CCS INTEGRATION REPORT

American Electric Power

Mountaineer CCS II Project

Phase 1

Prepared for

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1. SYNOPSIS

The purpose of this report is to explain the level of integration and various interface points between American Electric Power's Mountaineer generating station and the proposed nominal 235 MWe commercial scale application of Alstom's Chilled Ammonia Process (CAP) for CO_2 capture. The report provides an overview of the existing systems throughout the plant required to support the operation of the Carbon Capture and Sequestration (CCS) system, and presents how AEP considered and evaluated the integration of these systems during the Front End Engineering and Design (FEED) effort.

A general description of the Alstom Chilled Ammonia Process is provided, along with a discussion of how AEP's philosophy of operating a power generating station differs from that of a chemical processing plant, which currently available CO_2 technologies emulate. A key achievement from the Phase I Front End Engineering and Design (FEED) process was the marriage of these two fundamentally different operating philosophies so that the CCS system could be successfully implemented and operated at a commercial scale within an existing power generating facility.

AEP took a rather conservative approach to integration in the conceptual design. This approach was due in part to the fact that this project would be the largest commercial scale application of this technology, and also that integration opportunities often add complexity, cost, and may not be practical with respect to potential impacts to the existing plant. This report discusses AEP's approach to integration and outlines the opportunities that were evaluated at Mountaineer.

Finally this report presents concise summaries of engineering studies and evaluations that were carried out during the FEED to establish the conceptual design basis for how the Chilled Ammonia Process would ultimately be integrated at Mountaineer. Based on this conceptual design, AEP gained confidence that integration of a commercial scale Chilled Ammonia CO_2 capture system at an existing power generation station is achievable.

1.1 EXECUTIVE SUMMARY

The report will cover the following areas and describe the design basis for integration in each area:

- Steam supply to the CAP and steam condensate return
    - Steam is supplied from the main turbine and condensate returned to the main unit feed water heating system.
- Flue gas exhaust from the CAP
    - Flue gas exiting the CAP is returned to the existing Mountaineer stack for exhaust to atmosphere.

- Process makeup water to the CAP
    - Makeup water to all process users will be provided by the existing river water intake system.
    - Additional treatment equipment is necessary to meet process water quality requirements (evaporative condensers).
    - A new reverse-osmosis (RO) system will provide additional treatment of the makeup water to the CAP direct-contact cooler (DCC).
- Process wastewater
    - Condensate from the inlet flue gas to the CAP is returned to the Mountaineer flue gas desulfurization (FGD) system.
    - Condensate from the flue gas return is sent back to the CAP for re-use.
    - Evaporative condenser blowdown is sent to the existing Mountaineer wastewater pond.
- CAP By-product stream
    - Ammonium Sulfate from the CAP is concentrated to a 40% wt. solution and utilized as a fertilizer product by local fertilizer suppliers.
- Electrical power supply to the CAP
    - Main power is supplied from the existing Mountaineer 138 kV substation to dedicated transformers for the CAP.
- Control systems
    - The CAP is fully integrated into the existing Mountaineer distributed control system (DCS) and controlled from a stand-alone CCS control room.

Each area listed above presented unique challenges and opportunities to the engineering and design team. Often determination of an interface point led to in-depth evaluation of design parameters, performance effects, and economics. Furthermore, integration of the CCS system into the existing plant brought about opportunities for efficiency improvement, as well as challenges with respect to process chemical handling and utilization and process operations. Scaling, demonstrating, and assessing the operation of this new CO_2 capture technology were the primary technical objectives of the project. The engineering and design team was further tasked with addressing the balance between the benefits and complexity of integration and the potential impacts that over-integration too early in the evolution of this complex technology could have on achieving those primary objectives.

2. INTRODUCTION

Process Description

The proposed CO_2 capture facility at AEP's existing Mountaineer Plant utilizes Alstom's CAP technology to capture approximately 1.5 million metric tons of CO_2 annually based on a design target of 90 percent CO_2 reduction from a 235-MW flue gas slipstream of the 1,300-MW Mountaineer Power Plant. The captured CO_2 is transported by pipeline to injection wells located up to approximately 12 miles (approx. 19 kilometers) from the plant.

The existing Mountaineer Plant began commercial operation in 1980. The plant consists of a 1,300-MW pulverized coal-fired electric generating unit, a hyperbolic cooling tower, material handling and unloading facilities, and various ancillary facilities required to support plant operation. The plant uses (on average) approximately 10,000 tons of coal per day. Coal is delivered to the plant by barge (on the Ohio River), rail, and conveyors from a nearby coal mine located west of the site. The plant is equipped with air emissions control equipment, which includes: (1) an electrostatic precipitator for particulate control; (2) selective catalytic reduction for nitrogen oxides (NO_x) control; (3) a wet flue gas desulfurization (FGD) unit for sulfur dioxide (SO_2) control; and (4) a Trona injection system for sulfur trioxide (SO_3) control.

The existing Mountaineer Plant Product Validation Facility (PVF) utilizes Alstom's CAP system and treats approximately 20 MW of flue gas, or 1.5 percent of the total plant flue gas flow. The PVF started capturing CO_2 in September 2009 and initiated injection in October 2009. The PVF is designed to capture and store approximately 100,000 metric tons of CO_2 annually. Captured CO_2 from the PVF is injected via two onsite wells into two geologic formations (Rose Run and Copper Ridge) located approximately 1.5 miles below the plant site. The PVF also includes three deep monitoring wells used for monitoring geologic conditions and assessing the suitability of the geologic formations for future storage. The PVF supplied data to support the design and engineering of the MT CCS II project.

The CO_2 capture system proposed for the Mountaineer CCS II Project is similar to the Alstom CAP system currently operating at the Mountaineer Plant PVF, but approximately 12 times the scale. As with the PVF, the process uses an ammonia-based reagent to capture CO_2 and isolate it in a form suitable for geologic storage. The captured CO_2 stream is cooled and compressed to a supercritical state for pipeline transport to the injection well sites. In general terms, supercritical CO_2 exhibits properties of both a gas and a liquid. The process is designed to remove approximately 90 percent of the CO_2 from the 235-MW slipstream of flue gas.

The CAP uses an ammonia-based reagent to remove CO_2 from the flue gas. The first step in the process is to cool the flue gas with chilled water to temperatures necessary for CO_2 capture. The capture process involves CO_2 reacting with ammonia (NH_3) ions to form a solution containing ammonia-CO_2 salts. These reactions occur at relatively low temperatures and pressures within the absorption vessels. The solution of ammonia-CO_2 salts is then pumped to a regeneration vessel. In the regeneration vessel, the solution is heated under pressure with steam from the power plant, and the reactions are reversed, resulting in a high-purity stream of CO_2. The regenerated reagent is then recycled back to the absorption vessel to repeat the process. The CO_2 stream is scrubbed to remove excess ammonia, then compressed, and transported via pipeline to injection wells for geologic storage.

