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Abstract

The Final Technical documents all work performed during the award period on the Mountaineer Commercial Scale Carbon Capture & Storage project. This report presents the findings and conclusions produced as a consequence of this work.

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Executive Summary

As identified in the Cooperative Agreement DE-FE0002673, AEP's objective of the Mountaineer Commercial Scale Carbon Capture and Storage (MT CCS II) project is to design, build and operate a commercial scale carbon capture and storage (CCS) system capable of treating a nominal 235 MWe slip stream of flue gas from the outlet duct of the Flue Gas Desulfurization (FGD) system at AEP's Mountaineer Power Plant (Mountaineer Plant), a 1300 MWe coal-fired generating station in New Haven, WV. The CCS system is designed to capture 90% of the CO_2 from the incoming flue gas using the Alstom Chilled Ammonia Process (CAP) and compress, transport, inject and store 1.5 million tonnes per year of the captured CO_2 in deep saline reservoirs.

Specific Project Objectives include:

1. Achieve a minimum of 90% carbon capture efficiency during steady-state operations.
2. Demonstrate progress toward capture and storage at less than a 35% increase in cost of electricity (COE).
3. Store CO_2 at a rate of 1.5 million tonnes per year in deep saline reservoirs.
4. Demonstrate commercial technology readiness of the integrated CO_2 capture and storage system.

The MT CCS II project was planned to be executed in four phases: Phase I - Project Definition (February 2010 – September 2011), Phase II - Design & Permitting (October 2011 – December 2012), Phase III – Construction & Start-up (January 2013 – August 2015), and Phase IV – Operations (September 2015 – June 2019). *Phase I - Project Definition*, included resolution of outstanding conditions with the Department of Energy (DOE) cooperative agreement, front-end engineering and design, initiation of the NEPA process, and identification of exceptionally long lead time items. The front-end engineering and design package incorporated knowledge gained and lessons learned from the Mountaineer Product Validation Facility (PVF). The front-end engineering and design package is also expected to establish the fit, form, and function of the project including design criteria, mass & energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc. *Phase II - Design & Permitting*, would include detailed engineering and design, permitting activities, refinement of cost estimate, design review board meeting(s) and scope freeze, procurement activities, site preparation activities, and injection well construction. *Phase III – Construction & Start-up*, will include construction, start-up and commissioning, and initial performance testing of the CO_2 capture and storage systems. *Phase IV – Operations*, will correlate to DOE's Operations, Data Collection, and Reporting Phase and will include DOE required data collection and reporting associated with the initial four years of project operation and subsequent two years of post injection monitoring of the storage system.

During Phase I, AEP developed the integrated project team responsible for completing the project objectives. The project team consisted of individuals from Alstom Power, Inc., the CAP technology owner who would be responsible for the development of the CAP conceptual design, WorleyParsons Group, Inc., who provided architectural and engineering services for the balance of plant (BOP) scope, and Battelle Memorial Institute, who held responsibility for the development of the CO_2 storage scope. Additionally, AEP executed multiple agreements to formulate a Geologic Experts Team. The Geologic Experts Team (Team) served as an advisory body which considered the strategies, plans, designs, operations, problems, concerns, results and recommendations of AEP and its project team as they

relate to the injection and sequestration of carbon dioxide as part of the MT CCS II Project, and to provide guidance to AEP to promote the success of the project.
The project identified many significant findings through the course of the Phase I studies, investigations, and conceptual design. A prime example being the Lower Copper Ridge formation, identified through PVF efforts, was confirmed to be a suitable storage reservoir in the Mountaineer area through analysis of regional data as well as data obtained from the Borrow Area characterization well (BA-02). The project team was successful in completing the conceptual design of a commercial scale CCS facility, capable of capturing 90% of the CO_2 from the flue gas stream and sequestering 1.5 million tonnes of CO_2, per year in deep saline reservoirs. Additionally, during Phase I, the project developed a refined cost estimate for the engineering, design, construction, commissioning, and the initial four years of operation of this facility. The complete scope of this project, being a first of its kind, was estimated to cost $1.065 billion including risk based contingency.

As the project was drawing near the end of Phase I, AEP expressed its intention to suspend the project and terminate the Cooperative Agreement following the completion of Phase I objectives. This decision was result of the changes in the CCS arena since the beginning of the project, and in the ability to fund AEP's cost share of the commercial scale project. Although the project will not continue into Phase II immediately following the conclusion of Phase I, the project did complete the Phase I objectives and key milestones identified in the cooperative agreement. The work completed in Phase I continues to support the commercial readiness of Alstom's CAP technology at the intended scale and provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere in the U.S.

I Project Approach

More specifically to the Phase I Project Definition effort, AEP was required to complete resolution of outstanding conditions with the DOE cooperative agreement, project specific developmental activities (i.e. front-end engineering and design), development of an Environmental Impact Statement (EIS) to satisfy National Environmental Policy Act (NEPA), and identification of exceptionally long lead-time items. The front-end engineering and design (FEED) package incorporates knowledge gained and lessons learned (engineering, design, construction and operations related) from the Mountaineer Product Validation Facility (PVF). The FEED package also establishes the fit, form, and function of the project including design criteria, mass & energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc.

During Phase I (Project Definition), the DOE identified the following key milestones:

- +/- 25% Cost Estimate Complete
- Project Design Basis Complete
- Detailed Phase II Project Schedule Developed
- Provide DOE with all information it needs to complete the NEPA process.
- Select Prime Construction Contractor(s)
- Issue Preliminary PFD and Overall Mass and Energy Balance
- Complete FEED
- Submit Phase I Decision Point Application

The activities outlined in Section III, Results and Discussion, provide the summary of work completed during the Phase I, Project Definition of the MT CCS II project in order to achieve the key milestones identified for Phase I while working toward achieving the overall project objectives.

II FEED Approach

1.1 Process Overview

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, shown simplified in Figure 1 below, to treat 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, shown in Figure 6 below) 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 designed 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.

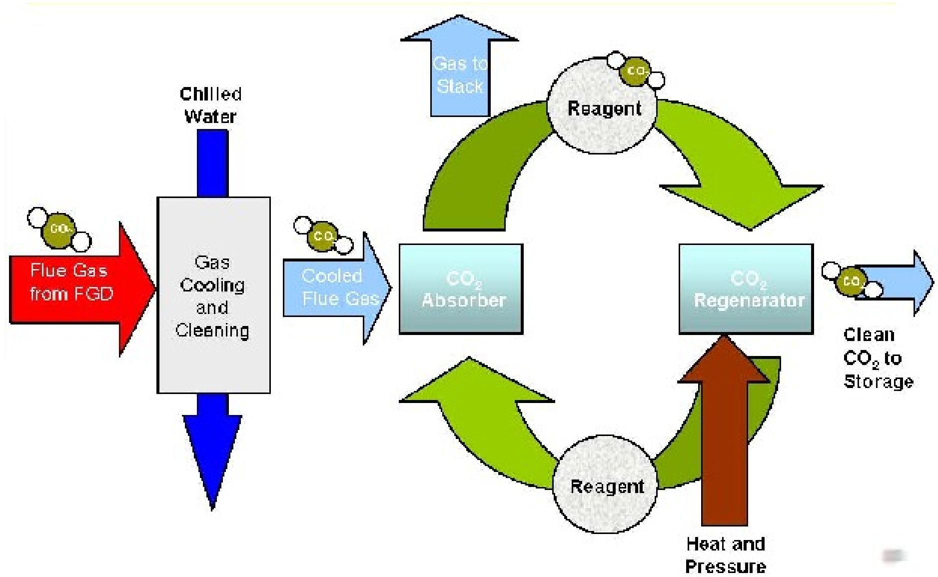

Figure 1: Simplified Chilled Ammonia Process Schematic

The CAP uses an ammonia-based reagent to remove CO_2 from the flue gas. As shown in Figure 2 below, the first step in the process is to cool the flue gas, following treatment by the plant's FGD system, 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.

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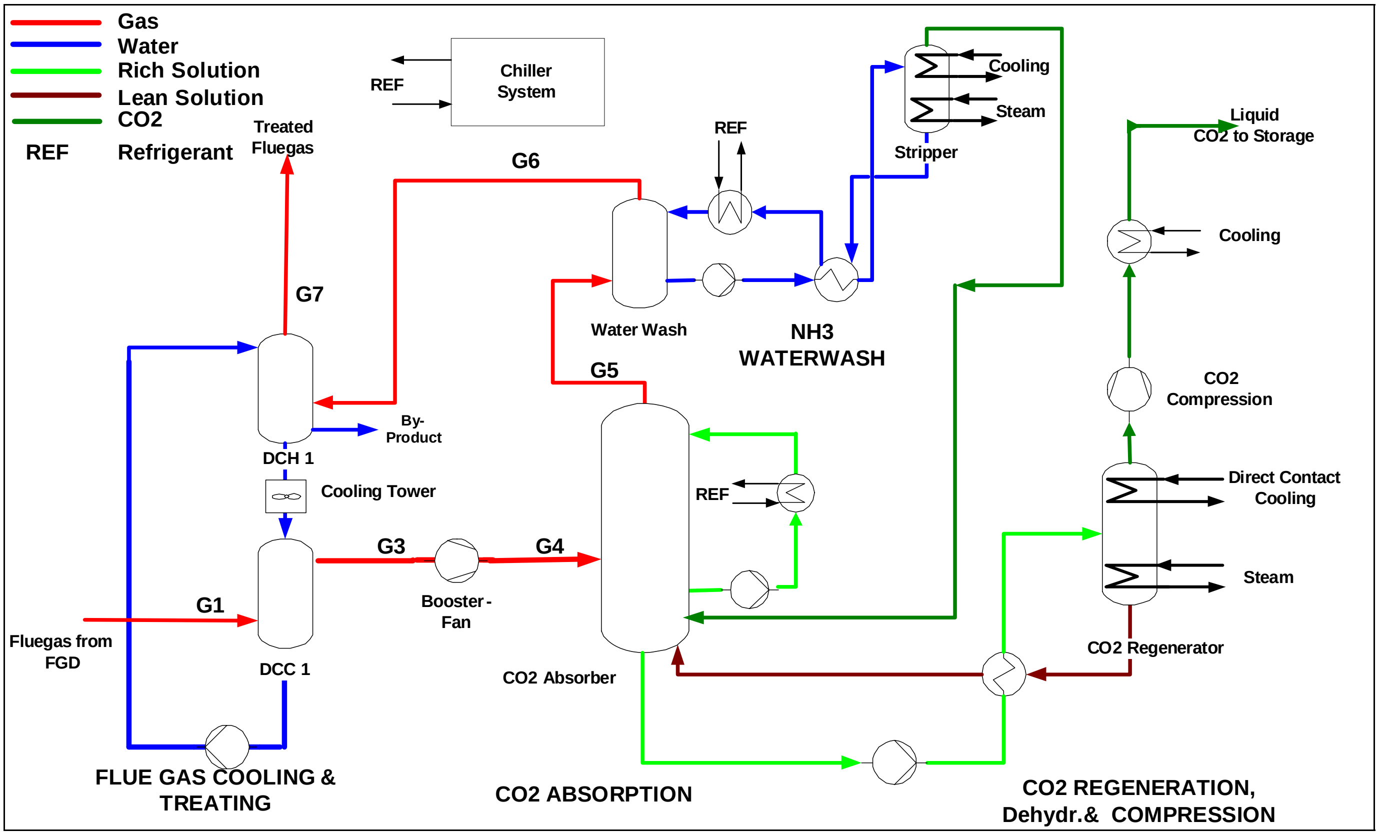


Figure 2: Chilled Ammonia Process Schematic

1.2 Technical Approach to Integration

Prior to presenting how the systems would ultimately be retrofitted and integrated into the existing Mountaineer Plant, it is important to understand AEP's approach to integration and the philosophy on which technical and design basis decisions were made.

The CAP for CO_2 capture, like other post-combustion CO_2 capture technologies, is a complex chemical process with a certain energy demand. 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:

- Power plants and chemical plants have different operating philosophies.
- Integration philosophy drives process efficiency, and process complexity.

1.3 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. Meeting this challenge requires technical innovation spurred by operating experience. Flue Gas Desulfurization (FGD) systems did not achieve 95+% SO_2 removal efficiency overnight, and similar success should not be expected of post-combustion CO_2 capture technology. Evolution in FGD technology and improvements in operating techniques since its inception have allowed the industry to achieve positive and consistent results over time. CCS technology innovation, while challenging at present, will likely evolve in similar fashion.

Lessons learned through the operation of the PVF pointed to this difference in operating philosophy. Operation of the PVF proved that often minor process variability could lead to upset conditions in the CAP. Based on years of Power Plant operational experience, AEP has successfully incorporated "levers" into the design and operation of integrated 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. A goal of the MT CCS II design was to understand where in the CAP process it was appropriate to have design margin and process flexibility that would allow rapid recovery of process upsets and operational issues.

An advantage of the MT CCS II project scale was that the CAP could operate at its maximum capacity (nominally 235 MW) for all normal operating loads of the main unit. Mountaineer normally operates between 55% and 100% of its rated capacity (1300 MW net). Within this operating range, the CAP would not be required to follow load on the main unit, as there would always be a 235 MW equivalent flue gas slipstream available for the process. Therefore, the process's ability to adjust and follow unit load was not investigated in detail for the Phase I conceptual design. Alstom provided margin the CAP design to achieve a 50% turndown to accommodate process upsets, startup and shutdown, etc., but the ability to follow load on the main unit was not a design priority. Operation of the facility in Phase 4 would provide operational data and experience needed to address this issue on future scale-up of the technology.

Alstom and AEP, equipped with lessons-learned from the PVF, approached the design and integration of the commercial scale project with the intent of ensuring 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 develop a design that would accept as much process variability as practical. 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 AEP and Alstom process engineers in Weisbaden, Germany and Knoxville, Tennessee. During this time, the team worked together to understand 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.

1.4 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 CAP 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 CAP energy demand.
- 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).

From this list, 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 energy demand 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.

Section 1.1 – Studies and Investigations discusses how various aspects of the overall project were evaluated and integrated into the existing power plant for the MT CCS II project.

III Results and Discussion

To establish the design basis of the CCS system, the engineering and design team, comprised of individuals from Alstom, AEP, Battelle, and WorleyParsons collaborated to integrate lessons-learned with respect to capture and storage from the PVF, with additional studies and investigations specific to the design and characterization of the commercial-scale system. The studies and investigations performed in Phase I served as a basis for key design decisions, and outlined the decision-making process which generally included options considered, economics, and risk evaluation.

The studies, investigations and plans described herein are in general treated as protected data as they contain such data. They are available to the DOE but are not a part of this public document. The summaries and discussions in this section have been worded as to not compromise the integrity of any intellectual property.

1.1 Studies & Investigations

1.1.1 Chilled Ammonia Process bleed stream study

Alstom's CAP produces a byproduct stream rich in dissolved ammonium sulfate. Possible 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
- Reuse of the ammonium sulfate solution within the Mountaineer flue gas path.

At the request of AEP, the re-injection options were eliminated from consideration for this study. As a team, Alstom, AEP, and WorleyParsons selected the following options for evaluation in this study: (a) Recovery of Crystallized Ammonium Sulfate for Resale (Base Case Option); (b) Recovery of 40 Weight Percent Ammonium Sulfate for Resale (Alternate Option 1); (c) 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 (Alternate Option 2).

The CAP byproduct stream is proposed to be a 25 weight percent (typical) aqueous solution of dissolved ammonium sulfate. However, the CAP byproduct stream could be as dilute as 10 percent total dissolved solids (TDS) ($(NH_4)_2SO_4$) under non-steady-state operating conditions. In order to accommodate a large range of composition for the CAP bleed, the CAP byproduct treatment options are designed for 15 weight percent TDS, with additional tanks to handle dilute CAP by-product. As such, treatment operation with the CAP byproduct stream greater than 15 weight percent TDS would proceed as designed, and for periods when TDS is below 15 weight percent, 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 steady-state operation and the CAP byproduct stream was greater than 15 weight percent TDS, the low and lower purity storage tanks would be drawn down, mixed with higher purity byproduct and processed through the treatment option to the extent possible.

OEMs were contacted to aid 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 expense (CAPEX) and operating expense (OPEX) values 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 and first year operating costs for the three treatment options considered are summarized in Table 1 below.

Case	CAPEX Estimate	1st Year OPEX Estimate
Base Case (Crystallized Ammonium Sulfate)	Base	Base
Option 1 (Ammonium Sulfate Solution)	-32%	+2.7%
Option 2 (Lime Boil Process)	-19%	+148%

Table 1: CAPEX & 1st Year OPEX Summary for Byproduct Handling Options

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.

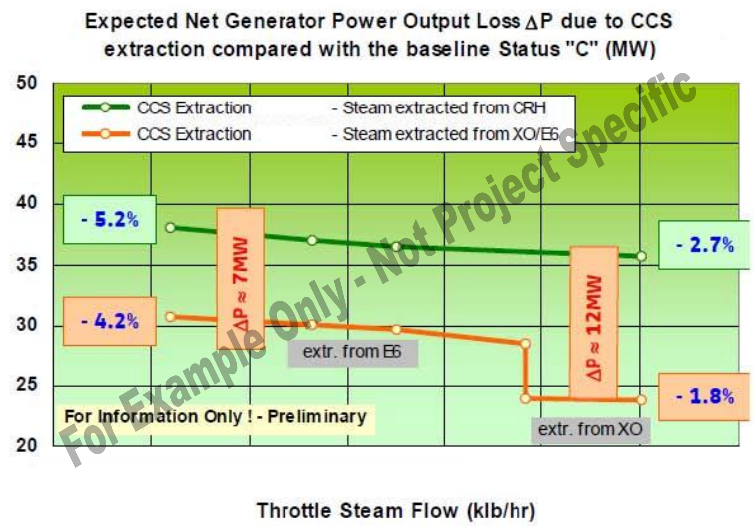
1.1.2 Heat Sourcing and Integration (Steam Supply / Condensate Return) Study

The purpose of this study was to evaluate alternative scenarios for steam extraction and condensate return from/to the power plant and to recommend the optimum extraction/return methods for use in terms of energy penalty and reliability at the Mountaineer Carbon Capture II Project at the AEP Mountaineer Power Plant Facility.

