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Coal-Based Power Plants of the Future: Electricity and Ammonia Polygeneration Technology Gap Analysis

Submitted To:

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1. Concept Background

Team AST developed a coal-based power system for application in the evolving bulk power system. Specifically, the design is a polygeneration plant for the co-production of electricity and ammonia from coal in a flexible system that can adapt to complex and shifting realities inherent in a modern electrical grid with significant renewable penetration. At a high level, the plant consists of two gasifier trains, a power island and two ammonia loops.

The general business philosophy of the polygeneration design centers on offering multiple potential revenue streams, including (1) commercial electricity available for sale to the grid, (2) salable ancillary services (e.g., capacity markets, frequency stability, voltage regulation, etc.), (3) and NH_3 for commercial delivery at or near retail (as opposed to wholesale) prices. By combining these three different revenue streams in a polygeneration facility that offers high operational flexibility, it is possible to modulate plant operations on a very short time scale to meet emerging market signals and opportunities. This ability to correctly match production to market demand will allow for optimization of plant profitability.

While the plant has the flexibility to operate at a multitude of operating points, the edges of the overall operating range are currently described by five specific operation modes, as seen in Exhibit 1-1:

Exhibit 1-1 Summary of Operating Modes

Operating Point	Net Export Power	Ammonia Production	Gasifier Operation	GT Operation	ST Operation	Ammonia Train Operation
Balanced Generation, 3 GT's	48 MW	600 MTPD	100% of Capacity	Three Turbines @ 67% Capacity	Primary ST @ 86% load	Both Trains @ 100% Capacity
Balanced Generation, 2 GT's	51 MW	600 MTPD	100% of Capacity	Two Turbines @ 100% Capacity	Primary ST @ 91% Load	Both Trains @ 100% Capacity
Net Zero Power	0 MW	600 MTPD	66% of Capacity	One Turbine at 67% Capacity	Primary ST @ 40% Load	Both Trains @ 100% Capacity
High Electricity Production	82 MW	380 MTPD	100% of Capacity	Three Turbines @ 100% Capacity	Primary ST @ 88% Load	Both Trains @ 63% Capacity
Max Electricity Production	112 MW	59 MTPD	100% of Capacity	Three Turbines @ 100% Capacity	Primary ST @ 100% Load, Secondary ST @ 85% Load	Both Trains @ 10% Capacity

These operating modes define an operating window that provides the flexibility to modulate ammonia and net electricity production to meet market demand while enabling the two gasifier trains to operate at ~65% of capacity even in the absence of net electricity demand by the grid. This will allow the plant owner to choose operating points to maximize profitability while reducing the potential of being forced into outage by curtailed market demand.

The intent is to operate the polygeneration facility at a high service factor more typical of a chemical production facility rather than what would be normally expected from a pure, fossil fuel-based electricity generation facility that is subjected to forced curtailment. A number of design decisions have been made to support this goal. Multiple gasifier trains have been selected to provide the ability to run one train in conjunction with utilization of stored syngas (if required) while another train is shut down for maintenance. Additionally, if service is required to either the ammonia loop or power island, it can be performed at time when high demand is predicted for the alternative plant production capacity (i.e., if ammonia loop maintenance is required, it can be scheduled during a time of predicted high net energy demand, reducing the overall turndown for the plant as a whole.

The ability to perform opportunistic maintenance as described above, as well as the ability to match plant output to market demand, should support a service factor closer to the 96% metric achievable by chemical production facilities. However, it should be noted that the standard electrical generation service metric does not have as clear of a meaning for a polygeneration plant with multiple, viable operating points.

At the reference *Balanced Production, 3 GT's* operating point, ~71,000 kg/hr of as-received, Illinois #6 coal will be dried in a fluidized bed before passing to two SES U-Gas gasifiers, which will produce ~172,000 kg/hr of raw syngas. After passing through a water-gas shift reactor and various syngas cleaning and emission control technologies[1], the clean syngas will be nominally distributed to the ammonia train and power block. This *Balanced Production* syngas disposition will support net power generation of 49 MW and ammonia generation of 600 MTPD.

As detailed above in Exhibit 1-1, the 600 MTPD represents the maximum ammonia production for this plant. By shifting to the *High Electricity Production* operating mode, it is possible to increase net power generation to 82 MW while reducing ammonia production to ~380 MTPD. This net power export can be further increased to 112 MW, as seen in the *Max Electricity Production* operating point. This 112 MW net power export relied on a deep turndown of the ammonia trains (both trains operating at 10% of maximum capacity).

2. Performance Gap Assessment

The *Performance Results* report provides a detailed assessment of the polygeneration system's performance over a broad range of operating points that define the overall plant operating window. Additionally, *Section 4* of the *Performance Results* report provides an explicit evaluation on how the polygeneration system meets the objectives of the Coal FIRST program. Of these, the only objective that is not unambiguously satisfied is system efficiency. The efficiency of the system varies with operating mode and an aggregate efficiency is difficult to define for a polygeneration system without more detailed analysis and significant forecasting of assumptions on what percentage of time the plant will spend at each operational point.[2] As such, any estimate of overall HHV efficiency of the plant incorporates a level of subjectivity in choosing a representative reference operating point. However, since the system reaches high efficiency numbers across a wide operational range, it is believed that no significant performance gap will exist, especially

[1] Details on ammonia removal, mercury removal, acid gas removal, CO_2 compression and drying, sulfur recovery, and tail gas treatment can be found in the *Performance Analysis Report*.

