lb/MBtu) x Heat Input (MBtu/hr)
NOx Emission Concentration, lb/MBtu	0.4463	0.4374	0.3319	0.0639	0.276	0.0479	0.0627	0.3394	0.3843	0.272	0.3169	0.3139	0.0584	0.0589	0.076	0.076	0.4011	0.3864	Data from E-ON
NOx Emission Rate, lb/hr	446	728	1,368	343	1,194	263	343	544	675	704	1,022	1,039	246	302	404	500	340	444	= NOx Emission (lb/MBtu) x Heat Input (MBtu/hr)
Hg Emission Concentration, lb/TBtu	5.0	5.0	5.0	2.0	3.5	2.0	2.0	3.5	3.5	3.5	3.0	3.0	2.5	2.5	1.2	1.0	5.5	5.5	Data from E-ON
Hg Emission Rate, lb/hr	5.00E-03	8.33E-03	2.06E-02	1.07E-02	1.51E-02	1.10E-02	1.09E-02	5.61E-03	6.15E-03	9.06E-03	9.67E-03	9.93E-03	1.05E-02	1.28E-02	6.37E-03	6.58E-03	4.66E-03	6.33E-03	= Hg Emission (lb/TBtu) x Heat Input (MBtu/hr) / 1,000,000
HCl Emission Concentration, lb/MBtu	0.002	0.002	0.002	0.0015	0.0017	0.0015	0.0015	0.00095	0.00095	0.00095	0.0015	0.0015	0.0015	0.0015	0.00085	0.00085	0.017	0.017	Data from E-ON
HCl Emission Rate, lb/hr	2	3	8	8	7	8	8	2	2	2	5	5	6	8	5	6	14	20	= HCl Emission (lb/MBtu) x Heat Input (MBtu/hr)
CO Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
CO Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
Dioxin/Furan Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known
Dioxin/Furan Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known

Notes:

1. Current Outlet Emissions as noted in E-ON Matrix

Revision History:

Rev	Date	Description
0	5/21/2010	Initial Issue
1	6/1/2010	Final Issue

Appendix D
Air Quality Control Technology Descriptions

CONTROL TECHNOLOGY DESCRIPTIONS

NO_x Reduction Technologies

Low NO_x Burners (LNB)

The new-generation LNB have better NO_x removal performance than the first-generation LNB and are a fundamental component of the boiler design. The term ultra-low NO_x burners applies only to gas fired applications and does not apply to coal fired boilers.

LNB control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce NO_x by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This minimizes the reaction time at oxygen-rich, high-temperature conditions. Conventional burners, however, typically mix the secondary air with the primary air/fuel stream immediately following injection into the furnace, creating a high intensity combustion process.

Wall mounted LNB are typically a multiple-register (damper) type with two separate secondary airflow paths through the burner and into the furnace. Common features include dedicated total secondary airflow control dampers and separate dedicated dampers or vanes to control the flow and spin of the individual secondary airflows through the burner. The vanes that control spin or flame shape are typically set during initial startup and then locked in place.

Control and balancing of the secondary air, primary air, and coal distribution among the burners is a basic requirement of all manufacturers. Typical allowable flow deviations from the mean are 10 percent for individual burner air and coal flows. This requirement may necessitate changes in operating procedures related to individual burner level turn down at part load. Conversely, additional control provisions and flow monitoring capability is required to preserve the option to operate with unbalanced firing at part load.

The basic NO_x reduction principles for LNB are to control and balance the fuel and air flow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high-temperature zones are not oxygen rich. Figure D-1 shows the low NOx burners

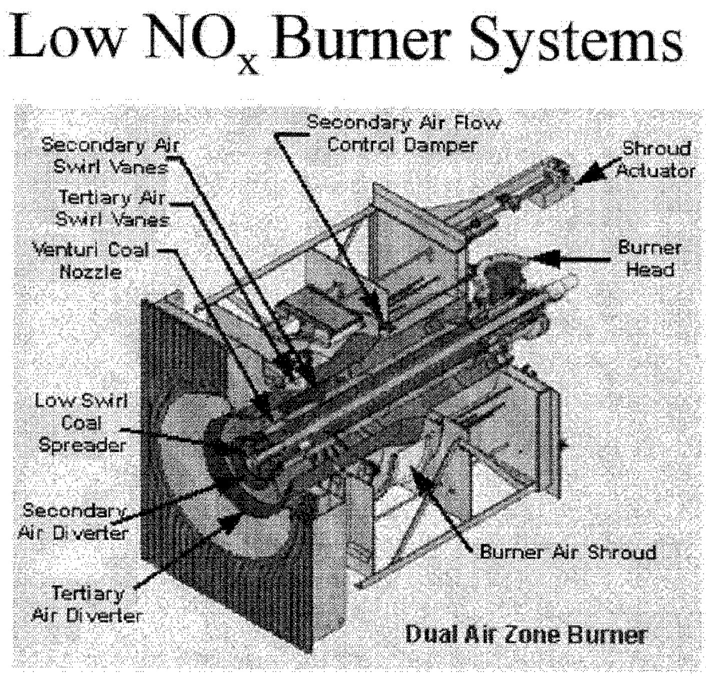

Figure D-1
Low NO_X Burners (Courtesy: DB Riley)

Overfire Air (OFA)

OFA is an air staging NO_x reduction technique that is based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the high temperature zone of the furnace. OFA can be used in conjunction with the LNB system. Unburned carbon and combustible materials may increase as a result of the addition of OFA because of the staging of the combustion process.

With the installation of an OFA system, the main combustion burners are operated at or near stoichiometric ratio to limit available oxygen, flame temperature, and NO_x formation. The remainder of the combustion air is then injected through the OFA ports to complete combustion. The quantity of OFA introduced is sufficient to increase the overall excess air in the boiler to 15 to 20 percent to ensure complete combustion and maintain flue gas flow through the convective sections of the boiler.

OFA systems reduce NO_X formation by creating a fuel rich combustion zone. The OFA is introduced above the main combustion zone (fuel is introduced in an oxygen-starved environment) where fuel burnout can be completed at a lower temperature with fewer volatile nitrogen-bearing combustion products.

The OFA ports will be designed to allow adequate mixing of the combustion air and flue gas and with sufficient temperatures and residence times to ensure complete combustion to achieve optimum NO_x reductions. The location of the OFA ports is critical in achieving optimum NO_x reductions without affecting unburned carbon losses. Figure D-2 shows the overfire air

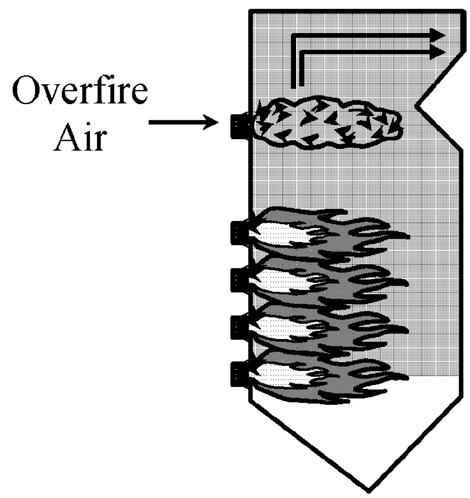

Figure D-2
Overfire Air System

Selective Noncatalytic Reduction System (SNCR)

Selective non-catalytic NO_x reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve NO_x reductions. SNCR systems can use either ammonia (Thermal DeNO_x) or urea (NO_xOUT) as reagents.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside this range. Injection of reagent below this temperature window results in excessive ammonia slip emissions. Injection of reagent above this temperature window results in increased NO_x emissions. A PC boiler operates at temperatures of between 2,500 and 3,000° F. Therefore, the optimum temperature window in a PC boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature range are very limited, further detracting from optimum SNCR performance. Finally, there is no provision for feedforward control of reagent injection, relying only on feedback control. This results in over injection of reagent and high ammonia slip emissions.

SNCR systems are less efficient NO_x reduction systems than SCR systems. In general, SNCR systems on large PC-fired boilers will be capable of only up to 50 percent NO_x reduction. Figure D-3 shows a schematic of SNCR system.

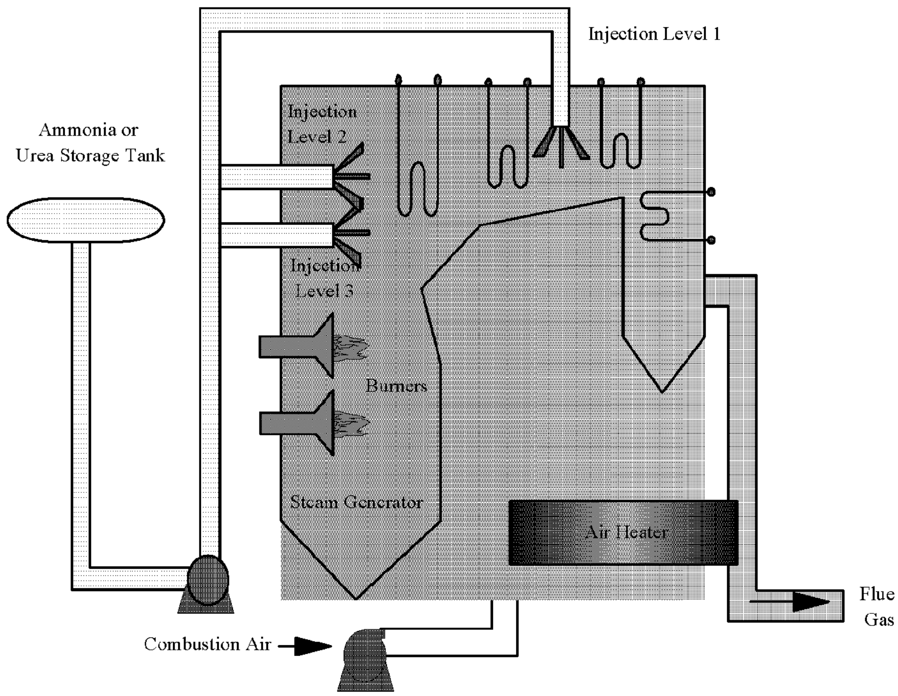

Figure D-3
Schematic of SNCR System with Multiple Injection Levels

Selective Catalytic Reduction System (SCR)

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_x into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_x-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_x levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_x available for removal. Essentially, as NO_x is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature is costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure D-4 shows a schematic diagram of SCR.

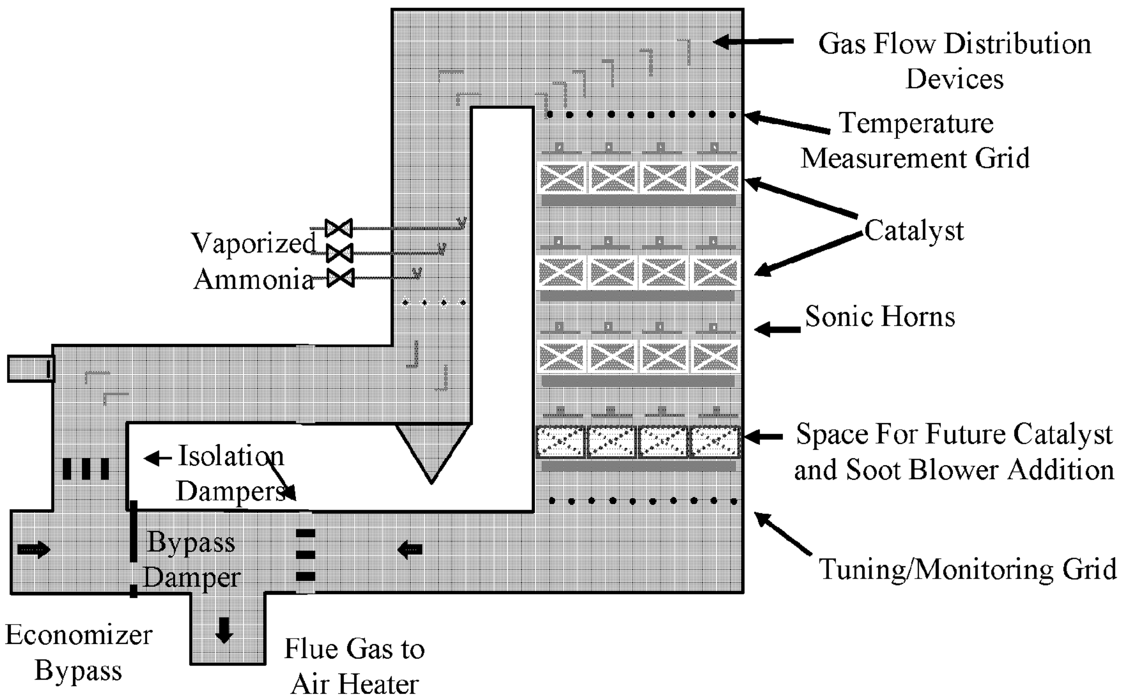

Figure D-4
Schematic Diagram of a Typical SCR Reactor

SNCR/SCR Hybrid System

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and potential for high NH_3 slip associated with SNCR systems with the high reduction potential and low NH_3 slip inherent with catalyst based SCR systems. The result is an NO_x reduction alternative that can meet initial NO_x reduction requirements but can be upgraded to meet higher reductions at a future date, if required. Typically, installation of an SCR system with a single layer of in-duct catalyst is capable of reducing NO_x emissions from 40 to 70 percent, depending on the amount of NH_3 slip from the SCR and the volume of the single layer of catalyst.

The SNCR component of the hybrid system is identical to the SNCR system, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would inject higher amounts of reagent into the flue gas. This increased reagent flow has a two-fold effect: NO_x reduction within the boiler is increased while NH_3 slip is also increased. The NH_3 that slips from the SNCR is then used as the reagent for the single layer of catalyst.

There are two design philosophies for using this excess NH_3 slip. The most conservative hybrid systems will use the catalyst simply as an NH_3 slip "scrubber" with some additional NO_x reduction. Similar to in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. While some NO_x reduction is achieved at the catalyst, the relatively small catalyst requirement of this design has the potential to fit all the catalyst in a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural adaptations.

The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of NH_3 slip, the catalyst volume, and the distribution of NH_3 to NO_x within the flue gas. Using NH_3 slip that is produced by the SNCR system is not a high efficiency method of introducing reagent, due to the low reagent utilization. Therefore, even though the reaction at the catalyst requires 1 ppm of NH_3 to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of NH_3 to generate 1 ppm of NH_3 at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the NH_3 distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the typical ductwork. If widening the ductwork cannot provide for adequate catalyst volume, then a separate reactor is required, which quickly negates the capital cost advantage of a hybrid system. Figure D-5 represents a schematic diagram of a typical SNCR/SCR Hybrid system.

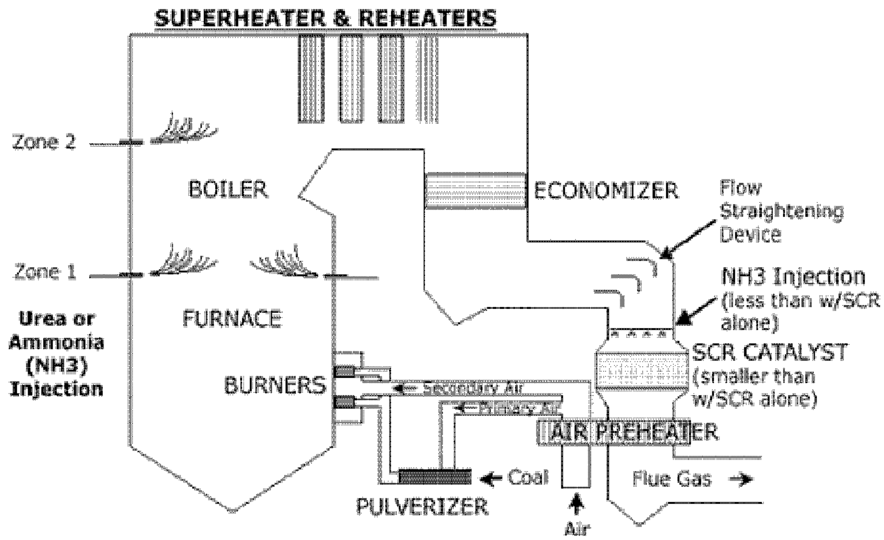

Figure D-5
Schematic Diagram of a Typical SNCR/SCR Hybrid System (Courtesy: Clean Environmental Protection Engineering Co. Ltd.)

SO_2 and HCl Reduction Technologies

Wet Flue Gas Desulfurization (FGD) System

Wet limestone-based FGD processes are frequently applied to pulverized coal fired boilers that burns medium-to-high sulfur eastern coals. All of the FGD systems installed in response to Phase I of the 1990 CAA were based on a wet FGD system using either lime or limestone as the reagent. Typically, the wet FGD processes on a pulverized coal facility are characterized by high efficiency (> 98 percent) and high reagent utilization (95 to 97 percent) when combined with a high sulfur fuel. The ability to realize high removal efficiencies on higher sulfur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes. It is well known that SO_2 removal efficiencies for wet FGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove SO_2 are faster if the inlet SO_2 concentration is higher. The absolute emissions level becomes a limiting factor due to a reduction in the chemical driving forces of the reactions that are occurring. Thus, the calculated removal efficiency of the various types of wet scrubbers declines as the fuel sulfur content decreases; this is the case for low sulfur western and PRB coals.

In a wet FGD system, the absorber module is located downstream of the induced draft (ID) fans (or booster ID fans, if required). Flue gas enters the module and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3 \bullet 1/2H_2O$ and $CaSO_4 \bullet 2H_2O$. SO_2 reacts with limestone reagent through the following overall reactions:

$$SO_2 + CaCO_3 + \frac{1}{2}H_2O \rightarrow CaSO_3 \bullet \frac{1}{2}H_2O + CO_2$$
$$SO_2 + CaCO_3 + 2H_2O + \frac{1}{2}O_2 \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

The flue gas leaving the absorber will be saturated with water, and the stack will have a visible moisture plume. Because of the chlorides present in the mist carry-over from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and the flue stack. Careful design of the stack is needed to prevent the "rainout" from condensation that occurs in the downstream ductwork and stack. These factors contribute to the relatively high capital costs of the wet FGD SO_2 control alternative.

The reaction products are typically dewatered by a combination of hydrocyclones and vacuum filters. The resulting filter cake is suitable for landfill disposal. In early lime- and limestone-based FGD processes, the byproduct solids were primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$), and the byproduct solids were mixed with fly ash (stabilization) or fly ash and lime (fixation) to produce a physically stable material. In the current generation of wet FGD systems, air is bubbled through the reaction tank (or in some cases, a separate vessel) to practically convert all of the $CaSO_3 \bullet 1/2H_2O$ into calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$), which is commonly known as gypsum. This step is termed "forced oxidation" and has been applied to both lime- and limestone-based FGD processes. Compared to calcium sulfite hemihydrate, gypsum has much superior dewatering and physical properties, and forced oxidized FGD systems tend to have few internal scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many FGD systems in the United States are using the forced-oxidation process to produce a commercial grade of gypsum that can be used in the production of portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinyl ester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The byproduct dewatering equipment is also relatively complex and expensive. These factors result in relatively higher initial capital costs. Wet FGD processes are also characterized by higher raw water usage than semi-dry FGD systems. This can be a significant disadvantage or even a fatal flaw in areas where raw water availability is in short supply.

A countercurrent spray tower has become one of the most widely used absorber types in wet limestone-based FGD service. Flue gas enters at the bottom of the absorber and flows upward. Slurry with 10 to 15 percent solids is sprayed downward from higher elevations in the absorber and is collected in a reaction tank at its base. The SO_2 in the flue gas is transferred from the flue gas to the recycle slurry. The hot flue gas is also cooled and saturated with water. Recycled slurry is pumped continuously from the reaction tank to the slurry spray headers. Each header has numerous individual spray nozzles that break the slurry flow into small droplets and distribute them evenly across the cross section of the absorber. Prior to leaving the absorber, the treated flue gas passes through a two-stage, chevron-type mist eliminator that removes entrained slurry droplets from the gas. The mist eliminator is periodically washed to keep it free of solids.

In the reaction tank, the SO_2 absorbed from the flue gas reacts with soluble calcium ions in the recycle slurry to form insoluble calcium sulfite and calcium sulfate solids. In forced-oxidization processes, air is bubbled through the slurry to convert all of the solids to calcium sulfate dihydrate (gypsum). A lime or limestone reagent slurry is added to the reaction tank to replace the calcium consumed.

To control the solids content of the recycle slurry, a portion of the slurry is discharged from the reaction tank to the byproduct dewatering equipment. Depending on the ultimate disposal of the byproduct solids, the dewatering equipment may include settling ponds, thickeners, hydrocyclones, vacuum filters, and centrifuges. The liquid that is separated from the byproduct solids slurry is stored in the reclaim water tank. Water in the reclaim water tank is returned to the absorber reaction tank as makeup water and used to prepare the reagent slurry.

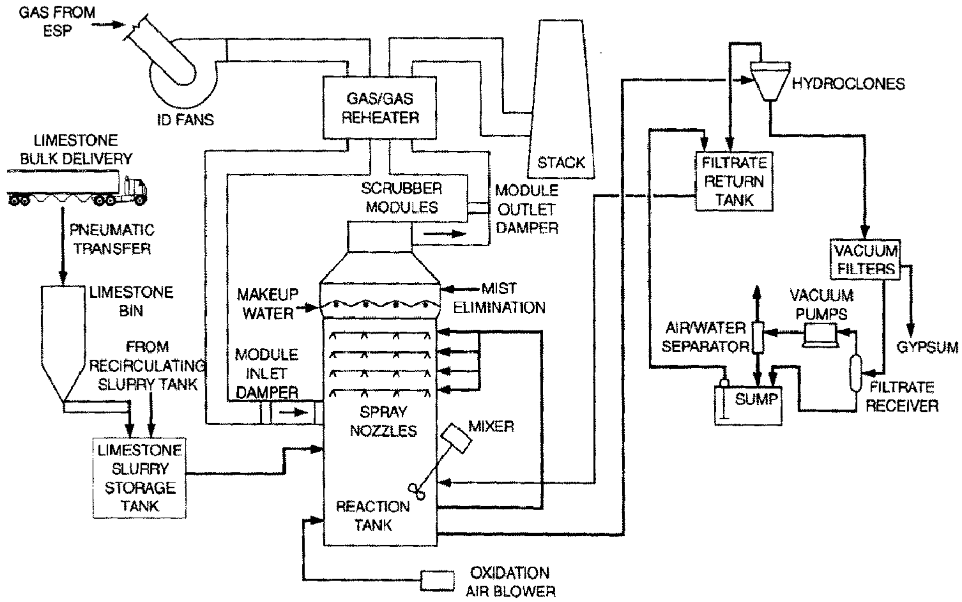

Figure D-6
Process Flow Diagram of FGD Process

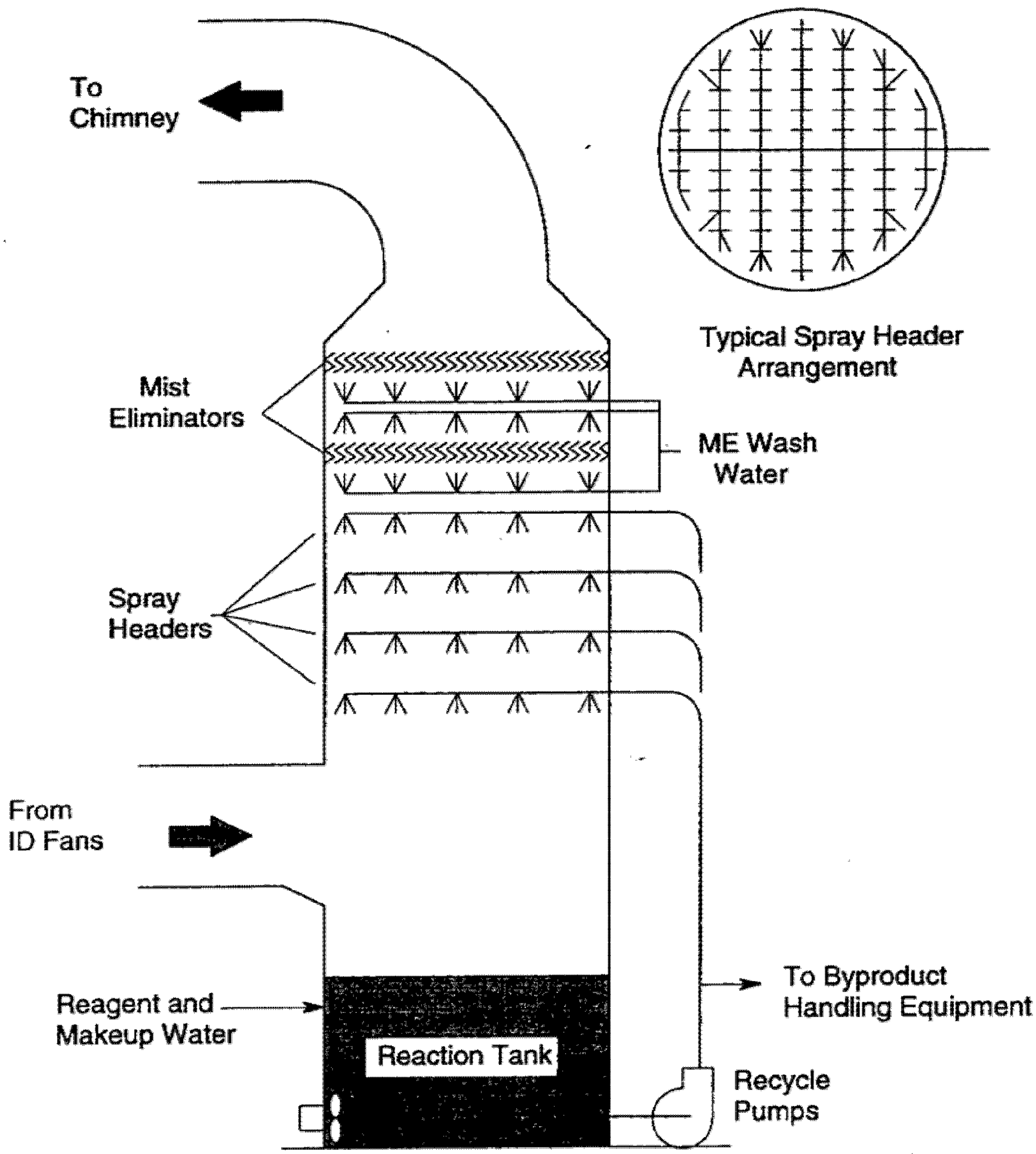

Figure D-7
Countercurrent Spray Tower FGD Process

Spray Dryer Absorber

Spray dryer absorber (SDA) FGD processes have been extensively used. US utilities have installed numerous SDA FGD systems on boilers using low sulfur fuels.

These installations, primarily located in the western United States, use either lignite or subbituminous coals such as PRB as the boiler fuel and generally have spray dryer systems designed for a maximum fuel sulfur content of less than 2 percent. The SDA lime-based FGD system has an inherent removal efficiency limitation of 94 percent from inlet concentration.

The SDA FGD process uses calcium hydroxide [$Ca(OH)_2$] produced from the lime reagent as either a slurry or as a dry powder to the flue gas in a reactor designed to provide good gas-reagent contact. The SO_2 in the flue gas reacts with the calcium in the reagent to produce primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$) and a smaller amount of calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$) through the following reactions:

$$SO_2 + Ca(OH)_2 \rightarrow CaSO_3 \bullet \tfrac{1}{2}H_2O + \tfrac{1}{2}H_2O$$
$$SO_2 + Ca(OH)_2 + \tfrac{1}{2}O_2 \rightarrow CaSO_4 \bullet 2H_2O$$

Water is also added to the reactor (either as part of the reagent slurry or as a separate stream) to cool and humidify the flue gas, which promotes the reaction and reagent utilization. The amount of water added is typically sufficient to cool the flue gas to within 30° to 40° F of the flue gas adiabatic saturation temperature. Significantly less water is used in these SDA FGD processes compared to wet FGD processes.

The reaction byproducts and excess reagent are dried by the flue gas and removed from the flue gas by a particulate control device (either fabric filter or DESP). Fabric filters are preferred for most systems, because the additional contact of the flue gas with the particulate on the filter bags provides additional SO_2 removal and higher reagent utilization. A portion of the reaction byproducts collected is recycled to the reagent preparation system in order to increase the utilization of the lime.

Because of the large amount of excess lime present in the FGD byproducts, the byproducts (and fly ash, if present) will experience pozzolanic (cementitious) reactions when wetted. When wetted and compacted, the byproduct makes a fill material with low permeability (low lengthening characteristics) and high bearing strength. However, other than as structural fill, this byproduct has limited commercial value and typically must be disposed of as a waste material.

The SDA FGD processes offer benefits in addition to SO_2 removal, including the lack of a visible vapor plume and SO_3 removal. Because the SDA FGD systems do not saturate the flue gas with water, there is no visible plume from the stack under most weather conditions. Environmental concerns with SO_3 emissions are also reduced with the SDA scrubber. SO_3 is formed during combustion and will react with the moisture in the flue gas to form sulfuric acid (H_2SO_4) mist in the atmosphere. An increase in H_2SO_4

emissions will increase PM_{10} emissions. The gas temperature leaving the reactor is lowered below the sulfuric acid dew point, and significant SO_3 removal will be attained as the condensed acid reacts with the alkaline reagent. By removing SO_3 in the flue gas, the condensable particulate matter emissions can be reduced. This will reduce the potential for any SO_3 plume that may cause opacity in stacks. Similar type of SO_3 removal is not achievable with a wet scrubber.

All current SDA designs use a vertical gas flow absorber. These absorbers are designed for co-current or a combination of co-current and countercurrent gas flow. In co-current applications, gas enters the cylindrical vessel near the top of the absorber and flows downward and outward. In combination-flow absorbers, a gas disperser located near the middle of the absorber directs a fraction of the total flue gas flow upward toward the slurry atomizers.

In both cases, the atomizers are located in the roof of the absorber. Both rotary and two-fluid nozzles have been applied to this approach. The atomizer produces an umbrella of atomized reagent slurry through which the flue gas passes. The SO_2 in the flue gas is absorbed into the atomized droplets and reacts with the calcium to form calcium sulfite and calcium sulfate. Before the slurry droplet can reach the absorber wall, the water in the droplet evaporates and a dry particulate is formed.

Some vendors base their designs on a single large rotary atomizer per absorber; others use up to three smaller rotary atomizers per absorber. Two-fluid atomizers are installed as an array of up to 16 nozzles per atomizer; all three approaches to spray atomizers have been successfully applied.

The flue gas, then containing fly ash and FGD byproduct solids, leaves the absorber and is directed to a fabric filter. The fly ash and byproduct solids collected in the fabric filter are pneumatically transferred to a silo for disposal. To improve both reagent utilization and spray solids drying efficiency, a large portion of the solids collected is directed to a recycle system, where it is slurried and re-injected into the spray dryer along with the fresh lime reagent.

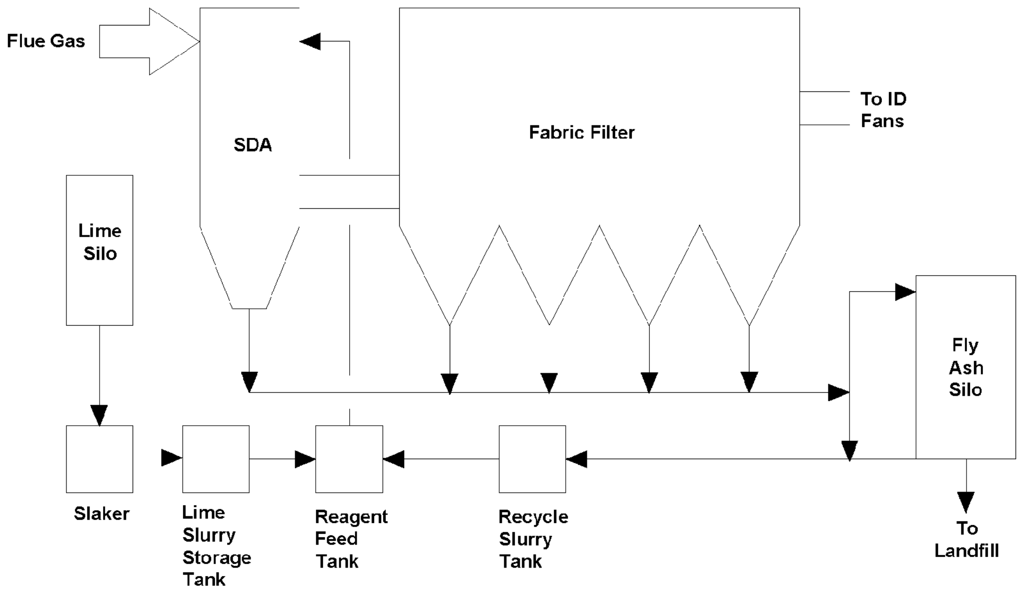

Figure D-8
SDA FGD Process

Circulating Dry Scrubber (CDS)

The CDS FGD process is a semi-dry, lime-based FGD process that uses a circulating fluid bed contactor rather than an SDA. The CDS absorber module is a vertical solid/gas reactor between the unit's air heater and its particulate control device. Water is sprayed into the reactor to reduce the flue gas temperature to the optimum temperature for reaction of SO_2 with the reagent. Hydrated lime [$Ca(OH)_2$] and recirculated dry solids from the particulate control device are injected cocurrently with the flue gas into the base of the reactor just above the water sprays. The gas velocity in the reactor is reduced and a suspended bed of reagent and fly ash is developed. The SO_2 in the flue gas reacts with the reagent to form predominately calcium sulfite. Fine particles of byproduct solids, excess reagent, and fly ash are carried out of the reactor and removed by the particulate removal device (either a fabric filter or electrostatic precipitator [ESP]). Over 90 percent of these solids are returned to the reactor to improve reagent utilization and increase the surface area for SO_2/reagent contact.

The CDS FGD system produces an extremely high solids load on the particulate removal device due to the recycling of the byproduct/fly ash mixture. For this reason, some CDS FGD system vendors prefer to use an ESP rather than a fabric filter. Most of the recycled material can be collected in the first field of an ESP with minimal effect on the overall ESP sizing. On the other hand, a fabric filter in this same service would require special design features to avoid reduced bag life associated with frequent bag cleaning. Figure D-9 provides an illustration of the CDS FGD system.

The CDS can be considered an acceptable FGD removal technology in some applications because of its ability to remove significant amounts of SO_2, the commercial status of the technology, and the use of conventional reagents. It has disadvantages relating to the downstream particulate load imposed on collectors but its implementation schedule and minimal impact on local communities adds to its acceptability.

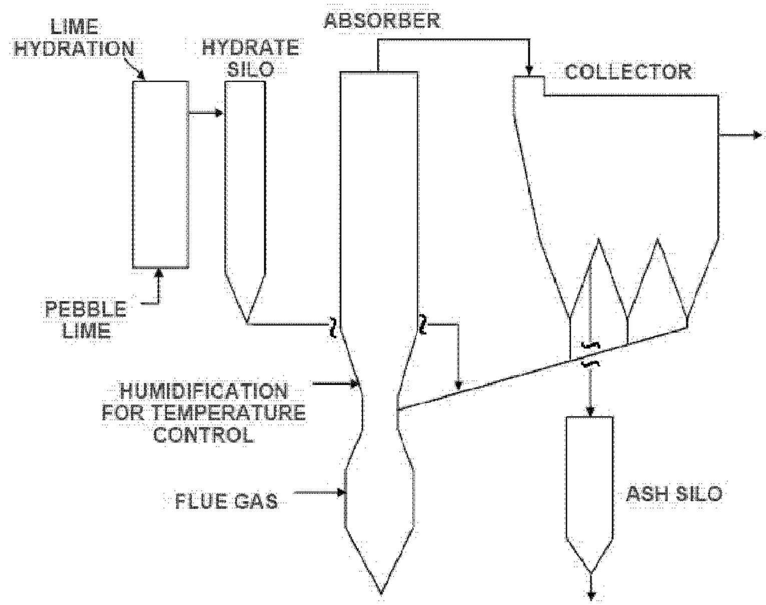

Figure D-9
Circulating Dry Scrubber System (Courtesy: Lurgi Lentjes North America)

Particulate Matter (PM) Reduction Technologies

Dry Electrostatic Precipitator (ESP)

ESPs are the most widely installed utility particulate matter (PM) removal technology. ESPs use transformer/rectifiers (TRs) to energize "discharge electrodes" and to produce a high voltage, direct current electrical field between the discharge electrodes and the grounded collecting plates. PM entering the electrical field acquires a negative charge and migrates to the grounded collecting plates. This migration can be expressed in engineering terms as an empirically determined effective migration velocity, but takes place in a turbulent flow regime with the particulate entrained within the turbulent gas patterns. Thus, the charged particles are actually captured when the combined effect of electrical attraction and gas flow patterns moves the PM close enough for it to attach to the collecting surfaces. A layer of collected particles forms on the collecting plates and is removed periodically by mechanically impacting or "rapping" the plates. The collected particulate matter drops into hoppers below the precipitator and is removed by the ash handling system. Some particulate is also re-entrained and either collected in subsequent electrical fields or emitted from the ESP. A graphic showing the sections of an ESP is shown on Figure D-10.

The required particulate removal efficiency, the expected electrical resistivity of the fly ash to be collected, and the expected electrical characteristics of the energization system determine the physical size of an ESP. Many parameters determine the ESP's capability for particulate collection including the following major items:

- The first parameter is the Specific Collection Area (SCA). ESP size is often measured in terms of SCA. SCA is defined as the total collecting area in square feet (ft^2) divided by the volumetric flue gas flow rate (1,000's of actual cubic feet per minute [acfm]).
- The treatment time of the flue gas within the electric collection fields of the ESP is an important aspect of particulate collection. High efficiency ESPs typically have treatment times between 7 and 20 seconds. Treatment time is becoming a major design parameter as lower particulate emissions are being mandated.
- Flue gas velocity, which is the speed at which the flue gas moves through the ESP, is important in the design and sizing of an ESP. Design gas velocities that range between 3 to 4 fps are common. The aspect ratio of the treatment length to the collection plate height is also important in the design and sizing of the ESP. As the aspect ratio increases, the re-entrainment losses from the ESP are minimized. Many existing ESPs have aspect ratios of approximately 0.8 to 1.2; newer ESPs, especially those meeting new particulate emission limits, have aspect ratios of approximately 1.2 to 2.0.
- The gas distribution for optimum particulate removal requires a uniform gas velocity throughout the entire ESP treatment volume, with minimal gas bypass around the discharge electrodes or collecting plates. If flue gas distribution is uneven, the particulate removal efficiency will decrease, and re-entrainment losses will increase in high velocity areas and reduce overall collection efficiency.
- Fly ash resistivity is a measure of how easily the ash or particulate acquires an electric charge. Typical coal fly ash resistivity values range from 1×10^8 ohm-cm to 1×10^{14} ohm-cm. The ideal resistivity range for electrostatic precipitation of fly ash is 5×10^9 to 5×10^{10} ohm-cm. Operating resistivity varies with flue gas moisture, SO_3 concentration, temperature, and ash chemical composition. As a result of fly ash resistivity being sensitive to these constituents, ESPs can be affected greatly by changes in fuel or operating conditions.

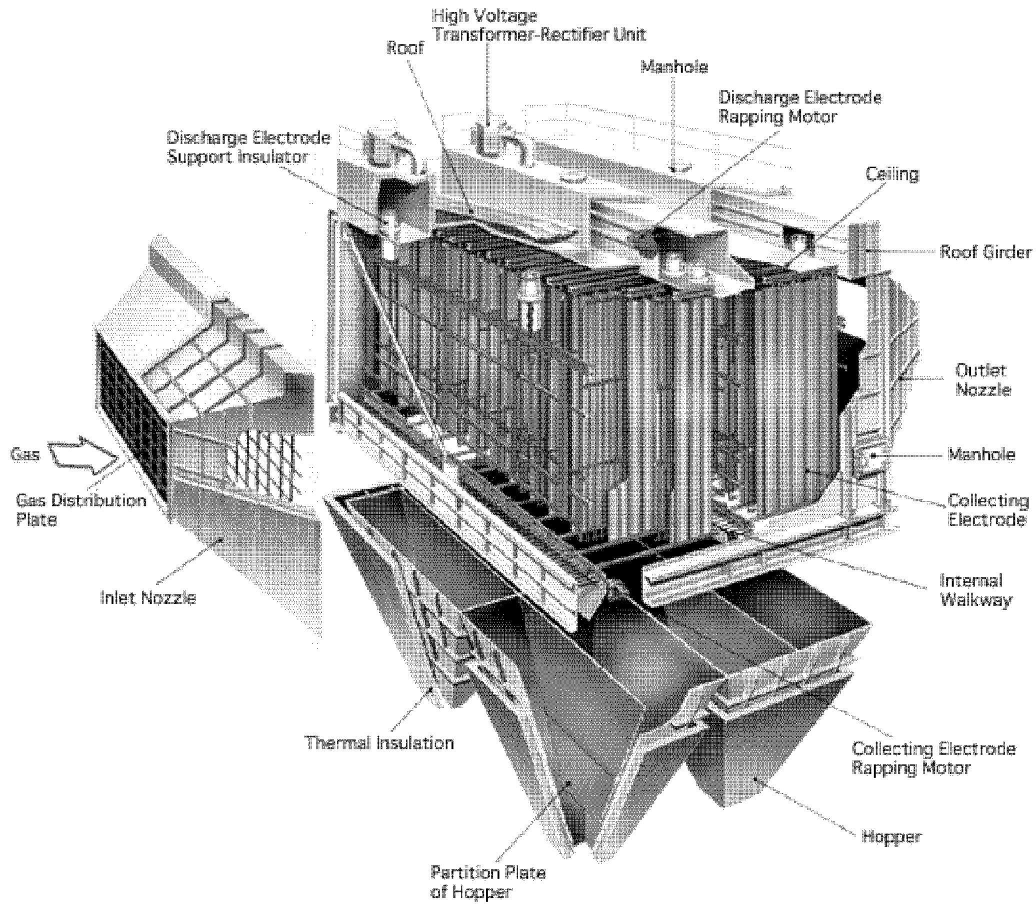

Figure D-10
Electrostatic Precipitator System (MHI)

Pulse Jet Fabric Filter (PJFF)

Fabric filters have been used for over 20 years on existing and new coal fired boilers and are media filters through which flue gas passes to remove the particulate. The success of FFs is predominately due to their ability to economically meet the low particulate emission limits for a wide range of particulate operations and fuel characteristics. Proper application of the FF technology can result in clear stacks (generally less than 5 percent opacity) for a full range of operations. In addition, the FF is relatively insensitive to ash loadings and various ash types, offering superb coal flexibility.

FFs are the current technology of choice when low outlet particulate emissions or Hg reduction is required for coal fired applications. FFs collect particle sizes ranging from submicron to 100 microns in diameter at high removal efficiencies. Provisions can be made for future addition of activated carbon injection to enhance gas phase elemental

Hg removal from coal fired plants. Some types of fly ash filter cakes will also absorb some elemental Hg.

FFs are generally categorized by type of cleaning. The two predominant cleaning methods for utility applications are reverse gas and pulsejet. Initially, utility experience in the United States was almost exclusively with Reverse Gas Fabric Filters (RGFF). Although they are a very reliable and effective emissions control technology, RGFFs have a relatively large footprint, which is particularly difficult for implementations. PJFFs can be operated at higher flue gas velocities and, as a result, have a smaller footprint. The PJFF usually has a lower capital cost than a RGFF and matches the performance and reliability of a RGFF. As a result, only PJFFs will be considered further.

Cloth filter media is typically sewn into cylindrical tubes called bags. Each FF may contain thousands of these filter bags. The filter unit is typically divided into compartments that allow on-line maintenance or bag replacement after a compartment is isolated. The number of compartments is determined by maximum economic compartment size, total gas volume rate, air-to-cloth ratio, and cleaning system design. Extra compartments for maintenance or off-line cleaning not only increase cost, but also increase reliability. Each compartment includes at least one hopper for temporary storage of the collected fly ash. A cutaway view of a PJFF compartment is illustrated on Figure D-11.

Fabric bags vary in composition, length, and cross section (diameter or shape). Bag selection characteristics vary with cleaning technology, emissions limits, flue gas and ash characteristics, desired bag life, capital cost, air-to-cloth ratio, and pressure differential. Fabric bags are typically guaranteed for 3 years but frequently last 5 years or more.

In PJFFs, the flue gas typically enters the compartment hopper and passes from the outside of the bag to the inside, depositing particulate on the outside of the bag. To prevent the collapse of the bag, a metal cage is installed on the inside of the bag. The flue gas passes up through the center of the bag into the outlet plenum. The bags and cages are suspended from a tubesheet.

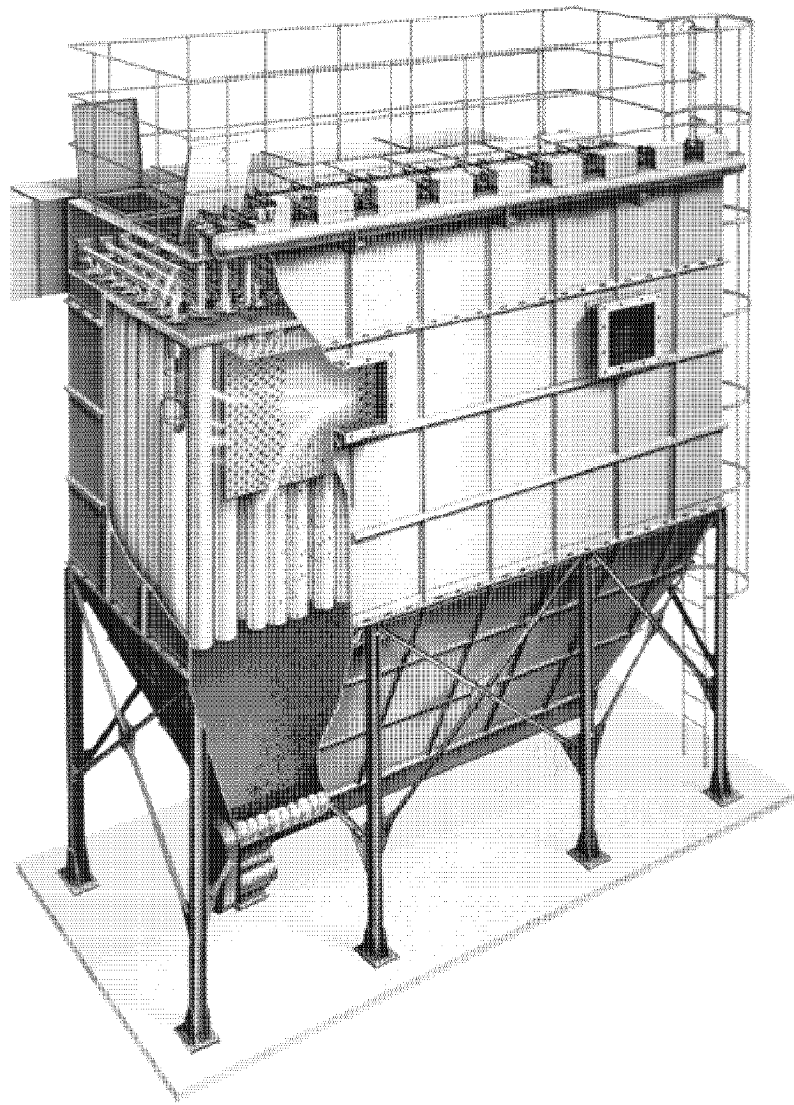

Figure D-11
Pulse Jet Fabric Filter Compartment

Cleaning is performed by initiating a downward pulse of air into the top of the bag. The pulse causes a ripple effect along the length of the bag. This dislodges the dust cake from the bag surface, and the dust falls into the hopper. This cleaning may occur with the compartment on line or off-line. Care must be taken during design to ensure that the upward velocity between bags is minimized so that particulate is not re-entrained during the cleaning process.

The PJFF cleans bags in sequential, usually staggered, rows. During on-line cleaning, part of the dust cake from the row that is being cleaned may be captured by the adjacent rows. Despite this apparent shortcoming, PJFFs have successfully implemented on-line cleaning on many large units.

The PJFF bags are typically made of felted materials that do not rely as heavily on the dust cake's filtering capability as woven fiberglass bags do. This allows the PJFF bags to be cleaned more vigorously. The felted materials also allow the PJFF to operate at a much higher cloth velocity, which significantly reduces the size of the unit and the space required for installation.

Compact Hybrid Particulate Collector (COHPAC™)

Another control technology that is effective in removing particulate matter is a high air-to-cloth ratio fabric filter installed after an existing cold-side ESP. Commonly referred to as a Compact Hybrid Particulate Collector (COHPAC™), this technology was developed and trademarked by the Electric Power Research Institute (EPRI). The COHPAC™ filter typically operates at air-to-cloth ratios ranging from 6 to 8 ft/min. compared to a conventional fabric filter that typically operate at air-to-cloth ratios of about 4 ft/min. For a COHPAC™ system, the majority of the particulate is collected in the upstream ESP. Therefore, the performance requirements of a high air-to-cloth ratio fabric filter is reduced allowing installation of this technology in a smaller footprint area, with less steel and filtration media to substantially lower both capital and operating costs compared to conventional fabric filters.

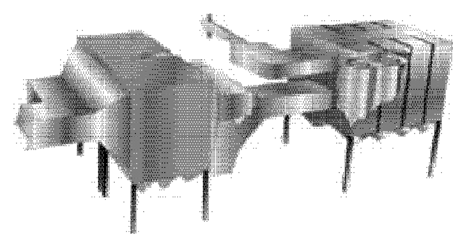

Figure D-12
COHPAC ™ I Arrangement (Courtesy: Hamon Research-Cottrell)

Mercury and Dioxin/Furan Reduction Technologies

Powdered Activated Carbon (PAC) Injection

With reported Hg removals of more than 90 percent for bituminous coal applications, PAC injection is an effective and mature technology in the control of Hg in Municipal Solid Waste (MSW) and Medical Waste Combustors (MWC). Its potential effectiveness on a wide range of coal fired power plant applications is gaining acceptance based on recent pilot and slipstream testing activities sponsored by the Department of

Energy (DOE), Environmental Protection Agency (EPA), Electric Power Research Institute (EPRI), and various research organizations and power generators. However, recent pilot scale test results indicate that the level of Hg control achieved with a PAC injection system is impacted by variables such as the type of fuel, the speciation of Hg in the fuel, operating temperature, fly ash properties, flue gas chloride content, and the mechanical collection device used in the removal of Hg.

PAC injection typically involves the use of a lignite based carbon compound that is injected into the flue gas upstream of a particulate control device as illustrated on Figure D-13. Elemental and oxidized forms of Hg are adsorbed into the carbon and are collected with the fly ash in the particulate control device.

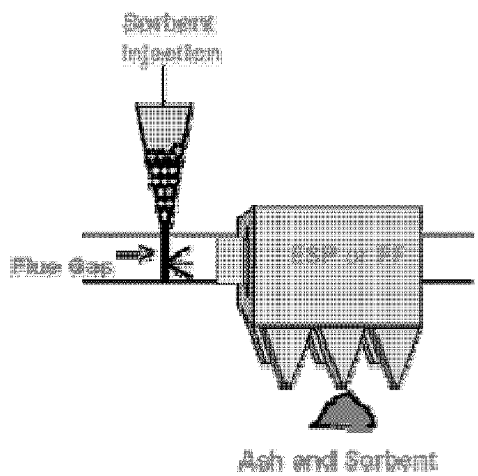

Figure D-13
Activated Carbon Injection System

PAC injection is generally added upstream of either PJFFs or ESPs. For ESPs, the Hg species in the flue gas are removed as they pass through a dust cake of unreacted carbon products on the surface of the collecting plates. Additionally, a significantly higher carbon injection rate is required for PAC injection upstream of a ESP than is required for PAC injection upstream of a high air-to-cloth ratio PJFF or a PJFF that is located downstream of a SDA FGD system. Literature indicates that PAC injection upstream of a cold ESP can reduce Hg emissions up to 60 percent for units that burn a sub-bituminous or lignite coal, and up to 80 percent for units that burn a bituminous coal. The addition of activated carbon does not directly affect the function of the ash handling system. The additional activated carbon in the fly ash does, however, affect the quality of the ash that is produced. For units that currently sell fly ash, this will negatively impact their continued ability to sell the ash.

Since the sale of fly ash depends on the carbon content of the ash, increasing the amount of carbon in the ash also makes it unsuitable for sale. To maintain the ash quality required for sale, the ash must either be removed upstream of the PAC injection system or the activated carbon should be injected into the flue gas so that it is not mixed with all the collected fly ash or is mixed with only a small portion of the total fly ash that is collected in the particulate control device. This can be accomplished by using a high air-to-cloth ratio PJFF downstream of cold ESP.

Numerous testing efforts and studies have shown that most of the Hg resulting from the combustion of coal leaves the boiler in the form of elemental Hg, and that the level of chlorine in the coal has a major impact on the efficiency of Hg removal with PAC injection and the particulate removal system. Low chlorine coals, such as sub-bituminous and lignite coals, typically demonstrate relatively low Hg removal efficiency. Sub-bituminous and lignite coals produce very low levels (approximately 100 parts per million [ppm]) of HCl during combustion and; therefore, normal PAC injection would be anticipated to achieve very low elemental Hg removal.

The removal efficiency that is attained by halogenated PAC injection can be significantly increased by the use of PAC that has been pretreated with halogens, such as iodine or bromine. Recent testing results indicate that halogenated PAC injection upstream of a cold ESP can reduce Hg emissions up to 80 percent for units that burn a sub-bituminous or lignite coal and up to 90 percent for units that burn a bituminous coal. Pretreated PAC is more expensive than untreated PAC: (approximately $5.00/lb of iodine, $1.00/lb of bromine, and $0.50/lb of PAC). However, less pretreated PAC is required to achieve significant removals, if such removal rates are dictated by more stringent Hg control regulations.

PAC can also be injected upstream of a PJFF located downstream of a semi-dry lime FGD. When a semi-dry lime FGD and a PJFF is injected with PAC upstream of the FGD, the activated carbon absorbs most of the oxidized Hg. This is a result of the additional residence time in the FGD and will basically allow greater contact between the Hg particles and the activated carbon. Because of the accumulated solids cake on the bags, the activated carbon is given another opportunity to interact with the Hg prior to disposal or recycle. Since the ash and reagent collected in the PJFF are already contaminated, the additional carbon collected in the PJFF will not affect ash sales or disposal. Recent literature indicates that PAC injection upstream of a semi-dry FGD and PJFF can reduce Hg emissions by 60 to 80 percent.

Halogenated PAC injection upstream of a semi-dry lime FGD and PJFF is basically similar in design to standard PAC, as described previously. Halogenated PAC includes halogens such as bromine or iodine. Literature indicates that halogenated sorbents require significantly lower injection rates (in some cases the difference is as much as a factor of 3) upstream of a semi-dry lime FGD and PJFF combination, as compared to an ESP, and can reduce Hg emissions of up to 95 percent.

CO Reduction Technologies

Good Combustion Controls

As products of incomplete combustion, CO and VOC emissions are very effectively controlled by ensuring the complete and efficient combustion of the fuel in the boiler (i.e., good combustion controls). Typically, measures taken to minimize the formation of NO_x during combustion inhibit complete combustion, which increases the emissions of CO and VOC. High combustion temperatures, adequate excess air, and good air/fuel mixing during combustion minimize CO and VOC emissions. These parameters also increase NO_x generation, in accordance with the conflicting goals of optimum combustion to limit CO and VOC, but lower combustion temperatures to limit NO_x. The products of incomplete combustion are substantially different and often less pronounced when the unit is firing high sulfur bituminous coals, which is the rationale for the slightly higher BACT emissions limits found on units permitted to burn low sulfur PRB subbituminous coals. In addition, depending on the manufacturer, good combustion controls vary in terms of meeting CO emissions limits.

Neural Networks

Neural networks utilize a DCS based computer system that obtains plant data such as load, firing rate, burner position, air flow, CO emissions, etc. The computer system analyzes the impact of various combustion parameters on CO emissions. The system then provides feedback to the control system to improve operation for lower CO emissions. With this combustion system performance monitoring equipment in place, it is expected that sufficient information would be available to maintain the performance of each burner at optimum conditions to enable operations personnel to maintain the most economical balance of peak fuel efficiency and emissions of NOx, and CO. In addition to burner performance these monitoring systems also allow continuous indication of pulverizer, classifier and fuel delivery system performance to provide early indication of impending component failures or maintenance requirements. This system is also used to improve heat rate and often provides operational cost savings along with CO control. It is commercially proven and has demonstrated CO reductions. 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.

Appendix E
Approved Air Quality Control Technology Options

E.W. Brown

Comments on Brown AQC study by Black and Veatch
Brad Pabian

B&V recommended either a SNCR or SCR on Brown units 1 and 2 in their initial assessment of Brown station. This was due to their assertion that NOx limits would be imposed on a unit by unit basis. If this is the case, then their recommendations are valid. If, however, the NOx limits are imposed on a plant wide basis, then there may be a cheaper alternative. Brown 3 will be fitted with an SCR capable of 0.07 lbs/MMBTU NOx output. If Brown 2 was fitted with a similar SCR, Brown 1 may be able to come into compliance simply with better low NOx burners and over fired air. The rough calculations below show how this may be possible. These are not detailed and accurate numbers, only rough approximations.

Current Unit 3 Full Load Heat Input: ~4700 MMBTU/hr
Current Unit 2 Full Load Heat Input: ~1730 MMBTU/hr
Current Unit 1 Full Load Heat Input: ~1070 MMBTU/hr
Total Plant Full Load Heat Input: ~7500 MMBTU/hr
Maximum Plant Full Load NOx Emissions (at 0.11 lb/MMBTU): 825 lb/hr
Maximum Unit 3 NOx Emissions with 0.07 lb/MMBTU SCR in service: 329 lb/hr
Maximum Unit 2 NOx Emissions with 0.07 lb/MMBTU SCR in service: 121 lb/hr

Maximum allowable Unit 1 NOx Emissions with Unit 2 and 3 SCR in service: 375 lb/hr
Maximum allowable Unit 1 NOx Emission rate: 0.35 lb/MMBTU

Unit 1 currently runs between 0.4 and 0.5 lb/MMBTU, which is the reason that it seemed possible to attain 0.35 lb/MMBTU with less costly means. In addition, when capacity factor is considered, the allowable NOx emission rate on Unit 1 would be higher, since it has historically had a lower capacity factor than the other two units at Brown. I would suggest that capacity factor be treated as safety margin with respect to meeting the limits and that B&V propose a cost to upgrade burner equipment on Unit 1 to achieve approximately 0.3 to 0.32 lb/MMBTU emissions. The only time that this would not be a practical solution would be if the NOx limits were applied on a continuous basis, rather than by year. If so, then a Unit 3 outage would put the plant over the limit. This could be managed, possibly, with overlapping outages, etc. If the NOx regulations are applied on a unit by unit basis, NOx removal of 30-40% by an SNCR as described by B&V would not be capable of bringing Unit 1 into compliance, and a full SCR would be required.

The second major question I had was relative to disposal of material captured by a future baghouse, particularly considering heavy metals that would be captured. Please be sure B&V identifies costs that may be associated with construction of facilities to handle the waste. It should also be made clear in their final document that the potential baghouse requirements for Units 1 and 2 could be met by a single combined baghouse.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NOx compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required****. Existing common WFGD to units 1, 2 and 3 can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available****. Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected****. Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	□ Yes □ No

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Air Quality Control Technology Assessment
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Plant: ***E.W. Brown***
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Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

E.ON Comments:

Please clarify if the PJFF is shared between Units 1&2. Also, the plant would prefer B&V to estimate the option of using low NOx burners and overfire air on Unit 1 and put the SCR on Unit 2 and 3 in order to achieve Plant compliance. According to the sheet titled, "Estimated Requirements Under Future New Environmental Regulations" provided to B&V by E.ON, the revised CAIR section 4.9 calls for Plant wide compliance. The Brown Team does not believe that an SCR should be the first option for compliance for this Unit. Please see the attached document prepared by Brad Pabian for further details.

Therefore, B&V should explore this option for the basis of the estimate. Eileen Saunders will discuss with management if E.ON would like B&V to provide costs associated with adding an SCR to Unit 1.

Is an SNCR feasible for the Brown Station? If not, please explain.

E.ON US
Coal-Fired Fleet Wide
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Plant: ***E.W. Brown***
Unit: ***1***

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Plant: *E.W. Brown*
Unit: *1*

Pollutant: NO_x

Feasible Control Options:
- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:
- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be located downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – No space is available outside the boiler building on the north side to install the SCR. Therefore, the new SCR needs to be constructed on the east side of the boiler building. Potentially at an elevated level.
- Construction Issues – Tight space for tie-in and connection of ductwork between economizer outlet and SCR.
  - Soot blower air compressor tanks, service water piping and circulating water piping needs to be demolished and relocated.
  - Demineralization system building, which is currently not in use and is located on the north side of the boiler building, needs to be demolished.
  - Secondary air duct may need to be raised to clear the space.

Pollutant: SO_2

Feasible Control Options:
- **No new SO_2 control technology is required**. The unit is currently equipped with a shared/common wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

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Plant: *E.W. Brown*
Unit: *1*

Pollutant: Particulate (PM)

Feasible Control Options:
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:
- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 1 will be located downstream of the ductwork exiting the ID fans of Unit 1 and upstream of new booster fans for Unit 1.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Heavy foundations and supports.
    - New PJFF will be installed at a higher elevation above the existing ESP, needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: CO

Feasible Control Options:
- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *1*

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 1.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 1.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *2*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required****. Existing common WFGD to units 1, 2 and 3 can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***2***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

Please clarify if the PJFF is shared between Units 1&2. If so, B&V needs to make sure that the cost estimate only reflects one baghouse.

See comments on Unit 1 regarding the SCR estimate.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***2***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but not a long term solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be required downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – Limited space available at grade level outside the boiler building on the north side to install the SCR. Therefore the new SCR will need to be constructed at an elevation above grade level.
- Construction Issues – Unit 2 abandoned dry stack and main auxiliary transformer on the north side outside the boiler building.
  - Demolition and relocation of main auxiliary transformer of Unit 2.
  - Demolition of existing pre-dust collectors.
  - SCR will need to be constructed on a dance floor.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with a shared/common wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *2*

Pollutant: Particulate (PM)

Feasible Control Options:
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:
- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but not a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 2 will be located downstream of the ductwork exiting the ID fans of Unit 2 and upstream of new booster fans for Unit 2.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Heavy foundations and supports.
  - New PJFF will be installed at a higher elevation above the existing ESP, needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: CO

Feasible Control Options:
- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *2*

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 2.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 2.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *The new SCR which will be constructed in 2012 can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required***. *Existing common WFGD to units 1, 2 and 3 can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing common WFGD to units 1, 2 and 3 can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	□ Yes □ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

No additional comments

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *3*

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit will be equipped with SCR in 2012 that can meet the future target NO_x emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but not a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 3 will be located downstream of the existing ID fans of Unit 3 and upstream of common wet FGD scrubber.
- Real Estate Constraints – No real estate constraints.
- Construction Issues – Possible underground service water pipelines interference.
    - May require relocation of underground service water pipelines

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***E.W. Brown***
Unit: ***3***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 3.
- *PAC to be injected downstream of the existing ESP but upstream of new full size PJFF for Unit 3.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *E.W. Brown*
Unit: *3*

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Ghent

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10^{th}, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBtu emissions.*	□ Yes □ No (See Qualifier in Comments Section)
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected***. *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

General Comments for ALL Units:

- In the document, where "South" is used for location, it should be "West"
- For Units 1, 3 and 4, under the section "Special Considerations", please use the phrase, "The plant currently uses an SO3 mitigation system" instead of saying they are "planning injection technology".
- For Unit 2, under the section "Special Considerations", please us the phrase, "The plant will be installing an SO3 mitigation system" instead of saying, "Likely require SO3 mitigation system".
- Please make it clear in the document that the PJFF system must be under negative pressure.
- For SO2, the existing technology can meet the new 0.25 requirements but if the limit becomes more stringent, modifications may have to be made to **consistently** meet the requirements. Please include this clarification in the descriptions of SO2 for all units.
- For various locations cited by B&V as potential locations for PJFF systems, another project run by B&V has plans to locate equipment in those locations (Ash Handling Project). B&V needs to coordinate discussions within their company to ensure that the basis of estimate is accurate. The other project has a 2013 date.