The AEP Mountaineer Power Plant 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. Figure 3 shows the effect based upon an approximate thermal load chosen to determine the impact on the steam cycle.



The Power Output Loss when extracting from CRH, is expected to be as follows (for information only):

- **approx. - 12 MW (≈ 1%) ! at higher and full load**
- **approx. - 7 MW ! at part load**

Figure 3: 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 4): 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.

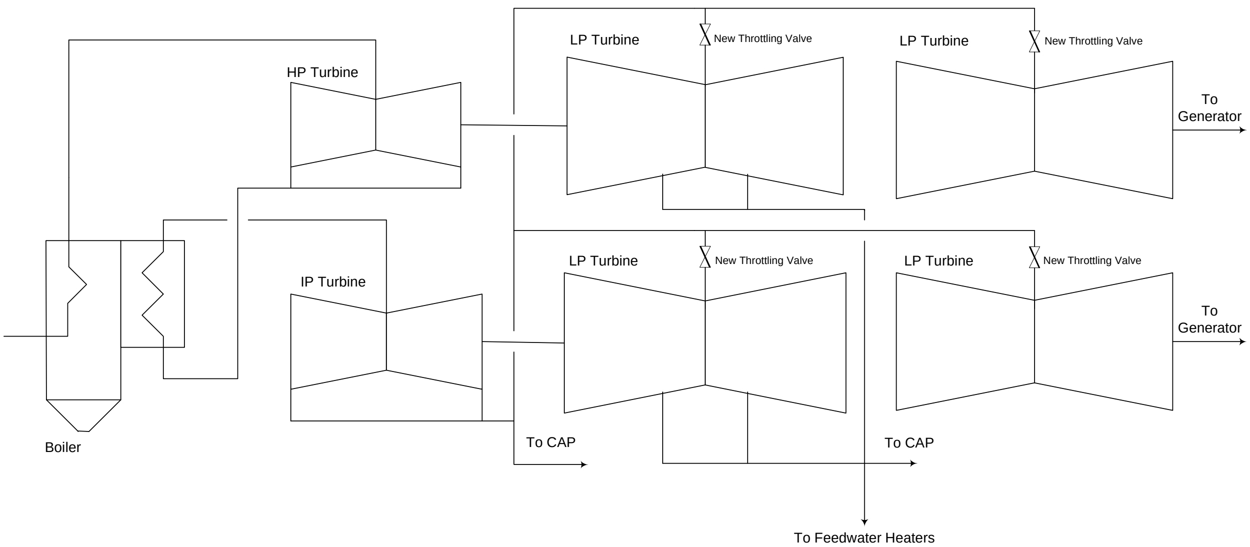


Figure 4: Simplified Schematic of Mountaineer Turbine Arrangement with CAP Integration

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 5 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 control valves would justify the upgrade.

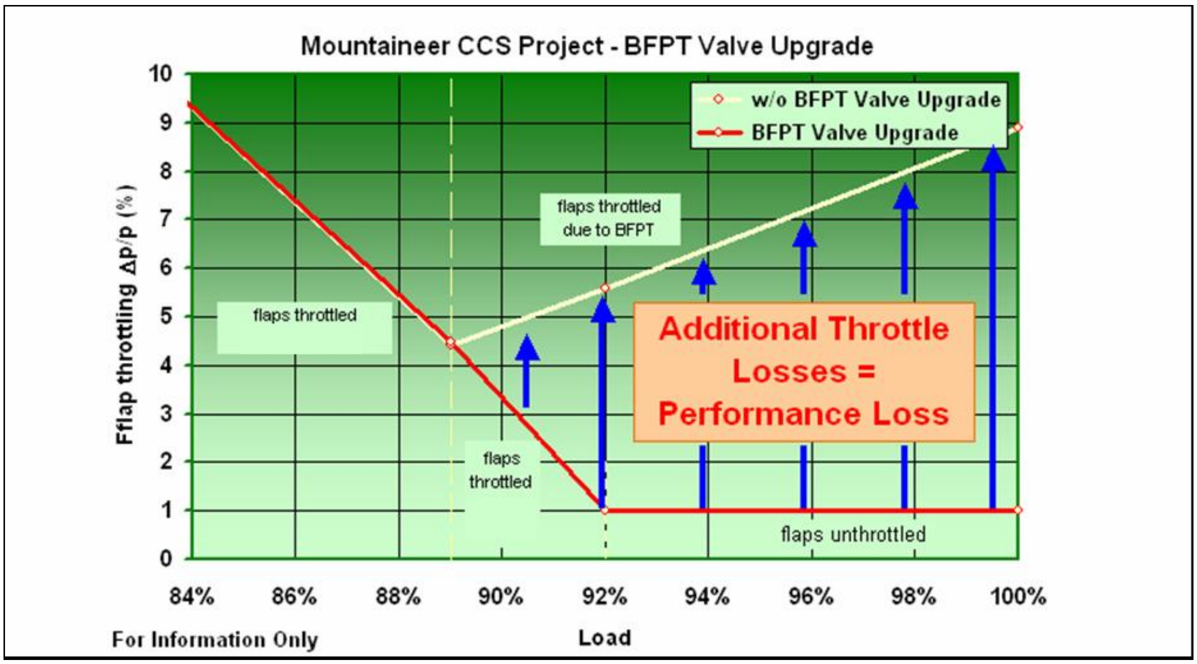


Figure 5, Throttling of Crossover Valves with and without BFPT valve upgrade

1.1.3 Compression Study

The purpose of this study is to explain the results of a technology study that evaluated options for compressing the full CO_2 product stream from the proposed nominal 235 MWe commercial scale application of Alstom's chilled ammonia process (CAP) at American Electric Power's Mountaineer generating station, in New Haven, West Virginia.

The study focused on commercially available, integrally-geared, inter-cooled, gas compression systems. The scope of the study included all of the equipment required to compress and condition the captured CO_2 for sequestration. Geologic characterization information and actual operating data from the Mountaineer Chilled Ammonia Product Validation Facility (PVF), which operated from 2009 to 2011, provided injection parameters on which to base the design for the commercial scale compression system. Equipment arrangements, auxiliary power demands, balance of plant integration, and capital and operating costs were considered in the evaluation of each compression system.

Five basic configuration options to pressurize CO_2 from a nominal 300 psia (20.7 bar) to 3,000 psig (207 bar) were identified. Two of the five options evaluated were an emerging compression technology and are not discussed in this report due to intellectual property concerns with the technology supplier. The remaining three alternatives are:

- Option 1 – Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 1,320 psig (91 bar) followed by pump and after-cooler to 3,000 psig (207 bar).
- Option 3 – Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 860 psig (59 bar) followed by cooling with cooling water and liquefaction via heat exchange with a refrigerant. Liquid CO_2 then pumped to 3,000 psig (207 bar).
- Option 4 - Integrally-geared, inter-cooled, centrifugal compressor with after-cooler to 3,000 psig (207 bar).

Process Flow Diagrams (PFD's) were developed for each option. Based on the PFD's developed, equipment suppliers and OEMs were contacted in order to procure budgetary proposals, performance data and cost estimates for the equipment defined by the configuration descriptions given above.

Heat recovery via heat exchange with the CAP and/or Mountaineer steam cycle was considered as part of the overall study as a means to reduce the overall energy demand. 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 1200 psi – 1500 psi (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.

The compression study generated the following primary conclusions:

- All options evaluated are technically feasible

- Compression to an intermediate pressure (Options 1 and 3), followed by variable speed pumping to the final injection pressure offers greater flexibility and efficiency over the life of the system as compared to full compression to the maximum expected injection pressure (Option 4).

- Performance and total evaluated cost for Option 1, compression with an integrally-geared compressor to an intermediate supercritical condition followed by cooling and pumping to final pipeline pressure, and Option 3, subcritical compression, cooling and CO_2 liquefaction followed by pumping to final pipeline pressure, are similar. Detailed engineering and design in Phase II of the project, focusing on these options, is recommended to determine the best option for Mountaineer plant.

Based on the study, the team recommended that integrally-geared centrifugal compression to either a super-critical (Option 1) or sub-critical (Option 3) condition followed by cooling and pumping to the final CO_2 pipeline pressure be employed for the MT CCS II installation. The technology is proven, cost effective, and offers, with the use of a variable-speed drive on the CO_2 pump, a wide range of outlet pressure flexibility over the other options considered. Based on experience with injection at Mountaineer, pressures below 3000 psig are likely to be sufficient to inject CO_2 into the targeted underground reservoirs, which would result in additional power savings and reduced total evaluated costs for options having the flexibility to produce lower injection pressures. Estimated performance and total evaluated cost values for options 1 and 3 are similar. It is recommended that further work in Phase II be undertaken in order to determine the optimal solution. For Phase I, it is recommended that the cost estimate reflect the cost for Option 3 as that would be the more conservative approach in that Option 1 is less complicated, with less moving parts, lower CAPEX, and lower total installed cost.

1.1.4 Geologic Characterization Study

The purpose of this study is to develop a sub-regional and local geologic characterization using seismic survey data, drilling of a test well, reservoir testing, conceptual system design for injection and monitoring, and development of overall project schedule and cost estimates. This final report discusses the sub-regional and site characterization activities that included drilling and logging a deep test well, analyzing new 2D surface seismic data, and performing other related characterization activities. The comprehensive characterization effort was completed to support CO_2 storage applications near the site.

The subsurface geological investigations of the Mountaineer site and surrounding sub-region conducted under this project during 2010 and 2011 build on a large amount of work done at the site during the last eight years, under two separate projects. First, DOE and others funded Battelle to conduct an initial site characterization effort under the Ohio Valley CO_2 Storage Project, from 2002 to 2007, which included a 2D seismic survey and drilling of a deep characterization well (AEP-1) in 2003 followed by logging, reservoir testing, geochemical analysis, modeling, and conceptual CCS design. Second, AEP hired Battelle in 2007 to construct the sequestration infrastructure for the 20 MW CCS pilot system called the Product Validation Facility (PVF). This included transformation of AEP-1 into an injection well and drilling of an additional deep injection well

(AEP-2) and three new deep monitoring wells (MW-1, MW-2, MW-3) within the Mountaineer Plant property. A schematic of the PVF wells is shown below in Figure 6. This system was commissioned in 2009 and CO_2 injection lasted until May 2011.

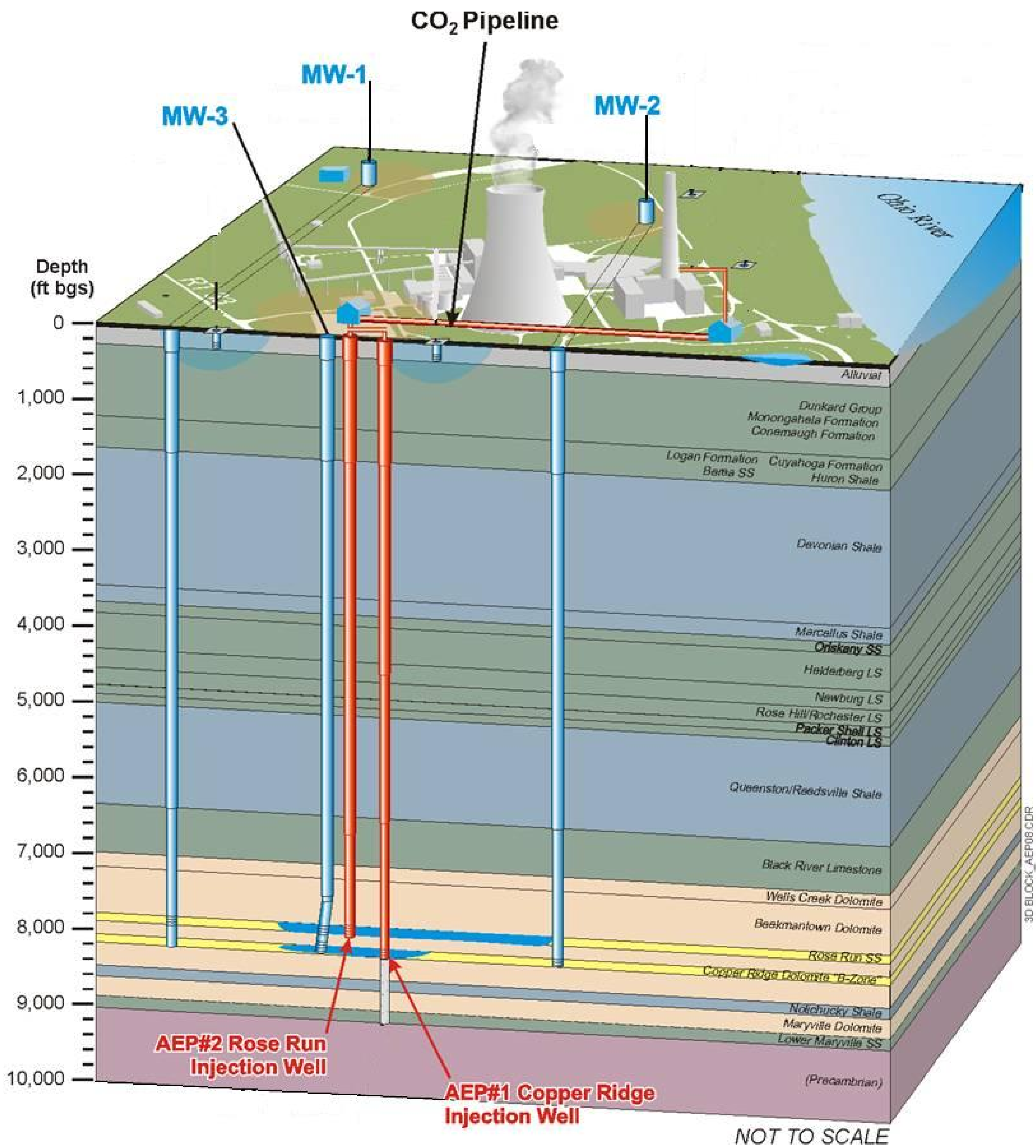


Figure 6, Schematic of the location of the injection and monitoring wells for PVF.

The investigations in Phase-1 of the characterization effort have focused on the evaluation of cap rock (Silurian/Ordovician shales) and Cambrian age reservoirs in the Knox Dolomite Group, including Rose Run and underlying Copper Ridge Formations. Extensive evaluation of wireline log, core, and pressure test data from the Product Validation Facility wells (AEP-1, MW-1, MW-2, and MW-3) and the newly completed Borrow Area (BA-02) characterization well indicate that the lower part of the Copper Ridge Formation may have significant reservoir storage potential. While additional injection potential is present in the Rose Run Sandstone and Beekmantown dolomite, the injectivity might be lower compared to the Lower Copper Ridge zone.

In the past eight years a significant amount of detailed subsurface geological information has been collected at the PVF and more recently the BA-02 characterization well. This effort has lead to the detailed evaluation and understanding of a relatively small subsurface area surrounding the Mountaineer facility. In order to understand how this information can be extrapolated away from this site and to understand the lateral continuity of the potential reservoirs, a sub-regional geologic study was undertaken. An extensive database has been created with data from more than 7,000 wells in and around Mason County, West Virginia. It includes all wells from Meigs, Gallia, and Lawrence Counties in Ohio as well as Mason, Jackson, Putnam, and Cabell Counties in West Virginia. There are a limited number of oil and gas wells that penetrate the Cambrian-Ordovician rocks near the Mountaineer site (Figure 7a).

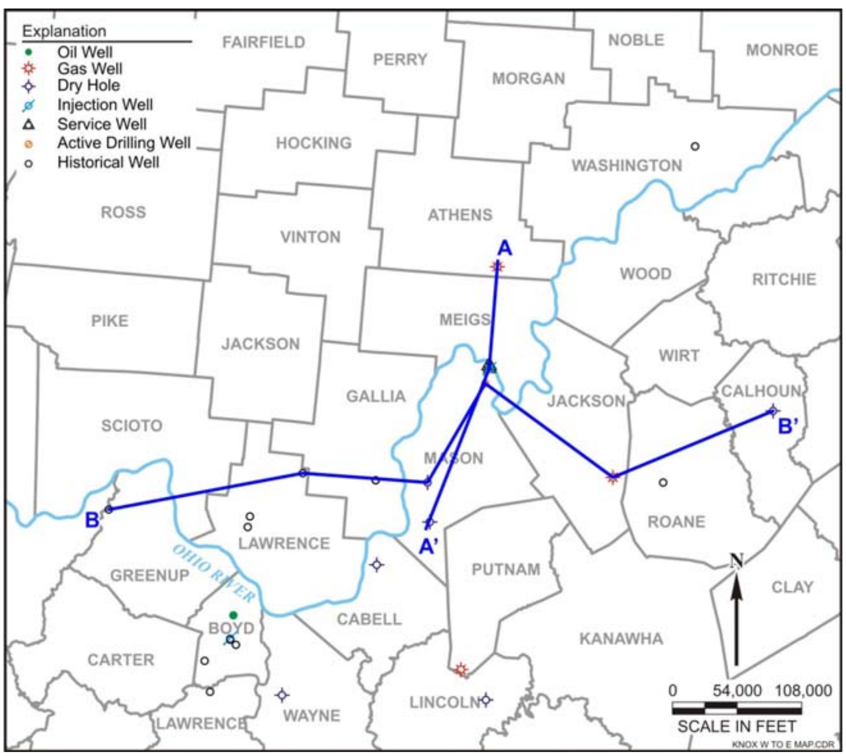


Figure 7a: Reference map for Rose Run and Copper Ridge cross sections.