[2] A financial and investment model has been developed for inclusion in the final report that is capable of forecasting time spent at each defined operating point under a given set of economic conditions. However, as the results of this model are highly dependent on the specifics of the user-defined scenario and forecasting market evolution over a 10+ year time frame is inherently difficult, it is not reasonable to present a definitive statement regarding projected time spent at each operating point at this time.

when considering a non-capture case. As such, no further research and development efforts are *required* for the polygeneration system to meet the objectives of the Coal FIRST program.

Additionally, as described below, all of the equipment in the designed polygeneration system can be commercially procured at this time. The specifications of equipment sent for bid may be adjusted through process validation and piloting to complement the current systems analysis, but there is no anticipated novel function or equipment that will need to be created. As such, no further research and development is *required* to deploy the equipment currently detailed on the polygeneration flowsheet.

While no inventive or inherently risky development is required to deploy the described system, the system can still benefit from additional process development and engineering activities aimed at lowering the technical risk to full-scale deployment through validation of modeled and simulated system performance and operating characteristics. Given the mature nature of the core unit operations and the manageable level of technical risks associated with system integration, a higher risk approach of omitting the pilot phase could be considered to accelerate deployment. In this instance, the first commercial application would be a pioneer plant with the understanding that evaluation of the pilot plant objectives would come during initial pioneer plant operations leading to an improvement-based turnaround that implements the learning of the pilot stage investigations undertaken during the early operations of the pioneer plant. However, this approach is inherently risky, and, as such, the current recommendation incorporates separate piloting and commercial phases, particularly as successful pilot operations will prove out a reduced project risk level and lead to better financing terms. Additionally, while not required for deployment, the performance of polygeneration technology platform may be improved by supporting innovation outside of the current work and commercially available offerings.

A pilot plant program serves both of these goals by providing an opportunity to validate modeled and simulated results in a real-world setting, as well as providing an option to explore integration of novel innovations into the system. These benefits are captured in the pilot plant objectives section below.

3. Commercialization Assessment

The section will provide an assessment of the ability to move forward and implement the polygeneration system described in the *Performance Results* report. This section would typically contain discussion of further research and development required to move forward and implement the designed system, had there been any required. Discussion on additional systems integration, validation, and opportunity for incorporating further innovation during pilot plant operations is covered in *Section 4: Pilot Plant Operations*. The later sub-section of the *Commercialization Assessment* is to document the basis and resources that Team AST (Allegheny Science and Technology, Worley, and Catalyte) used in undertaking that assessment.

3.1 High-Level Commercial Readiness

Exhibit 3-1 provides a high-level assessment of the commercial readiness of each major unit operation in the design basis, as well as high-level notes on application of generally available commercial components to the specific polygeneration plant design. The technology readiness levels (TRLs) are based on the Department of Energy definitions. By design, the polygeneration system integrates mature, stable, and fully commercialized subsystems (TRLs of 9).

With this being said, there are two subsystems with specific, minor demonstration needs related directly to the designed use that may warrant a slightly lower TRL designation:

- While fluidized bed drying of coal is an established and demonstrated process, it has not been demonstrated for this specific coal basis.
- The operational design of the gasifier includes partial oxidation in the freeboard to reduce the methane content of the produced syngas. While this combines two well-established commercial operations and the selected vendor has specific experience with such application, the operation requires some specific operational validation under the polygeneration design conditions.

The TRL designations of 9 on all other subsystems are justified both by extensive relevant commercial operations and commercial availability of all relevant subsystem equipment.

Exhibit 3-1: Commercial Readiness of Plant Operating Sections

Operating Section	Component Availability	Pathway Forward
Coal Receiving and Handling	Commercially Available	Mature, stable, and established technology. Technology Readiness Level: 9
Coal Preparation and Feed Systems	Commercially Available	Mature, stable, and established technology. Technology Readiness Level: 9
Coal Drying System	Commercially Available	Bubbling bed drying and desorption is an established and demonstrated process. Disciplined detailed engineering and scale-up of this bubbling bed is required. This process can be fabricated by standard qualified, coded vessel fabrication shops based on a design provided during a future detailed design phase or by competitive solicitations based on a duty specification Technology Readiness Level: 9/7; same scale, but different coal feed basis, have operated commercially. Minor demonstration for this coal in the context of this system will be helpful to fully mitigate technical risk.
Air Separation Unit	Commercially Available	Mature, stable, and established technology. If future generations of this technology platform change scale then pressure swing adsorption options should be reconsidered; however, this is also an established commercial technology. Technology Readiness Level: 9