Project Approach to Integration

This report discusses the integration of Alstom's chilled ammonia process (CAP) with the existing Mountaineer generating unit and balance of plant (BOP) systems. Prior to presenting how the systems were ultimately integrated for the Phase I conceptual design, it is important to understand AEP's approach to integration and the philosophy on which technical and design basis decisions were made.

From the explanation above, it is understood that the chilled ammonia process (CAP) for CO_2 capture, like other post-combustion CO_2 capture technologies, is a complex chemical process with parasitic energy demands. As such, the power plant, operating with CO_2 capture capabilities, resembles a chemical plant with process equipment like regenerating columns, packed absorber columns, and stripping equipment. Much of this equipment, while not dramatically different in scale or appearance from equipment found in a modern conventional coal-fired power plant, is still unique and often must be approached differently with respect to design, engineering, operation, and maintenance.

AEP began the MT CCS II commercial scale application of the chilled ammonia technology with the philosophy that is typical for retrofit of major equipment across the AEP fleet. That philosophy is built upon over a century of power plant design and operating experience that has been incorporated and documented in engineering specifications, design criteria, and operating procedures which form a standardized technical basis for the engineering, design, installation and operation of any new equipment or system. However, AEP had less knowledge and experience with respect to the chemical process equipment that comprises the CAP. Much of the knowledge that went into the design basis for the MT CCS II project was obtained through operation of the PVF, interface with Alstom process engineers and operators, supplier interaction, and a core team of AEP process and operations engineers dedicated to understanding how this first-of-a-kind technology can be integrated into a power plant, and fostering its advancement.

The outcome of AEP's experience with the PVF and efforts to better understand the CAP's application in a power plant setting resulted in two key findings:

1. Power plants and chemical plants have different operating philosophies.

2. Integration philosophy drives process efficiency, but also process complexity.

Operational Philosophy

Chemical plants are generally designed to produce a product to meet certain specifications, and the raw materials or feedstock required to produce the products in a chemical plant are generally supplied to the process in a uniform fashion with minimal variability. Process upsets can and do occur, but generally the processes and products within a chemical plant are held within specified tolerances, and consistent production schedules. Variables are minimized to reduce the impact to processes and products.

Mountaineer Plant first and foremost is a power generating station. It is designed and operated to generate reliable electricity to meet consumer demand. The demand for electricity is not constant, but often cyclical based on seasonal weather, time of day, or other factors. To meet this changing demand, generating units like Mountaineer must adjust their operating load. Load adjustments can be infrequent with the unit "base loaded" at a constant load for days or weeks; or frequent with the unit increasing and/or shedding hundreds of megawatts of its load in as little as an hour.

While Mountaineer's primary product (electricity) is consistent with respect to quality, its feedstock (the coal fuel), and the feed rate of that feedstock can vary dramatically. Coal characteristics vary with respect to region of origin, chemical composition, heating value, moisture content, etc. Furthermore, variable fuel characteristics, coupled with variable operating loads, produce varying flue gas characteristics (temperature, moisture content, CO_2 content, chemical composition, etc.). The flue gas leaving the plant ultimately becomes the feedstock for post combustion CO_2 capture systems.

The challenge then becomes operating a complex system of chemical processing equipment, typically designed with a chemical plant operations philosophy of high consistency and low variability, with a continuously variable feedstock of flue gas, to produce a highly consistent, high purity (> 99.5%) CO_2 product.

Lessons learned through the operation of the PVF continuously pointed to this difference in operating philosophy. Operation of the PVF proved that often minor variability could lead to upset conditions. From years of operating Power Plants, the technology and design has incorporated "levers" throughout the various systems such that if variability in one system arises, a "lever" is available that allows operations to adjust the process, and alleviate the problem before it becomes a significant issue and threatens unit operability or availability. Alstom and AEP, equipped with such lessons-learned from the PVF, approached the design and integration of the commercial scale project with the intent of insuring that sufficient margin or "levers" existed in the system's design to handle many of the variables that might be encountered. To achieve the necessary margin in the design, AEP worked closely with Alstom to incorporate as much process variability as practical into the design. This was accomplished by effective communication to develop:

- Detailed flue gas specifications with expected ranges for significant characteristics like temperature, moisture content, CO_2 content, SO_2 content, etc. which can vary based on fuel or unit operating parameters.

- Expected quality and temperature range of makeup water (which can vary significantly season to season) to properly identify equipment sizing, treatment needs, and heat exchanger capacities.

- Expected quality and quantity of available steam (which can change significantly in the heat cycle based on unit load changes and ambient conditions) to accurately identify the steam source, maximize efficiency, and minimize complexity of operations.

- A suite of material and energy balances depicting not only the main generating unit's variability with respect to changes in load and ambient conditions, but also the CAP's modeled process variability with respect to these conditions, which impacts equipment sizing, and the sizing of auxiliary support systems.

The effort outlined above was the result of approximately four (4) months of collaborative effort between Alstom and AEP process engineers to take what was learned from the PVF, apply it to the ongoing engineering and design efforts of Alstom's dedicated process engineering team, and produce a CAP design that both AEP and Alstom agreed could be successfully implemented and operated at a power plant on a commercial scale.

Integration Philosophy

AEP approached integration of the CAP at Mountaineer from a conservative perspective. As mentioned previously, AEP has a long history of power plant design, engineering, operation and innovation. Over the years AEP has consistently pushed the industry limits to achieve higher efficiency, lower emissions, and enhanced performance and reliability across its fleet of generating units. These efforts have earned AEP a sense of what can practically be accomplished within the boundaries of the power plant with respect to safety, efficiency, performance, complexity, operations flexibility and return on investment.

The chilled ammonia process for post-combustion CO_2 capture is a complex array of systems and components working together to capture and generate a high-purity stream of CO_2. It demands energy (in the form of heat and electricity) to accomplish this task. As a result there are several areas in the system and around the power plant that deserve to be explored to potentially recover that energy and reduce the CAP's overall demand. Areas considered for integration of heat and/or energy during Phase I of the MT CCSII project were:

- Flue gas heat recovery to reduce the flue gas temperature entering the CAP

- Heat of compression recovery from the CO_2 compression process prior to injection.

- Steam extraction from the Mountaineer steam turbine and condensate return from the CAP to Mountaineer's feed water heating system for heat recovery.

- Rich/Lean heat exchanger network design by Alstom to maximize the CAP efficiency (not discussed in detail due to Alstom intellectual property concerns).