Unit 1 specific comments:

For PM: if this unit is required to meet a new PM limit of .03 lb/MBtu and the Hg Reg does not materialize, the ESP will need to be replaced or upgraded. It does not meet the limit of .03 lb/MBtu on a consistent basis. As long as a PAC/PJFF system is installed to take care of Hg and Dioxin/Furan, then PM will be fine. Please insert this comment on the

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E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

description on the first page. (And include estimate to replace/upgrade.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required.** The unit is currently equipped with an ESP technology that can meet the future target PM emission level of 0.03 lb/MBTU.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 1.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 1.*
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 1 will be located downstream of the existing ID fans of Unit 1 and upstream of the new booster fans for Unit 1.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, with Booster fan or ID fan upgrades.
- Construction Issues – Ductwork and abandoned stack interference. Access for heavy cranes may be a possible issue
    - Require demolition of ductwork
    - May require demolition of existing abandoned dry stack of Unit 1
    - Demolition and relocation of pipe rack for access

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***1***

Pollutant: Dioxin/Furan

<u>Feasible Control Options</u>:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new* NO_x *compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required****. Existing WFGD can meet the new* SO_2 *compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected****. Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	□ Yes □ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

If the Mercury requirement ultimately is by plant and not unit, can Ghent meet the PM requirement without installing a PJFF system on Unit 2?

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E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New booster and/or ID fan installation as needed.
- Location: SCR would be required downstream of the existing economizer and upstream of the air heater.
- Real Estate Constraints – Space is available outside the boiler building on the south side to install the SCR. The SCR will be elevated above grade.
- Construction Issues – Access for heavy equipment and cranes is not available.
    - Demolition and relocation of overhead walkway from Unit 2 to Unit 3 boiler building.
    - Demolition and relocation of some of the overhead power lines.
    - Tower cranes are required for access of heavy equipment and construction of SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: Particulate (PM)

Feasible Control Options:
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:
- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 2 will be located downstream of the existing ID fans of Unit 2 and upstream of the new booster fans for Unit 2.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, with Booster fan or ID fan upgrades.
- Construction Issues – Ductwork interference. Access for heavy cranes may be a possible issue
    - Requires demolition of ductwork
    - Demolition and relocation of pipe rack for access

Pollutant: CO

Feasible Control Options:
- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***2***

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 2.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 2.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Ghent***
Unit: ***3***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in		

E.ON US
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Plant: ***Ghent***
Unit: ***3***

the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

E.ON Comments:

For the Mercury section, page 4, under "Special Considerations", the wording should be changed to reflect this unit is a hot-side ESP not a cold-side ESP.

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Plant: *Ghent*
Unit: *3*

Pollutant: NO_x

Feasible Control Options:

- **No new NO_x control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF)

Special Considerations:

- COHPAC may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 3 will be located downstream of the existing ID fans of Unit 3 and upstream of the new booster fans for Unit 3.

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- Real Estate Constraints – There is very limited space available between the ID fan outlet and wet scrubber inlet on the west side. The new PJFF will be installed on the south side of Unit 4 ESP, with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole, electrical duct banks and circulating water and storm water drain piping running underground on the south side of Unit 4 ESP will need to be relocated to make real estate available.
    - Warehouse needs to be demolished
    - Well water pumps needs to be relocated

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 3.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 3.*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

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Plant: *Ghent*
Unit: *3*

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

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Technology Options

Plant: *Ghent*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBtu emissions.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBtu (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

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Plant: ***Ghent***
Unit: ***4***

and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

E.ON Comments:

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Plant: ***Ghent***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- **No new NOx control technology is required**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO_2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required** to meet the 0.03 lb/MBTU emissions limit.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

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Plant: ***Ghent***
Unit: ***4***

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction with new full size PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- PJFF for Unit 4.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 4.*
- New booster and/or ID fan installation as needed.
- Existing ESP to be kept for additional PM filtration.
- Location: A new PJFF for Unit 4 will be located downstream of the existing ID fans of Unit 4 and upstream of the new booster fans for Unit 4.
- Real Estate Constraints – There is very limited space available between the ID fan outlet and wet scrubber inlet on the west side. The new PJFF will be installed on the south side of Unit 4 ESP, with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole, electrical duct banks and circulating water and storm water drain piping running underground on the south side of Unit 4 ESP will need to be relocated to make real estate available.
    - Warehouse needs to be demolished
    - Well water pumps needs to be relocated

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

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Plant: ***Ghent***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Cane Run

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Plant: ***Cane Run***
Unit: ***4***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	□ Yes □ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No

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Plant: ***Cane Run***
Unit: ***4***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 4.
- New ID Fans and wet liner/stack required for Unit 4 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

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Plant: ***Cane Run***
Unit: ***4***

E.ON Comments:

General Comments:

- During the site visits and in subsequent discussions with EON personnel, the outage timeframes were depicted in the 18-20 month range not 20-30 month range. Please explain the discrepancy.
- For the SCR's, an SO3 mitigation system is described as likely needed. To ultimately understand the total cost impact for Cane Run, EON will need to know those costs. Please contact Eileen Saunders regarding this item.

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Plant: ***Cane Run***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

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Plant: *Cane Run*
Unit: *4*

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 4 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 4 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

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Technology Options

Plant: ***Cane Run***
Unit: ***4***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 4 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

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Plant: ***Cane Run***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

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Plant: ***Cane Run***
Unit: ***5***

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	☐ Yes ☐ No

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Plant: *Cane Run*
Unit: *5*

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 5.
- New ID Fans and wet liner/stack required for Unit 5 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

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Plant: ***Cane Run***
Unit: ***5***

E.ON Comments:

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Plant: *Cane Run*
Unit: *5*

Pollutant: NO_x

Feasible Control Options:
- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:
- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NO_x emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- Location: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:
- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:
- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

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Plant: *Cane Run*
Unit: *5*

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 5 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 5 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

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Plant: ***Cane Run***
Unit: ***5***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 5 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 5*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

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Plant: ***Cane Run***
Unit: ***5***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *6*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:

- Complete demolition of everything behind the boiler.
- Demolish and Build in Phases; requires ~20-30 month of construction outage for Unit 6.
- New ID Fans and wet liner/stack required for Unit 6 which will be a common concrete shell for units 4, 5 and 6 with separate wet flue liners.
- Relocate existing overhead power lines towards the backend equipment to minimize construction hazards.
- New common stack located near unit 5.
- Existing stacks demolished.
- Construction sequence starts with unit 5.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

E.ON Comments:

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- New air heater needed.
- Existing air heater demolished.
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the new air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Cane Run units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than

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Air Quality Control Technology Assessment
Technology Options

Plant: *Cane Run*
Unit: *6*

0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fan installation as needed.
- Existing WFGD will be demolished.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the new stack.
- To minimize outage time, Unit 6 Scrubbers will be installed in parallel with SCR. and installation of baghouse.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF) .

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation as needed.
- Existing ESP will be demolished (no additional PM filtration proposed for ash sales).
- New air heater needed.
- Existing air heater demolished.
- Location: A new PJFF for Unit 6 will be located downstream of the new air heater and upstream of the new ID fans.
- Existing ID fans will be demolished.

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Technology Options

Plant: ***Cane Run***
Unit: ***6***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note* : Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A Full size PJFF in conjunction with PAC injection for Unit 6 is recommended to remove 90% mercury emissions.
- *PAC to be injected downstream of the new air heater but upstream of new full size PJFF for Unit 6*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Cane Run***
Unit: ***6***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Mill Creek

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new* NO_x *compliance limit of 0.11 lb/MBtu.*	☐ Yes ☐ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new* SO_2 *compliance limit of 0.25 lb/MBtu.*	☐ Yes ☐ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu. Plus, new cold-side dry ESP for pre-filtration for ash sales.*	☐ Yes ☐ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	☐ Yes ☐ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of* 1×10^{-6} *lb/MBtu.*	☐ Yes ☐ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	☐ Yes ☐ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of* 15×10^{-18} *lb/MBtu.*	☐ Yes ☐ No

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Erection of new pre-filter ESP/ and new PJFF and ID fans prior to demolition of existing ESP required in meeting recommended phased approach to create real estate for new SCR.
- SCR will be installed in same physical location as existing ESP.
- Existing wet stack will be reused.
- Phased erection is required to minimize unit outage for tie-in to existing components.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

E.ON Comments:

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- Existing air heater will be retained
- Existing ESP will be demolished.
- New economizer bypass will be provided
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible

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Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *1*

and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fans installation is needed.
- Existing WFGD will be demolished in a phased approach.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the existing stack. The existing wet stack liner and breaching including the connecting ductwork will be reused as is.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fans installation is needed.
- Existing ESP will be demolished.
- A new cold-side dry ESP will be used as a pre-filter to remove 80-85% fly ash that can be sold to the cement plant to lower the ash land filling liability. A new down stream full size PJFF will be used for mercury, acid and some PM control.
- Location: A new PJFF for Unit 1 will be located downstream of the existing air heater and upstream of the new ID fans. The PJFF will possibly be installed on the top of the pre-filter ESP due to site real estate constraints.
- Existing ID fans will be demolished.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP or new proposed cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A full size PJFF is recommended for Unit 1 in conjunction with PAC injection.
- *PAC to be injected downstream of the new pre-filter ESP but upstream of new full size PJFF for Unit 1*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***1***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

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Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	□ Yes □ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu. Plus, new cold-side dry ESP for pre-filtration for ash sales.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x10^{-18} lb/MBtu.*	□ Yes □ No

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Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail.

E.ON to return written approval and comments sections to B&V.

Special Considerations Summary:

- Erection of new pre-filter ESP/ and new PJFF and ID fans prior to demolition of existing ESP required in meeting recommended phased approach to create real estate for new SCR.
- SCR will be installed in same physical location as existing ESP.
- Existing wet stack will be reused.
- Phased erection is required to minimize unit outage for tie-in to existing components.

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Technology Options

Plant: ***Mill Creek***
Unit: ***2***

E.ON Comments:

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Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

Pollutant: NO_x

Feasible Control Options:

- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:

- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigation system.
- New ID fan installation as needed.
- Existing air heater will be retained
- Existing ESP will be demolished.
- New economizer bypass will be provided
- Location: SCR would be required downstream of the existing economizer and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *2*

and expandable control technology considered for SO_2 reduction including future requirements.

- New ID fans installation is needed.
- Existing WFGD will be demolished in a phased approach.
- Existing ID fans will be demolished
- Location: WFGD would be required downstream of the new ID fans and upstream of the existing stack. The existing wet stack liner and breaching including the connecting ductwork will be reused as is.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP
- Compact Hybrid Particulate Collector (COHPAC^{TM}).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fans installation is needed.
- Existing ESP will be demolished.
- A new cold-side dry ESP will be used as a pre-filter to remove 80-85% fly ash that can be sold to the cement plant to lower the ash land filling liability. A new down stream full size PJFF will be used for mercury, acid and some PM control.
- Location: A new PJFF for Unit 2 will be located downstream of the existing air heater and upstream of the new ID fans. The PJFF will possibly be installed on the top of the pre-filter ESP due to site real estate constraints.
- Existing ID fans will be demolished.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing cold-side dry ESP or new proposed cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A full size PJFF is recommended for Unit 2 in conjunction with PAC injection.
- *PAC to be injected downstream of the new pre-filter ESP but upstream of new full size PJFF for Unit 2*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and similarly it is expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD recommended.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

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Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***2***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

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Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15 x10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

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Technology Options

Plant: *Mill Creek*
Unit: *3*

and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:

- New booster fans required following PJFF.
- New ductwork will bypass existing FGD equipment that will be demolished following installation of new equipment.
- Existing stack can be reused with new FGD and PJFF elevated above existing road and rails.

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Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***3***

E.ON Comments:

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Plant: ***Mill Creek***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:

- **<u>No new NOx control technology is required</u>**. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing WFGD will be demolished.
- <u>Location</u>: WFGD would be required downstream of the new booster fans and upstream of the existing stack.
- <u>New wet FGD absorber and reaction tank to be installed over the existing main access way on elevated steel supports and hence heavy duty steel support and foundations are expected</u>. *Existing railroad tracks as well as pipe racks are kept intact by elevating the new PJFF and the WFGD absorber.*

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP

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Plant: *Mill Creek*
Unit: *3*

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation is needed.
- Existing ESP to be kept for additional PM filtration and lime injection for SO_3 mitigation to be located upstream of existing ESP.
- <u>Location</u>: A new PJFF for Unit 3 will be located over the main access way downstream of the existing ID fans and upstream of the new booster fans.
- <u>Real Estate Constraints</u> – No space is available at grade level to install the new PJFF because the existing access way is critical to plant operation. Therefore the new PJFF will need to be constructed at an elevation above grade level, with new Booster fans.

Pollutant: CO

Feasible Control Options:

- ***<u>No feasible and proven technology is available for this type and size of unit</u>*** to meet the 0.02 lb/MBtu emission limit.
- *<u>Note</u>*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

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Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *3*

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF in conjunction with PAC injection is recommended for Unit 3.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 3*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NO_x compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***New Wet Flue Gas Desulfurization (WFGD) is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu.*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new full size Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

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Technology Options

Plant: ***Mill Creek***
Unit: ***4***

and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:
- New booster fans required following PJFF.
- New ductwork will bypass existing FGD equipment that will be demolished following installation of new equipment.
- Existing stack can be reused with new FGD and PJFF elevated above existing road and rails.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Mill Creek***
Unit: ***4***

E.ON Comments:

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Technology Options

Plant: ***Mill Creek***
Unit: ***4***

Pollutant: NO_x

Feasible Control Options:

- <u>**No new NOx control technology is required**</u>. The unit is currently equipped with SCR that can meet the future target NOx emissions level of 0.11 lb/MBtu.

Special Considerations:

- Plant is currently planning injection technology to mitigate SO_3 from the SCR.

Pollutant: SO_2

Feasible Control Options:

- Semi-Dry Flue Gas Desulfurization (FGD)
- Wet Flue Gas Desulfurization (WFGD)

Special Considerations:

- Semi-Dry FGD systems may be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu but it will not provide a long term consistent solution for SO_2 emissions less than 0.25 lb/MBtu on high sulfur fuels. The O&M costs economics could favor use of a wet FGD technology when scrubbing high sulfur coals expected to be burned at Mill Creek units.
- WFGD can consistently achieve SO_2 emissions of 0.25 lb/MBtu on a continuous basis and has a capability to expand to meet the SO_2 emissions even lower than 0.25 lb/MBtu burning high sulfur content coals. Hence WFGD is the most feasible and expandable control technology considered for SO_2 reduction including future requirements.
- New booster and/or ID fan installation as needed.
- Existing WFGD will be demolished.
- <u>Location</u>: WFGD would be required downstream of the new booster fans and upstream of the existing stack.
- <u>New wet FGD absorber and reaction tank to be installed over the existing main access way on elevated steel supports and hence heavy duty steel support and foundations are expected</u>. *Existing railroad tracks as well as pipe racks are kept intact by elevating the new PJFF and the WFGD absorber.*

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold-Side Dry ESP

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Technology Options

Plant: *Mill Creek*
Unit: *4*

- Compact Hybrid Particulate Collector (COHPAC™).
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New booster and/or ID fan installation is needed.
- Existing ESP to be kept for additional PM filtration and lime injection for SO_3 mitigation to be located upstream of existing ESP.
- Location: A new PJFF for Unit 4 will be located over the main access way downstream of the existing ID fans and upstream of the new booster fans.
- Real Estate Constraints – No space is available at grade level to install the new PJFF because the existing access way is critical to plant operation. Therefore the new PJFF will need to be constructed at an elevation above grade level, with new Booster fans.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note*: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Mill Creek*
Unit: *4*

Special Considerations:

- The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF in conjunction with PAC injection is recommended for Unit 4.
- *PAC to be injected downstream of the existing ID fans but upstream of new full size PJFF for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCl emissions with an existing Wet FGD and expected to meet the same target emission level of 0.002 lb/MBtu with new Wet FGD.

Special Considerations:

- New WFGD proposed as control technology for SO_2 reduction for future requirements will also meet HCl target emission level.

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Trimble County

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Trimble County*
Unit: *1*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***No new technology is required***. *Existing SCR can meet the new NOx compliance limit of 0.11 lb/MBtu*	□ Yes □ No
SO_2	***No new technology is required***. *Existing WFGD can meet the new SO_2 compliance limit of 0.25 lb/MBtu*	□ Yes □ No
PM	***No new technology is required*** *for PM as current ESP is capable of meeting 0.03 lb/MBTU emissions.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new full size PJFF.***	□ Yes □ No
HCl	***No new technology selected.*** *Existing WFGD can meet the new HCl compliance limit of 0.002 lb/MBtu*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection*** *and new Pulse Jet Fabric Filter (PJFF) required to meet the compliance requirements.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*		

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Trimble County***
Unit: ***1***

E.ON Comments:

Under the "Special Considerations" section for Hg, B&V discusses the use of adding a booster fan or upgrading the ID fan. The plant would prefer to upgrade the existing ID Fan motors which will need to be replaced or rewound. Modifications will need to be made to the ID Fans which may include replacement of the fans.

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Coal-Fired Fleet Wide
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Plant: ***Trimble County***
Unit: ***1***

Pollutant: NO_x

Feasible Control Options:

- **No new NO_x control technology is required**. The unit is currently equipped with state of the art SCR that can meet future target NOx emissions level of 0.11 lb/MBtu.

Pollutant: SO_2

Feasible Control Options:

- **No new SO_2 control technology is required**. The unit is currently equipped with wet FGD technology that can meet future target SO2 emissions level of 0.25 lb/MBtu.

Pollutant: Particulate (PM)

Feasible Control Options:

- **No new PM control technology is required** to meet the 0.03 lb/MBTU emissions limit.

Special Considerations:

- A new PJFF will be required to meet mercury control using PAC. The existing ESP alone will not be capable of meeting the mercury compliance emissions using PAC.

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- *Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.*

Pollutant: Mercury (Hg)

Feasible Control Options:

- **New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF** can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a

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Technology Options

Plant: *Trimble County*
Unit: *1*

continuous basis and hence is the most feasible control technology. The existing cold-side dry ESP will not be capable to removing 90% mercury with PAC injection and hence not recommended for cost considerations.

Special Considerations:

- Full size PJFF.
- *PAC to be injected downstream of the existing ESP but upstream of new PJFF.*
- Location: A PJFF would be required downstream of the PAC injection system.
- Real Estate Constraints – No space is available at grade level to install the new PJFF. Therefore the new PJFF will need to be constructed at an elevation above grade level, probably above the existing ESP with Booster fan or ID fan upgrades.
- Construction Issues – Electrical manhole and electrical duct banks running underground between the existing ID fans and scrubber inlet duct will need to be avoided or relocated to make real estate available.
    - Array of I-beam structures (currently supporting no equipment) located between the existing ID fans and scrubber inlet needs to be demolished.
    - New PJFF will be installed at a higher elevation needing heavy support columns that need to be landing outside the existing ESP foundations.

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- **No new control technology is required** as the unit is currently meeting target emission level of 0.002 lb/MBtu HCL emissions with an existing Wet FGD.

Pollutant: Dioxin/Furan

Feasible Control Options:

- The **new PAC injection with new PJFF considered for mercury control** can meet the dioxin/furan compliance limit of 15 x 10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

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Technology Options

Plant: ***Trimble County***
Unit: ***1***

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Green River

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *3*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	□ Yes □ No
SO_2	***New Circulating Dry Scrubber (CDS) Desulfurization is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) which is part of the CDS technology for SO_2 removal is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***New CDS technology*** *can meet the new HCl compliance limit of 0.002 lb/MBtu.*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:
- New ID Fans, Air Heater and dry carbon steel Stack required for Unit 3.
- Underground aux electric duct banks need to be avoided during foundations for future AQC equipment.

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Technology Options

Plant: ***Green River***
Unit: ***3***

E.ON Comments:

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Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: NO_x

Feasible Control Options:
- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:
- SNCR/SCR Hybrid systems may be able to achieve the new NO_x compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NO_x emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NO_x emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NO_x reduction including future requirements.
- Likely require SO_3 mitigate system.
- New ID fan installation is needed.
- Existing air heater will be demolished and used as SCR ductwork.
- New air heater.
- New economizer bypass will be built
- <u>Location</u>: SCR would be required downstream of the existing economizer and upstream of the new air heater. New air heater to be located straight under the new SCR.

Pollutant: SO_2

Feasible Control Options:
- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:
- Both WFGD and Semi-Dry FGD systems will be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu on a continuous basis on high sulfur fuels. However for small size boilers like Unit 3, it would be economically feasible to build a semi-dry FGD or CDS system than Wet FGD system. The CDS system will offer more operational flexibility compared to the two other technologies when load flexibility is an issue. The CDS technology will incorporate an internal flue

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Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *3*

gas recycle to maintain the lime bed during low load operations. Hence CDS is the most feasible control technology considered for SO_2 reduction based on the size of the unit.

- New ID fan installation is needed.
- Existing ID fans will be demolished
- Location: CDS would be required downstream of the new air heater and upstream of the new ID fans.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold Side Dry ESP
- COHPAC™.
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation is needed.
- Existing ESP will be retired in place. This will not be demolished. Exhaust gas stream will bypass the existing ESP.
- Location: A new PJFF for Unit 3 will be located downstream of the new CDS and upstream of the new ID fans.
- Existing ID fans will be demolished.
- New Air Heater will be installed straight under the new SCR.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: CO

Feasible Control Options:
- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:
- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1 x 10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:
- The existing cold-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- A new full size PJFF for Unit 3 is recommended in conjunction with PAC injection.
- PAC to be injected downstream of the new air heater but upstream of CDS FGD system for Unit 3

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:
- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:
- WFGD, Semi-Dry FGD, and CDS systems will be able to achieve the new HCl compliance limit of 0.002 lb/MBtu on a continuous basis.
- However, since a new CDS system will be installed for SO_2 control, it will also control HCl. Therefore, no new HCl control technology is required beyond the proposed CDS. The new CDS technology with PJFF will remove the HCl to the compliance levels of 0.002 lb/MBtu.

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Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***3***

Pollutant: Dioxin/Furan

Feasible Control Options:

- PAC injection with new CDS and PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *4*

The following AQC control technologies comprise the recommended technologies to control unit pollutant emissions to the targeted emission levels. As summarized on the following pages, the recommended technologies are based on the known technology limitations, future expanding capability, arrangement or site fatal flaws, constructability challenges, unit off-line schedule requirements or site-specific considerations developed or understood during the field work conducted during the week of May 10th, as well as information provided by E.ON. B&V will analyze costs for the one selected/approved technology for each applicable pollutant.

AQC Technology Recommendation		
Pollutant	AQC Equipment	E.ON Approval to Cost*
NO_x	***New Selective Catalytic Reduction (SCR) is required*** *to meet the new NO_x compliance limit of 0.11 lb/MBtu.*	□ Yes □ No
SO_2	***New Circulating Dry Scrubber (CDS) Desulfurization is required*** *to meet the new SO_2 compliance limit of 0.25 lb/MBtu.*	□ Yes □ No
PM	***New full size Pulse Jet Fabric Filter (PJFF) which is part of the CDS technology for SO_2 removal is required*** *to meet the new PM compliance limit of 0.03 lb/MBtu.*	□ Yes □ No
CO	***No feasible and proven technology is available.*** *Existing combustion controls cannot meet the new CO compliance limit of 0.02 lb/MBTU (Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu)*	□ Yes □ No
Hg	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new Hg compliance limit of 1×10^{-6} lb/MBtu.*	□ Yes □ No
HCl	***New CDS technology*** *can meet the new HCl compliance limit of 0.002 lb/MBtu.*	□ Yes □ No
Dioxin/Furan	***New Powdered Activated Carbon (PAC) Injection required with new CDS and Pulse Jet Fabric Filter (PJFF)*** *to meet the new dioxin/furan compliance limit of 15×10^{-18} lb/MBtu.*	□ Yes □ No
Note: If E.ON does not approve a specific technology, an explanation can be included in the following section--comments by E.ON on specific issues regarding control equipment		

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *4*

and a decision to approve a technology should be described in detail. *E.ON to return written approval and comments sections to B&V.*

Special Considerations Summary:

- New ID Fans and dry carbon steel Stack required for Unit 4. Booster fans options to be evaluated.
- Relocate existing power lines and tower.
- Will require demolition of abandoned Unit 1 and Unit 2 ID fans, scrubber and stack to make room for Unit 4 new AQC equipment.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

E.ON Comments:

- Under Special Considerations Summary, the Unit 1 and Unit 2 ID fan statement is incorrect. There is only one fan and it is a booster fan that was originally used for the scrubber.
- For the entire station, there is no extra Aux Power. Any estimate has to include and upgrade to that system as the current system cannot handle any additional power requirements.
- For the SCR considerations for Units 3 and 4, the estimate should include new, enamel air heater baskets as discussed during the site visits.
- The estimate should include ductwork replacement as the current ductwork is in poor condition.
- In the Green River Unit 4 template, on page 4 of 7, it should read, "Unit 4" instead of "Unit 3" under the Special Consideration's section.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *4*

Pollutant: NO_x

Feasible Control Options:
- Selective Non Catalytic Reduction (SNCR) / Selective Catalytic Reduction (SCR) Hybrid
- Selective Catalytic Reduction (SCR)

Special Considerations:
- SNCR/SCR Hybrid systems may be able to achieve the new NOx compliance limit of 0.11 lb/MBtu but it will not provide a long term consistent solution for NOx emissions less than 0.11 lb/MBtu.
- SCR can consistently achieve NOx emissions of 0.11 lb/MBtu on a continuous basis and has a capability to expand to meet the NOx emissions even lower than 0.11 lb/MBtu. Hence SCR is the most feasible and expandable control technology considered for NOx reduction including future requirements.
- Likely require SO_3 mitigate system.
- New ID fan installation is needed if booster fans do not make sense.
- Existing air heater will be used
- New economizer bypass will be built
- Location: SCR would be required downstream of the existing hot-side ESP and upstream of the existing air heater.

Pollutant: SO_2

Feasible Control Options:
- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:
- Both WFGD and Semi-Dry FGD systems will be able to achieve the new SO_2 compliance limit of 0.25 lb/MBtu on a continuous basis on high sulfur fuels. However for small size boilers like Unit 3, it would be economically feasible to build a semi-dry FGD or CDS system than Wet FGD system. The CDS system will offer more operational flexibility compared to the two other technologies when load flexibility is an issue. The CDS technology will incorporate an internal flue gas recycle to maintain the lime bed during low load operations. Hence CDS is

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: *Green River*
Unit: *4*

the most feasible control technology considered for SO_2 reduction based on the size of the unit.

- New ID fan installation is needed if booster fans do not make sense.
- Existing ID fans will be retired in place if new ID fans are used in lieu of booster fans.
- Location: CDS would be required downstream of the existing air heater and upstream of the new ID fans. Existing ID fans located at higher elevation will either be retired in place if new ID fans are selected or reused when new booster fans are added CDS with new dry carbon steel stack.

Pollutant: Particulate (PM)

Feasible Control Options:

- Cold Side Dry ESP
- COHPAC^{TM}.
- Pulse Jet Fabric Filter (PJFF).

Special Considerations:

- Both dry cold-side ESP and COHPAC combination may be able to achieve the new PM compliance limit of 0.03 lb/MBtu but it is not considered a long term solution for PM emissions less than 0.03 lb/MBtu. However a full size PJFF offers more direct benefits or co-benefits of removing future multi-pollutants using some form of injection upstream when compared to dry ESPs. Hence either ESPs or COHPAC combination is not recommended.
- A full-size PJFF can consistently achieve PM emissions of less than 0.03 lb/MBtu on a continuous basis and has a capability to expand to meet the PM emissions lower than 0.03 lb/MBtu. Hence a full size PJFF is the most feasible and expandable control technology considered for PM reduction including future requirements.
- New ID fan installation is needed if booster fans do not make sense.
- Existing hot side ESP to be kept to minimize the arrangement challenges for new SCR. The existing ESP will remain functional (energized) and used for additional PM filtration.
- Location: A new PJFF for Unit 4 will be located downstream of the new CDS and upstream of the new ID fans.
- Existing ID fans will be retired in place if new ID fans are used in lieu of booster fans.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

Pollutant: CO

Feasible Control Options:

- ***No feasible and proven technology is available for this type and size of unit*** to meet the 0.02 lb/MBtu emission limit.
- Note: Please confirm CO emission level is 0.02 and not 0.20 lb/MBtu.

Pollutant: Mercury (Hg)

Feasible Control Options:

- New Powdered Activated Carbon (PAC) Injection in conjunction new PJFF can meet the new Hg compliance limit of 1×10^{-6} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

- The existing hot-side dry ESP will not be capable of removing 90% mercury with PAC injection and hence not recommended for cost considerations.
- Full size PJFF for Unit 4.
- *PAC to be injected downstream of the existing air heater but upstream of CDS FGD system for Unit 4*

Pollutant: Hydrogen Chloride (HCl)

Feasible Control Options:

- Wet Flue Gas Desulfurization (WFGD)
- Semi-Dry Flue Gas Desulfurization (FGD)
- Circulating Dry Scrubber (CDS)

Special Considerations:

- WFGD, Semi-Dry FGD, and CDS systems will be able to achieve the new HCl compliance limit of 0.002 lb/MBtu on a continuous basis.
- However, since a new CDS system will be installed for SO_2 control, it will also control HCl. Therefore, no new HCl control technology is required beyond the proposed CDS. The new CDS technology with PJFF will remove the HCl to the compliance levels of 0.002 lb/MBtu.

E.ON US
Coal-Fired Fleet Wide
Air Quality Control Technology Assessment
Technology Options

Plant: ***Green River***
Unit: ***4***

Pollutant: Dioxin/Furan

Feasible Control Options:

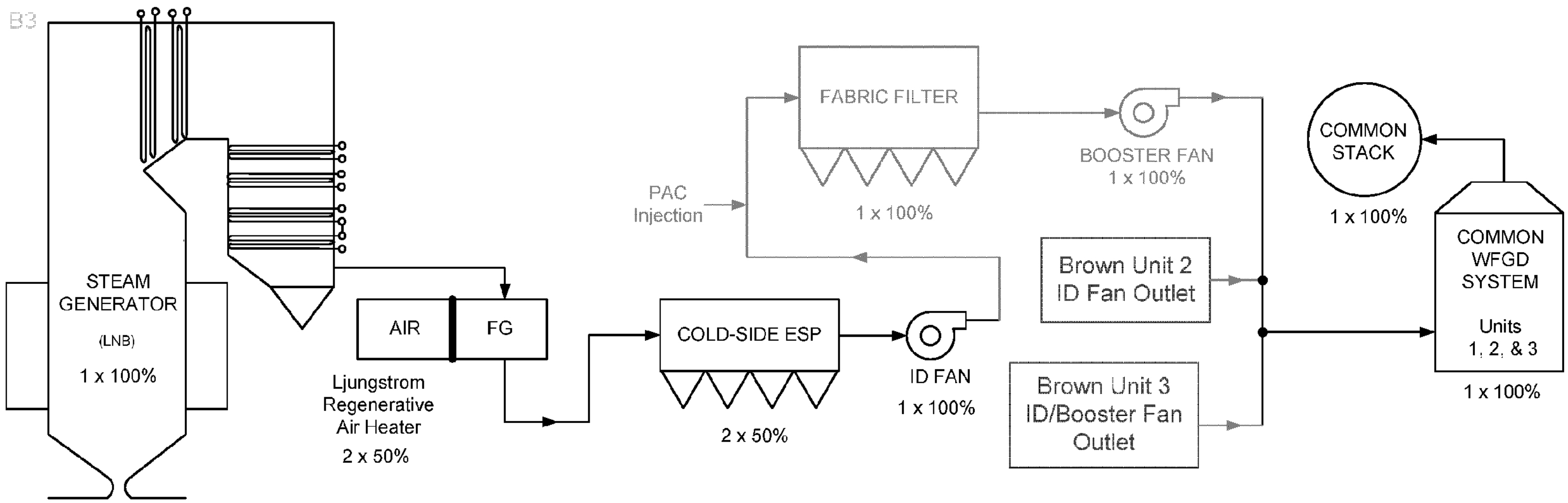
- PAC injection with new CDS and PJFF considered for mercury control can meet the dioxin/furan compliance limit of 15×10^{-18} lb/MBtu or lower on a continuous basis and hence is the most feasible control technology.

Special Considerations:

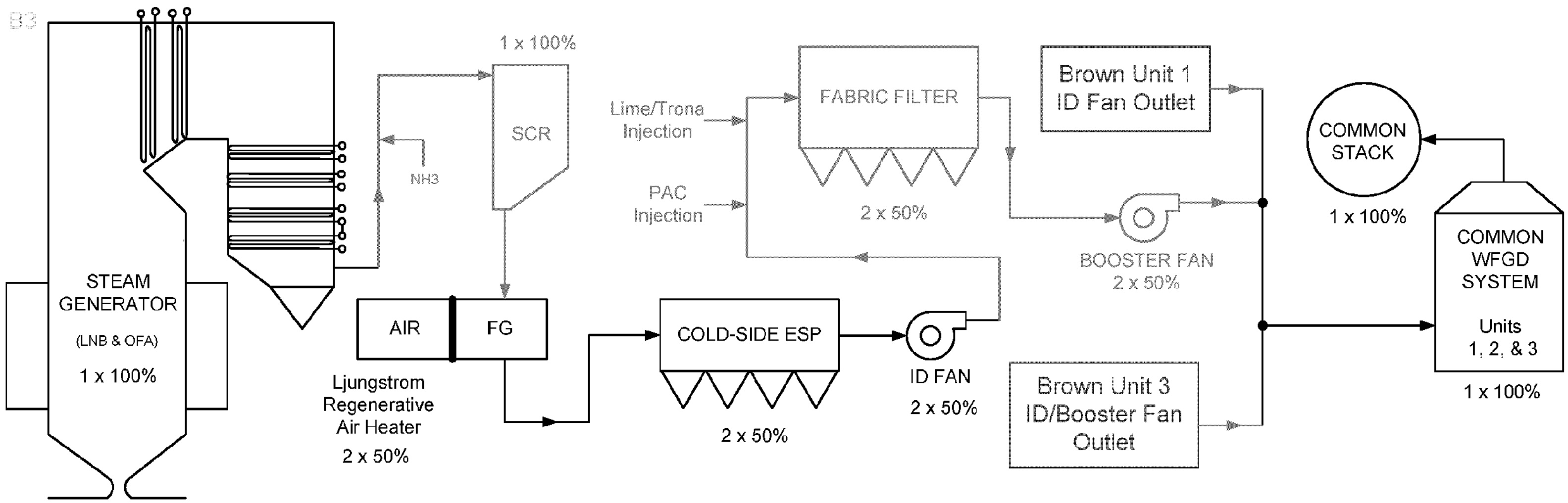
- Dioxin and Furan removal will be a co-benefit with targeted mercury emissions removal and additional PAC consumption beyond mercury removal will be required.

Appendix F
Process Flow Diagrams

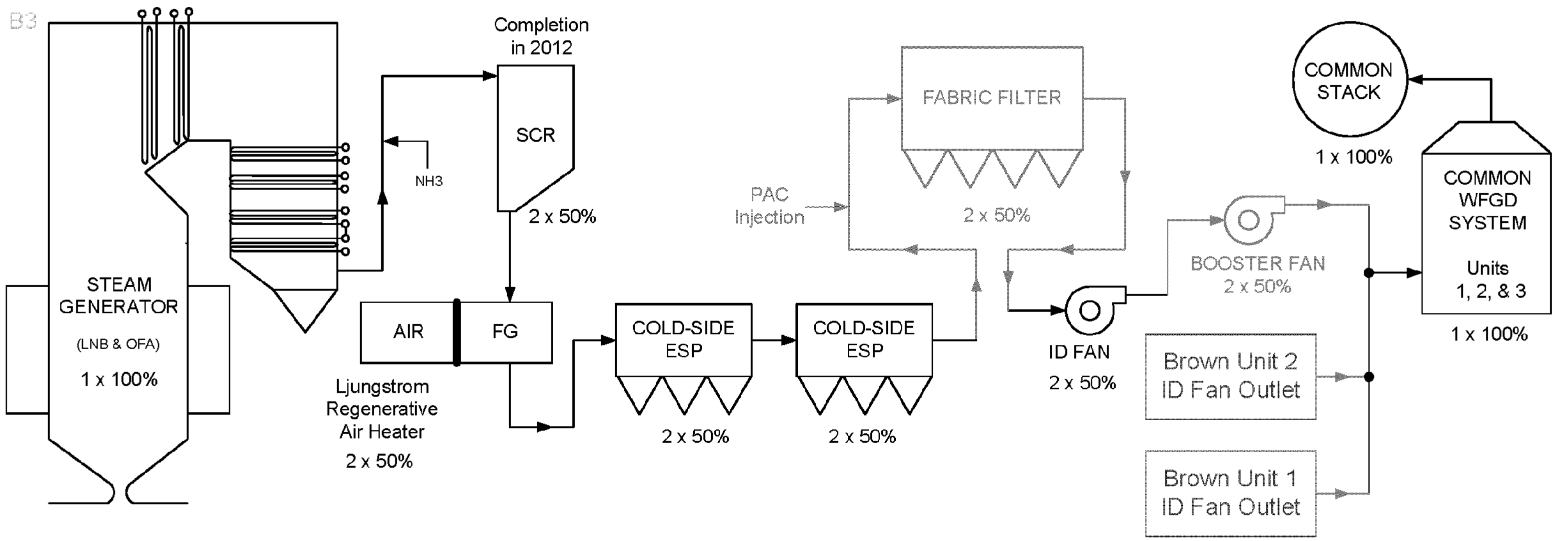
E.W. Brown



Brown Unit 1: Future
110 MW

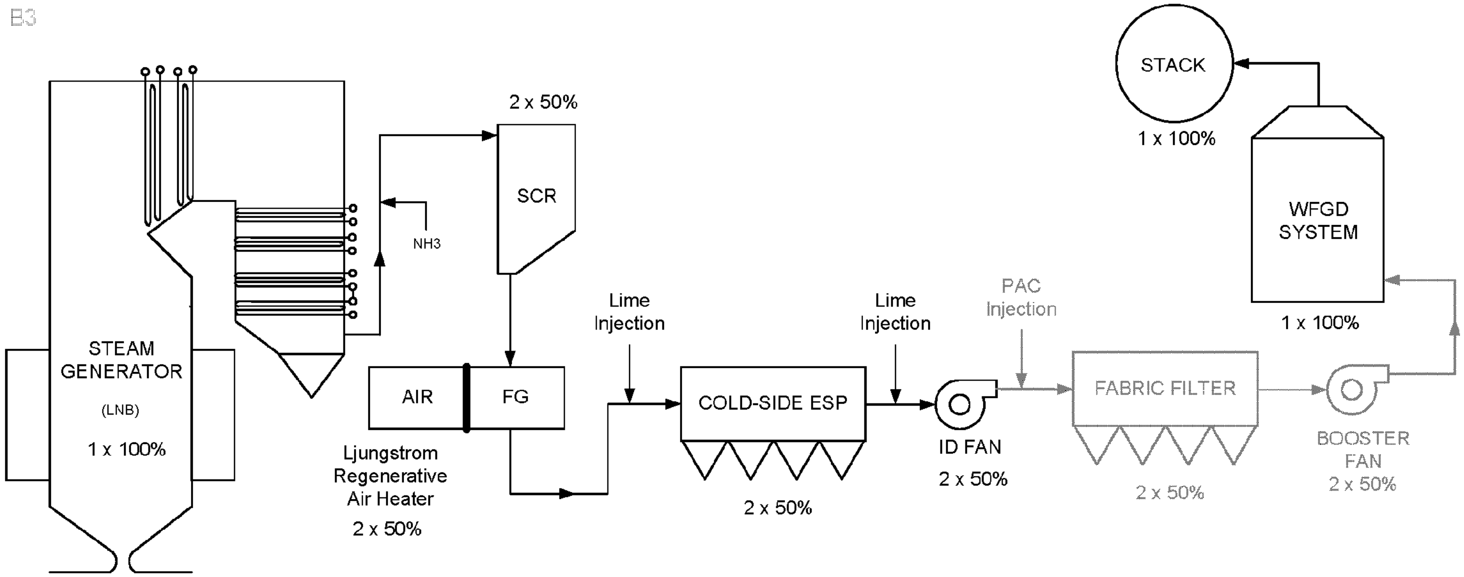


Brown Unit 2: Future
180 MW

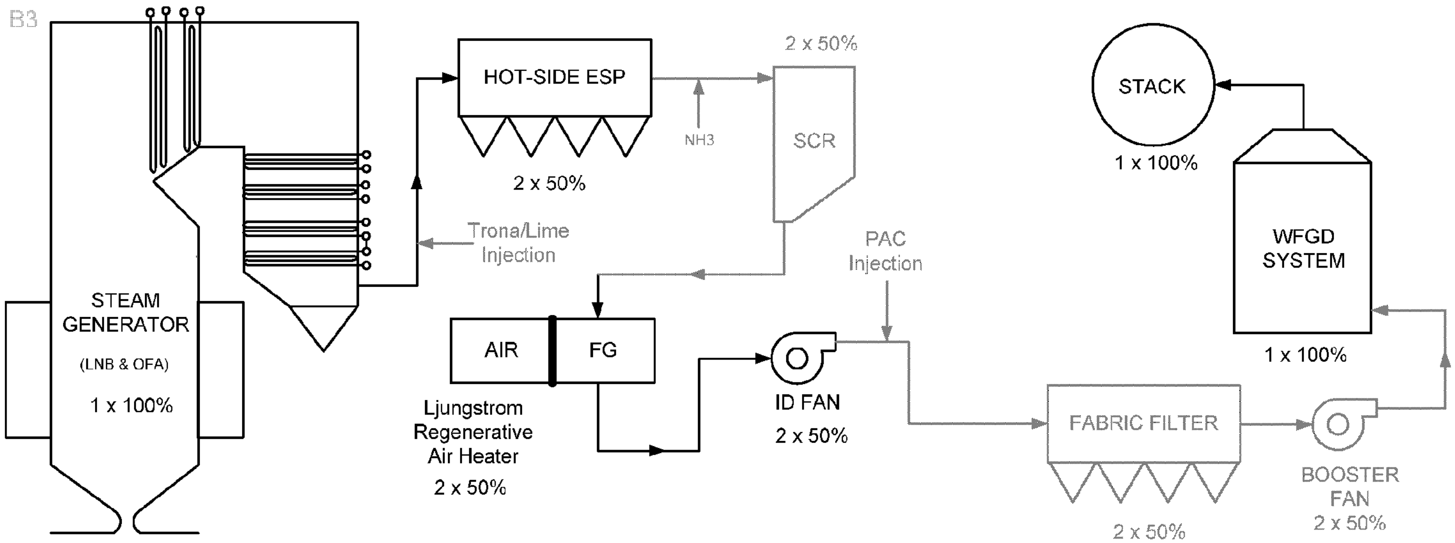


Brown Unit 3: Future
457 MW

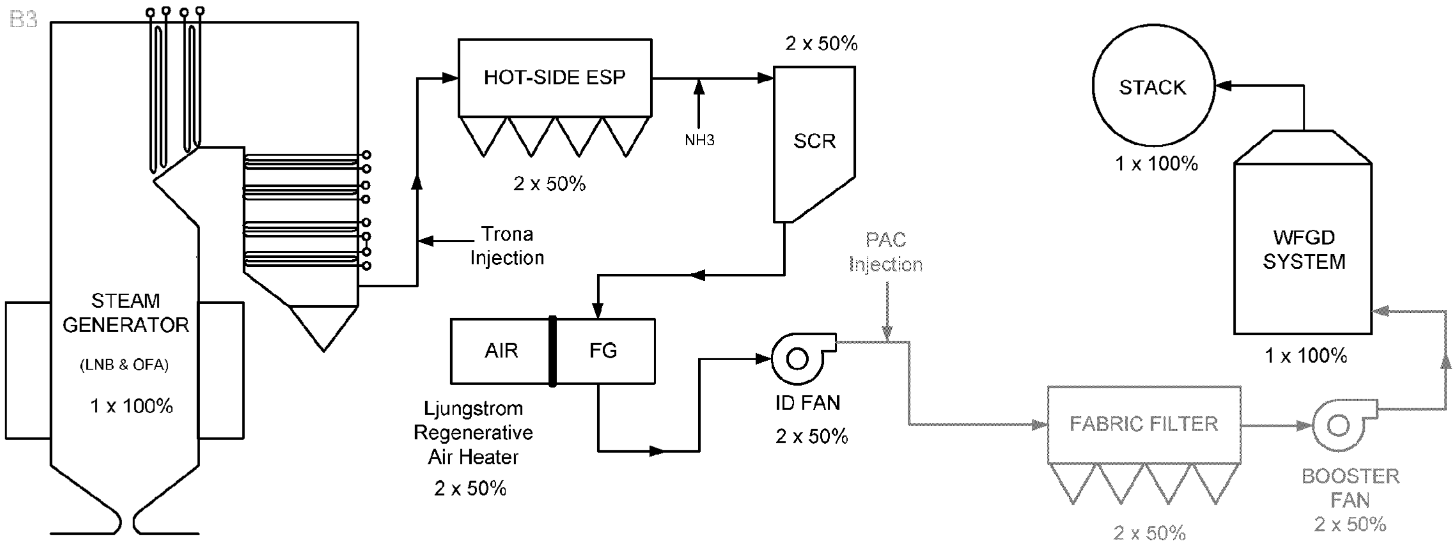
Ghent



Ghent Unit 1: Future

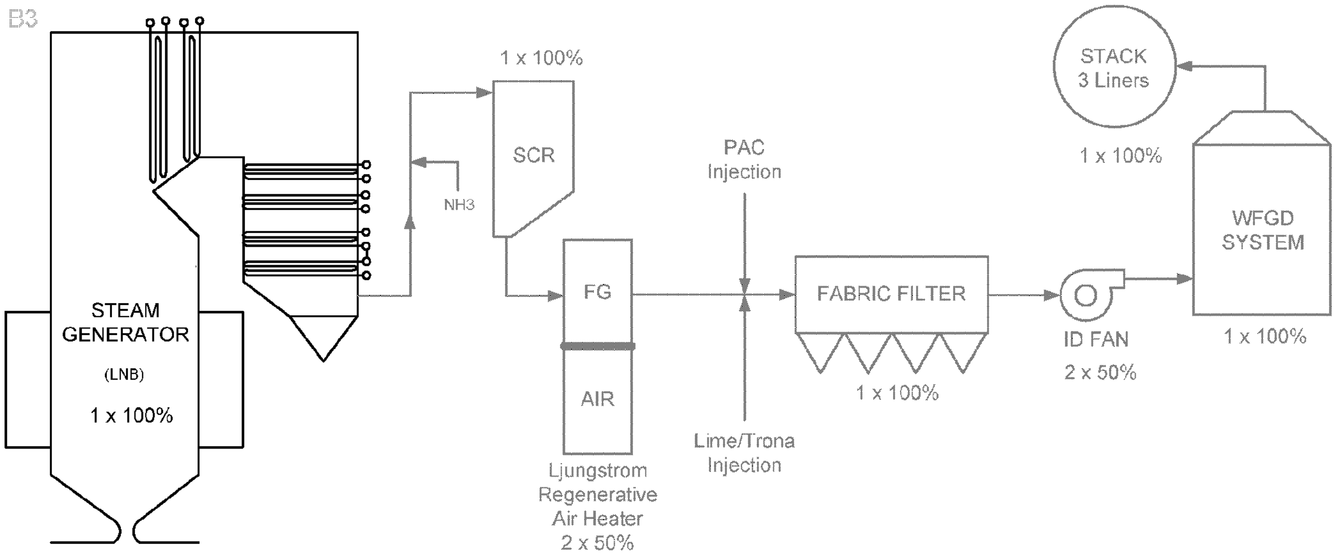


Ghent Unit 2: Future

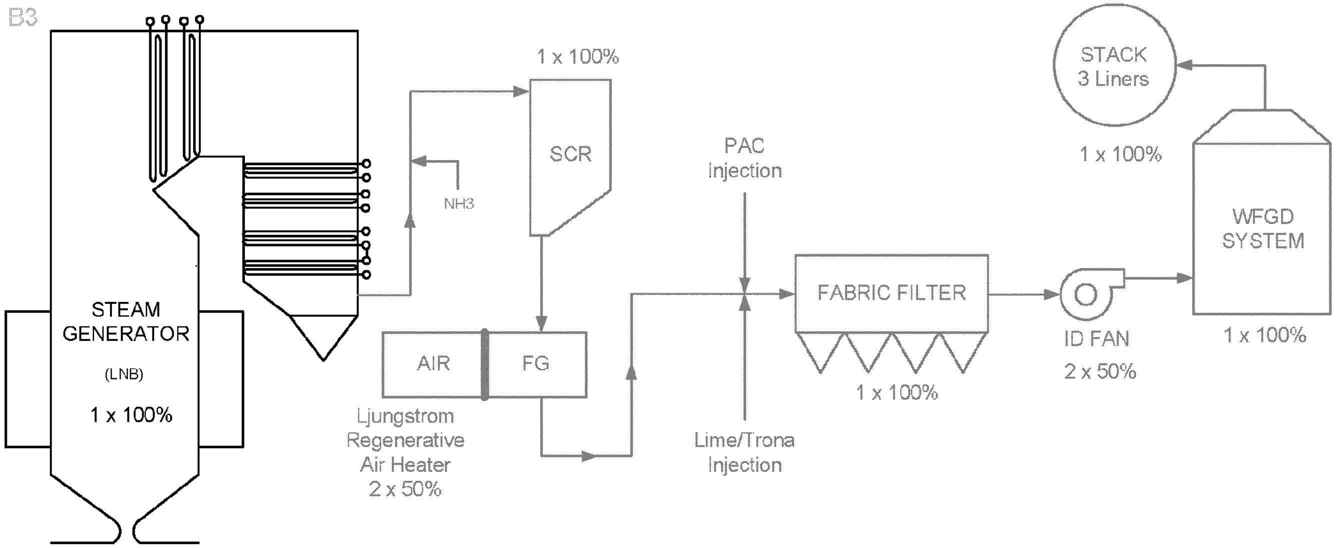


Ghent Unit 3/4: Future

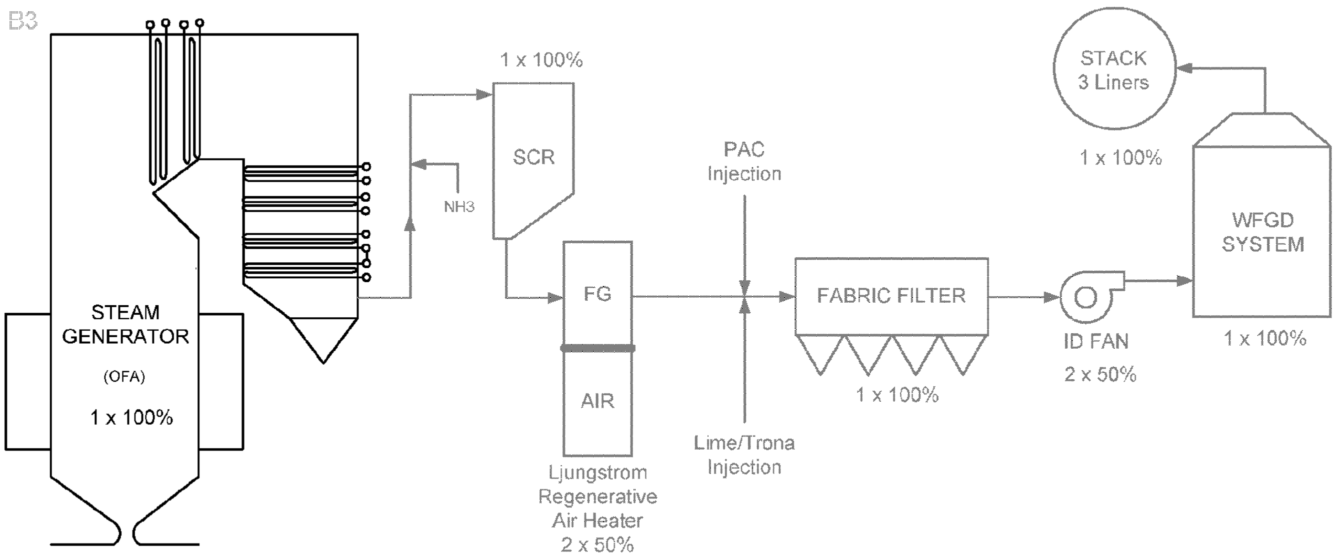
Cane Run



Cane Run Unit 4: Future
168 MW

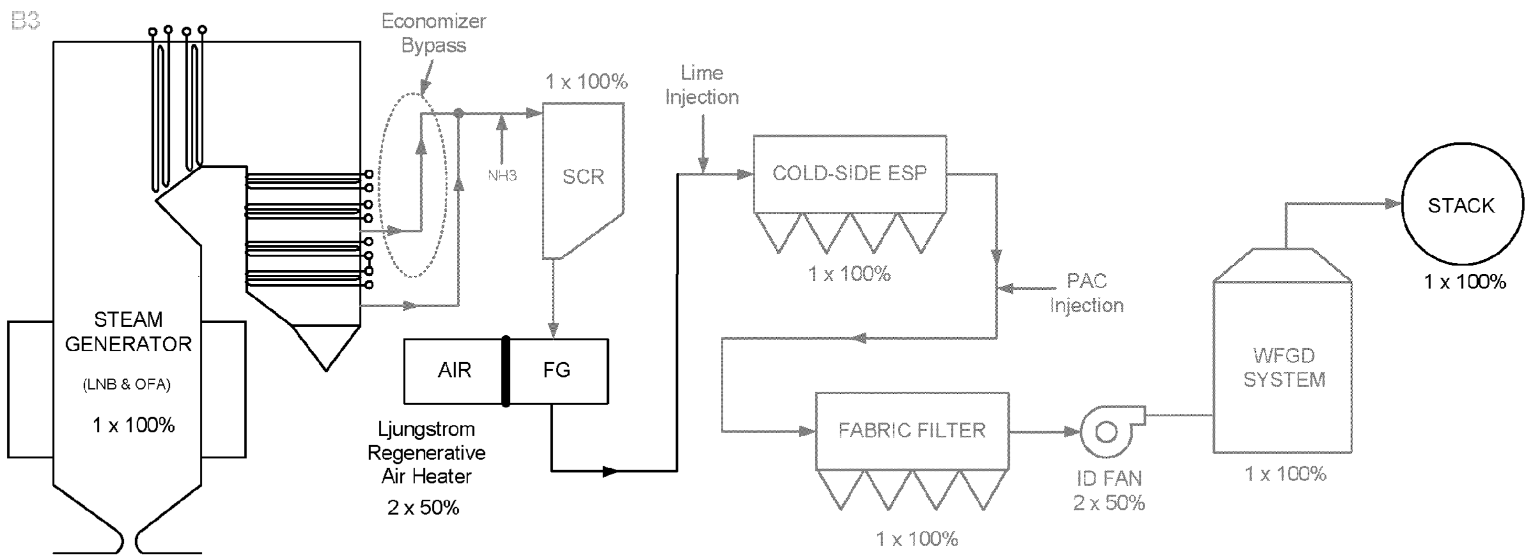


Cane Run Unit 5: Future
181 MW

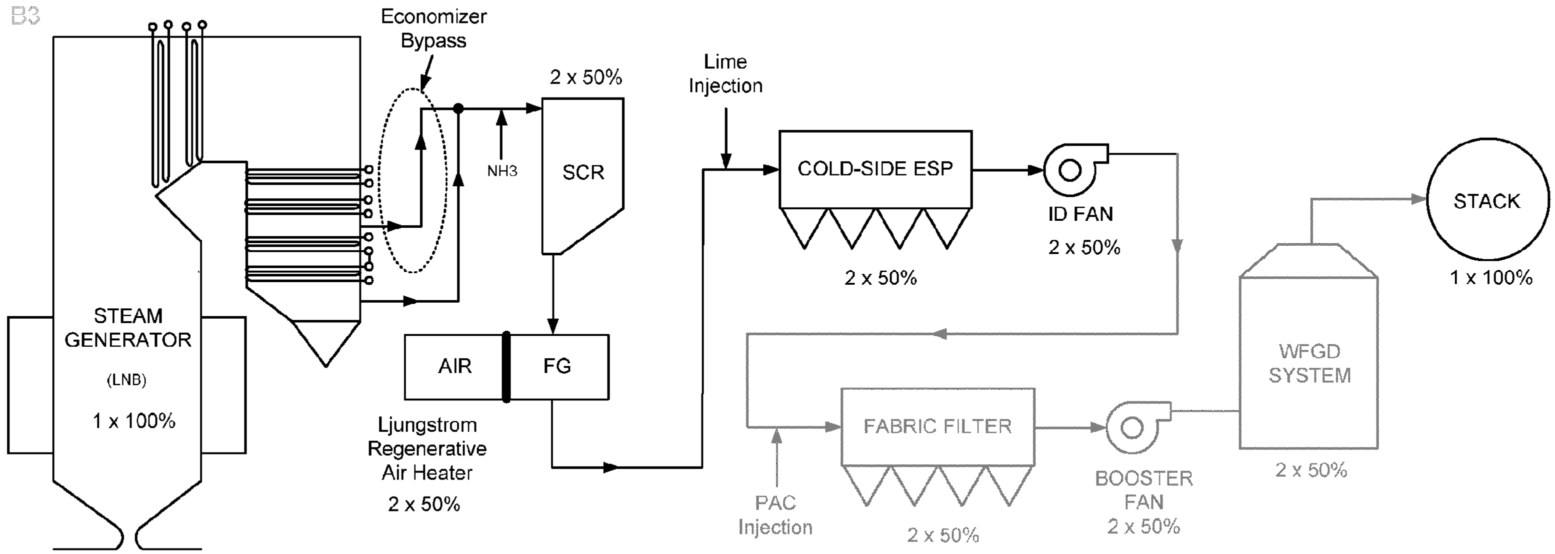


Cane Run Unit 6: Future
261 MW

Mill Creek

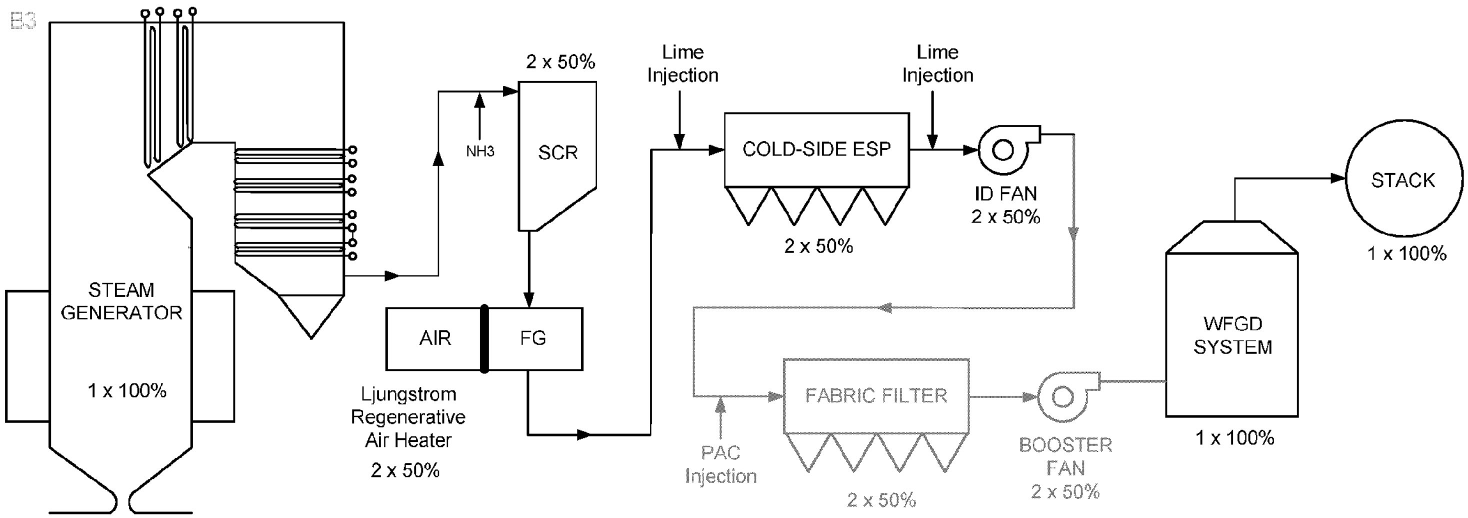


Mill Creek Unit 1/2: Future
Unit 1: 330 MW
Unit 2: 330 MW



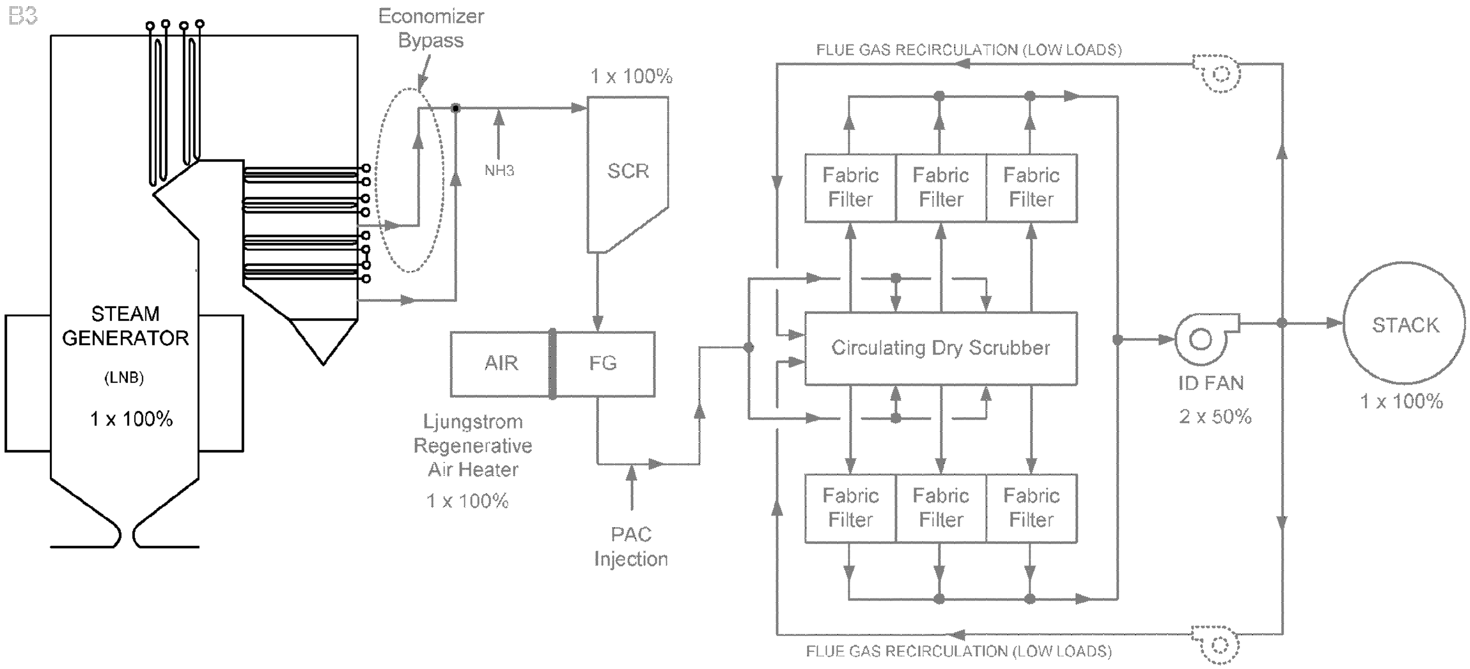
Mill Creek Unit 3/4: Future
Unit 3: 423 MW
Unit 4: 525 MW