Information had to be collected, analyzed, and related to the site from as far away as 100 miles. In Figure 7a above, the MT Plant is located near the point where lines A-A and B-B cross. The database incorporates all publically available data sets to include such information as well location, lease name, total well depth, available formation tops, and available geophysical logs and cores. Two software packages, PETRA developed by IHS and Petral developed by Schlumberger, were used to conduct a detailed local and sub-regional evaluation and delineate locations with the best potential for deep reservoir CO_2 injection, focusing primarily on the Rose Run, Copper Ridge, and Beekmantown formations. Geological cross sections, shown in Figure 7b & 7c, isopach maps, and structure maps have been generated to clarify the relationship between the stratigraphy and structure at the Mountaineer area in relation to that of the sub-region. This analysis points strongly towards the discovery of a significant new storage reservoir in the upper portion of the lower Copper Ridge dolomite.

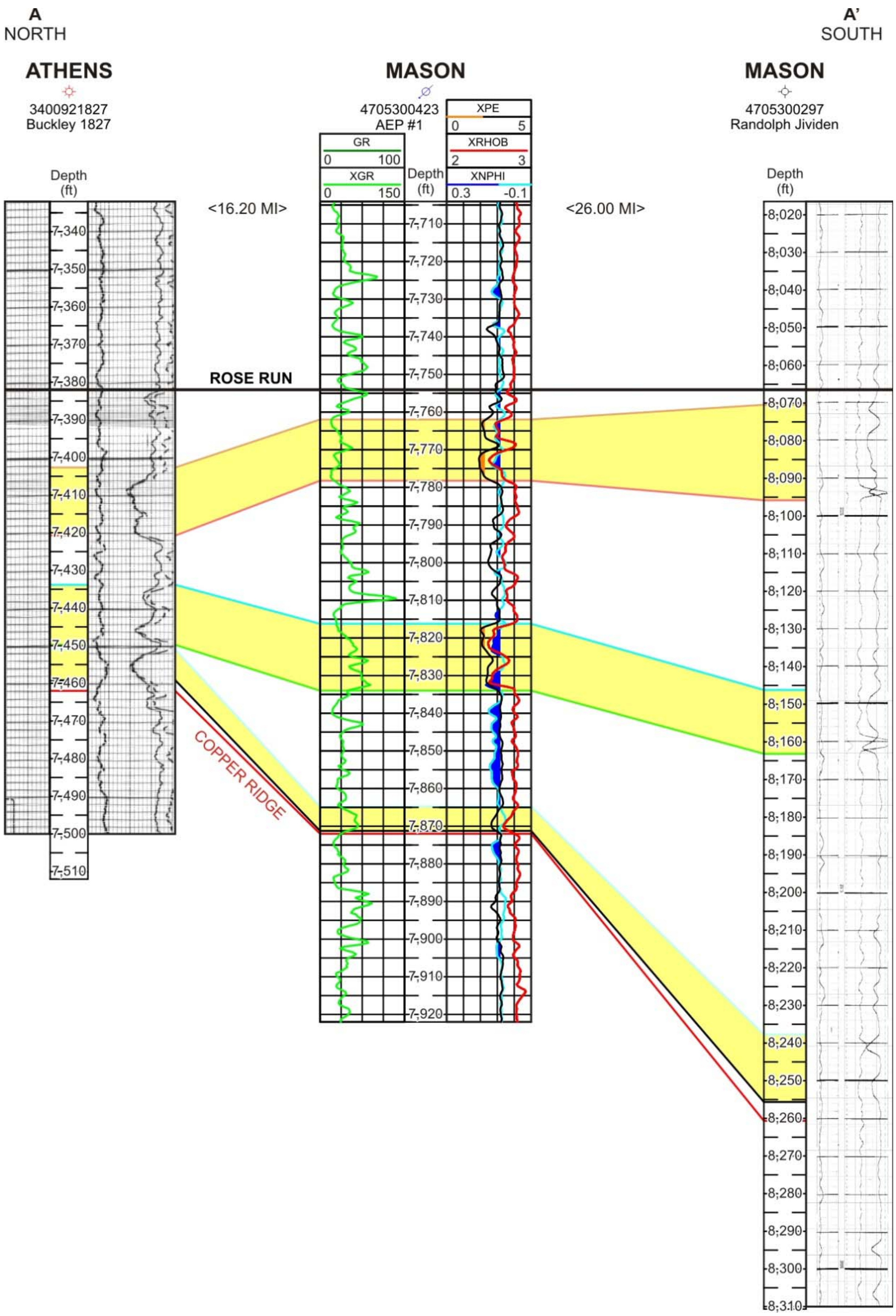


Figure 7b: Cross section showing Rose Run (A-A) from north to south (datum top of the Rose Run sandstone).

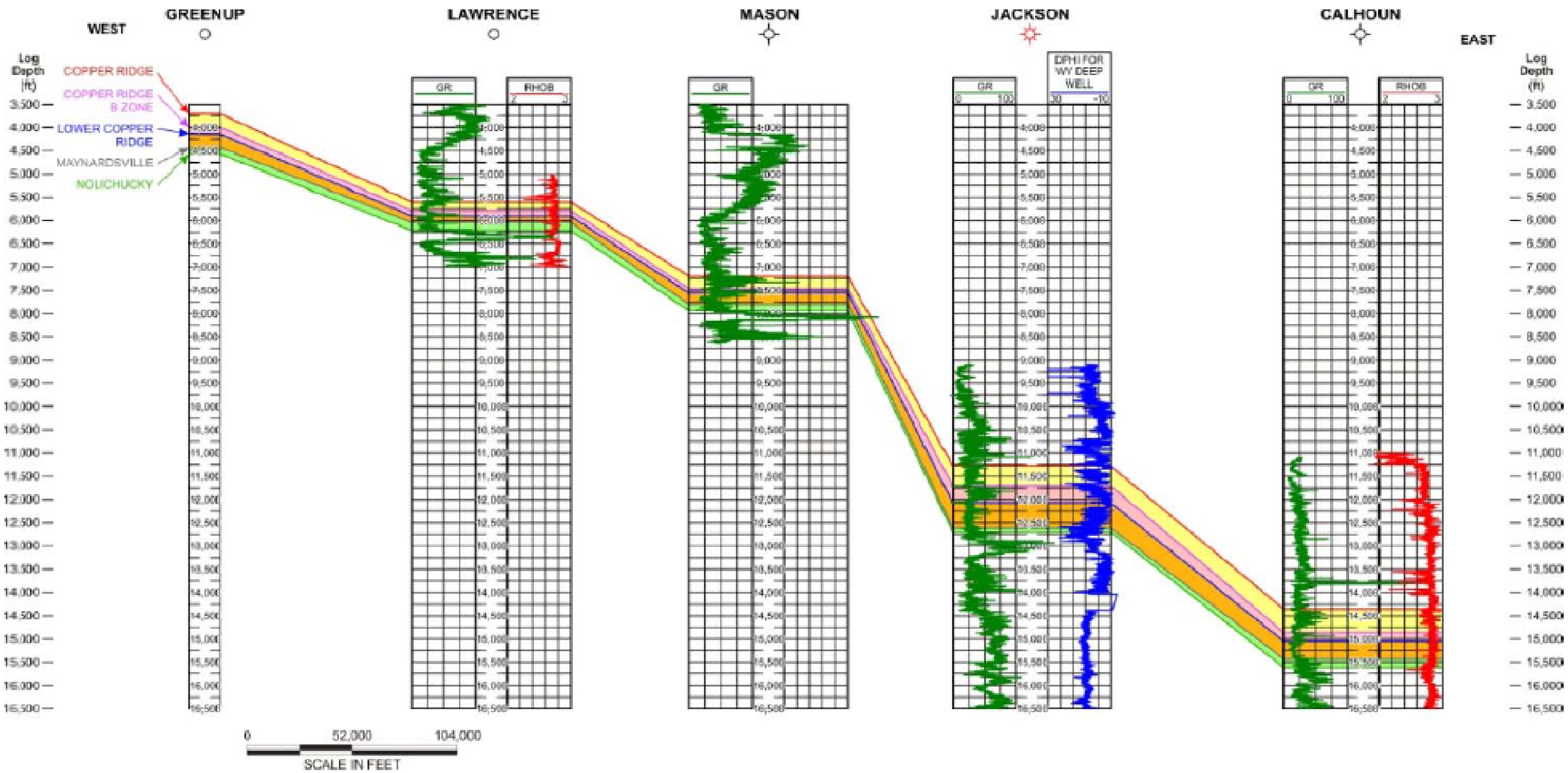


Figure 7c: Cross section of Copper Ridge (B-B) Formation showing structure from west to east.

Analysis indicates that the good secondary vugular porosity present in the Lower Copper Ridge dolomite has potential for storage of large volumes of carbon dioxide. Analysis of wells in the sub-region that penetrate the Copper Ridge Formation, up to 25 miles from the Mountaineer Plant indicate that this vugular porosity is wide spread and appears to be laterally continuous to the north/south and east/west. A detailed sequence stratigraphy analysis of the Mountaineer wells has revealed the relationship between reservoir quality and depositional and diagenetic overprints. The integration of stratigraphic, digenetic, and tectonic data for predicting lateral and vertical heterogeneity in the Copper Ridge reservoir may indicate a compartmentalized reservoir.

In conjunction with the petrophysical work, seismic evaluations using data from purchased 2D seismic lines (near Jordan tract) and previously collected seismic data in 2003 were performed. The Jordan tract 2D lines cover approximately 22.5 miles. Preliminary structural analysis indicates the absence of any major geologic features, especially near the Mountaineer Plant, with formations gently dipping to the southeast. However, the potential for some faulting closer to the Rome Trough area in the southeast cannot be ruled out until more detailed seismic surveys are completed in the area.

Tangential to these efforts, a lineament analysis was completed based on remote sensing data and oriented core data from Devonian shale (obtained from wells close to the Mountaineer plant). The lineament analysis suggested that the reservoirs can have a preferential flow direction along N33–75°E This trend is the principal stress direction in this part of the Appalachian Basin. This trend is also evident in the image log rose diagram from 6,703 to 8, 840 feet. Orthogonal to the principal stress direction are natural fractures found in the WV-5 shale well (N53°W) near the PVF and lineaments in Area 4 (Figure 8a & 8b) that trend N50°W. This direction is also found on this image log, although it is not as prominent as the northeast trend. The northeast to southwest trend will potentially influence the flow path direction for the injection of carbon dioxide in the Rose Run and Copper Ridge reservoirs.

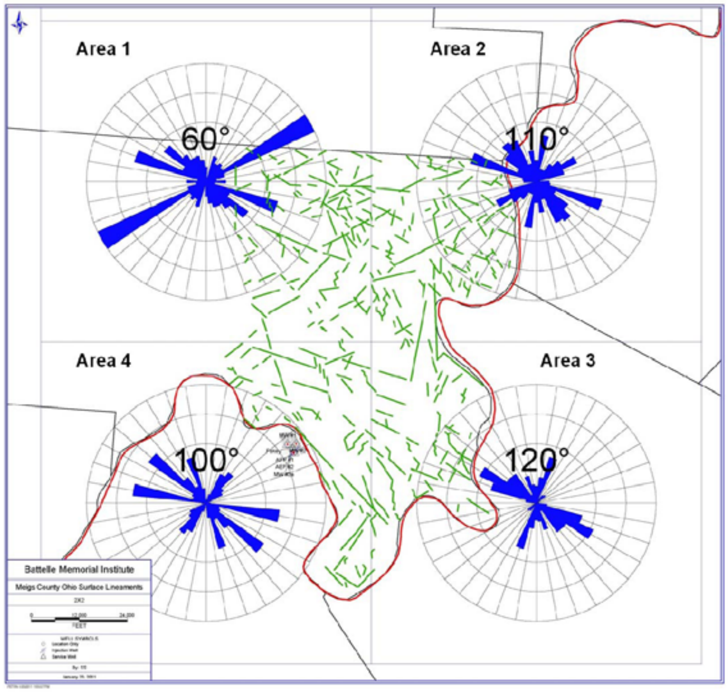


Figure 8a: Meigs County Linament broken into four areas

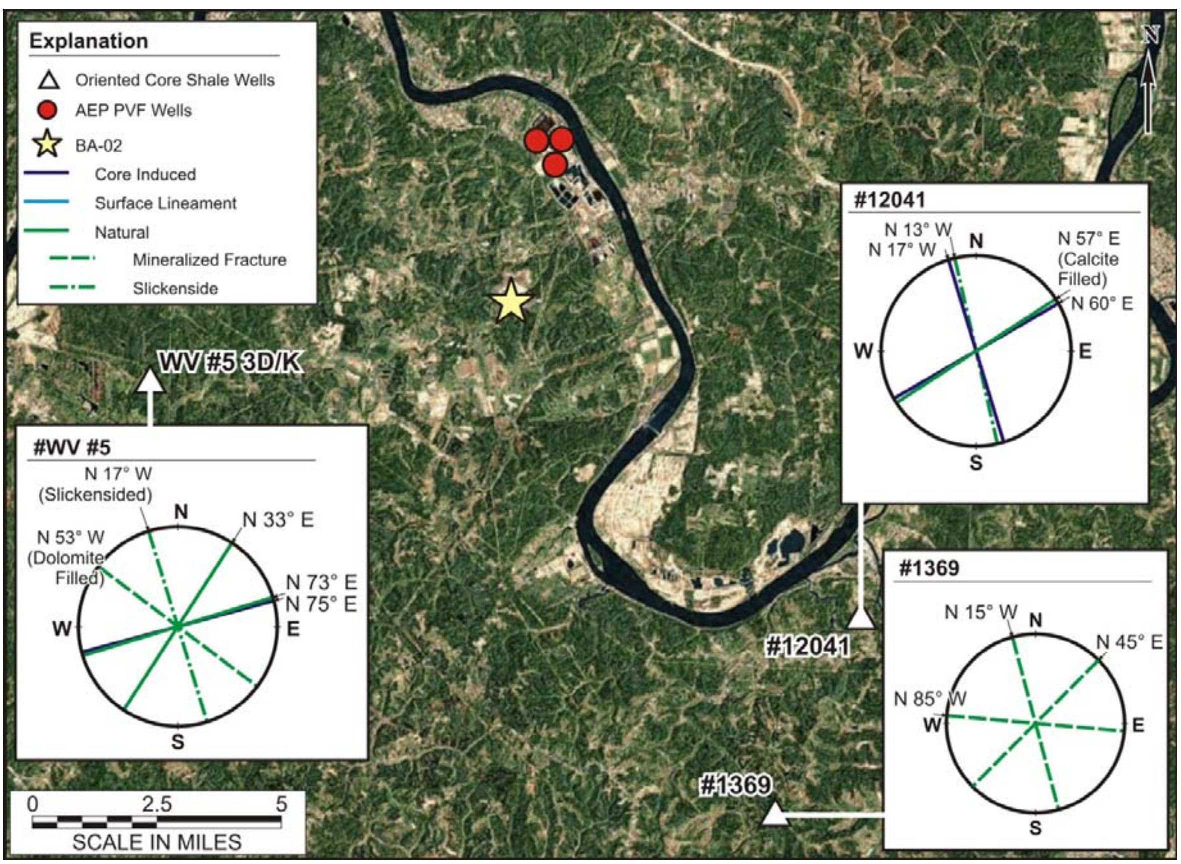


Figure 8b: Aerial relationship between Devonian shale core fracture orientations and the BA-02 characterization well.

An 8,875-foot deep characterization well (BA-02) was completed two miles south of the Mountaineer Power Plant site to characterize the sub-surface geology. The borehole penetrated all of the Copper Ridge formation and was drilled into the Maryville dolomite. Well construction methods were designed to facilitate the reservoir testing of the Beekmantown dolomite, Rose Run sandstone, and Copper Ridge dolomite Formations. Separate reports were generated to document the well construction and reservoir testing. A full suite of wireline logs was completed to obtain a continuous log of the rock formations in the test well. Wireline logs were used for identifying formation tops, casing points, reservoir potential, and selection of coring depths. Over 40 rock formations were identified through evaluation of wireline logs, drill cuttings logs, and rock cores. Most of the rock consisted of dense shale, mudstone, limestone, dolomite, and sandstone. The Copper Ridge reservoir that was identified in PVF well AEP-1 was also identified in the BA-02 characterization well.

A continuous oriented core in the Black River unit was taken for 30 feet and measured 4 inches in diameter; continuous core in the Copper Ridge Formation was taken for ~270 feet and measured 3.5 inches in diameter. In all, 67 sidewall cores were collected from key depth intervals. The rock core samples were subject to many hydraulic, geochemical, and geomechanical tests to determine the suitability of key formations for CO_2 injection and storage.

Vertical containment at the Borrow Area site is provided by an unbroken succession of Ordovician shales and dolomites. These formations include the Wells Creek shale, Gull River, Black River, and Trenton limestones, which have an aggregated thickness of over 1,300 feet. With the single exception of the Wells Creek, each of these units is massively bedded, thick, and largely homogenous. Wireline logs indicate that none of these units has enough primary or secondary porosity development to be considered a zone of potential migration. This is reinforced from the fracture analyses that were performed on Core #1 that was taken in the Black River Formation. Detailed analysis indicates that only stylolites and wavy sedimentary bedding are present with no observable fractures or slickensides.

From earlier investigations and experience at the Product Validation Facility, oil and gas in commercial volumes is unlikely in this area in the zones of interest for CO_2 storage. The historical record of exploration in this area indicated a poor capacity for formations that were tested for oil and gas in Mason County and adjacent counties. These horizons include the Berea sandstone, the Lower Huron shale, and to a lesser extent the Clinton sandstone. The well was drilled through these units with only minor shows, if any, of gas. Similarly, there minor shows of gas in deeper horizons with porosity, such as the Beekmantown dolomite, Rose Run sandstone, and Lower Copper Ridge dolomite.