Flue gas heat recovery was omitted very early from consideration due to space constraints at the site. The suggested interface location was very congested due to the Flue Gas Desulfurization (FGD) system equipment and the duct configuration around the induced draft (ID) fans. Thus, trying to incorporate the necessary equipment for heat recovery would have been extremely challenging. Furthermore, the operational risks associated with heat recovery for a slipstream demonstration application, and the potential negative impacts to existing critical equipment (e.g. ID fans, FGD process equipment), which could result from temperature or pressure fluctuations related to the operation of a large heat exchanger in the ductwork, were deemed infeasible for consideration during Phase I.

From the list above, AEP focused on heat of compression integration and steam/condensate heat integration. However, both scenarios produced what AEP determined to be low value sensible heat, offering little if any significant energy benefit to the Mountaineer plant or CAP. AEP engineers considered the heat recovery options, and screened each option qualitatively and then quantitatively if the option appeared promising from a qualitative perspective. For example, the option for flue gas heat recovery to reduce CAP inlet temperature was immediately dismissed because of space constraints and the operational risks imposed to the main unit. Additional screening criteria employed by the team were:

- Qualitative complexity related to location of the equipment, required piping runs, control parameters, and additional equipment/components required to achieve proposed energy recovery.
- Qualitative assessment of impact of heat recovery to other systems/equipment.
- Quantitative assessment of maximum energy recovery potential (Btu or kJ), availability of energy with respect to time (e.g. is the benefit only seasonal, etc.) and average $/Btu based on Mountaineer-specific economic evaluation factors.
- Quantitative assessment of additional capital cost to achieve proposed energy recovery versus operating cost benefit of recovering the energy, and the payback period.

It must also be understood that in addition to the screening criteria above, AEP's integration assessments involved the recurring element of risk associated with the incorporation of a first-of-a-kind technology in a slip-stream application. The team was reluctant to integrate systems to improve efficiency without a firm grasp of how the system was going to ultimately function. As with any technology, the level of integration will significantly improve as functionality and operations are better understood. This is evident in the power generation industry, as unit efficiencies have improved significantly over the years, while the premise of the technology remains essentially unchanged. CCS technology will experience similar improvements in its innovation over time. For the MT CCS II project, AEP chose not to prematurely add to the complexity of scaling, demonstrating and assessing the technology by attempting to over-integrate.

3. SYSTEMS INTEGRATION DISCUSSION

3.1 CAP Steam Supply and Steam Condensate Return

The AEP Mountaineer Power Plant was put into service in 1980 and consists of a B&W boiler and an Alstom turbine set. The turbines are arranged in a “cross compound” arrangement due to the large size. The arrangement consists of two turbine shafts, one consisting of the High Pressure (HP) turbine and two Low Pressure (LP) turbines connected to one Generator, the other shaft consisting of the Intermediate Pressure (IP) turbine and the remaining two LP turbines connected to a second generator.

In order to efficiently supply the CAP with the required steam to be utilized as heating media, the water steam cycle of the AEP Mountaineer facility was investigated and modeled. The extraction of steam can be done in several locations; however the extraction philosophy and selection will have significant impact on the final energy penalty of the capture plant addition. To illustrate this difference, a comparison was made for extraction from various locations in the steam cycle. The analysis included extraction from the cold reheat (CRH), compared to extraction from the intermediate pressure (IP) turbine, as well as from the cross-over between IP turbine and the low pressure (LP) turbine. The results clearly indicate the advantage of choosing an extraction point with a pressure that is as close as possible to the required operating pressure. As an example, Figure 1 shows the hypothetical effect based on a thermal load of 120 MW (not a project-specific value, but rather chosen just to show the effects).

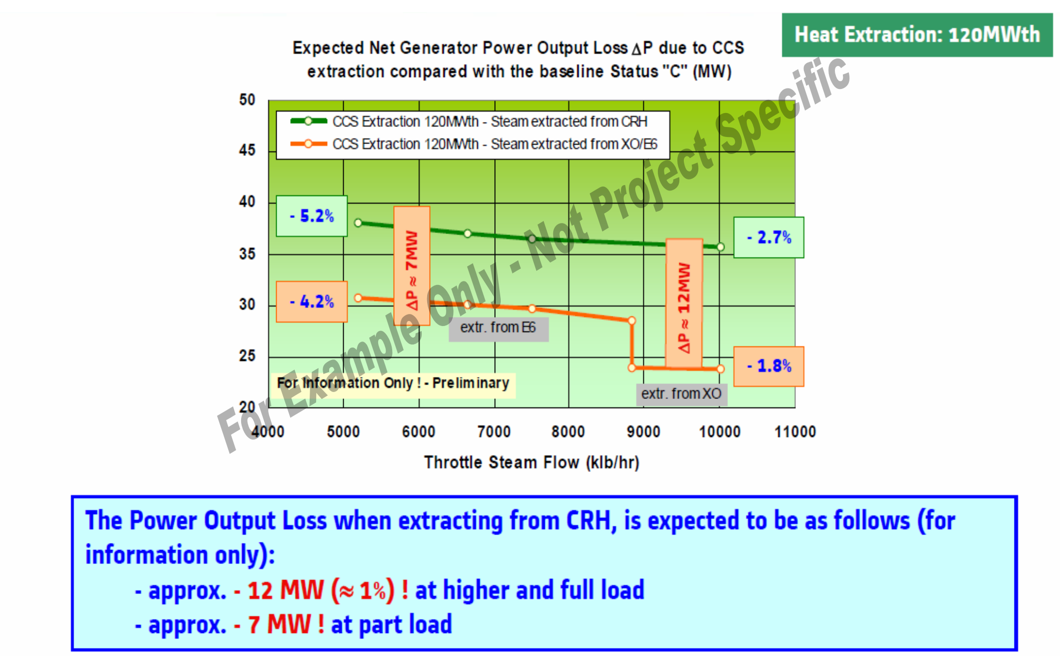

Figure 1: Steam Extraction Location and Energy Penalty

Because this application is treating a slipstream of the flue gas, the capture plant is expected to operate at, or close to 100% of its capacity over the entire range of power plant loads from 55-100%. Due to the variance in available pressure at each extraction point during normal unit operation in this range, a single extraction point could likely not provide the required steam conditions to the CAP. The first approach investigated transferring to another steam extraction point at a certain unit load when the pressure in the IP/LP cross-over falls below the required value.

The advantage of this multiple extraction method is that it can be designed without any additional throttling devices in the steam line, and hence exhibits excellent performance at the design point. Disadvantages are the capital expense of multiple extraction ties, potential for turbine modifications to better match steam conditions, and the controls required to provide smooth transitions during load swings or other unstable events. As an alternative, the team considered the installation of throttling valves in the IP/LP cross-over line to eliminate the need to change extraction points with load changes. Correctly sized, these valves can provide minimal pressure drop at the design point when they are fully open and gradually close at part load in order to keep the extraction pressure constant.