Trimble County

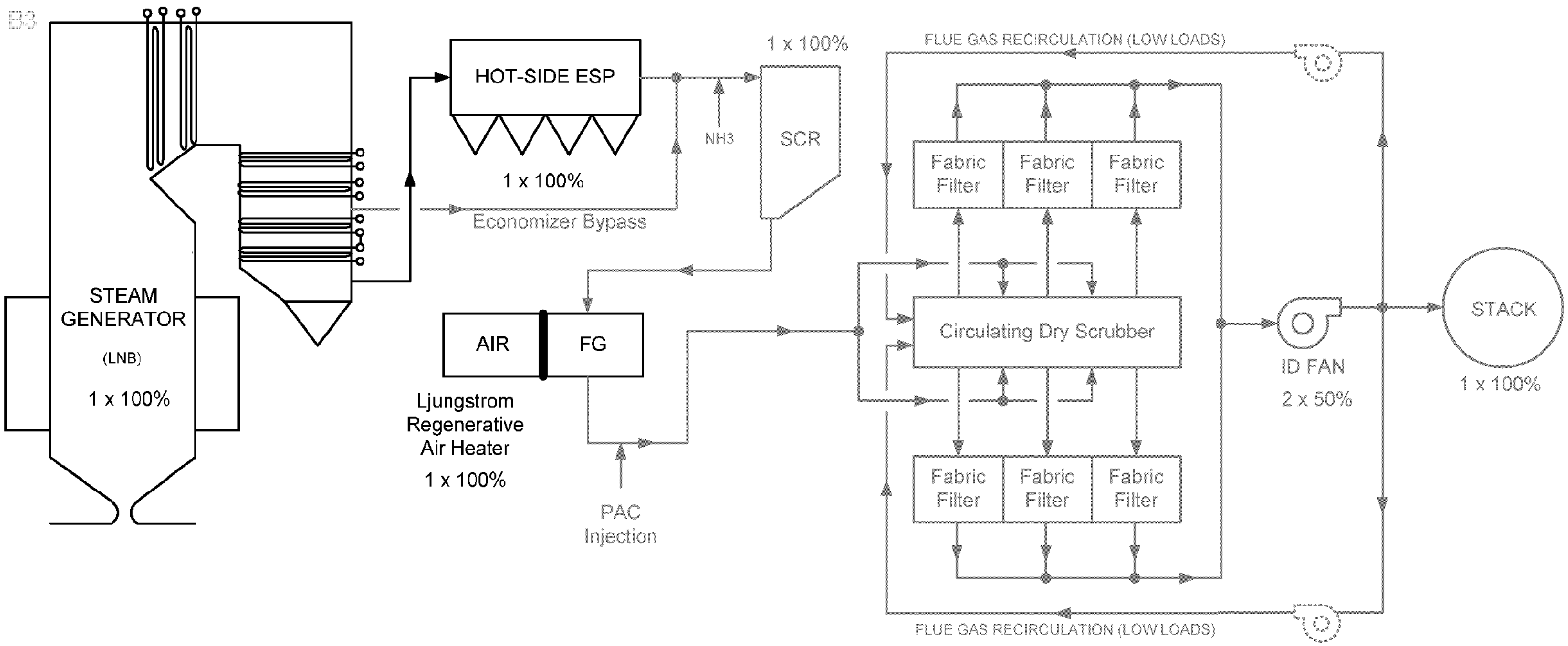


Trimble County Unit 1: Future

Green River



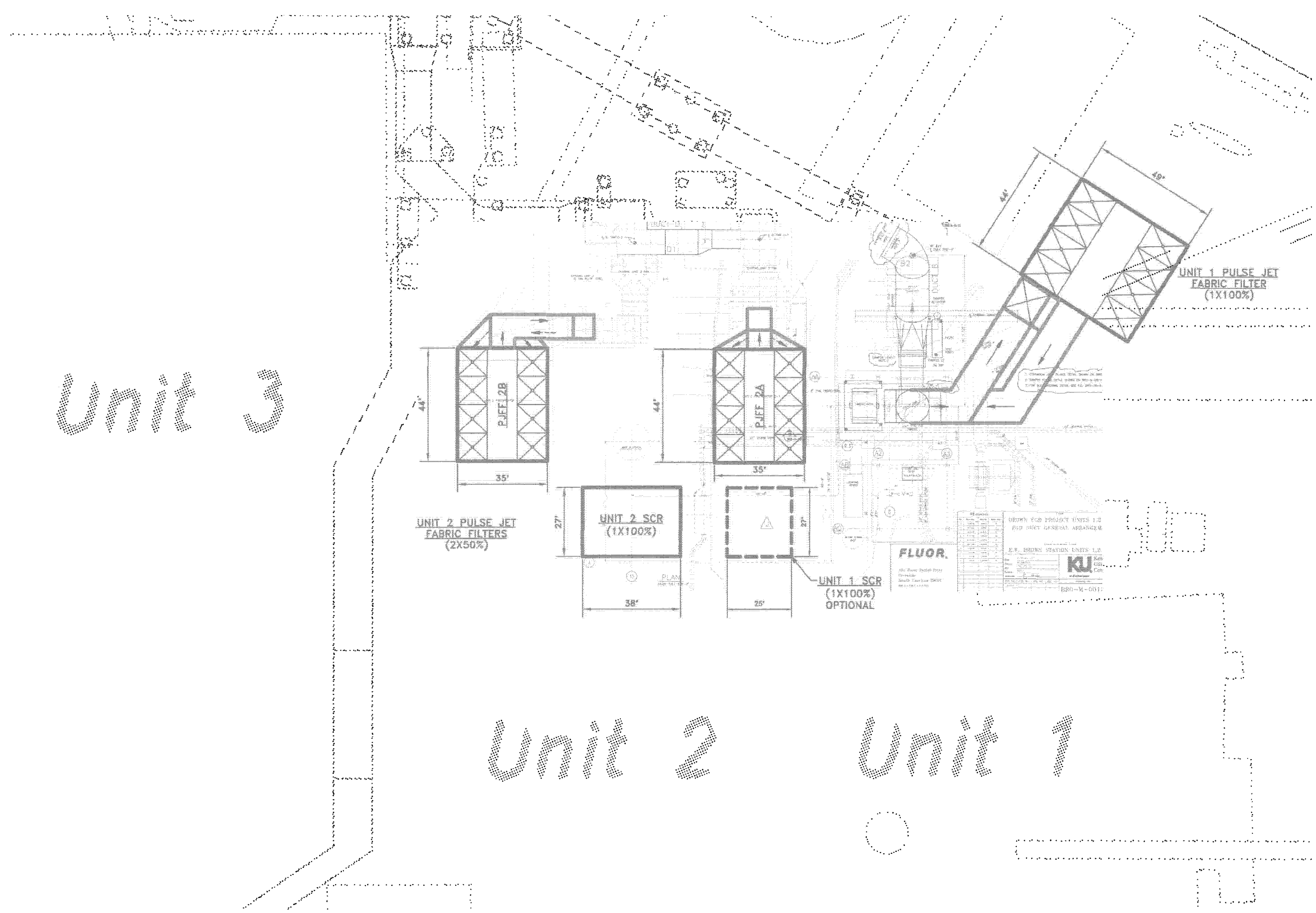
Green River Unit 3: Future
71 MW



Green River Unit 4: Future
109 MW

Appendix G
Air Quality Control Equipment Arrangement Drawings

E.W. Brown



E.W. Brown Units 1 & 2
Constructability Challenges

SCR Constructability Challenges

- Real estate constraints for Unit 1 & Unit 2 SCR
- The new SCR duct tie-ins to the existing Unit 1 Air Heater inlet duct will require extensive relocation of existing plant components:
    1. Rotate Secondary Air Heater Duct
    2. Modify boiler building structural steel bracing and girts to accommodate ductwork
    3. Relocate 440V Switchgear 1A and 1B
- 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 box will require extensive relocation/demolition of existing plant components:
    1. Relocate or protect field fabricated tank located in base of abandoned Unit 2 chimney shell
    2. Demolish Unit 2 chimney
    3. Demolish the dust collection ductwork located along the northeast exterior wall of Unit 2 boiler building
    4. Relocate Unit 2 Auxiliary Transformer located outside of the northeast exterior wall of Unit 2 boiler building
- The existing coal conveyor and ductwork block crane access to the northeast side of Unit 2 boiler house. This will require Unit 2 SCR structure 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

PJFF Constructability Challenges

- Real estate constraints for Unit 2 PJFF
- Elevated PJFF for Unit 2
- 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 Fabric Filter structure 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
- Heavy foundations required on the outer ends of Unit 2 ESP's for construction of Unit 2 PJFF.
- Difficult to stage construction equipment for ductwork support frame & associated foundations near ID fans of Unit 1 & Unit 2

LEGEND:
NEW EQUIPMENT=
NEW DUCTWORK=

NOT TO BE USED FOR CONSTRUCTION

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NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	16/JUN/10	INITIAL ISSUE	MLW				

200' 100' 0 200' 400'
1"=200'

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E.ON.
E W BROWN UNITS 1 & 2 SCR

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT	DRAWING NUMBER	REV
167987-CAQC-M1006		0

CODE
AREA

<u>E.W. Brown Unit 3</u>

Constructability Challenges

- Relocate ductwork and associated support steel for tie-in.
- Relocate underground utilities

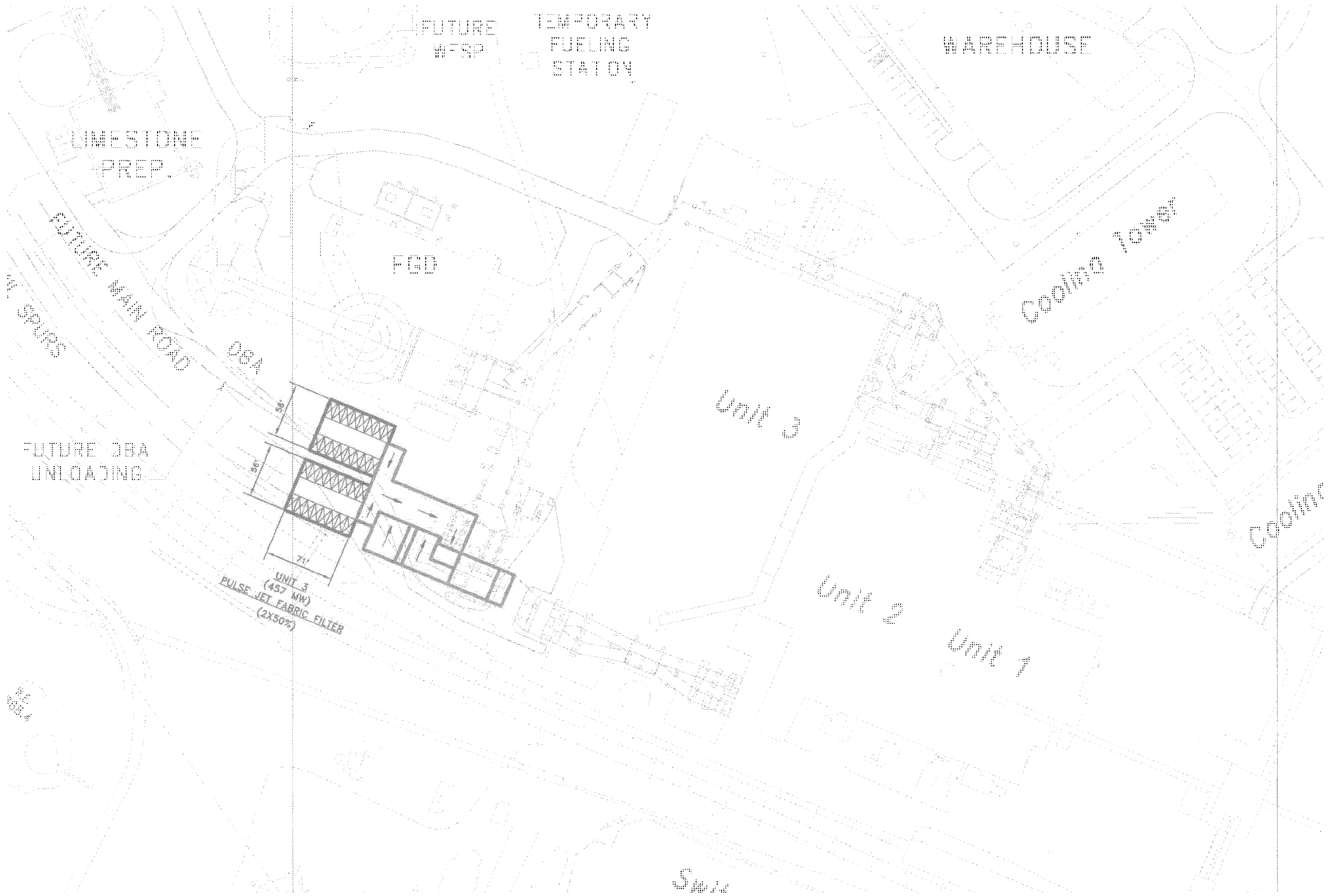
AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:

NEW EQUIPMENT=

NEW DUCTWORK=



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500' 250' 0 500' 1000'

1"=500'

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Ghent

Ghent Unit 1

Constructability Challenges

- Real estate constraints
- Elevated New Pulse Jet Fabric Filter
- Crane access is difficult at Unit 1 due to low overhead pipe rack 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 permanently relocated. Lattice boom crawler crane booms will need to be final assembled at the working location.
- Access lanes around Unit 1 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.

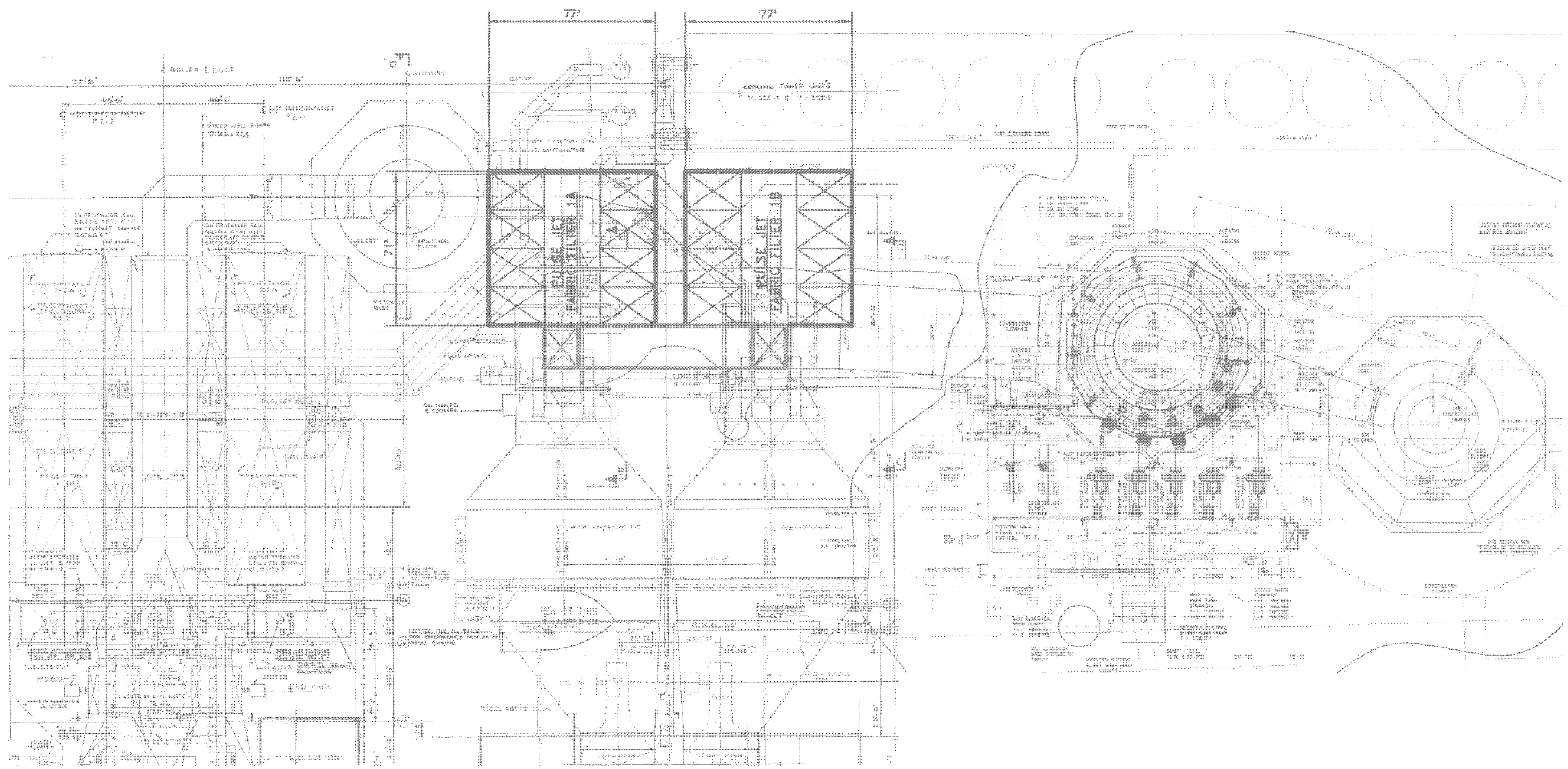
AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:

NEW EQUIPMENT=

NEW DUCTWORK=



PULSE JET FABRIC FILTERS
(2X50%)

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300' 150' 0 300' 600'
1"=300'

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E.ON.
GHENT – UNIT 1

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

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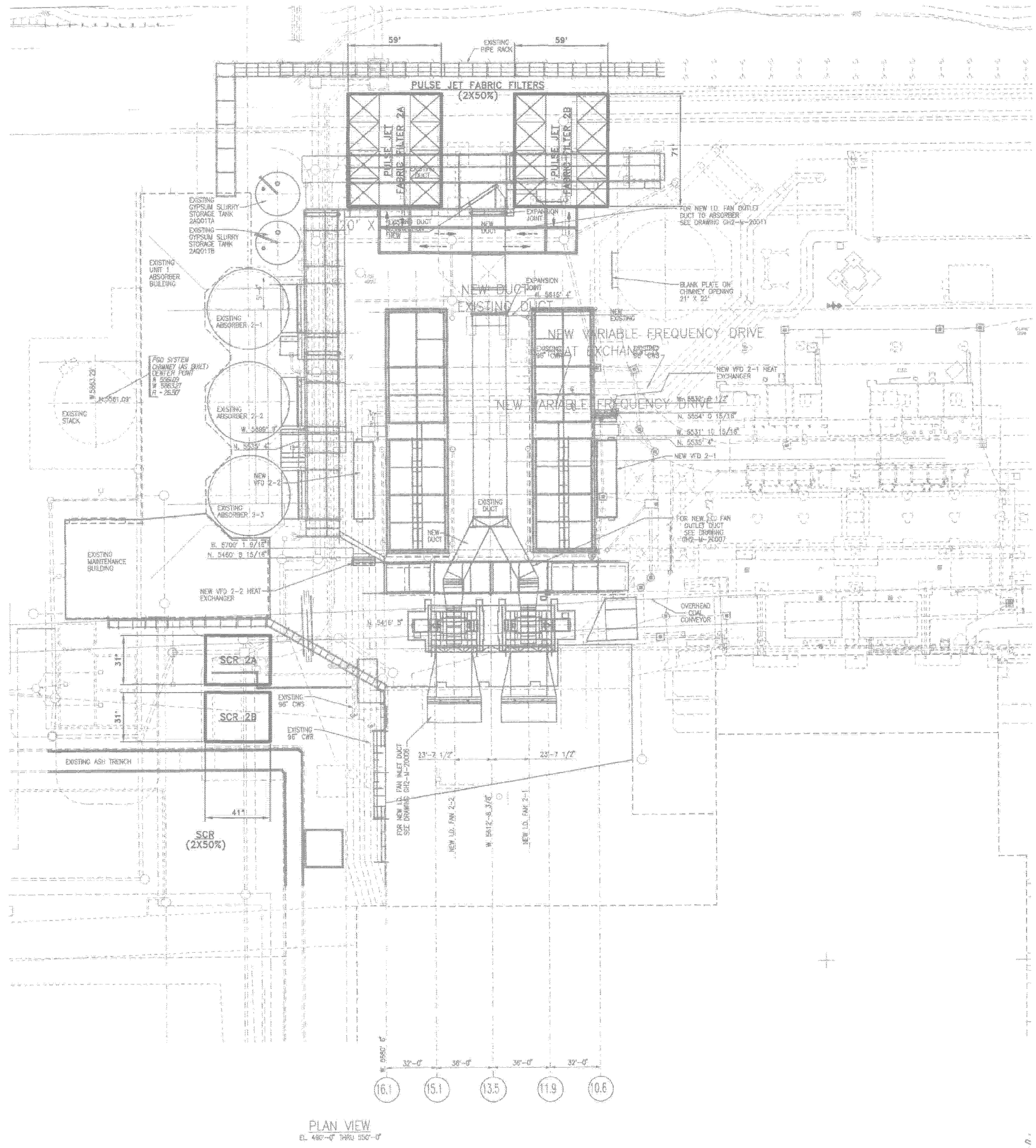

<u>Ghent Unit 2 Pulse Jet Fabric Filter</u>

Constructability Challenges
- Real estate constraints
- Elevated Pulse Jet Fabric Filter
- Crane access is difficult at Unit 2 due to low overhead pipe rack 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 at the working location.
- Access lanes around Unit 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 by-pass 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.

<u>Ghent Unit 2 SCR</u>

Constructability Challenges
- Erection of Unit 2 SCR will require construction material and equipment to be lifted over areas of high personnel traffic.
- Demolition of overhead walkway.
- Possible use of tower crane for final assembly of SCR
- Demolition & Relocation of pipe rack.

AQC Technology and Equipment
- Selective Catalyst Reduction
- Pulse Jet Fabric Filter

LEGEND:

NEW EQUIPMENT=

NEW DUCTWORK=

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1"=300'

BLACK & VEATCH CORPORATION	E.ON. GHENT – UNIT 2	PROJECT / DRAWING NUMBER: 167987–CAQC–M1002	REV: 0
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Ghent Units 3&4

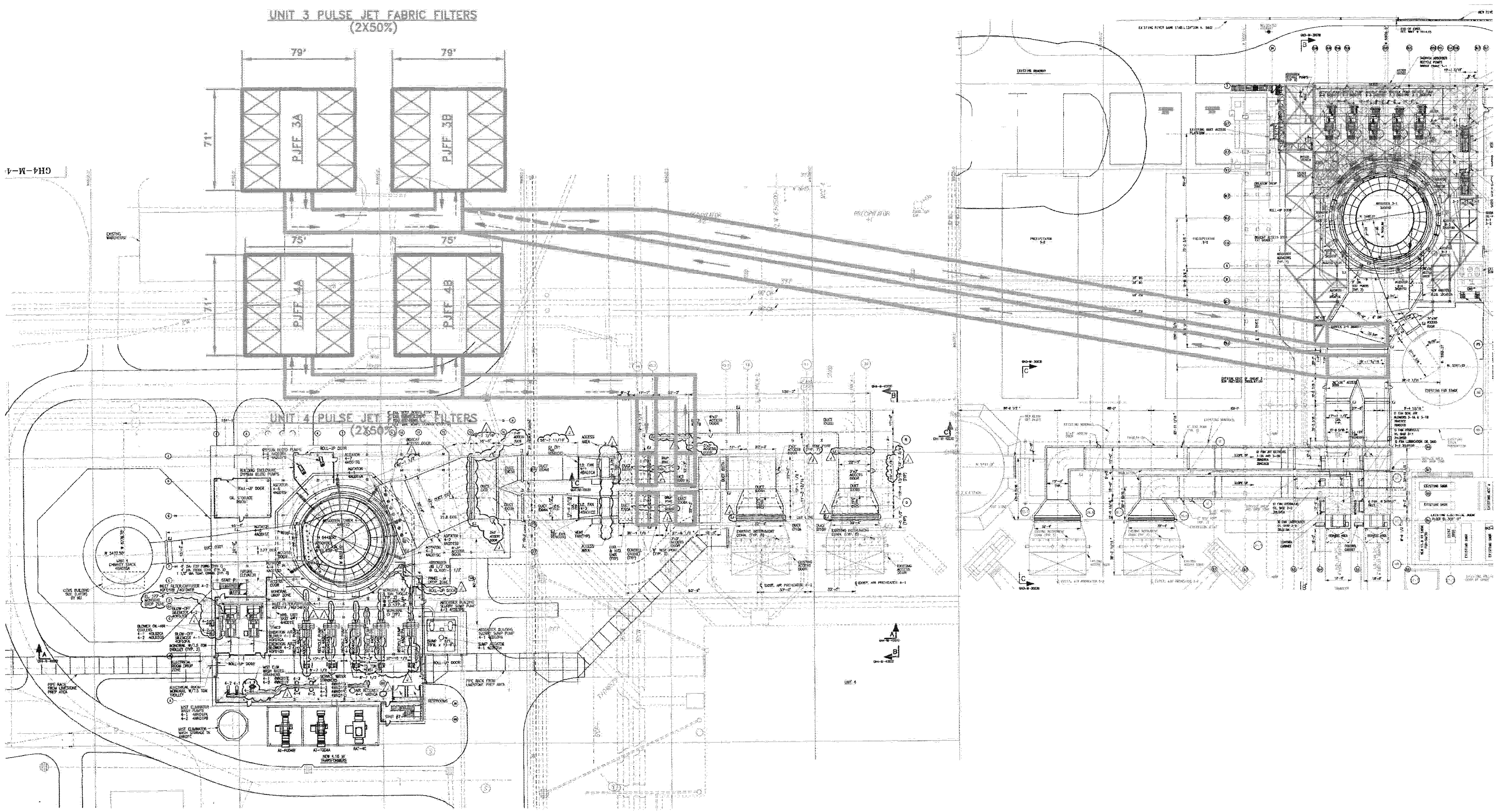
Constructability Challenges

- 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 & 4 ESP's. Access around the footprint of the ESP's 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.

AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:
NEW EQUIPMENT=
NEW DUCTWORK=



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1"=400'

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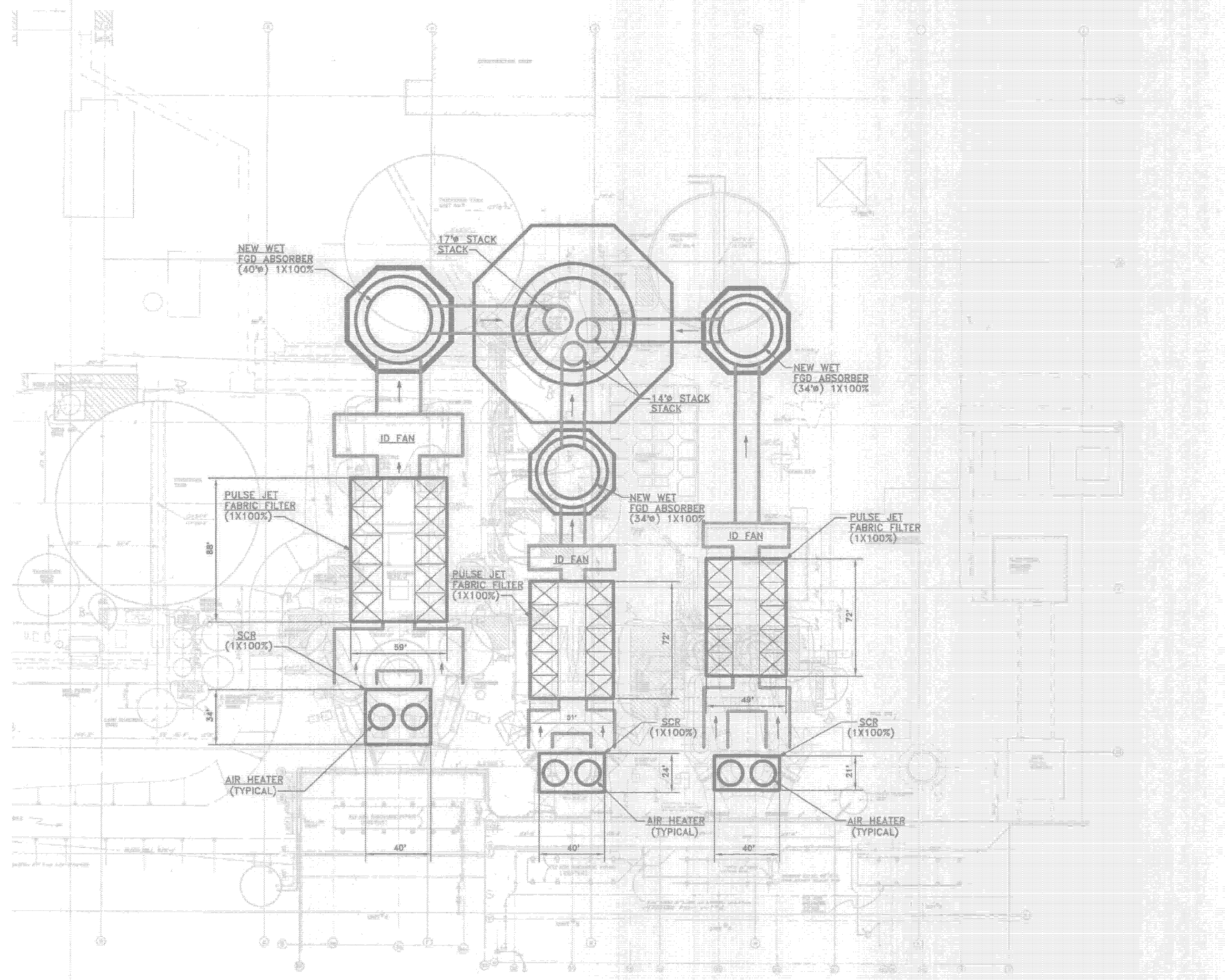
DATE

E.ON.
GHENT - UNITS 3 & 4
FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER 167987-CAQC-M1003
REV 0
CODE
AREA

Cane Run



Cane Run Units 4, 5 & 6
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 ach unit and must be relocated for crane access.
- 4kv 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/demob/outages for tie-ins and access to build new AQCS equipment.
- Underground utility interferences/relocations.
- Above ground utility interferences/relocations.
- Need for areas to build ammonia storage, ASH handling systems, limestone handling, Reagant Prep, Dewatering (Ancillary Systems)
- Extended outages (entire plant) needed to accommodate construction of new AQCS 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.

AQC Technology and Equipment

- Selective Catalytic Reduction
- Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization
- Stack
- Air heater

LEGEND:
NEW EQUIPMENT=
NEW DUCTWORK=

NOT TO BE USED FOR CONSTRUCTION

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1"=300'

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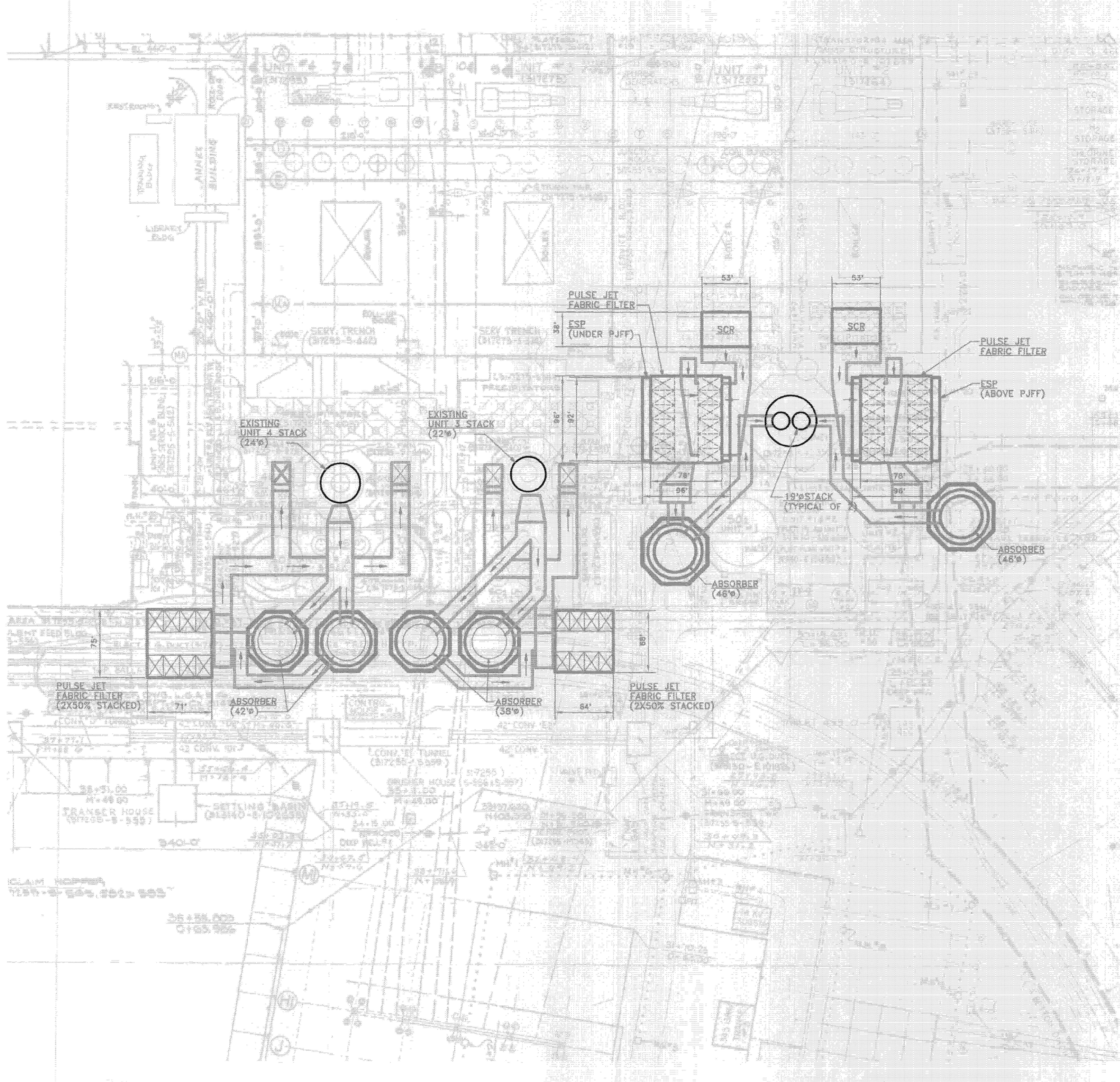
CANE RUN UNITS 4, 5 & 6

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT DRAWING NUMBER: 167987-CAQC-M1004 REV 0

Mill Creek



Mill Creek Units 1, 2, 3 & 4

Constructability Challenges

- Real estate constraints for all the units.
- Unit 1 & Unit 2 ESP elevated.
- Unit 3 & Unit 4 PJFF (2x50%) stacked one above another.
- Barge unloading is not economically feasible.
- Overhead power lines and @ least 2 transmission towers must be moved.
- Numerous underground utility interferences/relocations
- Numerous above ground utility interferences/relocations
- Very limited access around units due to existing AQCS Systems.
- Multiple mob/demob (very selective) dismantling operations are needed to insure tie-in work is accomplished efficiently.
- Building between units 1 & 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 AQCS systems.
- Ground stability will need to be verified, modified to accommodate heavy lift cranes.
- Multiple plant outages will be needed for tie-ins because we are utilizing existing scrubbers, etc…through out project.
- Ductwork routing is more extensive due to the lay out of the existing plant and existing AQCS 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 existing rail road tracks.

AQC Technology and Equipment Units 1 & 2

- Selective Catalyst Reduction.
- Electrostatic Precipitator and Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization

AQC Technology and Equipment Units 3 & 4

- Pulse Jet Fabric Filter
- Wet Flue Gas Desulfurization

LEGEND:

NEW EQUIPMENT=

NEW DUCTWORK=

EXISTING EQUIPMENT=

NOT TO BE USED FOR CONSTRUCTION

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500' 250' 0 500' 1000'

1"=500'

BLACK & VEATCH CORPORATION

ENGINEER | DRAWN MLW | CHECKED | DATE

E.ON.
MILL CREEK UNITS 1, 2, 3 & 4

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT | DRAWING NUMBER: 167987-CAQC-M1008 | REV 0

CODE | AREA

Trimble County

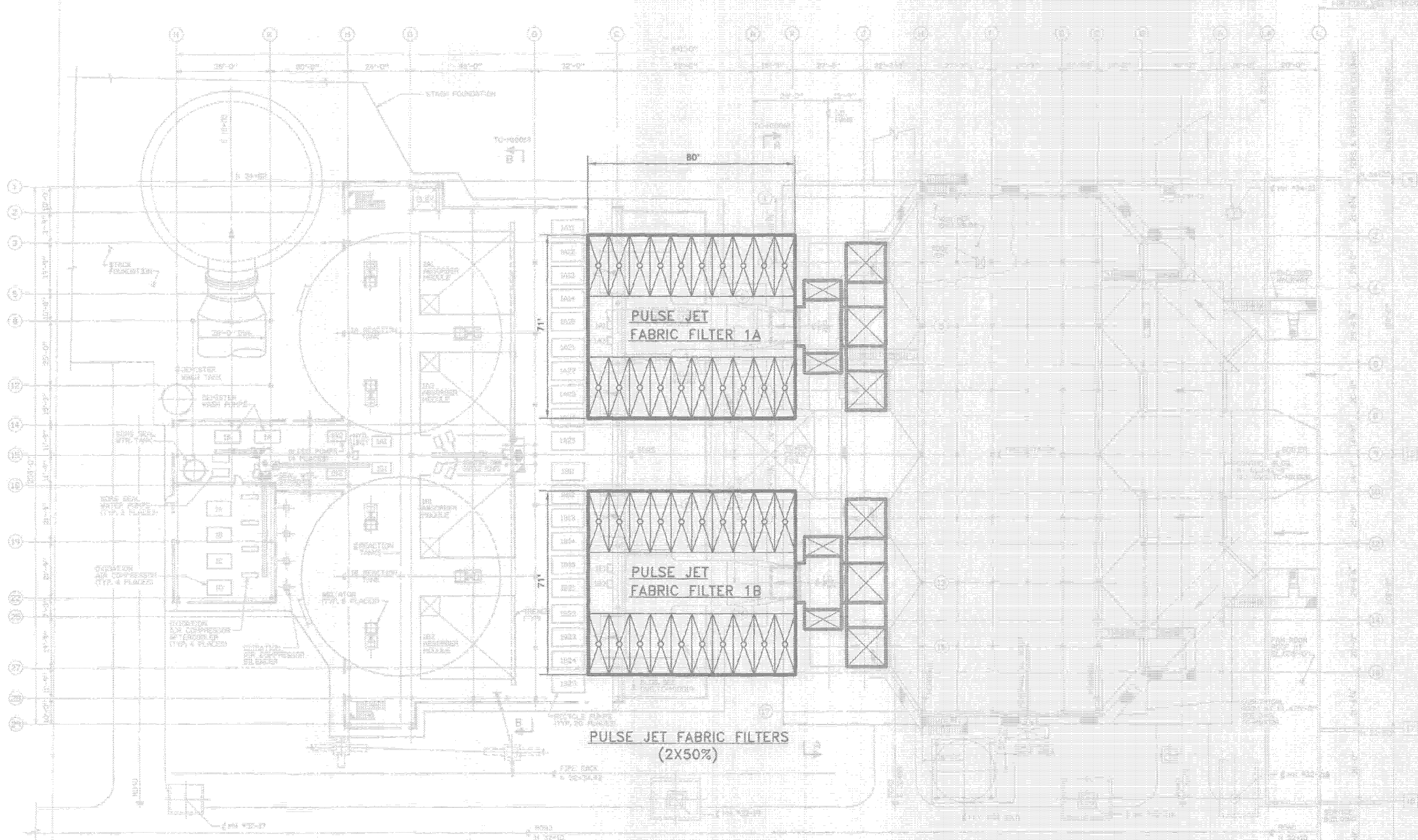
Trimble County Unit 1
Constructability Challenges

- Real estate constraints
- Elevated Pulse Jet Fabric Filter
- Extensive underground investigation will be required to identify operating utilities prior to installing new foundations
- 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.

AQC Technology and Equipment

- Pulse Jet Fabric Filter

LEGEND:
NEW EQUIPMENT–
NEW DUCTWORK–



PULSE JET FABRIC FILTERS (2X50%)

NOT TO BE USED FOR CONSTRUCTION

THE DISTRIBUTION AND USE OF THE NATIVE FORMAT CAD FILE OF THIS DRAWING IS UNCONTROLLED. THE USER SHALL VERIFY TRACEABILITY OF THIS DRAWING TO THE LATEST CONTROLLED VERSION.

NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	16/JUN/10	INITIAL ISSUE	MLW				

200' 100' 0 200' 400'
1" = 200'

BLACK & VEATCH CORPORATION

ENGINEER | DRAWN MLW | CHECKED | DATE

E.ON.
TRIMBLE COUNTY UNIT 1

FUTURE AQC TECHNOLOGY
CONCEPTUAL PLOT PLAN

PROJECT / DRAWING NUMBER: 167987-CAQC-M1009
REV: 0
CODE
AREA

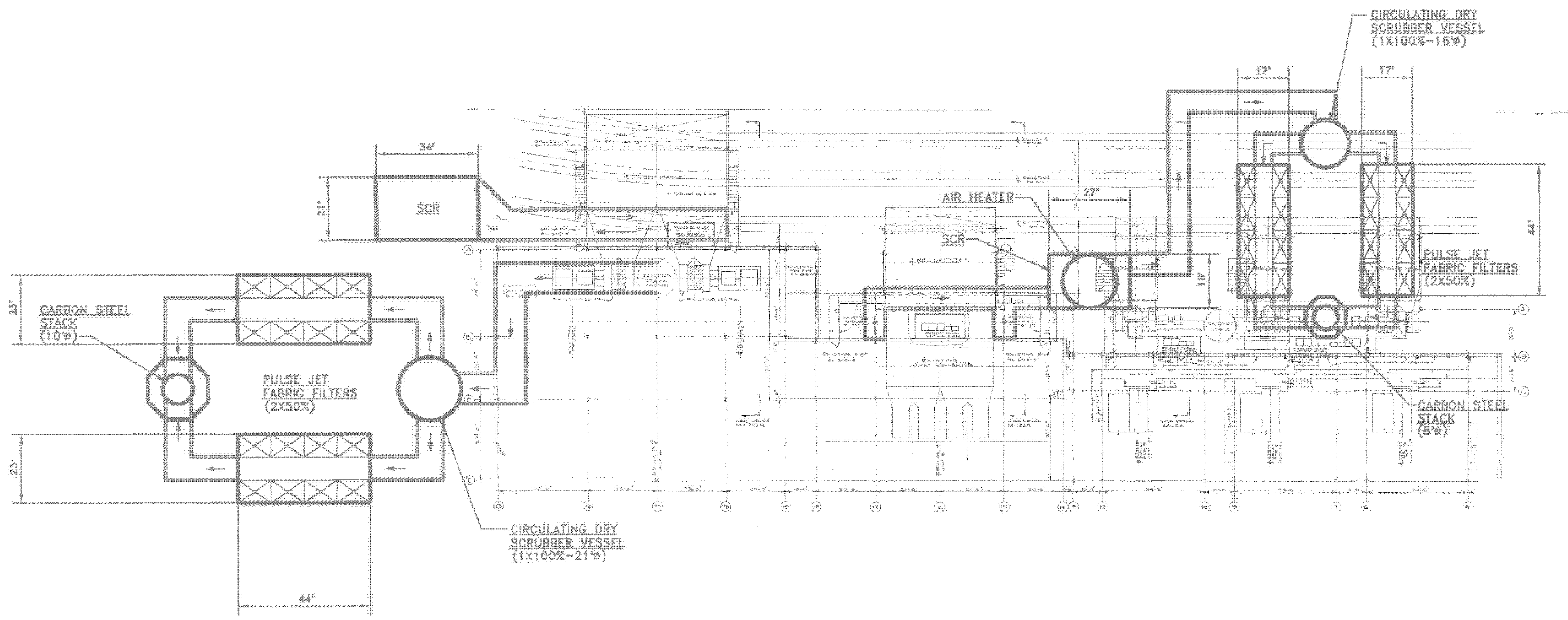
Green River

Green River Units 3 & 4

Constructability Challenges
- Overhead power lines and one tower needs to be relocated.
- Underground utility interferences/relocations
- Above ground utility interferences/relocations

AQC Technology and Equipment
- Selective Catalyst Reduction
- Circulating Dry Scrubber
- Pulse Jet Fabric Filter
- Stack
- Air Heater

LEGEND:
NEW EQUIPMENT=
NEW DUCTWORK=



NOT TO BE USED FOR CONSTRUCTION

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NO	DATE	REVISIONS AND RECORD OF ISSUE	DRN	DES	CHK	PDE	APP
0	15/JUN/10	INITIAL ISSUE	MLW				

200' 100' 0 200' 400'
1"=200'

BLACK & VEATCH CORPORATION

E.ON. GREEN RIVER UNITS 3 & 4	PROJECT / DRAWING NUMBER: 167987-CAQC-M1007	REV: 0
ENGINEER:	DRAWN: MLW	FUTURE AQC TECHNOLOGY CONCEPTUAL PLOT PLAN	CODE:
CHECKED:	DATE:		AREA:

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Appendix H
Air Quality Control Technology Costs

E.W. Brown

Plant Name: Brown
Unit: 1
MW 110
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
Fabric Filter	$40,000,000	$364	$1,477,000	$6,345,000
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	$44,022,000	$400	$2,273,000	$7,631,000

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BROWN UNIT 1 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$1,969,000			
Mechanical - Balance of Plant (BOP)	$5,641,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$119,000			
Control - DCS Instrumentation	$133,000			
ID Fans	$1,166,000	Engineering Estimates		
Subtotal Purchase Contract	**$9,028,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$1,752,000			
Civil/Structural Construction - Sub-Structures	$666,000			
Mechanical/Chemical Construction	$6,664,000			
Electrical/Control Construction	$2,250,000			
Service Contracts & Construction Indirects	$109,000			
Demolition Costs	$5,000,000	Engineering Estimates		
Subtotal Construction Contracts	**$16,441,000**			
Construction Difficulty Costs	**$11,508,700**	Engineering Estimates		
Total Direct Costs	**$36,977,700**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$1,426,000			
EPC Construction Management (Includes G&A & Fee)	$933,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$141,000			
Sales Taxes	$50,000			
Project Contingency - 18%	$526,000			
Total Indirect Costs	**$3,076,000**			
Total Contracted Costs	$40,000,000			
Cost Effectiveness	*$364 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	44%	
Maintenance labor and materials	$1,200,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$1,200,000**			
Variable Annual Costs				
Byproduct disposal	$6,000	210 lb/hr and	15	$/ton
Bag replacement cost	$91,000	2,740 bags and	100	$/bag
Cage replacement cost	$46,000	2,740 cages and	50	$/cage
ID fan power	$117,000	710 kW and	0.04266	$/kWh
Auxiliary power	$17,000	105 kW and	0.04266	$/kWh
Subtotal Variable Annual Costs	$277,000			
Total Annual Costs	$1,477,000			
Levelized Capital Costs	**$4,868,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$6,345,000			

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$92,670	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$60,897	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$84,726	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$10,591	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$39,716	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$254,179	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$13,239	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$556,018					
Freight	$14,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$570,000					
Direct installation costs						
Foundation & supports	$57,000	(PEC) X	10.0%			
Handling & erection	$114,000	(PEC) X	20.0%			
Electrical	$57,000	(PEC) X	10.0%			
Piping	$29,000	(PEC) X	5.0%			
Insulation	$11,000	(PEC) X	2.0%			
Painting	$29,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$297,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$942,000					
Indirect Costs						
Engineering	$113,000	(DC) X	12.0%			
Owner's cost	$113,000	(DC) X	12.0%			
Construction management	$94,000	(DC) X	10.0%			
Start-up and spare parts	$14,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$188,000	(DC) X	20.0%			
Total indirect costs (IC)	$622,000					
Allowance for Funds Used During Construction (AFDC)	$35,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$1,599,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$28,000	(DC) X	3.0%			
Operating labor	$123,000		1 FTE and	123,325 $/year		Estimated manpower
Total fixed annual costs	$151,000					
Variable annual costs				44 %		capacity factor
Reagent (BPAC)	$445,000		105 lb/hr and	2200 $/ton		
Byproduct disposal cost	$3,000		105 lb/hr and	15 $/ton		
Auxiliary power	$15,000		90 kW and	0.04266 $/kWh		
Total variable annual costs	$463,000					
Total direct annual costs (DAC)	$614,000					
Indirect Annual Costs						
Cost for capital recovery	$195,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$195,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$809,000					

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: Overfire Air System Operation **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Neuco NOx optimization package	$13,000	B&V cost estimate			
NOx monitoring equipment	$40,000	B&V cost estimate			
Water cannon system	$317,000	B&V cost estimate			
Subtotal capital cost (CC)	$370,000				
Freight	$19,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$389,000				
Direct installation costs					
Foundation & supports	$0	(PEC) X	0.0%		
Handling & erection	$78,000	(PEC) X	20.0%		
Electrical	$58,000	(PEC) X	15.0%		
Piping	$8,000	(PEC) X	2.0%		
Insulation	$0	(PEC) X	0.0%		
Painting	$0	(PEC) X	0.0%		
Demolition	$10,000	(PEC) X	2.5%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$154,000				
Site preparation	$0	N/A			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$543,000				
Indirect Costs					
Engineering	$54,000	(DC) X	10.0%		
Owner's cost	$11,000	(DC) X	2.0%		
Construction management	$27,000	(DC) X	5.0%		
Start-up and spare parts	$11,000	(DC) X	2.0%		
Performance test	$50,000	Engineering estimate			
Contingencies	$54,000	(DC) X	10.0%		
Total indirect costs (IC)	$207,000				
Allowance for Funds Used During Construction (AFDC)	$17,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$767,000				
Cost Effectiveness	*$7 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance materials	$10,000	B&V cost estimate			
Maintenance labor	$14,000	B&V cost estimate, 6 man weeks/yr			
Total fixed annual costs	$24,000				
Variable annual costs					
Replacement power due to efficiency hit	$108,000	Engineering estimates, 0.2% efficiency drop, and 0.05 $/kWh			
Total variable annual costs	$108,000				
Total direct annual costs (DAC)	$132,000				
Indirect Annual Costs					
Cost for capital recovery	$93,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$93,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$225,000				

EW Brown Unit 1
110 MW
High Level Emissions Control Study

Technology: Upgraded Low NOx Burners **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
New coal elbow, nozzle with air vane, fuel injector barrel, air zone swirler and coal piping	$602,000				
Subtotal capital cost (CC)	$602,000				
Freight	$30,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$632,000				
Direct installation costs					
Foundation & supports	$0	(PEC) X	0.0%		
Handling & erection	$126,000	(PEC) X	20.0%		
Electrical	$63,000	(PEC) X	10.0%		
Piping	$0	(PEC) X	0.0%		
Insulation	$0	(PEC) X	0.0%		
Painting	$0	(PEC) X	0.0%		
Demolition	$16,000	(PEC) X	2.5%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$205,000				
Site preparation	$0	N/A			
Buildings	$0	N/A			
Total direct costs (DC) = (PEC) + (DIC)	$837,000				
Indirect Costs					
Engineering	$84,000	(DC) X	10.0%		
Owner's cost	$17,000	(DC) X	2.0%		
Construction management	$42,000	(DC) X	5.0%		
Start-up and spare parts	$17,000	(DC) X	2.0%		
Performance test	$50,000	Engineering estimate			
Contingencies	$84,000	(DC) X	10.0%		
Total indirect costs (IC)	$294,000				
Allowance for Funds Used During Construction (AFDC)	$25,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$1,156,000				
Cost Effectiveness	*$11 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
N/A	$0	Similar annual costs as current LNB			
Total fixed annual costs	$0				
Variable annual costs					
N/A	$0	Similar annual costs as current LNB			
Total variable annual costs	$0				
Total direct annual costs (DAC)	$0				
Indirect Annual Costs					
Cost for capital recovery	$141,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$141,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$141,000				

E-ON Fleetwide Study Black & Veatch Cost Estimates 167987

Plant Name: Brown
Unit: 2
MW 180
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$92,000,000	$511	$3,278,000	$14,474,000
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	$148,715,000	$826	$7,532,000	$25,630,000

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BROWN UNIT 2 - SCR COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$4,636,000			
Ductwork and Breeching	$3,580,000			
Mechanical - Balance of Plant (BOP)	$1,173,000			
Electrical - Equipment, Raceway	$1,339,000			
VFDs, Motors and Couplings	$500,000	Engineering Estimates		
Switchgear and MCCs	$468,000			
Control - DCS Instrumentation	$151,000			
Air Heater Modifications	$0	Engineering Estimates		
ID Fans	$1,158,000	Engineering Estimates		
Catalyst	$1,883,000			
Selective Catalytic Reduction System (Including Ammonia System)	$1,643,000			
Subtotal Purchase Contract	**$16,531,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$2,854,000			
Civil/Structural Construction - Sub-Structures	$742,000			
Mechanical/Chemical Construction	$8,971,000			
Electrical/Control Construction	$4,103,000			
Service Contracts & Construction Indirects	$14,331,000			
Demolition Costs	$6,500,000	Engineering Estimates		
Subtotal Construction Contracts	**$37,501,000**			
Construction Difficulty Costs	**$26,250,700**	Engineering Estimates		
Total Direct Costs	**$80,282,700**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$2,696,000			
EPC Construction Management (Includes G&A & Fee)	$1,691,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$444,000			
Sales Taxes	$627,000			
Project Contingency	$6,326,000			
Total Indirect Costs	**$11,784,000**			
Total Contracted Costs	**$92,000,000**			
Capital Cost Effectiveness	***$511***	***/kW***		

ANNUAL COST

			Capacity Factor =	62%
Fixed Annual Costs				
Operating labor	$123,000	1 FTE and	123,325	$/year
Maintenance labor & materials	$2,408,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$2,581,000**			
Variable Annual Costs				
Reagent	$309,000	215 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$186,000	940 kW and	0.03646	$/kWh
Catalyst replacement	$202,000	50 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$697,000**			
Total Annual Costs	**$3,278,000**			
Levelized Capital Costs	**$11,196,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$14,474,000**			

BROWN UNIT 2 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$2,646,000			
Mechanical - Balance of Plant (BOP)	$7,580,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$161,000			
Control - DCS Instrumentation	$178,000			
ID Fans	$535,000	Engineering Estimates		
Subtotal Purchase Contract	**$11,100,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$2,355,000			
Civil/Structural Construction - Sub-Structures	$895,000			
Mechanical/Chemical Construction	$8,956,000			
Electrical/Control Construction	$3,024,000			
Service Contracts & Construction Indirects	$146,000			
Demolition Costs	$5,000,000	Engineering Estimates		
Subtotal Construction Contracts	**$20,376,000**			
Construction Difficulty Costs	**$14,263,200**	Engineering Estimates		
Total Direct Costs	**$45,739,200**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$2,334,000			
EPC Construction Management (Includes G&A & Fee)	$1,527,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$231,000			
Sales Taxes	$82,000			
Project Contingency - 18%	$860,000			
Total Indirect Costs	**$5,034,000**			
Total Contracted Costs	$51,000,000			
Cost Effectiveness	*$283*	*/kW*		

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	62%	
Maintenance labor and materials	$1,530,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$1,530,000**			
Variable Annual Costs				
Byproduct disposal	$5,000	120 lb/hr and	15	$/ton
Bag replacement cost	$129,000	3,880 bags and	100	$/bag
Cage replacement cost	$65,000	3,880 cages and	50	$/cage
ID fan power	$200,000	1,010 kW and	0.03646	$/kWh
Auxiliary power	$30,000	150 kW and	0.03646	$/kWh
Subtotal Variable Annual Costs	$429,000			
Total Annual Costs	$1,959,000			
Levelized Capital Costs	**$6,207,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$8,166,000			

Brown Unit 2
180 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$133,800	From Previous Mill Creek BACT Study				
Short-term storage silo	$88,800	From Previous Mill Creek BACT Study				
Air blowers	$121,800	From Previous Mill Creek BACT Study				
Rotary feeders	$19,800	From Previous Mill Creek BACT Study				
Injection system	$80,400	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$526,800	From Previous Mill Creek BACT Study				
Instrumentation and controls	$25,200	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$996,600					
Freight	$45,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$1,042,000					
Direct installation costs						
Foundation & supports	$104,000	(PEC) X	10.0%			
Handling & erection	$208,000	(PEC) X	20.0%			
Electrical	$104,000	(PEC) X	10.0%			
Piping	$52,000	(PEC) X	5.0%			
Insulation	$21,000	(PEC) X	2.0%			
Painting	$52,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$541,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$1,658,000					
Indirect Costs						
Engineering	$199,000	(DC) X	12.0%			
Owner's cost	$199,000	(DC) X	12.0%			
Construction management	$166,000	(DC) X	10.0%			
Start-up and spare parts	$25,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$332,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,021,000					
Allowance for Funds Used During Construction (AFDC)	$60,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,739,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$50,000	(DC) X	3.0%			
Operating labor	$123,000		1 FTE and	123,325 $/year		Estimated manpower
Total fixed annual costs	$173,000					
Variable annual costs				62 %		capacity factor
Lime	$754,000		2,100 lb/hr and	132.19 $/ton		
Byproduct disposal cost	$208,000		2,400 lb/hr and	15 $/ton		
Auxiliary power	$20,000		100 kW and	0.03646 $/kWh		
Total variable annual costs	$982,000					
Total direct annual costs (DAC)	$1,155,000					
Indirect Annual Costs						
Cost for capital recovery	$333,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$333,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,488,000					

Brown Unit 2
180 MW
High Level Emissions Control Study

Technology: PAC Injection | **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$151,641	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$99,650	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$138,643	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$17,330	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$64,989	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$415,930	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$21,663	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$909,847				
Freight	$23,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$933,000				
Direct installation costs					
Foundation & supports	$93,000	(PEC) X	10.0%		
Handling & erection	$187,000	(PEC) X	20.0%		
Electrical	$93,000	(PEC) X	10.0%		
Piping	$47,000	(PEC) X	5.0%		
Insulation	$19,000	(PEC) X	2.0%		
Painting	$47,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$486,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$1,494,000				
Indirect Costs					
Engineering	$179,000	(DC) X	12.0%		
Owner's cost	$179,000	(DC) X	12.0%		
Construction management	$149,000	(DC) X	10.0%		
Start-up and spare parts	$22,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$299,000	(DC) X	20.0%		
Total indirect costs (IC)	$928,000				
Allowance for Funds Used During Construction (AFDC)	$54,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,476,000				
Cost Effectiveness	*$14 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$45,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$168,000				
Variable annual costs				62 %	capacity factor
Reagent (BPAC)	$896,000		150 lb/hr and	2200 $/ton	
Byproduct disposal cost	$6,000		150 lb/hr and	15 $/ton	
Auxiliary power	$20,000		100 kW and	0.03646 $/kWh	
Total variable annual costs	$922,000				
Total direct annual costs (DAC)	$1,090,000				
Indirect Annual Costs					
Cost for capital recovery	$301,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$301,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,391,000				

Plant Name:	Brown
Unit:	3
MW	457
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
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

BROWN UNIT 3 - PJFF COSTS

CAPITAL COST

Purchase Contracts					
Civil/Structural	$4,628,000				
Mechanical - Balance of Plant (BOP)	$13,257,000				
Electrical - Equipment, Raceway, Switchgears, MCC	$281,000				
Control - DCS Instrumentation	$312,000				
ID Fans	$1,930,000	Engineering Estimates			
Subtotal Purchase Contract	**$20,408,000**				
Construction Contracts					
Civil/Structural Construction - Super Structures	$4,118,000				
Civil/Structural Construction - Sub-Structures	$1,565,000				
Mechanical/Chemical Construction	$15,663,000				
Electrical/Control Construction	$5,289,000				
Service Contracts & Construction Indirects	$255,000				
Demolition Costs	$500,000	Engineering Estimates			
Subtotal Construction Contracts	**$27,390,000**				
Construction Difficulty Costs	**$0**	Engineering Estimates			
Total Direct Costs	**$47,798,000**				
Indirect Costs					
Engineering Costs (Includes G&A & Fee)	$5,925,000				
EPC Construction Management (Includes G&A & Fee)	$3,877,000				
Startup Spare Parts (Included)	$0				
Construction Utilites (Power & Water) - Included	$0				
Project Insurance	$586,000				
Sales Taxes	$209,000				
Project Contingency - 18%	$2,183,000				
Total Indirect Costs	**$12,780,000**				
Total Contracted Costs	$61,000,000				
Cost Effectiveness	*$133*	*/kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	57%		
Maintenance labor and materials	$1,830,000	(DC) X 3.0%			
Subtotal Fixed Annual Costs	**$1,830,000**				
Variable Annual Costs					
Byproduct disposal	$11,000	290	lb/hr and	15	$/ton
Bag replacement cost	$588,000	17,630	bags and	100	$/bag
Cage replacement cost	$294,000	17,630	cages and	50	$/cage
ID fan power	$460,000	2,540	kW and	0.03624	$/kWh
Auxiliary power	$138,000	760	kW and	0.03624	$/kWh
Subtotal Variable Annual Costs	$1,491,000				
Total Annual Costs	$3,321,000				
Levelized Capital Costs	**$7,424,000**	(TCI) X 12.17%	CRF		
Levelized Annual Costs	$10,745,000				

EW Brown Unit 3
457 MW
High Level Emissions Control Study

Technology: **PAC Injection** **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$350,000	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$230,000	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$320,000	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$40,000	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$150,000	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$960,000	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$50,000	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$2,100,000				
Freight	$53,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$2,153,000				
Direct installation costs					
Foundation & supports	$215,000	(PEC) X	10.0%		
Handling & erection	$431,000	(PEC) X	20.0%		
Electrical	$215,000	(PEC) X	10.0%		
Piping	$108,000	(PEC) X	5.0%		
Insulation	$43,000	(PEC) X	2.0%		
Painting	$108,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,120,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,348,000				
Indirect Costs					
Engineering	$402,000	(DC) X	12.0%		
Owner's cost	$402,000	(DC) X	12.0%		
Construction management	$335,000	(DC) X	10.0%		
Start-up and spare parts	$50,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$670,000	(DC) X	20.0%		
Total indirect costs (IC)	$1,959,000				
Allowance for Funds Used During Construction (AFDC)	$119,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$5,426,000				
Cost Effectiveness	*$12 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$100,000	(DC) X	3.0%		
Operating labor	$123,000		1 FTE and	123,325 $/year	Estimated manpower
Total fixed annual costs	$223,000				
Variable annual costs				57 %	capacity factor
Reagent (BPAC)	$2,060,000		375 lb/hr and	2200 $/ton	
Byproduct disposal cost	$14,000		375 lb/hr and	15 $/ton	
Auxiliary power	$33,000		180 kW and	0.03624 $/kWh	
Total variable annual costs	$2,107,000				
Total direct annual costs (DAC)	$2,330,000				
Indirect Annual Costs					
Cost for capital recovery	$660,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$660,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$2,990,000				

Ghent

Plant Name:	Ghent
Unit:	1
MW	541
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
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

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GHENT UNIT 1 - PJFF COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$5,121,000	
Mechanical - Balance of Plant (BOP)	$14,669,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$311,000	
Control - DCS Instrumentation	$345,000	
ID Fans	$2,493,000	Engineering Estimates
Subtotal Purchase Contract	**$22,939,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$4,557,000	
Civil/Structural Construction - Sub-Structures	$1,732,000	
Mechanical/Chemical Construction	$17,332,000	
Electrical/Control Construction	$5,853,000	
Service Contracts & Construction Indirects	$283,000	
Demolition Costs	$6,000,000	Engineering Estimates
Subtotal Construction Contracts	**$35,757,000**	
Construction Difficulty Costs	**$57,211,200**	Engineering Estimates
Total Direct Costs	**$115,907,200**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$7,014,000
EPC Construction Management (Includes G&A & Fee)	$4,590,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$693,000
Sales Taxes	$247,000
Project Contingency - 18%	$2,585,000
Total Indirect Costs	**$15,129,000**
Total Contracted Costs	$131,000,000
Cost Effectiveness	*$242 /kW*

ANNUAL COST

Fixed Annual Costs Capacity Factor = 81%

Maintenance labor and materials	$3,930,000	(DC) X 3.0%
Subtotal Fixed Annual Costs	**$3,930,000**	

Variable Annual Costs

Byproduct disposal	$0	0 lb/hr and	15 $/ton
Bag replacement cost	$786,000	23,590 bags and	100 $/bag
Cage replacement cost	$393,000	23,590 cages and	50 $/cage
ID fan power	$600,000	3,400 kW and	0.02487 $/kWh
Auxiliary power	$179,000	1,015 kW and	0.02487 $/kWh
Subtotal Variable Annual Costs	$1,958,000		
Total Annual Costs	$5,888,000		
Levelized Capital Costs	**$15,943,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$21,831,000		