Gasifier	Commercially Available	SES U-Gas design is a mature, stable, and established commercial design. This gasifier has successful been deployed at this scale on utilizing Illinois #6 coal. Partial oxidation is commercially known and deployed technology. This reduces the need for significant supporting experimentation (cold flow), modeling (CFD), or analysis based on fluid bed design and scale-up methodologies as the vendor has already completed this process. Minor demonstration of the partial oxidation in the freeboard would be helpful to fully mitigate technical risk. SES is in the middle of corporate restructure and ownership changes, but based on previous conversations with representatives, there is a high degree of confidence that some entity will retain and support the licensing of the SES U-gas design. Technology Readiness Level: 9/8.
Water Gas Shift	Commercially Available	Mature, stable, and established technology. Technology Readiness Level: 9
Syngas Cooling	Commercially Available	Mature, stable, and established technology. Technology Readiness Level: 9
Syngas Clean Up	Commercially Available	Mature, stable, and established technology options. Honeywell UOP Selexol technology forms the basis of the carbon capture component. Future generations of this platform can look to integrate improvements in pre-combustion capture when their technical maturity is sufficient to warrant the risk. Pre-combustion capture has the potential to provide a step change improvement in financial performance via reduced capital expenditures, reduced parasitic load, and an easier to handle stream of CO_2. Technology Readiness Level: 9
Syngas Management	Commercially Available	Mature, stable, and established technology. Technology Readiness Level: 9
Ammonia Generation	Commercially Available; Current R&D offers significant opportunities for future designs	Mature, stable, and established technology options at scale relevant to this project. Active R&D in areas such as catalysis and process intensification offer potential innovation opportunities for future generations of this technology platform (see description in the Pilot Plant Objectives section below). Multiple vendors (KBR, Proton Ventures, Linde, ThyssenKrupp, Casale, JGC, and Haldor Topsøe) have offerings at scales at or greater than the scale of interest, albeit their “standard” packages would need to be adapted to this application. The cycling of the NH_3 train will complicate vendor negotiations with respect to warranty and performance assurance, regardless the current system interacts with these trains within known dynamic performance. Technology Readiness Level: 9

Power Block	Commercially Available	Mature, stable, and established technology. Selected turbine (LM2500+) has displayed capability to operate with high H_2 content fuels. General Electric has been leveraged by Worley experts in modeling their performance for this application. The more detailed heat integration and recovery during this pre-FEED study has led to more optimized operation and integration of steam turbine generation based on well-established techniques. Please refer to the *Performance Results* report for a more detailed discussion of the heat integration strategy. Technology Readiness Level: 9

A detailed *Major Equipment List* associated with these operating sections is provided in Appendix A. None of the detailed equipment requires significant research and development activities in order to be procured and delivered. The process description, modeling, and specifications (functional duty specification) are substantially developed to the point where they could be used to structure competitive bids on the equipment in the time frames outlined in the *Execution Plan*, when financing for a pilot or pioneer plant supports such activity.

There are systems integration and validation piloting activities that will lower the risk associated with developing the functional specifications of this equipment solely based on process modeling and simulation. These development activities that focus on systems integration and validation are described below in *Section 4: Pilot Plant Objectives*. There are no equipment development or issues in the performance of the equipment to preclude implementing the system within the timelines targeted by the Coal FIRST program. The project implementation and execution timelines have been developed and presented in the *Execution Plan*.

3.2 Summary of Team Experience with Relevant OEMs

Team AST member Worley has extensive experience with relevant OEM and project databases to translate the commercially ready options listed above to this project. Additionally, Team AST member Catalyte has extensive experience in ammonia projects, including interfacing and interacting with ammonia licensors and vendors to complement Worley's expertise.

Worley Group Inc. (formally WorleyParsons Group, Inc.) provides the Architecture and Engineering (A&E) firm component of Team AST. The A&E functions serves to assure designs that reflect state of the art commercial practice, leverages relevant vendor relationships, and can draw on learnings from an extensive and relevant set of projects. From Worley's experience working on a range of similar study type projects and commercial power generation projects, Worley has developed a range of contacts with Original Equipment Manufacturers (OEMs). The following provides an overview of Worley and Team AST's experience with OEMs for the critical equipment of this polygeneration system. Also, since the conceptual design phase and the pre-FEED study phase, the merger of Worley and Jacobs Engineering's Energy, Chemicals, and Resources group. This merger doubled the size of Worley and has resulted in a substantial expansion of the resources, network of OEM contracts, past reference projects, databases, and experience that can be provided relative to the resources available during the Conceptual Design

Phase.

3.2.1 Gasifier

Worley has worked extensively with the licensor and fabricators to develop the capital costs for this unit. The Worley lead has been in contact with SES for guidance on application of the U-gas design to support modeling efforts.

3.2.2 Gas Turbine & Steam Turbine

Worley has successfully built many power projects that utilizes gas turbines from various OEMs including that of General Electric, Siemens, Mitsubishi, and Alstom. From small aero-derivative gas turbine to the largest advanced class H, J and JAC class gas turbines, Worley had been involved with major OEMs and projects spanning throughout the world. These relationships have been leveraged in assessing turbine choices from the conceptual design process through the current more formed description and model of the polygeneration system. Worley conducts annual technology meetings with major OEMs, during which each OEM will showcase their latest advancements in their gas turbine products and lessons learnt from their projects worldwide. Worley tracks current advancements in the Gas Turbine Technologies. For this project, Worley received input on the suitability and performance from General Electric on a range of aero derivative gas turbines before selecting the LM2500+ GT for this project, specifically in the area of ensuring compatibility with high hydrogen content fuel. The design of the power block and selection of the steam turbines was done using software cross referenced with the Worley Group Project Library database.

3.2.3 Air Separation Unit (ASU)

Worley has worked as an EPC as well as at the FEED and Pre-FEED study level on many ASU projects, working with all the major vendors including Air Liquide, Air Products and Linde.

3.2.4 Syngas Cooler

Worley has worked with major Syngas cooler equipment suppliers on various study projects as well as on some of the combined cycle gas turbine power projects.