Data acquired from the previous PVF well tests indicated that the primary injection reservoir is essentially contained in a single zone in the upper portion of the lower Copper Ridge Formation. In contrast, data acquired from the BA-02 well indicates reservoir potential in the Beekmantown and Rose Run Formations, as well as in the Copper Ridge Formation. As an overall trend, the average porosity for all potential reservoir zones tracked the closest to the porosities derived from log cross plots. Neutron porosity tended to track high across all zones, while density porosity tended to track lower. The best zones of calculated porosity, within the lower Rose Run sandstone and the upper portion of the Lower Copper Ridge dolomite, correlated well with the best indications of porosity from the log cross plots.

Image log analysis of the reservoir sections did not indicate large numbers of natural fractures. However, the number of observed drilling induced fractures, particularly in the Queenston and Utica shale sections, was significant. In any 10-foot section, it is rare to find more than five fractures, including drilling fractures. In this log image, the maximum count is 12 fractures in a 10-foot interval within the Queenston shale section. The Beekmantown Formation was not found to have any significant fractures. Overall, the dominant type of fracture is drilling-induced. Zone 3 (Beekmantown "B" zone) was found to have the highest concentration of natural fractures (Figure 9). This may indicate that the porosity in this interval is fracture-controlled. The Rose Run Formation has a low density of fractures compared to most of the rest of the well. It does not appear that the porosity in the Rose Run is due to secondary porosity. Although it appeared that the vugs developed along fractures in the Copper Ridge Formation, this phenomenon is not well represented in the image logs. It is likely the fractures seen in the cores were not easily interpreted within the log. There are no drilling induced fractures in the interval where vugs are present; however, there are some natural fractures, which are likely a subset of the ones represented in the core.

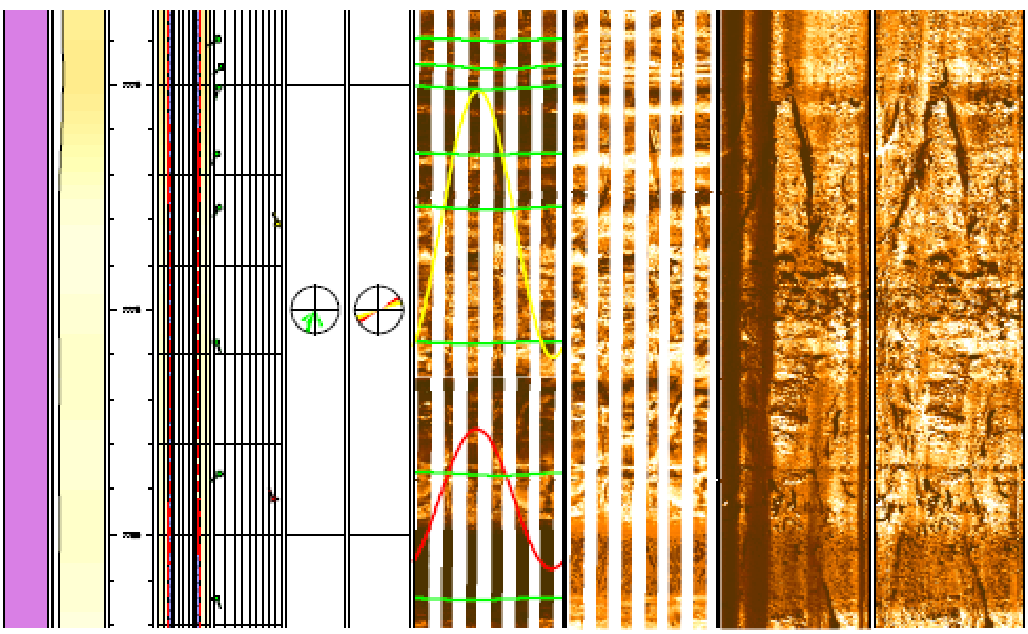


Figure 9: Example of image log within the Beekmantown formation showing some of the fractures (red) and the bedding planes (green).

The CT scan was utilized to determine with greater precision the presence and depths of vugs within the Copper Ridge dolomite. The correlation between internal structure and observation on the whole and slabbed core was confirmed. The connectivity of the vugs throughout the core was also established by being able to see into the core with the CT scan technology. The CT scan also revealed the tendency of the vugs to track along fracture features. Finally, the highly variable nature of the vugs with respect to vertical depth was confirmed (Figure 10).

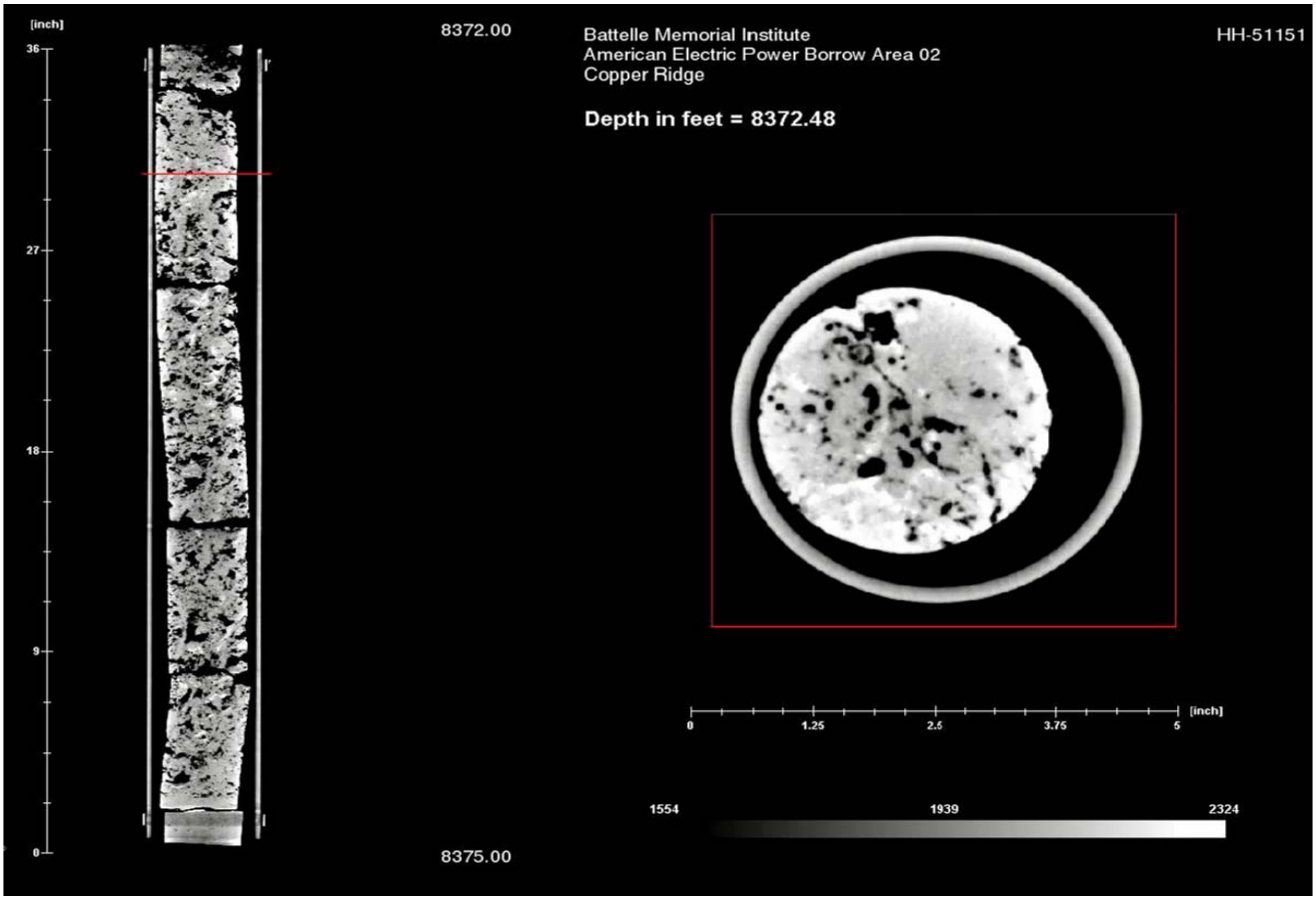


Figure 10: CT scan of a core sample from BA-02 showing the presence of vugs.

A good potential correlation was noted between core identified vugs, the triple combo neutron peaks, and vugs visible on the image log. A neutron cut off between 7–8% correlates well all of the vuggy intervals that were identified in the core (Figure 11). Within the Lower Copper Ridge, an upper and lower bound to the vuggy interval was identified. This interval was approximately 130–140 feet in total thickness, and correlates well with the current depositional model. The vugs are not present everywhere throughout this larger interval. This work allows the identification of the vuggy intervals by the triple combo only. Since it is positively correlated in the core in BA-02, future wells may have less need to take full core in the same intervals. Further, by tying the vuggy intervals to the triple combo, future work may be able to tie it to the 3D seismic as the gross interval of 130–140 feet should be resolvable on 3D seismic images. This can be potentially used as a prospecting tool for vugs detection via seismic without having to drill more wells right away.

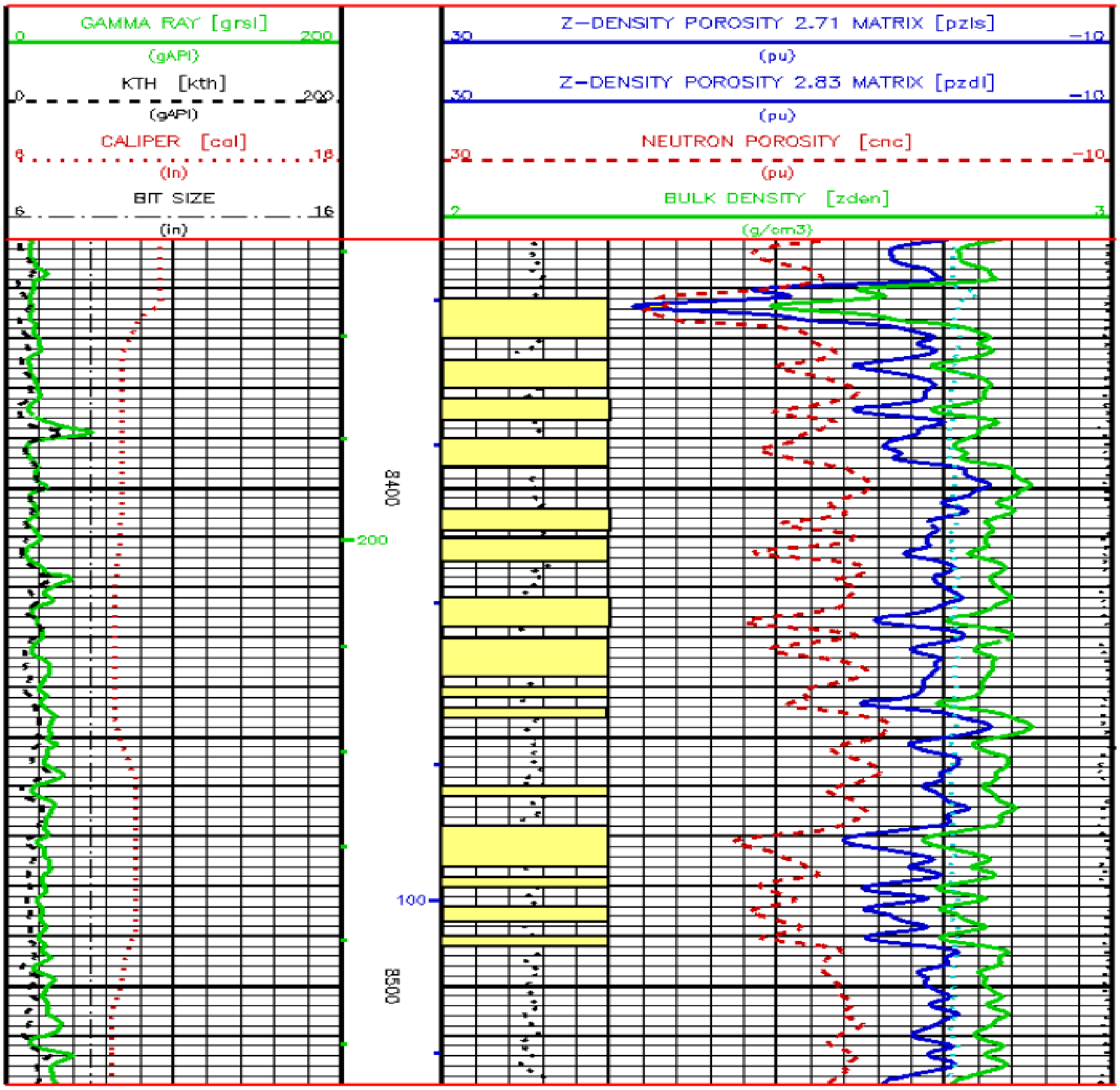


Figure 11: Example of integration of core mapping on triple combo log; yellow segments indicate depth from which side wall cores were obtained.

The wireline log derived fracture pressure for the Trenton-Black River Formation appears to average consistently around 0.9 psi/ft, with only slight variation plus or minus evident in the curve throughout the log. This is consistent with the monolithic behavior in these formations. As is seen within the PVF wells, the Rose Run Formation exhibits a lower fracture pressure in the sandy members. In BA-02 well, fracture pressure averages around 0.7 psi/ft. The more dolomitic sections are at the overall well average of 0.9 psi/ft. Within the Copper Ridge Formation, the vugular region shows a slight drop in fracture pressure from 0.9 psi/ft to closer to 0.8 psi/ft.

Overall, the regional analysis and data from the BA-02 well have yielded important results. The potential injection interval in the Lower Copper Ridge has been confirmed in the data from the BA-02 well and anecdotal evidence from the wells analyzed nearby indicates that the vugs may be wide spread (shown in

Figure 7 above). Through the core analysis, the beginning of a relationship between the core, the wireline logs, and the seismic reflection data has been developed that may allow for identifying optimal drilling locations for future sequestration sites.

Three main recommendations for future work have come out of this effort. A 3D seismic survey in the Mason County area will help to delineate any significant geologic features, such as faulting associated with the Rome Trough, as well as form the basis for attempting to map the location of high-quality reservoir rock with high probability. Future work should focus on fully analyzing the data and formally integrating it with the wireline data. Finally, an additional characterization well, at the Jordan Tract site, would assist in continuing to refine the geologic understanding of the area.

1.1.5 Pipeline Routing / Siting Study

The purpose of the pipeline routing and siting study was to identify a proposed pipeline route, characterize the soil conditions of the area in which the pipeline would be installed, identify any pipeline crossings, and develop technical specifications for the pipe, linings, coatings, and cathodic protection of the CO_2 pipeline for the MT CCS II CAP.

The captured CO_2 is compressed and then pumped to a supercritical fluid with sufficient pressure to inject into the well. AEP has selected two injection well sites, Borrow Area 2 approximately 2.5 miles from the plant and Jordan Tract, approximately 10.5 miles from the plant where the CO_2 is planned to be injected into deep saline reservoirs. The pipeline was routed through AEP properties and transmission line corridors where possible. The maximum operating conditions are 3000 psig and 110^{o}F at the CO_2 Compressor Building. The pipeline design conditions are 3300 psig and 140^{o}F.

The supercritical CO_2 is pumped from the compressor building overhead on utility racks to an area beneath the Mountaineer Plant precipitators where it is routed in an open swale with the ash pipes across the plant to the south side. From this area it is routed above ground, supported from an existing gypsum conveyor (Gypsum Overland Conveyor No. 1), across Route 62 at the west end of the plant.

This routing study applies to the pipeline located west of Route 62 as shown on the routing drawings. This pipeline is designed in accordance with ASME B31.4, “Pipeline Transportation Systems for Liquid Hydrocarbons and Other Liquids”. The pipeline is 12-inch diameter API 5L-X65 with a wall thickness of 0.469 (Ref. Doc No. AEPMT-1-LI-1.01.02.01.05-0009). The pipeline is provided with an internal high density polyethylene (HDPE) lining and an external fusion bonded epoxy (FBE) coating in accordance with the specifications included in this report. A pig launcher is provided at the beginning of the pipeline west of Route 62 and a pig receiver is provided near the end of the pipeline at the Jordan Tract well site. Pigging is not provided for the pipeline branch to the Borrow Area well site since this branch line is short.

WorleyParsons used USGS mapping to design potential pipeline routes and then walked each route to prepare the preliminary routing drawings Initially four sites were chosen from properties owned by AEP near the Mountaineer Power Plant; the four initial sites included Western Sporn, Borrow Area, Eastern Sporn and the Jordan Tract. The choice of these four sites was driven by availability of AEP owned property in the vicinity of the Mountaineer power plant. Parts of the Western Sporn land parcel was identified as wetlands and was not considered as a prospective injection site. The accessibility of Eastern Sporn site was an issue and hence this site was also dropped as a prospective injection location. Finally Borrow Area and Jordan Tract were selected as the preferred sites for CO_2 injection. Figure 12 shows the location of the Mountaineer plant, the preliminary pipeline layout plan and the initially selected injection sites.