Ghent Unit 1
514 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$414,333	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$272,276	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$378,818	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$47,352	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$177,571	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$1,136,455	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$59,190	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$2,485,996				
Freight	$62,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$2,548,000				
Direct installation costs					
Foundation & supports	$255,000	(PEC) X	10.0%		
Handling & erection	$510,000	(PEC) X	20.0%		
Electrical	$255,000	(PEC) X	10.0%		
Piping	$127,000	(PEC) X	5.0%		
Insulation	$51,000	(PEC) X	2.0%		
Painting	$127,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,325,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,948,000				
Indirect Costs					
Engineering	$474,000	(DC) X	12.0%		
Owner's cost	$474,000	(DC) X	12.0%		
Construction management	$395,000	(DC) X	10.0%		
Start-up and spare parts	$59,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$790,000	(DC) X	20.0%		
Total indirect costs (IC)	$2,292,000				
Allowance for Funds Used During Construction (AFDC)	$140,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,380,000				
Cost Effectiveness	*$12 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$118,000	(DC) X	3.0%		
Operating labor	$121,000		1 FTE and	121,000 $/year	Estimated manpower
Total fixed annual costs	$239,000				
Variable annual costs				81 %	capacity factor
Reagent (BPAC)	$3,903,000		500 lb/hr and	2200 $/ton	
Byproduct disposal cost	$27,000		500 lb/hr and	15 $/ton	
Auxiliary power	$39,000		220 kW and	0.02487 $/kWh	
Total variable annual costs	$3,969,000				
Total direct annual costs (DAC)	$4,208,000				
Indirect Annual Costs					
Cost for capital recovery	$776,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$776,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$4,984,000				

Plant Name:	Ghent
Unit:	2
MW	517
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$227,000,000	$439	$7,078,000	$34,704,000
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	$359,592,000	$696	$17,835,000	$61,597,000

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GHENT UNIT 2 - SCR COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$8,731,000	
Ductwork and Breeching	$6,743,000	
Mechanical - Balance of Plant (BOP)	$2,208,000	
Electrical - Equipment, Raceway	$2,522,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$882,000	
Control - DCS Instrumentation	$284,000	
Air Heater Modifications	$0	Engineering Estimates
ID Fans	$2,858,000	Engineering Estimates
Catalyst	$3,547,000	
Selective Catalytic Reduction System (Including Ammonia System)	$3,094,000	
Subtotal Purchase Contract	**$31,369,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$5,375,000	
Civil/Structural Construction - Sub-Structures	$1,397,000	
Mechanical/Chemical Construction	$16,896,000	
Electrical/Control Construction	$7,727,000	
Service Contracts & Construction Indirects	$26,991,000	
Demolition Costs	$9,000,000	Engineering Estimates
Subtotal Construction Contracts	**$67,386,000**	
Construction Difficulty Costs	**$94,340,400**	Engineering Estimates
Total Direct Costs	**$193,095,400**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$7,743,000	
EPC Construction Management (Includes G&A & Fee)	$4,858,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$1,275,000	
Sales Taxes	$1,800,000	
Project Contingency	$18,169,000	
Total Indirect Costs	**$33,845,000**	
Total Contracted Costs	**$227,000,000**	
Capital Cost Effectiveness	***$439***	***/kW***

ANNUAL COST

Capacity Factor = 71%

Fixed Annual Costs

Operating labor	$121,000	1 FTE and	121,000	$/year
Maintenance labor & materials	$5,793,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$5,964,000**			

Variable Annual Costs

Reagent	$459,000	285 lb/hr and	517.55	$/ton
Auxiliary and ID fan power	$355,000	2,320 kW and	0.02459	$/kWh
Catalyst replacement	$300,000	65 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$1,114,000**			
Total Annual Costs	**$7,078,000**			
Levelized Capital Costs	**$27,626,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$34,704,000**			

GHENT UNIT 2 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$4,984,000			
Mechanical - Balance of Plant (BOP)	$14,275,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$302,000			
Control - DCS Instrumentation	$336,000			
ID Fans	$1,319,000	Engineering Estimates		
Subtotal Purchase Contract	**$21,216,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$4,435,000			
Civil/Structural Construction - Sub-Structures	$1,686,000			
Mechanical/Chemical Construction	$16,866,000			
Electrical/Control Construction	$5,695,000			
Service Contracts & Construction Indirects	$275,000			
Demolition Costs	$6,000,000	Engineering Estimates		
Subtotal Construction Contracts	**$34,957,000**			
Construction Difficulty Costs	**$48,939,800**	Engineering Estimates		
Total Direct Costs	**$105,112,800**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$6,703,000			
EPC Construction Management (Includes G&A & Fee)	$4,386,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$662,000			
Sales Taxes	$236,000			
Project Contingency - 18%	$2,470,000			
Total Indirect Costs	**$14,457,000**			
Total Contracted Costs	$120,000,000			
Cost Effectiveness	*$232 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	71%	
Maintenance labor and materials	$3,600,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$3,600,000**			
Variable Annual Costs				
Byproduct disposal	$5,000	115 lb/hr and	15	$/ton
Bag replacement cost	$592,000	17,770 bags and	100	$/bag
Cage replacement cost	$296,000	17,770 cages and	50	$/cage
ID fan power	$392,000	2,560 kW and	0.02459	$/kWh
Auxiliary power	$117,000	765 kW and	0.02459	$/kWh
Subtotal Variable Annual Costs	$1,402,000			
Total Annual Costs	$5,002,000			
Levelized Capital Costs	**$14,604,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$19,606,000			

Ghent Unit 2
517 MW
High Level Emissions Control Study

Technology: Sorbent Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$279,493	From Previous Mill Creek BACT Study			
Short-term storage silo	$185,493	From Previous Mill Creek BACT Study			
Air blowers	$254,427	From Previous Mill Creek BACT Study			
Rotary feeders	$41,360	From Previous Mill Creek BACT Study			
Injection system	$167,947	From Previous Mill Creek BACT Study			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$1,100,427	From Previous Mill Creek BACT Study			
Instrumentation and controls	$52,640	From Previous Mill Creek BACT Study			
Subtotal capital cost (CC)	$2,081,787				
Freight	$94,000	(CC) X	4.5%		
Total purchased equipment cost (PEC)	$2,176,000				
Direct installation costs					
Foundation & supports	$218,000	(PEC) X	10.0%		
Handling & erection	$435,000	(PEC) X	20.0%		
Electrical	$218,000	(PEC) X	10.0%		
Piping	$109,000	(PEC) X	5.0%		
Insulation	$44,000	(PEC) X	2.0%		
Painting	$109,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,133,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,384,000				
Indirect Costs					
Engineering	$406,000	(DC) X	12.0%		
Owner's cost	$406,000	(DC) X	12.0%		
Construction management	$338,000	(DC) X	10.0%		
Start-up and spare parts	$51,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$677,000	(DC) X	20.0%		
Total indirect costs (IC)	$1,978,000				
Allowance for Funds Used During Construction (AFDC)	$121,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$5,483,000				
Cost Effectiveness	*$11 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$102,000	(DC) X	3.0%		
Operating labor	$121,000		1 FTE and	121,000 $/year	
Total fixed annual costs	$223,000				
Variable annual costs				71 %	capacity factor
Lime	$2,233,000		5,450 lb/hr and	131.78 $/ton	
Byproduct disposal	$291,000		6,230 lb/hr and	15 $/ton	
Auxiliary power	$28,000		180 kW and	0.02459 $/kWh	
Total variable annual costs	$2,552,000				
Total direct annual costs (DAC)	$2,775,000				
Indirect Annual Costs					
Cost for capital recovery	$667,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$667,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$3,442,000				

Ghent Unit 2
517 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$395,952	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$260,197	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$362,013	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$45,252	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$169,694	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$1,086,039	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$56,565	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$2,375,711					
Freight	$59,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$2,435,000					
Direct installation costs						
Foundation & supports	$244,000	(PEC) X	10.0%			
Handling & erection	$487,000	(PEC) X	20.0%			
Electrical	$244,000	(PEC) X	10.0%			
Piping	$122,000	(PEC) X	5.0%			
Insulation	$49,000	(PEC) X	2.0%			
Painting	$122,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$1,268,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$3,778,000					
Indirect Costs						
Engineering	$453,000	(DC) X	12.0%			
Owner's cost	$453,000	(DC) X	12.0%			
Construction management	$378,000	(DC) X	10.0%			
Start-up and spare parts	$57,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$756,000	(DC) X	20.0%			
Total indirect costs (IC)	$2,197,000					
Allowance for Funds Used During Construction (AFDC)	$134,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,109,000					
Cost Effectiveness	*$12 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$113,000	(DC) X	3.0%			
Operating labor	$121,000		1 FTE and	121,000 $/year		Estimated manpower
Total fixed annual costs	$234,000					
Variable annual costs				71 %		capacity factor
Reagent (BPAC)	$2,600,000		380 lb/hr and	2200 $/ton		
Byproduct disposal cost	$18,000		380 lb/hr and	15 $/ton		
Auxiliary power	$28,000		180 kW and	0.02459 $/kWh		
Total variable annual costs	$2,646,000					
Total direct annual costs (DAC)	$2,880,000					
Indirect Annual Costs						
Cost for capital recovery	$743,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$743,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$3,623,000					

Plant Name: Ghent
Unit: 3
MW 523
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
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

GHENT UNIT 3 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$10,036,000			
Mechanical - Balance of Plant (BOP)	$14,374,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$305,000			
Control - DCS Instrumentation	$338,000			
ID Fans	$2,654,000	Engineering Estimates		
Subtotal Purchase Contract	**$27,707,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$8,931,000			
Civil/Structural Construction - Sub-Structures	$3,395,000			
Mechanical/Chemical Construction	$16,984,000			
Electrical/Control Construction	$5,735,000			
Service Contracts & Construction Indirects	$277,000			
Demolition Costs	$1,500,000	Engineering Estimates		
Subtotal Construction Contracts	**$36,822,000**			
Construction Difficulty Costs	**$58,915,200**	Engineering Estimates		
Total Direct Costs	**$123,444,200**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$6,781,000			
EPC Construction Management (Includes G&A & Fee)	$4,437,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$670,000			
Sales Taxes	$239,000			
Project Contingency - 18%	$2,499,000			
Total Indirect Costs	**$14,626,000**			
Total Contracted Costs	$138,000,000			
Cost Effectiveness	*$264 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	78%	
Maintenance labor and materials	$4,140,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$4,140,000**			
Variable Annual Costs				
Byproduct disposal	$4,000	85 lb/hr and	15	$/ton
Bag replacement cost	$799,000	23,960 bags and	100	$/bag
Cage replacement cost	$399,000	23,960 cages and	50	$/cage
ID fan power	$601,000	3,455 kW and	0.02544	$/kWh
Auxiliary power	$179,000	1,030 kW and	0.02544	$/kWh
Subtotal Variable Annual Costs	$1,982,000			
Total Annual Costs	$6,122,000			
Levelized Capital Costs	**$16,795,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$22,917,000			

Ghent Unit 3
523 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$400,547	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$263,217	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$366,214	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$45,777	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$171,663	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$1,098,643	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$57,221	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$2,403,282				
Freight	$60,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$2,463,000				
Direct installation costs					
Foundation & supports	$246,000	(PEC) X	10.0%		
Handling & erection	$493,000	(PEC) X	20.0%		
Electrical	$246,000	(PEC) X	10.0%		
Piping	$123,000	(PEC) X	5.0%		
Insulation	$49,000	(PEC) X	2.0%		
Painting	$123,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,280,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,818,000				
Indirect Costs					
Engineering	$458,000	(DC) X	12.0%		
Owner's cost	$458,000	(DC) X	12.0%		
Construction management	$382,000	(DC) X	10.0%		
Start-up and spare parts	$57,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$764,000	(DC) X	20.0%		
Total indirect costs (IC)	$2,219,000				
Allowance for Funds Used During Construction (AFDC)	$136,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,173,000				
Cost Effectiveness	*$12 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$115,000	(DC) X	3.0%		
Operating labor	$121,000		1 FTE and	121,000 $/year	Estimated manpower
Total fixed annual costs	$236,000				
Variable annual costs				78 %	capacity factor
Reagent (BPAC)	$3,833,000		510 lb/hr and	2200 $/ton	
Byproduct disposal cost	$26,000		510 lb/hr and	15 $/ton	
Auxiliary power	$39,000		225 kW and	0.02544 $/kWh	
Total variable annual costs	$3,898,000				
Total direct annual costs (DAC)	$4,134,000				
Indirect Annual Costs					
Cost for capital recovery	$751,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$751,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$4,885,000				

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Plant Name:	Ghent
Unit:	4
MW	526
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
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

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GHENT UNIT 4 - PJFF COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$5,035,000	
Mechanical - Balance of Plant (BOP)	$14,424,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$306,000	
Control - DCS Instrumentation	$339,000	
ID Fans	$2,574,000	Engineering Estimates
Subtotal Purchase Contract	**$22,678,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$4,481,000	
Civil/Structural Construction - Sub-Structures	$1,703,000	
Mechanical/Chemical Construction	$17,042,000	
Electrical/Control Construction	$5,755,000	
Service Contracts & Construction Indirects	$278,000	
Demolition Costs	$1,500,000	Engineering Estimates
Subtotal Construction Contracts	**$30,759,000**	
Construction Difficulty Costs	**$49,214,400**	Engineering Estimates
Total Direct Costs	**$102,651,400**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$6,820,000
EPC Construction Management (Includes G&A & Fee)	$4,463,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$674,000
Sales Taxes	$240,000
Project Contingency - 18%	$2,513,000
Total Indirect Costs	**$14,710,000**
Total Contracted Costs	$117,000,000
Cost Effectiveness	*$222 /kW*

ANNUAL COST

Fixed Annual Costs Capacity Factor = 77%

Maintenance labor and materials	$3,510,000	(DC) X 3.0%
Subtotal Fixed Annual Costs	**$3,510,000**	

Variable Annual Costs

Byproduct disposal	$0	0 lb/hr and	15 $/ton
Bag replacement cost	$758,000	22,730 bags and	100 $/bag
Cage replacement cost	$379,000	22,730 cages and	50 $/cage
ID fan power	$551,000	3,280 kW and	0.0249 $/kWh
Auxiliary power	$165,000	980 kW and	0.0249 $/kWh
Subtotal Variable Annual Costs	$1,853,000		
Total Annual Costs	$5,363,000		
Levelized Capital Costs	**$14,239,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$19,602,000		

Ghent Unit 4
526 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$402,845	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$264,726	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$368,315	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$46,039	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$172,648	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$1,104,945	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$57,549	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$2,417,068				
Freight	$60,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$2,477,000				
Direct installation costs					
Foundation & supports	$248,000	(PEC) X	10.0%		
Handling & erection	$495,000	(PEC) X	20.0%		
Electrical	$248,000	(PEC) X	10.0%		
Piping	$124,000	(PEC) X	5.0%		
Insulation	$50,000	(PEC) X	2.0%		
Painting	$124,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$1,289,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$3,841,000				
Indirect Costs					
Engineering	$461,000	(DC) X	12.0%		
Owner's cost	$461,000	(DC) X	12.0%		
Construction management	$384,000	(DC) X	10.0%		
Start-up and spare parts	$58,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$768,000	(DC) X	20.0%		
Total indirect costs (IC)	$2,232,000				
Allowance for Funds Used During Construction (AFDC)	$137,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,210,000				
Cost Effectiveness	*$12 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$115,000	(DC) X	3.0%		
Operating labor	$121,000		1 FTE and	121,000 $/year	Estimated manpower
Total fixed annual costs	$236,000				
Variable annual costs				77 %	capacity factor
Reagent (BPAC)	$3,599,000		485 lb/hr and	2200 $/ton	
Byproduct disposal cost	$25,000		485 lb/hr and	15 $/ton	
Auxiliary power	$36,000		215 kW and	0.0249 $/kWh	
Total variable annual costs	$3,660,000				
Total direct annual costs (DAC)	$3,896,000				
Indirect Annual Costs					
Cost for capital recovery	$756,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$756,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$4,652,000				

Cane Run

Plant Name: Cane Run
Unit: 4
MW 168
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$63,000,000	$375	$2,219,000	$9,886,000
WFGD	$152,000,000	$905	$8,428,000	$26,926,000
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	$253,395,000	$1,508	$14,691,000	$45,529,000

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CANE RUN UNIT 4 - SCR COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$4,448,000			
Ductwork and Breeching	$3,435,000			
Mechanical - Balance of Plant (BOP)	$1,125,000			
Electrical - Equipment, Raceway	$1,285,000			
VFDs, Motors and Couplings	$500,000	Engineering Estimates		
Switchgear and MCCs	$449,000			
Control - DCS Instrumentation	$145,000			
Air Heater	$2,910,000	Engineering Estimates		
ID Fans	$1,717,000	Engineering Estimates		
Catalyst	$1,807,000			
Selective Catalytic Reduction System (Including Ammonia System)	$1,576,000			
Subtotal Purchase Contract	**$19,397,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$2,738,000			
Civil/Structural Construction - Sub-Structures	$712,000			
Mechanical/Chemical Construction	$8,607,000			
Electrical/Control Construction	$3,937,000			
Service Contracts & Construction Indirects	$13,750,000			
Demolition Costs	$2,754,000	Engineering Estimates		
Subtotal Construction Contracts	**$32,498,000**			
Construction Difficulty Costs	**$0**	Engineering Estimates		
Total Direct Costs	**$51,895,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$2,516,000			
EPC Construction Management (Includes G&A & Fee)	$1,579,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$414,000			
Sales Taxes	$585,000			
Project Contingency	$5,904,000			
Total Indirect Costs	**$10,998,000**			
Total Contracted Costs	**$63,000,000**			
Capital Cost Effectiveness	***$375***	***/kW***		
ANNUAL COST				
		Capacity Factor =	60%	
Fixed Annual Costs				
Operating labor	$127,000	1 FTE and	126,882	$/year
Maintenance labor & materials	$1,557,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$1,734,000**			
Variable Annual Costs				
Reagent	$202,000	145 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$146,000	965 kW and	0.0288	$/kWh
Catalyst replacement	$137,000	35 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$485,000**			
Total Annual Costs	**$2,219,000**			
Levelized Capital Costs	**$7,667,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$9,886,000**			

CANE RUN UNIT 4 - WFGD COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$1,712,000			
Ductwork and Breeching	$2,638,000			
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$56,758,000			
Electrical - Equipment, Raceway	$6,304,000			
VFDs, Motors and Couplings	$3,705,000			
Switchgear and MCCs	$3,825,000			
Control - DCS Instrumentation	$3,537,000			
ID Fans	$1,189,000	Engineering Estimates		
Subtotal Purchase Contract	**$79,668,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$6,373,000			
Civil/Structural Construction - Sub-Structures	$621,000			
Mechanical/Chemical Construction	$14,560,000			
Electrical/Control Construction	$5,969,000			
Service Contracts & Construction Indirects	$11,344,000			
Subtotal Construction Contracts	**$38,867,000**			
Construction Difficulty Costs	**$0**	Engineering Estimates		
Total Direct Costs	**$118,535,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$4,849,000			
EPC Construction Management (Includes G&A & Fee)	$6,369,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$653,000			
Sales Taxes	$26,000			
Project Contingency	$21,236,000			
Total Indirect Costs	**$33,133,000**			
Total Contracted Costs	$152,000,000			
Cost Effectiveness	*$905 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	60%	
Operating labor	$2,538,000	20 FTE and	126,882	$/year
Maintenance labor and materials	$3,556,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$6,094,000**			
Variable Annual Costs				
Reagent	$479,000	15,795 lb/hr and	11.54	$/ton
Byproduct disposal	$1,071,000	27,170 lb/hr and	15	$/ton
Auxiliary and ID fan power	$607,000	4,010 kW and	0.03	$/kWh
Water	$177,000	280 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$2,334,000			
Total Annual Costs	$8,428,000			
Levelized Capital Costs	**$18,498,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$26,926,000			

CANE RUN UNIT 4 - PJFF COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$2,539,000	
Mechanical - Balance of Plant (BOP)	$7,272,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$154,000	
Control - DCS Instrumentation	$171,000	
ID Fans	$793,000	Engineering Estimates
Subtotal Purchase Contract	**$10,929,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$2,259,000	
Civil/Structural Construction - Sub-Structures	$859,000	
Mechanical/Chemical Construction	$8,592,000	
Electrical/Control Construction	$2,901,000	
Service Contracts & Construction Indirects	$140,000	
Demolition Costs	$2,754,000	Engineering Estimates
Subtotal Construction Contracts	**$17,505,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$28,434,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$2,178,000	
EPC Construction Management (Includes G&A & Fee)	$1,425,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$215,000	
Sales Taxes	$77,000	
Project Contingency - 18%	$803,000	
Total Indirect Costs	**$4,698,000**	
Total Contracted Costs	$33,000,000	
Cost Effectiveness	*$196 /kW*	

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	60%	
Maintenance labor and materials	$990,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$990,000**			
Variable Annual Costs				
Byproduct disposal	$551,000	13,975 lb/hr and	15	$/ton
Bag replacement cost	$134,000	4,030 bags and	100	$/bag
Cage replacement cost	$67,000	4,030 cages and	50	$/cage
ID fan power	$159,000	1,050 kW and	0.03	$/kWh
Auxiliary power	$23,000	155 kW and	0.03	$/kWh
Subtotal Variable Annual Costs	$934,000			
Total Annual Costs	$1,924,000			
Levelized Capital Costs	**$4,016,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$5,940,000			

Cane Run Unit 4
168 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$124,880	From Previous Mill Creek BACT Study				
Short-term storage silo	$82,880	From Previous Mill Creek BACT Study				
Air blowers	$113,680	From Previous Mill Creek BACT Study				
Rotary feeders	$18,480	From Previous Mill Creek BACT Study				
Injection system	$75,040	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$491,680	From Previous Mill Creek BACT Study				
Instrumentation and controls	$23,520	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$930,160					
Freight	$42,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$972,000					
Direct installation costs						
Foundation & supports	$97,000	(PEC) X	10.0%			
Handling & erection	$194,000	(PEC) X	20.0%			
Electrical	$97,000	(PEC) X	10.0%			
Piping	$49,000	(PEC) X	5.0%			
Insulation	$19,000	(PEC) X	2.0%			
Painting	$49,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$505,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$1,552,000					
Indirect Costs						
Engineering	$186,000	(DC) X	12.0%			
Owner's cost	$186,000	(DC) X	12.0%			
Construction management	$155,000	(DC) X	10.0%			
Start-up and spare parts	$23,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$310,000	(DC) X	20.0%			
Total indirect costs (IC)	$960,000					
Allowance for Funds Used During Construction (AFDC)	$57,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,569,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$47,000	(DC) X	3.0%			
Operating labor	$127,000		1 FTE and	126,882 $/year	Estimated manpower	
Total fixed annual costs	$174,000					
Variable annual costs				60 %	capacity factor	
Lime	$702,000		2,020 lb/hr and	132.19 $/ton		
Byproduct disposal	$91,000		2,310 lb/hr and	15 $/ton		
Auxiliary power	$16,000		105 kW and	0.0288 $/kWh		
Total variable annual costs	$809,000					
Total direct annual costs (DAC)	$983,000					
Indirect Annual Costs						
Cost for capital recovery	$313,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$313,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,296,000					

Cane Run Unit 4
168 MW
High Level Emissions Control Study

Technology: PAC Injection   **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$141,532	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$93,007	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$129,400	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$16,175	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$60,656	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0				
Electrical system upgrades	$388,201	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$20,219	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$849,190				
Freight	$21,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$870,000				
Direct installation costs					
Foundation & supports	$87,000	(PEC) X	10.0%		
Handling & erection	$174,000	(PEC) X	20.0%		
Electrical	$87,000	(PEC) X	10.0%		
Piping	$44,000	(PEC) X	5.0%		
Insulation	$17,000	(PEC) X	2.0%		
Painting	$44,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$453,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$1,398,000				
Indirect Costs					
Engineering	$168,000	(DC) X	12.0%		
Owner's cost	$168,000	(DC) X	12.0%		
Construction management	$140,000	(DC) X	10.0%		
Start-up and spare parts	$21,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$280,000	(DC) X	20.0%		
Total indirect costs (IC)	$877,000				
Allowance for Funds Used During Construction (AFDC)	$51,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,326,000				
Cost Effectiveness	*$14 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$42,000	(DC) X	3.0%		
Operating labor	$127,000		1 FTE and	126,882 $/year	Estimated manpower
Total fixed annual costs	$169,000				
Variable annual costs				60 %	capacity factor
Reagent (BPAC)	$896,000		155 lb/hr and	2200 $/ton	
Byproduct disposal	$6,000		155 lb/hr and	15 $/ton	
Auxiliary power	$16,000		105 kW and	0.0288 $/kWh	
Total variable annual costs	$918,000				
Total direct annual costs (DAC)	$1,087,000				
Indirect Annual Costs					
Cost for capital recovery	$283,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$283,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,370,000				

Plant Name: Cane Run
Unit: 5
MW 181
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$66,000,000	$365	$2,421,000	$10,453,000
WFGD	$159,000,000	$878	$8,789,000	$28,139,000
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	$265,742,000	$1,468	$15,530,000	$47,871,000

CANE RUN UNIT 5 - SCR COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$4,651,000			
Ductwork and Breeching	$3,592,000			
Mechanical - Balance of Plant (BOP)	$1,176,000			
Electrical - Equipment, Raceway	$1,344,000			
VFDs, Motors and Couplings	$500,000	Engineering Estimates		
Switchgear and MCCs	$470,000			
Control - DCS Instrumentation	$151,000			
Air Heater	$3,135,000	Engineering Estimates		
ID Fans	$1,864,000	Engineering Estimates		
Catalyst	$1,890,000			
Selective Catalytic Reduction System (Including Ammonia System)	$1,648,000			
Subtotal Purchase Contract	**$20,421,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$2,864,000			
Civil/Structural Construction - Sub-Structures	$744,000			
Mechanical/Chemical Construction	$9,001,000			
Electrical/Control Construction	$4,117,000			
Service Contracts & Construction Indirects	$14,379,000			
Demolition Costs	$2,967,000	Engineering Estimates		
Subtotal Construction Contracts	**$34,072,000**			
Construction Difficulty Costs	**$0**	Engineering Estimates		
Total Direct Costs	**$54,493,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$2,711,000			
EPC Construction Management (Includes G&A & Fee)	$1,701,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$446,000			
Sales Taxes	$630,000			
Project Contingency	$6,361,000			
Total Indirect Costs	**$11,849,000**			
Total Contracted Costs	**$66,000,000**			
Capital Cost Effectiveness	***$365***	***/kW***		

ANNUAL COST

Capacity Factor = 62%

Fixed Annual Costs

Operating labor	$127,000	1 FTE and	126,882	$/year
Maintenance labor & materials	$1,635,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$1,812,000**			
Variable Annual Costs				
Reagent	$273,000	190 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$155,000	1,005 kW and	0.02835	$/kWh
Catalyst replacement	$181,000	45 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$609,000**			
Total Annual Costs	**$2,421,000**			
Levelized Capital Costs	**$8,032,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$10,453,000**			

CANE RUN UNIT 5 - WFGD COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$1,791,000	
Ductwork and Breeching	$2,759,000	
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$59,354,000	
Electrical - Equipment, Raceway	$6,592,000	
VFDs, Motors and Couplings	$3,874,000	
Switchgear and MCCs	$4,000,000	
Control - DCS Instrumentation	$3,698,000	
ID Fans	$1,291,000	Engineering Estimates
Subtotal Purchase Contract	**$83,359,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$6,665,000	
Civil/Structural Construction - Sub-Structures	$649,000	
Mechanical/Chemical Construction	$15,226,000	
Electrical/Control Construction	$6,242,000	
Service Contracts & Construction Indirects	$11,862,000	
Subtotal Construction Contracts	**$40,644,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$124,003,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$5,147,000	
EPC Construction Management (Includes G&A & Fee)	$6,760,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$693,000	
Sales Taxes	$27,000	
Project Contingency	$22,541,000	
Total Indirect Costs	**$35,168,000**	
Total Contracted Costs	$159,000,000	
Cost Effectiveness	*$878 /kW*	

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	62%	
Operating labor	$2,538,000	20 FTE and	126,882	$/year
Maintenance labor and materials	$3,720,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$6,258,000**			
Variable Annual Costs				
Reagent	$542,000	17,310 lb/hr and	11.54	$/ton
Byproduct disposal	$1,216,000	29,850 lb/hr and	15	$/ton
Auxiliary and ID fan power	$617,000	4,010 kW and	0.03	$/kWh
Water	$156,000	240 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$2,531,000			
Total Annual Costs	$8,789,000			
Levelized Capital Costs	**$19,350,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$28,139,000			

CANE RUN UNIT 5 - PJFF COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$2,655,000	
Mechanical - Balance of Plant (BOP)	$7,605,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$161,000	
Control - DCS Instrumentation	$179,000	
ID Fans	$861,000	Engineering Estimates
Subtotal Purchase Contract	**$11,461,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$2,362,000	
Civil/Structural Construction - Sub-Structures	$898,000	
Mechanical/Chemical Construction	$8,985,000	
Electrical/Control Construction	$3,034,000	
Service Contracts & Construction Indirects	$146,000	
Demolition Costs	$2,967,000	Engineering Estimates
Subtotal Construction Contracts	**$18,392,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$29,853,000**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$2,347,000
EPC Construction Management (Includes G&A & Fee)	$1,536,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$232,000
Sales Taxes	$83,000
Project Contingency - 18%	$865,000
Total Indirect Costs	**$5,063,000**
Total Contracted Costs	$35,000,000
Cost Effectiveness	*$193 /kW*

ANNUAL COST

Fixed Annual Costs — Capacity Factor = 62%

Maintenance labor and materials	$1,050,000	(DC) X 3.0%
Subtotal Fixed Annual Costs	**$1,050,000**	

Variable Annual Costs

Byproduct disposal	$624,000	15,315 lb/hr and	15 $/ton
Bag replacement cost	$134,000	4,030 bags and	100 $/bag
Cage replacement cost	$67,000	4,030 cages and	50 $/cage
ID fan power	$162,000	1,050 kW and	0.03 $/kWh
Auxiliary power	$24,000	155 kW and	0.03 $/kWh
Subtotal Variable Annual Costs	$1,011,000		
Total Annual Costs	$2,061,000		
Levelized Capital Costs	**$4,260,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$6,321,000		

Cane Run Unit 5
181 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$134,543	From Previous Mill Creek BACT Study				
Short-term storage silo	$89,293	From Previous Mill Creek BACT Study				
Air blowers	$122,477	From Previous Mill Creek BACT Study				
Rotary feeders	$19,910	From Previous Mill Creek BACT Study				
Injection system	$80,847	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$529,727	From Previous Mill Creek BACT Study				
Instrumentation and controls	$25,340	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$1,002,137					
Freight	$45,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$1,047,000					
Direct installation costs						
Foundation & supports	$105,000	(PEC) X	10.0%			
Handling & erection	$209,000	(PEC) X	20.0%			
Electrical	$105,000	(PEC) X	10.0%			
Piping	$52,000	(PEC) X	5.0%			
Insulation	$21,000	(PEC) X	2.0%			
Painting	$52,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$544,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$1,666,000					
Indirect Costs						
Engineering	$200,000	(DC) X	12.0%			
Owner's cost	$200,000	(DC) X	12.0%			
Construction management	$167,000	(DC) X	10.0%			
Start-up and spare parts	$25,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$333,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,025,000					
Allowance for Funds Used During Construction (AFDC)	$61,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,752,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$50,000	(DC) X	3.0%			
Operating labor	$127,000		1 FTE and	126,882	$/year	Estimated manpower
Total fixed annual costs	$177,000					
Variable annual costs				62	%	capacity factor
Lime	$793,000		2,210 lb/hr and	132.19	$/ton	
Byproduct disposal	$103,000		2,530 lb/hr and	15	$/ton	
Auxiliary power	$16,000		105 kW and	0.0288	$/kWh	
Total variable annual costs	$912,000					
Total direct annual costs (DAC)	$1,089,000					
Indirect Annual Costs						
Cost for capital recovery	$335,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$335,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,424,000					

Cane Run Unit 5
181 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$152,484	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$100,204	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$139,414	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$17,427	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$65,350	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$418,241	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$21,783	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$914,902					
Freight	$23,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$938,000					
Direct installation costs						
Foundation & supports	$94,000	(PEC) X	10.0%			
Handling & erection	$188,000	(PEC) X	20.0%			
Electrical	$94,000	(PEC) X	10.0%			
Piping	$47,000	(PEC) X	5.0%			
Insulation	$19,000	(PEC) X	2.0%			
Painting	$47,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$489,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$1,502,000					
Indirect Costs						
Engineering	$180,000	(DC) X	12.0%			
Owner's cost	$180,000	(DC) X	12.0%			
Construction management	$150,000	(DC) X	10.0%			
Start-up and spare parts	$23,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$300,000	(DC) X	20.0%			
Total indirect costs (IC)	$933,000					
Allowance for Funds Used During Construction (AFDC)	$55,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$2,490,000					
Cost Effectiveness	*$14 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$45,000	(DC) X	3.0%			
Operating labor	$127,000		1 FTE and	126,882 $/year		Estimated manpower
Total fixed annual costs	$172,000					
Variable annual costs				62 %		capacity factor
Reagent (BPAC)	$926,000		155 lb/hr and	2200 $/ton		
Byproduct disposal	$6,000		155 lb/hr and	15 $/ton		
Auxiliary power	$16,000		105 kW and	0.0288 $/kWh		
Total variable annual costs	$948,000					
Total direct annual costs (DAC)	$1,120,000					
Indirect Annual Costs						
Cost for capital recovery	$303,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$303,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,423,000					

Plant Name: Cane Run
Unit: 6
MW 261
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$86,000,000	$330	$2,793,000	$13,259,000
WFGD	$202,000,000	$774	$10,431,000	$35,014,000
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	$340,863,000	$1,306	$18,649,000	$60,132,000

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CANE RUN UNIT 6 - SCR COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$5,794,000	
Ductwork and Breeching	$4,475,000	
Mechanical - Balance of Plant (BOP)	$1,465,000	
Electrical - Equipment, Raceway	$1,673,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$585,000	
Control - DCS Instrumentation	$189,000	
Air Heater	$4,700,000	Engineering Estimates
ID Fans	$2,349,000	Engineering Estimates
Catalyst	$2,354,000	
Selective Catalytic Reduction System (Including Ammonia System)	$2,053,000	
Subtotal Purchase Contract	**$26,137,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$3,567,000	
Civil/Structural Construction - Sub-Structures	$927,000	
Mechanical/Chemical Construction	$11,211,000	
Electrical/Control Construction	$5,128,000	
Service Contracts & Construction Indirects	$17,911,000	
Demolition Costs	$4,279,000	Engineering Estimates
Subtotal Construction Contracts	**$43,023,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$69,160,000**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$3,909,000
EPC Construction Management (Includes G&A & Fee)	$2,453,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$644,000
Sales Taxes	$909,000
Project Contingency	$9,172,000
Total Indirect Costs	**$17,087,000**
Total Contracted Costs	**$86,000,000**
Capital Cost Effectiveness	***$330 /kW***

ANNUAL COST

Capacity Factor = 54%

Fixed Annual Costs

Operating labor	$127,000	1 FTE and 126,882 $/year
Maintenance labor & materials	$2,075,000	(DC) X 3.0%
Yearly emissions testing	$25,000	Engineering Estimates
Catalyst activity testing	$5,000	Engineering Estimates
Fly ash sampling and analysis	$20,000	Engineering Estimates
Subtotal Fixed Annual Costs	**$2,252,000**	

Variable Annual Costs

Reagent	$207,000	165 lb/hr and 530.03 $/ton
Auxiliary and ID fan power	$194,000	1,360 kW and 0.03018 $/kWh
Catalyst replacement	$140,000	40 m3 and 6,500 $/m3
Subtotal Variable Annual Costs	**$541,000**	
Total Annual Costs	**$2,793,000**	
Levelized Capital Costs	**$10,466,000**	(TCI) X 12.17% CRF
Levelized Annual Costs	**$13,259,000**	

CANE RUN UNIT 6 - WFGD COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$2,231,000	
Ductwork and Breeching	$3,437,000	
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$73,931,000	
Electrical - Equipment, Raceway	$8,211,000	
VFDs, Motors and Couplings	$4,826,000	
Switchgear and MCCs	$4,983,000	
Control - DCS Instrumentation	$4,607,000	
ID Fans	$1,626,000	Engineering Estimates
Subtotal Purchase Contract	**$103,852,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$8,302,000	
Civil/Structural Construction - Sub-Structures	$809,000	
Mechanical/Chemical Construction	$18,966,000	
Electrical/Control Construction	$7,775,000	
Service Contracts & Construction Indirects	$14,776,000	
Subtotal Construction Contracts	**$50,628,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$154,480,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$6,898,000	
EPC Construction Management (Includes G&A & Fee)	$9,060,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$929,000	
Sales Taxes	$36,000	
Project Contingency	$30,210,000	
Total Indirect Costs	**$47,133,000**	
Total Contracted Costs	$202,000,000	
Cost Effectiveness	*$774 /kW*	

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	54%	
Operating labor	$2,538,000	20 FTE and	126,882	$/year
Maintenance labor and materials	$4,634,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$7,172,000**			
Variable Annual Costs				
Reagent	$696,000	25,510 lb/hr and	11.54	$/ton
Byproduct disposal	$1,560,000	43,980 lb/hr and	15	$/ton
Auxiliary and ID fan power	$799,000	5,595 kW and	0.03	$/kWh
Water	$204,000	360 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$3,259,000			
Total Annual Costs	$10,431,000			
Levelized Capital Costs	**$24,583,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$35,014,000			

CANE RUN UNIT 6 - PJFF COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$3,307,000	
Mechanical - Balance of Plant (BOP)	$9,473,000	
Electrical - Equipment, Raceway, Switchgears, MCC	$201,000	
Control - DCS Instrumentation	$223,000	
ID Fans	$1,084,000	Engineering Estimates
Subtotal Purchase Contract	**$14,288,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$2,943,000	
Civil/Structural Construction - Sub-Structures	$1,119,000	
Mechanical/Chemical Construction	$11,192,000	
Electrical/Control Construction	$3,779,000	
Service Contracts & Construction Indirects	$182,000	
Demolition Costs	$4,279,000	Engineering Estimates
Subtotal Construction Contracts	**$23,494,000**	

Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$37,782,000**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$3,384,000
EPC Construction Management (Includes G&A & Fee)	$2,214,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$334,000
Sales Taxes	$119,000
Project Contingency - 18%	$1,247,000
Total Indirect Costs	**$7,298,000**
Total Contracted Costs	$45,000,000
Cost Effectiveness	*$172 /kW*

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	54%
Maintenance labor and materials	$1,350,000	(DC) X 3.0%	
Subtotal Fixed Annual Costs	**$1,350,000**		

Variable Annual Costs

Byproduct disposal	$801,000	22,570 lb/hr and	15 $/ton
Bag replacement cost	$188,000	5,630 bags and	100 $/bag
Cage replacement cost	$94,000	5,630 cages and	50 $/cage
ID fan power	$208,000	1,460 kW and	0.03 $/kWh
Auxiliary power	$31,000	215 kW and	0.03 $/kWh
Subtotal Variable Annual Costs	$1,322,000		
Total Annual Costs	$2,672,000		
Levelized Capital Costs	**$5,477,000**	(TCI) X 12.17%	CRF
Levelized Annual Costs	$8,149,000		

Cane Run Unit 6
261 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$194,010	From Previous Mill Creek BACT Study				
Short-term storage silo	$128,760	From Previous Mill Creek BACT Study				
Air blowers	$176,610	From Previous Mill Creek BACT Study				
Rotary feeders	$28,710	From Previous Mill Creek BACT Study				
Injection system	$116,580	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$763,860	From Previous Mill Creek BACT Study				
Instrumentation and controls	$36,540	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$1,445,070					
Freight	$65,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$1,510,000					
Direct installation costs						
Foundation & supports	$151,000	(PEC) X	10.0%			
Handling & erection	$302,000	(PEC) X	20.0%			
Electrical	$151,000	(PEC) X	10.0%			
Piping	$76,000	(PEC) X	5.0%			
Insulation	$30,000	(PEC) X	2.0%			
Painting	$76,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$786,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,371,000					
Indirect Costs						
Engineering	$285,000	(DC) X	12.0%			
Owner's cost	$285,000	(DC) X	12.0%			
Construction management	$237,000	(DC) X	10.0%			
Start-up and spare parts	$36,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$474,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,417,000					
Allowance for Funds Used During Construction (AFDC)	$85,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$3,873,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$71,000	(DC) X	3.0%			
Operating labor	$127,000		1 FTE and	126,882	$/year	Estimated manpower
Total fixed annual costs	$198,000					
Variable annual costs				54	%	capacity factor
Lime	$1,019,000		3,260 lb/hr and	132.19	$/ton	
Byproduct disposal	$132,000		3,730 lb/hr and	15	$/ton	
Auxiliary power	$18,000		125 kW and	0.03018	$/kWh	
Total variable annual costs	$1,169,000					
Total direct annual costs (DAC)	$1,367,000					
Indirect Annual Costs						
Cost for capital recovery	$471,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$471,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,838,000					

Cane Run Unit 6
261 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$219,880	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$144,492	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$201,033	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$25,129	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$94,234	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$603,098	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$31,411	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$1,319,278					
Freight	$33,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$1,352,000					
Direct installation costs						
Foundation & supports	$135,000	(PEC) X	10.0%			
Handling & erection	$270,000	(PEC) X	20.0%			
Electrical	$135,000	(PEC) X	10.0%			
Piping	$68,000	(PEC) X	5.0%			
Insulation	$27,000	(PEC) X	2.0%			
Painting	$68,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$703,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,130,000					
Indirect Costs						
Engineering	$256,000	(DC) X	12.0%			
Owner's cost	$256,000	(DC) X	12.0%			
Construction management	$213,000	(DC) X	10.0%			
Start-up and spare parts	$32,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$426,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,283,000					
Allowance for Funds Used During Construction (AFDC)	$77,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$3,490,000					
Cost Effectiveness	*$13 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$64,000	(DC) X	3.0%			
Operating labor	$127,000		1 FTE and	126,882 $/year	Estimated manpower	
Total fixed annual costs	$191,000					
Variable annual costs				54 %	capacity factor	
Reagent (BPAC)	$1,119,000		215 lb/hr and	2200 $/ton		
Byproduct disposal	$8,000		215 lb/hr and	15 $/ton		
Auxiliary power	$18,000		125 kW and	0.03018 $/kWh		
Total variable annual costs	$1,145,000					
Total direct annual costs (DAC)	$1,336,000					
Indirect Annual Costs						
Cost for capital recovery	$425,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$425,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$1,761,000					

Mill Creek

E-ON Fleetwide Study | Black & Veatch Cost Estimates | 167987

Plant Name: Mill Creek
Unit: 1
MW 330
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$97,000,000	$294	$3,366,000	$15,171,000
WFGD	$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 Networks	$1,000,000	$3	$100,000	$222,000
Total	$517,774,000	$1,569	$29,102,000	$92,116,000

MILL CREEK UNIT 1 - SCR COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$6,669,000	
Ductwork and Breeching	$5,151,000	
Mechanical - Balance of Plant (BOP)	$1,687,000	
Electrical - Equipment, Raceway	$1,926,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$674,000	
Control - DCS Instrumentation	$217,000	
Air Heater Modifications	$1,704,000	Engineering Estimates
ID Fans	$3,262,000	Engineering Estimates
Catalyst	$2,709,000	
Selective Catalytic Reduction System (Including Ammonia System)	$2,363,000	
Subtotal Purchase Contract	**$26,862,000**	

Construction Contracts

Civil/Structural Construction - Super Structures	$4,106,000	
Civil/Structural Construction - Sub-Structures	$1,067,000	
Mechanical/Chemical Construction	$12,906,000	
Electrical/Control Construction	$5,902,000	
Service Contracts & Construction Indirects	$20,617,000	
Demolition Costs	$4,104,000	Engineering Estimates
Subtotal Construction Contracts	**$48,702,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$75,564,000**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$4,942,000
EPC Construction Management (Includes G&A & Fee)	$3,101,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$814,000
Sales Taxes	$1,149,000
Project Contingency	$11,597,000
Total Indirect Costs	**$21,603,000**
Total Contracted Costs	**$97,000,000**
Capital Cost Effectiveness	***$294 /kW***

ANNUAL COST

Capacity Factor = 68%

Fixed Annual Costs

Operating labor	$133,000	1	FTE and	132,901	$/year
Maintenance labor & materials	$2,267,000	(DC) X 3.0%			
Yearly emissions testing	$25,000	Engineering Estimates			
Catalyst activity testing	$5,000	Engineering Estimates			
Fly ash sampling and analysis	$20,000	Engineering Estimates			
Subtotal Fixed Annual Costs	**$2,450,000**				

Variable Annual Costs

Reagent	$418,000	265	lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$233,000	1,815	kW and	0.02156	$/kWh
Catalyst replacement	$265,000	60	m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$916,000**				
Total Annual Costs	**$3,366,000**				
Levelized Capital Costs	**$11,805,000**	(TCI) X 12.17%	CRF		
Levelized Annual Costs	**$15,171,000**				

MILL CREEK UNIT 1 - WFGD COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$2,568,000			
Ductwork and Breeching	$3,956,000			
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$85,104,000			
Electrical - Equipment, Raceway	$9,452,000			
VFDs, Motors and Couplings	$5,555,000			
Switchgear and MCCs	$5,736,000			
Control - DCS Instrumentation	$5,303,000			
ID Fans	$2,510,000	Engineering Estimates		
Subtotal Purchase Contract	**$120,184,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$9,556,000			
Civil/Structural Construction - Sub-Structures	$931,000			
Mechanical/Chemical Construction	$21,832,000			
Electrical/Control Construction	$8,950,000			
Service Contracts & Construction Indirects	$17,009,000			
Demolition Costs	$12,313,000	Engineering Estimates		
Subtotal Construction Contracts	**$70,591,000**			
Construction Difficulty Costs	**$49,414,000**	Engineering Estimates		
Total Direct Costs	**$240,189,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$8,322,000			
EPC Construction Management (Includes G&A & Fee)	$10,930,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$1,121,000			
Sales Taxes	$44,000			
Project Contingency	$36,445,000			
Total Indirect Costs	**$56,862,000**			
Total Contracted Costs	$297,000,000			
Cost Effectiveness	*$900 /kW*			
ANNUAL COST				
Fixed Annual Costs		Capacity Factor =	68%	
Operating labor	$2,658,000	20 FTE and	132,901	$/year
Maintenance labor and materials	$7,206,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$9,864,000**			
Variable Annual Costs				
Reagent	$713,000	31,765 lb/hr and	7.54	$/ton
Byproduct disposal	$2,444,000	54,715 lb/hr and	15	$/ton
Auxiliary and ID fan power	$963,000	7,495 kW and	0.02156	$/kWh
Water	$357,000	500 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$4,477,000			
Total Annual Costs	$14,341,000			
Levelized Capital Costs	**$36,145,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$50,486,000			

MILL CREEK UNIT 1 - PJFF COSTS

CAPITAL COST

Purchase Contracts						
Civil/Structural	$4,568,000					
Mechanical - Balance of Plant (BOP)	$13,085,000					
Electrical - Equipment, Raceway, Switchgears, MCC	$277,000					
Control - DCS Instrumentation	$308,000					
ID Fans	$1,757,000	Engineering Estimates				
Subtotal Purchase Contract	**$19,995,000**					
Construction Contracts						
Civil/Structural Construction - Super Structures	$4,065,000					
Civil/Structural Construction - Sub-Structures	$1,545,000					
Mechanical/Chemical Construction	$15,460,000					
Electrical/Control Construction	$5,221,000					
Service Contracts & Construction Indirects	$252,000					
Demolition Costs	$4,104,000	Engineering Estimates				
Subtotal Construction Contracts	**$30,647,000**					
Construction Difficulty Costs	**$21,452,900**	Engineering Estimates				
Total Direct Costs	**$72,094,900**					
Indirect Costs						
Engineering Costs (Includes G&A & Fee)	$4,279,000					
EPC Construction Management (Includes G&A & Fee)	$2,800,000					
Startup Spare Parts (Included)	$0					
Construction Utilites (Power & Water) - Included	$0					
Project Insurance	$423,000					
Sales Taxes	$151,000					
Project Contingency - 18%	$1,577,000					
Total Indirect Costs	**$9,230,000**					
Total Contracted Costs	$81,000,000					
Cost Effectiveness	*$245 /kW*					
ANNUAL COST						
Fixed Annual Costs		Capacity Factor =	68%			
Maintenance labor and materials	$2,430,000	(DC) X 3.0%				
Subtotal Fixed Annual Costs	**$2,430,000**					
Variable Annual Costs						
Byproduct disposal	$0	0	lb/hr and	15	$/ton	
Bag replacement cost	$471,000	14,140	bags and	100	$/bag	
Cage replacement cost	$236,000	14,140	cages and	50	$/cage	
ID fan power	$262,000	2,040	kW and	0.02156	$/kWh	
Auxiliary power	$78,000	610	kW and	0.02156	$/kWh	
Subtotal Variable Annual Costs	$1,047,000					
Total Annual Costs	$3,477,000					
Levelized Capital Costs	**$9,858,000**	(TCI) X 12.17%	CRF			
Levelized Annual Costs	$13,335,000					

Mill Creek Unit 1
330 MW
High Level Emissions Control Study

Technology: Electrostatic Precipitator (ESP) **Date:** 6/16/2010

Cost Item	$	Remarks			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
ESP	$7,399,831	From Previous Study			
Ash handling system	$538,703	From Previous Study			
ID fan	$501,831	Apportioned Engineering Estimate			
Flue gas ductwork	$2,000,000	Engineering Estimate			
Subtotal capital cost (CC)	$10,440,365				
Instrumentation and controls	$209,000	(CC) X	2.0%		
Taxes	$731,000	(CC) X	7.0%		
Freight	$522,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$11,902,000				
Direct installation costs					
Foundation & supports	$1,785,000	(PEC) X	15.0%		
Handling & erection	$1,190,000	(PEC) X	10.0%		
Electrical	$2,380,000	(PEC) X	20.0%		
Piping	$298,000	(PEC) X	2.5%		
Insulation	$238,000	(PEC) X	2.0%		
Painting	$60,000	(PEC) X	0.5%		
Demolition	$2,052,000	Engineering Estimate			
Relocation	$1,000	(PEC) X	0.01%		
Total direct installation costs (DIC)	$8,004,000				
Site preparation	$200,000	Estimate			
Total direct costs (DC) = (PEC) + (DIC)	$20,106,000				
Indirect Costs					
Engineering	$2,413,000	(DC) X	12.0%		
Owners Cost	$603,000	(DC) X	3.0%		
Construction and field expenses	$2,011,000	(DC) X	10.0%		
Contractor fees	$2,011,000	(DC) X	10.0%		
Start-up	$603,000	(DC) X	3.0%		
Performance test	$40,000	(DC) X	0.2%		
Contingencies	$3,016,000	(DC) X	15.0%		
Total indirect costs (IC)	$10,697,000				
Allowance for Funds Used During Construction (AFDC)	$2,079,000	[(DC)+(IC)] X	4.50%	3 years (project time length)	
Total Capital Investment (TCI) = (DC) + (IC)	$32,882,000				
Cost Effectiveness	*$100 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$2,155,000	Engineering Estimates			
Total fixed annual costs	$2,155,000				
Variable annual costs				68 %	capacity factor
Byproduct disposal	$1,255,000	28,100	lb/hr and	15 $/ton	
ID fan power	$103,000	800	kW and	0.02156 $/kWh	
Auxiliary power	$68,000	530	kW and	0.02156 $/kWh	
Total variable annual costs	$1,426,000				
Total direct annual costs (DAC)	$3,581,000				
Indirect Annual Costs					
Cost for capital recovery	$4,002,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$4,002,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$7,583,000				

Mill Creek Unit 1
330 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$223,000	From Previous Mill Creek BACT Study				
Short-term storage silo	$148,000	From Previous Mill Creek BACT Study				
Air blowers	$203,000	From Previous Mill Creek BACT Study				
Rotary feeders	$33,000	From Previous Mill Creek BACT Study				
Injection system	$134,000	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$26,000	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$878,000	From Previous Mill Creek BACT Study				
Instrumentation and controls	$42,000	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$1,687,000					
Freight	$76,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$1,763,000					
Direct installation costs						
Foundation & supports	$176,000	(PEC) X	10.0%			
Handling & erection	$353,000	(PEC) X	20.0%			
Electrical	$176,000	(PEC) X	10.0%			
Piping	$88,000	(PEC) X	5.0%			
Insulation	$35,000	(PEC) X	2.0%			
Painting	$88,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$916,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,754,000					
Indirect Costs						
Engineering	$330,000	(DC) X	12.0%			
Owner's cost	$330,000	(DC) X	12.0%			
Construction management	$275,000	(DC) X	10.0%			
Start-up and spare parts	$41,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$551,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,627,000					
Allowance for Funds Used During Construction (AFDC)	$99,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$4,480,000					
Cost Effectiveness	*$14 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$83,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901	$/year	Estimated manpower
Total fixed annual costs	$216,000					
Variable annual costs				68	%	capacity factor
Lime	$1,428,000		4,060 lb/hr and	118.13	$/ton	
Byproduct disposal cost	$360,000		4,640 lb/hr and	15	$/ton	
Auxiliary power	$20,000		155 kW and	0.02156	$/kWh	
Total variable annual costs	$1,808,000					
Total direct annual costs (DAC)	$2,024,000					
Indirect Annual Costs						
Cost for capital recovery	$545,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$545,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$2,569,000					

Mill Creek Unit 1
330 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$278,009	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$182,691	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$254,179	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$31,772	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$119,147	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$23,829	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$762,538	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$39,716	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$1,691,882					
Freight	$42,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$1,734,000					
Direct installation costs						
Foundation & supports	$173,000	(PEC) X	10.0%			
Handling & erection	$347,000	(PEC) X	20.0%			
Electrical	$173,000	(PEC) X	10.0%			
Piping	$87,000	(PEC) X	5.0%			
Insulation	$35,000	(PEC) X	2.0%			
Painting	$87,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$902,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,711,000					
Indirect Costs						
Engineering	$325,000	(DC) X	12.0%			
Owner's cost	$325,000	(DC) X	12.0%			
Construction management	$271,000	(DC) X	10.0%			
Start-up and spare parts	$41,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$542,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,604,000					
Allowance for Funds Used During Construction (AFDC)	$97,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$4,412,000					
Cost Effectiveness	*$13 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$81,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901 $/year		Estimated manpower
Total fixed annual costs	$214,000					
Variable annual costs				68 %		capacity factor
Reagent (BPAC)	$1,966,000		300 lb/hr and	2200 $/ton		
Byproduct disposal cost	$13,000		300 lb/hr and	15 $/ton		
Auxiliary power	$20,000		155 kW and	0.02156 $/kWh		
Total variable annual costs	$1,999,000					
Total direct annual costs (DAC)	$2,213,000					
Indirect Annual Costs						
Cost for capital recovery	$537,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$537,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$2,750,000					

Plant Name:	Mill Creek
Unit:	2
MW	330
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$97,000,000	$294	$3,401,000	$15,206,000
WFGD	$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 Networks	$1,000,000	$3	$100,000	$222,000
Total	$517,774,000	$1,569	$29,744,000	$92,758,000

MILL CREEK UNIT 2 - SCR COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$6,669,000	
Ductwork and Breeching	$5,151,000	
Mechanical - Balance of Plant (BOP)	$1,687,000	
Electrical - Equipment, Raceway	$1,926,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$674,000	
Control - DCS Instrumentation	$217,000	
Air Heater Modifications	$1,704,000	Engineering Estimates
ID Fans	$3,262,000	Engineering Estimates
Catalyst	$2,709,000	
Selective Catalytic Reduction System (Including Ammonia System)	$2,363,000	
Subtotal Purchase Contract	**$26,862,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$4,106,000	
Civil/Structural Construction - Sub-Structures	$1,067,000	
Mechanical/Chemical Construction	$12,906,000	
Electrical/Control Construction	$5,902,000	
Service Contracts & Construction Indirects	$20,617,000	
Demolition Costs	$4,104,000	Engineering Estimates
Subtotal Construction Contracts	**$48,702,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$75,564,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$4,942,000	
EPC Construction Management (Includes G&A & Fee)	$3,101,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$814,000	
Sales Taxes	$1,149,000	
Project Contingency	$11,597,000	
Total Indirect Costs	**$21,603,000**	
Total Contracted Costs	**$97,000,000**	
Capital Cost Effectiveness	***$294***	***/kW***

ANNUAL COST

Capacity Factor = 70%

Fixed Annual Costs					
Operating labor	$133,000	1	FTE and	132,901	$/year
Maintenance labor & materials	$2,267,000	(DC) X 3.0%			
Yearly emissions testing	$25,000	Engineering Estimates			
Catalyst activity testing	$5,000	Engineering Estimates			
Fly ash sampling and analysis	$20,000	Engineering Estimates			
Subtotal Fixed Annual Costs	**$2,450,000**				
Variable Annual Costs					
Reagent	$431,000	265	lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$247,000	1,860	kW and	0.02169	$/kWh
Catalyst replacement	$273,000	60	m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$951,000**				
Total Annual Costs	**$3,401,000**				
Levelized Capital Costs	**$11,805,000**	(TCI) X 12.17%	CRF		
Levelized Annual Costs	**$15,206,000**				

MILL CREEK UNIT 2 - WFGD COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$2,568,000			
Ductwork and Breeching	$3,956,000			
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$85,104,000			
Electrical - Equipment, Raceway	$9,452,000			
VFDs, Motors and Couplings	$5,555,000			
Switchgear and MCCs	$5,736,000			
Control - DCS Instrumentation	$5,303,000			
ID Fans	$2,510,000	Engineering Estimates		
Subtotal Purchase Contract	**$120,184,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$9,556,000			
Civil/Structural Construction - Sub-Structures	$931,000			
Mechanical/Chemical Construction	$21,832,000			
Electrical/Control Construction	$8,950,000			
Service Contracts & Construction Indirects	$17,009,000			
Demolition Costs	$12,313,000	Engineering Estimates		
Subtotal Construction Contracts	**$70,591,000**			
Construction Difficulty Costs	**$49,414,000**	Engineering Estimates		
Total Direct Costs	**$240,189,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$8,322,000			
EPC Construction Management (Includes G&A & Fee)	$10,930,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$1,121,000			
Sales Taxes	$44,000			
Project Contingency	$36,445,000			
Total Indirect Costs	**$56,862,000**			
Total Contracted Costs	$297,000,000			
Cost Effectiveness	*$900 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	70%	
Operating labor	$2,658,000	20 FTE and	132,901	$/year
Maintenance labor and materials	$7,206,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$9,864,000**			
Variable Annual Costs				
Reagent	$754,000	32,620 lb/hr and	7.54	$/ton
Byproduct disposal	$2,584,000	56,195 lb/hr and	15	$/ton
Auxiliary and ID fan power	$1,023,000	7,695 kW and	0.02169	$/kWh
Water	$379,000	515 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$4,740,000			
Total Annual Costs	$14,604,000			
Levelized Capital Costs	**$36,145,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$50,749,000			

MILL CREEK UNIT 2 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$4,568,000			
Mechanical - Balance of Plant (BOP)	$13,085,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$277,000			
Control - DCS Instrumentation	$308,000			
ID Fans	$1,757,000	Engineering Estimates		
Subtotal Purchase Contract	**$19,995,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$4,065,000			
Civil/Structural Construction - Sub-Structures	$1,545,000			
Mechanical/Chemical Construction	$15,460,000			
Electrical/Control Construction	$5,221,000			
Service Contracts & Construction Indirects	$252,000			
Demolition Costs	$4,104,000	Engineering Estimates		
Subtotal Construction Contracts	**$30,647,000**			
Construction Difficulty Costs	**$21,452,900**	Engineering Estimates		
Total Direct Costs	**$72,094,900**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$4,279,000			
EPC Construction Management (Includes G&A & Fee)	$2,800,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$423,000			
Sales Taxes	$151,000			
Project Contingency - 18%	$1,577,000			
Total Indirect Costs	**$9,230,000**			
Total Contracted Costs	$81,000,000			
Cost Effectiveness	*$245 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	70%	
Maintenance labor and materials	$2,430,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$2,430,000**			
Variable Annual Costs				
Byproduct disposal	$0	0 lb/hr and	15	$/ton
Bag replacement cost	$484,000	14,520 bags and	100	$/bag
Cage replacement cost	$242,000	14,520 cages and	50	$/cage
ID fan power	$279,000	2,095 kW and	0.02169	$/kWh
Auxiliary power	$83,000	625 kW and	0.02169	$/kWh
Subtotal Variable Annual Costs	$1,088,000			
Total Annual Costs	$3,518,000			
Levelized Capital Costs	**$9,858,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$13,376,000			

Mill Creek Unit 2
330 MW
High Level Emissions Control Study

Technology: Electrostatic Precipitator (ESP) **Date:** 6/16/2010

Cost Item	$	Remarks			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
ESP	$7,399,831	From Previous Study			
Ash handling system	$538,703	From Previous Study			
ID fan	$501,831	Apportioned Engineering Estimate			
Flue gas ductwork	$2,000,000	Engineering Estimate			
Subtotal capital cost (CC)	$10,440,365				
Instrumentation and controls	$209,000	(CC) X	2.0%		
Taxes	$731,000	(CC) X	7.0%		
Freight	$522,000	(CC) X	5.0%		
Total purchased equipment cost (PEC)	$11,902,000				
Direct installation costs					
Foundation & supports	$1,785,000	(PEC) X	15.0%		
Handling & erection	$1,190,000	(PEC) X	10.0%		
Electrical	$2,380,000	(PEC) X	20.0%		
Piping	$298,000	(PEC) X	2.5%		
Insulation	$238,000	(PEC) X	2.0%		
Painting	$60,000	(PEC) X	0.5%		
Demolition	$2,052,000	Engineering Estimate			
Relocation	$1,000	(PEC) X	0.01%		
Total direct installation costs (DIC)	$8,004,000				
Site preparation	$200,000	Estimate			
Total direct costs (DC) = (PEC) + (DIC)	$20,106,000				
Indirect Costs					
Engineering	$2,413,000	(DC) X	12.0%		
Owners Cost	$603,000	(DC) X	3.0%		
Construction and field expenses	$2,011,000	(DC) X	10.0%		
Contractor fees	$2,011,000	(DC) X	10.0%		
Start-up	$603,000	(DC) X	3.0%		
Performance test	$40,000	(DC) X	0.2%		
Contingencies	$3,016,000	(DC) X	15.0%		
Total indirect costs (IC)	$10,697,000				
Allowance for Funds Used During Construction (AFDC)	$2,079,000	[(DC)+(IC)] X	4.50%	3 years (project time length)	
Total Capital Investment (TCI) = (DC) + (IC)	**$32,882,000**				
Cost Effectiveness	***$100 /kW***				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$2,155,000	Engineering Estimates			
Total fixed annual costs	$2,155,000				
Variable annual costs				70 %	capacity factor
Byproduct disposal	$1,327,000		28,860 lb/hr and	15 $/ton	
ID fan power	$110,000		825 kW and	0.02169 $/kWh	
Auxiliary power	$72,000		545 kW and	0.02169 $/kWh	
Total variable annual costs	$1,509,000				
Total direct annual costs (DAC)	$3,664,000				
Indirect Annual Costs					
Cost for capital recovery	$4,002,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$4,002,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	**$7,666,000**				

Mill Creek Unit 2
330 MW
High Level Emissions Control Study

Technology: Lime Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$223,000	From Previous Mill Creek BACT Study				
Short-term storage silo	$148,000	From Previous Mill Creek BACT Study				
Air blowers	$203,000	From Previous Mill Creek BACT Study				
Rotary feeders	$33,000	From Previous Mill Creek BACT Study				
Injection system	$134,000	From Previous Mill Creek BACT Study				
Ductwork modifications, supports, platforms	$26,000	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$878,000	From Previous Mill Creek BACT Study				
Instrumentation and controls	$42,000	From Previous Mill Creek BACT Study				
Subtotal capital cost (CC)	$1,687,000					
Freight	$76,000	(CC) X	4.5%			
Total purchased equipment cost (PEC)	$1,763,000					
Direct installation costs						
Foundation & supports	$176,000	(PEC) X	10.0%			
Handling & erection	$353,000	(PEC) X	20.0%			
Electrical	$176,000	(PEC) X	10.0%			
Piping	$88,000	(PEC) X	5.0%			
Insulation	$35,000	(PEC) X	2.0%			
Painting	$88,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$916,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,754,000					
Indirect Costs						
Engineering	$330,000	(DC) X	12.0%			
Owner's cost	$330,000	(DC) X	12.0%			
Construction management	$275,000	(DC) X	10.0%			
Start-up and spare parts	$41,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$551,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,627,000					
Allowance for Funds Used During Construction (AFDC)	$99,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$4,480,000					
Cost Effectiveness	*$14 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$83,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901 $/year	Estimated manpower	
Total fixed annual costs	$216,000					
Variable annual costs				70 %	capacity factor	
Lime	$1,510,000		4,170 lb/hr and	118.13 $/ton		
Byproduct disposal cost	$370,000		4,770 lb/hr and	15 $/ton		
Auxiliary power	$21,000		155 kW and	0.02169 $/kWh		
Total variable annual costs	$1,901,000					
Total direct annual costs (DAC)	$2,117,000					
Indirect Annual Costs						
Cost for capital recovery	$545,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$545,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$2,662,000					