3.2.5 Water Gas Shift

Worley has worked with all of the major water gas shift vendors including Johnson Matthey, Haldor Topsøe and Clariant on a variety of projects including power generation with carbon capture and coal to ammonia projects.

3.2.6 Gas Cooling and Desaturator

The desaturator, which is a packed column used as a direct contact heat exchanger, is commonly used in our chemical plant designs. Worley has worked closely on many projects with vendors for the column as well as the internal distributors and packing to optimize the design.

3.2.7 Acid Gas Removal

Worley has evaluated all of the major selective acid gas removal technologies for multiple clients, and for both IGCC and coal to ammonia projects, the Selexol™ technology for UOP is the most cost-effective solution. These projects have involved multiple sets of performance data from UOP (in one case over 20) as the design is optimized.

3.2.8 Sulfur Recovery Unit
Worley has supplied and / or licensed over 60% of the sulfur recovery units in the world.

3.2.9 Pressure Swing Adsorption (PSA)
Worley has worked with all of the major PSA vendors including Air Products, Air Liquide, Linde, UOP and others

3.2.10 CO_2 Compressors
Worley has interfaced with the compressor manufacturers like Kobelco, Atlas Copco, MAN Turbo, Ingersoll Rand etc. on our current projects involving gas compression duty for various gases including natural gas, CO_2, other product gases.

3.3 Equipment Information Resources
Worley has provided Team AST resources for equipment information including Vendor Data & Interfaces, the Worley Project Library, budgetary quotes, and past reference projects.

3.3.1 Vendor Data & Interface
Worley has direct key vendor contacts for major critical equipment in the gasification process. Worley interfaces with the OEMs directly on a regular basis. Some of the OEMs have given access to Worley Engineers to be able to run the OEM's performance estimation software on OEM's computer portals. Worley relationships with OEMs is also leveraged to have the OEMs provide the emission and performance estimates for given ambient conditions, fuel types, various load points and different cooling system configurations. This is useful completing vessel components such as the fluid bed dryer.

3.3.2 Past Project References
In addition to the above sources, Worley also has access to generic published data from previously completed studies performed by Worley on various gasification study projects.

Additionally, Worley and AST's limited experience with commercial ammonia process and catalyst equipment and technology licensors is complemented by the subject matter experts at Catalyte who are actively engaged in this area. Catalyte's contacts and experience was leveraged to verify offerings exist near our intended train size and that provided confidence that the vendors list above would be amenable to adapting their standard offerings to bid on a functional duty specification when it comes time to procure equipment.

4. Pilot Plant Objectives

The foundation Team AST's proposed polygeneration concept is the paradigm that meeting CFI's objectives is best accomplished by combining intelligent systems analysis, engineering process development, and novel applications of existing, proven technology platforms. This approach provides greater confidence in modelling and analysis since it does not rely on attempting multiple, significant, high-risk inventive steps based on emerging or nascent technology. The end result is that the polygeneration concept is more based on sound development than research.

Nonetheless, even the integration of established components benefits from pilot operation activities focused on validating systems modeling and analysis, gaining operational efficiency, and mitigating the risks of systems integration. Besides supporting the detailed engineering and equipment refinement inherent in proceeding with a complex engineering project, pilot plant operations provide fertile ground for additional supporting innovations (generally low to medium risk innovations) that improve operational understanding, inspire modifications to the flowsheet for further costs savings, increase operational flexibility, and improve performance. The pilot scale recommended at this time to be $1/10^{th}$ of the design basis, which would essentially entail a single gasifier and single ammonia loop (as opposed to two, as contemplated in the design basis) at $1/5^{th}$ capacity. This scale retains the essential system characteristics to properly assess dynamics, response, controls, and performance while not committing to a more expensive, higher-risk full-scale pioneer application. The activities identified to advance these objectives are below in *Section 4.1 Risk Mitigation and Validation of the Current Design Basis.*

Additionally, pilot operations provide the opportunity for the technology platform to capture external innovations for potential implementation in future generations. While such activities are not necessary for executing the first generation of the polygeneration concept described in the current design basis and performance summary reports, potential pilot plant activities aimed at improving future iterations of the polygeneration concept are captured below in *Section 4.2 Incorporation of Higher-risk Supporting Innovation into Future Generations of the Technology Platform*. This section is provided to show the potential arc of improvement for the polygeneration platform beyond the initial deployment envisioned as part of the Coal FIRST program.

4.1 Risk Mitigation and Validation of the Current Design Basis (First Generation)

While extensive modeling, analysis, and vendor interactions have occurred to optimize the integration of mature components into a polygeneration system response to the Coal FIRST program, validation and system integration is greatly enhanced through targeted pilot plant activities. Additionally, operational understanding and full appreciation of system dynamics are a secondary desired product of the pilot plant operations.

4.1.1 Process Controls Development

A core outcome of pilot plant operations is the development of the process control strategy and corresponding validation in real-world operation. Additionally, the controls strategy for a system designed for system flexibility and frequent, rapid transitions between states is an inherently different challenge than targeting steady-state name plate capacity for a "monogeneration" process (i.e., IGCC or ammonia-only production as opposed to polygeneration). One of the challenges in developing the controls for this polygeneration plant is the limited ability to fully capture the complex dynamic performance of multiple connected systems. The various state transitions and high turn down anticipated in the ammonia train are expected to require close attention, particularly with respect to the recovering the heat from the process.