Based on the desire to minimize extraction ties, eliminate significant turbine modifications, and keep the operation of the steam supply as simple as practical, it was decided to continue evaluation using throttling valves in the cross-over line between the IP and the LP turbines. Another factor that contributed to this decision is the fact that the AEP cross compound fleet of turbines are managed on a fleet basis, and any significant change to the Mountaineer turbines would make Mountaineer no longer interchangeable with the other turbines on the fleet.

In the end it was decided, based on steam cycle evaluation and process optimization, to extract steam at two different pressure levels (see Figure 2): higher pressure steam for regeneration from the IP/LP crossover utilizing throttling valves, and also a lower pressure to supply steam for process stripping. Both extraction points are able to supply the required steam for the expected range of main unit operating loads 55% - 100% without moving to an alternate extraction location (with minimal impact on energy consumption). Condensate leaving the CAP boundary is returned to the Mountaineer feed water heating system to reclaim the condensate as well as offset a portion of the overall energy demand. To minimize contamination concerns, a condensate storage “buffer” tank is included in the design, which is continuously monitored for contamination.

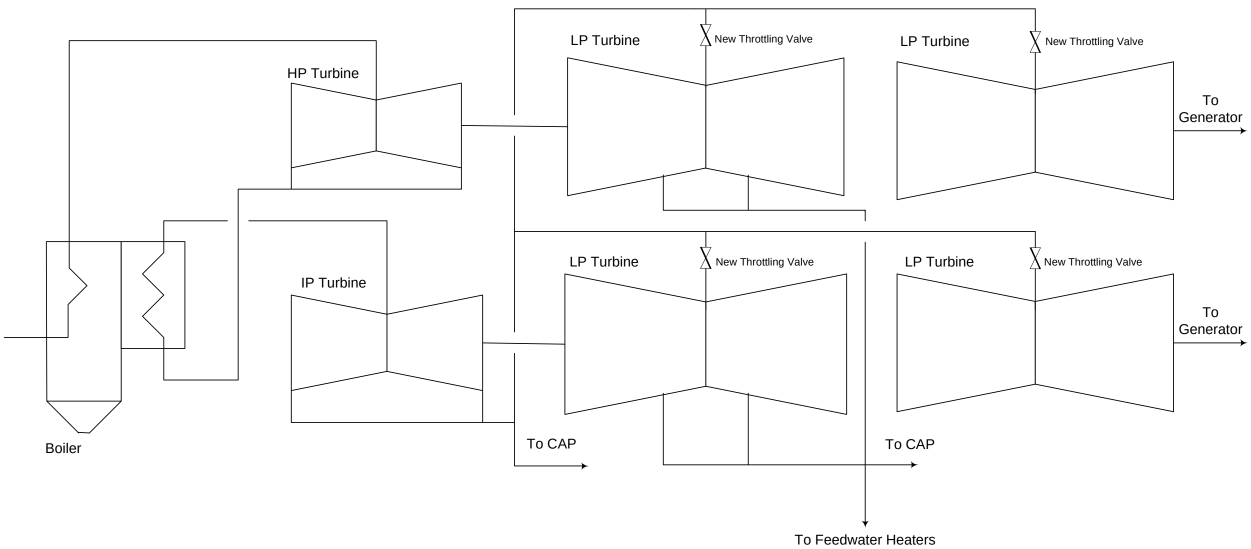

Figure 2: Simplified Schematic of Mountaineer Turbine Arrangement with CAP Integration

Challenges/Opportunities to Overcome Inefficiency

Any retrofit installation requires a balance to be struck between practicality, performance, and cost effectiveness. For the MT CCS II project, the team spent considerable effort evaluating various methods of steam supply and condensate return and, as mentioned above in the explanation of process extraction alternatives, sometimes opted for operations simplicity/practicality over maximizing efficiency. Furthermore, the team investigated and identified areas where capital improvements could be made to existing equipment to reduce overall energy demand of the CAP. The most prominent example of this involved the existing boiler feed pump turbine control valves at Mountaineer.

The boiler feed pump turbine (BFPT) at Mountaineer plant is equipped with inlet control valves that have an unusually high pressure drop. This is problematic during summer conditions when the plant is operated at maximum load; the valves are wide open allowing for little to no control of the feed water flow. This limits the operation of the unit, as it limits the flow of feed water to the boiler, hence also limiting steam flow. In order to increase unit load under these conditions, steam to the BFPT can be taken from the cold reheat line instead of from the IP/LP cross-over pipe, which negatively impacts unit efficiency.

The situation will worsen when combined with the steam extraction needs of the Mountaineer CO_2 capture plant. Heat balance analyses at peak summer conditions (cooling water inlet temperature 103°F) were performed, and demonstrated that without an upgrade of the BFPT valves, the throttle valves in the cross-over pipe will have to be further throttled to compensate for the pressure drop over the BFPT control valves. As Figure 3 shows, an upgrade of the BFPT valves could result in a considerable improvement of performance and efficiency during summer operation. AEP has been unable to justify an upgrade to these valves in the past, as the savings during peak summer conditions (when the upgrade is most effective) could not offset the capital expenditure. AEP would likely carry out additional economic evaluations in Phase II to determine if the reduced energy demand of the CAP as a result of new BFPT valves would justify the upgrade.