Mill Creek Unit 2
330 MW
High Level Emissions Control Study

Technology: **PAC Injection** **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$278,009	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$182,691	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$254,179	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$31,772	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$119,147	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$23,829	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$762,538	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$39,716	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$1,691,882					
Freight	$42,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$1,734,000					
Direct installation costs						
Foundation & supports	$173,000	(PEC) X	10.0%			
Handling & erection	$347,000	(PEC) X	20.0%			
Electrical	$173,000	(PEC) X	10.0%			
Piping	$87,000	(PEC) X	5.0%			
Insulation	$35,000	(PEC) X	2.0%			
Painting	$87,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$902,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$2,711,000					
Indirect Costs						
Engineering	$325,000	(DC) X	12.0%			
Owner's cost	$325,000	(DC) X	12.0%			
Construction management	$271,000	(DC) X	10.0%			
Start-up and spare parts	$41,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$542,000	(DC) X	20.0%			
Total indirect costs (IC)	$1,604,000					
Allowance for Funds Used During Construction (AFDC)	$97,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$4,412,000					
Cost Effectiveness	*$13 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$81,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901 $/year		Estimated manpower
Total fixed annual costs	$214,000					
Variable annual costs				70 %		capacity factor
Reagent (BPAC)	$2,091,000		310 lb/hr and	2200 $/ton		
Byproduct disposal cost	$14,000		310 lb/hr and	15 $/ton		
Auxiliary power	$21,000		155 kW and	0.02169 $/kWh		
Total variable annual costs	$2,126,000					
Total direct annual costs (DAC)	$2,340,000					
Indirect Annual Costs						
Cost for capital recovery	$537,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$537,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$2,877,000					

E-ON Fleetwide Study | Black & Veatch Cost Estimates | 167987

Plant Name:	Mill Creek
Unit:	3
MW	423
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
WFGD	$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 Networks	$1,000,000	$2	$100,000	$222,000
Total	$512,592,000	$1,212	$27,147,000	$89,530,000

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MILL CREEK UNIT 3 - WFGD COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$2,980,000			
Ductwork and Breeching	$4,591,000			
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$98,775,000			
Electrical - Equipment, Raceway	$10,970,000			
VFDs, Motors and Couplings	$6,447,000			
Switchgear and MCCs	$6,657,000			
Control - DCS Instrumentation	$6,155,000			
ID Fans	$2,445,000	Engineering Estimates		
Subtotal Purchase Contract	**$139,020,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$11,091,000			
Civil/Structural Construction - Sub-Structures	$1,080,000			
Mechanical/Chemical Construction	$25,339,000			
Electrical/Control Construction	$10,387,000			
Service Contracts & Construction Indirects	$19,741,000			
Demolition Costs	$15,784,000	Engineering Estimates		
Subtotal Construction Contracts	**$83,422,000**			
Construction Difficulty Costs	**$100,106,000**	Engineering Estimates		
Total Direct Costs	**$322,548,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$10,150,000			
EPC Construction Management (Includes G&A & Fee)	$13,332,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$1,367,000			
Sales Taxes	$54,000			
Project Contingency	$44,453,000			
Total Indirect Costs	**$69,356,000**			
Total Contracted Costs	$392,000,000			
Cost Effectiveness	*$927 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	75%	
Operating labor	$2,658,000	20 FTE and	132,901	$/year
Maintenance labor and materials	$9,676,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$12,334,000**			
Variable Annual Costs				
Reagent	$1,027,000	41,470 lb/hr and	7.54	$/ton
Byproduct disposal	$3,520,000	71,435 lb/hr and	15	$/ton
Auxiliary and ID fan power	$1,518,000	9,910 kW and	0.02331	$/kWh
Water	$512,000	650 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$6,577,000			
Total Annual Costs	$18,911,000			
Levelized Capital Costs	**$47,706,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$66,617,000			

MILL CREEK UNIT 3 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$5,302,000			
Mechanical - Balance of Plant (BOP)	$15,187,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$322,000			
Control - DCS Instrumentation	$357,000			
ID Fans	$1,467,000	Engineering Estimates		
Subtotal Purchase Contract	**$22,635,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$4,718,000			
Civil/Structural Construction - Sub-Structures	$1,793,000			
Mechanical/Chemical Construction	$17,944,000			
Electrical/Control Construction	$6,059,000			
Service Contracts & Construction Indirects	$292,000			
Demolition Costs	$5,262,000	Engineering Estimates		
Subtotal Construction Contracts	**$36,068,000**			
Construction Difficulty Costs	**$43,282,000**	Engineering Estimates		
Total Direct Costs	**$101,985,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$5,485,000			
EPC Construction Management (Includes G&A & Fee)	$3,589,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$542,000			
Sales Taxes	$193,000			
Project Contingency - 18%	$2,021,000			
Total Indirect Costs	**$11,830,000**			
Total Contracted Costs	$114,000,000			
Cost Effectiveness	*$270*	*/kW*		

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	75%	
Maintenance labor and materials	$3,420,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$3,420,000**			
Variable Annual Costs				
Byproduct disposal	$5,000	95 lb/hr and	15	$/ton
Bag replacement cost	$635,000	19,040 bags and	100	$/bag
Cage replacement cost	$317,000	19,040 cages and	50	$/cage
ID fan power	$420,000	2,745 kW and	0.02331	$/kWh
Auxiliary power	$126,000	820 kW and	0.02331	$/kWh
Subtotal Variable Annual Costs	$1,503,000			
Total Annual Costs	$4,923,000			
Levelized Capital Costs	**$13,874,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$18,797,000			

Mill Creek Unit 3
423 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$356,357	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$234,177	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$325,812	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$40,726	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$152,724	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$30,545	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$977,435	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$50,908	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$2,168,685					
Freight	$54,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$2,223,000					
Direct installation costs						
Foundation & supports	$222,000	(PEC) X	10.0%			
Handling & erection	$445,000	(PEC) X	20.0%			
Electrical	$222,000	(PEC) X	10.0%			
Piping	$111,000	(PEC) X	5.0%			
Insulation	$44,000	(PEC) X	2.0%			
Painting	$111,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$1,155,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$3,453,000					
Indirect Costs						
Engineering	$414,000	(DC) X	12.0%			
Owner's cost	$414,000	(DC) X	12.0%			
Construction management	$345,000	(DC) X	10.0%			
Start-up and spare parts	$52,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$691,000	(DC) X	20.0%			
Total indirect costs (IC)	$2,016,000					
Allowance for Funds Used During Construction (AFDC)	$123,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$5,592,000					
Cost Effectiveness	*$13 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$104,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901	$/year	Estimated manpower
Total fixed annual costs	$237,000					
Variable annual costs				75	%	capacity factor
Reagent (BPAC)	$2,927,000		405 lb/hr and	2200	$/ton	
Byproduct disposal cost	$20,000		405 lb/hr and	15	$/ton	
Auxiliary power	$29,000		190 kW and	0.02331	$/kWh	
Total variable annual costs	$2,976,000					
Total direct annual costs (DAC)	$3,213,000					
Indirect Annual Costs						
Cost for capital recovery	$681,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$681,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$3,894,000					

E-ON Fleetwide Study	Black & Veatch Cost Estimates	167987

Plant Name: Mill Creek
Unit: 4
MW 525
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
WFGD	$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 Networks	$1,000,000	$2	$100,000	$222,000
Total	$595,890,000	$1,135	$31,537,000	$104,058,000

MILL CREEK UNIT 4 - WFGD COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$3,392,000			
Ductwork and Breeching	$5,227,000			
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$112,444,000			
Electrical - Equipment, Raceway	$12,488,000			
VFDs, Motors and Couplings	$7,339,000			
Switchgear and MCCs	$7,578,000			
Control - DCS Instrumentation	$7,007,000			
ID Fans	$5,018,313	Engineering Estimates		
Subtotal Purchase Contract	**$160,493,313**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$12,626,000			
Civil/Structural Construction - Sub-Structures	$1,230,000			
Mechanical/Chemical Construction	$28,846,000			
Electrical/Control Construction	$11,825,000			
Service Contracts & Construction Indirects	$22,473,000			
Demolition Costs	$19,590,000	Engineering Estimates		
Subtotal Construction Contracts	**$96,590,000**			
Construction Difficulty Costs	**$115,908,000**	Engineering Estimates		
Total Direct Costs	**$372,991,313**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$12,065,000			
EPC Construction Management (Includes G&A & Fee)	$15,847,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$1,625,000			
Sales Taxes	$64,000			
Project Contingency	$52,840,000			
Total Indirect Costs	**$82,441,000**			
Total Contracted Costs	$455,000,000			
Cost Effectiveness	*$867 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	75%	
Operating labor	$2,658,000	20 FTE and	132,901	$/year
Maintenance labor and materials	$11,190,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$13,848,000**			
Variable Annual Costs				
Reagent	$1,250,000	50,465 lb/hr and	7.54	$/ton
Byproduct disposal	$4,284,000	86,935 lb/hr and	15	$/ton
Auxiliary and ID fan power	$1,770,000	12,055 kW and	0.02235	$/kWh
Water	$623,000	790 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$7,927,000			
Total Annual Costs	$21,775,000			
Levelized Capital Costs	**$55,374,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$77,149,000			

MILL CREEK UNIT 4 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$6,036,000			
Mechanical - Balance of Plant (BOP)	$17,289,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$366,000			
Control - DCS Instrumentation	$407,000			
ID Fans	$3,010,988	Engineering Estimates		
Subtotal Purchase Contract	**$27,108,988**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$5,371,000			
Civil/Structural Construction - Sub-Structures	$2,042,000			
Mechanical/Chemical Construction	$20,427,000			
Electrical/Control Construction	$6,898,000			
Service Contracts & Construction Indirects	$333,000			
Demolition Costs	$6,530,000	Engineering Estimates		
Subtotal Construction Contracts	**$41,601,000**			
Construction Difficulty Costs	**$49,921,000**	Engineering Estimates		
Total Direct Costs	**$118,630,988**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$6,807,000			
EPC Construction Management (Includes G&A & Fee)	$4,454,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$673,000			
Sales Taxes	$240,000			
Project Contingency - 18%	$2,508,000			
Total Indirect Costs	**$14,682,000**			
Total Contracted Costs	$133,000,000			
Cost Effectiveness	*$253 /kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	75%	
Maintenance labor and materials	$3,990,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$3,990,000**			
Variable Annual Costs				
Byproduct disposal	$1,000	30 lb/hr and	15	$/ton
Bag replacement cost	$768,000	23,050 bags and	100	$/bag
Cage replacement cost	$384,000	23,050 cages and	50	$/cage
ID fan power	$509,000	3,325 kW and	0.02331	$/kWh
Auxiliary power	$152,000	995 kW and	0.02331	$/kWh
Subtotal Variable Annual Costs	$1,814,000			
Total Annual Costs	$5,804,000			
Levelized Capital Costs	**$16,186,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$21,990,000			

Mill Creek Unit 4
##
High Level Emissions Control Study

Technology: **PAC Injection** **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$442,287	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$290,646	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$404,376	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$50,547	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$189,551	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$37,910	Ratio from Brown Unit 3 BACT Analysis				
Electrical system upgrades	$1,213,129	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$63,184	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$2,691,630					
Freight	$67,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$2,759,000					
Direct installation costs						
Foundation & supports	$276,000	(PEC) X	10.0%			
Handling & erection	$552,000	(PEC) X	20.0%			
Electrical	$276,000	(PEC) X	10.0%			
Piping	$138,000	(PEC) X	5.0%			
Insulation	$55,000	(PEC) X	2.0%			
Painting	$138,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$1,435,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$4,269,000					
Indirect Costs						
Engineering	$512,000	(DC) X	12.0%			
Owner's cost	$512,000	(DC) X	12.0%			
Construction management	$427,000	(DC) X	10.0%			
Start-up and spare parts	$64,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$854,000	(DC) X	20.0%			
Total indirect costs (IC)	$2,469,000					
Allowance for Funds Used During Construction (AFDC)	$152,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,890,000					
Cost Effectiveness	*$13 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$128,000	(DC) X	3.0%			
Operating labor	$133,000		1 FTE and	132,901 $/year		Estimated manpower
Total fixed annual costs	$261,000					
Variable annual costs				75 %		capacity factor
Reagent (BPAC)	$3,541,000		490 lb/hr and	2200 $/ton		
Byproduct disposal cost	$24,000		490 lb/hr and	15 $/ton		
Auxiliary power	$32,000		220 kW and	0.02235 $/kWh		
Total variable annual costs	$3,597,000					
Total direct annual costs (DAC)	$3,858,000					
Indirect Annual Costs						
Cost for capital recovery	$839,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$839,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$4,697,000					

Trimble County

Plant Name: Trimble County
Unit: 1
MW 547
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
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 Networks	$1,000,000	$2	$100,000	$222,000
Total	$135,451,000	$248	$10,295,000	$26,780,000

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TRIMBLE COUNTY UNIT 1 - PJFF COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$6,186,000			
Mechanical - Balance of Plant (BOP)	$17,720,000			
Electrical - Equipment, Raceway, Switchgears, MCC	$375,000			
Control - DCS Instrumentation	$417,000			
ID Fans	$2,493,000	Engineering Estimates		
Subtotal Purchase Contract	**$27,191,000**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$5,505,000			
Civil/Structural Construction - Sub-Structures	$2,092,000			
Mechanical/Chemical Construction	$20,936,000			
Electrical/Control Construction	$7,070,000			
Service Contracts & Construction Indirects	$341,000			
Demolition Costs	$3,050,000	Engineering Estimates		
Subtotal Construction Contracts	**$38,994,000**			
Construction Difficulty Costs	**$46,793,000**	Engineering Estimates		
Total Direct Costs	**$112,978,000**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$7,092,000			
EPC Construction Management (Includes G&A & Fee)	$4,641,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$701,000			
Sales Taxes	$250,000			
Project Contingency - 18%	$2,613,000			
Total Indirect Costs	**$15,297,000**			
Total Contracted Costs	$128,000,000			
Cost Effectiveness	*$234*	*/kW*		

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	85%	
Maintenance labor and materials	$3,840,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$3,840,000**			
Variable Annual Costs				
Byproduct disposal	$0	0 lb/hr and	15	$/ton
Bag replacement cost	$785,000	23,550 bags and	100	$/bag
Cage replacement cost	$393,000	23,550 cages and	50	$/cage
ID fan power	$588,000	3,395 kW and	0.02325	$/kWh
Auxiliary power	$176,000	1,015 kW and	0.02325	$/kWh
Subtotal Variable Annual Costs	$1,942,000			
Total Annual Costs	$5,782,000			
Levelized Capital Costs	**$15,578,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$21,360,000			

Trimble County Unit 1
547 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$418,928	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$275,295	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$383,020	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$47,877	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$179,540	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0					
Electrical system upgrades	$1,149,059	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$59,847	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$2,513,567					
Freight	$63,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$2,577,000					
Direct installation costs						
Foundation & supports	$258,000	(PEC) X	10.0%			
Handling & erection	$515,000	(PEC) X	20.0%			
Electrical	$258,000	(PEC) X	10.0%			
Piping	$129,000	(PEC) X	5.0%			
Insulation	$52,000	(PEC) X	2.0%			
Painting	$129,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$1,341,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$3,993,000					
Indirect Costs						
Engineering	$479,000	(DC) X	12.0%			
Owner's cost	$479,000	(DC) X	12.0%			
Construction management	$399,000	(DC) X	10.0%			
Start-up and spare parts	$60,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$799,000	(DC) X	20.0%			
Total indirect costs (IC)	$2,316,000					
Allowance for Funds Used During Construction (AFDC)	$142,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)		
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$6,451,000					
Cost Effectiveness	*$12 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$120,000	(DC) X	3.0%			
Operating labor	$132,000		1 FTE and	132,491 $/year	Estimated manpower	
Total fixed annual costs	$252,000					
Variable annual costs				85 %	capacity factor	
Reagent (BPAC)	$4,095,000		500 lb/hr and	2200 $/ton		
Byproduct disposal cost	$28,000		500 lb/hr and	15 $/ton		
Auxiliary power	$38,000		220 kW and	0.02325 $/kWh		
Total variable annual costs	$4,161,000					
Total direct annual costs (DAC)	$4,413,000					
Indirect Annual Costs						
Cost for capital recovery	$785,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$785,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$5,198,000					

Green River

Plant Name:	Green River
Unit:	3
MW	71
Project description	High Level Emissions Control Study
Revised on:	05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$29,000,000	$408	$1,040,000	$4,569,000
CDS-FF	$38,000,000	$535	$6,874,000	$11,499,000
PAC Injection	$1,112,000	$16	$323,000	$458,000
Neural Networks	$500,000	$7	$50,000	$111,000
Total	$68,612,000	$966	$8,287,000	$16,637,000

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GREEN RIVER UNIT 3 - SCR COSTS

CAPITAL COST

Purchase Contracts				
Civil/Structural	$2,126,000			
Ductwork and Breeching	$1,642,000			
Mechanical - Balance of Plant (BOP)	$538,000			
Electrical - Equipment, Raceway	$614,000			
VFDs, Motors and Couplings	$500,000	Engineering Estimates		
Switchgear and MCCs	$215,000			
Control - DCS Instrumentation	$69,000			
Air Heater	$1,638,000	Engineering Estimates		
ID Fans	$718,534	Engineering Estimates		
Catalyst	$864,000			
Selective Catalytic Reduction System (Including Ammonia System)	$753,000			
Subtotal Purchase Contract	**$9,677,534**			
Construction Contracts				
Civil/Structural Construction - Super Structures	$1,309,000			
Civil/Structural Construction - Sub-Structures	$340,000			
Mechanical/Chemical Construction	$4,113,000			
Electrical/Control Construction	$1,881,000			
Service Contracts & Construction Indirects	$6,571,000			
Demolition Costs	$395,000	Engineering Estimates		
Subtotal Construction Contracts	**$14,609,000**			
Construction Difficulty Costs	**$0**	Engineering Estimates		
Total Direct Costs	**$24,286,534**			
Indirect Costs				
Engineering Costs (Includes G&A & Fee)	$1,063,000			
EPC Construction Management (Includes G&A & Fee)	$667,000			
Startup Spare Parts (Included)	$0			
Construction Utilites (Power & Water) - Included	$0			
Project Insurance	$175,000			
Sales Taxes	$247,000			
Project Contingency	$2,495,000			
Total Indirect Costs	**$4,647,000**			
Total Contracted Costs	**$29,000,000**			
Capital Cost Effectiveness	***$408***	***/kW***		

ANNUAL COST

			Capacity Factor =	26%
Fixed Annual Costs				
Operating labor	$122,000	1 FTE and	121,547	$/year
Maintenance labor & materials	$729,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$901,000**			
Variable Annual Costs				
Reagent	$60,000	100 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$37,000	470 kW and	0.03433	$/kWh
Catalyst replacement	$42,000	25 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$139,000**			
Total Annual Costs	**$1,040,000**			
Levelized Capital Costs	**$3,529,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$4,569,000**			

GREEN RIVER UNIT 3 - CDS-FF COSTS

CAPITAL COST

Purchase Contracts					
Civil/Structural	$863,000				
Ductwork and Breeching	$554,000				
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$114,000				
Electrical - Equipment, Raceway	$660,000				
Cable Bus	$180,000				
Switchgear and MCCs	$252,000				
Control - DCS Instrumentation	$166,000				
CDS Fabric Filter	$9,704,000				
ID Fans	$663,263	Engineering Estimates			
Subtotal Purchase Contract	**$13,156,263**				
Construction Contracts					
Civil/Structural Construction - Super Structures	$2,627,000				
Civil/Structural Construction - Sub-Structures	$1,780,000				
Mechanical/Chemical Construction	$3,996,000				
Electrical/Control Construction	$1,517,000				
Service Contracts & Construction Indirects	$7,004,000				
Subtotal Construction Contracts	**$16,924,000**				
Construction Difficulty Costs	**$0**	Engineering Estimates			
Total Direct Costs	**$30,080,263**				
Indirect Costs					
Engineering Costs (Includes G&A & Fee)	$2,623,000				
EPC Construction Management (Includes G&A & Fee)	$1,038,000				
Startup Spare Parts (Included)	$0				
Construction Utilites (Power & Water) - Included	$0				
Project Insurance	$272,000				
Sales Taxes	$502,000				
Project Contingency	$3,858,000				
Total Indirect Costs	**$8,293,000**				
Total Contracted Costs	$38,000,000				
Cost Effectiveness	*$535*	*/kW*			

ANNUAL COST

Fixed Annual Costs		Capacity Factor =	26%		
Operating labor	$1,459,000	12	FTE and	121,547	$/year
Maintenance labor and materials	$902,000	(DC) X 3.0%			
Subtotal Fixed Annual Costs	**$2,361,000**				
Variable Annual Costs					
Reagent	$3,431,000	22,790	lb/hr and	132.19	$/ton
Byproduct disposal	$914,000	53,535	lb/hr and	15	$/ton
Auxiliary and ID fan power	$138,000	1,760	kW and	0.03433	$/kWh
Water	$30,000	110	gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$4,513,000				
Total Annual Costs	$6,874,000				
Levelized Capital Costs	**$4,625,000**	(TCI) X 12.17%	CRF		
Levelized Annual Costs	$11,499,000				

Green River Unit 3
71 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis			
CAPITAL COST					
Direct Costs					
Purchased equipment costs					
Long-term storage silo (with truck unloading sys.)	$60,000	Ratio from Brown Unit 3 BACT Analysis			
Short-term storage silo	$39,000	Ratio from Brown Unit 3 BACT Analysis			
Air blowers	$55,000	Ratio from Brown Unit 3 BACT Analysis			
Rotary feeders	$7,000	Ratio from Brown Unit 3 BACT Analysis			
Injection system	$26,000	Ratio from Brown Unit 3 BACT Analysis			
Ductwork modifications, supports, platforms	$0	From Ductwork Cost Calc			
Electrical system upgrades	$164,000	Ratio from Brown Unit 3 BACT Analysis			
Instrumentation and controls	$9,000	Ratio from Brown Unit 3 BACT Analysis			
Subtotal capital cost (CC)	$360,000				
Freight	$9,000	(CC) X	2.5%		
Total purchased equipment cost (PEC)	$369,000				
Direct installation costs					
Foundation & supports	$37,000	(PEC) X	10.0%		
Handling & erection	$74,000	(PEC) X	20.0%		
Electrical	$37,000	(PEC) X	10.0%		
Piping	$18,000	(PEC) X	5.0%		
Insulation	$7,000	(PEC) X	2.0%		
Painting	$18,000	(PEC) X	5.0%		
Demolition	$0	(PEC) X	0.0%		
Relocation	$0	(PEC) X	0.0%		
Total direct installation costs (DIC)	$191,000				
Site preparation	$0	N/A			
Buildings	$75,000	Engineering estimate			
Total direct costs (DC) = (PEC) + (DIC)	$635,000				
Indirect Costs					
Engineering	$76,000	(DC) X	12.0%		
Owner's cost	$76,000	(DC) X	12.0%		
Construction management	$64,000	(DC) X	10.0%		
Start-up and spare parts	$10,000	(DC) X	1.5%		
Performance test	$100,000	Engineering estimate			
Contingencies	$127,000	(DC) X	20.0%		
Total indirect costs (IC)	$453,000				
Allowance for Funds Used During Construction (AFDC)	$24,000	[(DC)+(IC)] X	4.50%	1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$1,112,000				
Cost Effectiveness	*$16 /kW*				
ANNUAL COST					
Direct Annual Costs					
Fixed annual costs					
Maintenance labor and materials	$19,000	(DC) X	3.0%		
Operating labor	$122,000		1 FTE and	121,547 $/year	Estimated manpower
Total fixed annual costs	$141,000				
Variable annual costs				26 %	capacity factor
Reagent (BPAC)	$175,000		70 lb/hr and	2200 $/ton	
Byproduct disposal	$1,000		70 lb/hr and	15 $/ton	
Auxiliary power	$6,000		75 kW and	0.03433 $/kWh	
Total variable annual costs	$182,000				
Total direct annual costs (DAC)	$323,000				
Indirect Annual Costs					
Cost for capital recovery	$135,000	(TCI) X	12.17%	CRF	
Total indirect annual costs (IDAC)	$135,000				
Total Annual Cost (TAC) = (DAC) + (IDAC)	$458,000				

Plant Name: Green River
Unit: 4
MW 109
Project description High Level Emissions Control Study
Revised on: 05/28/10

AQC Equipment	Total Capital Cost	$/kW	O&M Cost	Levelized Annual Costs
SCR	$42,000,000	$385	$1,442,000	$6,553,000
CDS-FF	$54,000,000	$495	$10,289,000	$16,861,000
PAC Injection	$1,583,000	$15	$515,000	$708,000
Neural Networks	$500,000	$5	$50,000	$111,000
Total	$98,083,000	$900	$12,296,000	$24,233,000

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GREEN RIVER UNIT 4 - SCR COSTS

CAPITAL COST

Purchase Contracts		
Civil/Structural	$3,138,000	
Ductwork and Breeching	$2,423,000	
Mechanical - Balance of Plant (BOP)	$794,000	
Electrical - Equipment, Raceway	$906,000	
VFDs, Motors and Couplings	$500,000	Engineering Estimates
Switchgear and MCCs	$317,000	
Control - DCS Instrumentation	$102,000	
Air Heater	$1,638,000	Engineering Estimates
ID Fans	$1,207,000	Engineering Estimates
Catalyst	$1,275,000	
Selective Catalytic Reduction System (Including Ammonia System)	$1,112,000	
Subtotal Purchase Contract	**$13,412,000**	
Construction Contracts		
Civil/Structural Construction - Super Structures	$1,932,000	
Civil/Structural Construction - Sub-Structures	$502,000	
Mechanical/Chemical Construction	$6,072,000	
Electrical/Control Construction	$2,777,000	
Service Contracts & Construction Indirects	$9,700,000	
Demolition Costs	$606,000	Engineering Estimates
Subtotal Construction Contracts	**$21,589,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$35,001,000**	
Indirect Costs		
Engineering Costs (Includes G&A & Fee)	$1,632,000	
EPC Construction Management (Includes G&A & Fee)	$1,024,000	
Startup Spare Parts (Included)	$0	
Construction Utilites (Power & Water) - Included	$0	
Project Insurance	$269,000	
Sales Taxes	$380,000	
Project Contingency	$3,831,000	
Total Indirect Costs	**$7,136,000**	
Total Contracted Costs	**$42,000,000**	
Capital Cost Effectiveness	***$385***	***/kW***

ANNUAL COST

Capacity Factor = 32%

Fixed Annual Costs				
Operating labor	$122,000	1 FTE and	121,547	$/year
Maintenance labor & materials	$1,050,000	(DC) X 3.0%		
Yearly emissions testing	$25,000	Engineering Estimates		
Catalyst activity testing	$5,000	Engineering Estimates		
Fly ash sampling and analysis	$20,000	Engineering Estimates		
Subtotal Fixed Annual Costs	**$1,222,000**			
Variable Annual Costs				
Reagent	$93,000	125 lb/hr and	530.03	$/ton
Auxiliary and ID fan power	$65,000	725 kW and	0.03187	$/kWh
Catalyst replacement	$62,000	30 m3 and	6,500	$/m3
Subtotal Variable Annual Costs	**$220,000**			
Total Annual Costs	**$1,442,000**			
Levelized Capital Costs	**$5,111,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	**$6,553,000**			

GREEN RIVER UNIT 4 - CDS-FF COSTS

CAPITAL COST

Purchase Contracts

Civil/Structural	$1,190,000	
Ductwork and Breeching	$764,000	
Mechanical - Balance of Plant (BOP) (includes reagent prep and dewatering systems)	$158,000	
Electrical - Equipment, Raceway	$910,000	
Cable Bus	$249,000	
Switchgear and MCCs	$348,000	
Control - DCS Instrumentation	$229,000	
CDS Fabric Filter	$13,384,000	
ID Fans	$1,114,350	Engineering Estimates
Subtotal Purchase Contract	**$18,346,350**	

Construction Contracts

Civil/Structural Construction - Super Structures	$3,623,000	
Civil/Structural Construction - Sub-Structures	$2,454,000	
Mechanical/Chemical Construction	$5,511,000	
Electrical/Control Construction	$2,092,000	
Service Contracts & Construction Indirects	$9,660,000	
Subtotal Construction Contracts	**$23,340,000**	
Construction Difficulty Costs	**$0**	Engineering Estimates
Total Direct Costs	**$41,686,350**	

Indirect Costs

Engineering Costs (Includes G&A & Fee)	$4,027,000
EPC Construction Management (Includes G&A & Fee)	$1,593,000
Startup Spare Parts (Included)	$0
Construction Utilites (Power & Water) - Included	$0
Project Insurance	$418,000
Sales Taxes	$770,000
Project Contingency	$5,923,000
Total Indirect Costs	**$12,731,000**
Total Contracted Costs	$54,000,000
Cost Effectiveness	*$495 /kW*

ANNUAL COST

Fixed Annual Costs — Capacity Factor = 32%

Operating labor	$1,459,000	12 FTE and	121,547	$/year
Maintenance labor and materials	$1,251,000	(DC) X 3.0%		
Subtotal Fixed Annual Costs	**$2,710,000**			

Variable Annual Costs

Reagent	$5,726,000	30,905 lb/hr and	132.19	$/ton
Byproduct disposal	$1,526,000	72,600 lb/hr and	15	$/ton
Auxiliary and ID fan power	$265,000	2,970 kW and	0.03187	$/kWh
Water	$62,000	185 gpm and	2	$/1,000 gal
Subtotal Variable Annual Costs	$7,579,000			
Total Annual Costs	$10,289,000			
Levelized Capital Costs	**$6,572,000**	(TCI) X 12.17%	CRF	
Levelized Annual Costs	$16,861,000			

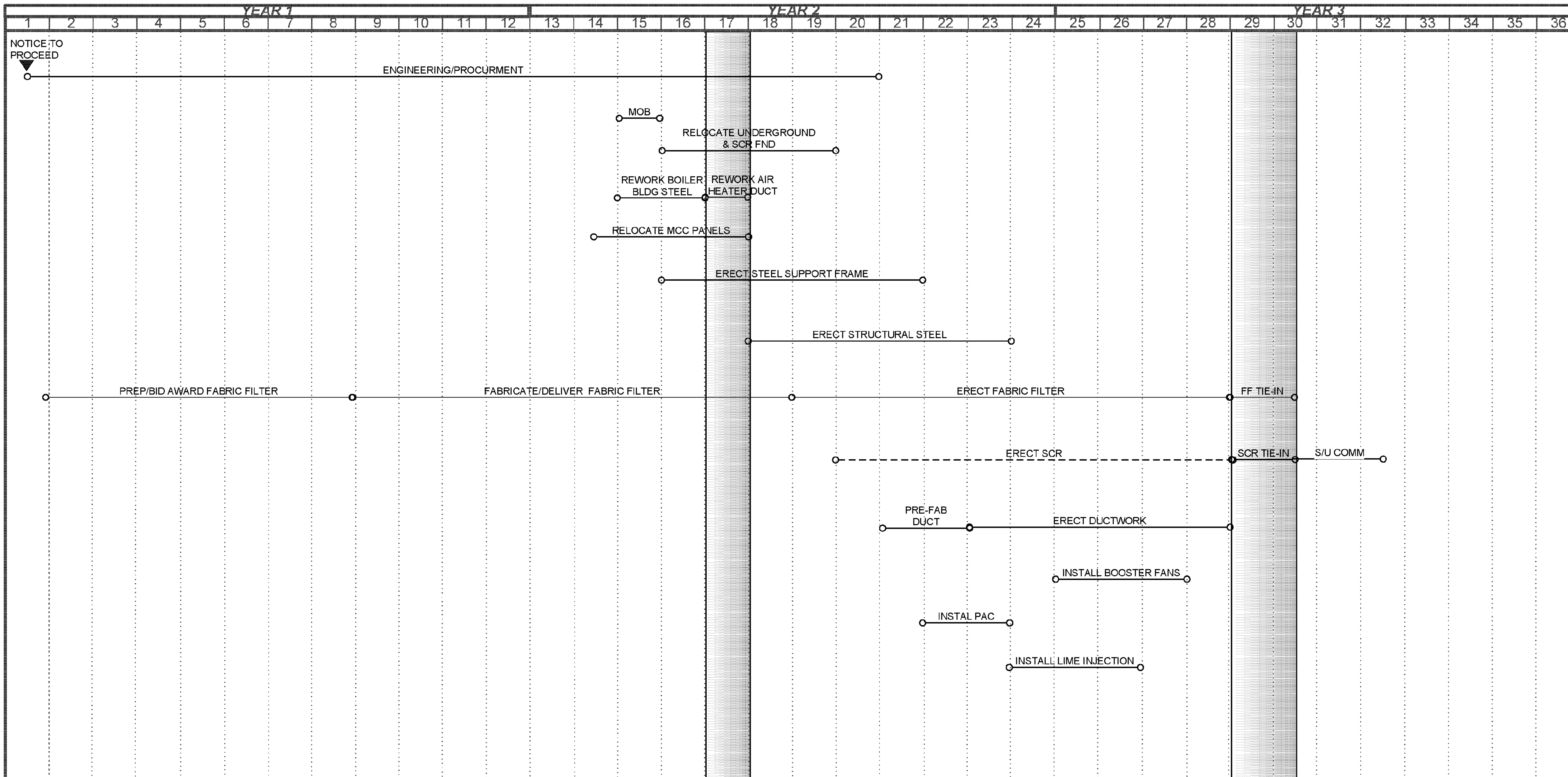
Green River Unit 4
109 MW
High Level Emissions Control Study

Technology: PAC Injection **Date:** 6/16/2010

Cost Item	$	Remarks/Cost Basis				
CAPITAL COST						
Direct Costs						
Purchased equipment costs						
Long-term storage silo (with truck unloading sys.)	$92,000	Ratio from Brown Unit 3 BACT Analysis				
Short-term storage silo	$60,000	Ratio from Brown Unit 3 BACT Analysis				
Air blowers	$84,000	Ratio from Brown Unit 3 BACT Analysis				
Rotary feeders	$10,000	Ratio from Brown Unit 3 BACT Analysis				
Injection system	$39,000	Ratio from Brown Unit 3 BACT Analysis				
Ductwork modifications, supports, platforms	$0	From Ductwork Cost Calc				
Electrical system upgrades	$252,000	Ratio from Brown Unit 3 BACT Analysis				
Instrumentation and controls	$13,000	Ratio from Brown Unit 3 BACT Analysis				
Subtotal capital cost (CC)	$550,000					
Freight	$14,000	(CC) X	2.5%			
Total purchased equipment cost (PEC)	$564,000					
Direct installation costs						
Foundation & supports	$56,000	(PEC) X	10.0%			
Handling & erection	$113,000	(PEC) X	20.0%			
Electrical	$56,000	(PEC) X	10.0%			
Piping	$28,000	(PEC) X	5.0%			
Insulation	$11,000	(PEC) X	2.0%			
Painting	$28,000	(PEC) X	5.0%			
Demolition	$0	(PEC) X	0.0%			
Relocation	$0	(PEC) X	0.0%			
Total direct installation costs (DIC)	$292,000					
Site preparation	$0	N/A				
Buildings	$75,000	Engineering estimate				
Total direct costs (DC) = (PEC) + (DIC)	$931,000					
Indirect Costs						
Engineering	$112,000	(DC) X	12.0%			
Owner's cost	$112,000	(DC) X	12.0%			
Construction management	$93,000	(DC) X	10.0%			
Start-up and spare parts	$14,000	(DC) X	1.5%			
Performance test	$100,000	Engineering estimate				
Contingencies	$186,000	(DC) X	20.0%			
Total indirect costs (IC)	$617,000					
Allowance for Funds Used During Construction (AFDC)	$35,000	[(DC)+(IC)] X	4.50%		1 years (project time length X 1/2)	
Total Capital Investment (TCI) = (DC) + (IC) + (AFDC)	$1,583,000					
Cost Effectiveness	*$15 /kW*					
ANNUAL COST						
Direct Annual Costs						
Fixed annual costs						
Maintenance labor and materials	$28,000	(DC) X	3.0%			
Operating labor	$122,000		1 FTE and	121,547 $/year		Estimated manpower
Total fixed annual costs	$150,000					
Variable annual costs				32 %		capacity factor
Reagent (BPAC)	$355,000		115 lb/hr and	2200 $/ton		
Byproduct disposal	$2,000		115 lb/hr and	15 $/ton		
Auxiliary power	$8,000		90 kW and	0.03187 $/kWh		
Total variable annual costs	$365,000					
Total direct annual costs (DAC)	$515,000					
Indirect Annual Costs						
Cost for capital recovery	$193,000	(TCI) X	12.17%	CRF		
Total indirect annual costs (IDAC)	$193,000					
Total Annual Cost (TAC) = (DAC) + (IDAC)	$708,000					

Appendix I
Level 1 Schedules

E.W. Brown



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Engineer | Drawn: S. CARUTHERS

Checked: T. VANGILDER | Date: JUNE 07, 2010

E.W. BROWN UNIT 1
OPTIONAL SCR & FABRIC FILTER

LEVEL 1 SCHEDULE

Drawing Number - REV 0

Code | Area

Page 1 of 1

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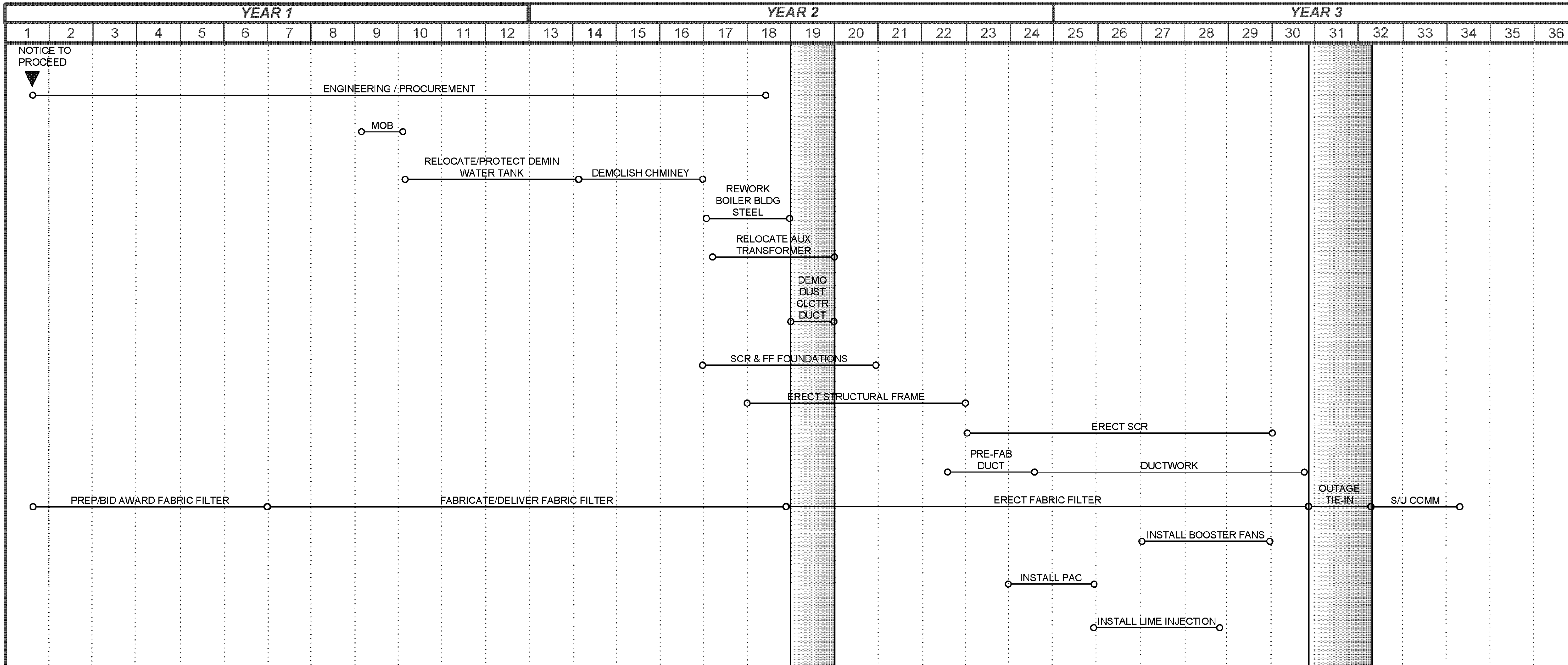

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E.W. BROWN UNIT 2
SCR & FABRIC FILTER

LEVEL 1 SCHEDULE

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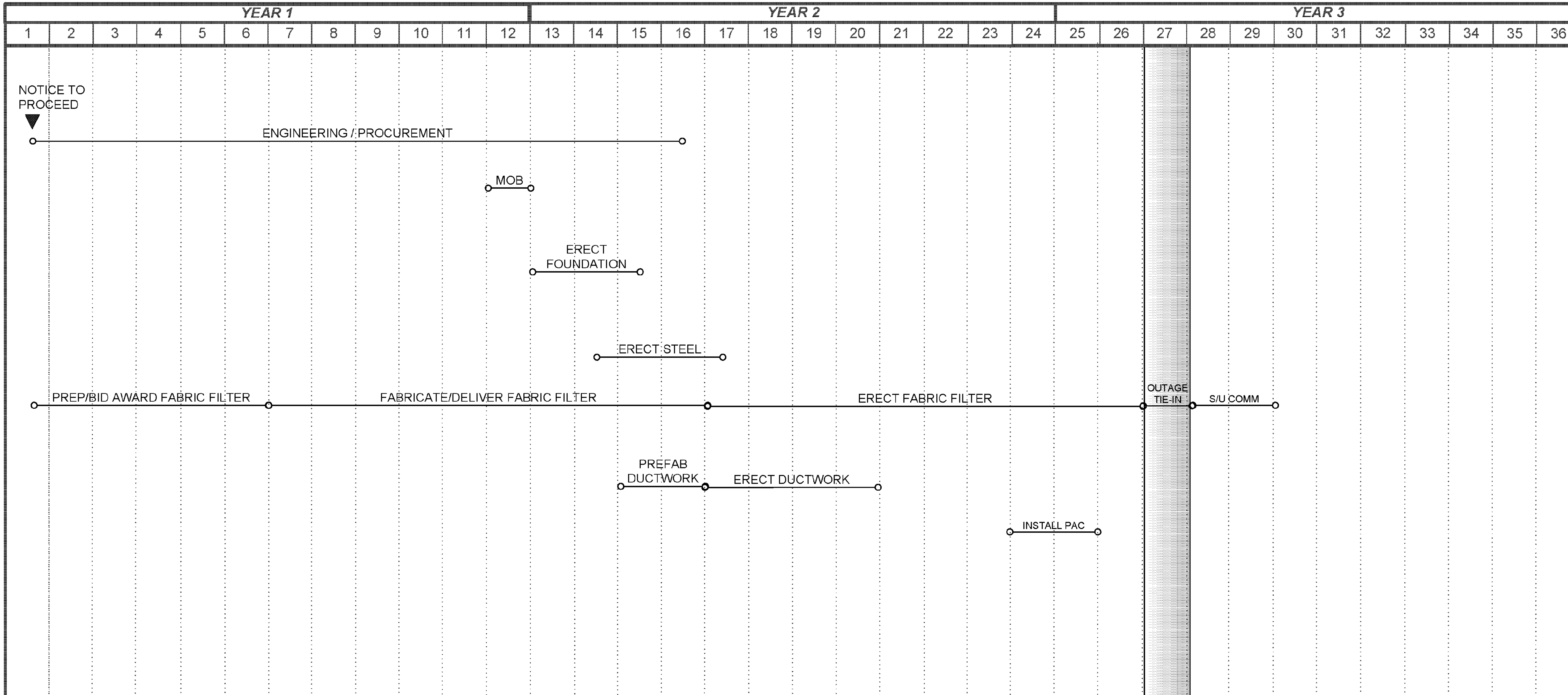

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E.W. BROWN UNIT 3
FABRIC FILTER

LEVEL 1 SCHEDULE

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Page 1 of 1

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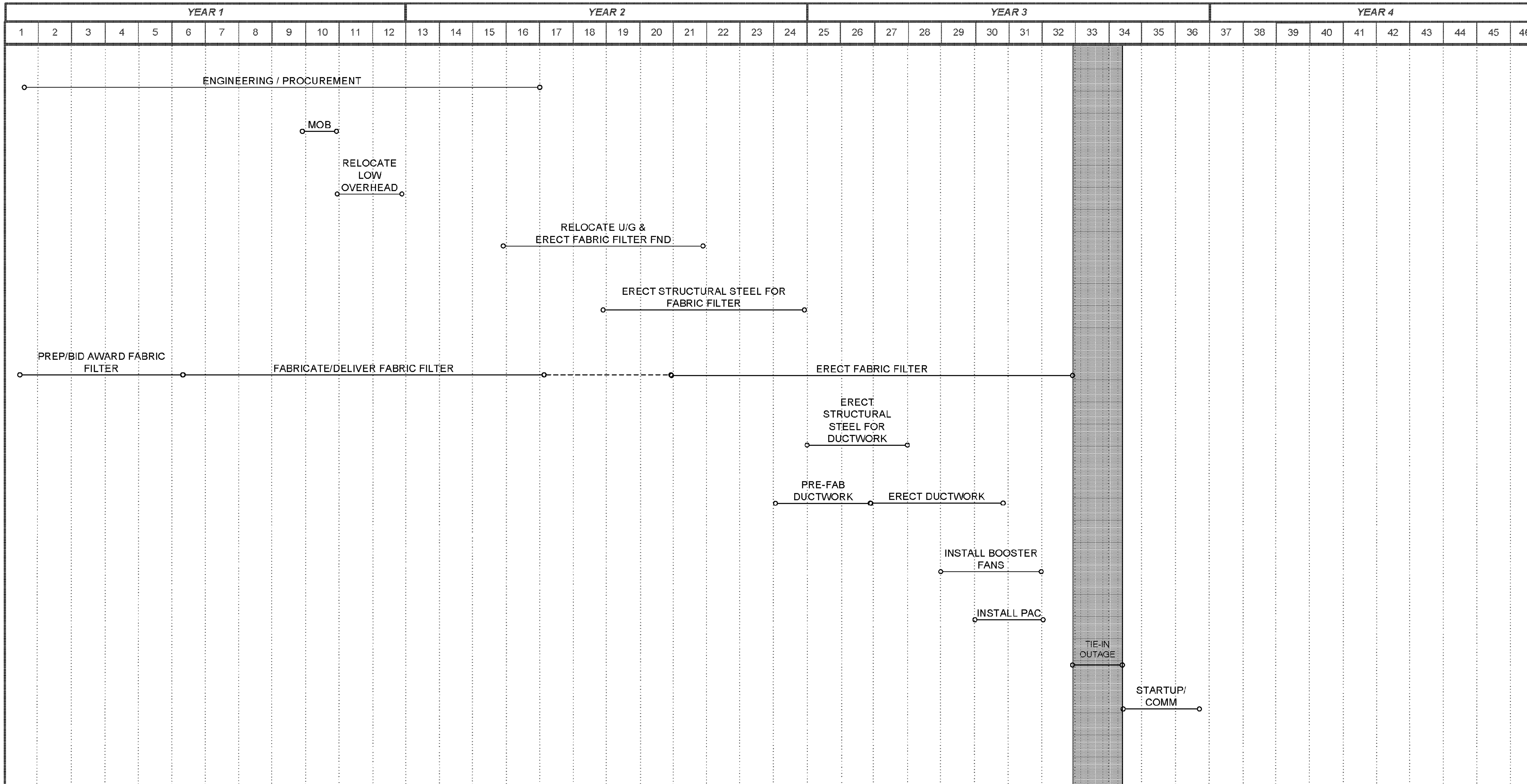

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GHENT UNIT 1
FABRIC FILTER

LEVEL 1 SCHEDULE

Drawing Number - REV 0

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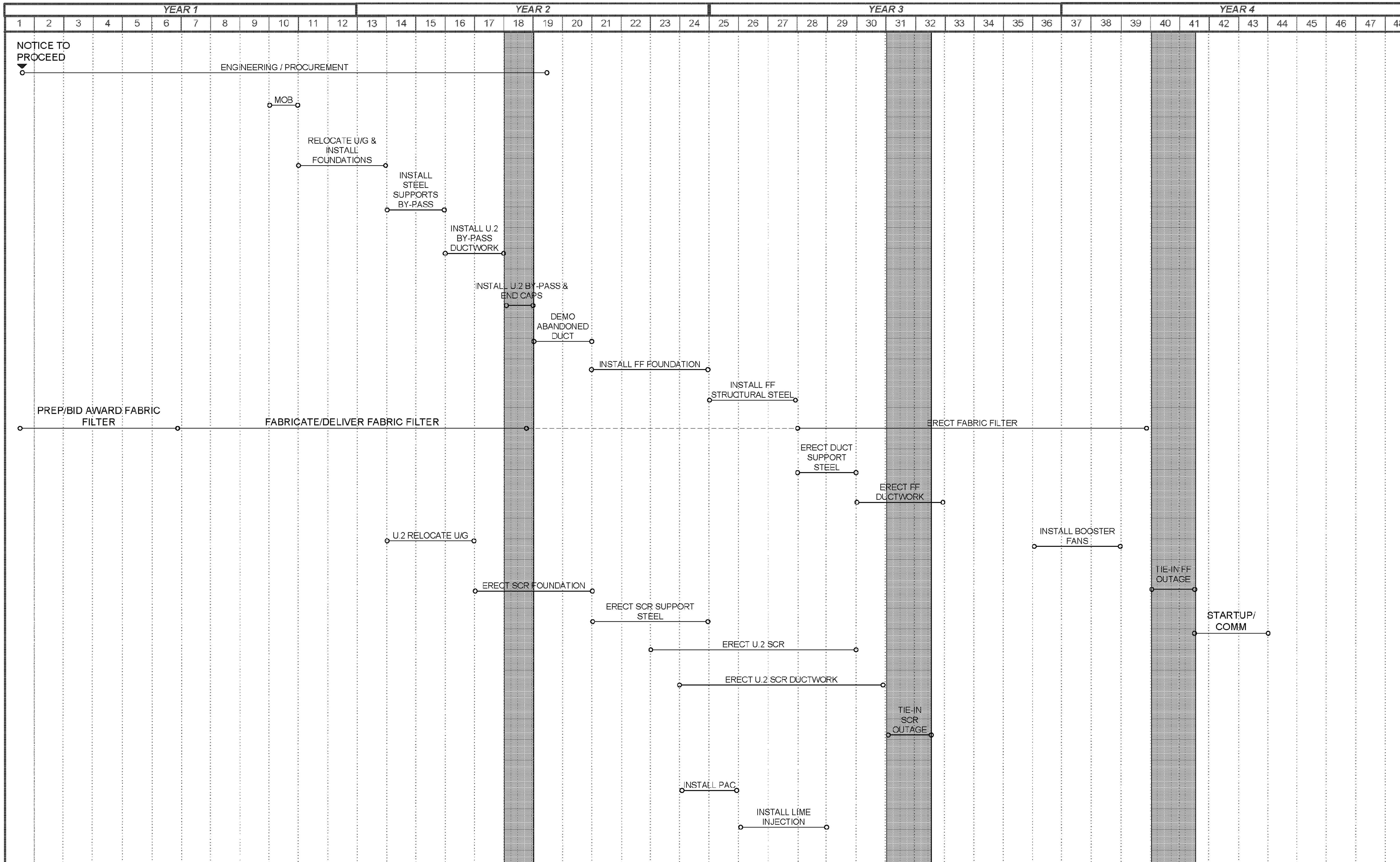
Page 1 of 1



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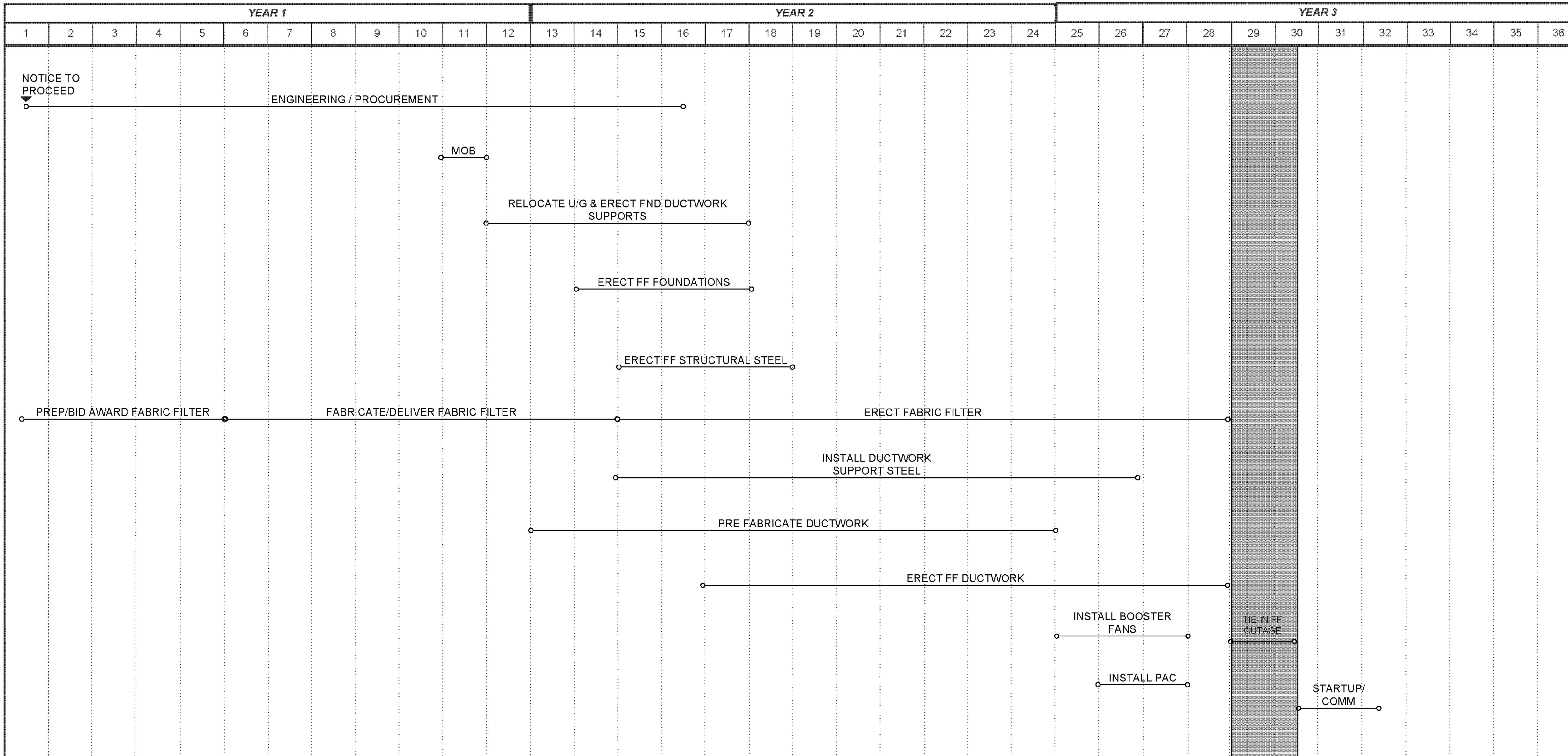
SCR & FABRIC FILTER

LEVEL 1 SCHEDULE

Drawing Number - REV 0
Code | Area

Page 1 of 1



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GHENT UNIT 3
FABRIC FILTER

LEVEL 1 SCHEDULE

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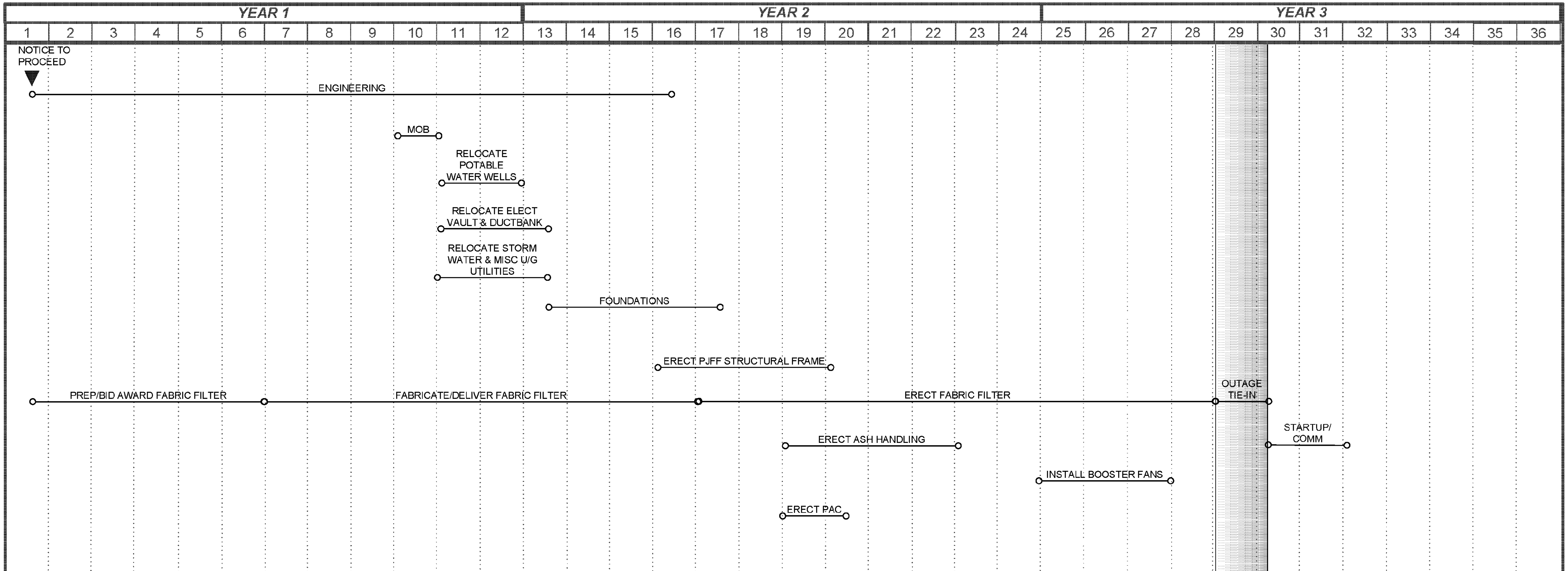

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GHENT UNIT 4
PAC & FABRIC FILTER

LEVEL 1 SCHEDULE

Code
Area

Page 1 of 1

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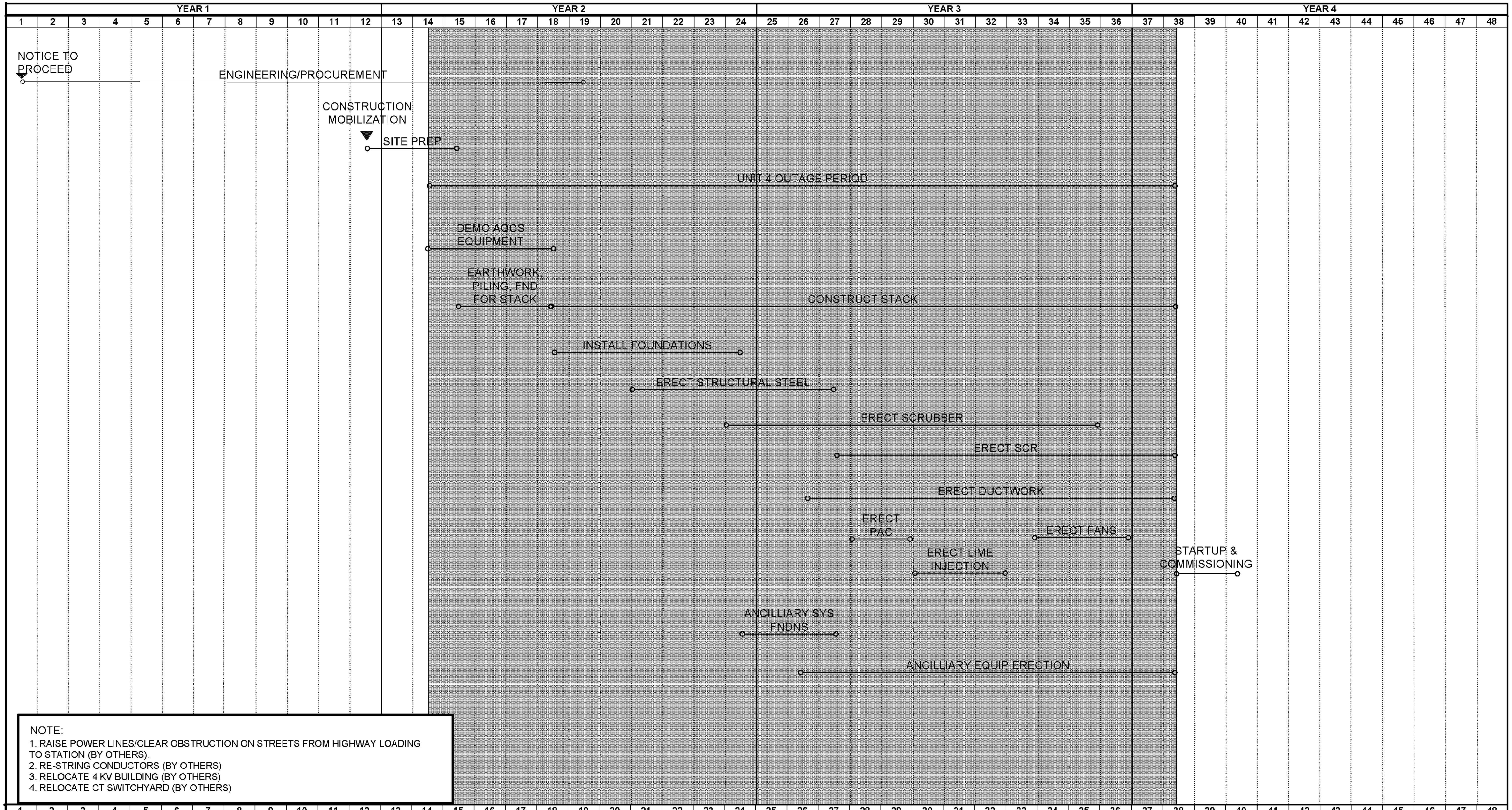
Cane Run



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CANE RUN UNIT 4
SCR & SCRUBBER