The discipline of completing the hazard-operability reviews required for a pilot plant operation has the added benefit of forcing the detailed assessment of how the system truly operates and how the transitions occur, providing validation of the transitions described in the *Performance Assessment*. This ancillary benefit of proper process safety is invaluable in developing a complete and full set of control loops to allow the system to perform as intended, as well as identify needed automated alarms, shutdowns, and emergency response.

Operational experience of this initial set of control loops allow validation and then improvement of controller strategy, design and tuning. The strategy and design of controls entails a detailed understanding of the system dynamics and understanding not only how a specific action creates reactions throughout the system, but also a conscious decision of how one intends to make individual control actions to initiate (i.e., selection of the manipulated variable-control variable pairings and the associated controls methodology) intended system reactions. Additionally, pilot demonstration allows unit operators and engineers the ability to start to innovate alternate control methodology which can be considered and, eventually, lead to evolution of the overall process control scheme.

While none of the activities described in developing the control scheme require innovative research, they are fundamental, required process development steps that are critical to safely and effectively making the transitions that this polygeneration system was designed to do.

4.1.2 Operations and Transitions Validation

Related to the operations that allow control system development are operations to validate that the system operates at steady-state as intended. Additionally, the transition between steady-states (e.g. the operating modes described in Performance Results) both in terms of timing and avoidance of problems also must be validated. Transitions between operating points are best validated due to difficulties in reliably and (more often) comprehensively modeling dynamic system operations (permutations grow geometrically with the number of unit operations, systems, and potential operator choices).

Operational data allows analysis of unit operations to determine short-comings and determine if the specifications determined through modeling require additional functionality to operate as intended. Often the issues are that the specifications derived from modeling are incomplete and there are other operational aspects (e.g. minimal velocity to prevent entrained solids from ‘salting out’ at an inconvenient location) that need to be added to the specification. While the Pre-FEED study included detailed heat integration analysis and careful consideration of the implementation and frequency of anticipated transitions, actual operating experience has historically proven to be the only true manner to assess and optimize a complex engineered systems’ response to transitions and disturbances. This operational guidance allows an understanding of the process beyond the five modeled operational modes. Additionally, this allows for definition of operational points and transitions with enough data to do true root case analyses (fishbone, 5 whys, Pareto analysis, Kepner-Tregoe analysis, etc.) to truly understand operations.

Again, such activities do not require innovative research but are fundamental activities of process development driving a design basis from a paper exercise to a commercially complete design basis with minimal technical risk.

4.1.3 Validate Fluid Bed Dryer Operations

The primary purpose of the fluid bed dryer is to (1) facilitate drying of the as-received feedstock to meet the requirements of the SES U-Gas gasifier and to (2) release any hydrocarbons that are adsorbed in the pores of the crushed coal.

The fluid bed dryer meets these objectives by:

- Reducing the moisture content of the coal prior to delivery to the gasifier
- Reducing the amount of light hydrocarbons adsorbed in the pores of the coal.[3]

Through these functions, the fluid bed dryer assures a more consistent feedstock for the gasifier. Specifically, the wet coal (11.12% moisture content by weight) is dried within the fluid bed dryer to a ~5% moisture content by weight through indirect heating supplied by excess low-pressure steam that is generated in other plant processes. ASU-supplied nitrogen will be introduced as a stripping gas into the fluid bed dryer to aid in stripping of the removed moisture and absorbed light hydrocarbons from the system. In addition to serving as the sweep gas, this nitrogen forms the bulk of the diluent that will be required to ensure that the syngas composition meets the requirements of the turbine that has been selected.

The resulting overhead stream from this drying and desorption process contains the stripping gas, the moisture driven off of the as-received coal, and any desorbed hydrocarbons. The resulting overhead stream from this drying and desorption process contains the stripping gas, the moisture driven off of the as-received coal, and any desorbed hydrocarbons.[4] Water is knocked-out from the overhead stream by condensation through a transfer line exchanger prior to re-integration of the overhead stream with the post-water gas shifted (WGS) syngas stream. This re-integration occurs after the acid gas removal (AGR) system and before fuel gas conditioning.[5]

The core product of the fluid bed dryer is the sufficiently dried coal stream. The final disposition of this solid stream is delivered to the gasifier for conversion to syngas.

[3] The coal selected for this study, as defined by DOE, is assumed to be "adsorbed hydrocarbon free." However, it is believed that the potential exists for trace amounts of adsorbed hydrocarbons in real-world feedstocks.

[4] It is the intention and belief that the overhead stream will only contain minimal amounts of desorbed hydrocarbons with pilot plant testing to quantify and characterize hydrocarbons that wind up in the fluid bed dryer overhead stream (most likely desorbed hydrocarbons from the pore volume of the coal, but possibly generated but unintended chemical transformation of the coal in "hots spots" or other poor operation transients).

[5] If piloting reveals significant hydrocarbons, heteroatoms compounds, etc., then this approach may need to be re-visited. Possible inclusion of a baghouse prior to fuel gas conditioning can be used to protect down-stream equipment.

The details of the fluid bed dryer need to be validated during pilot plant operations. Specifically, we need to assure that the size of this overhead stream is very small, predominately comprised of nitrogen and water, and devoid of operationally difficult tars, ash, particulates and entrained atomized hydrocarbons. The default specification of Illinois #6 coal for NETL systems studies does not facilitate modeling of adsorbed hydrocarbons. The minute production of tars and atomized hydrocarbons are not well captured in process simulation analysis but do create significant operational issues when accumulated.