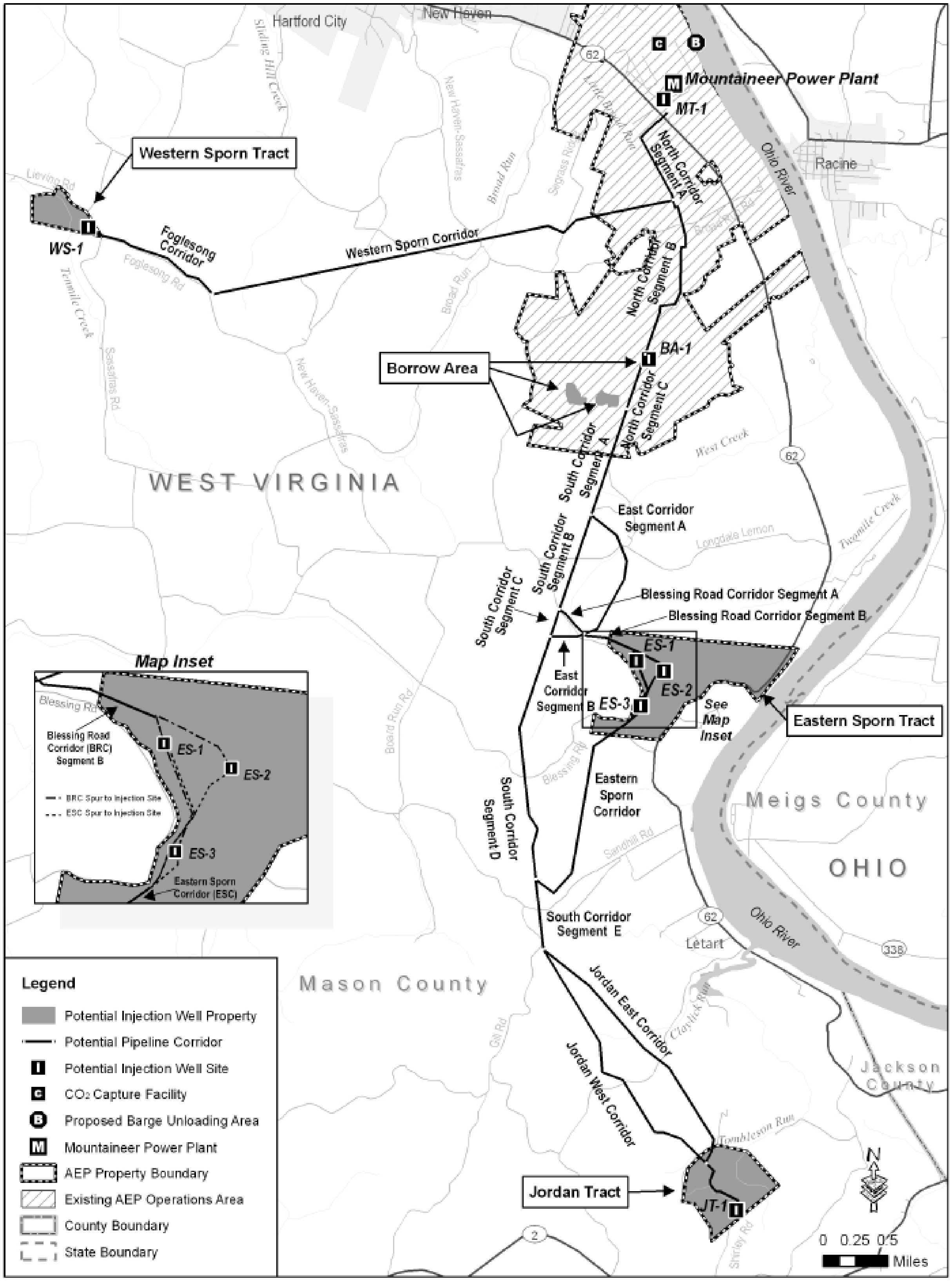


Figure 12: Site location for pipeline and injection wells for the MT CCS II project.

The piping downstream of the CO_2 pump discharge is carbon steel, ASTM A106 Grade C, Schedule 160 in accordance with ASME B31.1, Power Piping. This section is above ground and is unlined, however, the standard schedule 160 used for this onsite portion includes corrosion allowance of 0.161 over the code required minimum wall thickness. The B31.1 piping code was applied since the piping was being routed through the plant site area with greater exposure to plant traffic and operations. At the point where the piping is supported from the gypsum conveyor the piping code transitions to ASME B31.4 since exposure to plant traffic is reduced and the pipe weight can be reduced for support from the existing conveyor. The pipe material is API 5L-X52 pipe with a wall thickness of 0.809 inch. This pipe section is provided with HDPE lining similar to that of the main pipeline.

1.1.6 CAP Design Basis

As part of the Phase I, Conceptual Design of the MT CCS II project, Alstom developed a process design basis for the CAP facility. The design basis supported the overall Phase I conceptual design effort, and was used as a basis for developing the material and energy balances, equipment sizing, and ultimately the refined cost estimate.

The design basis characterizes the conditions and characteristics of the flue gas inlet and outlet, CCS equipment turndown capabilities, system reagents and refrigerant specifications, makeup and cooling water requirements and conditions, process cooling tower and evaporative condenser specifications, CO_2 product stream characteristics, byproduct bleed stream characteristics, the refrigeration system design basis, steam, electrical, and auxiliary plant requirements, and overall site conditions for the Mountaineer Power Generating Station.

1.1.7 CAP Reagent / Material Handling Study

The purpose of the CAP Reagent/ Material Handling Study was to evaluate and select the reagent to be used in the CAP, and to determine scope of supply, design criteria, controls and equipment associated with the storage and handling of the process reagent.

The CAP utilizes an ammonia based reagent for the removal of carbon dioxide gas from combustion flue gases. The technology allows the use of various ammonia based reagents to replenish ammonia losses in the CO_2 product stream, byproduct bleed stream, and from ammonia slip into the exiting flue gas. The reagents considered in this study from commercially available ammonia products were:

- Anhydrous ammonia
- Urea / ammonia on demand (AOD)
- Aqueous ammonia - 19 wt% and 29 wt% solution
- Ammonium carbonate
- Ammonium bicarbonate

These reagents were first evaluated based on technical factors. After initial screening, anhydrous ammonia and 29% aqueous ammonia were recommended for more detailed evaluation. The other reagents were eliminated for various reasons, which most notably include difficulty with maintaining required ammonia molarity due to non-ammonia constituents (H20, CO_2, etc.) included in the reagent, lack of operating experience with the reagent, and inadequate supply.

For anhydrous ammonia and 29% aqueous ammonia, a detailed economic evaluation was performed consisting of total installed capital costs and annual operating costs. Sourcing constraints, material safety, and handling characteristics were also considered. The reagent costs used for evaluation purposes were obtained from suppliers and AEP.

Based on the technical information developed for this report, anhydrous ammonia is the recommended reagent for use on the Mountaineer CCS II Project.

Anhydrous ammonia is recommended over other ammonia based reagents for the following reasons:

- Anhydrous ammonia has the lowest capital and operating cost of the reagents compared. Anhydrous ammonia offers significant capital and operating costs savings over 29% aqueous ammonia.

- Anhydrous ammonia is the optimum reagent to maintain/control ammonia molarity in the CAP and to recover from molarity upsets during process upsets, load fluctuations and maintenance activities.

- Anhydrous ammonia has the least risk of impurity addition, which can cause process upsets, and effluent for streams requiring additional treatment.

Anhydrous ammonia, like other chemical reagents, has safety hazards associated with its use and requires a safety program and preventative maintenance auditing to maintain and operate the equipment and site storage facilities in a responsible manner. These safety programs are well established and are implemented for SCRs in power plants and other facilities across the country.

It should be noted that all reagents considered in this study require precautions, special handling, and training for use within the CAP and the power plant.

The CAP anhydrous ammonia storage and material handling system consists of two (2) storage tanks, reagent unloading equipment including a vaporizer system, piping, controls, and electrical equipment. All system equipment will comply with AEP design specifications.

1.1.8 Miscellaneous Studies

The subtask for Miscellaneous Studies was created for any new studies identified during Phase I. One such study was evaluation of the Mountaineer Power Plant barge unloading system and design of the facility to be used during the construction of the CCS plant. The results of this study are discussed and incorporated into the MT CCS II Constructability Study (see subtask 1.1.18).

Additionally, AEP conducted periodic risk review and analysis of the project's perceived risks. Risk reviews brought together key individuals from AEP, Alstom, WorleyParsons, and Battelle. The sessions typically consisted of a review of previously identified risks containing discussion on progression of mitigation efforts and any changes in probability of occurrence or severity of impact. The sessions also allowed for discussion of any new risks identified since the previous risk review. Following completion of each session, AEP would update the project risk register and issue updates to the integrated project team. Some of the key risks identified on the project include: uncertainty associated with the Class VI Underground Injection Control (UIC) Permit requirements, cost and schedule risks associated with well drilling activities, cost and schedule risks encountered due to late design changes and/ or requirements, and the volatility of the escalation factors applied to the project cost estimate due to various influences such as hyperinflation, market saturation, material availability, etc.

1.1.9 Process Makeup Water and Wastewater Study

The purpose of this study was to verify and document the interfaces between the CAP and existing plant water and wastewater systems. The report also describes any new facilities and systems necessary to accommodate those interfaces.

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, wash down hose stations, process water makeup, and Direct Contact Cooler (DCC) makeup. The primary demand for makeup water is makeup to the CAP refrigeration system evaporative condensers.

Three (3) existing pumps, each rated at 20,000 gpm, furnish river water makeup from the Ohio River to supply the existing demand of the Mountaineer Plant. The existing river water makeup pump capacity is considered 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 (RO) 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.

	Flow Rate (% of CAP Total Makeup)
Evaporative condenser evaporation	51%
Evaporative condenser blowdown	26%
Pump seal cooling water	4%
Wash down 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 2: Mountaineer CAP Makeup Water Usage

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

Table 3: Typical Ohio River Water Quality

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

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), 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.

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 will eventually be needed 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.

1.1.10 <u>Flue Gas Study</u>

This study was performed to evaluate 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, be eliminated from consideration based upon technical and environmental risk factors associated with discharging flue gas in a cooling tower. Therefore, this option was not evaluated in detail.

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 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.

Concerns were addressed in the study with respect to 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 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. For the purposes of the FEED, the return duct in Option 1 was assumed to be insulated, Further evaluation during the detailed engineering and design would determine the extent of insulation required to maintain the desired outlet flue gas temperatures. The exhaust duct for Option 2 would not be insulated, as the run of ductwork to the new stack would be no more than 100 feet. It should be noted that, based on feedback from FRP vendors, shop fabrication may be a consideration for the 15’ diameter duct. Further evaluation is required to determine if shop fabrication might yield an overall cost savings to the project

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 the detailed engineering and design 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. A lower stack height requirement may allow the stacks to be placed on top one of the CAP vessels, which would further reduce 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.

Based on the technical and economic results of this evaluation, the project team initially recommended Option 2, where the CAP exhaust is sent to a new, dedicated stack. However, uncertainties associated with modeling and permitting a new stack in the timeframe of the project restricted AEP from considering this option for the Phase I conceptual design. 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 during detailed engineering and design and ultimately implemented.

1.1.11 Refrigerant Study

The purpose of this study was to provide an overview of the potential refrigerants available for use in the CAP refrigeration system, and to ultimately select the design basis refrigerant for the CAP. The study was based on a relative comparison of different refrigerants with respect to various technical and economic parameters.

The chilled ammonia process uses ammonia solution as chemical solvent to remove CO_2 from the flue gas. The chemical reactions are exothermic resulting in the release of heat to the process. The reactions are also reversible allowing for the regeneration of the ammonia reagent and re-use in CO_2 absorption. After the solvent has absorbed the CO_2, it is routed to a regenerator where the CO_2 is desorbed by heating the solvent with steam. The operating temperature in part of the process is slightly below ambient temperature most times of the year, which requires the application of a refrigeration system.

The refrigeration system is a significant portion of the CAP's energy demand, so selection of the optimum refrigerant is an important factor in minimizing the CAP's power consumption. This study indicated which refrigerants are commonly available and provides information regarding physical properties, environmental impact, safety considerations and specific power consumptions as a basis for the selection of the right refrigerant for this CAP application.

In the past decade, synthetic refrigerants like Chlorofluorocarbons (CFC) and Hydrochlorofluorocarbons (HCFC) were widely used because of advantageous qualities, such as low toxicity and non-flammability, compared to most of the existing refrigerants. After observation of the hazardous impact of these substances on the earth's atmosphere, the international community decided with the 1987 Montreal protocol to eliminate the application and production of these substances. Therefore CFCs and HCFCs cannot be used anymore for new facilities, and were not considered in this study.

Chemical companies are trying to develop safe, cost effective, and efficient refrigerants for industry that encompass a wide range of applications. Hydrofluorocarbons (HFC) are a promising solution as these refrigerants do not deplete the ozone layer and have many of the desirable properties of CFCs and HCFCs. However, they contribute to global warming if released to the atmosphere. Countries, trade associations and companies are increasingly adopting regulations and voluntary programs to minimize these releases and, hence, minimize potential environmental effects while continuing to allow use of these refrigerants.

During the realization of the Montreal protocol (phase-out procedure) and the limitation of the application of partly halogenated hydrocarbons, the utilization of synthetic refrigerants has been reduced and there is growing interest in hydrocarbons and natural refrigerants. Table 4 below shows a compilation of various refrigerants considered for this project and their Ozone Depletion Potential (ODP) and their Global Warming Potential (GWP).

Substance	ODP	GWP
Ammonia	0	0
Carbon Dioxide	0	1
Hydrocarbons	0	3
HFCs (R134a, R-410A, etc.)	0	>1,000
HCFCs	0.05	>1,000
CFCs	1	>1,000

Table 4: ODP & GWP of various refrigerants considered

Besides environmental considerations, a good refrigerant should have low specific power consumption, which is not the case when carbon dioxide is used as a refrigerant. The power consumption is approx. 40% higher compared with the refrigerant with the lowest specific power consumption. Therefore the use of carbon dioxide as a refrigerant is usually limited to applications where power savings is not a consideration, and non-toxicity, low ozone depletion, and global warming potential are of most importance.

A comparison of the refrigerant specific power consumption is indicated below (Table 5) using ammonia as the baseline as it has the lowest specific power consumption.

Substance	Specific Power Consumption (%)*
Ammonia (Base Case)	100
HFCs (R134a, R-410A, etc.)	103-110
Hydrocarbons	104-142
Carbon Dioxide	142

*Specific power consumption (%) is defined as the compressor power of the refrigeration system divided by the chilling duty.

Table 5: Refrigerant specific power consumption

Due to their flammability, hydrocarbons are rarely used in refrigeration systems having chillers inside of closed buildings, which is typical for air conditioning or in the food industries. However, hydrocarbons are often applied in industrial refrigeration systems. The design of such plants needs special consideration regarding fire protection, but these systems are well established in the industry and have a long record of experience.

Ammonia is the single natural refrigerant being used extensively in industrial applications for its good thermodynamic and thermophysical characteristics. Ammonia is an excellent refrigerant but also a hazardous substance. Although hazardous, there are well established practices, common in industry, for the safe handling of anhydrous ammonia.

The focus for safe handling and operation of ammonia is concentrated on:

- Using a small quantity of circulating flow rate
- Limitation of accident impacts

The potential environmental and safety risk of chemicals depends, among other factors, on the inventory of the system. In this regard, ammonia has an advantage compared to other substances, due to its high volumetric cooling capacity. The indicated figures below provide a list of the system inventory of different refrigerants compared to ammonia.

Substance	**Inventory (%)***
Ammonia (Base Case)	100
Hydrocarbons	350
Carbon Dioxide	740
HFCs (R134a, R-410A, etc.)	420-1,000

*The system inventory (%) is defined as the total amount of refrigerant inside of the refrigeration system (equipment and piping) on a mass basis.

The evaluation and comparisons carried out in the study showed that an ammonia refrigeration system is optimal for the Mountaineer CCS II project. This system has the lowest energy consumption (highest efficiency) and the lowest installed capital cost, with minimal environmental impact with respect to ozone depletion, greenhouse effect, or global warming.

1.1.12 Power Assessment Study

The purpose of this study was to identify the electrical system configuration and specific equipment ratings for the AEP Mountaineer CCS II Project. This auxiliary power system assessment establishes the system configuration, the sizing and the ratings for the auxiliary transformers, secondary auxiliary transformers, station service transformers, medium voltage switchgear, medium voltage starters, low voltage switchgear, and low voltage motor control centers to provide an electrical distribution system that has sufficient capacity to start-up and run all the loads for AEP Mountaineer CCS II Project.

The electrical system configuration was developed using AEP electrical design criteria and the overall electrical load list for the CCS II system. The following four alternatives were considered after the base configuration was determined:

1. Three (3) winding auxiliary transformers
2. Variable frequency drive (VFD) for the HT Refrigerant Compressor motor

3. Soft start for the HT Refrigerant Compressor motor
4. Using the Plant Reserve 138/13.8kV Spare Auxiliary Transformer as the spare transformer for CCS II System

Each configuration was evaluated to determine the steady state load flows, large motor starting, resultant bus voltage and short circuit duty to size and determine the equipment ratings.

Based on the results of the power assessment, a VFD is recommended for the HT Refrigerant Compressor: Equipment ratings for the medium voltage switchgear should be specified to accommodate use of the Plant Reserve 138/13.8kV Spare Auxiliary Transformer as the spare Auxiliary Transformer for the CCS II System.

The following are the recommended electrical system configuration and equipment ratings:

1. The auxiliary transformers steps down the 138kV lines from the Mountaineer Sub Station to 13.8kV and provides 13.8kV power to the medium voltage switchgear.

   Auxiliary Transformers:
   - Quantity: 2
   - 2 winding
   - MVA: 54/72
   - Impedance: 8%

2. The medium voltage switchgear feeds the secondary auxiliary transformers, the station service transformers and large motor loads over 5000hp.

   13.8kV Switchgear:
   - Quantity: 1
   - Configuration: Double ended (Main – Tie – Main)
   - Bus 1 Rating: 3000A (Feeds Large Motors)
   - Interrupting rating: 50kAIR

   13.8kV Switchgear:
   - Quantity: 1
   - Configuration: Double ended (Main – Tie – Main)
   - Bus 2 Rating: 2000A (Feeds Auxiliary Transformers and Station Service Transformers)
   - Interrupting rating: 50kAIR

3. The secondary auxiliary transformers steps down the 13.8kV to 4.16kV and provides 4.16kV to the medium voltage switchgear / medium voltage motor control center.