LEVEL 1 SUMMARY SCHEDULE

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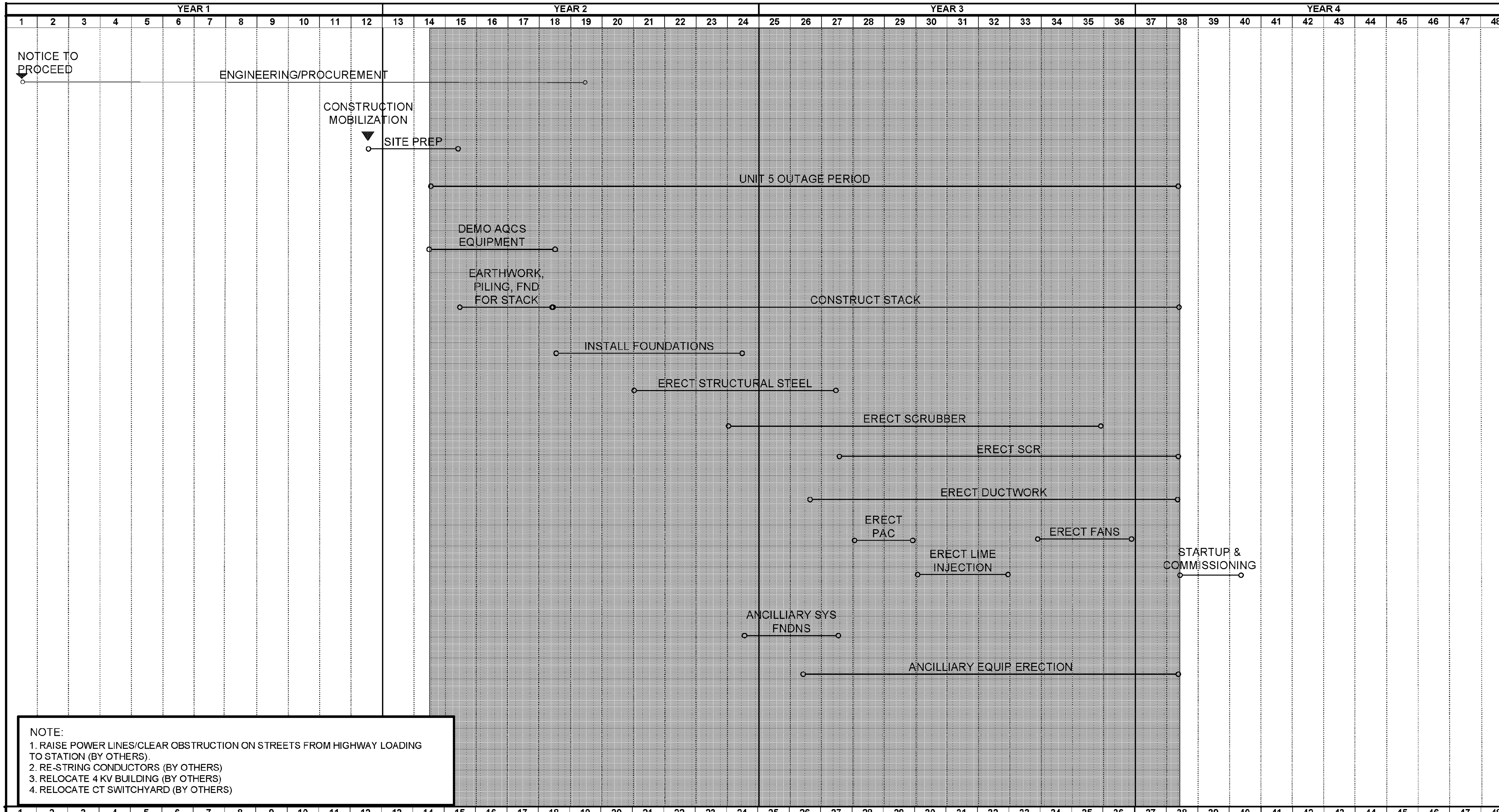

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CANE RUN UNIT 5
SCR & SCRUBBER

LEVEL 1 SUMMARY SCHEDULE

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AREA

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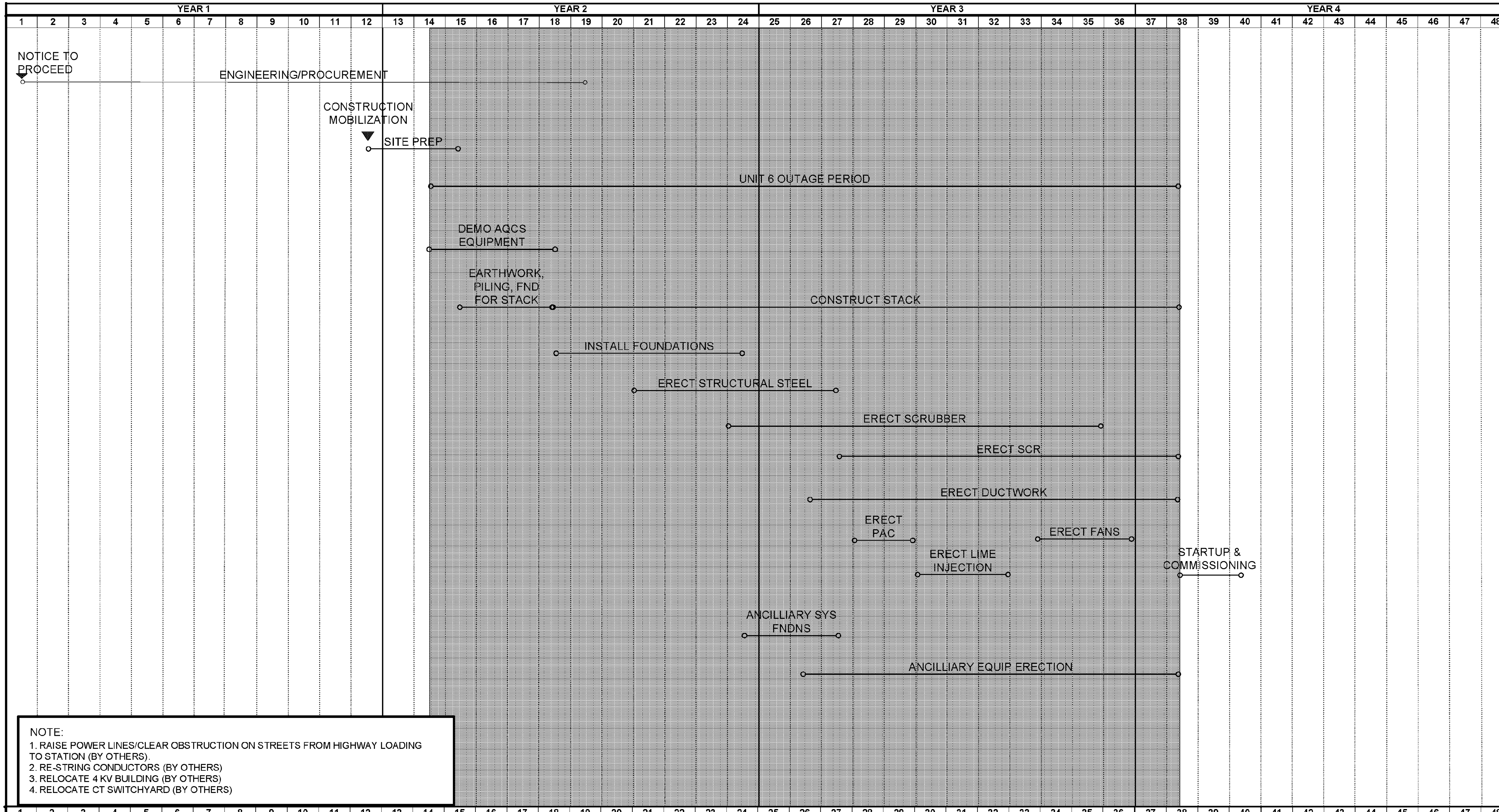

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CANE RUN UNIT 6
SCR & SCRUBBER

LEVEL 1 SUMMARY SCHEDULE

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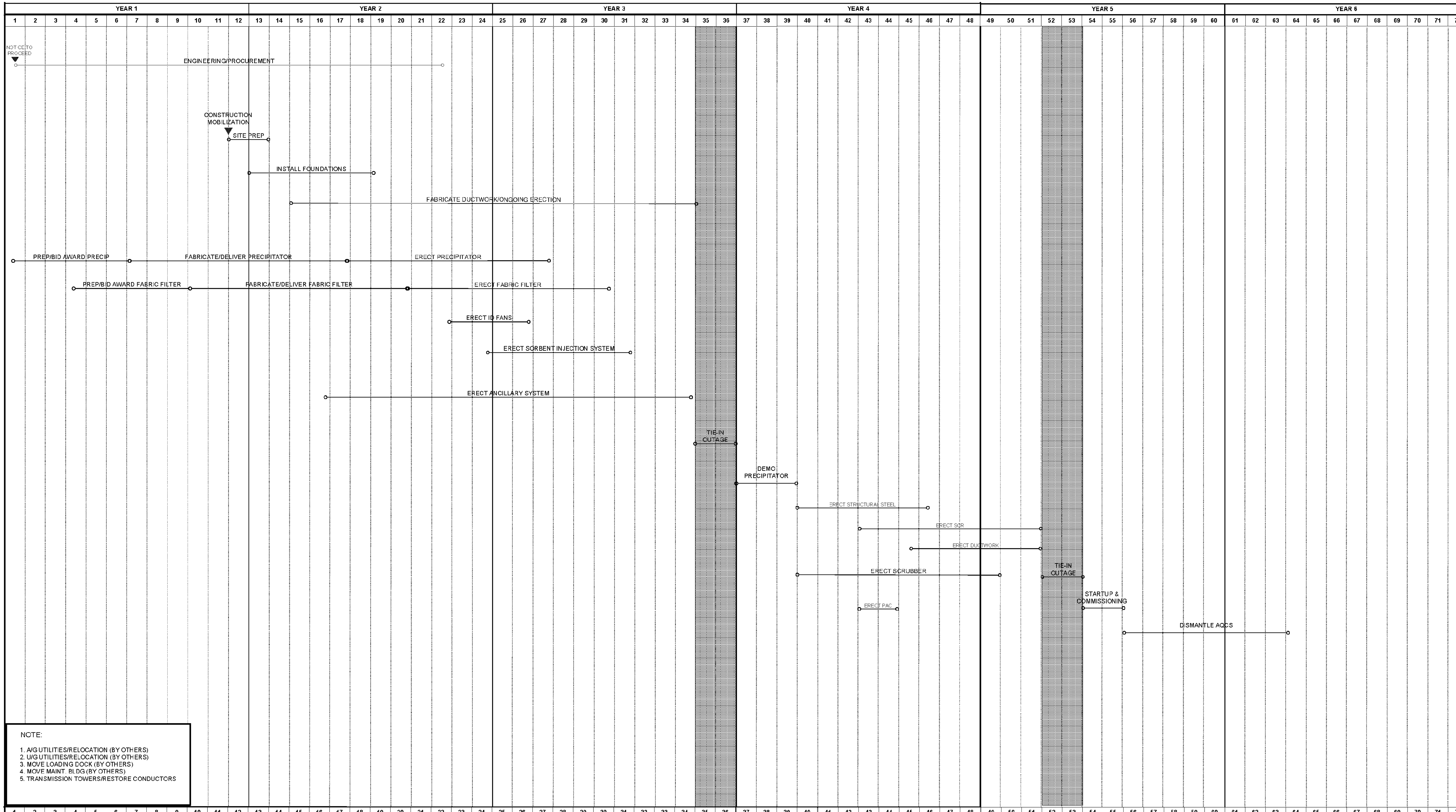
CODE | AREA

PAGE 1 OF 1

Mill Creek



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DATE 06/03/2010

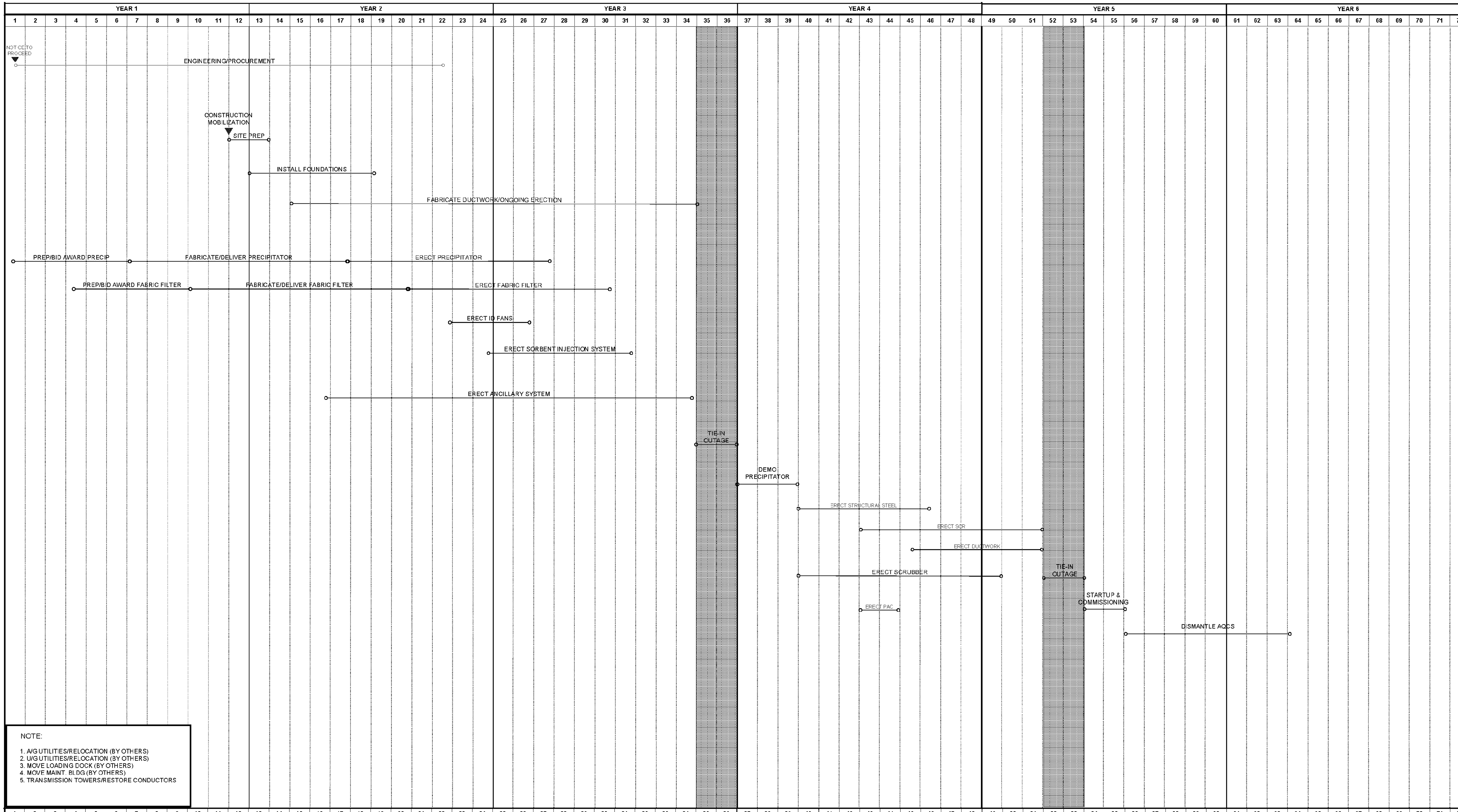
MILL CREEK UNIT 1
SCRUBBER, ESP, FABRIC FILTER, & SCR

LEVEL 1 SUMMARY SCHEDULE

DRAWING NUMBER REV 0

CODE AREA

PAGE 1 OF 1



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MILL CREEK UNIT 2
SCRUBBER, ESP, FABRIC FILTER, & SCR

LEVEL 1 SUMMARY SCHEDULE

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CODE AREA

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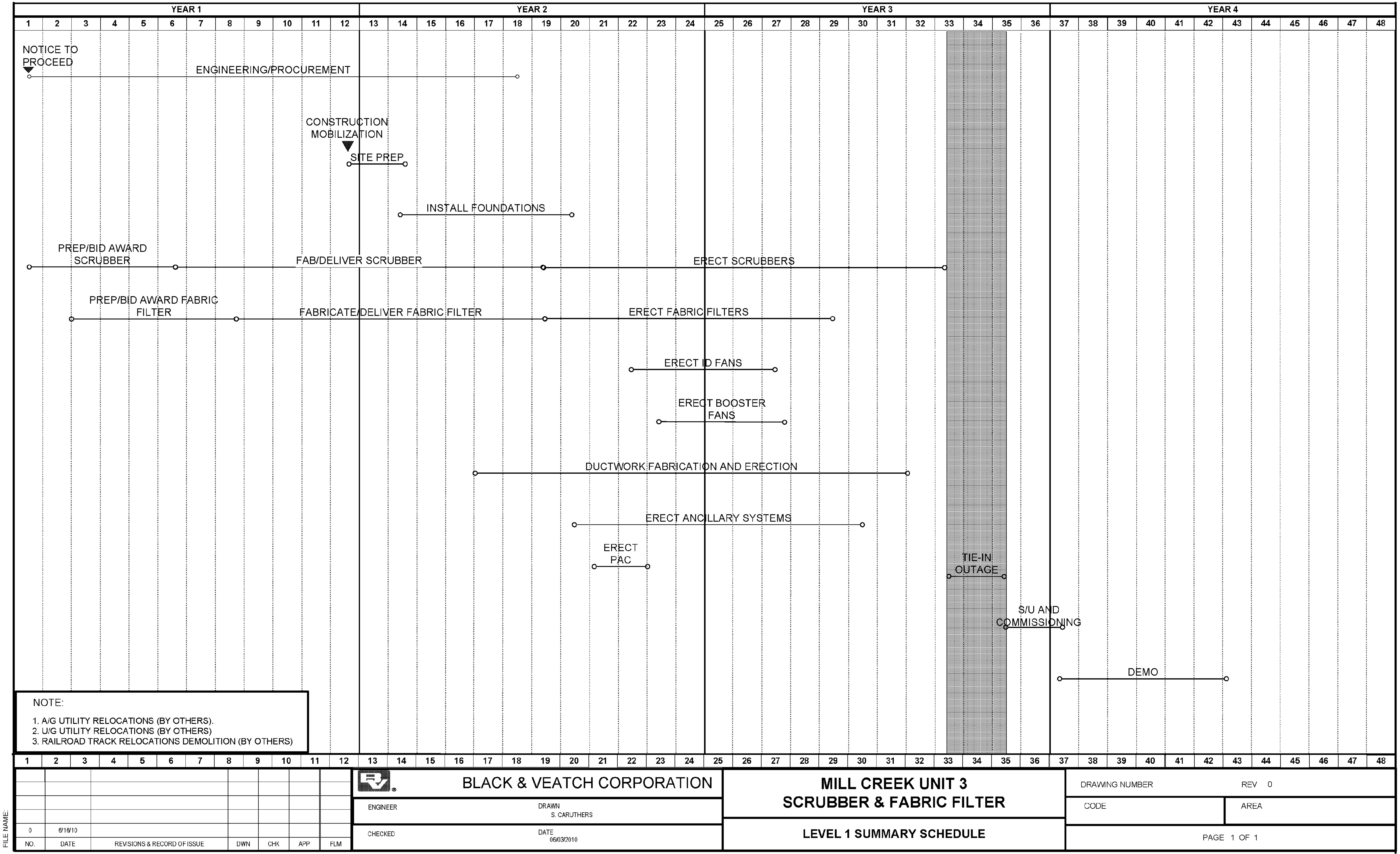
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YEAR 2
YEAR 3
YEAR 4
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NOTICE TO PROCEED
ENGINEERING/PROCUREMENT
CONSTRUCTION MOBILIZATION
SITE PREP
INSTALL FOUNDATIONS
PREP/BID AWARD SCRUBBER
FAB/DELIVER SCRUBBER
ERECT SCRUBBERS
PREP/BID AWARD FABRIC FILTER
FABRICATE/DELIVER FABRIC FILTER
ERECT FABRIC FILTERS
ERECT ID FANS
ERECT BOOSTER FANS
DUCTWORK FABRICATION AND ERECTION
ERECT ANCILLARY SYSTEMS
ERECT PAC
TIE-IN OUTAGE
S/U AND COMMISSIONING
DEMO
NOTE:
1. A/G UTILITY RELOCATIONS (BY OTHERS).
2. U/G UTILITY RELOCATIONS (BY OTHERS)
3. RAILROAD TRACK RELOCATIONS DEMOLITION (BY OTHERS)
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MILL CREEK UNIT 3
SCRUBBER & FABRIC FILTER
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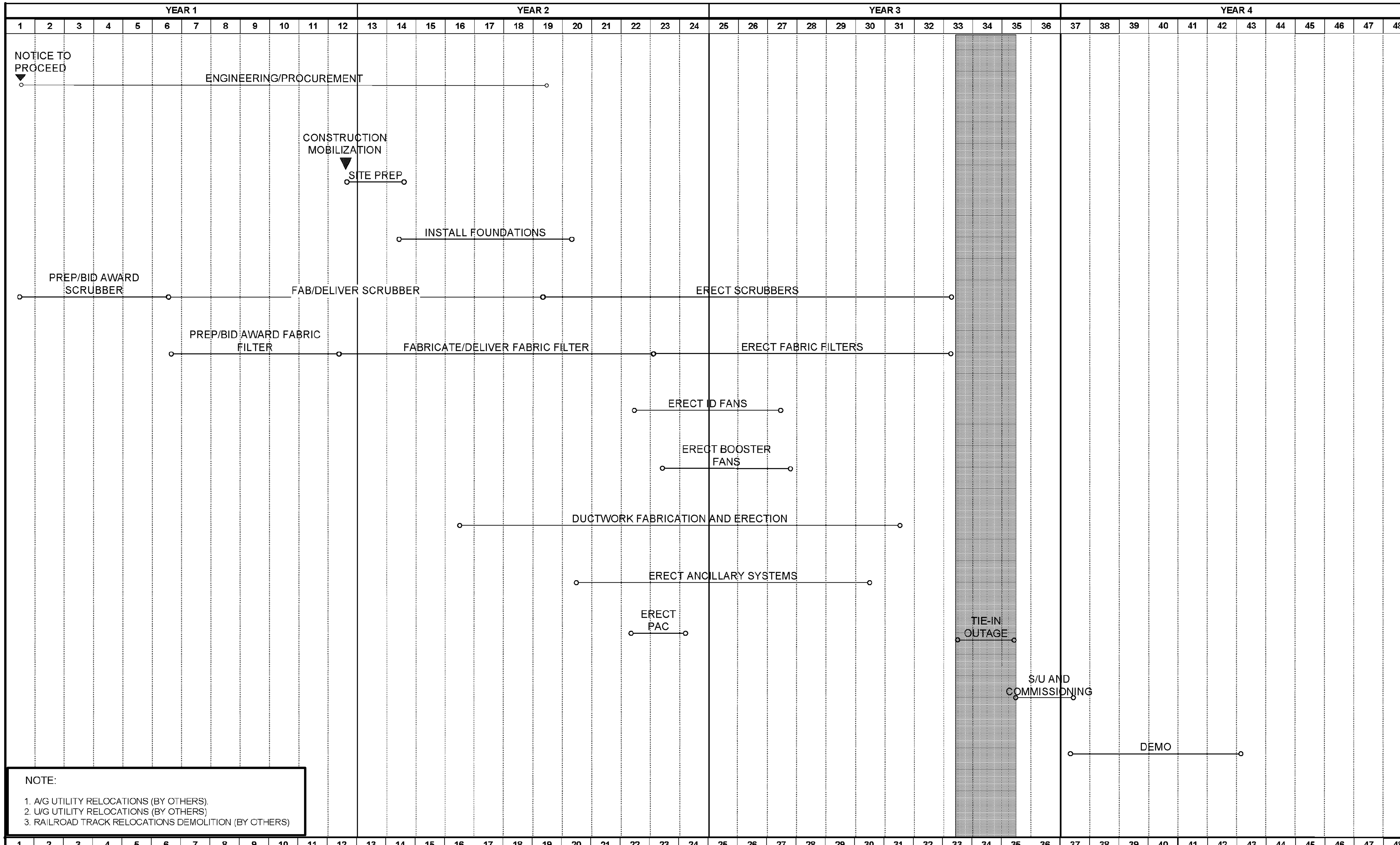

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MILL CREEK UNIT 4
SCRUBBER & FABRIC FILTER

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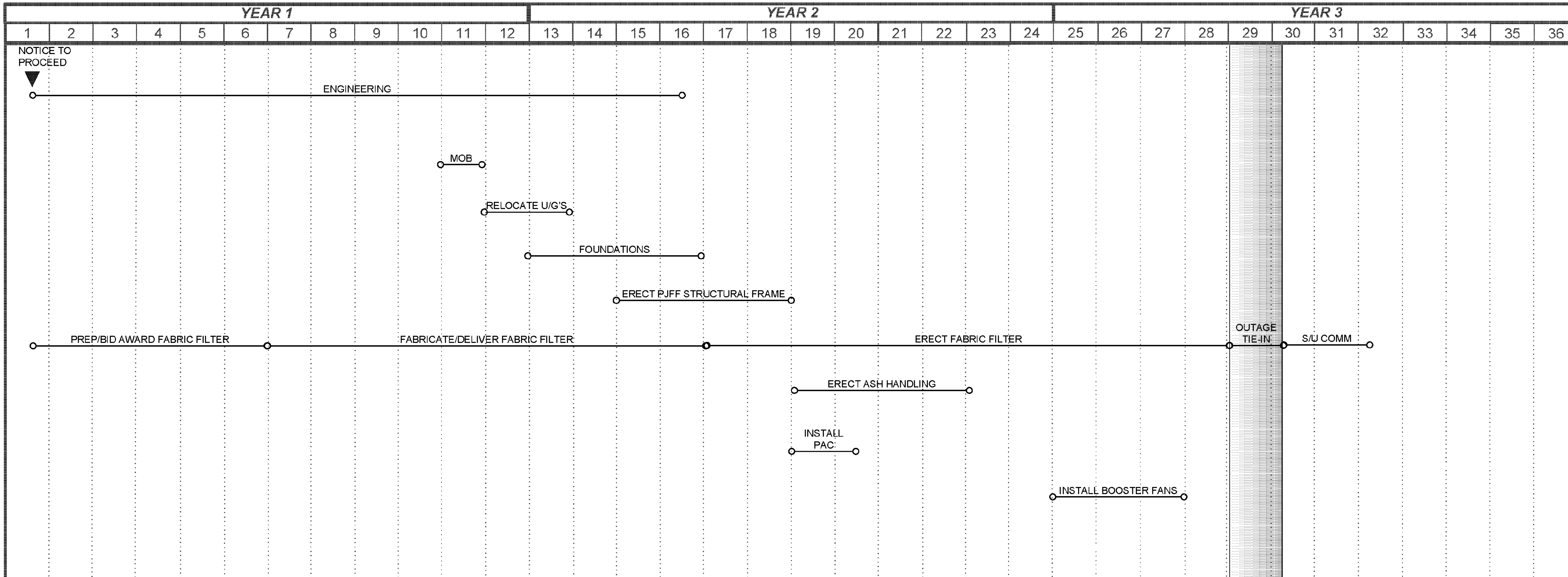
Trimble County



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TRIMBLE COUNTY UNIT 1
PAC & FABRIC FILTER

LEVEL 1 SCHEDULE

Code | Area

Page 1 of 1

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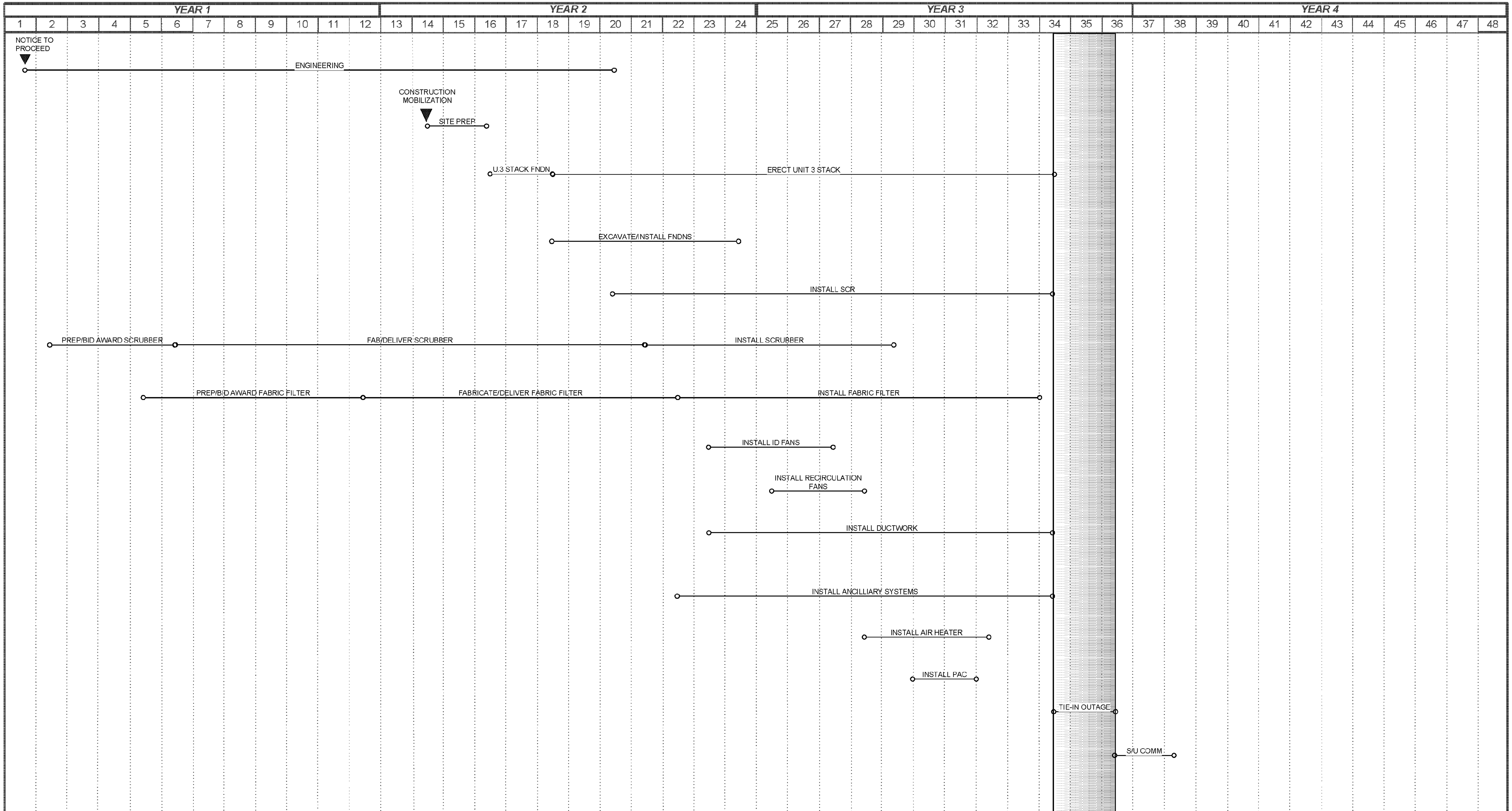
Green River



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GREEN RIVER UNIT 3
SCR, SCRUBBER & FABRIC FILTER

LEVEL 1 SCHEDULE

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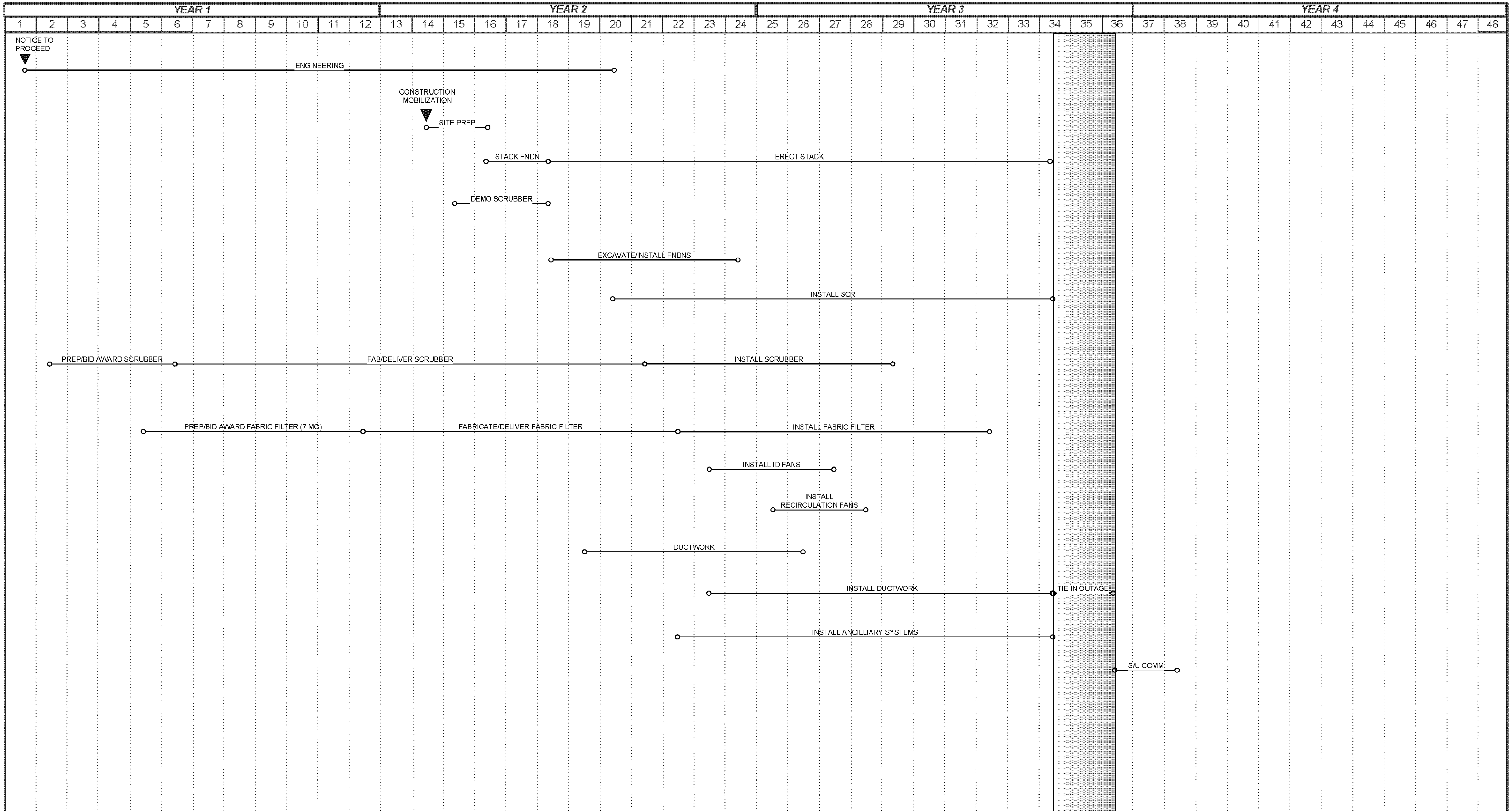

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GREEN RIVER UNIT 4
SCR, SCRUBBER & FABRIC FILTER

LEVEL 1 SCHEDULE

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Page 1 of 1

From:	Ritchey, Stacy
To:	Saunders, Eileen
Sent:	6/2/2010 2:34:40 PM
Subject:	Updated Environmental Study by Unit
Attachments:	Environmental Summay (rev4 6-1-10).xlsx

Stacy Ritchey
Budget Analyst III, Project Engineering
BOC 3
BOC Phone: (502) 627-4388
EW Brown Phone (859) 748-4455
Fax: (502) 217-4980
E-mail: Stacy.Ritchey@eon-us.com

Black & Veatch Study Cost Estimates
$ in thousands

	Capital Cost	O&M Cost	Total Capital and O&M	Levelized Annual Costs
BROWN				
Brown 1 - Low NOx Burners	$1,156	$0	$1,156	$141
Brown 1 - Baghouse	$40,000	$1,477	$41,477	$6,345
Brown 1 - PAC Injection	$1,599	$614	$2,213	$809
Brown 1 - Neural Networks	$500	$50	$550	$111
Brown 1 - Overfire Air	$767	$132	$899	$225
Total Brown 1	**$44,022**	**$2,273**	**$46,295**	**$7,631**
Brown 2 - SCR	$92,000	$3,278	$95,278	$14,474
Brown 2 - Baghouse	$51,000	$1,959	$52,959	$8,166
Brown 2 - PAC Injection	$2,476	$1,090	$3,566	$1,391
Brown 2 - Neural Networks	$500	$50	$550	$111
Brown 2 - Lime Injection	$2,739	$1,155	$3,894	$1,488
Total Brown 2	**$148,715**	**$7,532**	**$156,247**	**$25,630**
Brown 3 - Baghouse	$61,000	$3,321	$64,321	$10,745
Brown 3 - PAC Injection	$5,426	$2,330	$7,756	$2,990
Brown 3 - Neural Networks	$1,000	$100	$1,100	$222
Total Brown 3	**$67,426**	**$5,751**	**$73,177**	**$13,957**
Total Brown	**$260,163**	**$15,556**	**$275,719**	**$47,218**
GHENT				
Ghent 1 - Baghouse	$131,000	$5,888	$136,888	$21,831
Ghent 1 - PAC Injection	$6,380	$4,208	$10,588	$4,984
Ghent 1 - Neural Networks	$1,000	$100	$1,100	$222
Total Ghent 1	**$138,380**	**$10,196**	**$148,576**	**$27,037**
Ghent 2 - SCR	$227,000	$7,078	$234,078	$34,704
Ghent 2 - Baghouse	$120,000	$5,002	$125,002	$19,606
Ghent 2 - PAC Injection	$6,109	$2,880	$8,989	$3,623
Ghent 2 - Lime Injection	$5,483	$2,775	$8,258	$3,442
Ghent 2 - Neural Networks	$1,000	$100	$1,100	$222
Total Ghent 2	**$359,592**	**$17,835**	**$377,427**	**$61,597**
Ghent 3 - Baghouse	$138,000	$6,122	$144,122	$22,917
Ghent 3 - PAC Injection	$6,173	$4,134	$10,307	$4,885
Ghent 3 - Neural Networks	$1,000	$100	$1,100	$222
Total Ghent 3	**$145,173**	**$10,356**	**$155,529**	**$28,024**

	A	B	C	D	E	F	G	H	I	J
47	Ghent 4 - Baghouse		$117,000		$5,363		$122,363		$19,602	
48	Ghent 4 - PAC Injection		$6,210		$3,896		$10,106		$4,652	
49	Ghent 4 - Neural Networks		$1,000		$100		$1,100		$222	
50	Total Ghent 4		$124,210		$9,359		$133,569		$24,476	
51										
52	**Total Ghent**		**$767,355**		**$47,746**		**$815,101**		**$141,134**	
53										
54										
55	**GREEN RIVER**									
56	Green River 3 - SCR		$29,000		$1,040		$30,040		$4,569	
57	Green River 3 - CDS-FF		$38,000		$6,874		$44,874		$11,499	
58	Green River 3 - PAC Injection		$1,112		$323		$1,435		$458	
59	Green River 3 - Neural Networks		$500		$50		$550		$111	
60	Total Green River 3		**$68,612**		**$8,287**		**$76,899**		**$16,637**	
61										
62	Green River 4 - SCR		$42,000		$1,442		$43,442		$6,553	
63	Green River 4 - CDS-FF		$54,000		$10,289		$64,289		$16,861	
64	Green River 4 - PAC Injection		$1,583		$515		$2,098		$708	
65	Green River 4 - Neural Networks		$500		$50		$550		$111	
66	Total Green River 4		**$98,083**		**$12,296**		**$110,379**		**$24,233**	
67										
68	**Total Green River**		**$166,695**		**$20,583**		**$187,278**		**$40,870**	
69										
70										
71	**CANE RUN**									
72	Cane Run 4 - FGD		$152,000		$8,428		$160,428		$26,926	
73	Cane Run 4 - SCR		$63,000		$2,219		$65,219		$9,886	
74	Cane Run 4 - Baghouse		$33,000		$1,924		$34,924		$5,940	
75	Cane Run 4 - PAC Injection		$2,326		$1,087		$3,413		$1,370	
76	Cane Run 4 - Lime Injection		$2,569		$983		$3,552		$1,296	
77	Cane Run 4 - Neural Networks		$500		$50		$550		$111	
78	Total Cane Run 4		**$253,395**		**$14,691**		**$268,086**		**$45,529**	
79										
80	Cane Run 5 - FGD		$159,000		$8,789		$167,789		$28,139	
81	Cane Run 5 - SCR		$66,000		$2,421		$68,421		$10,453	
82	Cane Run 5 - Baghouse		$35,000		$2,061		$37,061		$6,321	
83	Cane Run 5 - PAC Injection		$2,490		$1,120		$3,610		$1,423	
84	Cane Run 5 - Lime Injection		$2,752		$1,089		$3,841		$1,424	
85	Cane Run 5 - Neural Networks		$500		$50		$550		$111	
86	Total Cane Run 5		**$265,742**		**$15,530**		**$281,272**		**$47,871**	
87										
88	Cane Run 6 - FGD		$202,000		$10,431		$212,431		$35,014	
89	Cane Run 6 - SCR		$86,000		$2,793		$88,793		$13,259	
90	Can Rune 6 - Baghouse		$45,000		$2,672		$47,672		$8,149	
91	Cane Run 6 - PAC Injection		$3,490		$1,336		$4,826		$1,761	
92	Cane Run 6 - Lime Injection		$3,873		$1,367		$5,240		$1,838	

	A	B	C	D	E	F	G	H	I	J
93	Cane Run 6 - Neural Networks		$500		$50		$550		$111	
94	Total Can Run 6		$340,863		$18,649		$359,512		$60,132	
95										
96	**Total Cane Run**		**$860,000**		**$48,870**		**$908,870**		**$153,532**	
97										
98										
99	**Mill Creek**									
100	Mill Creek 1 - FGD		$297,000		$14,341		$311,341		$50,486	
101	Mill Creek 1 - SCR		$97,000		$3,366		$100,366		$15,171	
102	Mill Creek 1 - Baghouse		$81,000		$3,477		$84,477		$13,335	
103	Mill Creek 1 - Electrostatic Precipitator		$32,882		$3,581		$36,463		$7,583	
104	Mill Creek 1 - PAC Injection		$4,412		$2,213		$6,625		$2,750	
105	Mill Creek 1 - Lime Injection		$4,480		$2,024		$6,504		$2,569	
106	Mill Creek 1 - Neural Networks		$1,000		$100		$1,100		$222	
107	Total Mill Creek 1		**$517,774**		**$29,102**		**$546,876**		**$92,116**	
108										
109	Mill Creek 2 - FGD		$297,000		$14,604		$311,604		$50,749	
110	Mill Creek 2 - SCR		$97,000		$3,401		$100,401		$15,206	
111	Mill Creek 2 - Baghouse		$81,000		$3,518		$84,518		$13,376	
112	Mill Creek 2 - Electrostatic Precipitator		$32,882		$3,664		$36,546		$7,666	
113	Mill Creek 2 - PAC Injection		$4,412		$2,340		$6,752		$2,877	
114	Mill Creek 2 - Lime Injection		$4,480		$2,117		$6,597		$2,662	
115	Mill Creek 2 - Neural Networks		$1,000		$100		$1,100		$222	
116	Total Mill Creek 2		**$517,774**		**$29,744**		**$547,518**		**$92,758**	
117										
118	Mill Creek 3 - FGD		$392,000		$18,911		$410,911		$66,617	
119	Mill Creek 3 - Baghouse		$114,000		$4,923		$118,923		$18,797	
120	Mill Creek 3 - PAC Injection		$5,592		$3,213		$8,805		$3,894	
121	Mill Creek 3 - Neural Networks		$1,000		$100		$1,100		$222	
122	Total Mill Creek 3		**$512,592**		**$27,147**		**$539,739**		**$89,530**	
123										
124	Mill Creek 4 - FGD		$455,000		$21,775		$476,775		$77,149	
125	Mill Creek 4 - Baghouse		$133,000		$5,804		$138,804		$21,990	
126	Mill Creek 4 - PAC Injection		$6,890		$3,858		$10,748		$4,697	
127	Mill Creek 4 - Neural Networks		$1,000		$100		$1,100		$222	
128	Total Mill Creek 4		**$595,890**		**$31,537**		**$627,427**		**$104,058**	
129										
130	**Total Mill Creek**		**$2,144,030**		**$117,530**		**$2,261,560**		**$378,462**	
131										
132										
133	**TRIMBLE**									
134	Trimble 1 - Baghouse		$128,000		$5,782		$133,782		$21,360	
135	Trimble 1 - PAC Injection		$6,451		$4,413		$10,864		$5,198	
136	Trimble 1 - Neural Networks		$1,000		$100		$1,100		$222	
137	Total Trimble 1		$135,451		$10,295		$145,746		$26,780	
138										

	A	B	C	D	E	F	G	H	I	J
139	**Total Trimble**		**$135,451**		**$10,295**		**$145,746**		**$26,780**	
140										
141										
142	**Grand Total**		**$4,333,694**		**$260,580**		**$4,594,274**		**$787,996**	

	A	B	C	D	E
1	Black & Veatch Study Cost Estimates				
2					
3					
4					
5			**MW**		**$/kW**
6	**BROWN**				
7	Brown 1 - Low NOx Burners				$11
8	Brown 1 - Baghouse				$364
9	Brown 1 - PAC Injection				$15
10	Brown 1 - Neural Networks				$5
11	Brown 1 - Overfire Air				$7
12	Total Brown 1		110		**$400**
13					
14	Brown 2 - SCR				$511
15	Brown 2 - Baghouse				$283
16	Brown 2 - PAC Injection				$14
17	Brown 2 - Neural Networks				$3
18	Brown 2 - Lime Injection				$15
19	Total Brown 2		180		**$826**
20					
21	Brown 3 - Baghouse				$133
22	Brown 3 - PAC Injection				$12
23	Brown 3 - Neural Networks				$2
24	Total Brown 3		457		**$148**
25					
26	**Total Brown**		**747**		**$348**
27					
28					
29	**GHENT**				
30	Ghent 1 - Baghouse				$242
31	Ghent 1 - PAC Injection				$12
32	Ghent 1 - Neural Networks				$2
33	Total Ghent 1		541		**$256**
34					
35	Ghent 2 - SCR				$439
36	Ghent 2 - Baghouse				$232
37	Ghent 2 - PAC Injection				$12
38	Ghent 2 - Lime Injection				$11
39	Ghent 2 - Neural Networks				$2
40	Total Ghent 2		517		**$696**
41					
42	Ghent 3 - Baghouse				$264
43	Ghent 3 - PAC Injection				$12
44	Ghent 3 - Neural Networks				$2
45	Total Ghent 3		523		**$278**
46					

	A	B	C	D	E
47	Ghent 4 - Baghouse				$222
48	Ghent 4 - PAC Injection				$12
49	Ghent 4 - Neural Networks				$2
50	Total Ghent 4		526		$236
51					
52	**Total Ghent**		**2,107**		**$364**
53					
54					
55					
56	**GREEN RIVER**				
57	Green River 3 - SCR				$408
58	Green River 3 - CDS-FF				$535
59	Green River 3 - PAC Injection				$16
60	Green River 3 - Neural Networks				$7
61	Total Green River 3		71		**$966**
62					
63	Green River 4 - SCR				$385
64	Green River 4 - CDS-FF				$495
65	Green River 4 - PAC Injection				$15
66	Green River 4 - Neural Networks				$5
67	Total Green River 4		109		**$900**
68					
69	**Total Green River**		**180**		**$926**
70					
71					
72	**CANE RUN**				
73	Cane Run 4 - FGD				$905
74	Cane Run 4 - SCR				$375
75	Cane Run 4 - Baghouse				$196
76	Cane Run 4 - PAC Injection				$14
77	Cane Run 4 - Lime Injection				$15
78	Cane Run 4 - Neural Networks				$3
79	Total Cane Run 4		168		**$1,508**
80					
81	Cane Run 5 - FGD				$878
82	Cane Run 5 - SCR				$365
83	Cane Run 5 - Baghouse				$193
84	Cane Run 5 - PAC Injection				$14
85	Cane Run 5 - Lime Injection				$15
86	Cane Run 5 - Neural Networks				$3
87	Total Cane Run 5		181		**$1,468**
88					
89	Cane Run 6 - FGD				$774
90	Cane Run 6 - SCR				$330
91	Can Rune 6 - Baghouse				$172
92	Cane Run 6 - PAC Injection				$13

	A	B	C	D	E
93	Cane Run 6 - Lime Injection				$15
94	Cane Run 6 - Neural Networks				$2
95	Total Can Run 6		261		$1,306
96					
97	**Total Cane Run**		**610**		**$1,410**
98					
99					
100	**Mill Creek**				
101	Mill Creek 1 - FGD				$900
102	Mill Creek 1 - SCR				$294
103	Mill Creek 1 - Baghouse				$245
104	Mill Creek 1 - Electrostatic Precipitator				$100
105	Mill Creek 1 - PAC Injection				$13
106	Mill Creek 1 - Lime Injection				$14
107	Mill Creek 1 - Neural Networks				$3
108	Total Mill Creek 1		330		**$1,569**
109					
110	Mill Creek 2 - FGD				$900
111	Mill Creek 2 - SCR				$294
112	Mill Creek 2 - Baghouse				$245
113	Mill Creek 2 - Electrostatic Precipitator				$100
114	Mill Creek 2 - PAC Injection				$13
115	Mill Creek 2 - Lime Injection				$14
116	Mill Creek 2 - Neural Networks				$3
117	Total Mill Creek 2		330		**$1,569**
118					
119	Mill Creek 3 - FGD				$927
120	Mill Creek 3 - Baghouse				$270
121	Mill Creek 3 - PAC Injection				$13
122	Mill Creek 3 - Neural Networks				$2
123	Total Mill Creek 3		423		**$1,212**
124					
125	Mill Creek 4 - FGD				$867
126	Mill Creek 4 - Baghouse				$253
127	Mill Creek 4 - PAC Injection				$13
128	Mill Creek 4 - Neural Networks				$2
129	Total Mill Creek 4		525		**$1,135**
130					
131	**Total Mill Creek**		**1,608**		**$1,333**
132					
133					
134	**TRIMBLE**				
135	Trimble 1 - Baghouse				$234
136	Trimble 1 - PAC Injection				$12
137	Trimble 1 - Neural Networks				$2
138	Total Trimble 1		547		$248

	A	B	C	D	E
139					
140	**Total Trimble**		**547**		**$248**
141					
142					
143	**Grand Total**		**5,799**		**$747**

From:	Saunders, Eileen
To:	Cosby, David
Sent:	6/11/2010 3:03:10 PM
Subject:	Draft -Cost Estimates and Assumptions
Attachments:	Environmental Summay (rev5 6-3-10).xlsx

David,

I was thinking the other day that you may be interested in seeing the cost summary we have shared with Stuart's group. Next week, we will receive schedules that will help us determine a cash flow so we can see when the O&M and Capital cost impacts will hit. Also, the O&M numbers represent a combined fixed and variable cost. When we receive their report on the 18th, the costs will be broken out.

Please see the list of assumptions below as you review the summary.

Thanks,

Eileen

From: Saunders, Eileen
Sent: Tuesday, June 08, 2010 10:29 AM
To: Wilson, Stuart; Karavayev, Louanne
Subject: Assumptions

Stuart and LouAnne,

Here are the assumptions I sent to John, Ralph and Scott:

Enclosed, please find a summary of the costs provided by B&V as part of the Environmental Compliance Study. As you review this information, please note the following:

- *The cost estimate does not meet the criteria for Level I Engineering. As Scott and I discussed, it may take 6-8 months to reach that level of Engineering.*
- *This estimate does not include the outage impact costs.*
- *The cost estimate does not include provisions for SO3 Mitigation Systems or Combined Cycle Costs. Both of those costs will be included in estimates provided by others.*
- *For Cane Run, Ghent, Trimble, Mill Creek and Green River, mercury technology solutions are included by Unit. The Brown Plant Management Team preferred to look at a mercury solution by plant. Environmental is unsure as to if the mercury regulations will be by plant or by unit so I supported their requests. If we believe that we should look at mercury by plant as the basis of what goes into the MTP, the costs may go down.*
- *A generic Neural Network number was used as a means of addressing CO.*
- *The second attachment, from Environmental Affair, has been updated to reflect the proper CO limits.*

Additionally, we discussed yesterday that the estimate does not account for market impact (i.e. markups we may receive from vendors/contractors since the demand for equipment will increase due to the new regulations).

Please call me if you have any questions.

Thank you,

Eileen

	A	B	C	D	E	F	G	H
1	Black & Veatch Study Cost Estimates							
2	$ in thousands							
3								
4								
5			**Capital Cost**		**O&M Cost**		**Levelized Annual Costs**	
6	**BROWN**							
7	Brown 1 - Low NOx Burners		$1,156		$0		$141	
8	Brown 1 - Baghouse		$40,000		$1,477		$6,345	
9	Brown 1 - PAC Injection		$1,599		$614		$809	
10	Brown 1 - Neural Networks		$500		$50		$111	
11	Brown 1 - Overfire Air		$767		$132		$225	
12	Total Brown 1		**$44,022**		**$2,273**		**$7,631**	
13								
14	Brown 2 - SCR		$92,000		$3,278		$14,474	
15	Brown 2 - Baghouse		$51,000		$1,959		$8,166	
16	Brown 2 - PAC Injection		$2,476		$1,090		$1,391	
17	Brown 2 - Neural Networks		$500		$50		$111	
18	Brown 2 - Lime Injection		$2,739		$1,155		$1,488	
19	Total Brown 2		**$148,715**		**$7,532**		**$25,630**	
20								
21	Brown 3 - Baghouse		$61,000		$3,321		$10,745	
22	Brown 3 - PAC Injection		$5,426		$2,330		$2,990	
23	Brown 3 - Neural Networks		$1,000		$100		$222	
24	Total Brown 3		**$67,426**		**$5,751**		**$13,957**	
25								
26	**Total Brown**		**$260,163**		**$15,556**		**$47,218**	
27								
28								
29	**GHENT**							
30	Ghent 1 - Baghouse		$131,000		$5,888		$21,831	
31	Ghent 1 - PAC Injection		$6,380		$4,208		$4,984	
32	Ghent 1 - Neural Networks		$1,000		$100		$222	
33	Total Ghent 1		**$138,380**		**$10,196**		**$27,037**	
34								
35	Ghent 2 - SCR		$227,000		$7,078		$34,704	
36	Ghent 2 - Baghouse		$120,000		$5,002		$19,606	
37	Ghent 2 - PAC Injection		$6,109		$2,880		$3,623	
38	Ghent 2 - Lime Injection		$5,483		$2,775		$3,442	
39	Ghent 2 - Neural Networks		$1,000		$100		$222	
40	Total Ghent 2		**$359,592**		**$17,835**		**$61,597**	
41								
42	Ghent 3 - Baghouse		$138,000		$6,122		$22,917	
43	Ghent 3 - PAC Injection		$6,173		$4,134		$4,885	
44	Ghent 3 - Neural Networks		$1,000		$100		$222	
45	Total Ghent 3		**$145,173**		**$10,356**		**$28,024**	
46								

	A	B	C	D	E	F	G	H
47	Ghent 4 - Baghouse		$117,000		$5,363		$19,602	
48	Ghent 4 - PAC Injection		$6,210		$3,896		$4,652	
49	Ghent 4 - Neural Networks		$1,000		$100		$222	
50	Total Ghent 4		$124,210		$9,359		$24,476	
51								
52	**Total Ghent**		**$767,355**		**$47,746**		**$141,134**	
53								
54								
55	**GREEN RIVER**							
56	Green River 3 - SCR		$29,000		$1,040		$4,569	
57	Green River 3 - CDS-FF		$38,000		$6,874		$11,499	
58	Green River 3 - PAC Injection		$1,112		$323		$458	
59	Green River 3 - Neural Networks		$500		$50		$111	
60	Total Green River 3		**$68,612**		**$8,287**		**$16,637**	
61								
62	Green River 4 - SCR		$42,000		$1,442		$6,553	
63	Green River 4 - CDS-FF		$54,000		$10,289		$16,861	
64	Green River 4 - PAC Injection		$1,583		$515		$708	
65	Green River 4 - Neural Networks		$500		$50		$111	
66	Total Green River 4		**$98,083**		**$12,296**		**$24,233**	
67								
68	**Total Green River**		**$166,695**		**$20,583**		**$40,870**	
69								
70								
71	**CANE RUN**							
72	Cane Run 4 - FGD		$152,000		$8,428		$26,926	
73	Cane Run 4 - SCR		$63,000		$2,219		$9,886	
74	Cane Run 4 - Baghouse		$33,000		$1,924		$5,940	
75	Cane Run 4 - PAC Injection		$2,326		$1,087		$1,370	
76	Cane Run 4 - Lime Injection		$2,569		$983		$1,296	
77	Cane Run 4 - Neural Networks		$500		$50		$111	
78	Total Cane Run 4		**$253,395**		**$14,691**		**$45,529**	
79								
80	Cane Run 5 - FGD		$159,000		$8,789		$28,139	
81	Cane Run 5 - SCR		$66,000		$2,421		$10,453	
82	Cane Run 5 - Baghouse		$35,000		$2,061		$6,321	
83	Cane Run 5 - PAC Injection		$2,490		$1,120		$1,423	
84	Cane Run 5 - Lime Injection		$2,752		$1,089		$1,424	
85	Cane Run 5 - Neural Networks		$500		$50		$111	
86	Total Cane Run 5		**$265,742**		**$15,530**		**$47,871**	
87								
88	Cane Run 6 - FGD		$202,000		$10,431		$35,014	
89	Cane Run 6 - SCR		$86,000		$2,793		$13,259	
90	Can Rune 6 - Baghouse		$45,000		$2,672		$8,149	
91	Cane Run 6 - PAC Injection		$3,490		$1,336		$1,761	
92	Cane Run 6 - Lime Injection		$3,873		$1,367		$1,838	

	A	B	C	D	E	F	G	H
93	Cane Run 6 - Neural Networks		$500		$50		$111	
94	Total Can Run 6		$340,863		$18,649		$60,132	
95								
96	**Total Cane Run**		**$860,000**		**$48,870**		**$153,532**	
97								
98								
99	**Mill Creek**							
100	Mill Creek 1 - FGD		$297,000		$14,341		$50,486	
101	Mill Creek 1 - SCR		$97,000		$3,366		$15,171	
102	Mill Creek 1 - Baghouse		$81,000		$3,477		$13,335	
103	Mill Creek 1 - Electrostatic Precipitator		$32,882		$3,581		$7,583	
104	Mill Creek 1 - PAC Injection		$4,412		$2,213		$2,750	
105	Mill Creek 1 - Lime Injection		$4,480		$2,024		$2,569	
106	Mill Creek 1 - Neural Networks		$1,000		$100		$222	
107	Total Mill Creek 1		**$517,774**		**$29,102**		**$92,116**	
108								
109	Mill Creek 2 - FGD		$297,000		$14,604		$50,749	
110	Mill Creek 2 - SCR		$97,000		$3,401		$15,206	
111	Mill Creek 2 - Baghouse		$81,000		$3,518		$13,376	
112	Mill Creek 2 - Electrostatic Precipitator		$32,882		$3,664		$7,666	
113	Mill Creek 2 - PAC Injection		$4,412		$2,340		$2,877	
114	Mill Creek 2 - Lime Injection		$4,480		$2,117		$2,662	
115	Mill Creek 2 - Neural Networks		$1,000		$100		$222	
116	Total Mill Creek 2		**$517,774**		**$29,744**		**$92,758**	
117								
118	Mill Creek 3 - FGD		$392,000		$18,911		$66,617	
119	Mill Creek 3 - Baghouse		$114,000		$4,923		$18,797	
120	Mill Creek 3 - PAC Injection		$5,592		$3,213		$3,894	
121	Mill Creek 3 - Neural Networks		$1,000		$100		$222	
122	Total Mill Creek 3		**$512,592**		**$27,147**		**$89,530**	
123								
124	Mill Creek 4 - FGD		$455,000		$21,775		$77,149	
125	Mill Creek 4 - Baghouse		$133,000		$5,804		$21,990	
126	Mill Creek 4 - PAC Injection		$6,890		$3,858		$4,697	
127	Mill Creek 4 - Neural Networks		$1,000		$100		$222	
128	Total Mill Creek 4		**$595,890**		**$31,537**		**$104,058**	
129								
130	**Total Mill Creek**		**$2,144,030**		**$117,530**		**$378,462**	
131								
132								
133	**TRIMBLE**							
134	Trimble 1 - Baghouse		$128,000		$5,782		$21,360	
135	Trimble 1 - PAC Injection		$6,451		$4,413		$5,198	
136	Trimble 1 - Neural Networks		$1,000		$100		$222	
137	Total Trimble 1		$135,451		$10,295		$26,780	
138								

	A	B	C	D	E	F	G	H
139	**Total Trimble**		**$135,451**		**$10,295**		**$26,780**	
140								
141								
142	**Grand Total**		**$4,333,694**		**$260,580**		**$787,996**	

	A	B	C	D	E
1	Black & Veatch Study Cost Estimates				
2					
3					
4					
5			**MW**		**$/kW**
6	**BROWN**				
7	Brown 1 - Low NOx Burners				$11
8	Brown 1 - Baghouse				$364
9	Brown 1 - PAC Injection				$15
10	Brown 1 - Neural Networks				$5
11	Brown 1 - Overfire Air				$7
12	Total Brown 1		110		**$400**
13					
14	Brown 2 - SCR				$511
15	Brown 2 - Baghouse				$283
16	Brown 2 - PAC Injection				$14
17	Brown 2 - Neural Networks				$3
18	Brown 2 - Lime Injection				$15
19	Total Brown 2		180		**$826**
20					
21	Brown 3 - Baghouse				$133
22	Brown 3 - PAC Injection				$12
23	Brown 3 - Neural Networks				$2
24	Total Brown 3		457		**$148**
25					
26	**Total Brown**		**747**		**$348**
27					
28					
29	**GHENT**				
30	Ghent 1 - Baghouse				$242
31	Ghent 1 - PAC Injection				$12
32	Ghent 1 - Neural Networks				$2
33	Total Ghent 1		541		**$256**
34					
35	Ghent 2 - SCR				$439
36	Ghent 2 - Baghouse				$232
37	Ghent 2 - PAC Injection				$12
38	Ghent 2 - Lime Injection				$11
39	Ghent 2 - Neural Networks				$2
40	Total Ghent 2		517		**$696**
41					
42	Ghent 3 - Baghouse				$264
43	Ghent 3 - PAC Injection				$12
44	Ghent 3 - Neural Networks				$2
45	Total Ghent 3		523		**$278**
46					

	A	B	C	D	E
47	Ghent 4 - Baghouse				$222
48	Ghent 4 - PAC Injection				$12
49	Ghent 4 - Neural Networks				$2
50	Total Ghent 4		526		$236
51					
52	**Total Ghent**		**2,107**		**$364**
53					
54					
55					
56	**GREEN RIVER**				
57	Green River 3 - SCR				$408
58	Green River 3 - CDS-FF				$535
59	Green River 3 - PAC Injection				$16
60	Green River 3 - Neural Networks				$7
61	Total Green River 3		71		**$966**
62					
63	Green River 4 - SCR				$385
64	Green River 4 - CDS-FF				$495
65	Green River 4 - PAC Injection				$15
66	Green River 4 - Neural Networks				$5
67	Total Green River 4		109		**$900**
68					
69	**Total Green River**		**180**		**$926**
70					
71					
72	**CANE RUN**				
73	Cane Run 4 - FGD				$905
74	Cane Run 4 - SCR				$375
75	Cane Run 4 - Baghouse				$196
76	Cane Run 4 - PAC Injection				$14
77	Cane Run 4 - Lime Injection				$15
78	Cane Run 4 - Neural Networks				$3
79	Total Cane Run 4		168		**$1,508**
80					
81	Cane Run 5 - FGD				$878
82	Cane Run 5 - SCR				$365
83	Cane Run 5 - Baghouse				$193
84	Cane Run 5 - PAC Injection				$14
85	Cane Run 5 - Lime Injection				$15
86	Cane Run 5 - Neural Networks				$3
87	Total Cane Run 5		181		**$1,468**
88					
89	Cane Run 6 - FGD				$774
90	Cane Run 6 - SCR				$330
91	Can Rune 6 - Baghouse				$172
92	Cane Run 6 - PAC Injection				$13

	A	B	C	D	E
93	Cane Run 6 - Lime Injection				$15
94	Cane Run 6 - Neural Networks				$2
95	Total Can Run 6		261		$1,306
96					
97	**Total Cane Run**		**610**		**$1,410**
98					
99					
100	**Mill Creek**				
101	Mill Creek 1 - FGD				$900
102	Mill Creek 1 - SCR				$294
103	Mill Creek 1 - Baghouse				$245
104	Mill Creek 1 - Electrostatic Precipitator				$100
105	Mill Creek 1 - PAC Injection				$13
106	Mill Creek 1 - Lime Injection				$14
107	Mill Creek 1 - Neural Networks				$3
108	Total Mill Creek 1		330		**$1,569**
109					
110	Mill Creek 2 - FGD				$900
111	Mill Creek 2 - SCR				$294
112	Mill Creek 2 - Baghouse				$245
113	Mill Creek 2 - Electrostatic Precipitator				$100
114	Mill Creek 2 - PAC Injection				$13
115	Mill Creek 2 - Lime Injection				$14
116	Mill Creek 2 - Neural Networks				$3
117	Total Mill Creek 2		330		**$1,569**
118					
119	Mill Creek 3 - FGD				$927
120	Mill Creek 3 - Baghouse				$270
121	Mill Creek 3 - PAC Injection				$13
122	Mill Creek 3 - Neural Networks				$2
123	Total Mill Creek 3		423		**$1,212**
124					
125	Mill Creek 4 - FGD				$867
126	Mill Creek 4 - Baghouse				$253
127	Mill Creek 4 - PAC Injection				$13
128	Mill Creek 4 - Neural Networks				$2
129	Total Mill Creek 4		525		**$1,135**
130					
131	**Total Mill Creek**		**1,608**		**$1,333**
132					
133					
134	**TRIMBLE**				
135	Trimble 1 - Baghouse				$234
136	Trimble 1 - PAC Injection				$12
137	Trimble 1 - Neural Networks				$2
138	Total Trimble 1		547		$248

	A	B	C	D	E
139					
140	**Total Trimble**		**547**		**$248**
141					
142					
143	**Grand Total**		**5,799**		**$747**

From:	Straight, Scott
To:	Thompson, Paul; Voyles, John; Bowling, Ralph; Sturgeon, Allyson; Hudson, Rusty; Hincker, Loren; Sinclair, David; Schetzel, Doug; Yussman, Eric; Jackson, Fred
CC:	Waterman, Bob; Imber, Philip; Lively, Noel; Saunders, Eileen; Gregory, Ronald; Heun, Jeff; Cooper, David; Hance, Chuck
Sent:	3/1/2010 10:10:47 AM
Subject:	Project Engineering's ES Bi-Weekly Report - March 1, 2010
Attachments:	PE's Bi-Weekly Update of 3-1-10.docx

Energy Services - Bi-Weekly Update
March 1, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – NTR
  - Auditing – NTR
  - Schedule/Execution:
    - Ghent Remaining Scope/Schedule
      - Chimney Coatings – Scheduled for May 2010.
      - SCR/FGD Icing Siding – installation in progress.
      - Unit 4 ID Fans – Negotiations continue with FW and WEG on the ID Fan motor rebuild settlement. A meeting with senior management was held in Greenville the week of 2/15. WEG agreed to provide a full, new motor warranty on the rebuilt motor that is being set on magnetic center in Evansville, IN. The motor is fully expected to be on-site for the outage.
      - Chimney Capping - Bids are due back 3/5 with work to begin the week of 4/19.
    - Brown
      - FGD, Limestone and BOP construction continues to track to plan. The main focus right now is completing the pre-outage work, planning and preparation for the upcoming BR3 outage in a few weeks.
  - Budget:
    - Brown – The budget with Fluor this period is at $487.6m with eight (8) pending change orders totaling $2.8m. The current month Fluor forecast decreased by $14.9m for a total projected savings to budget of $73.6m. PE plans to use some of this reduction to take care of the TC2 budget shortfall projected from the Labor Claim noted below.
    - Ghent – NTR
  - Contract Disputes/Resolution:
    - FGD Alliance – NTR
    - Ghent 4 ID Fan Motor – see Unit 4 ID Fans above.
  - Issues/Risks:
    - NTR

- **TC2**
  - Safety – Bechtel continues to experience higher recordable rates than target. All injuries have been minor in nature.
  - Permitting – NTR
  - Auditing – Auditing is conducting their annual audit of the EPC Agreement.
  - Schedule/Execution:
    - Bechtel EPC –Bechtel continues to focus on startup activities required to begin steam blows that are currently scheduled for 3/3. **Bechtel is now indicating the Substantial Completion date is June 22.**
    - Non-Bechtel Scope:
      - PRB Upgrades – The wash down booster pumps are in commissioning, which has been slowed by subfreezing temperatures.
      - PM Baghouses – TC2's baghouse testing scheduled with TC2 commissioning.