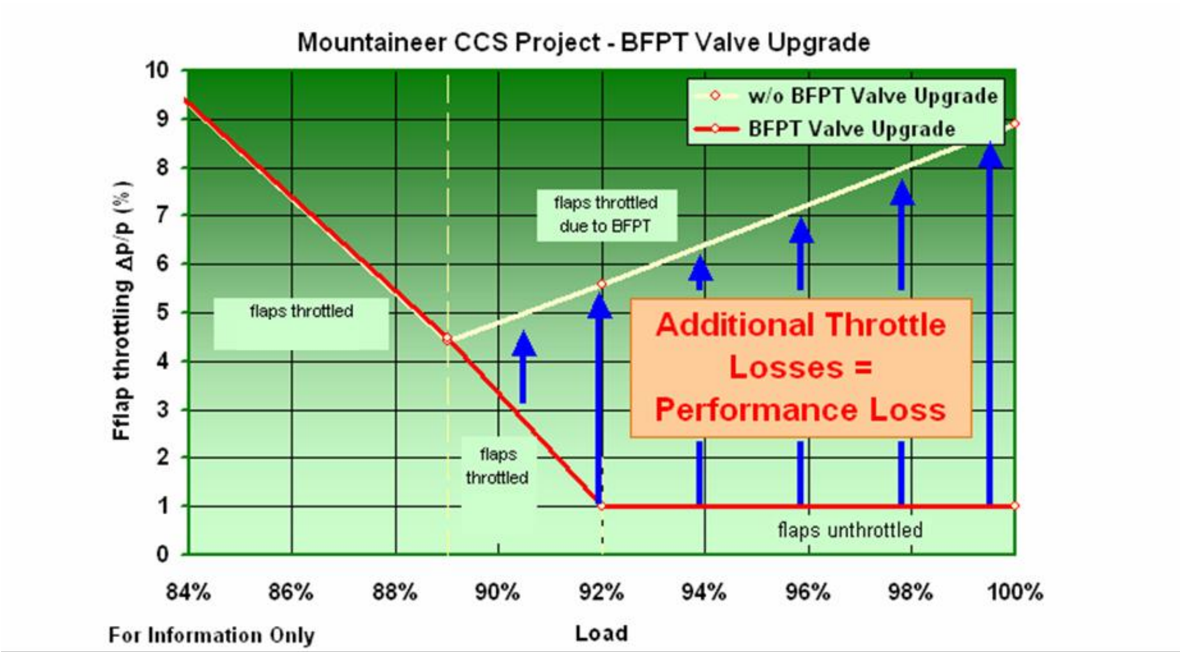

Figure 3, Throttling of Crossover Valves with and without BFPT valve upgrade

3.2 Flue Gas Exhaust

The team evaluated options for exhausting treated flue gas from the CAP. The three options considered were:

- Option 1 – CAP exhaust to existing Mountaineer stack
- Option 2 – CAP exhaust to newly constructed stack close-coupled to the process island
- Option 3 – CAP exhaust to existing Mountaineer hyperbolic cooling tower

AEP recommended early in the project that Option 3, the hyperbolic cooling tower flue gas discharge option, be eliminated from consideration based upon technical and environmental risk factors associated with discharging flue gas in a cooling tower. While common in Europe, cooling tower discharge is relatively new to the United States and would have required significant analysis of environmental impacts, including re-modeling of the emissions source (cooling tower) and plume effects based on the addition of flue gas. Furthermore, this option would have required considerable technical evaluation of the existing tower by the manufacturer to determine the structural integrity, impacts to materials of construction, and potential performance issues. Finally the decision to locate the CAP equipment to the north of the main unit where space was most adequate made flue gas duct routing to the hyperbolic cooling tower extremely difficult. For these reasons, this option was not evaluated in detail, and dismissed early in Phase I.

The evaluation was based on the economics of total installed costs between the option to return flue gas to the exist stack (Option 1) and the option to install a new stack (Option 2). Refer to Table 1 for a summary of the cost comparison.

ITEM DESCRIPTION	Option 1	Option 2
Flue Gas Ductwork Support Steel	Base	-41%
Flue Gas Ductwork Foundation	Base	-21%
Continuous Emission Monitoring System (CEMS)	Base	+121%
Modifications to FGD exhaust transition duct	Same	Same
Modifications to existing stack	Base (compare to New Stack)	Not Required
New Stack w/ FRP Liner & Foundation	Not Required	+850% (compare to Modifications)
FRP Ductwork (Supply Duct – 17' Diameter)	Same	Same
FRP Ductwork (Return Duct - 15' Diameter)	Base	-95%
Expansion Joint (Supply Duct)	Same	Same
Expansion Joint (Return Duct)	Base	-83%
Insulation and Lagging (Return Duct)	+$1M	N/A
Vents and Drains system for Supply Duct	Same	Same
Vents and Drains system for Return Duct	Base	-94%
TOTAL	**Base**	**-0.6%**
NOTES:	2,3,4	1,2,3,4

1. New stack capital cost was based on vendor quote.
2. For Option 1, supply duct is 1524 linear feet and return duct is 1825 linear feet. For Option 2, the supply duct is 1524 linear feet, and return duct is 100 linear feet.
3. Costs for drain system is based on FRP piping, pumps and tanks, with heat tracing, and insulation.
4. Mercury monitor was included in CEMS allowance.

TABLE 1: Cost Comparison of CAP Flue Gas Exhaust Options

The major differences between options are as follows:

Option 1 requires approximately twice the duct length as compared to Option 2. For Option 1, the CAP exhaust ductwork returns the flue-gas to the existing stack, whereas in Option 2, the exhaust is sent to a new dedicated stack in close proximity to the CAP facility. The estimated installed cost of the two options was nearly equal; Option 2 having a slight cost advantage of approximately 0.6%, which is likely negligible with respect to the accuracy of the estimate.

Option 2 also offers an operating cost benefit over Option 1 due to lower auxiliary power consumption of the existing ID Fans and the new CAP Booster Fan as a result of eliminating the return duct to the existing stack. Option 2 would operate at a lower static pressure to exhaust the flue gas out of a new, closely-coupled stack.

Based on the economic results of this evaluation, the project team recommended Option 2, where the CAP exhaust is sent to a new dedicated stack. However, uncertainties associated with modeling and permitting a new stack restricted AEP from considering this option for the Phase I conceptual design, and it was determined that selecting Option 1 was the more conservative approach. As more information becomes available with respect to CAP exhaust gas constituents and characteristics, Option 2 could be revisited in Phase II (detailed engineering and design) and ultimately implemented.

Challenges and Opportunities

With the Option 1 configuration, there was a concern with introducing cooler CAP gas back into the saturated wet FGD exhaust gas stream. This was analyzed during Phase I and determined that the change in mass flow through the stack for this option is negligible. The flue gas temperature decrease in the existing stack due to the cooler CAP flue gas re-entry also has minimal, if any, effect on the flue gas buoyancy in the existing stack. The volumetric flow through the existing stack for Option 1 is based on the mixture of 84% higher temperature untreated flue gas and 16% lower temperature treated flue gas. The decrease in stack velocity is considered to be negligible. The existing stack drainage system is adequately sized to handle the additional moisture that will condense in the stack due to flue gas cooling. Estimated stack condensation was calculated using ASPEN process modeling software to determine the effect of mixing the two saturated gas streams at different temperatures, and is based on a flue gas moisture content of approximately 10% to 15% by volume.

The proposed supply and return ducts are round fiberglass reinforced plastic (FRP) based on its cost effectiveness and resistivity to corrosion. No insulation is included for the supply duct since heat loss is not a concern. Unlike Option 1, the exhaust duct for Option 2 will not be insulated, as the run of ductwork to the new stack is no more than 100 feet. It should be noted that, based on feedback from FRP vendors, shop fabrication may be possible for the 15’ diameter FRP which would yield substantial cost savings.

For Option 2, the new stack height considered in the Phase I evaluation was 593.5’ based on “Good Engineering Practice" (GEP) stack height. The basic stack components include a concrete shell and a 15’ diameter FRP flue liner. During Phase II of this project, a dispersion model should be performed to determine the necessary stack height, which may be lower than the estimated GEP height, potentially reducing the cost of Option 2.

In addition, a more-detailed computational fluid dynamics (CFD) analysis is recommended to determine any modifications required to existing duct work and/or flow distribution devices in the existing stack. A flow model analysis is also recommended to optimize the drain collection system within the ductwork and stack for any potential impacts related to the design. A transient analysis is also recommended during Phase II to minimize the duct design pressures and potentially reduce costs for either option.