   Secondary Auxiliary Transformers:
   - Quantity: 2
   - MVA: 15/20
   - Impedance: 6.5%

4. The 4.16kV medium voltage switchgear / medium voltage motor control center feeds the medium voltage motors less than 5000hp.

4.16kV Switchgear/ Medium Voltage Motor Control Center:
- Quantity: 1
- Configuration: Double ended (Main – Tie – Main)
- Bus Rating: 3000A
- Interrupting rating: 50kAIR

5. The station service transformers steps down the 13.8kV to 480V and provides 480V to the low voltage switchgear
   Station Service Transformers:
   - Quantity: 8
   - kVA: 2000/2666
   - Impedance: 5.75

6. The 480V low voltage switchgear feeds the low voltage motor control centers and building feeds.
   480 Switchgear:
   - Quantity: 4
   - Configuration: Main – Tie – Main
   - Bus Rating: 3200A
   - Interrupting rating: 65kAIR

7. The 480V low voltage switchgear feeds the low voltage motors and miscellaneous 480V loads.
   480 Motor Control Centers:
   - Quantity: 16
   - Bus Rating: 800A – 1200A
   - Interrupting rating: 65kAIR

Mountaineer lacked the additional capacity in its existing electrical system to adequately accommodate the equipment and infrastructure needed to operate the CAP system. To meet the demands of the process and BOP equipment it was determined that two (2) dedicated 138 kV circuits were needed. Mountaineer's existing substation did not have available 138 kV breakers sufficient for this service. 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 to accommodate the CAP. 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.

1.1.13 Building / Architectural Study

As part of the building architectural study, WorleyParsons developed the conceptual design for an administrative building, control room/ laboratory, electrical building, and a warehouse to service the CCS plant. Basic floor plans for these buildings were developed as a basis for the cost estimate.

Prior to developing the building designs, the project investigated the measures needed in order to meet a Leadership in Energy and Environmental Design (LEED) classification. The study evaluated multiple areas including sustainable sites, water efficiency, energy and atmosphere, materials and resources, indoor environmental quality, innovation and design, and regional priority. Under each category of evaluation, there are multiple qualifiers with respective ratings or points. For each qualifier which is met by the building, the points are "earned". Once the building has been evaluated in all categories, the "earned" points are summarized. To be a LEED certified facility, 40-49 points must be earned, LEED Silver requires 50-59 points, LEED Gold requires 60-79 points, and LEED Platinum requires 80-110 points.

The project team evaluated the items identified within each category and determined whether the buildings for the project would be designed in order to meet the qualifier. After this evaluation, a LEED Silver rating was determined to be the standard that would be used on the project in the design of the administrative building, control room/ laboratory, electrical building, and warehouse for the CCS plant.

1.1.14 Refrigeration Heat Rejection Vapor Study

This study was performed to evaluate the impact of the plume emitted by the evaporative cooling equipment included in the CAP for the AEP Mountaineer CCS II Project. The equipment concerned consists of the refrigeration system Evaporative Condenser and the Direct Contact (DC) Cooling Tower, shown in 13 below.

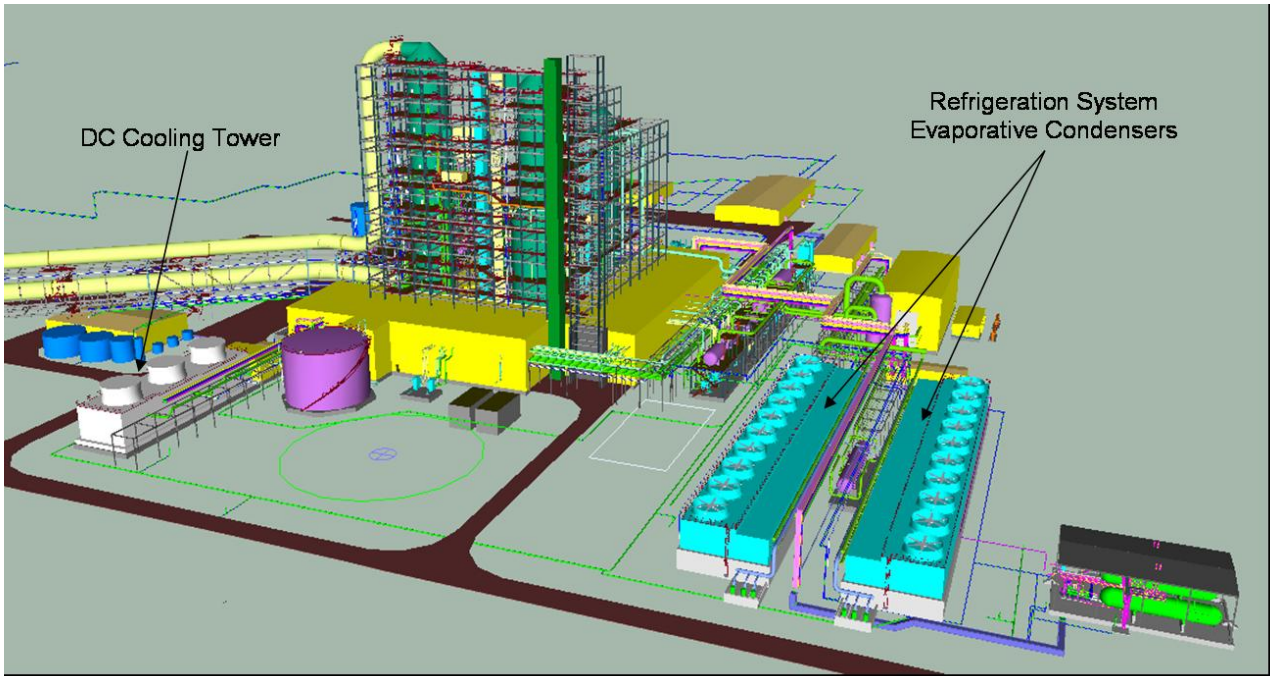


Figure 13: Location of Vapor Plume Sources (From 3-D Model)

The evaluation was performed based on the design site ambient conditions provided in the Project Specific Design Criteria, AEPMT-1-DB-1.01.01.01.06-0001. The prevailing wind direction for the site is 220 degrees (SW) with an overall average wind speed of 7 mph. Monthly site wind direction and speed frequency data in the form of wind roses were used based on the USDA wind data for Huntington, WV airport. Data for the Evaporative Condenser and DC Cooling Tower were provided by Alstom. The locations considered in the study are those shown on the plant layout drawings. The location was examined with respect to negative wind effects to the equipment's performance as well as negative impacts of the vapor plume drift.

Based on this evaluation, the location and orientation of the evaporative condenser is acceptable and should not cause frequent problems with the vapor plume becoming a nuisance or hazard for surrounding roads and structures. The condenser is in a favorable orientation with the centerline nearly parallel to the prevailing wind direction. In addition, it is sufficiently distant from surrounding tall structures that the plume will not likely drift into those structures.

The location of the smaller DC Cooling Tower is not ideal. Its location was chosen to minimize distance between it and the process equipment it serves, and, to maintain space for future equipment. For prevailing winds, plume problems associated with its location are not expected. When the wind blows opposite the direction of the prevailing winds, the DC Cooling Tower plume will, during unfavorable weather, be carried into the open absorber steel structure in the higher elevations. Given the small size of the tower and its distance from the structure, this effect is not expected to be significant. The effect can be further minimized by adjusting operation of the tower. To accomplish this, provisions should be included in the tower for future addition of individual cell bypass and variable speed fans, to allow the plume carryover effect to be minimized.

1.1.15 Accessibility Review

Throughout the course of Phase I, the project team held monthly 3-D model reviews to assess the accessibility of the facility's design. A tremendous amount of effort and detail went into the 3-D model to demonstrate a realistic view of the conceptual design. The 3-D model, a snapshot of which is shown in Figure 14, contains detailed information such as:

- Building sizes
- All major process and BOP piping (≥2.5")
- All major process and BOP equipment
- Equipment arrangements
- Containment barriers
- Access/egress design and critical maintenance considerations (pull spaces, tool cart access)
- Structural steel
- Electrical panels, cable tray, and pipe racks

The complete 3-D model allowed Alstom and WorleyParsons to obtain precise quantity take-offs for the detailed bottom-up cost estimate for the project.

Alstom also used the 3-D model to develop detailed facility renderings that display what the CAP facility and auxiliary support systems will look like as a finished product. The renderings and model snapshots were used in the team's Phase I presentations to AEP Management, DOE, and others to better facilitate understanding of the finished commercial-scale facility and to show the amount of detail that went into the project's cost estimate and plan for future phases.

In future project phases, the 3-D model will be updated as the facility design matures to ensure adequate accessibility and maintainability.

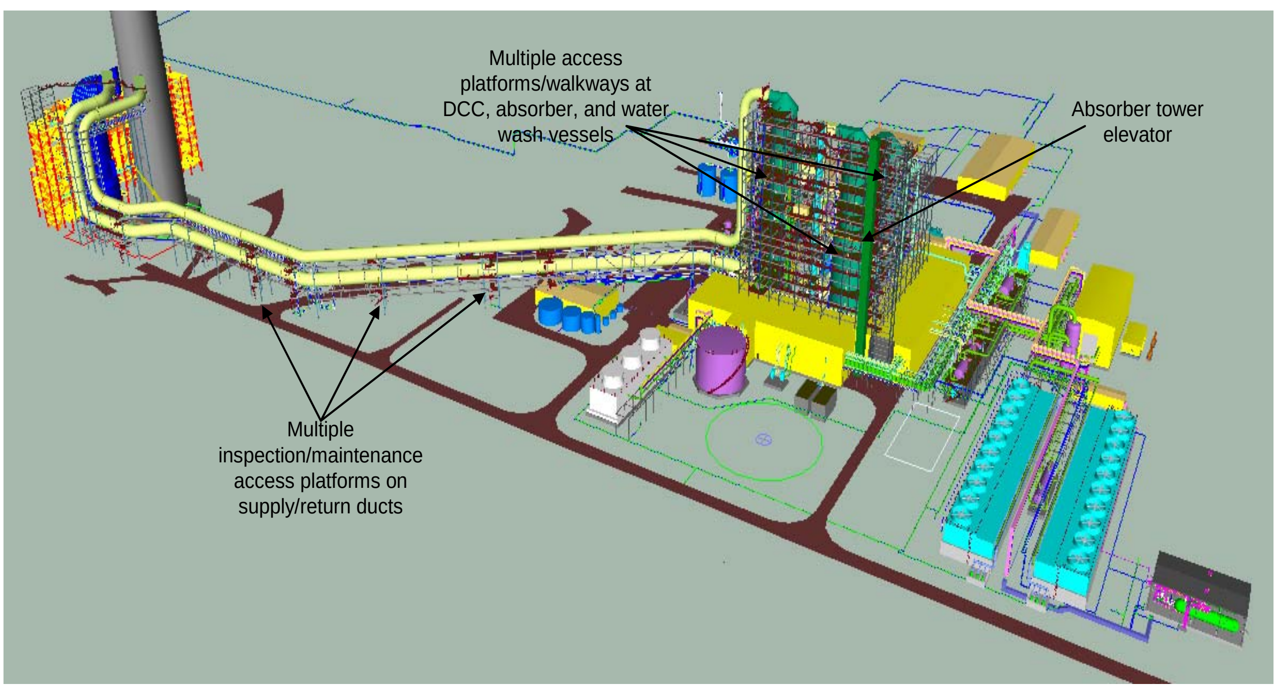


Figure 14: 3-D Model Snapshot showing Some Aspects of Accessibility

1.1.16 Spares Study

Alstom in coordination with AEP performed a Reliability, Accessibility, Maintainability (RAM) study during the Phase I FEED. Based on the design requirements set, the CCS Plant shall have a minimum capability of 85% Availability Factor. During this 85% Availability of the plant, the CCS plant shall be able to demonstrate a capture capability of 90 wt.% of CO_2 from the flue gas. Both these factors are considered as success criteria and were considered as target values for the RAM study.

The RAM study was performed by Alstom using data from existing pilot and demonstration projects and technical information available during the Phase I FEED. It is expected that in the detailed design and engineering phase, this study would be refined based on more detailed process design and vendor information. The results of this study are summarized as follows:

- Considering the redundancy provided on the PFDs and P&IDs, and under the assumption that there would be "no spares" in stock available on CCS II site, the calculated Equivalent Availability Factor is calculated as:
    - 91.0% for the CCS II Plant (without BOP and Sequestration Network)
    - 87.7% for the CCS II Plant (incl. BOP and Sequestration Network)

Note: the assumption of 'no spares on site' is conservative and indeed unrealistic in this context. The Equivalent Availability is more likely to be closer to the value calculated with full spares on site (shown next):

- Considering the redundancy provided as shown on the PFDs and P&IDs, and under the assumption that all required spares would be available on CCS II site, the calculated Equivalent Availability Factor is calculated as:
-
    - 94.4% for the CCS II Plant (without BOP and Sequestration Network)
    - 92.1% for the CCS II Plant (incl. BOP and Sequestration Network)

The most critical components in terms of having adverse effects on the CCS II plant availability (in case of failure) can be considered as:

- CO_2 Compressor (CP-6070),
- HT Refrigerant Compressor (CP-6002)
- LT Refrigerant Compressor (CP-6002)
- Air Compressor (1-IA-CP-6090)

Below is a summary table of the calculated Equivalent Availabilities; CAP availabilities not including BOP and the Sequestration Network are reported in bold and including BOP and the Sequestration Network are in parenthesis.

	Equivalent Availability
Current Redundancy, no spares on site	91.0% (87.7%)
Current Redundancy, full spares on site	94.4% (92.1%)

Table 6: Summary of RAM calculated results

It should be noted that the Phase I RAM study was a preliminary assessment of equivalent availability based upon the complete equipment scope as determined in Phase I. Detailed engineering, design, and analysis of failure modes, repair durations, startup/shutdown durations, curtailment effects, and lessons learned from other CAP systems in operation will significantly improve the accuracy of the MT CCS II equivalent availability expectations. The team did not have adequate time or information in Phase I to appropriately evaluate all of the factors that affect availability of the system. For the purposes of the Phase I +/- 25% cost estimate, the "Current redundancy, no spares on site" was the identified basis of estimate.

1.1.17 Constructability Study

This study presented Phase I information on constructability issues related to the Mountaineer CCS II project. Key constructability issues include modularization, equipment delivery methods, crane/lift requirements, lay-down and staging, site improvements, impact on equipment design, sequencing/schedule planning, and risk mitigation.

The primary value of this study is enhancement of early project planning with the goal of steering the project toward a successful and cost-effective construction plan. Two meetings involving the primary stakeholders were conducted in Columbus during the Phase I conceptual design process. Following is a summary of the constructability plans based on Phase I information:

- Equipment and structures will be modularized to the extent practical to enhance quality, improve productivity, decrease overall project cost, and improve schedule.
- Barge transport will be the primary delivery method for large modularized items.
- The CAP absorber area vessels will be fabricated and delivered in ring sections and erected with a standard crane.
- The more slender, but heavier, regenerator vessels will be delivered in one horizontal piece and up-righted with a crane.
- The absorber packing vendor strongly recommends an absorber erection sequence that avoids field-welding of ring sections with "pre-installed" packing, therefore packing will be installed after vessel welding is complete.
- Unloading and transport of large equipment items will require site improvements at the barge unloading facility.
- CAP vessel and equipment design must consider anticipated delivery and construction methods to ensure integrity from fabrication through erection.
- Construction-specific risks include river water level, absorber vessel packing material flammability, and weather exposure of the absorber packing material.

Key recommendations to ensure that constructability issues remain prevalent as the project moves forward include:

1. Schedule follow-up meeting(s) to track progress.
2. Include early activities for site investigation in Phase II schedule development.
3. Continue Phase III schedule development with input from all key stakeholders.
4. Designate dedicated lay-down areas on arrangement drawings.
5. Maintain heavy lift contractor's involvement in delivery/erection discussions as design progresses.
6. Confirm/update equipment weights as design progresses.
7. Consult other AEP projects for any relevant "lessons-learned."
8. Incorporate risk mitigation measures into Phase II schedule as appropriate.
9. Consider adding included risks to the project register.

1.2 Civil / Structural

1.2.1 Preliminary Plot Plan

As part of the Phase I effort, WorleyParsons developed the preliminary plot plan of the CCS Capture facility and of the Geologic Sequestration System (GSS) site plan. Each of the two plans provide an overview of the entire plant site, showing site boundaries and major facilities such as buildings, switch yards, major equipment, water intakes, roadways, and interfaces with any existing facilities. The process of developing the preliminary plot plan was iterative throughout the Phase I FEED to optimize the arrangements for access while conserving the available area. The final preliminary plot plans identify the arrangements which were the basis of the refined project cost estimate and identified in the NEPA Environmental Impact Statement.

1.2.2 General Arrangement Drawings

The general arrangements of the CAP and GSS are more detailed depictions than shown in the overall plot plans. The general arrangement of the CAP facility identifies the arrangement of CAP specific equipment and further details dimensions and other components of the various process systems. The GSS general arrangement also distinguishes a greater detail of information specific to the two primary sites of interest, Borrow Area and Jordan Tract. The layout depicts the proposed layout of injection and monitoring wells along with the anticipated area of review based upon model simulations performed by Battelle.

1.3 Chilled Ammonia Process

1.3.1 Preliminary Safety Analysis

This study presented preliminary information on potential hazards related to the Mountaineer CCS II project. It is a fundamental risk study based on preliminary design information and represents participation of the key stakeholders involved in the design process. The primary value of this study is enhancement of early project planning through identification and assessment of potential events that present risk to health, safety, and environment; the Phase I effort also focuses on risk identification for potential impact on the capital cost estimate and Phase II planning. This analysis is limited to the "Capture" portion of the project scope;

the safety analysis for the "Storage" portion of the project is the responsibility of the storage contractor, Battelle, and is discussed in section 1.8.1.