It is currently believed that the fluid bed dryer will act as nothing more than a robust and resilient coal dryer. Thus, based on the known physical chemistry of the feedstock and at the operating temperatures there will not be cracking of the hydrocarbons contained in the coal. The designed operating temperature is well below that at which thermal cracking can occur, thus regardless of the presence of light hydrocarbons adsorbed in the pores of the coal. The dryer will be below the temperatures at which coal devolatilizes and releases tars, oils and other components. Even should these undesirable species release from the coal, the dryer will be operating below temperatures where these thermally crack. Provided operations stay within the parameters mentioned, the overhead stream should only contain the relatively small amounts of hydrocarbons that were previously adsorbed in the pores of the coal. Significant cracking of hydrocarbons in the coal will impact the amount of hydrocarbon feed to the gasifier, based on the current routing of the overhead stream.

The piloting plant will sample this overhead stream to evaluate the amount of hydrocarbons present. If the hydrocarbon content exceeds an acceptable limit, the operation of the fluid bed dryer will be evaluated to see if the drying of the coal can still be accomplished without the production of increased hydrocarbons in the overhead.[6] If that proves unsuccessful, alternative methods will be evaluated, including use of a different drying method or changes to the reintegration strategy for the overhead stream. There also will be active attempts to track tars and atomized hydrocarbons—this is often difficult and often requires either significant operating hours or deliberate routing to filters and other items that would not be part of a commercial flow sheet.

Additionally, pilot operations will monitor for potential unintended release of mercury for the coal. The mercury content of the overhead stream will be monitored and evaluated during the piloting process. As the current design basis includes re-integration of the overhead stream after the mercury removal bed[7], any mercury contained in the overhead stream will not be captured and will eventually be exhausted as part of the power island's flue gas. As high mercury emission levels are undesirable, it is important to measure the mercury content of the overhead stream in the pilot plant to validate that it is low enough to be considered "acceptable" for plant operation. If high mercury content is found, fluid bed dryer operation will be examined to attempt to eliminate the creation or driving off of mercury into the overhead stream. If this proves unsuccessful, the feasibility and impacts of reintegrating the overhead stream upstream of

[6] The most likely possible sources of unintended hydrocarbon cracking include unintended chemical transformation of the coal in "hots spots" within the fluid bed or other poor operation transients.
[7] This point has been selected for re-integration because it allows for use of an existing compressor, reducing the need for additional capital expenditures.

the mercury removal bed will be examined to ensure that the exhaust gas from the power island exhibits a low mercury content.

4.1.4 Methane Control in the SES U-Gas Gasifier

Gasification will be completed through the use of an SES U-Gas style gasifier. This style of gasifier has been selected as it is vendor supported as well as the fact that there are a number of existing and recent commercial operations, helping to ensure a flow of active and fresh operating knowledge. Additionally, both the vendor and selected gasifier design have demonstrated experience operating with the selected Illinois #6 feedstock. These factors combine to lower the technological risk associated with piloting and commercialization of the overall plant design.

One area of concern with the selection of this gasifier design is the fact that standard operating conditions result in syngas with a methane content of ~7%. As the selected carbon mitigation approach (i.e., a standard, dual-stage Selexol system) will not capture any of the carbon contained in the methane, this level of methane content in the syngas will make it very difficult to economically achieve the 90% carbon capture goal of the design basis.

In order to address this concern, oxygen injection into the freeboard of the gasifier can result in a reduction of the methane content to ~1% through partial oxidation of the methane. While SES has indicated that they have utilized a similar approach before (in fact, it was SES who originally recommended this potential solution) and while the partial oxidation of methane is well known, validation of this approach during piloting ensures that this approach is an effective means to control methane content and does not have any spurious operational issues (such as afterburning due to the lack of thermal mass in the freeboard) and to identify the required operating characteristics, both at steady state and during system transients.

4.2 Incorporation of Higher-risk Supporting Innovation into Future Generations of the Technology Platform

This section documents potential improvements to the polygeneration system that could be developed in pilot plant operations. These potential improvements are too risky to deploy in the first generation of the polygeneration platform and not necessary (based on our Performance Results) to meet the objectives of the Coal FIRST program. Potential improvements are documented below so the future arc of platform performance can be understood and that any pilot plant design considers the capability to support investigation of these options.

4.2.1 Fluid Bed Dryer's Impact on Coal Feed Flexibility

One initial justification for using a bubbling fluid bed dryer was the potential for leveraging existing, deployed capital equipment to further increase operational flexibility and value opportunities throughout the plant's lifecycle. Specifically, the fluid bed vessel provides an opportunity to handle high-sulfur content coals with minimal modifications and capital outlay through the use of limestone injection. Sulfur removal via limestone injection is a known method of desulfurizing coal feeds, that typically requires more intense (higher temperature) conditions than used in the current drying process. The design basis, equipment specifications and plant cost estimate include a dryer vessel with sufficient size, material and pressure specifications to handle the necessary temperature and pressure to investigate sulfur removal via limestone injection. If successful, this additional sulfur mitigation opportunity can enable the use of high sulfur coal sources at some point in the plant's lifecycle without the need to expand the fixed capacity of the acid gas removal system beyond the size of the originally installed system. This capability is analogous to the ability of refineries to accept various qualities of crude oil feedstocks, this unit operation increases overall plant flexibility and supports potential future arbitrage opportunities among different available coal feedstocks.