3.3 Process Makeup Water

The Makeup Water System for Mountaineer CCS II Project is designed to receive raw water from the Ohio River using the plant's existing river water makeup system and to treat the water for use by various consumers, including evaporative condensers, pump seal water, washdown hose stations, process water makeup, and DCC makeup. The primary demand for makeup water is makeup to the CAP refrigeration system evaporative condensers.

Three (3) pumps rated at 20,000 gpm each furnish river water makeup from the Ohio River. River water makeup pump capacity is considered to be more than adequate to supply the additional makeup required for the CAP process.

The entire makeup water stream for the capture plant is treated by chlorination for biological control and by chemical precipitation and clarification, primarily for removal of total suspended solids (TSS) that might interfere with operation of the evaporative condensers and other equipment requiring makeup water. Treatment will reduce the concentration of iron and other heavy metals that might be present in the water.

The makeup water treatment plant required for the capture plant at Mountaineer will consist of the following principal components:

- Rapid mix tank
- Reactor tank
- Clarifier/thickener
- Sludge recirculation pumps
- Sludge blowdown pumps
- Chemical storage tanks
- Chemical feed pumps

The portion of the makeup water used for DCC makeup requires additional treatment to produce relatively high purity water. The existing plant condensate system could not support the maximum demand of the

CAP. Therefore, makeup to the DCC will receive treatment by additional multimedia filtration and a new two-pass reverse osmosis system.

The multimedia filtration and reverse osmosis system will consist of the following principal components:

- Multimedia filters, including filter feed pumps, filter vessels and media, filter backwash pumps, and filter air scour blowers
- Reverse osmosis system, including two-pass reverse osmosis system, cartridge filters, and RO booster pumps
- Chemical feed systems, including antiscalant, sodium bisulfite, and caustic soda
- RO cleaning system, including solution tank, cleaning pump, and cartridge filter
- RO permeate tank and forwarding pumps

The nominal makeup water requirement is summarized in Table 2, and typical Ohio River water quality is provided in Table 3.

Table 2: Mountaineer CAP Makeup Water Usage

	Flow Rate (% of CAP Total Makeup)
Evaporative condenser evaporation	51%
Evaporative condenser blowdown	26%
Pump seal cooling water (25 pumps, 4 gpm each, avg.)	4%
Washdown hose stations	4%
Process water makeup (clarified water)	3%
DCC makeup (RO product)	7%
Filter backwash and RO concentrate	3%
Makeup water clarifier sludge blowdown	2%
Total makeup requirement	100%

Table 3: Typical Ohio River Water Quality

Parameter	Nominal	Range
Iron, Fe (mg/l)	3.29	-
Copper, Cu (µg/l)	5.39	-
Sulfate, SO_4 (mg/l)	131	56 - 169
Total Hardness, as $CaCO_3$ (mg/l)	197	95 - 210
Chloride, Cl (mg/l)	60	14 - 60
Total Dissolved Solids (mg/l)	-	300 - 500
Conductivity @ 25 ºC (µmho)	600	300 - >1000
Total Suspended Solids	30	<100
pH @ 25 ºC	7.7	6.4 – 9.1
Alkalinity, Total (mg/l as $CaCO_3$)	-	80 max.
Calcium, Ca (mg/l)	-	7 - 50
Magnesium, Mg (mg/l)	10	7 - 17
Sodium, Na (mg/l)	-	11 - 35
Potassium, K (mg/l)	-	2 - 4
Manganese, Mn (mg/l)	-	<0.5
Total Organic Carbon (mg/l)	-	2 - 17
Total Kjehldahl Nitrogen (mg/l)	-	0.3 – 1.41
Total Phosphorus, P (mg/l)	-	0.03 – 0.24
Silica (mg/l)	-	0.7 – 6.3
Temperature, ºF	60	33 - 90
Pressure, psig	-	20 - 50

The Ohio River water used for makeup is relatively high in concentrations of total dissolved solids (TDS), conductivity, sulfate, and total hardness.

3.4 Process Wastewater

The CAP is designed to minimize wastewater production, as liquid streams generated by the process are either usable (as in the case of the ammonium sulfate by-product to be discussed later), or returned, to the extent practical, back to the process. The most significant non-usable liquid streams generated from the cooling of the flue gas and capture of CO_2 are 1) condensed moisture from the flue gas entering the CAP and 2) evaporative condenser blowdown from the CAP refrigeration system. The decision not to reuse these streams in the CAP was due mainly to their quantity and not so much their quality. Future integration opportunities for these streams could possibly be explored. However, for the Phase I conceptual design, the expected constituents of these streams did not justify beneficial use in the process, nor did they call for additional waste treatment, so it was determined to send them to the existing wastewater pond at the site.

Moisture condensing out of the flue gas as it enters the CAP via the supply duct will be collected and sent back to the main stack drain system which flows to the plant's wastewater ponds and eventually to outfall. The supply duct will have a dedicated drain system, which will be separate from the drain tanks of the return ductwork. The flue gas condensate collected in the flue gas return duct will be sent to a local drain tank. As the liquid in the drain tanks reaches the high level, the condensate will be pumped back to the CAP island to be re-used in the process.

The separate drain systems were a site-specific requirement and were provided as a precaution in the event that a CAP upset increased the ammonia concentration in the return flue gas condensate, which could potentially impact the plant's ammonia discharge limits. It is expected that as CAP technology is demonstrated, a common drain system could be employed.

The design and optimization of gutters and liquid collectors in the ductwork and stack flue are dependent on the duct/stack geometry, gas velocity, and flow patterns. Therefore, a flow model study is recommended in Phase II to determine the optimum location and configuration of the gutters and liquid collectors within the ductwork and stack.

Evaporative condenser blowdown will be discharged to existing plant wastewater ponds through a new 10-inch line connecting to the existing 18-inch main unit cooling tower blowdown line. A blowdown sump and two (2) 100% capacity blowdown sump pumps will be added to pump the evaporative condenser blowdown to the interface point with the existing line. Clarifier sludge blowdown, multimedia filter backwash and RO concentrate will be discharged to the water treatment building sump, from which the wastewater will be pumped to the wastewater pond via the new 10-inch evaporative condenser blowdown sump discharge line mentioned above. Solid waste from the sump will be collected and taken to the landfill.

Sanitary wastewater will be collected from all CAP facilities that use potable water (with the exception of some emergency showers) and will be connected to the existing plant sanitary wastewater collection system, which discharges to the New Haven, West Virginia municipal system through a duplex pneumatic lift station.