Two meetings involving AEP, Alstom, WorleyParsons, and the Department of Energy were conducted for risk identification and assessment; the results of these sessions were recorded on a spreadsheet that employs WorleyParsons Risk Management Software for processing and prioritizing of the input. This exercise was completed in Phase I with the understanding that the process will continue through Phase II with confirmation and completion of risk evaluation and treatment.

The two risk planning sessions, along with the resulting risk register and preliminary action plan, satisfy the objectives of the Phase I planning effort with respect to health, safety, and environmental risk analysis. The impact of risk items affecting project design and budget have been incorporated into the Phase I planning effort.

1.3.2 Process Flow Diagram (PFD) and Mass and Energy Balance

One of the earliest efforts in Phase I was the development of the process flow diagrams and material and energy balances which would serve as the basis for the Phase I conceptual design. Alstom issued the initial material and energy balances in August 2010. Upon review of the PFD and mass and energy balances, AEP and Alstom agreed that there were several areas of the design and its integration into the Mountaineer plant that needed to be addressed before finalizing the conceptual design.

Alstom and AEP engineering met in Alstom's Wiesbaden, Germany office during a two week period in September 2010 to discuss the design. Several process design alternatives were proposed that would potentially correct problems experienced on the PVF, simplify the process, and/or make it more operator-friendly. Further design workshops were held throughout October and November to work through the final details of design concerns, address Balance of Plant (BOP) integration, and to review process simulations. Alstom issued final PFD's and full load material and energy balances in December 2010, and later provided additional mass and energy balance simulations at defined operating parameters that better defined the operating envelope of the CAP. Additionally, WorleyParsons developed PFD's encompassing the BOP scope.

1.3.3 Piping & Instrumentation Diagram (P&ID)

As identified the Cooperative Agreement, Alstom and WorleyParsons developed P&IDs for the CAP facility, advancing the detail shown in the process PFDs. P&IDs fully depict all processes, controls and instrumentation; P&IDs include all major pipe, equipment, equipment tag numbers, nominal pipe sizes, pipe material, control and safety valves, specialties, and instrumentation designation.

The development of the P&IDs underwent multiple design reviews during Phase I. The final P&IDs were used in the development of the process functional design and mechanical functional design, and furthermore incorporated into requests for quotations submitted to vendors.

1.3.4 Process Description

The CAP Process Description describes the major process components of the CAP Island. The CAP system includes:

- Flue Gas Cooling/Cleaning
- Absorber
- Regenerator
- CO_2 Compressor
- Reagent Handling
- Refrigeration

The Process Description provides the basis for normal operation, start-up, and commissioning procedures for the process and is based on information developed and obtained during the Phase I FEED process.

The BOP Process Description outlines the operation of the BOP equipment intended to support the Mountaineer CCS II Project. These systems support the CAP whose function is removal of CO_2 from the flue gas stream.

The BOP systems include:

- Byproduct Storage and Processing
- Flue Gas Duct Drains
- Instrument and Service Air
- Potable Water
- Process Steam Condensate
- Process Steam
- Makeup Water / Service Water
- Waste Water

The BOP Systems for AEP's Mountaineer CCS II Project are designed to meet the applicable requirements of the AEP Project Specific Design Criteria and other AEP criteria documents specified therein. For each BOP system, the process description discusses a description of the equipment, functional requirements, and a general description of the control and operation.

1.4 Mechanical

1.4.1 Equipment List

An equipment list was developed as an all inclusive document providing the piece of equipment, equipment tag number, equipment rating, manufacturer's model number, electric motor rating and speed.

1.5 Electrical / I&C

1.5.1 Preliminary Electrical One Lines

Preliminary electrical one-lines developed for the MT CCS II project depict the schematic representation of the electrical system, including generators, transformers, switch gear, motor control centers, breakers, etc., showing redundancy, control methods, sparks, phase relationship, power cable rating, and electrical characteristics of equipment.

1.5.2 Distributed Control System (DCS) Control Philosophy

The CAP Process Control Description is intended to provide the Process Control Description for the systems comprising the Carbon Capture System at AEP's Mountaineer Station. This document describes the purpose, equipment make-up, and process description for each of the following systems:

- Flue Gas Cooling
- Circulation Water Distribution
- Absorption
- NH_3 Wash and Stripping
- Regeneration
- CO_2 Compression
- Refrigeration
- Auxiliaries and Sumps
- Sulfuric Acid
- Ammonia Storage and Handling
- Process Monitoring
- Gas Analyzers

During the Phase I effort, Alstom developed the CAP Process Control Description and provided to AEP. AEP reviewed the document and submitted comments in return. AEP agreed to push resolution of the comments to this document until a future phase, as Alstom's document adequately described the functionality to a level of detail appropriate for Phase I design and estimating.

In addition to the Process Control Description for the CAP scope developed by Alstom, WorleyParsons was given the task to develop the CCS DCS Control Description. This document describes the operating, control and monitoring philosophy associated with the MT CCS II project. As part of the general control philosophy, WorleyParsons identified plant functions, critical protection and trips, non-critical protection and trips, critical control, non-critical control, monitoring, permissive and interlocks, overrides, and e-stops requirements. The DCS Control philosophy also discusses general operator interface, the operator interface terminal, controls, equipment arrangement, system control and I/O, redundancy and separation, DCS data communication, DCS monitoring, process historian, and flue gas monitoring.

Battelle was also responsible for developing the control logic for the well monitoring and maintenance system (WMMS) as part of the Phase I efforts. Within the WMMS control logic, Battelle provides an overview of hardware which makes up the WMMS control system, the programmable logic controller (PLC) software, the WMMS operation, preliminary alarm conditions, and interlocks and fail safe operation.

1.6 Permits, Insurance, & Infrastructure

1.6.1 Relocations

As part of the Phase I effort, WorleyParsons completed a relocation study. Once equipment arrangements were finalized, WorleyParsons investigated the area for interferences with utilities and structures in the area of the CCS facility and determined what if any relocations were necessary. Following completion of the study, WorleyParsons developed a drawing showing the items identified by the study and proposed location for the utility to be moved.

1.6.2 Identify Permits

Identification of permits needed to complete the MT CCS II project was an important process in the planning of future phases of the project. Much of this effort was handled by AEP's internal resources who are accustomed to permitting requirements specific to the Mountaineer Plant. WorleyParsons aided AEP in the identification of required permits as did Battelle in relation to the CO_2 pipeline and GSS wells, respectively. Some planning, such as that associated with the UIC Class VI permit, required greater coordination with the West Virginia Department of Environmental Protection (WV DEP) or corresponding government agency. Permit requirements were documented in the Permit Summary Report (Attachment A), and were incorporated into other project documents such as the project schedule and cost estimate.

1.7 Professional Services

1.7.1 WBS

A Work Breakdown Structure (WBS) was developed in the initial phase of the project and incorporated into the Cooperative Agreement. The WBS sectioned Phase I into the Capture portion, the Storage portion, AEP activities and NEPA activity. The project Phase I schedule and costs, along with their metrics, were reported based on the WBS.

The WBS was later expanded to delineate all phases of the project and maintained the same sections within each phase of Capture, Storage and AEP Services. Phase II was tailored to the Engineering and Design phase of the project and included a further breakdown by component systems within each section. Phase III focused on the construction activities by system and category. Phase IV reflected the operations phase.

The WBS was utilized by the project team as the outline of the project and was used to relate various elements including cost, schedule, communications, scope management, and division of work. AEP, Alstom, Worley Parsons and Battelle collaborated on the items contained in the WBS and contributed to the published definitions of limits and inclusions within each WBS.

1.7.2 Cost Estimate

One of the main deliverables for Phase I of the project was a +/-25% cost estimate of all phases of the total project. A detailed Work Breakdown Structure (WBS) was established that continued the delineation of the project between Capture and Storage initiated in Phase I. The sections were further broken down to component systems and basic construction categories. The WBS evolved with the addition and changes in scope and each WBS was defined to determine what was to be included in each.

Early in Phase I, a kick-off meeting was held with all entities contributing to the final estimate. The purpose of the meeting was to inform participants of the various common aspects of the estimate and the expectations. This initial meeting was followed up with bi-weekly meetings to discuss progress in completing deliverables, identify obstacles in meeting timing and make decisions to resolve issues.

The following factors were initiated in advance of the estimate development and contributed to the successful compilation of the estimate:

- A matrix with all WBS codes was published to all entities showing who supplied the quantities, material costs, labor cost and input to the consolidated estimate.
- An estimate format and template was established that was compatible with the estimating systems of all the entities and easily consolidated in the master estimate.
- Coding was developed for estimate source code, contracting strategy, escalation and risk factors applicable to individual items that was common to all entities.
- Labor unit rates, crews, productivity factors and indirect costs were determined in conjunction with all entities and applied uniformly to all component estimates.
- Escalation was a composite forecast based on various sources both internally and externally for several high level categories such as type of work, commodities, equipment and services. A table was developed and applied consistently.
- Major material costs were obtained by RFQ wherever possible.
- Several meetings and discussions along with input from an erection contractor were utilized to focus on constructability of the system components including delivery, on site handling, erection and sequencing. These factors were incorporated into the fabrication and estimated costs of the components.

Several meetings were held to review the estimate. One was with all parties to review the estimate by individual WBS to determine if there were any omissions, changes, or deletions based on the current scope and also to validate the reasonableness of various items. Separate meetings were held to determine which items had risk and/or opportunity potential and to what extent. A risk analysis was performed using the double triangle method suggested by the DOE. The risk was incorporated into the final estimated amount where appropriate.

The overall thoroughness in executing the estimate resulted in a product that achieved the anticipated +/- 25% accuracy. Details of the estimate are described in the Preliminary Public Design Report which is available on the NETL website (netl.doe.gov). The total estimated constructed cost including escalation and risk based contingency is approximately $1 billion.

1.7.3 Project Schedule

As part of the Phase I effort, Alstom, Worley Parsons, Battelle & AEP developed the necessary activities for Phase II and III. Each group developed a Level 1 for their scope in each phase. Once the Level 1 was reviewed, integrated and approved by the project team, the schedule was then detailed to a Level 2. The Level 2 was reviewed, integrated and approved by the project team and the process of developing the Phase II Level 3 schedule proceeded.

To develop the Level 3 schedule, each group developed the detailed activities they identified for Phase II. Once the activities were entered into the software, meetings were held to discuss the logic and integration and actions were taken to detail new activities. Critical Path Method reviews were done and an integrated Phase I, II & III schedule was completed in June 2011.

1.7.4 Procurement Template

A procurement template was developed for the MT CCS II project following the general AEP procurement guidelines. The procurement template consists of an Engineering Requisition, a detailed Scope of Work document, Proposal Requirements, AEP Project and Field Services Invoicing Requirements, Project Engineering and Design Criteria, Specifications, Guidelines, and Standards, and a Bid/ Contract Summary.

1.7.5 Contract Template

AEP developed a standard contract template for use on the MT CCS II project. This template consists of a Request for Proposal, a detailed Scope of Work document, Proposal Requirements, AEP General Terms and Conditions, Supplemental Safety Terms and Conditions, Government Flowdown Requirements, AEP Scheduling Requirements, AEP Project and Field Services Invoicing Requirements, Project Engineering and Design Criteria, Specifications, Guidelines, and Standards, and the vendor's proposal.

Due to AEP's position at the Phase I Decision Point, AEP did not proceed with Phase II contract negotiations.

1.7.6 Phase I Alstom Contract

As the identified owner of the CAP technology, AEP negotiated a contract with Alstom to participate in the conceptual design of the MT CCS II facility. AEP began negotiations with Alstom on February 1, 2010, once the Cooperative Agreement with the U.S. DOE was finalized, and reached agreement on June 4, 2010.

1.7.7 Phase I Storage Contract

A contract was also negotiated with Battelle Memorial Institute to perform the Phase I work of developing the conceptual design for the GSS. AEP began contract negotiations with Battelle in March 2010, and executed a contract on July 16, 2010.

1.7.8 Phase II Alstom Contract

AEP engineering, in conjunction with Alstom and WorleyParsons engineering, developed a detailed division of responsibility. The division of responsibility depicts in a tabular format, the organization which is responsible for the functional design, detailed design, detailed design review, deliverable submittal, equipment/ material supply, fabrication drawing approval, site erection supervision, site erection execution, and site commissioning for each WBS element.

In anticipation of the Phase II contract development, Alstom developed a description of the scope which would be performed by Alstom during Phase II of the project. Further contract negotiation never came to fruition due to AEP's decision to suspend the project after completion of Phase I deliverables.

1.7.9 Phase II Storage Contract

AEP engineering, in conjunction with WorleyParsons and Battelle, developed a detailed division of responsibility. The division of responsibility depicts in a tabular format, the organization which is responsible for the functional design, detailed design, detailed design review, deliverable submittal, equipment/ material supply, fabrication drawing approval, site erection supervision, site erection execution, and site commissioning for each WBS element.

In anticipation of the Phase II contract development, Battelle Memorial Institute developed a description of the planned scope which would be performed by Battelle during Phase II of the project. Further contract negotiation never came to fruition due to AEP Management's decision to suspend the project after completion of Phase I deliverables.

1.7.10 Phase II Construction Contract

A construction contract was not required for the Phase II effort planned during Phase I; however AEP, Alstom, WorleyParsons, and Battelle developed a proposed contracting strategy for the construction work to occur in Phase III. The contracting strategy is discussed below in section 1.9.14.

1.7.11 Phase II Project Work Plan

The development of the Phase II Project Work Plan was originally planned to be developed during the final three months of Phase I following AEP's delivery of the Phase I Decision Point Application. Due to AEP's position at the Decision Point, AEP did not proceed with development of the Phase II Project Work Plan.

1.7.12 Contracting Strategy

AEP, with input from Alstom, WorleyParsons, and Battelle, developed a proposed contracting strategy for the MT CCS II project. The contracting strategy for the project is to firm price as many contracts as possible, where the scope and schedule are well known, followed by unit price, cost reimbursable, or T&M contracts where the scope of work is not well defined or there are other constraints. The contracting strategy document lists all anticipated contracts required for Phases 2-3 along with the corresponding strategy. This strategy was incorporated into the Division of Responsibility and refined cost estimate.

1.8 Wells and Monitoring Verification and Accounting (MVA) System

1.8.1 Preliminary Safety Analysis

Similar to the preliminary safety analysis conducted for the capture and compression scope of the project, Battelle performed a safety analysis of the geologic storage system. For the purpose of the Safety Analysis the project was divided into distinct elements called "Nodes" as listed below:

- Node 1: Drilling / Monitoring Injection Well
- Node 2: Well Completion
- Node 3: CO_2 Pipeline Transport
- Node 4: Injection
- Node 5: Site/Well Closure

- Node 6: Post Injection Storage & Monitoring
- Node 7: Maintenance and Workover Programs

The method used to conduct this safety analysis was the "what-if analysis". The what-if analysis technique was developed specifically for the process industry to identify both safety hazards and operability problems that could compromise the ability to achieve design productivity.

The what-if study method entails analyzing hazardous events (incidents) to see how they may occur and what undesired consequences are possible. Each sequence of failures and conditions leading to an accident event is a unique scenario. Every accident scenario includes an initiating event or cause (e.g., mechanical or human failure), an accidental event or consequence, and an impact (injuries and/or damage). Safeguards may be employed to keep the incident from occurring. Mitigation may reduce the severity of the impact.
The concept of the system review is to assume that the system works well when operating under design conditions. Problems arise when deviations from the design conditions occur. The what-if methodology requires a team of subject matter experts to review the system of interest, in this case the transport, injection, and storage of CO_2. The system is divided into its major elements (nodes) and what-if questions are generated for each element within the system. Following are the type of what-if questions that are asked during the review:

- What if {a specific accident} occurs?
- What if {a specific system} fails?
- What if {a specific human error} occurs?
- What if {a specific external event} occurs?

The team then responds to the what-if questions with potential consequences, assuming no safeguards are in place. Once the potential consequences are determined, the team then identifies possible engineering and/or administrative safeguards to protect against a particular mishap. The team assesses the protection measures included in the system design that may reduce the likelihood of the scenario and/or to prevent or minimize the consequences or impacts. Based on the estimated frequency and severity of the consequences, the team may make recommendations to reduce the overall risk of the scenario.

Although the overall objective of the safety review is to identify potential accident scenarios and identify opportunities for risk reduction, it is important to table discussions on risk reduction solutions outside of the safety review to ensure that all of the potential scenarios can be addressed in a timely manner.

For each scenario, the risk associated with that scenario was estimated. The risk estimate was formed by assigning a score to the probability of the scenario occurring and the impact of the consequence, considering each with and without safeguards. The team looked at the health and safety, environmental and business loss consequences to determine an overall consequence of the scenario.

1.8.2 Develop the Preliminary Monitoring Plan

The Preliminary Monitoring Plan developed by Battelle provides an overview of the testing and monitoring that can be deployed near the Mountaineer Power Plant.

The specific testing and monitoring requirements for the commercial-scale project are not known at this time because an Underground Injection Control (UIC) permit has not yet been issued for the project. Therefore, it was assumed that testing and monitoring requirements for the commercial-scale project will be similar to those for the ongoing pilot-scale CO_2 capture and storage project at the Mountaineer Power Plant. It was also assumed that the testing and monitoring requirements in U.S. EPA's new Geologic Sequestration (GS) Rule will apply. The 20 MW PVF pilot scale project is authorized by West Virginia Department of Environmental Protection (WVDEP) Underground Injection Control (UIC) Permit No. 1189-08-53, a Class V (experimental) permit. The Class V permit stipulates testing and monitoring requirements to verify that the experimental geologic sequestration project is operating as permitted and is not endangering underground sources of drinking water (USDW). The U.S. EPA, in December 2010, issued the GS Rule, which establishes a new class of injection well, Class VI, for wells that will be used to inject CO_2 into deep geologic formations for long-term storage (sequestration). The GS rule sets minimum federal technical criteria for Class VI wells for the purpose of protecting USDWs and mandates comprehensive monitoring of all aspects of well integrity, CO_2 injection and storage, and groundwater quality during the injection operation and the post-injection site care period. A Class VI UIC permit will be sought for the commercial-scale project; therefore, testing and monitoring requirements in the new GS Rule were considered in developing this testing and monitoring plan.