- Budget:
  - Bechtel's labor claim for the second half of 2009 was received, and as expected given the higher amounts of labor and schedule extensions, is higher than the accrued amount for the same period. On a net basis, the claim is about $4.5m higher than budget. PE is reviewing all project cost-to-date and will be reconciling the projected final cost for all over/under spends against the budget and sanction in concert with the power credit review that Rusty is doing with Finance. The significant underruns on the FGD Program can fund this overrun to keep PE overall spend well within budget for 2010.
- Contract Disputes/Resolution:
  - Bechtel FM Claims – Bechtel submitted a fifth Force Majeure claim for weather related impacts to the BCP truck delivery during the recent snow storm in the Northeast. Bechtel (Brightman and Hobbs) reviewed the methodology of claim calculations with PE on 2/23.
  - Air Blow Change Order – Still waiting on Bechtel's revised change order on the cancellation of Air Blows.
- Issues/Risk:
  - Bechtel's schedule performance, Excusable Event claims, start-up of all plant equipment to operational mode, and the expected increase in Labor Claim amounts against budget.

- **Brown 3 SCR**
  - Schedule/Execution – PE is working with Brown management and Generation Planning to evaluate moving the BR3 outage from the fall of 2012 to the spring of 2012. This will give Brown the entire summer to operate the SCR instead of having the SCR commissioning just a month ahead of the Dec 31, 2012 CD date. **A decision is likely within the next two weeks to move the outage to the spring of 2012 given Gen Planning review indicates very little impacts to overall 2010 plan.**
  - Permitting – PE attended a meeting with the KYDAQ and EA on 2/19. KDAQ is on board with KU but wants to ensure proper supporting documentation to mitigate possible litigation concerns. KDAQ requested, and KU accepted, a site tour on 3/16.
  - Engineering – RPI has begun engineering and procurement activities. Flow model witnessing is planned for April, 2010 along with a visit to CERAM to see their catalyst manufacturing facility.
  - Budget:
    - $45m has been given back to the RAC on this project.
    - A Tax Exemption Certificate is being prepared in conjunction with EA to provide to RPI and eventually Zachry.
  - Contracting:
    - EPC – Initial round of negotiations held with Zachry on 2/15-2/16. Next meeting scheduled for 3/8-3/9. Zachry is planning another engineering site visit to confirm demolition, relocation, and interferences scope. Conformance of Technical Specifications and Agreement Exhibits on-going.
  - SCR Supplier – Contract is fully executed. RPI is in full engineering and procurement.
  - Issues/Risk – NTR

- **Brown CCP Project – Ash Ponds**
  - <u>E.W. Brown Starter Dike</u>

  - Safety – NTR
  - Auditing - Nearing completion of work for an audit of the Summit contract with a focus on award process, change order management and invoicing/payments.
  - Schedule/Execution:
    - Starter Dike – all work tracking to plan.
    - Rock placement production quantities have increased.
  - Budget – NTR
  - Contract Disputes/Resolution - Fuel oil baseline adjustment review with Summit continues.
  - Issues/Risk – NTR

- E.W. Brown Aux Pond 900'
  - Schedule/Execution:
    - The original 7 bidders have been short listed to 4 with follow up questions and review meetings being scheduled.
  - Budget – NTR.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Cane Run CCP Project - Landfill**
  - Schedule/Execution:
    - **404/401 and Landfill Permit applications have been submitted and are currently under review. Public Notice for the 404 Permit was issued by the USACE on 2/12 with a closing date of 3/13.**
    - Development of construction drawings is on hold until the EPA's presents its CCP ruling and the KYDWM has completed their initial review.
    - A meeting was held with Transmission to review the status of their design. A final route for the 345kV lines has been agreed to and the design of the 69kV line has been completed. PE is evaluating the option to relocate the line this year.
  - Budget - NTR
  - Contract Disputes - NTR
  - Issues - NTR

- **TC CCP Project – Holcim**
  - Schedule/Execution:
    - Discussions between the Plant and Holcim have resumed however no action has been taken to restart the design of the barge loading system.
  - Budget – NTR
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – Status of Holcim contract.

- **TC CCP Project – BAP/GSP**
  - Schedule/Execution:
    - Construction on the project has stopped due to the inclement weather with the exception of the concrete work for the southwest pipe culvert.
  - Budgeting – NTR
  - Engineering – NTR
  - Permitting – NTR

  - Contract Disputes/Resolution – PE held the first meeting with GAI Consultants to resolve a dispute over engineering costs for the mechanical engineering for the project. GAI's financial counter offer is under review.
  - Issues/Risk – Weather. Currently not anticipating impact on the final completion date.

- **TC CCP Project – Landfill**
  - Schedule/Execution – NTR
  - Budgeting – NTR
  - Engineering – Engineering continues on the single landfill alternative.
  - Permitting – Follow-up meetings with US Fish & Wildlife to negotiate the mitigation of a juvenile female Indiana Bat have not progressed as well as the earlier meeting in mid-January, 2010. Meeting held with EA on 2/26 with a plan forward with USF&W. The outcome will likely result in continuing to perform the stream mitigation and a negotiated offset for fees to cover the bat issue.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
  - Schedule/Execution – NTR
  - Budget – NTR
  - Engineering – Detailed Engineering of gypsum fines and Conceptual Engineering on CCP transport for landfill continues with Black & Veatch.
  - Permitting – 401/404 Permit revisions are being made by GAI Consultants after review by EON US. The Division of Waste Management (DWM) Permit is being reviewed by EON US. Permit filing is still planned for spring 2010, regardless of final landfill footprint and land acquisition issues.
  - Contract Disputes/Resolution – NTR
  - Issues/Risk:
    - Land Acquisition – Meeting held with D. O'Brien and J. Voyles to review status of land purchase. PE is working with Real Estate and Legal to draft "last and final" written offers to the remaining three property owners prior to recommending condemnation proceedings. PE is also reviewing potential modifications to the landfill design to possibly eliminate the need for the remaining few properties.

- **General CCP Projects (Impoundment Management Program Development)**
    - PE is leading the development of the Impoundment Integrity Program, including the scheduling of meetings with management for conceptual approval of the impoundment document.

- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3)**
  - Safety - NTR
  - Schedule/Execution:
    - MC3's schedule is now tied to the BART requirement for the end of 2011. Tie-in work during spring 2011 outage is still required.
    - Preliminary Engineering on Wet (URS) and Dry (Nol-Tec) are on-going with results expected in a few weeks. Decision to bid wet and/or dry will be made as a result of these studies.

        - Considering dry sorbent injection testing on MC 3 & 4. Both units have a spring outage in which we can install nozzles. Set a site walk down for the nozzle installations with A&D, UGS, and Hall for 3/3. Meetings with Nol-Tec, ADA, BCSI and UCC are in progress to discuss temporary injection equipment and crews.
    - Budget – may require timing shifts in the 2011 MTP to account for shift in scheduled need.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk - NTR

- **NBU1 and Other Generation Development**
    - LFG
        - PE requested to contract specific engineering design work related to gas compression and pipeline work at Valley View and power generation at Tri-K and Ohio County.
        - The PO for sampling and lab analysis of the Republic Landfills will be released to MCC after resolution of insurance issues.
    - NBU 1 – NTR
    - Mercury Planning
        - Submitted unsupported SCR & Hg Capture costs to Generation Planning.
        - A new Final Draft of the B&McD study is expected to be published the week of 3/1.
        - Phase II planning and study required.
    - Biomass –
        - Started Mill Creek Design Development RFP.
    - FutureGen – NTR

- General
    - Supporting the environmental "scenario planning" team by providing very speculative cost and timing for SCRs on all other units, FGD upgrades to CR, Hg control (with added PM control), and other miscellaneous cost (i.e., O&M cost) to Generation Planning. These values and timing are NOT supported by any engineering or project development. These values were created on a relative basis in less than a week.

Metrics

MBE/WBE Spend

Project Engr. direct spend for 2009	
2009 Spend	$12,816,000
MBE target	5%
	$640,800
WBE target	2%
	$256,320
Total M/WBE	$897,120

Bechtel - TC 2 Spend - 2009	
	$13,000,000
MBE target	3%
	$390,000
WBE target	2%
	$260,000
Total M/WBE	$650,000

Fluor - FGD Spend - 2009	
	$48,000,000
MBE target	5%
	$2,400,000
WBE target	2%
	$960,000
Total M/WBE	$3,360,000

Total Project Engineering 2009	
	$73,816,000
MBE target	5%
	$3,430,800
WBE target	2%
	$1,476,320
Total M/WBE	$4,907,120

Project Engr. direct spend for 2010	
2010 Spend	$44,744,000
MBE target	5%
	$2,237,200
WBE target	2%
	$894,880
Total M/WBE	$3,132,080

Bechtel - TC 2 Spend - 2010	
	$3,500,000
MBE target	3%
	$105,000
WBE target	2%
	$70,000
Total M/WBE	$175,000

Fluor - FGD Spend - 2010	
	$11,000,000
MBE target	5%
	$550,000
WBE target	2%
	$220,000
Total M/WBE	$770,000

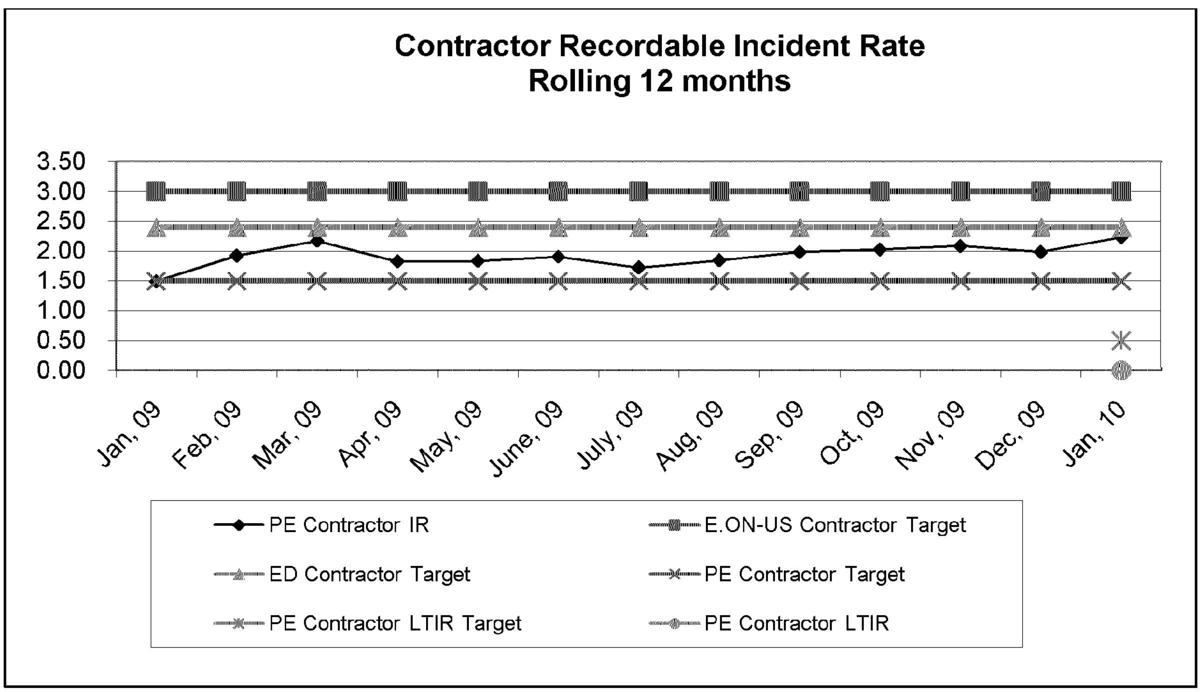
Total Project Engineering 2010	
	$59,244,000
MBE target	5%
	$2,892,200
WBE target	2%
	$1,184,880
Total M/WBE	$4,077,080

Project Engr. direct spend for 2011	
2011 Spend	$69,150,000
MBE target	5%
	$3,457,500
WBE target	2%
	$1,383,000
Total M/WBE	$4,840,500

Bechtel - TC 2 Spend - 2011
N/A

Fluor - FGD Spend - 2011
N/A

Total Project Engineering 2011	
	$69,150,000
MBE target	5%
	$3,457,500
WBE target	2%
	$1,383,000
Total M/WBE	$4,840,500



Upcoming PWT Needs:

Project Engineering
Investment Committee Schedule

INVESTMENT COMMITTEE SCHEDULE

Project Manager	Description	Amount $000s	D	F	MAR10	APR10	MAY10	JUN10	JUL10	AUG10	SEP10	OCT10	NOV10	DEC10
JH	CR CCP - Landfill Phase I Project (Not to IC until Feb 20	18,898												
JH	BR CCP - Aux Pond 900' Contract	13,473												
RCW	TC CCP - BAP/GSP Contract	17,352												
RCW	TC CCP - Landfill/BAP Update													
RCW	TC CCP - Landfill													
PI	BioMass Coal Firing	10,300,000												
PI	MC3, MC4, BR3 SO3 Mitigation	19,200,000												
JC	EW Brown SCR EPC Contract	40,000,000												
PI	Land Fill Gas Engineering- (Need to verify with Schetzel)													
RCW	TC CCP - Ghent Landfill													

Full Presentation at PWT Brie
Date of IC Meeting

Staffing:

ME position to replace Bill Maki is still active. Interviews are being scheduled.

From: Saunders, Eileen
To: Voyles, John
Sent: 5/14/2010 8:16:36 AM
Subject: Deliverables
Attachments: AQCS Fleetwide Compliance Matrix B&V May 3 2010.xls

John,

Here is an excerpt from an email I sent to out explaining the Deliverables in answer to a question posed by David Cosby:

All,

I believe there is some confusion that I hope the following schedule will help clear up:

B&V Deliverables

Week of May 10, 2010:

- *B&V Kickoff Meeting, Site Visits and finalize Compliance Matrix.*

Week of May 17, 2010:

- *B&V will produce a Design Basis document with a list of options and their recommendation for the AQCS solution of choice for each unit. E.ON Approval will be needed at this point to choose the "stake in the ground" for technology for estimating purposes.*

Week of May 24, 2010:

- *B&V will begin their cost estimating of the design choices approved by E.ON.*

Week of May 31, 2010:

- *E.ON will receive costs, by unit for each station by June 1, 2010.*

Week of June 14, 2010:

- *E.ON will receive a revised cost estimate.*

Week of July 4, 2010

- *E.ON will receive the final cost estimate and report.*

We will receive costs by June 1st, but ***not*** *for each AQCS option that is possible. We will only receive costs based on the design basis we choose the week of May 17. We will be given various scenarios that we can ultimately ask B&V to build upon, but in the timeframe given, the only way we can meet the MTP schedule, is to choose one option per unit/station and have them estimate that as our baseline.*

For the finance guys, you will have numbers to use by June 1, 2010. I verified this with Tim from B&V and this schedule of activities will be reflected in their meeting notes.

As an aside, we can add estimating various scenarios to B&V's scope at anytime but the first priority, as I understand it, is to have numbers to use as a place holder during this MTP cycle.

If anyone has any questions, please let me know.

We discussed these items in the meeting that took place on May 10, 2010. Several handouts were reviewed as well including the B&V Scope Document that I can send to you if you would like. In the meantime, I have attached a sample of a spreadsheet that B&V will complete for each Unit at the stations as part of their deliverables.

Thank you,

Eileen

	A	B	C	D	E	F	G	H	I	J	K	L	M
1													**EON Fleetwide AQCS Co**
2													
3	Item #	Plant/Site	Vintage	Unit	Unit rating MWg	MW Net	Priority	Fuel Burned	Pollutant	Compliance D	AQC Control	Uncontrolled Er	Removal %
4		E. W. Brown											
5	1			1					NOx				
6	2								SO2				
7	3								PM				
8	4								PM				
9	5												
10	6								CO				
11	7								VOC				
12	8								Hg				
13	9								HAPs				
14	10								H2SO4				
15	11								SO3-SAM				
16	12								HCL				
17	13								HF				
18													
19													
20													
21													
22				2					NOx				
23									SO2				
24									PM				
25									PM				
26													
27									CO				
28									VOC				
29									Hg				
30									HAPs				
31									H2SO4				
32									SO3-SAM				
33									HCL				
34									HF				
35													
36													
37													
38													
39				3					NOx				
40									SO2				
41									PM				
42									PM				
43													
44									CO				
45									VOC				
46									Hg				

	N	O	P	Q	R	S	T	U	V	W
1	**mpliance Analysis and High Level Capital and O&M Cost Estimation**									
2										
3	Current Controlled	Future Required Er	Future Regulatory D	Tons removed with (	Tons removed with	Capital costs		Cost Corrections if applicable		O&M Costs
4						*$/ton removed*	*$/kW*	*$/ton removed*	*$/kW*	*$*
5										
6										
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47									HAPs				
48									H2SO4				
49									SO3-SAM				
50									HCL				
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57		Revision #											
58		Date of Revision											
59		Notes											
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	A	B	C	D	E	F	G	H	I	J	K	L	M
1													EON Fleetwide AQCS Co
2													
3	Item #	Plant/Site	Vintage	Unit	Unit rating MWg	MW net	Priority	Fuel Burned	Pollutant	Compliance D	AQC Control	Uncontrolled Er	Removal %
4		Ghent											
5	1			1					NOx				
6	2								SO2				
7	3								PM				
8	4								PM				
9	5												
10	6								CO				
11	7								VOC				
12	8								Hg				
13	9								HAPs				
14	10								H2SO4				
15	11								SO3-SAM				
16	12								HCL				
17	13								HF				
18													
19													
20													
21													
22				2					NOx				
23									SO2				
24									PM				
25									PM				
26													
27									CO				
28									VOC				
29									Hg				
30									HAPs				
31									H2SO4				
32									SO3-SAM				
33									HCL				
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39				3					NOx				
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3	Item #	Plant/Site	Vintage	Unit	Unit rating MWg	MW net	Priority	Fuel Burned	Pollutant	Compliance D	AQC Control	Uncontrolled Er	Removal %
4		Cane Run											
5	1			4					NOx				
6	2								SO2				
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3	**Item #**	**Plant/Site**	**Vintage**	**Unit**	**Unit rating MWg**	**MW net**	**Priority**	**Fuel Burned**	**Pollutant**	**Compliance D**	**AQC Control**	**Uncontrolled Er**	**Removal %**
4		Mill Creek											
5	1			1					NOx				
6	2								SO2				
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39				3					NOx				
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3	Current Controlled	Future Required Er	Future Regulatory D	Tons removed with (	Tons removed with	Capital costs		Cost Corrections		O&M Costs
4						*$/ton removed*	*$/kW*	*$/ton removed*	*$/kW*	*$*
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3	Item #	Plant/Site	Vintage	Unit	Unit rating MWg	MW net	Priority	Fuel Burned	Pollutant	Compliance D	AQC Control	Uncontrolled En	Removal %
4		Trimble County											
5	1			1					NOx				
6	2								SO2				
7	3								PM				
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13	9								HAPs				
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15	11								SO3-SAM				
16	12								HCL				
17	13								HF				
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22				2					NOx				
23									SO2				
24									PM				
25									PM				
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1	**mpliance Analysis and High Level Capital and O&M Cost Estimation**									
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3	Current Controlled	Future Required Er	Future Regulatory D	Tons removed with (	Tons removed with	Capital costs		Cost Corrections		O&M Costs
4						*$/ton removed*	*$/kW*	*$/ton removed*	*$/kW*	*$*
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3	**Item #**	**Plant/Site**	**Vintage**	**Unit**	**Unit rating MWg**	**MW net**	**Priority**	**Fuel Burned**	**Pollutant**	**Compliance D**	**AQC Control**	**Uncontrolled Er**	**Removal %**
4		Green River											
5	1			3					NOx				
6	2								SO2				
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23									SO2				
24									PM				
25									PM				
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31									H2SO4				
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4						*$/ton removed*	*$/kW*	*$/ton removed*	*$/kW*	*$*
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From:	Gregory, Ronald
To:	Saunders, Eileen
Sent:	6/17/2010 4:09:52 PM
Subject:	PE's Bi-Weekly Update of 6-17-10 (rdg).docx
Attachments:	PE's Bi-Weekly Update of 6-17-10 (rdg).docx

Tag you are it.

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Energy Services - Bi-Weekly Update
June 17, 2010
PROJECT ENGINEERING

- **KU SOx**
  - Safety – Nothing new to report.
  - Auditing – Internal Auditing is in the final stages of activities for the Brown FGD audit.
  - Schedule/Execution:
    - Ghent Remaining Scope/Schedule
      - Chimney Coatings – Coating application is complete. The seven day cure process has begun and the coating will be tested next week.
      - SCR/FGD Icing Siding – Installation in progress and nearing completion.
      - Unit 4 ID Fans – On plan for fall 2010 install.
      - Chimney Capping – Contractor will mobilize mid-June.
      - Elevators- Bids are due June 7, 2010.
    - Brown
      - FGD, Limestone and BOP construction continues to track to plan. The FGD tie-in for Brown Unit 3 was successfully completed during the BR3 outage that ended on May 21, 2010 and has continued to operate since. Brown Unit 2 is expected to be directed through the FGD sometime before the end of this month, unless something changes.
      - E.W. Brown Gypsum Dewatering Facility
        - Schedule/Execution:
          - Commissioning of the vacuum pump, motor, and filter belt continues.
          - Fluor continues to work on the DCS and commissioning of the Fluor supplied equipment.
          - Construction and commissioning work to be complete week of 6/21.
          - Facility operation contract bid reviews ongoing.
      - E.W. Brown Gypsum Lab
        - Schedule/Execution:
          - Construction 97% complete.
          - Plumbing inspection and final building inspection to occur week of 6/14.
  - Budget:
    - Brown – NTR.
    - Ghent – NTR
    - Contract Disputes/Resolution - NTR
  - Issues/Risks:
    - NTR.

- **TC2**
  - Safety – NTR
  - Permitting – NTR
  - Auditing – Auditing released their audit report on TC2 invoicing with no findings.
  - Schedule/Execution:
    - Bechtel EPC – TC2 achieved initial synchronization May 18 and has been at 200 MW intermittently for mill tuning. First full load is planned for mid-June. **This supports Bechtel's latest forecasted substantial completion date of July 22.**

        - Non-Bechtel Scope:
            - PRB Upgrades – Complete. NOTE: The non-Bechtel scope will be removed from future reports due to all scope being completed.
    - Budget – Revised EPC authorization and project sanction was approved in the May IC meeting.
    - Contract Disputes/Resolution:
        - Bechtel FM Claims – Parked at the present time by both parties.
    - Issues/Risk:
        - Commissioning versus schedule.
        - Current unit issues: Economizer inlet valve actuator, turbine bearing #6 high metal temperature, FD fan controller, 2B ID fan blade pitch actuator hysteresis, BAP water level.

- **Brown 3 SCR**
    - Schedule/Execution – PE and the station have agreed to move the outage to the spring of 2012.
    - Permitting –SAM testing on EW Brown units taking place the week of May 24.
    - Engineering – EPC engineering kick off meeting scheduled for June 3 in Denver, CO (home of Zachry Engineering).
    - Budget:
        - NTR
    - Contracting:
        - EPC – Contract with Zachry signed May 19, including the assignment of the RPI purchase agreement to Zachry.
    - SCR Supplier – SCR Supplier Contract amended and assigned to EPC Contractor.
    - Issues/Risk – NTR

- **Ohio Falls Rehabilitation**
    - Schedule/Execution – Voith Hydro, the original vendor for first two units completed, has submitted tentative schedule for third unit work to begin in June, 2011 with the remaining five following every 7/8 months, with all units complete by the end of 2014. PE is investigating being able to de-water two units simultaneously to gain schedule float.
    - Permitting – NTR
    - Engineering/General:
        - Reviewing Voith updated scope for rehabilitation minus automation.
        - Reviewed plant goals for keeping automation scope in-house.
        - Working with power marketing group on interconnection issues regarding unit testing and commercial dates.
        - Reviewing Historic Preservation and Maintenance Plan developed in 2008.
        - Reviewing inventory of parts on hand for third unit.
    - Budget:
        - Voith Hydro submitted revised pricing as planned. Their submittal is under review. PE continues to assemble pricing for work outside hydro vendor scope
    - Contracting:
        - Work continues on developing a dewatering engineering scope of work for RFQ.
    - Issues/Risk

        - If Voith remains as hydro equipment supplier, they will need to release their turbine runner for the fourth unit sometime in early August in order to meet the tentative schedule.
        - The tentative schedule for completion of all units by late 2014 is highly dependent on year-round dewatering.

- **Cane Run CCP Project**
    - Permitting
        - 404/401 and Landfill Permit applications have been submitted and are currently under review. Working to respond to comments on the 404 and Landfill Permit applications. To date permitting process has gone better than expected.
        - KYDWM held a public meeting on Mary 25th with a turnout of over 100 people. The meeting included some heated remarks but no major issues that would deter our permit were identified.
        - Running Buffalo Cover study was performed with no findings.
    - Engineering
        - Development of construction drawings are on hold until the KYDWM has completed their initial review.
        - Transmission working towards relocation of the 69kV line.
    - Budget – project remains tracking to or below sanction.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk – NTR

- **Trimble Co. Barge Loading/Holcim**
    - NTR

- **TC CCP Project – BAP/GSP**
    - Schedule/Execution:
        - Construction on the project continues with work on the MSE Wall, Dike Extension, and Piping.
    - Budgeting – NTR
    - Engineering – NTR
    - Permitting – NTR
    - Contract Disputes/Resolution – NTR
    - Issues/Risk
        - Weather. The contractor has submitted a letter requesting adjustments to the project's Liquidated Damages due to the weather delays. Meetings continue to be held with the contractor concerning the scheduling issues.
        - Project Engineering is developing plans to expedite the completion of the GSP and/or South Dike to help mitigate the high water elevations in the BAP.

- **TC CCP Project – Landfill**
    - Schedule/Execution – NTR
    - Budgeting – NTR
    - Engineering – A Scope of Work for the Detailed Engineering phase has been developed and being prepared to be sent to bidders. A Pre-Bid Meeting will occur in June, 2010.
    - Permitting – Negotiations continue with USFWS on the resolution of the Indiana Bat issue.
    - Contract Disputes/Resolution – NTR

- Issues/Risk – NTR

- **Ghent CCP Projects - Landfill**
    - Schedule/Execution – NTR
    - Budget – NTR
    - Engineering – Detailed Engineering of gypsum fines and Conceptual Engineering on CCP transport for landfill continues with Black & Veatch. Conceptual Design for the CCP transport at Ghent is complete. Procurement activities for the gypsum fines project are in progress.
    - Permitting – All permit applications have been made. Project Engineering is working with the various agencies on minimal questions being asked during the review of the permit application.
    - Contract Disputes/Resolution – NTR
    - Issues/Risk:
        - Land Acquisition – the review of potential modifications to the landfill's footprint has been completed. Additional land purchases, while preferred, are not necessarily needed. Review of CCP production is currently on-going to finalize path forward on land purchases. . A meeting with Project Engineering and Real Estate is scheduled during the week of 31May10 to develop strategy going forward.

- **General CCP Projects**

  Project Engineering will be developing a high level order of magnitude cost estimate to bring the entire EON US fleet of CCP ponds into compliance with the EPA's Draft CCP Ruling of 5/5 for Subpart C, D and D Prime. The review is expected to be in draft form the first week in June.

- **E.W. Brown Starter Dike**
    - **Safety – (0) Recordable**
    - **Schedule/Execution:**
        - **Approximately 60% of the pond covered with straw mats for dust control. Mats rolled up in areas as needed to facilitate ash-grading activity and rock embankment placement.**
        - **Rock placement began on the West and South Embankments. Approximately 88% of the rock embankment has been placed to date.**
        - **In-Situ work 95% complete.**
        - **Ash grading continued on the South and East portion of the pond and in the In-Situ interface areas where applicable.**
        - **Clay placement began and is slow due to the amount of oversized rock present in the stockpiled material.**
    - **Budget – NTR**
    - **Contract Disputes/Resolution: NTR**
    - **Issues/Risk – Discussed open issues with Summit management on 6/14/10 pertaining to inclement weather delays and fuel oil adjustment.**

- **E.W. Brown Aux Pond 900'**
    - Schedule/Execution:
        - Construction contract awarded to Charah.
        - Mobilization began on 6/14/10.
    - <u>Budget</u> – project remains tracking to or below sanction.

  - Contract Disputes/Resolution – NTR
  - Issues/Risk – NTR

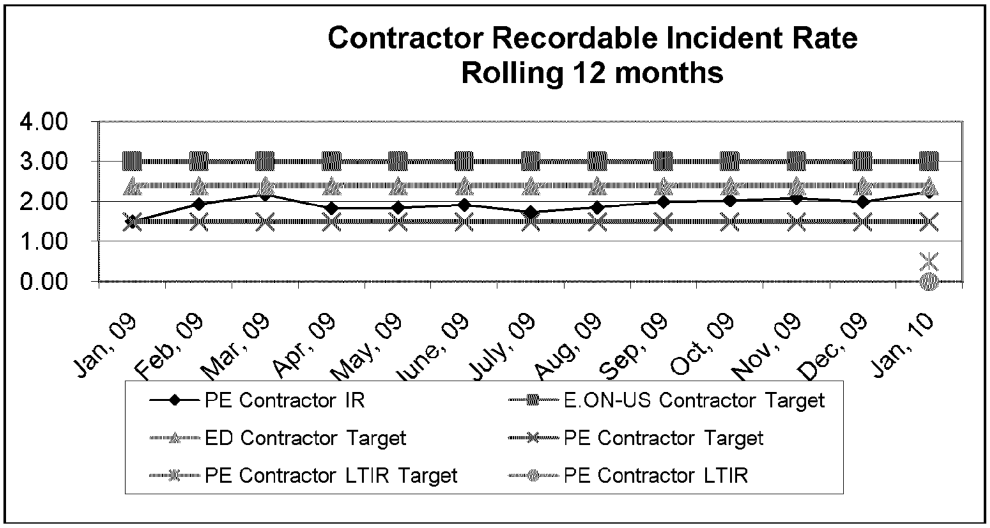
- **SO3 Mitigation (Mill Creek 3, Mill Creek 4, Brown 3)**
  - Safety - NTR
  - Schedule/Execution:
    - MC3 and MC4's schedule is now tied to the BART requirement for the end of 2011, with tie-in still required during spring 2011 outage.
    - MC 4 tests: E.ON Engineering results for PM testing have not been published. .
    - MC 3 air heater inlet and SCR inlet test ports installed by Hall the week of May 24. A&D is 40% complete on the ESP inlet and ESP outlet test ports; work to be complete May 29.. Testing by E.ON Engineering with ADA/Breen Temporary Injection is planned for the week of June 7.

- **SO3 Mitigation (Ghent)**
  - Ghent 2 testing postponed until the "permanent" temporary system is installed by the plant. The Project Engineering test plan for the week of May 24th was canceled.
  - B&V contracted for BACT Analysis, SAM Generation White Paper, and CEMS/Compliance Monitoring Test White Paper.
  - Contract signed to Emissions Monitoring Inc. (Jim Peeler) to provide a white paper on CEMS/Compliance Monitoring Test White Paper.
  - Had teleconference with Duke regarding experience with SBS Injection System at Gibson.

- **NBU1 and Other Generation Development**
  - LFG
    - First Landfill Gas Sample Result received.
    - LFG Technologies is under contract to perform study work.
  - NBU CR – HDR had site visit/kick off on May 25th at Cane Run.
  - Biomass – Black and Veatch under contract to perform MC Project Implementation Planning study work. Site visit/kick off meeting at Mill Creek was held on May 18.
  - FutureGen – NTR

- General
  - Impoundment Integrity Program
    - Met with Energy Services Training Staff to discuss the process of incorporating the new impoundment integrity policy information into the Coursemill program.
    - Scheduling a meeting with Legal for week of May 31, 2010 to review comments.
    - Working on completing the Site Specific sections of the program.
  - Environmental Scenario Planning – B&V completed site visits and gave preliminary technology recommendations to PE for review. Recommendations were discussed with plant management and their staff and comments were returned to B&V. Initial cost estimates are being prepared and will be sent to PE by close of business on June 1, 2010.
  - Alstom Master Agreement- Negotiations continue.

Metrics



Upcoming PWT Needs:

This calendar is in the process of being modified. Next report will include the revised calendar.

Staffing - NTR

From:	Lucas, Kyle J.
To:	Saunders, Eileen
CC:	Hillman, Timothy M.; Mahabaleshwarkar, Anand; Lawson, Stacy J.
Sent:	6/17/2010 10:19:48 PM
Subject:	167987.26.0000 100617 - EON Draft AQC Technology Cost Report
Attachments:	COMPLETE Draft EON AQC Cost Study 061710.pdf

Eileen,
Attached, please find the draft air quality control Technology Cost Report. Please review the document and provide one set of consolidated written comments by COB Thursday June 24, 2010. B&V will review the consolidated comments and incorporate, as appropriate, into the final report.

Additionally, Please confirm receipt of this document.

Regards,
Kyle

Kyle Lucas | Environmental Permitting Manager
Black & Veatch - Building a World of Difference™
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Overland Park, KS 66211
Phone: **(913) 458-9062** | Fax: **(913) 458-9062**
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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
June 2010
Rev. B

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Tables

Summary of Plant AQC Technology Costs

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. Table ES-1 summarizes the capital and O&M cost totals rolled up for each facility.

Table ES-1
Summary of 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	260,163	1,374	15,556	47,218
Ghent	767,355	1,465	47,746	141,134
Cane Run	860,000	4,282	48,870	153,532
Mill Creek	2,144,030	5,485	117,530	378,462
Trimble County	135,451	248	10,295	26,780
Green River	166,695	1,866	20,583	40,870
Total	4,333,694	14,720	260,580	787,996

This report contains a breakdown of the aforementioned costs and summarizes the basis and supporting documentation used to develop them. 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 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.

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), carbon monoxide (CO), mercury (Hg), hydrogen chloride (HCl), and dioxin/furans. This report documents the assumptions and findings of the assessment, 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

[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.

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.

Table 3-1
Black & Veatch Team Members

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

3.2 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.

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[2]. All cost information was produced for unit-specific combinations of new AQC technology components —

[2] 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.

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.
- 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.

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.

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.

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.

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

3.3.2 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.

3.2.2.1 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).

3.2.2.2 Electric Power Costs. Additional auxiliary power will be required to run some of the new control 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.

3.2.2.3 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.

3.2.2.4 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.

3.2.2.5 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.

3.2.2.6 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.

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.

- 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.

3.4.1 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[3]. 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[4] (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.

[3] 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.

[4] 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[5].

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). 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.

[5] It should be noted that Black & Veatch originally recommended an SCR for E.W. Brown Unit 1. However, on May 21, 2010, E.ON approved LNB and OFA technology in lieu of SCR. E.ON later requested costs for SCR, which were provided separately on June 14, 2010.

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 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 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 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.

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 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.

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.

4.1.3 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), $149,000,000 ($826/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	$92,000,000	$511	$3,278,000	$14,474,000
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	**$148,715,000**	**$826**	**$7,532,000**	**$25,630,000**

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**

4.1.4 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.
- **Ammonia Storage**--Ammonia storage for Unit 3 can be utilized to supply 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.
- **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.

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.

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.

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 SCR being installed during the first outage. This allows for the major construction of the PJFFs with the plant in operation and requiring another shorter outage for the tie-in.

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 $260,000,000 ($1,400/kW). The O&M and levelized annual costs of new AQC equipment at E.W. Brown is nominally $15,600,000 and $47,000,000, 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), $360,000,000

($696/kW), $145,000,000 ($278/kW), and $124,000,000 ($236/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-4, 4-5, 4-6, and 4-7. Detailed cost summaries are included in Appendix H.

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.

Table 4-4
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 4-5
Capital and O&M Cost Summary – Ghent Unit 2

AQC Equipment	Capital Cost, $	$/kW	O&M Cost, $	Levelized Annual Cost, $
SCR	$227,000,000	$439	$7,078,000	$34,704,000
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	**$359,592,000**	**$696**	**$17,835,000**	**$61,597,000**

Table 4-6
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 4-7
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**

- **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.

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 $767,400,000 ($1,500/kW). The O&M and levelized annual costs of new AQC equipment at Ghent is nominally $47,800,000 and $141,000,000, 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 $253,000,000 ($1,508/kW), $266,000,000 ($1,468/kW), and $341,000,000 ($1,306/kW), respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-8, 4-9, and 4-10. Detailed cost summaries are included in Appendix H.

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.

Table 4-8
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	$152,000,000	$905	$8,428,000	$26,926,000
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	**$253,395,000**	**$1,508**	**$14,691,000**	**$45,529,000**

Table 4-9
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	$159,000,000	$878	$8,789,000	$28,139,000
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	**$265,742,000**	**$1,468**	**$15,530,000**	**$47,871,000**

Table 4-10
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	$202,000,000	$774	$10,431,000	$35,014,000
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	$340,863,000	$1,306	$18,649,000	$60,132,000

- **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.

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 $860,000,000 ($4,300/kW). The O&M and levelized annual costs of new AQC equipment at Cane Run is nominally $48,900,000 and $153,500,000, 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.

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.

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.

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 15×10^{-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.

4.4.3 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 4-11, 4-12, 4-13, and 4-14. Detailed cost summaries are included in Appendix H.

Table 4-11
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 4-12
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 4-13
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 4-14
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**

4.4.4 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.

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.

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.

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.

4.5 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 15×10^{-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 4-15. Detailed cost summaries are included in Appendix H.

Table 4-15
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.

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 decommissioned in January 2002 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 1948. 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 $69,000,000 ($966/kW) and $98,000,000 ($900/kW) respectively. Capital, O&M, and levelized annual costs are shown in Tables 4-16 and 4-17. Detailed cost summaries are included in Appendix H.

Table 4-16
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	$38,000,000	$535	$6,874,000	$11,499,000
PAC Injection	$1,112,000	$16	$323,000	$458,000
Neural Network	$500,000	$7	$50,000	$111,000
Total	**$68,612,000**	**$966**	**$8,287,000**	**$16,637,000**

Table 4-17
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	$54,000,000	$495	$10,289,000	$16,861,000
PAC Injection	$1,583,000	$15	$515,000	$708,000
Neural Network	$500,000	$5	$50,000	$111,000
Total	**$98,083,000**	**$900**	**$12,296,000**	**$24,233,000**

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.

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 $167,000,000 ($1,900/kW). The O&M and levelized annual costs of new AQC equipment at Green River are nominally $20,600,000 and $40,900,000, respectively.

Appendix A
E.ON Environmental Matrix

Estimated Requirements Under Future New Environmental Regulations

Task No.	Program Name	Regulated Pollutants: Pollutant	Regulated Pollutants: Limit	Regulated Pollutants: Units	Unit/Plant Averaging	Forcasted Date for Compliance
4.1	GHG Inventory	No additional limits			N/A	Spring - 2010
4.2	New & Existing Engine NSPS and RICE MACT	PM NO_x VOC CO	Varies by Model Year and Horsepower. Certified to meet Tier III, Interim Tier IV or Tier IV		Unit	Spring 2013 for existing MACT & at installation for new NSPS
4.3	Mill Creek BART	MC3 - SAM MC4 - SAM	64.3 76.5	lbs/hour lbs/hour	Unit	During - 2011
4.4	Jefferson Co. STAR Reg.	metals in fuels (As) 20 - 50 ppm or ~$1x10^{-5}$ lbs/mmBtu emission rate			Plant	Spring - 2012
4.5 & 4.6	Brown Consent Decree	PM SO_2 NO_x SAM	0.03 97% 0.07 /0.08 110 -220	lbs/mmBtu Removal lbs/mmBtu lbs/mmBtu	Unit 3	SO_2 & PM - December, 2010 NO_x & SAM - December, 2012
4.7	Ghent NOVs	SAM	3.5 - 10	ppm	Unit	During - 2012
4.8	GHG NSR	GHG	Energy Efficiency Projects		Unit/Plant	January, 2011
4.9	Revised CAIR	SO_2 NO_x	0.25 0.11	lbs/mmBtu lbs/mmBtu	Plant	Beginning in 2014
4.10	New EGU MACT	Mercury	90% or 0.012	Removal lbs/GWH	Plant	January, 2015; with 1-yr extension - January, 2016
		Acids (HCl) Metals (PM) Metals (As) Organics (CO) Dioxin/Furan	0.002 0.03 0.5×10^{-5} 0.02 15×10^{-18}	lbs/mmBtu lbs/mmBtu lbs/mmBtu lbs/mmBtu lbs/mmBtu	Unit	
4.11	Jefferson Co. Ozone Non-attainment	NO_x	5 - 10 % reduction	NOx emissions	County-wide	Spring - 2016
4.11	New 1-hour NAAQS for NO_x	NO_x	To be determined based on modeling	lbs/hours	Plant	During - 2015
4.12	New 1-hour NAAQS for SO_2	SO_2	To be determined based on modeling	lbs/hours	Plant	Spring - 2016
4.13	GHG Reduction & Renewables	GHG	To be determined based on modeling	tons/year	Fleet	Beginning in 2014
Plan Risk	$PM_{2.5}$ Emission Reductions	PM2.5 (Condensables)	To be determined based on modeling	lbs/mmBtu	Unit/Plant	After 2013
4.14	CWA 316(a)	Thermal impacts	Biological Studies	N/A	Plant	Starting in 2010
4.15	CWA 316(b)	Withdraw impacts	Biological Studies	N/A	Plant	Starting in 2012
4.16	New Effluent Standard	Metals, Chlorides, etc.	EPA anaylsis is just beginning	EPA anaylsis is just beginning	Plant	During - 2015
4.17	CCR Classification	Toxic Metals	Handle dry in landfill; possible closing existing ash ponds in 5 years		Plant	Beginning in 2012;

- New requirements have been finalized

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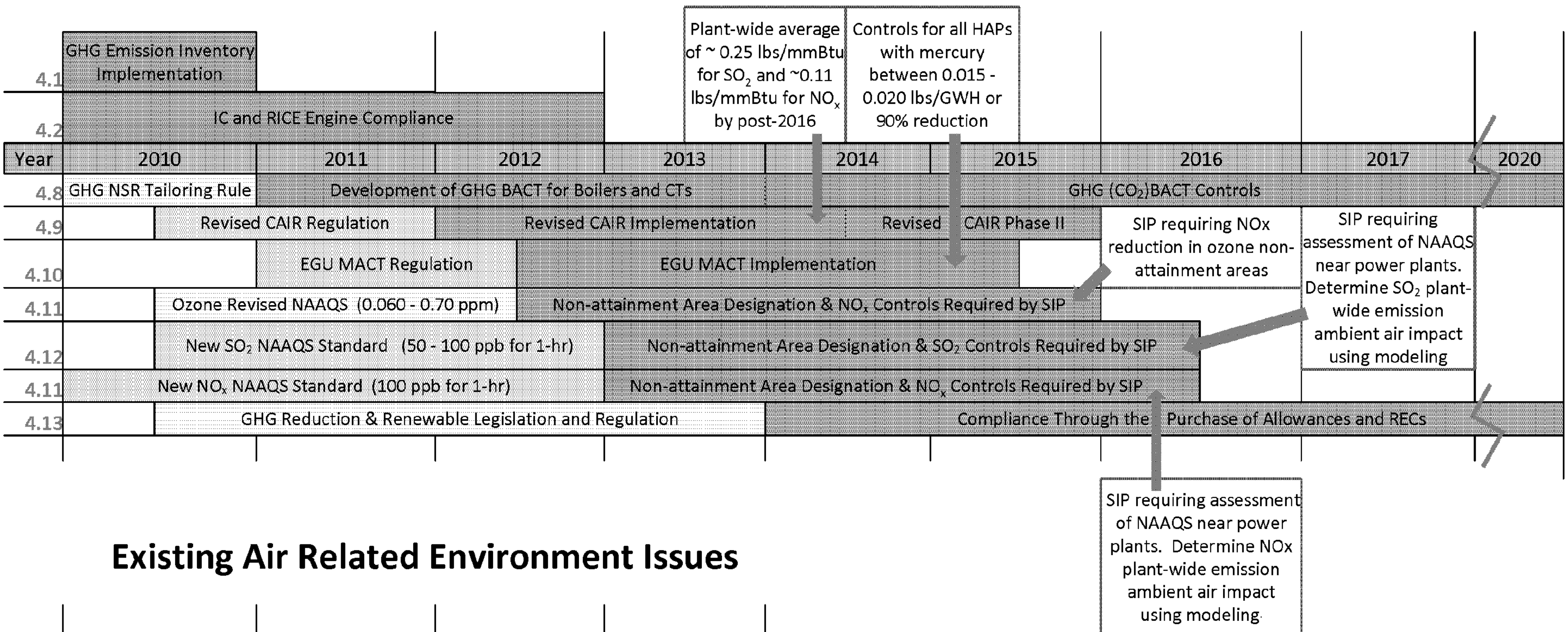
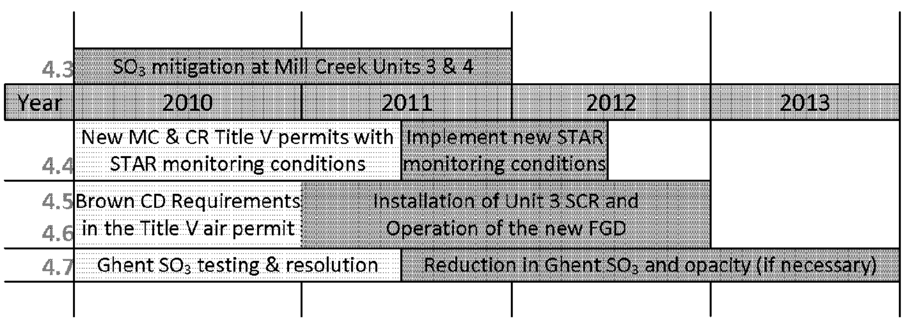
Major Assumptions (Air)

Generation
2011-2013 MTP

Air Related Environmental Regulatory Program Implementation



Existing Air Related Environment Issues

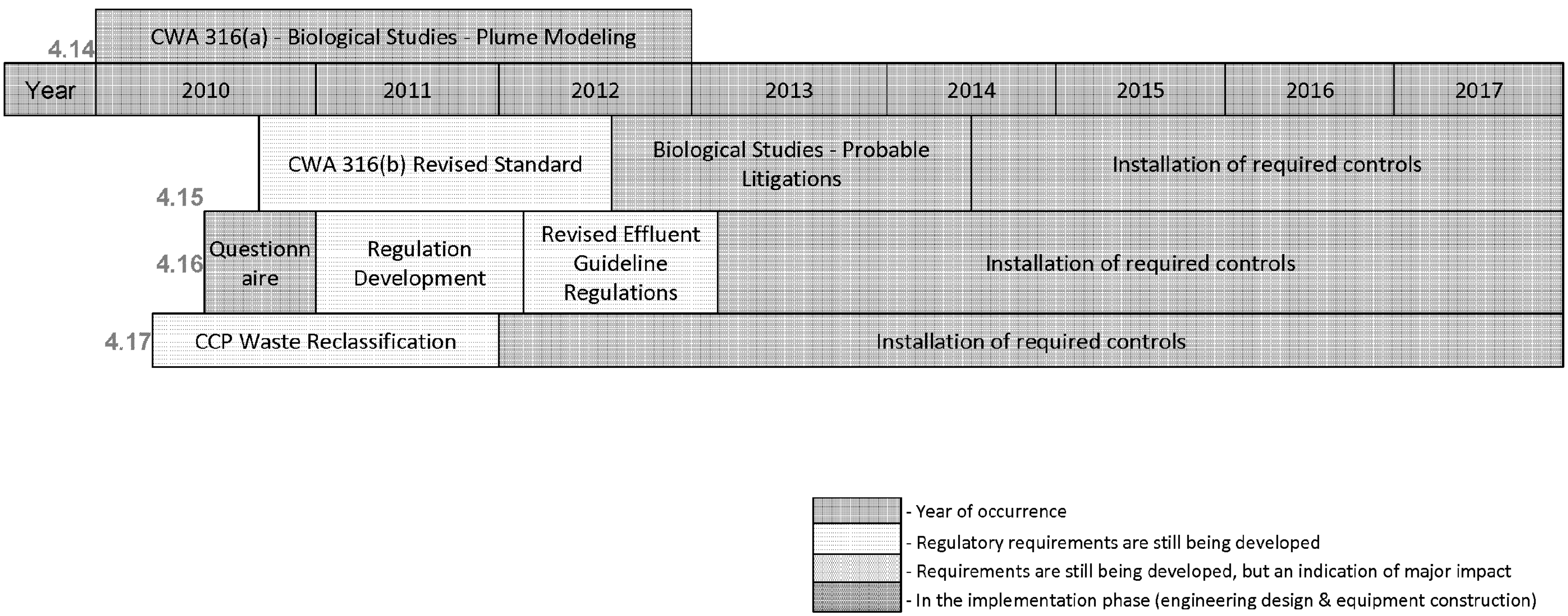


Note:
If the environmental action is above the "Year" row, then regulatory requirements are finalized.

- Year of occurrence
- Regulatory requirements are still being developed
- Requirements are still being developed, but an indication of major impact
- In the implementation phase (engineering design & equipment construction)

e·on | U.S. **Major Assumptions (Land & Water)** Generation 2011-2013 MTP

Land & Water Related Environmental Regulatory Program Implementation



Appendix B
E.ON Unit Specific Data

E.W. Brown

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit 3	Unit X		Notes
Maximum (Design) Fuel Burn Rate		4 * 14.91 Tons/hr	4 * 22.6 Tons/hr	5 * 46.75 Tons		MBtu/hr	# Pulv * Pulv rating
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall-Fired	Tangential Fired	Tangential Fired			
Boiler Manufacturer		B&W	CE	CE			
Net MW Rating (specify plant or turbine MW)		102	169	433		MW	Dispatch Generator Ratings
Gross MW Rating		110	180	457		MW	Dispatch Generator Ratings
Net Unit Heat Rate		9802	9855	9516		Btu/kWh	S&L Design Heat Balance
Net Turbine Heat Rate		8104	8149	8019		Btu/kWh	S&L Design Heat Balance
Boiler SO2 to SO3 Conversion Rate (if known)		na	na	na		%	
Fly Ash/Bottom Ash Split		80/20	80/20	80/20		%	Typical values used on other reports
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		N	N	N			
In operation? (Y/N)							
Flue Gas Recirculation (if installed)						%	
Type of Air Heater		Ljungstrom	Ljungstrom	Ljungstrom			
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical	Vertical	Vertical			
Design Pressure/Vacuum Rating for Steam Generator	+/-					in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-					in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)							
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)							
Neural Network Installed? (Y/N)							
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)							
Extra Capacity available in DCS?							
Historian Manufacturer							
Additional Controls from DCS or local PLC w/tie-in							
Transformer Rating for Intermediate Voltage Switchgear							
(SUS's) and Ratings of Equipment in These Cubicles							
Auxiliary Electric Limited (Y/N)							
Operating Conditions							
Economizer Outlet Temperature		650	730	730		°F	Typical data from PI historian
Economizer Outlet Pressure		-8	-3.7	-5		in wg.	Typical data from PI historian
Excess Air or Oxygen at Economizer Outlet (full load/min load)		5/8 O2	3/4 O2	2.8/3.3		%	Typical data from PI historian
Economizer Outlet Gas Flow		na	na	na		acfm	
						lb/hr	
Air Heater Outlet Temperature		350	330	340		°F	Typical data from PI historian
Air Heater Outlet Pressure		-14	-8	-18		in wg.	Typical data from PI historian; Unit 1 has back pass dampers
Particulate Control Equipment Outlet Temperature		340	320	330		°F	Typical data from PI historian
Particulate Control Equipment Outlet Pressure		-18	-12	-19		in wg.	Typical data from PI historian
FGD Outlet Temperature (if applicable)		na	na	na		°F	Typical data from PI historian
FGD Outlet Pressure (if applicable)		na	na	na		in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

NOx Emissions	Unit X	Unit X	Unit X	Unit X		Notes
Emissions Limit	0.5	0.45	0.07		lb/MBtu	Units 1 & 2 on averaging plan for Nox so this is target rather
Type of NOx Control (if any) - LNB, OFA, etc.	lnb	lnb, ofa	lnb, ofa			
Current NOx Reduction with existing controls	na	na	na		%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)						
Reagent Cost					$/ton	
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit	0.254	0.162	0.03		lb/MBtu	Title V permit for 1 & 2, Consent Decree Unit 3
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold Side ESP	Cold Side ESP	Cold Side ESP			
Oxygen Content of Flue Gas @ Air Heater Outlet	na	na	na		%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	na	na	na		%	
Current Emissions	0.241	0.068	0.07		lb/MBtu	Latest compliance PM testing
Fly Ash Sold (Y/N) - See Economic Section	n	n	n			
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	5.15	5.15	.1 or 97%		lb/MBtu	Title V permit for 1 & 2, Consent Decree Unit 3
Type of Emission Control - wet or semi-dry FGD (if any)						
Current Emissions	2.5	2.5	2.5		lb/hr	Typical Value from CEMS (typically varies from 1.5 to 3.5 wit
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

ID Fan Information (at Full Load):	Unit X	Unit X	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-14	-8	-18		in wg.	
ID Fan Discharge Pressure	0.5	0.5	0.5		in wg.	
ID Fan Inlet Temperature	340	320	330		F	
Oxygen Content of Flue Gas @ ID Fan Inlet	na	na	na		%	
ID Fan Motor Voltage (Rated)	13200	2300	13200		volts	
ID Fan Motor Amps (Operating)	na	400	na		A	
ID Fan Motor Amps (Rated)	see fan curve	see fan curve	see fan curve		A	
ID Fan Motor Power (Rated)	see fan curve	see fan curve	see fan curve		hp	
ID Fan Motor Service Factor (1.0 or 1.15)	see fan curve	see fan curve	see fan curve			

Chimney Information:						
Flue Liner Material						
Flue Diameter					ft	
Chimney Height					ft	
Number of Flues						

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

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Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)	No		
Natural gas line (into the station) capacity (if applicable)	No		
Current Lost on Ignition (LOI)			
Start-up Fuel	# 2 Fuel Oil		
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate		B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		tangential	tangential	ont/back wall fired	ont/back wall fired		
Boiler Manufacturer		CE	CE	FW	FW		
Net MW Rating (specify plant or turbine MW)						MW	
Gross MW Rating		541	517	523	526	MW	
Net Unit Heat Rate		10557	8904	11180	11070	Btu/kWh	
Net Turbine Heat Rate		8733	7565	8404	8439	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		1.50%		1.95%	2.20%	%	
Fly Ash/Bottom Ash Split						%	
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		No	No	No	No		
In operation? (Y/N)		No	No	No	No		
Flue Gas Recirculation (if installed)		No	No	No	No	%	
Type of Air Heater		Lungstrom	Lungstrom	Lungstrom	Lungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)		vertical	vertical	vertical	vertical		
Design Pressure/Vacuum Rating for Steam Generator	+/-	35	26	35	35	in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	35"V	30" V	30" V	30" V	in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Emerson	Emerson	Emerson	Emerson		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Ovation	Ovation	Ovation	Ovation		
Neural Network Installed? (Y/N)		No	No	No	No		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		n/a	n/a	n/a	n/a		
Extra Capacity available in DCS?		yes	yes	yes	yes		
Historian Manufacturer		Emerson	Emerson	Emerson	Emerson		
Additional Controls from DCS or local PLC w/tie-in		yes	yes	yes	yes		
Transformer Rating for Intermediate Voltage Switchgear							
(SUS's) and Ratings of Equipment in These Cubicles							
Auxiliary Electric Limited (Y/N)							
Operating Conditions							
Economizer Outlet Temperature		729	610	731	791	°F	
Economizer Outlet Pressure		-323	-5.07	-5.12	-4.51	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		3	3.5	3.5	3.3	%	
Economizer Outlet Gas Flow		3775	4147	4506	4076	acfm	
						lb/hr	
Air Heater Outlet Temperature		345	309	315	309	°F	
Air Heater Outlet Pressure		-22.4	-18.6	-36.1	-29.4	in wg.	
Particulate Control Equipment Outlet Temperature		361	605	708	770	°F	
Particulate Control Equipment Outlet Pressure		-25.7	-10.8	-0.92	-0.82	in wg.	
FGD Outlet Temperature (if applicable)		125	83	130	128	°F	
FGD Outlet Pressure (if applicable)		1.65	1.45	2	1.56	in wg.	

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Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______

Unit ______ Project: ______

	Unit 1	Unit 2	Unit 3	Unit 4		Notes
NOx Emissions						
Emissions Limit	0.45	0.4	0.46	0.46	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA etc.	LNB	LNB/OFA	LNB/OFA	LNB/OFA		
Current NOx Reduction with existing controls	SCR	SCR	SCR	SCR	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	anhydrous	anhydrous	anhydrous	anhydrous		
Reagent Cost					$/ton	
Current Emissions	330	1300	330	330	lb/hr	
	930	850	4800	850	ton/yr	
	0.04	0.35	0.04	0.04	lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side ESP	Hot side ESP	Hot side ESP	Hot side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.02 to 0.045 lbs/r	0.025 lbs/mmbtu	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	No	No	No	No		
ESP						
Specific Collection Area (SCA)	153	223	328	328	ft^2/1000 acfm	
Discharge Electrode Type	rigid	wire	wire	wire		
Supplier	PECO	GE	GE	GE		
Efficiency	99.2	99			%	
No. of Electrical Sections	4 in series	4 in series	7 in series	7 in series		
% of Fly Ash Sold	0	0	0	0	%	
Fabric Filter						
Air to Cloth Ratio (net)	N/A				ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	5.67 lbs/mmbtu (24 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lbs/mmbtu (3 Hr)	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	wet FGD	wet FGD	wet FGD	wet FGD		
Current Emissions	600	600	1120	600	lb/hr	
	1400	2100	1400	1400	ton/yr	
	0.15	0.2	0.15	0.15	lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	yes	yes	yes	yes		

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit 3	Unit 4		Notes
ID Fan Inlet Pressure	-22.5	-18.7	-36	-28.9	in wg.	
ID Fan Discharge Pressure	6.08	11.4	5.94	14.6	in wg.	
ID Fan Inlet Temperature	358	309	322	309	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3	3.5	3.5	3.17	%	
ID Fan Motor Voltage (Rated)	4160	6600	13200	4000	volts	
ID Fan Motor Amps (Operating)	990	670	410	1385	A	
ID Fan Motor Amps (Rated)	1113	953	535	1020	A	
ID Fan Motor Power (Rated)	9000	12500	13600	8000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1.15	1.15		
Chimney Information:						
Flue Liner Material	fiber glass	brick	brick	fiber glass		Ghent 2 and 3 share a common stack-each unit is mixed
Flue Diameter	29'6"	34'5"	34'5"	29'6"	ft	into a common exit flue
Chimney Height	660	580	580	660	ft	
Number of Flues	1	2	2	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Cane Run

Black & Veatch AQCS Information Needs

Power Plant: Cane Run   Owner: Louisville Gas & Electric
Unit: Project:

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum	Notes
Carbon	61.4	59.8	63.14	
Hydrogen	4.3	4.09	4.3	
Sulfur	3.2	2.23	3.2	
Nitrogen	1.3	1.26	1.5	
Oxygen	6.5	6.62	7.44	
Chlorine	0.1			
Ash	10.8	9.13	11.67	
Moisture	12.4	11.92	15.18	
Total	100	95.05	106.43	
Higher Heating Value, Btu/lb (as received)	10921.64	10391	11673	
Ash Mineral Analysis (% by mass):				
Silica(SiO_2)	46.02	42.41	49.07	
Alumina (Al_2O_3)	23.27	20.81	25.64	
Titania (TiO_2)	1.09	0.99	1.21	
Phosphorous Pentoxide (P_2O_5)	0.255	0.16	0.34	
Calcium Oxide (CaO)	1.211	0.88	1.89	
Magnesium Oxide (MgO)	0.98	0.87	1.14	
Sodium Oxide (Na_2O)	0.3	0.22	0.44	
Iron Oxide (Fe_2O_3)	22.97	17.48	27.84	
Sulfur Trioxide (SO_3)	0.95	0.52	1.7	
Potassium Oxide (K_2O)	2.6	2.24	2.93	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium	46.75	%	
Arsenic	15.47	%	
Mercury	0.09	% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)	Y		
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel	Gas		
Ash Fusion Temperature			
Initial Deformation	2025.56	°F	
Softening	2211.44	°F	
Hemispherical	2332.11	°F	
Hardgrove Grindability Index	62		

Black & Veatch AQCS Information Needs

Power Plant: Cane Run   Owner: Louisville Gas & Electric
Unit: Project:

Plant Size and Operation Data: (provide for each unit)		CR4	CR5	CR6		Notes
Maximum (Design) Fuel Burn Rate		1601.9	1753.4	2395.7	MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall	Wall	Wall		
Boiler Manufacturer		CE	Riley	CE		
Net MW Rating (specify plant or turbine MW)		155	168	240	MW	
Gross MW Rating		168	181	261	MW	
Net Unit Heat Rate		10340	10458	10789	Btu/kWh	
Net Turbine Heat Rate		8414	8429	8625	Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		-	-	-	%	
Fly Ash/Bottom Ash Split		80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)		Y	N	N		
In operation? (Y/N)		Y	N	N		
Flue Gas Recirculation (if installed)					%	
Type of Air Heater		Ljungstrom	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)		Horizontal	Horizontal	Horizontal		
Design Pressure/Vacuum Rating for Steam Generator	+/-	1800/3.5	1800/1.5	2400/3.5	in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	no data	20" H2O/-8.75	no data	in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Honeywell	Honeywell	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		TDC3000/Experion	TDC3000/Experion	TDC3000/Experion		
Neural Network Installed? (Y/N)		Y	Y	Y		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		Neuco	Neuco	Neuco		
Extra Capacity available in DCS?		Y	Y	Y		
Historian Manufacturer		Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear						
(SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)		N	N	N		
Operating Conditions						
Economizer Outlet Temperature		580.45	630.24	617.2	°F	
Economizer Outlet Pressure					in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)					%	
Economizer Outlet Gas Flow					acfm	
					lb/hr	
Air Heater Outlet Temperature		369.22	299.15	317.59	°F	
Air Heater Outlet Pressure					in wg.	
Particulate Control Equipment Outlet Temperature		132.6	128.4	132.8	°F	Summer design Temperature
Particulate Control Equipment Outlet Pressure					in wg.	ID Fan Suction Pressure
FGD Outlet Temperature (if applicable)		127			°F	
FGD Outlet Pressure (if applicable)					in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Cane Run Owner: Louisville Gas & Electric
Unit: Project:

	CR4	CR5	CR6		Notes
NOx Emissions					
Emissions Limit	0.3372	0.3934	0.3276	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB	OFA		
Current NOx Reduction with existing controls				%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	N/A	N/A	N/A		
Reagent Cost				$/ton	
Current Emissions	0.337	0.384	0.286	lb/hr	
				ton/yr	
				lb/MBtu	
Particulate Emissions					
Emissions Limit	0.11	0.11	0.11	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF					
Oxygen Content of Flue Gas @ Air Heater Outlet	5.78	5.82	4.53	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet				%	
Current Emissions	0.041	0.034	0.024	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	N	N	N		
ESP					
Specific Collection Area (SCA)				ft^2/1000 acfm	
Discharge Electrode Type	0.109" Copper Bessemer	0.109" Copper Bessemer			
Supplier	Research-Cottrell	Research-Cottrell	Buell Engineering		Original supplier
Efficiency	99.1	96.1	99.2	%	
No. of Electrical Sections	48		49		
% of Fly Ash Sold	N/A	N/A	N/A	%	
Fabric Filter					
Air to Cloth Ratio (net)				ft/min	
Number of Compartments					
Number of Bags per Compartments					
Efficiency				%	
% of Fly Ash Sold	N/A	N/A	N/A	%	
SO_2 Emissions					
Emissions Limit	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet	Wet	Wet		
Current Emissions	0.411	0.419	0.676	lb/hr	
				ton/yr	
				lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section	N	N	N		

Black & Veatch AQCS Information Needs

Power Plant: Cane Run   Owner: Louisville Gas & Electric
Unit: Project:

ID Fan Information (at Full Load):	Unit X	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-9.11	-6.82	-9.84	in wg.	
ID Fan Discharge Pressure	8	7	8	in wg.	
ID Fan Inlet Temperature				F	
Oxygen Content of Flue Gas @ ID Fan Inlet				%	
ID Fan Motor Voltage (Rated)	4160	4160	4000	volts	
ID Fan Motor Amps (Operating)	104.23	194.37	146.11	A	
ID Fan Motor Amps (Rated)	157	211	265	A	
ID Fan Motor Power (Rated)	1250	3000	2000	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1	1.15		
Chimney Information:					
Flue Liner Material	Pre-Krete	Hadite/Pre-krete	Hastalloy C276		
Flue Diameter	14'2"	15'6"	24'41/2"	ft	
Chimney Height	239	239	500	ft	
Number of Flues	1	1	1		

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
Specific burner and overfire air ports arrangement (single wall, opposed fired, total number of burners, number of burner levels, number of overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Cane Run
Owner: Louisville Gas & Electric
Unit:
Project:

Economic Evaluation Factors:	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life	20	20	20	years	
Annual Capacity Factor (over life of study/plant)	65	65	65	%	
Contingency Margin (can be determined by B&V)				%	
Owner Indirects Cost Margin				%	
Interest During Construction				%	
Levelized Fixed Charge Rate or Capital Recovery Factor				%	
Present Worth Discount Rate	6.4	6.4	6.4	%	
Capital Escalation Rate	4%	4%	4%	%	
O&M Escalation Rate	3%	3%	3%	%	
Energy Cost (energy to run in-house equipment)				$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)				$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)				$/MBtu	
				$/ton	
Base Fuel Price				$/MBtu	
				$/ton	
Fuel Price Escalation Rate				%	
Water Cost				$/1,000 gal	
Limestone Cost	N/A	N/A	N/A	$/ton	
Lime Cost	$112.54	$112.54	$112.54	$/ton	Total cost $773,013.3
Ammonia Cost	N/A	N/A	N/A	$/ton	
Fully Loaded Labor Rate (per person)				$/year	
Fly Ash Sales	N/A	N/A	N/A	$/ton	
Bottom Ash Sales	N/A	N/A	N/A	$/ton	
FGD Byproduct Sales	N/A	N/A	N/A	$/ton	
Waste Disposal Cost					
Fly Ash	$2.73			$/ton	Values represent total O&M cost for 2009. Plant Total
Bottom Ash	$8.40			$/ton	Values represent total O&M cost for 2009. Plant total
Scrubber Waste	$3,469.00	$4,989.00	$8,734.00	000$	Values represent total O&M cost for 2009.