3.5 CAP Byproduct Stream

Alstom's Chilled Ammonia Process (CAP) produces a byproduct stream rich in dissolved ammonium sulfate. This stream must be treated before release from the plant. Possible treatment solutions for this waste stream include ammonium sulfate recovery for commercial end-use, reaction of ammonium sulfate to a secondary byproduct that can be either sold commercially or disposed of in a landfill, and reuse of the ammonium sulfate solution within the Mountaineer boiler gas path for additional emissions controls (enhanced NOx and/or particulate removal).

The CAP byproduct stream is proposed to be a 25 weight percent (typical) aqueous solution of dissolved ammonium sulfate. In order to accommodate a large range of composition for the CAP bleed, the CAP byproduct treatment options were designed to accommodate a stream as low as 15 weight percent (wt%) total dissolved solids (TDS). Based on the need for operational flexibility, a total of four (4) 50,000 gallon tanks were provided to handle dilute CAP by-product that may be less than 15 wt%. As such, for any upset or maintenance periods when TDS is below 15 wt%, the treatment option would accommodate design flow while the residual would be routed to the storage tanks. When operation of the CAP returned to normal operation and the CAP byproduct stream was greater than 15 weight percent TDS, the low and low-low purity storage tanks would be drawn down, mixed with higher purity byproduct and processed through the treatment option to the extent possible. As CAP technology matures, it is expected that the additional ammonium sulfate tank capacity for dilute by-product handling may not be required.

At the request of AEP, options for re-injection into the Mountaineer boiler gas path were eliminated from consideration. With a variable byproduct concentration, unknown impacts to existing equipment, and other uncertainties, this option presented too high a risk to integrate. As the CAP is operated and the byproduct stream characteristics and flow rate are better understood, the team might consider integrating this stream back into the plant for additional means of emissions control.

The following options were evaluated for treatment and handling of the byproduct stream:

- Concentration of the stream to a crystallized ammonium sulfate for resale as a fertilizer product (Base Case Option).
- Concentration to a 40 wt% ammonium sulfate solution for resale as a fertilizer product (Option 1).
- Alternate process referred to as "Lime Boil" to react ammonium sulfate with lime to recover ammonia and produce gypsum that could be combined with Mountaineer's gypsum waste product from the FGD (Option 2).

The project team contacted OEMs to assist in the development of heat and material balances, PFDs and P&IDs, equipment lists, and utility consumption values. These items were used, in turn, to develop capital and operating cost estimates (CAPEX and OPEX) for each option so that they could be assessed from an economic perspective. AEP contacted potential end-users of the fertilizer products to insure that the product would meet agricultural specifications and could in fact be considered for beneficial use. Potential end-users in the region indicated that either a crystallized product or a 40 wt% liquid product would be desirable. Estimated constituents of the byproduct were within acceptable agricultural specifications, so AEP proceeded with a design basis that relied upon beneficial use of the byproduct stream in lieu of disposal. AEP must take steps in future project phases, however to ensure a long term purchase contract can be established and that byproduct specification estimates do not change significantly.

The estimated capital costs for the three treatment options considered are summarized below.

Table 4: Capital Cost Summary for Byproduct Handling Options

Case	Capital Cost Estimate
Base Case (Crystallized Ammonium Sulfate)	Base
Option 1 (Ammonium Sulfate Solution)	-32%
Option 2 (Lime Boil Process)	-19%

Estimates of the first year operating costs are listed in the table below.

Table 5: First Year OPEX Summary for Byproduct Handling Options

Case	First Year OPEX Estimate
Base Case (Crystallized Ammonium Sulfate)	Base
Option 1 (Ammonium Sulfate Solution)	+2.7%
Option 2 (Lime Boil Process)	+148%

The project team decided that generation of a concentrated solution of ammonium sulfate (Option 1) be implemented as the CAP byproduct stream design basis. Generation of crystallized ammonium sulfate is also a viable alternative. Both employ some of the same equipment, so choosing the 40 wt% option as the design basis and allowing space in the equipment layout offers the opportunity at some point in the future of producing both a solid product and an aqueous solution. This provides maximum flexibility to increase marketability of the end product. As such, the conceptual design of the plant included space to add crystallized byproduct processing equipment with bagging and 15-day solid product storage capability. It should be noted that there might be occasions where the ammonium sulfate can not be sold.

The lime boil process was not selected for the conceptual design due to its expected high OPEX, and increase in solid waste material to the plant’s landfill.

3.6 CO_2 Compression

Heat of compression available from the compression of the CO_2 product stream prior to injection was considered by the project team for conventional, integrally-geared compression systems. Discussion of the evaluation of conventional integrally geared CO_2 compression technologies considered for the project can be found in the CO_2 Compression Report on The Global CCS Institute's website. A general discussion of how the Team considered integration of the heat of compression, and the outcome is provided below.

Based on results from the Mountaineer PVF, injection pressures in the 1200 psi – 1500 psi (83 – 103 bar) range are expected early in the life of the target injection wells. As CO_2 is injected over time, the required injection pressure is expected to increase, and the estimated maximum injection pressure into the geological formations targeted for the project is expected to be approximately 3000 psi (207 bar).

Heat of compression available at the lower injection pressures (83 – 103 bar) was not considered practical for use at Mountaineer as it was of little value to integrate back into the CAP or back into the Mountaineer main unit. It was determined that at the 3000 psi (207 bar) injection pressure, heat of compression integration with the CAP and the Mountaineer feed water heating system was possible to offset a portion of the compressor power. However, the heat integration provided no net overall energy reduction, thus the capital cost to implement the equipment and controls necessary to recover the heat could not be justified. Furthermore, at the lower expected injection pressures, the project team determined that variable speed injection pumps could be utilized downstream of the compressor to provide better process flexibility and operating efficiency over the life of the system.

3.7 CAP Power Supply

In order to provide power to the CO_2 capture plant at Mountaineer, an analysis was performed that considered the estimated electrical loads, steady state load flow requirements, large motor starting scenarios, and resultant bus voltage and short circuit duty to size and determine equipment ratings. It was determined that two new 138kV lines to a step-down station be installed to serve CAP island and associated BOP systems. In order to provide the needed power, AEP Transmission and Distribution engineers determined necessary modifications and additions to the existing 138kV auxiliary substation at Mountaineer. A summarized breakdown of the scope of integration required to supply the necessary electrical power to the Mountaineer CCS system is as follows:

- Installation of multiple additional circuit breakers, switches, control cables and breaker foundations
- Installation of three phase metering class capacitance coupled voltage transformers (CCVTs) on 138kV bus #1 and bus #2 and single phase metering class CCVTs on each feeder. The existing CCVT structure and foundation for bus #1 CCVT will be used, with new CCVT foundations and structures required on bus#2 and all feeders.