While current efforts have focused on the use of Illinois #6 as the primary fuel feedstock, initial analysis in the Conceptual Design phase suggests that this approach could support the use of additional coal feedstocks, including waste coal streams. However, as this significantly changes the operating characteristics of the fluid bed dryer and expands the operational goals of the unit process, it is important to perform adequate piloting efforts to verify that it will still operate successfully under these new conditions.

The first piloting goal in this area will be to confirm that limestone injection will be effective in removing sufficient sulfur to the point that expansion of the existing AGR system is not needed to handle such coal feedstocks. While limestone injection is a fairly standard process with generally well understood chemical interactions, it is important to verify the operating details in the specific system in order to properly control and operate all downstream systems, as well as to adequately size limestone feeds and waste disposal systems. Additionally, sulfur removal in this manner occurs at more severe processing conditions, the fluid bed dry begins to approach 'devolatilization' operations which requires extensive re-analysis of the 'dryer' overhead and understanding of the coal outlet to determine if devolatilization is occurring. If devolatilization occurs during this sulfur removal step, the system needs to re-evaluate where to reintroduce the devolatilized hydrocarbons into the system, quantify the impact on gasifier performance, and track cascading effects. A very detailed hazard and operability analysis should occur before undertaking this pilot plant activity. However, material specifications of the unit operations and extra flanges and nozzles on the dryer, gasifier, and other equipment should be considered in the pilot application to create options for conduction such work.

Piloting different coal feedstocks must involve a rigorous management of change process that assures the safety, health, and environmental impacts of feed switching are addressed and subsequently validated in pilot plant operations. For instances, if the feedstock change under consideration was from Illinois #6 to Powder River Basin coal, the level of drying would need to be changed to avoid the potential of creating an explosive dust. Additionally, the impact of the resultant change in the coal moisture level on gasifier operations would need to be assessed and validate in pilot plant operations.

4.2.2 Potential for Biomass-Coal Co-feed (Additional Feed Flexibility)

An additional opportunity for added flexibility to be examined during the pilot plant phase is the ability to utilize biomass as an alternative or supplemental feedstock for the gasifier. SES U-Gas advertises the ability to utilize biomass and, in fact, there have been multiple demonstrations of the U-Gas design fueled by biomass.

Aside from the logistical issues of finding a steady and suitable biomass feedstock in large enough quantities to significantly augment the coal-based feedstock, a number of process and operational elements will need to be evaluated, including:

- Moisture content of the biomass feed and the potential need for additional drying capabilities
- Evaluation of co-feed vs. separate feed trains
- Evaluation of need for partial oxidation to control methane generation

While this is an interesting opportunity, more pre-work will be required to sufficiently adapt the flowsheet and validate the operational costs and benefits through modeling and simulation. If these efforts suggest the potential for a net benefit to the system, even if only in niche deployments, development of a rational piloting plan may be justified.

4.2.3 Potential for Urea Production

Urea production was not explicitly considered as part of this Coal FIRST pre-FEED study because committing to urea production diverges from the concept of NH_3 as chemical energy storage mechanism and commits the facility to commodity chemical production. Nonetheless, while expansion of this project's scope requires significantly more capital and thus increasing the venture's risk profile, the outputs and byproducts of the plant, as designed, lend themselves to integration with a urea production facility. Combining NH_3 and CO_2 creates ammonium carbamate, which is then dehydrated to create urea. This integration would help provide a natural and stable disposition of the captured CO_2 (other than venting, expensive on-site storage, or requiring mature CO_2 transport infrastructure and markets). Such expansion of the facility would require significant adjustment to the business models and design basis. For example, the plant developers would need to decide if it makes more financial sense to invest in the urea production plant capital expenditures or if identifying an off-taker for the inputs to the urea process is most financially advantageous. If the decision is made to invest in the capital equipment, additional design and heat integration with the existing plant and facilities operations would be required.

4.2.4 Potential for Improved Pre-Combustion Capture

Commercially available pre-combustion capture systems are not optimized for the temperatures, pressures, and scales required this polygeneration system. As such, potential exists to develop pre-combustion capture systems targeted to this application that have efficiency and cost improvements relative to adapted conventional pre-combustion capture systems. Incorporation of such systems could improve financial performance via reduced capital expenditures, reduced parasitic load, and simplifying the handling of captured CO_2. The incorporation of such systems into the flowsheet, including an additional heat integration, and their impact on system dynamics (particularly during transitions) and control schemes would greatly benefit from pilot plant studies and validation activities.

5. Innovation Opportunities for Ammonia Generation

5.1 Overview

There is currently a large amount of innovation activity in the area of ammonia generation that align with the goals of the polygeneration concept (e.g., fast ramping, ammonia trains operating at 300 MTPD or less, etc.). This is predominately focused on using renewable energy sources to create hydrogen for ammonia synthesis, but includes other potential innovations as well.