Another driver for monitoring requirements is the Mandatory Reporting of Greenhouse Gases Rule (MRR) (74 FR 56260), which requires that all facilities that inject CO_2 for the purpose of long-term geologic sequestration to report basic information on CO_2 injected underground and imposes additional monitoring to quantify CO_2 emissions to the atmosphere.

The preliminary monitoring plan discusses design assumptions, a summary of the monitoring and testing program, and the purpose, description, baseline monitoring, and operational phase monitoring for the following components: quarterly analysis of the CO_2 injection stream, injection and annulus pressure/temperature monitoring, corrosion monitoring, external mechanical integrity testing, pressure fall-off testing, groundwater monitoring, surface microseismic monitoring, wireline logging for plume tracking, monitoring fluid chemistry in the injection reservoirs, monitoring pressure in injection reservoirs, modeling, and mandatory reporting requirements for the injection and geologic sequestration of carbon dioxide.

1.9 AEP Project Management and Support

As outlined in the Cooperative Agreement DE-FE0002673, AEP's Project Management Team (PMT) employed earned value management techniques meeting industry standards for tracking completion of work, keeping activities on schedule, and controlling costs to remain within the budget throughout the Phase I. The PMT implemented and managed the Project and reported on activities in accordance with the approved Project Management Plan (PMP).

The PMP is the critical document that integrates how: (a) work is executed to accomplish the Project objectives; (b) Project risks are considered; (c) the Project technical scope, cost and schedule are managed; (d) Project performance is monitored and controlled; and, (e) Project information is communicated within the Integrated Project Team (IPT) (which includes the DOE) and to external stakeholders.

1.10 National Environmental Policy Act (NEPA)

Pursuant to the National Environmental Policy Act (NEPA), the U.S. Department of Energy (DOE) was required to evaluate potential environmental impacts as part of its decision-making process to determine whether to provide financial assistance beyond Phase I of the commercial-scale Mountaineer CCS project.

The NEPA evaluation considered all aspects of the proposed project (i.e. CO_2 capture, transport, and storage) with a focus on 18 key resource areas: air quality; greenhouse gases; geology; physiography & soils; groundwater; surface water; wetlands & floodplains; biological resources; cultural resources; land use & aesthetics; traffic; noise; materials & waste management; human health & safety; utilities; community services; socioeconomics; and environmental justice.

This comprehensive evaluation is collectively referred to an Environmental Impact Statement (EIS). Preparation of the draft EIS required a significant amount of field studies to evaluate biological, cultural, and water resources that may be impacted by the project. DOE issued a draft EIS for public review on March 11, 2011. A copy of the draft EIS can be found at:
www.netl.doe.gov/technologies/coalpower/cctc/EIS/eis_mountaineer_draft.html

IV Conclusions

On July 7, 2011, AEP provided a letter to the DOE proposing a partial termination of the scope of work for Phases II, III or IV as defined in the Statement of Project Objectives (SOPO) contained in Attachment No. 2 to Cooperative Agreement DE-FE0002673. This decision resulted from the changes which have occurred in the CCS arena since the beginning of the project. When the original grant application was submitted by AEP in response to DE-FOA-0000042, AEP believed it was important to advance the science of CCS due to pending action regarding climate change legislation and/or regulations concerning CO_2 emissions at our coal-fired power plants. Various bills in Congress were introduced to limit emissions but also provide funding for early CCS projects. AEP also believed that regulatory support for the remaining cost recovery beyond the DOE or legislative support was probable given the potential for emission reduction requirements on an aggressive timetable. While AEP still believes the advancement of CCS is critical for the sustainability of coal-fired generation, the regulatory and legislative support for cost recovery simply does not exist at the present time to fund AEP’s cost share of the commercial scale CCS facility.

Notwithstanding AEP’s decision to dissolve the existing cooperative agreement and postpone project activities, AEP and its extended project team successfully completed the Phase I effort for the Mountaineer Commercial Scale Carbon Capture and Storage Project, as outlined in the cooperative agreement. Within Phase I the cooperative agreement called for:

- The resolution of outstanding conditions with the U.S. Department of Energy (DOE) cooperative agreement;
- Project specific developmental activities (i.e., front-end engineering and design);
- The initiation of the NEPA process; and
- The identification of exceptionally long lead time items.

The front-end engineering and design package developed within Phase I incorporated knowledge gained and lessons learned (construction and operations related) from the Mountaineer Product Validation Facility (PVF) and the design package also established the fit, form, and function of the project including design criteria, mass and energy balances, plot plans, general arrangement drawings, electrical one-lines, flow diagrams, P&IDs, etc. Based on the work completed in the front-end engineering and design package, AEP and its extended project team also:

- Developed a +/- 25% cost estimate,
- Developed a detailed Phase II project schedule,
- Provided DOE with all information it needed to complete the NEPA process,
- Developed a multi prime construction contracting strategy for Phase III,
- Issued preliminary PFD and overall mass and energy balances, and
- Completed preliminary project design.

In summary, the work completed in Phase I continues to support the commercial readiness of Alstom's CAP technology at the intended scale and provides AEP and DOE with a good understanding of the project's risks, capital cost, and expected operations and maintenance costs during planned Phase IV operations. The completed front-end engineering and design package provides a sound basis for completion of the project when conditions warrant the continuation of this or a similar project elsewhere in the U.S.

V Products Produced / Technology Transfer Activities

- DOE sponsored Japanese Utilities tour of the Mountaineer Product Validation Facility, 7/15/10.
- McElwee, Charles; Spitznogle, Gary. "Can America Capture and Store Carbon?" Charleston Gazette 9/5/10
- DOE CCS Program Conference, Pittsburgh, PA, 9/16/10.
- AEP gave project presentations at the Racine Town Council meeting on 10/18/10, the WV building trades meeting on 10/20/10, the Mason Town Council meeting on 10/21/10, and the New Haven Town Council meeting on 10/26/10 as part of the semiannual community leaders updates.
- AEP presented the MT CCS project semi-annual update to the Mason County Commission on 11/5/10.
- AEP conducted a Conference of Right hearing with the IRS on 11/23 to respond to the IRS' tentative adverse opinion on AEP's request for a Private Letter Ruling designating the Cooperative Agreement funding as non-taxable. AEP Legal responded to the IRS' position on two issues and submitted a supplemental letter to the IRS on 12/10/10 providing written confirmation of the information presented at the Conference of Right hearing. In response to AEP's requests, the IRS determined that published guidance is the appropriate way to address the CCPI funding tax status. The IRS will therefore not issue AEP's private ruling and will refund the $14,000 user fee.
- AEP hosted the DOE sponsored North America Knowledge Sharing Agreement task force on 11/30- 12/1/10. The activities included a tour of the 20 MWe Mountaineer CCS Product Validation Facility on 11/30/10 and CCS presentations and discussions on 12/1/10 at AEP's corporate office. The MT CCS II project team gave a presentation at the 12/1/10 conference including lessons learned from the MT PVF and MT CCS II projects.
- On 2/16/11, AEP issued a press release announcing the funding agreement with the Global CCS Institute.
- AEP developed an issued an Activity Management Plan to the Global CCS Institute on 4/15/11.
- AEP participated in the CCS Conference held in Pittsburgh, PA on 5/2-5/5/11.
- AEP's Matt Usher provided a presentation of the project at the Southeast Electric Exchange conference held in Atlanta, GA 5/18-5/20.
- AEP's Guy Cerimele provided a presentation of the project at the Southeast Electric Exchange conference held in Orlando, FL 6/29-7/1/11.
- AEP's Gary Spitznogle contributed to the article in *The Columbus Dispatch* "Ohio goal: Extract oil by getting rid of CO_2"
- AEP developed an issued a CCS Integration White Paper to the Global CCS Institute on 10/25/11.
- AEP presented at the Global CCS Institute's CCS Integration Conference in London, England on 11/3/11.
- AEP will present at the Global CCS Institute's CCS Roadshow events in Austin, Texas on 11/8/11, and in Calgary, Alberta, Canada.
- AEP has also developed additional reports for the Global CCS Institute including a report on CO_2 Storage, a Compression report, a FEED report, a Lessons Learned report, and a Financial Modeling/ Business Case report. AEP is in the process of addressing comments to these reports at this time, and expects to issue in final version by the end of 2011.

Appendix A
MT CCS II - Project Permit Summary Report

MT CCS II - Project Permit Summary

PERMIT NAME	GOVERNING AGENCY	PERMIT REQUIRED FOR	PERMIT DEVELOPMENT REQUIREMENTS	RESPONSIBLE GROUP/ ENGINEER	PERMIT DEVELOPMENT DURATION	PERMIT REVIEW DURATION	COMMENTS
ENVIRONMENTAL PERMITS							
AIR PERMITS							
WV Reg 13	WV DEP	Permit application for Stacks, Absorbers and other emission sources within Capture, Pipeline & Storage areas.	Mass balances, cooling tower location & emissions, CEMS, Design freeze	AQS	30 days	1 year	
WATER PERMITS							
Cultural Resource Investigation - Agency Concurrence	WV SHPO	Capture, Pipeline & Storage areas	Plot Plan, Cultural Resources Study	WERS	10 days	30 days	
Threatened/ Endangered Species Investigation - Agency Concurrence	WV DNR	Capture, Pipeline & Storage areas	Endangered species studies, plot plan	WERS	10 days	30 days	Indiana Bat, Zebra Mussel, etc. Can only be performed in warm weather. Wait until after EIS ROD received
Threatened/ Endangered Species Investigation - Agency Concurrence	US FWS	Capture, Pipeline & Storage areas	Endangered species studies, plot plan	WERS	10 days	30 days	Indiana Bat, Zebra Mussel, etc. Can only be performed in warm weather. Wait until after EIS ROD received
Section 10/404	US COE	Stream or river crossing and/or changes. Construction activities, dredging, dock improvements and borings within Capture, Pipeline and Storage areas. Permit required prior to site prep/ construction.	Field surveys, corridor and well site plans, mussel survey	WERS	2 months	9 months	Requires Threatened/ Endangered Species concurrences from WV DNR & US FWS, and Cultural Resource concurrence from WV SHPO
401 water Quality Certification	WV DEP	Capture, Pipeline & Storage areas	Field surveys, corridor and well site plans, mussel survey	WERS	2 months	9 months	Triggered by application for USA COE 10/404 Requires Threatened/ Endangered Species concurrences from WV DNR & US FWS, and Cultural Resource concurrence from WV SHPO
Mussel Survey	US FWS	Capture, Pipeline & Storage areas		WERS	10 days	5 months	Agency review/ approve plan - 30 (calendar) days Conduct Survey/ Prepare Final Report - 34 days Agency Concurrence - 30 (calendar) days Follow-up Field work - 30 days
Nationwide Permit	US COE	Stream or river crossing and/or changes. Construction activities, dredging, dock improvements and borings within Capture, Pipeline and Storage areas. Permit required prior to site prep/ construction.	Field surveys, corridor and well site plans, mussel survey	WERS	4-6 weeks	30 day completeness review + 45 day permit review	Issued in lieu of Section 10/404 Requires Threatened/ Endangered Species concurrences from WV DNR & US FWS, and Cultural Resource concurrence from WV SHPO
Underground Injection Control (UIC Permit)	WV DEP	Required prior to any site preparation work/ construction of injection well site(s)	Seismic study, well design	WERS	1 months	12 months +	Required prior to any site preparation work; 1 permit required for each injection site
Well work permit	WV DEP	Required prior to any site preparation work/ construction of well site(s)	Well design, site layout, UIC permit for injection wells, …	WERS	4 months	30 (calendar) days	UIC permit required prior to well work permit application for injection wells; 1 permit required for each well site
GHG (MRV) Monitoring Plan		required 180 days after UIC permit issuance	Monitoring plan	WERS	40 days	1 year	
NPDES/ Stormwater Construction Permit	WV DEP	Disturbance of a soil area 1.0 acre or greater within Capture, Pipeline and Storage areas	Plot Plan, stormwater calculations	WERS	6 weeks	4 months	
NPDES/ Plant Permit Modification	WV DEP	Operation/ Discharge of wastewater to surface water within Capture, Pipeline and Storage areas.	Plot Plan, P&IDs, General Arrangements	WERS	3 months	6 months	
NPDES - Hydrotest Pipeline	WV DEP	Hydrotesting the pipeline	Plot Plan, P&IDs, General Arrangements, pipeline contractor developed hydro plan	WERS	6 weeks	1 year	

MT CCS II - Project Permit Summary

PERMIT NAME	GOVERNING AGENCY	PERMIT REQUIRED FOR	PERMIT DEVELOPMENT REQUIREMENTS	RESPONSIBLE GROUP/ ENGINEER	PERMIT DEVELOPMENT DURATION	PERMIT REVIEW DURATION	COMMENTS
NON-ENVIRONMENTAL PERMITS							
Certificate of Public Convenience and Necessity	WV PUC	Prior to start of construction	Class II legal advertisement (public notice) in the publication area in each county.	P&FS	40 days	90 days	see Bob Long's Non-environmental permit procedures
Floodplain Development	Mason County Office of Emergency Services	Entire Carbon Capture & Storage Project area; required prior to start of any construction within designated floodplain boundaries	The exact size of the structure to be constructed, or repaired, The location of the construction on the property, The location of other existing structures, or ongoing construction projects on the property.	P&FS	10 days	30 days	One permit per county
FAA Aeronautical Study - Obstruction Lighting	FAA	Required for each structure =/< 200'; breaks a plane. Required approval prior to start of foundation excavation for stacks, etc.	One set of drawings and/or documents specifying the locations and dimensions of the construction or alteration.	P&FS	10 days	130 days	Also requires notice of start of construction 2 days prior (5 days to develop), and notice of construction complete no later than 5 days after reaching final height (5 days to develop)
Architectural Review	State Fire Marshall	Control Room/ Lab Bldg, Warehouse/ Maintenace Bldg, Admin Building, By-product Storage Bldg, Electrical Bldg, By-product Processing Bldg, Power Distribution Center, Refrigeration Compressor Bldg.; required prior to start of structure erection	Specifications, site plan, architectural plan, plubing plan, mechanical plan, electrical plan, bldg elevations and sections	P&FS	10 days	20 days	Durations are for each structure. Agency site inspection after completion of building construction; occupancy permit issued in conjunction with approval of Fire Alarm System and Sprinkler System; one per structure; permit fees calculated on % of building construction costs
Fire Alarm System Review	WV State Fire Marshall	Control Room/ Lab Bldg, Warehouse/ Maintenace Bldg, Admin Building; required prior to start of system installation	Architectural drawings which identify room usage, all alarm devices, wiring diagrams, spec sheets for fire alarms, devices and panels, and battery calculations.	P&FS	10 days	20 days	Durations are for each structure. Agency site inspection after completion of system installation; occupancy permit issued in conjunction with approval of Sprinkler System and Architectural Review
Sprinkler System	WV State Fire Marshall	agency approval required prior to start of system installation	Sprinkler system layout and devices, fire dept connection location, hydralic calculations, water flow test information, valves, tamper flow switches and gauges, underground piping size and location, water supply pump and tank size and location.	P&FS	10 days	20 days	Durations are for each system. Agency site inspection after completion of system installation; occupancy permit issued in conjunction with approval of Fire Alarm System and Architectural Review
Tank Review	WV State Fire Marshall	Review of all tanks containing flammable/ combustable liquids and gases to be installed as part of the project; required prior to tank erection	Site plan that locates the tank with respect to property lines, buildings and public ways; locates and provides the size of protection bollards; locates emergency shutoff valves and tank manufacturer's drawings and/or spec sheets (stamped and signed).	P&FS	10 days	20 days	Durations are for each tank. Agency site inspection after completion of tank installation
Fire Code Variance Request	WV State Fire Marshall	Required prior to start of system installation		P&FS	10 days	20 days	Durations are for each system. Agency site inspection after completion of system installation;
Railroad Spur Modification	CSX Transportation	needed prior to start of any construction work associated with the side track	Drawings stamped and signed by the supervising engineer	P&FS	5 days	5 days	
Railroad Crossing	CSX Transportation	Crossing over or Under Railroad Right-of-Way; required prior to accessing and/or starting any construction activity within railroad right-of-way	Drawings stamped and signed by the supervising engineer	P&FS	10 days	175 days	Requires to prepare/ submit notice of construction complete (5 days)
Highway Crossing	WV DOT	Crossing over or under highway; required approval prior to start of any work within, or occupancy of, highway right-of-way	Drawings that sufficiently show the nature of work to be performed	P&FS	10 days	30 days	Requires to prepare/ submit notice of construction complete (5 days)
Easements/ Right-of-Way	WV DOT & Railroad	Approval of pipeline route		Land Management			
Risk Management Plan	US EPA	Required to submit prior to containing anhydrous ammonia on site (will only be within Capture Area)	Plot Plan, P&IDs, General Arrangements	AEP Physical Security	1 year	None	
Environmental & Safety Plans			Existing Environmental & Safety Plans	PEC	3 months	None	
Seismic Permit	see comments	-	-	see comments	-	-	Battelle is responsible for obtaining prior to performing any seismic studies
Elevator Inspection	see comments	-	-	see comments	-	-	Elevator contractor is responsible for certifying all installed elevators; must be ASME 17.1 certified