Mill Creek

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________
Unit ____________ Project: ____________

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon	64			%	
Hydrogen	4.5			%	
Sulfur	3.5			%	
Nitrogen	1.3			%	
Oxygen	4.62			%	
Chlorine	0.08			%	
Ash	12			%	
Moisture	10			%	
Total	100.00				
Higher Heating Value, Btu/lb (as received)	11471.82			Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)			Notes
Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: ______________ Owner: ______________
Unit ______________ Project: ______________

Plant Size and Operation Data: (provide for each unit)	Unit 1	Unit 2	Unit 3	Unit 4		Notes
Maximum (Design) Fuel Burn Rate	B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)	Tangential fired	Tangential fired	opposed wall	opposed wall		
Boiler Manufacturer	CE	CE	B&W	B&W		
Net MW Rating (specify plant or turbine MW) Winter ratings	303MW	303MW	397MW	492MW	MW	
Gross MW Rating Winter ratings	330MW	330MW	423MW	525MW	MW	
Net Unit Heat Rate	10639	10929	10602	10410	Btu/kWh	
Net Turbine Heat Rate					Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)					%	
Fly Ash/Bottom Ash Split	80/20	80/20	80/20	80/20	%	
Flue Gas Recirculation (FGR)						
Installed? (Y/N)	N	N	N	N		
In operation? (Y/N)						
Flue Gas Recirculation (if installed)					%	
Type of Air Heater	Air Preheater Co.	Air Preheater Co.	Ljungstrom	Ljungstrom		
Air Heater Configuration (horizontal or vertical flow or shaft)	Vertical Flow	Vertical Flow	Vertical Flow	Vertical Flow		
Design Pressure/Vacuum Rating for Steam Generator +/-					in wg.	
Design Pressure/Vacuum Rating for Particulate Control +/-					in wg.	
Electrical / Control						
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Honeywell	Honeywell	Honeywel	Honeywell		
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	TC3000			Experion		
Neural Network Installed? (Y/N)	Y	Y	N	N		
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	Neuco	Neuco				
Extra Capacity available in DCS?	minimal	minimal	minimal	minimal		
Historian Manufacturer	Honeywell	Honeywell	Honeywell	Honeywell		
Additional Controls from DCS or local PLC w/tie-in						
Transformer Rating for Intermediate Voltage Switchgear						
Capacity of Spare Electrical Cubicles in Existing MCC's and LCUS's (SUS's) and Ratings of Equipment in These Cubicles						
Auxiliary Electric Limited (Y/N)	N	N	N	N		
Operating Conditions						
Economizer Outlet Temperature	760	760	690	640	°F	
Economizer Outlet Pressure	-5	-5	-5	-5	in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	5	5	5	5	%	
Economizer Outlet Gas Flow	1524804	1524804	1958726	2239453	acfm	
	2976508	2976508	4056287	4848440	lb/hr	
Air Heater Outlet Temperature	375	375	325	315	°F	
Air Heater Outlet Pressure	-10	-10	-18	-18	in wg.	
Particulate Control Equipment Outlet Temperature	375	375	325	315	°F	
Particulate Control Equipment Outlet Pressure	-14	-14	-23	-21	in wg.	
FGD Outlet Temperature (if applicable)	133	133	130	130	°F	
FGD Outlet Pressure (if applicable)	1	1	1	1	in wg.	

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

	Unit 1	Unit 2	Unit 3	Unit 4		Notes
NOx Emissions						
Emissions Limit			0.7	0.7	lb/MBtu	
Type of NOx Control (if any) - LNB, OFA etc.	LNB/OFA	LNB/OFA	LNB/SCR	LNB/SCR		
Current NOx Reduction with existing controls			90%	90%	%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)			Anhydrous	Anhydrous		
Reagent Cost			500	500	$/ton	
Current Emissions	0.32	0.32	0.05	0.05	lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit	0.115	0.115	0.105	0.105	lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold Side ESP	Cold Side ESP	Cold Side ESP	Cold Side ESP		
Oxygen Content of Flue Gas @ Air Heater Outlet	4	4	4	4	%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	4	4	4	4	%	
Current Emissions	0.36	0.48	0.05	0.04	lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section	Y	Y	Y	Y		Very minimal at this point in time
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit	1.2	1.2	1.2	1.2	lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	Wet FGD	Wet FGD	Wet FDG	Wet FGD		
Current Emissions	0.47	0.47	0.58	0.47	lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: ______ Owner: ______
Unit ______ Project: ______

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit 3	Unit 4		Notes
ID Fan Inlet Pressure	-16	-16.5	-22	-23	in wg.	
ID Fan Discharge Pressure	-2	-1			in wg.	
ID Fan Inlet Temperature	340	340	330	330	F	
Oxygen Content of Flue Gas @ ID Fan Inlet	4	4	4	4	%	
ID Fan Motor Voltage (Rated)	4160	4160	4160	4160	volts	
ID Fan Motor Amps (Operating)	275	275	920	1115	A	
ID Fan Motor Amps (Rated)	320	320	1176		A	
ID Fan Motor Power (Rated)	2500	2500	9000	9500	hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15	1	1.15		
Chimney Information:						
Flue Liner Material	C276	C276	C276	C276		
Flue Diameter	15' 6"	15' 6"	19' 6"	19' 6"	ft	top of liner
Chimney Height	623	623	630	630	ft	
Number of Flues	1	1	1	1		1&2 share a common stack

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: ____________ Owner: ____________

Unit ____________ Project: ____________

Economic Evaluation Factors:	Unit X	Unit X	Unit X	Unit X		Notes
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Trimble County

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit TC1 and TC2 Project:

References:

1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Trimble.xls 6/16/2010

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner:
Unit TC1 and TC2 Project:

Plant Size and Operation Data: (provide for each unit)		Unit 1	Unit 2	Unit X	Unit X		Notes
Maximum (Design) Fuel Burn Rate		B&V can determine some values from previous VISTA				MBtu/hr	
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Tangential	Wallfired				
Boiler Manufacturer		Combustion Engineering	Doosan				
Net MW Rating (specify plant or turbine MW)		turbine 512	760			MW	
Gross MW Rating		547	509			MW	
Net Unit Heat Rate		10372	8662 guarentteed			Btu/kWh	
Net Turbine Heat Rate		gross 8362.53	7066 turbine guarenteed			Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		NA	0.068 lb/MMBtu less than this at Econ outlet			%	
Fly Ash/Bottom Ash Split		80/20	80/20			%	
Flue Gas Recirculation (FGR)							
Installed? (Y/N)		N	N				
In operation? (Y/N)		N	NA				
Flue Gas Recirculation (if installed)		NA	NA			%	
Type of Air Heater		Regenerative	Regenerative				
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical 2 layer	Vertical 2 layer				
Design Pressure/Vacuum Rating for Steam Generator	+/-	26.5	24/35 +/- 24 on continuous +/-35 on transient basis			in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	42 at 100%	25/-6 +/-35 for DESP, PJFF +25/-6			in wg.	

Electrical / Control	Unit 1	Unit 2	Unit X	Unit X	Notes
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)	Emerson	Emerson			
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)	Ovation	Ovation			
Neural Network Installed? (Y/N)	N	N			
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)	N/A	N/A			
Extra Capacity available in DCS?	Y	Y			
Historian Manufacturer	Emerson	Emerson			
Additional Controls from DCS or local PLC w/tie-in	Y	Y			
Transformer Rating for Intermediate Voltage Switchgear	100.8 MVA? Need better definintion				
(SUS's) and Ratings of Equipment in These Cubicles	NA				
Auxiliary Electric Limited (Y/N)	N				

Operating Conditions	Unit 1	Unit 2	Unit X	Unit X		Notes
Economizer Outlet Temperature	700	586			°F	
Economizer Outlet Pressure	-6				in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)	3	3.2/8.15 25%			%	
Economizer Outlet Gas Flow	N/A	3200333			acfm	
	N/A				lb/hr	
Air Heater Outlet Temperature	600	324			°F	
Air Heater Outlet Pressure	diff 6.5				in wg.	
Particulate Control Equipment Outlet Temperature	N/A	313			°F	
Particulate Control Equipment Outlet Pressure	-0.3				in wg.	
FGD Outlet Temperature (if applicable)	130	12.9 diff			°F	
FGD Outlet Pressure (if applicable)					in wg.	stack draft

Black & Veatch AQCS Information Needs

Power Plant: Trimble   Owner:
Unit: TC1 and TC2   Project:

	Unit 1	Unit 2	Unit X	Unit X		Notes
NOx Emissions						
Emissions Limit					lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.						
Current NOx Reduction with existing controls					%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)						
Reagent Cost					$/ton	
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Particulate Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF						
Oxygen Content of Flue Gas @ Air Heater Outlet					%	
Oxygen Content of Flue Gas @ ESP/FF Outlet					%	
Current Emissions					lb/MBtu	
Fly Ash Sold (Y/N) - See Economic Section						
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type						
Supplier						
Efficiency					%	
No. of Electrical Sections						
% of Fly Ash Sold					%	
Fabric Filter						
Air to Cloth Ratio (net)					ft/min	
Number of Compartments						
Number of Bags per Compartments						
Efficiency					%	
% of Fly Ash Sold					%	
SO_2 Emissions						
Emissions Limit					lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)						
Current Emissions					lb/hr	
					ton/yr	
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Trimble   Owner:
Unit: TC1 and TC2   Project:

ID Fan Information (at Full Load):	Unit 1	Unit 2	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-0.3	-23.08			in wg.	
ID Fan Discharge Pressure	-0.3	15.77			in wg.	
ID Fan Inlet Temperature	300	313			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	3-6%	4.2-9.2			%	
ID Fan Motor Voltage (Rated)	6600	13200			volts	
ID Fan Motor Amps (Operating)	535	NA			A	
ID Fan Motor Amps (Rated)	740	780			A	
ID Fan Motor Power (Rated)	9000	20241			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1.15	1.15				
Chimney Information:						
Flue Liner Material	FRP	FRP				
Flue Diameter	18'	18' & 10'			ft	
Chimney Height	754'	754'			ft	
Number of Flues	1	2				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Trimble Owner: ____________
Unit TC1 and TC2 Project: ____________

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Green River

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

References:
1)
2)
3)
4)

Yellow highlight denotes Critical Focus Needs.

Fuel Data

Ultimate Coal Analysis (% by mass as received):	Typical	Minimum	Maximum		Notes
Carbon				%	
Hydrogen				%	
Sulfur				%	
Nitrogen				%	
Oxygen				%	
Chlorine				%	
Ash				%	
Moisture				%	
Total					
Higher Heating Value, Btu/lb (as received)				Btu/lb	
Ash Mineral Analysis (% by mass):					
Silica(SiO_2)				%	
Alumina (Al_2O_3)				%	
Titania (TiO_2)				%	
Phosphorous Pentoxide (P_2O_5)				%	
Calcium Oxide (CaO)				%	
Magnesium Oxide (MgO)				%	
Sodium Oxide (Na_2O)				%	
Iron Oxide (Fe_2O_3)				%	
Sulfur Trioxide (SO_3)				%	
Potassium Oxide (K_2O)				%	

Coal Trace Element Analysis (mercury and especially arsenic if fly ash is returned to boiler)

Vanadium		%	
Arsenic		%	
Mercury		% or ppm	
Other LOI		%	
Natural gas firing capability (if any at all)			
Natural gas line (into the station) capacity (if applicable)			
Current Lost on Ignition (LOI)			
Start-up Fuel			
Ash Fusion Temperature			
Initial Deformation		°F	
Softening		°F	
Hemispherical		°F	
Hardgrove Grindability Index			

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

Plant Size and Operation Data: (provide for each unit)		**Unit 3**	**Unit 4**	**Unit X**	**Unit X**		**Notes**
Maximum (Design) Fuel Burn Rate		880	1.2			MBtu/hr	Original Design
Boiler Type (e.g. wall-fired, tangential fired, cyclone)		Wall Fired	Wall Fired				
Boiler Manufacturer		B&W	B&W				
Net MW Rating (specify plant or turbine MW)		71	102			MW	
Gross MW Rating		75	109			MW	
Net Unit Heat Rate		11942	11278			Btu/kWh	
Net Turbine Heat Rate						Btu/kWh	
Boiler SO2 to SO3 Conversion Rate (if known)		Unknown	Unknown			%	
Fly Ash/Bottom Ash Split		80/20	80/20			%	
Flue Gas Recirculation (FGR)		NA	NA				
Installed? (Y/N)							
In operation? (Y/N)		NA	NA				
Flue Gas Recirculation (if installed)		NA	NA			%	
Type of Air Heater		Tubular	Lungstrom				
Air Heater Configuration (horizontal or vertical flow or shaft)		Vertical	Vertical				
Design Pressure/Vacuum Rating for Steam Generator	+/-	-18	-13.3			in wg.	
Design Pressure/Vacuum Rating for Particulate Control	+/-	-18	-13.3			in wg.	
Electrical / Control							
DCS Manufacturer (e.g. Westinghouse, Foxboro, Honeywell, etc.)		Honeywell	Honeywell				
Type of DCS (e.g. WDPF, Ovation, Net 90, Infi 90, Symphony, TDC 3000, etc.)		Experion	Experion				
Neural Network Installed? (Y/N)		N	N				
Neural Network Manufacturer (e.g. Pegasus, Westinghouse, etc.)		NA	NA				
Extra Capacity available in DCS?		Y	Y				
Historian Manufacturer		Honeywell	Honeywell				
Additional Controls from DCS or local PLC w/tie-in		Y Rockwell	Y Rockwell				
Transformer Rating for Intermediate Voltage Switchgear		7.5 MVA	9.375 MVA				
(SUS's) and Ratings of Equipment in These Cubicles		N/A	N/A				
Auxiliary Electric Limited (Y/N)		N	N				
Operating Conditions							
Economizer Outlet Temperature		475	610			°F	
Economizer Outlet Pressure		-5	-6			in wg.	
Excess Air or Oxygen at Economizer Outlet (full load/min load)		25%	25%			%	
Economizer Outlet Gas Flow						acfm	
		510	687			Klb/hr	
Air Heater Outlet Temperature		243	363			°F	
Air Heater Outlet Pressure		-9	-135			in wg.	
Particulate Control Equipment Outlet Temperature		230	600			°F	
Particulate Control Equipment Outlet Pressure		-11	-8.1			in wg.	
FGD Outlet Temperature (if applicable)		NA	NA			°F	
FGD Outlet Pressure (if applicable)		NA	NA			in wg.	

Black & Veatch AQCS Information Needs

Power Plant: Green River Owner:
Unit Project:

NOx Emissions	Unit 3	Unit 4	Unit X	Unit X		Notes
Emissions Limit	0.46	0.5			lb/MBtu	
Type of NOx Control (if any) - LNB, OFA, etc.	LNB	LNB				
Current NOx Reduction with existing controls	NA	NA			%	
Type of Ammonia Reagent Used (Anhydrous or % H_2O or Urea)	NA	NA				
Reagent Cost	NA	NA			$/ton	
Current Emissions					lb/hr	
					ton/yr	
	0.398	0.384			lb/MBtu	
Particulate Emissions						
Emissions Limit	0.29	0.14			lb/MBtu	
Type of Emission Control - Hot Side ESP, Cold Side ESP or FF	Cold side	Hot side				
Oxygen Content of Flue Gas @ Air Heater Outlet	~5%	~5%			%	
Oxygen Content of Flue Gas @ ESP/FF Outlet	~5%	~5%			%	
Current Emissions	Compliance	Compliance			lb/MBtu	Indirectly measured by Opacity
Fly Ash Sold (Y/N) - See Economic Section	N	N				
ESP						
Specific Collection Area (SCA)					ft^2/1000 acfm	
Discharge Electrode Type	Weighted Wire	Weighted Wire				
Supplier	Buell	Buell				
Efficiency	98.50%	99%			%	
No. of Electrical Sections	6	7				
% of Fly Ash Sold	0	0			%	
Fabric Filter						
Air to Cloth Ratio (net)	NA	NA			ft/min	
Number of Compartments	NA	NA				
Number of Bags per Compartments	NA	NA				
Efficiency	NA	NA			%	
% of Fly Ash Sold	NA	NA			%	
SO_2 Emissions						
Emissions Limit	4.57	4.57			lb/MBtu	
Type of Emission Control - wet or semi-dry FGD (if any)	NA	NA				
Current Emissions					lb/hr	
	5448	9276			ton/yr	2009 data
					lb/MBtu	
Byproduct Sold (Y/N) - See Economic Section						

Black & Veatch AQCS Information Needs

Power Plant: Green River
Unit:
Owner:
Project:

ID Fan Information (at Full Load):	Unit 3	Unit 4	Unit X	Unit X		Notes
ID Fan Inlet Pressure	-7	-15.5			in wg.	
ID Fan Discharge Pressure	0	-0.24			in wg.	
ID Fan Inlet Temperature	230	365			F	
Oxygen Content of Flue Gas @ ID Fan Inlet	~5%	~5%			%	
ID Fan Motor Voltage (Rated)	2300	2300			volts	
ID Fan Motor Amps (Operating)	105	230			A	
ID Fan Motor Amps (Rated)	98.3	224			A	
ID Fan Motor Power (Rated)	450	1000			hp	
ID Fan Motor Service Factor (1.0 or 1.15)	1	1				
Chimney Information:						
Flue Liner Material	Brick	Brick				
Flue Diameter	12	11			ft	
Chimney Height	198	247			ft	
Number of Flues	1	1				

Drawing and Other Information Needs:

Baseline pollutant emissions data for AQC analysis
Technical evaluations performed to support recent consent decree activity
Existing Plant/AQC system general design and performance issues
Full detailed boiler front, side, and rear elevation drawings
Boiler Design Data (Boiler Data Sheet)
Ductwork Arrangement Drawing (emphasis from economizer outlet to air heater inlet)
Ductwork Arrangement Drawing (emphasis from air heater outlet to stack)
Plant Arrangement Drawings (showing column row spacing)
CEM Quarterly and Annual Data (required if base emissions are to be verified)
Recent Particulate Emission Test Report (If available)
Current Mercury Testing Results (If available)
Current Site Arrangement Drawing
Foundation Drawings and/or Soils Report
Underground Utilities Drawings
Plant One Line Electrical Drawing
Fan Curves for Existing ID Fans (including current system resistance curve)
Acceptable Fan Operating Margins
Plant Outage Schedule
overfire air ports, number of overfire air levels, etc.)

Black & Veatch AQCS Information Needs

Power Plant: Green River
Unit
Owner:
Project:

Economic Evaluation Factors:	**Unit X**	**Unit X**	**Unit X**	**Unit X**		**Notes**
Remaining Plant Life/Economic Life					years	
Annual Capacity Factor (over life of study/plant)					%	
Contingency Margin (can be determined by B&V)					%	
Owner Indirects Cost Margin					%	
Interest During Construction					%	
Levelized Fixed Charge Rate or Capital Recovery Factor					%	
Present Worth Discount Rate					%	
Capital Escalation Rate					%	
O&M Escalation Rate					%	
Energy Cost (energy to run in-house equipment)					$/MWh	
Replacement Energy Cost (required to be purchased during unit outage)					$/MWh	
Year-by-Year Fuel Prices (over life of study/plant)					$/MBtu	
					$/ton	
Base Fuel Price					$/MBtu	
					$/ton	
Fuel Price Escalation Rate					%	
Water Cost					$/1,000 gal	
Limestone Cost					$/ton	
Lime Cost					$/ton	
Ammonia Cost					$/ton	
Fully Loaded Labor Rate (per person)					$/year	
Fly Ash Sales					$/ton	
Bottom Ash Sales					$/ton	
FGD Byproduct Sales					$/ton	
Waste Disposal Cost						
Fly Ash					$/ton	
Bottom Ash					$/ton	
Scrubber Waste					$/ton	

Appendix C
Project Design Memorandum (Design Basis)

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	EW Brown			Ghent				Cane Run			Mill Creek				Trimble County		Green River		Reference
	1	2	3	1	2	3	4	4	5	6	1	2	3	4	1	2	3	4	
Ultimate Coal analysis, wet basis																			
Carbon, %	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	61.20	65.41	65.41	Data from E-ON
Hydrogen, %	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.28	4.46	4.46	Data from E-ON
Sulfur, %	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	3.36	2.60	2.60	Data from E-ON
Nitrogen, %	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.27	1.34	1.34	Data from E-ON
Chlorine, %	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	Data from E-ON
Oxygen, %	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.89	6.69	6.69	Data from E-ON
Ash, %	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	12.00	9.00	9.00	Data from E-ON
Moisture, %	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	10.50	10.50	Data from E-ON
Higher Heating Value, Btu/lb	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,200	11,600	11,600	Data from E-ON
Trace Metal Analysis, ppm																			
Antimony (Sb)	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.07	1.07	Data from E-ON
Arsenic (As)	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	13.00	10.00	10.00	Data from E-ON
Barium (Ba)	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	74.00	49.00	49.00	Data from E-ON
Cadmium (Cd)	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.65	0.30	0.30	Data from E-ON
Chlorine (Cl)	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1600.00	1845.00	1845.00	Data from E-ON
Chromium (Cr)	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	23.00	17.00	17.00	Data from E-ON
Fluorine (F)	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	98.00	71.00	71.00	Data from E-ON
Lead (Pb)	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	Data from E-ON
Magnesium (Mg)	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	684.00	509.00	509.00	Data from E-ON
Mercury (Hg)	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.10	0.10	Data from E-ON
Nickel (Ni)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	14.00	14.00	Data from E-ON
Selenium (Se)	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	2.94	1.93	1.93	Data from E-ON
Strontium (Sr)	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	30.00	30.00	Data from E-ON
Vanadium (V)	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	Data from E-ON
Zinc (Zn)	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	48.00	50.00	50.00	Data from E-ON
Ash Analysis, % by mass																			
Alumina (Al2O3)	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	21.69	19.45	19.45	Data from E-ON
Barium Oxide (BaO)	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.06	0.06	Data from E-ON
Lime (CaO)	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.74	2.89	2.89	Data from E-ON
Iron Oxide (Fe2O3)	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	21.80	19.90	19.90	Data from E-ON
Magnesia (MgO)	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	0.91	Data from E-ON
Manganese Oxide (MnO)	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	Data from E-ON
Phosphorous Pentoxide (P2O5)	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.26	0.21	0.21	Data from E-ON
Potassium Oxide (K2O)	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.33	2.41	2.41	Data from E-ON
Silica (SiO2)	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	45.88	49.65	49.65	Data from E-ON
Sodium Oxide (Na2O)	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.77	0.77	Data from E-ON
Strontium Oxide (SrO)	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.04	Data from E-ON
Sulfur Trioxide (SO3)	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.47	2.47	Data from E-ON
Titania (TiO2)	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.04	1.08	1.08	Data from E-ON
Undetermined	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.13	0.13	Data from E-ON
Unit Characteristics																			
Gross Turbine Generator Load, MW	110	180	457	541	517	523	526	168	181	261	330	330	423	525	547	760	75	109	Data from E-ON
Boiler Efficiency, % (HHV)	85.32	86.73	86.53	85.74	86.83	86.31	86.77	85.12	87.14	87.09	85.40	85.40	86.51	86.51	86.88	86.92	89.02	85.25	Data from E-ON
Boiler Heat Input, MBtu/hr (HHV)	999.80	1,665.50	4,120.43	5,369	4,327	5,496	5,473	1,603	1,757	2,589	3,224	3,311	4,209	5,122	5,310	6,583	848	1,150	Data from E-ON
Coal Flow Rate, lb/hr	89,268	148,705	367,895	479,375	386,339	490,714	488,661	143,125	156,875	231,161	287,857	295,625	375,804	457,321	474,107	587,768	73,103	99,138	Data from E-ON
Capacity Factor, %	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	Data from E-ON
Fly Ash Portion of Total Ash, %	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	80.0	Data from E-ON
Air Heater Leakage, %	10.0	10.0	10.0	10.0	10.0	10.0	10.0	16.7	17.0	7.8	10.0	10.0	10.0	10.0	10.0	6.0	6.8	6.8	Data from E-ON
Excess Air, %	34.352	18.258	16.848	18.258	21.926	21.926	20.433	20.00	20.00	20.00	20.00	20.00	20.00	20.00	18.258	19.700	25.000	25.000	Data from E-ON
Economizer Outlet Conditions																			
Flue Gas Temperature, F	650	730	730	729	610	731	791	580	630	617	760	760	690	640	700	586	475	610	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-8.0	-3.7	-5.0	-3.2	-5.1	-5.1	-4.5	-4.0	-3.0	-4.0	-5.0	-5.0	-5.0	-5.0	-6.0	-6.0	-5.0	-6.0	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,090,927	1,615,221	3,952,267	5,206,933	4,316,060	5,482,104	5,397,559	1,575,668	1,727,042	2,544,856	3,169,029	3,254,545	4,137,234	5,034,667	5,149,714	6,455,853	886,785	1,202,598	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	509,072	796,739	1,955,176	2,563,081	1,922,533	2,718,161	2,805,958	680,015	779,254	1,137,376	1,608,445	1,651,849	1,979,343	2,303,938	2,490,348	2,816,034	345,095	536,927	B&V Combustion Calculations
Uncontrolled Sulfur Dioxide Concentration, lb/MBtu	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	4.48	4.48	= % Sulfur in Coal x 20,000 / HHV
Uncontrolled Sulfur Dioxide Mass Flow Rate, lb/hr	5,993	9,983	24,697	32,161	25,936	32,942	32,805	9,608	10,531	15,518	19,324	19,846	25,228	30,701	31,828	39,458	3,798	5,150	B&V Combustion Calculations
Uncontrolled PM Concentration, lb/MBtu	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	8.746	6.334	6.334	B&V Combustion Calculations
Uncontrolled PM Mass Flow Rate, lb/hr	8,744	14,566	36,037	46,957	37,844	48,068	47,867	14,020	15,367	22,643	28,197	28,958	36,812	44,797	46,441	57,575	5,371	7,284	= Uncontrolled PM (lb/MBtu) x Heat Input (MBtu/hr)
Uncontrolled Mercury Concentration, lb/TBtu	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	10.71	8.62	8.62	= Hg in Coal (ppm) x Coal Flow Rate (lb/hr) / Heat Input (MBtu/hr)
Uncontrolled HCl Mass Flow Rate, lb/hr	147	244.63	605.21	789	636	807	804	235	258	380	474	486	618	752	780	967	139	188	= HCl in Coal (ppm) / 1,000,000 x Coal Flow Rate (lb/hr) x MW of HCl / MW of Cl
Uncontrolled HCl Concentration, lb/MBtu	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.16	0.16	= HCl Flowrate (lb/hr) / Heat Input (MBtu/hr)
Hot-Side ESP Outlet Conditions																			
Flue Gas Temperature, F					605	708	770											600	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.					-10.80	-10.90	-10.8											-8.1	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	4,531,863	5,756,209	5,667,437	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	No Hot-side ESP. Unit has a Cold-side ESP	1,262,728	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm					2,041,027	2,843,960	2,947,083											562,236	B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu					0.0565	0.0451	0.0248											0.08	B&V Combustion Calculations
Controlled PM Mass Flow Rate, lb/hr					244	248	135.73											92	= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %					99.35	99.48	99.72											98.74	= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
SCR Outlet Conditions																			
Flue Gas Temperature, F				729		708	770						690	640	700	586			B&V Combustion Calculations
Flue Gas Pressure, in. w.g.				-13.2		-20.90	-20.8						-13.0	-13.0	-16.0	-11.0			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	No SCR	No SCR	New SCR Planned for 2012	5,311,071	No SCR	5,871,333	5,780,786	No SCR	No SCR	No SCR	No SCR	No SCR	4,219,979	5,135,360	5,252,708	6,584,970	No SCR	No SCR	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm				2,682,371		2,977,658	3,085,629						2,061,162	2,399,175	2,606,716	2,910,365			B&V Combustion Calculations
Controlled NOx Concentration, lb/MBtu				0.0639		0.0479	0.0627						0.0584	0.0589	0.076	0.076			Data from E-ON
Controlled NOx Mass Flow Rate, lb/hr				343		263	343						246	302	404	500			= Controlled NOx (lb/MBtu) x Heat Input (MBtu/hr)
Air Heater Outlet Conditions																			
Flue Gas Temperature, F	350	330	340	361	309	322	309	369	299	318	375	375	330	330	320	324	243	363	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-14.00	-8.00	-18.00	-22.4	-18.60	-36.10	-29.4	-8.0	-6.0	-8.0	-10.0	-10.0	-18.0	-18.0	-22.5	-16.0	-9.0	-13.5	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,200,020	1,776,743	4,347,494	5,842,179	4,985,049	6,458,467	6,358,865	1,839,262	2,021,310	2,744,081	3,485,932	3,580,000	4,641,976	5,648,896	5,777,979	6,980,068	947,426	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,851	589,646	1,498,187	2,091,568	1,657,754	2,288,309	2,175,592	641,787	642,552	896,674	1,229,416	1,262,592	1,581,582	1,924,653	1,965,750	2,345,528	280,496	473,593	B&V Combustion Calculations
Cold-Side ESP Outlet Conditions																			
Flue Gas Temperature, F	340	320	330	358				369	299	318	340	340	330	330	320	324	230		B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	-18.00	-12.00	-19.00	-25.7				-9.1	-6.8	-9.8	-14.0	-14.0	-23.0	-21.0	-25.5	-18.0	-11.0		B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288	No Cold-side ESP. Unit has a Hot-side ESP	No Cold-side ESP. Unit has a Hot-side ESP	No Cold-side ESP. Unit has a Hot-side ESP	1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797	No Cold-side ESP. Unit has a Hot-side ESP	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	436,197	618,296	1,559,510	2,209,920				676,568	676,855	947,034	1,250,977	1,284,735	1,684,442	2,039,199	2,082,968	2,502,995	290,916		B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu	0.241	0.1	0.1	0.023				0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.31	0.063		Data from E-ON
Controlled PM Mass Flow Rate, lb/hr	241	166.55	412.04	123				66	60	62	124	147	218	181	90	2041	53		= Controlled PM (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %	97.24	98.86	98.86	99.74				99.53	99.61	99.73	99.56	99.49	99.41	99.60	99.81	96.46	99.01		= { 1- Controlled PM (lb/MBtu) / Uncontrolled PM (lb/MBtu) } x 100
Fabric Filter Outlet Conditions																			
Flue Gas Temperature, F																313			B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																-23.1			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	No Fabric Filter	7,398,872	No Fabric Filter	No Fabric Filter	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																2,500,664			B&V Combustion Calculations
Controlled PM Concentration, lb/MBtu																0.015			Data from E-ON
Controlled PM Mass Flow Rate, lb/hr																99			= Controlled PM from fabric Filter (lb/MBtu) x Heat Input (MBtu/hr)
Particulate Removal Efficiency, %																95.16			= { 1- FF Controlled PM (lb/MBtu) / ESP Controlled PM (lb/MBtu) } x 100
ID Fan Outlet Conditions																			
Flue Gas Temperature, F	356.05	332.17	346.44	376.94	325.52	346.34	333.60	379.03	306.39	327.81	354.85	355.15	348.83	348.83	340.08	334.60	235.91	371.55	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	10.00	10.00	10.00	6.10	11.40	5.90	14.60	8.00	7.00	8.00	10.00	10.00	10.00	10.00	10.00	15.77	1.00	1.00	B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	1,260,021	1,865,580	4,564,869	6,134,288	4,985,049	6,458,467	6,358,865	1,931,225	2,122,376	2,881,285	3,660,228	3,759,000	4,874,075	5,931,341	6,066,878	7,398,872	994,797	1,349,077	B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	415,059	594,805	1,481,211	2,086,965	1,571,913	2,119,437	2,010,799	656,526	660,654	917,824	1,200,841	1,233,697	1,588,066	1,932,543	1,954,644	2,334,113	284,775	461,503	B&V Combustion Calculations

EON
EW Brown, Ghent, Cane Run, Mill Creek, Trimble County, Green River
Design Basis
6/1/2010

Unit Designation	EW Brown			Ghent				Cane Run			Mill Creek				Trimble County		Green River		Reference
	1	2	3	1	2	3	4	4	5	6	1	2	3	4	1	2	3	4	
Scrubber Outlet Conditions	(For 3 units combined to a common/shared scrubber)																		
Flue Gas Temperature, F	129.64			131.74	128.04	129.28	128.50	131.19	125.96	128.80	130.30	130.32	129.60	129.60	129.24	129.43	No Scrubber	No Scrubber	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.	2.00			1.70	1.50	2.00	1.60	2.00	2.00	2.00	1.00	1.00	1.00	1.00	2.00	6.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr	8,136,097			6,534,149	5,252,980	6,834,132	6,711,801	2,056,206	2,226,116	3,036,144	3,879,298	3,984,228	5,157,618	6,277,442	6,413,722	7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm	2,029,766			1,643,977	1,306,064	1,705,743	1,671,656	517,157	550,120	754,452	972,502	998,878	1,291,025	1,571,359	1,598,535	1,927,087			B&V Combustion Calculations
Controlled Sulfur Dioxide Mass Flow Rate, lb/hr	679			805	865	824	821	659	736	1,750	1,515	1,556	2,441	2,407	441	546			B&V Combustion Calculations
Controlled Sulfur Dioxide Concentration, lb/MBtu	0.10			0.150	0.200	0.150	0.150	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083			= Controlled SO_2 (lb/hr) / Heat Input (MBtu/hr)
Sulfur Dioxide Removal Efficiency, %	98.33			97.50	96.67	97.50	97.50	93.15	93.02	88.73	92.17	92.17	90.33	92.17	98.62	98.62			= { 1- Controlled SO_2 (lb/MBtu) / Uncontrolled SO_2 (lb/MBtu) } x 100
Wet ESP Outlet Conditions																			
Flue Gas Temperature, F	No WESP			No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	No WESP	129.43	No WESP	No WESP	B&V Combustion Calculations
Flue Gas Pressure, in. w.g.																2.00			B&V Combustion Calculations
Flue Gas Mass Flow Rate, lb/hr																7,813,543			B&V Combustion Calculations
Volumetric Flue Gas Flow Rate, acfm																1,945,943			B&V Combustion Calculations
Stack Outlet Emissions[1]																			
Sulfur Dioxide Emission Concentration, lb/MBtu	0.10	0.10	0.10	0.15	0.20	0.15	0.15	0.411	0.419	0.676	0.47	0.47	0.58	0.47	0.083	0.083	4.48	4.48	Data from E-ON
Sulfur Dioxide Emission Rate, lb/hr	100	167	412	805	865	824	821	659	736	1,750	1,515	1,556	2,441	2,407	441	546	3,798	5,150	= SO_2 Emission (lb/MBtu) x Heat Input (MBtu/hr)
PM Emission Concentration, lb/MBtu	0.241	0.1	0.1	0.023	0.0565	0.0451	0.0248	0.041	0.034	0.024	0.0385	0.0443	0.0517	0.0354	0.017	0.015	0.063	0.08	Data from E-ON
PM Emission Rate, lb/hr	241	167	412	123	244	248	136	66	60	62	124	147	218	181	90	99	53	92	= PM Emission (lb/MBtu) x Heat Input (MBtu/hr)
NOx Emission Concentration, lb/MBtu	0.4463	0.4374	0.3319	0.0639	0.276	0.0479	0.0627	0.3394	0.3843	0.272	0.3169	0.3139	0.0584	0.0589	0.076	0.076	0.4011	0.3864	Data from E-ON
NOx Emission Rate, lb/hr	446	728	1,368	343	1,194	263	343	544	675	704	1,022	1,039	246	302	404	500	340	444	= NOx Emission (lb/MBtu) x Heat Input (MBtu/hr)
Hg Emission Concentration, lb/TBtu	5.0	5.0	5.0	2.0	3.5	2.0	2.0	3.5	3.5	3.5	3.0	3.0	2.5	2.5	1.2	1.0	5.5	5.5	Data from E-ON
Hg Emission Rate, lb/hr	5.00E-03	8.33E-03	2.06E-02	1.07E-02	1.51E-02	1.10E-02	1.09E-02	5.61E-03	6.15E-03	9.06E-03	9.67E-03	9.93E-03	1.05E-02	1.28E-02	6.37E-03	6.58E-03	4.66E-03	6.33E-03	= Hg Emission (lb/TBtu) x Heat Input (MBtu/hr) / 1,000,000
HCl Emission Concentration, lb/MBtu	0.002	0.002	0.002	0.0015	0.0017	0.0015	0.0015	0.00095	0.00095	0.00095	0.0015	0.0015	0.0015	0.0015	0.00085	0.00085	0.017	0.017	Data from E-ON
HCl Emission Rate, lb/hr	2	3	8	8	7	8	8	2	2	2	5	5	6	8	5	6	14	20	= HCl Emission (lb/MBtu) x Heat Input (MBtu/hr)
CO Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
CO Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	CO Emissions are not known
Dioxin/Furan Emission Concentration, lb/MBtu	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known
Dioxin/Furan Emission Rate, lb/hr	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	--	Dioxin/Furan Emissions are not known

Notes:

1. Current Outlet Emissions as noted in E-ON Matrix

Revision History:

Rev	Date	Description
0	5/21/2010	Initial Issue
1	6/1/2010	Final Issue

Appendix D
Air Quality Control Technology Descriptions

CONTROL TECHNOLOGY DESCRIPTIONS

NO_x Reduction Technologies

Low NO_x Burners (LNB)

The new-generation LNB have better NO_x removal performance than the first-generation LNB and are a fundamental component of the boiler design. The term ultra-low NO_x burners applies only to gas fired applications and does not apply to coal fired boilers.

LNB control the mixing of fuel and air in a pattern designed to minimize flame temperatures and quickly dissipate heat. These burners typically reduce NO_x by maintaining a reducing atmosphere at the coal nozzle and diverting additional combustion air (to complete combustion) to secondary air registers. This minimizes the reaction time at oxygen-rich, high-temperature conditions. Conventional burners, however, typically mix the secondary air with the primary air/fuel stream immediately following injection into the furnace, creating a high intensity combustion process.

Wall mounted LNB are typically a multiple-register (damper) type with two separate secondary airflow paths through the burner and into the furnace. Common features include dedicated total secondary airflow control dampers and separate dedicated dampers or vanes to control the flow and spin of the individual secondary airflows through the burner. The vanes that control spin or flame shape are typically set during initial startup and then locked in place.

Control and balancing of the secondary air, primary air, and coal distribution among the burners is a basic requirement of all manufacturers. Typical allowable flow deviations from the mean are 10 percent for individual burner air and coal flows. This requirement may necessitate changes in operating procedures related to individual burner level turn down at part load. Conversely, additional control provisions and flow monitoring capability is required to preserve the option to operate with unbalanced firing at part load.

The basic NO_x reduction principles for LNB are to control and balance the fuel and air flow to each burner, and to control the amount and position of secondary air in the burner zone so that fuel devolatization and high-temperature zones are not oxygen rich. Figure D-1 shows the low NOx burners

Low NO_x Burner Systems

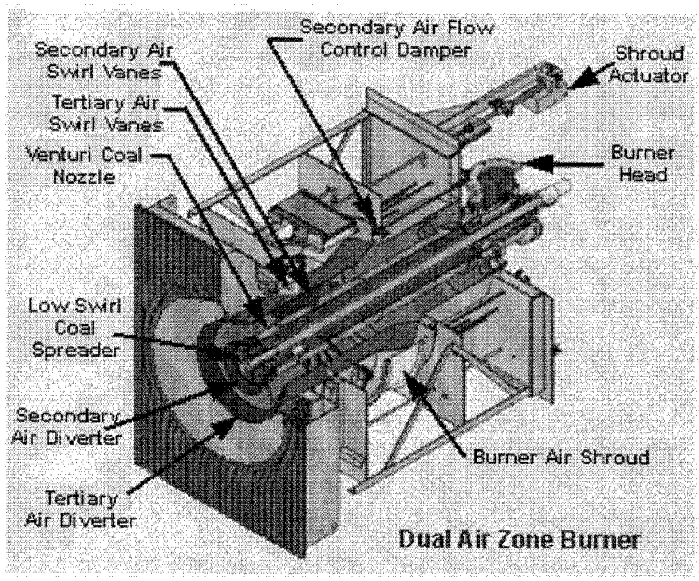

Figure D-1
Low NO_X Burners (Courtesy: DB Riley)

Overfire Air (OFA)

OFA is an air staging NO_x reduction technique that is based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the high temperature zone of the furnace. OFA can be used in conjunction with the LNB system. Unburned carbon and combustible materials may increase as a result of the addition of OFA because of the staging of the combustion process.

With the installation of an OFA system, the main combustion burners are operated at or near stoichiometric ratio to limit available oxygen, flame temperature, and NO_x formation. The remainder of the combustion air is then injected through the OFA ports to complete combustion. The quantity of OFA introduced is sufficient to increase the overall excess air in the boiler to 15 to 20 percent to ensure complete combustion and maintain flue gas flow through the convective sections of the boiler.

OFA systems reduce NO_X formation by creating a fuel rich combustion zone. The OFA is introduced above the main combustion zone (fuel is introduced in an oxygen-starved environment) where fuel burnout can be completed at a lower temperature with fewer volatile nitrogen-bearing combustion products.

The OFA ports will be designed to allow adequate mixing of the combustion air and flue gas and with sufficient temperatures and residence times to ensure complete combustion to achieve optimum NO_x reductions. The location of the OFA ports is critical in achieving optimum NO_x reductions without affecting unburned carbon losses. Figure D-2 shows the overfire air

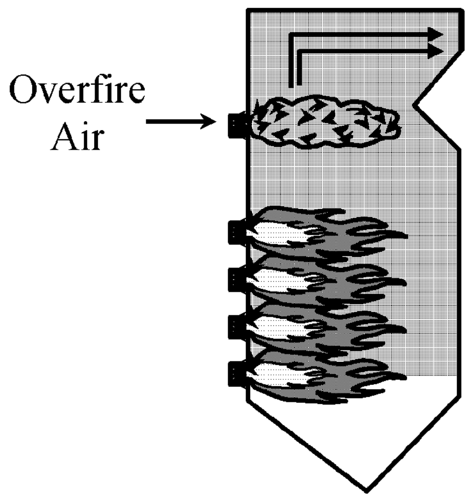

Figure D-2
Overfire Air System

Selective Noncatalytic Reduction System (SNCR)

Selective non-catalytic NO_x reduction systems rely on the appropriate reagent injection temperature and good reagent/gas mixing rather than a catalyst to achieve NO_x reductions. SNCR systems can use either ammonia (Thermal DeNO_x) or urea (NO_xOUT) as reagents.

The optimum temperature range for injection of ammonia or urea is 1,550 to 1,900° F. The NO_x reduction efficiency of an SNCR system decreases rapidly at temperatures outside this range. Injection of reagent below this temperature window results in excessive ammonia slip emissions. Injection of reagent above this temperature window results in increased NO_x emissions. A PC boiler operates at temperatures of between 2,500 and 3,000° F. Therefore, the optimum temperature window in a PC boiler occurs somewhere in the backpass of the boiler. To further complicate matters, this temperature location will change as a function of unit load. In addition, residence times in this temperature range are very limited, further detracting from optimum SNCR performance. Finally, there is no provision for feedforward control of reagent injection, relying only on feedback control. This results in over injection of reagent and high ammonia slip emissions.

SNCR systems are less efficient NO_x reduction systems than SCR systems. In general, SNCR systems on large PC-fired boilers will be capable of only up to 50 percent NO_x reduction. Figure D-3 shows a schematic of SNCR system.

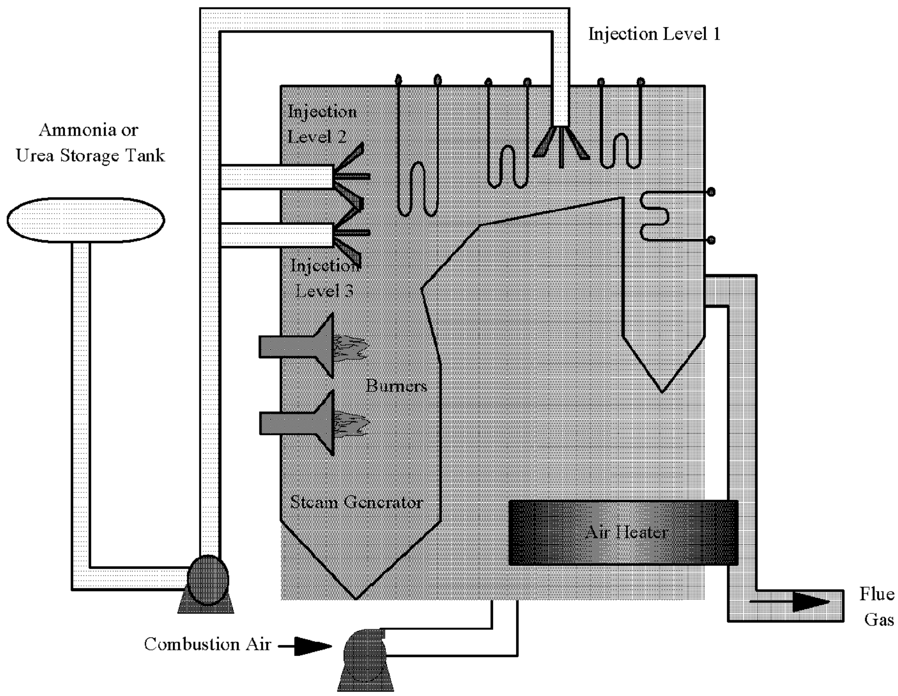

Figure D-3
Schematic of SNCR System with Multiple Injection Levels

Selective Catalytic Reduction System (SCR)

In an SCR system, ammonia is injected into the flue gas stream just upstream of a catalytic reactor. The ammonia molecules in the presence of the catalyst dissociate a significant portion of the NO_x into nitrogen and water.

The aqueous ammonia is received and stored as a liquid. The ammonia is vaporized and subsequently injected into the flue gas by compressed air or steam as a carrier. Injection of the ammonia must occur at temperatures above 600° F to avoid chemical reactions that are significant and operationally harmful. Catalyst and other considerations limit the maximum SCR system operating temperature to 840° F. Therefore, the system is typically located between the economizer outlet and the air heater inlet. The SCR catalyst is housed in a reactor vessel, which is separate from the boiler. The conventional SCR catalysts are either homogeneous ceramic or metal substrate coated. The catalyst composition is vanadium-based, with titanium included to disperse the vanadium catalyst and tungsten added to minimize adverse SO_2 and SO_3 oxidation reactions. An economizer bypass may be required to maintain the reactor temperature during low load operation. This will reduce boiler efficiency at lower loads.

The SCR process is a complex system. The SCR requires precise NO_x-to-ammonia distribution in the presence of the active catalyst site to achieve current BACT levels. In the past, removal efficiencies were the measure of catalyst systems because of extremely high inlet NO_x levels. Current technology SCR systems do not use removal efficiency as a primary metric because the current generation of LNB/OFA systems limits the amount of NO_x available for removal. Essentially, as NO_x is removed through the initial layers of catalyst, the remaining layers have difficulty sustaining the reaction.

A number of alkali metals and trace elements (especially arsenic) poison the catalyst, significantly affecting reactivity and life. Other elements such as sodium, potassium, and zinc can also poison the catalyst by neutralizing the active catalyst sites. Poisoning of the catalyst does not occur instantaneously, but is a continual steady process that occurs over the life of the catalyst. As the catalyst becomes deactivated, ammonia slip emissions increase, approaching design values. As a result, catalyst in a SCR system is consumable, requiring periodic replacement at a frequency dependent on the level of catalyst poisoning. However, effective catalyst management plans can be implemented that significantly reduce catalyst replacement requirements.

There are two SCR system configurations that can be considered for application on pulverized coal boilers: high dust and tail end. A high dust application locates the SCR system before the particulate collection equipment, typically between the economizer outlet and the air heater inlet. A tail end application locates the catalyst downstream of the particulate and FGD control equipment.

The high dust application requires the SCR system to be located between the economizer outlet and the air heater inlet in order to achieve the required optimum SCR operating temperature of approximately 600° to 800° F. This system is subject to high levels of trace elements and other flue gas constituents that poison the catalyst, as previously noted. The tail end application of SCR would locate the catalyst downstream of the particulate control and FGD equipment. Less catalyst volume is needed for the tail end application, since the majority of the particulate and SO_2 (including the trace elements that poison the catalyst) have been removed. However, a major disadvantage of this alternative is a requirement for a gas-to-gas reheater and supplemental fuel firing to achieve sufficient flue gas operating temperatures downstream of the FGD operating at approximately 125° F. The required gas-to-gas reheater and supplemental firing necessary to raise the flue gas to the sufficient operating temperature is costly. The higher front end capital costs and annual operating cost for the tail end systems present higher overall costs compared to the high dust SCR option with no established emissions control efficiency advantage. Figure D-4 shows a schematic diagram of SCR.

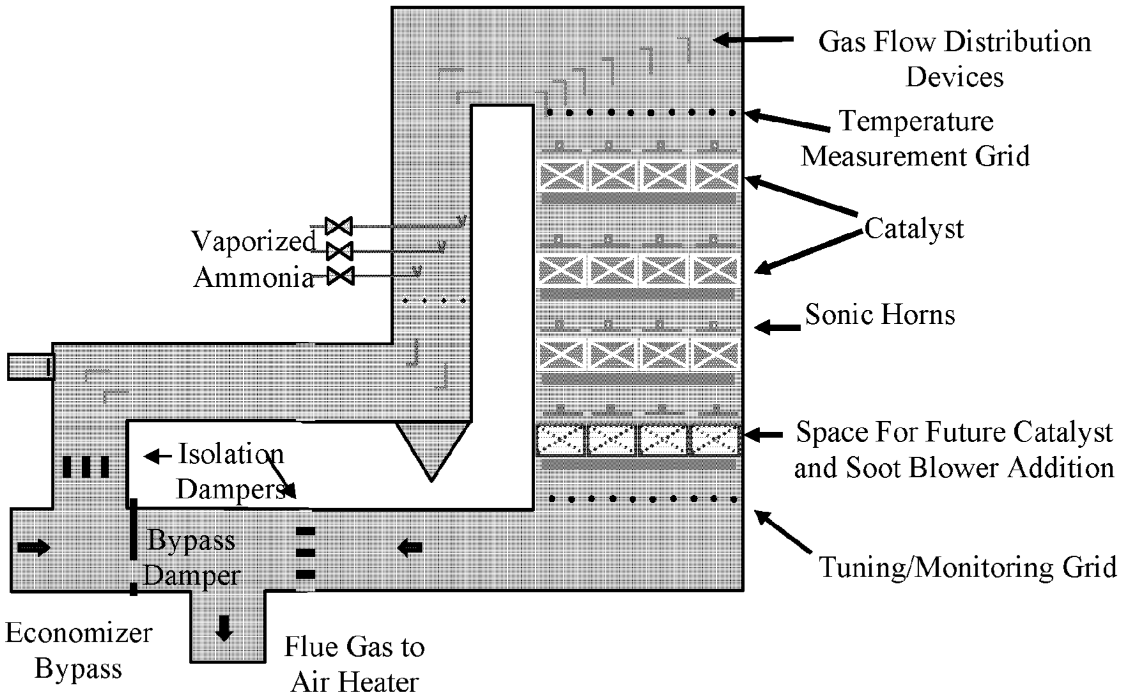

Figure D-4
Schematic Diagram of a Typical SCR Reactor

SNCR/SCR Hybrid System

The SNCR/SCR hybrid system uses components and operating characteristics of both SNCR and SCR systems. Hybrid systems were developed to combine the low capital cost and potential for high NH_3 slip associated with SNCR systems with the high reduction potential and low NH_3 slip inherent with catalyst based SCR systems. The result is an NO_x reduction alternative that can meet initial NO_x reduction requirements but can be upgraded to meet higher reductions at a future date, if required. Typically, installation of an SCR system with a single layer of in-duct catalyst is capable of reducing NO_x emissions from 40 to 70 percent, depending on the amount of NH_3 slip from the SCR and the volume of the single layer of catalyst.

The SNCR component of the hybrid system is identical to the SNCR system, except that the hybrid system may have more levels of multiple lance nozzles for reagent injection. This will increase the capital cost of the SNCR component of the hybrid system. During operation, the SNCR system would inject higher amounts of reagent into the flue gas. This increased reagent flow has a two-fold effect: NO_x reduction within the boiler is increased while NH_3 slip is also increased. The NH_3 that slips from the SNCR is then used as the reagent for the single layer of catalyst.

There are two design philosophies for using this excess NH_3 slip. The most conservative hybrid systems will use the catalyst simply as an NH_3 slip "scrubber" with some additional NO_x reduction. Similar to in-duct systems, the flue gas velocity through the catalyst is an important factor in design. Operating in this mode allows maximum NO_x reduction within the boiler by the SNCR while minimizing the catalyst volume requirement. While some NO_x reduction is achieved at the catalyst, the relatively small catalyst requirement of this design has the potential to fit all the catalyst in a true in-duct arrangement, with no significant ductwork changes, arrangement interference, or structural adaptations.

The second philosophy uses adequate catalyst volume to obtain significant levels of additional NO_x reduction. The additional reduction is a function of the quantity of NH_3 slip, the catalyst volume, and the distribution of NH_3 to NO_x within the flue gas. Using NH_3 slip that is produced by the SNCR system is not a high efficiency method of introducing reagent, due to the low reagent utilization. Therefore, even though the reaction at the catalyst requires 1 ppm of NH_3 to remove 1 ppm of NO_x, the SNCR must inject at least 3 ppm of NH_3 to generate 1 ppm of NH_3 at the catalyst.

Catalyst volume is strongly influenced by the NO_x reduction required and the NH_3 distribution. The impact of catalyst volume on the design of a hybrid system is on the size of the reactor required to hold the catalyst. If multiple levels of catalyst operating at low flue gas velocity are required, some modifications will be required to the typical ductwork. If widening the ductwork cannot provide for adequate catalyst volume, then a separate reactor is required, which quickly negates the capital cost advantage of a hybrid system. Figure D-5 represents a schematic diagram of a typical SNCR/SCR Hybrid system.

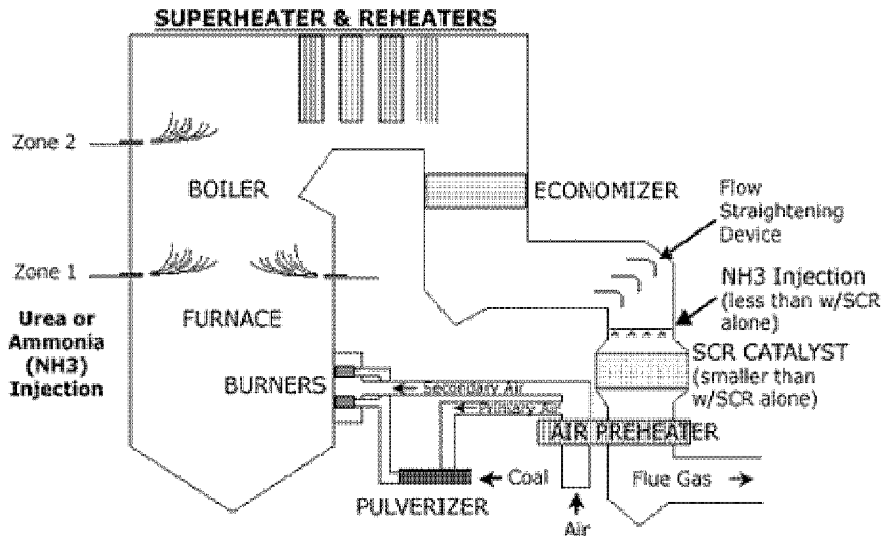

Figure D-5
Schematic Diagram of a Typical SNCR/SCR Hybrid System (Courtesy: Clean Environmental Protection Engineering Co. Ltd.)

SO_2 and HCl Reduction Technologies

Wet Flue Gas Desulfurization (FGD) System

Wet limestone-based FGD processes are frequently applied to pulverized coal fired boilers that burns medium-to-high sulfur eastern coals. All of the FGD systems installed in response to Phase I of the 1990 CAA were based on a wet FGD system using either lime or limestone as the reagent. Typically, the wet FGD processes on a pulverized coal facility are characterized by high efficiency (> 98 percent) and high reagent utilization (95 to 97 percent) when combined with a high sulfur fuel. The ability to realize high removal efficiencies on higher sulfur fuels is a major difference between wet scrubbers and semi-dry/dry FGD processes. It is well known that SO_2 removal efficiencies for wet FGD systems are generally higher for high sulfur coal applications than for low sulfur coal applications, for the fundamental physical reason that the chemical reactions that remove SO_2 are faster if the inlet SO_2 concentration is higher. The absolute emissions level becomes a limiting factor due to a reduction in the chemical driving forces of the reactions that are occurring. Thus, the calculated removal efficiency of the various types of wet scrubbers declines as the fuel sulfur content decreases; this is the case for low sulfur western and PRB coals.

In a wet FGD system, the absorber module is located downstream of the induced draft (ID) fans (or booster ID fans, if required). Flue gas enters the module and is contacted with a slurry containing reagent and byproduct solids. The SO_2 is absorbed into the slurry and reacts with the calcium to form $CaSO_3 \bullet 1/2H_2O$ and $CaSO_4 \bullet 2H_2O$. SO_2 reacts with limestone reagent through the following overall reactions:

$$SO_2 + CaCO_3 + \tfrac{1}{2}H_2O \rightarrow CaSO_3 \bullet \tfrac{1}{2}H_2O + CO_2$$
$$SO_2 + CaCO_3 + 2H_2O + \tfrac{1}{2}O_2 \rightarrow CaSO_4 \bullet 2H_2O + CO_2$$

The flue gas leaving the absorber will be saturated with water, and the stack will have a visible moisture plume. Because of the chlorides present in the mist carry-over from the absorber and the pools of low pH condensate that can develop, the conditions downstream of the absorber are highly corrosive to most materials of construction. Highly corrosion-resistant materials are required for the downstream ductwork and the flue stack. Careful design of the stack is needed to prevent the "rainout" from condensation that occurs in the downstream ductwork and stack. These factors contribute to the relatively high capital costs of the wet FGD SO_2 control alternative.

The reaction products are typically dewatered by a combination of hydrocyclones and vacuum filters. The resulting filter cake is suitable for landfill disposal. In early lime- and limestone-based FGD processes, the byproduct solids were primarily calcium sulfite hemihydrate ($CaSO_3 \bullet 1/2H_2O$), and the byproduct solids were mixed with fly ash (stabilization) or fly ash and lime (fixation) to produce a physically stable material. In the current generation of wet FGD systems, air is bubbled through the reaction tank (or in some cases, a separate vessel) to practically convert all of the $CaSO_3 \bullet 1/2H_2O$ into calcium sulfate dihydrate ($CaSO_4 \bullet 2H_2O$), which is commonly known as gypsum. This step is termed "forced oxidation" and has been applied to both lime- and limestone-based FGD processes. Compared to calcium sulfite hemihydrate, gypsum has much superior dewatering and physical properties, and forced oxidized FGD systems tend to have few internal scaling problems in the absorber and mist eliminators. Dewatered gypsum can be landfilled without stabilization or fixation. Many FGD systems in the United States are using the forced-oxidation process to produce a commercial grade of gypsum that can be used in the production of portland cement or wallboard. Marketing of the gypsum can eliminate or greatly reduce the need to landfill FGD byproducts.

The absorber vessels are fabricated from corrosion-resistant materials such as epoxy/vinyl ester-lined carbon steel, rubber-lined carbon steel, stainless steel, or fiberglass. The absorbers handle large volumes of abrasive slurries. The byproduct dewatering equipment is also relatively complex and expensive. These factors result in