- Expansion of the existing 138 kV substation control house by 10ft in order to fit the new panels. This involves land improvement work to restore a ditch right next to the control house.
- Expansion of the existing fence and addition of new ground grid.
- Upgrade of existing battery and charger to a larger capacity.
- Miscellaneous bus work to accommodate the two new CCS feeders.
- Installation of two steel poles inside the substation.
- Installation of fiber-optic line between 138kv mountaineer station and 765kv mountaineer station for metering data transfer.
- Installation of a fiber multiplexer and any other necessary electronics to provide as much bandwidth as needed to support the telecommunications needs of the capture plant.

3.8 CCS Controls Systems

All control and monitoring associated with process systems and equipment will generally be from the Distributed Control System (DCS) terminal located in a dedicated CCS control room located near the CAP. The CCS control room will be designed as a continuously occupied control center designed to accommodate two (2) operators and a shift supervisor. The CCS control room will include all the necessary displays for safe operation of both the capture and storage systems. Note: A controls integration description for the CO_2 storage and Well Maintenance and Monitoring System (WMMS) is provided in the Mountaineer Commercial Scale Carbon Capture and Storage Project CO_2 Storage Report, also provided to the Global CCS Institute.

Main power distribution breakers associated with the CCS plant, rotating equipment start / stop, valve positioning, and subsystem start / stop (e.g., compressor) will be initiated from the CCS control room. Sufficient instrumentation and equipment feedback status will be provided through the DCS to ensure safe and proper operation of the process. The DCS will be provided with sufficient redundant instrumentation, controls, processors, power supplies, and operator interface and data communication equipment to ensure that the critical operational or protection functions continue to operate when there is a failure of a component. The design intent was to ensure that no single point of failure above the I/O card level would limit the ability to control the CCS plant process systems.

Normal control and monitoring will be from the DCS Operator Interface Terminal (OIT). Local control will not be possible (other than E-stop functionality) until the operator has selected “local” control from the OIT. Local operator control of subsystems or individual equipment can be achieved and may be required when equipment is out of service (to perform specific maintenance operations), or it has been discussed with Plant Operations and determined that local control is necessary. Local packaged equipment provided with its own independent control microprocessor, such as an air compressor, will be capable of being placed into local control, or controlled via the DCS. Packaged control systems will be provided with a "Local / Off / Remote" selector switch. Whenever the selector switch is in the local position, an alarm will be initiated in the DCS and the packaged equipment can then be fully controlled and operated locally. With selector switch in remote position, the packaged control system will be capable of accepting high-level commands such as start / stop from the DCS; however, protection and control of the packaged equipment is supervised by the packaged control system microprocessor.

Monitoring functions for the equipment or systems will be maintained at the OIT in both the "local" and" remote" modes. The local panel will include indication that control is "local" or "remote" and monitoring functions may be available in both modes. At a minimum each OIT will have the capability to open / close breakers, start / stop motors, open / close valves, start / stop automatic sequence controllers, and position process regulating devices. Additionally the operator will be able to select automatic / manual operation of equipment, adjust set points, and perform manual signal selection, process monitoring, alarm acknowledgement, and equipment "tagout" from the OIT. The DCS OITs will be provided with multiple levels of security to control access to the above functions. OIT hardware topology will allow access to all DCS logic controllers from every OIT. Multiple OITs will be provided such that a failure of a single OIT will not result in the loss of communication with the DCS logic controllers. The total number of OITs will be based on the number of operators and process systems.

The following identifies the proposed location(s) of OITs for control and monitoring:

Table 6: Summary of CCS Operator Interface Terminal Locations

Control / Monitoring / Process	CCS Control Room	Local	Notes
BOP Systems	**X**		
CAP System	**X**		
By-product Handling Systems	**X**	**X**	
Truck Loading / Unloading		**X**	**(1)**

Notes: (1) Alarms in the CCS control room via the DCS. Monitors in the CCS control room to display local camera video.

Graphic displays will be developed to monitor and control all process systems directly controlled by the DCS. This includes specific equipment that may only use high level control functions (e.g., compressor) and monitoring through the DCS.

The DCS will monitor data returned from the CO_2 storage Well Maintenance & Monitoring System (WMMS) PLC at each well site and compare this data to the data from instrumentation monitoring pipeline leakage. CO_2 leakage will be alarmed in the CCS control room for operator action.

A dedicated monitor in the CCS control room will be used to display status of selected Mountaineer power block systems (unit load, etc.). The monitor will be connected through the plant LAN, but will not have capability of controlling any of the main power block systems. Similarly, the CCS DCS will be connected to the plant LAN to allow the CCS systems' status to be displayed in the main Mountaineer control room.

The DCS architecture will include a data historian to collect and store a history of process values, alarms, and status changes. The historian will operate on a dedicated workstation or processor and not interfere with the operation of the DCS network. The configuration will include buffered signal collection to prevent interruption of data collection during a server outage. The data collected will be time stamped to allow retrieval of information in a chronological order of events and values. The historian will include pre-configured reports, as well as, the ability to create custom reports. The historian will be accessible from any workstation on the network or a PC that has network access.

The flue gas supply to the CAP and return gas to the plant stack will be monitored by dedicated Continuous Emissions Monitoring System (CEMS) type analyzers controlled by local PLCs. The data collected by the CEMS will be communicated to the CCS control room via datalink. The collected data will also be communicated and integrated into the plant stack CEMS so that proper emissions data can be reported to satisfy regulatory requirements.

4. CONCLUSIONS

Overall the Phase I design and integration of the CAP and its associated BOP systems into the Mountaineer power generating station was a success. The project team is confident that a prudent balance was struck between the operations and integration philosophies that existed at the onset of this effort, and through cooperation and collaboration of the engineering and design teams, the design basis is one that can successfully move beyond Phase I.

As the report explains, key objectives to the engineering and design effort were to effectively strike that balance of philosophy, successfully integrate lessons-learned from the operation of the PVF at Mountaineer, incorporate margin in the CAP design to counterbalance areas of uncertainty and/or variability, and establish "levers" in the process design and how it is integrated at the plant to provide operations with a means to react, adjust, and handle upsets. Several examples of how the integration approach addressed these objectives are:

- Selection of process steam source that minimized extraction ties, eliminated significant turbine modifications, and kept the operation of the steam supply as simple as practical.
- Incorporation of a condensate return storage "buffer" tank to alleviate contamination concerns with respect to the main unit steam cycle.
- The ability to re-introduce CO_2 into the CAP return duct in the event that the product does not meet specifications for injection, or if the injection wells are out of service.

- Separate flue gas condensate (inlet/outlet) drainage and collection systems provided as a precaution in the event that a CAP upset increased the ammonia concentration in the return flue gas condensate, which could potentially impact the plant's ammonia discharge limits.
- Additional byproduct storage tanks to handle dilute byproduct and increase operational flexibility.

The project team understood that the design effort could neither predict nor prevent all of the issues that might arise as a result of scaling up this technology. However, the collaborative process was instrumental in identifying many of the technical risk factors up front, and in designing a capture and storage facility that could be practically integrated and successfully operated at Mountaineer.