Catalyte LLC was chosen for participation in Team AST due to their unique insights from the international and domestic ammonia technology and market landscapes. A major driving force for the intensification of ammonia innovation are the European Union and Japanese climate mitigation efforts, with targets ranging from an 80% to 95% reduction in greenhouse gas (GHG) emission by 2050 when compared to 1990 or 2010 levels.[8] These policy goals have spurred international development for dynamic, low-CO_2, renewable NH_3 production which should provide complementary innovation and technology developments that offer potential advantages to the polygeneration design.

The leading United States-based technology licensor is KBR, while several other players are involved at some level, including: RTI (ammonia partner Casale SA, Switzerland), University of Minnesota, Air Products (US and UK), Praxair (with Linde in Germany), Catalyte, Colorado School of Mines, and Kansas State. Additional entities funded by the ARPA-e REFUEL program, include: West Virginia University, University of Delaware, Giner, Rensselaer Polytechnic Institute, and Wichita State. The forefront of non-USA ammonia engineering, procurement, and construction (EPC) and research and development companies are primarily located in Germany, Netherlands, Denmark and Japan. The European Commission and Japanese government seek to use ammonia as a hydrogen carrier,[9] which drives focus on ammonia generation as an important part of a future Hydrogen Economy. To this extent, the European Commission has funded Horizon 2020 grants on the future of ammonia, [10] as well as other and major players in the ammonia space, such as the Yara plan's solar-and-wind-driven NH_3 facilities.

Various new renewable ammonia technologies are funded by the Japanese National Institute of Advanced Industrial Science and Technology's (AIST) Cross Ministerial Strategic Innovation Promotion Program (SIP) whose developments may translate to more traditional ammonia processes such as those used in this polygeneration platform. AIST's research and development includes a demonstration plant by JGC at 20 kg/day starting in 2019,[11] using new, low-temperature

[8] Jensterle, Miha; Jana Narita, Raffaele Piria, Sascha Samadi, Magdolna Prantner, Kilian Crone, Stefan Siegemund, Sichao Kan, Tomoko Matsumoto, Yoshiaki Shibata and Jill Thesen 2019: The role of clean hydrogen in the future energy systems of Japan and Germany. Berlin: adelphi.
[9] Path to Hydrogen Competitiveness, A Cost Perspective, 20 January 2020, Hydrogen Council
[10] https://ec.europa.eu/programmes/horizon2020/en/news/commission-invest-€11-billion-new-solutions-societal-challenges-and-drive-innovation-led
[11] https://www.jgc.com/en/news/assets/pdf/20181019e.pdf

(< 400 ºC) and low-pressure enabling catalysts. AIST and JGC C&C developed a new Ru/CeO_2 catalyst[12] as a first step, however the demonstration of this catalyst was in a low pressure (5 MPa) synthesis loop.

The burgeoning international research and development landscape in ammonia synthesis provides opportunities for some innovations could be incorporated in future generations of the polygeneration concept. Some new technology developments in the NH_3 generation space are so dramatic that one may no longer be able to refer to ammonia synthesis as strictly a Haber-Bosch process. The high degree of integration between the ammonia train and the other elements of the polygeneration system means that there will be multiple effects to the flowsheet when incorporating any advancements in ammonia synthesis. While modeling and analysis will provide the foundational assessment of such engineering opportunities, pilot plant operations would need to validate the altered operations and transitions.

Exhibit 5-1 below identifies some ammonia synthesis process improvements that are being tracked for future (not the current design basis) manifestations of this polygeneration technology platform. Pertinent details are provided in order to demonstrate the flourishing ammonia innovation landscape. Additional details are also provided below regarding the catalyst (*Section 5.2)* and ammonia separation improvements (*Section 5.3)* that are being tracked for future inclusion in the technology platform.

Exhibit 5-1: Potential Ammonia Synthesis Improvements

Process Component	Readiness of New Alternative	Area to Improve	Proposed Alternative
Catalyst	<TRL 3 [13] < TRL5 [5] TRL 6 -7 [13]	-High Pressure/temperature	-Low temp Ru-Ba-Cs MOF -Ru/Ba-$Ca(NH_2)_2$ -Ru/CeO_2 -Ru (10%)-Cs/MgO -Chemical looping
NH_3 separation & Absorbent-enhances Haber-Bosch	TRL 5 - 8	-Recycle Heat-up (lowers parasitic load)	-Absorbents [Alkaline Earth Chlorides, such as, $MgCl_2$] -600 kg NH_3/m^3 target -Efficiency > flash drums.
Make up gas compressor	Commercial	-Energy consumption -Spare on-site	-Centrifugal -Lower reactor pressure (catalyst material improvements)
Synthesis Loop Design	< TRL 8	-Massive -180 in 600 MTPD turndown	-Lower pressure and temperature (increase catalyst activity) -At temperature NH_3 absorption
NH_3 Liquid storage	TRL 6 to 8	-Potential fugitive gas	-Borohydrides and Metal halides

[12] https://www.ammoniaenergy.org/wp-content/uploads/2019/08/20191112.0826-AIChE2019_NH3_EnergyJGC_Final.pdf Fujimura, Kai, Fujimoto, Atsui, Nishi, Mochizuki and Nanba.
[13] *Catal. Sci. Technol.*, 2020, **10**, 105-112, Ignacio Luz, Sameer Parvathikar, Timothy Bellamy , Kelly Amato , J Carpenter and Marty Lail, MOF-derived nanostructured catalysts for low-temperature NH_3 synthesis

5.2 Potential Catalyst Improvements

Motivating much of the research and development in ammonia synthesis is the notion that, while the thermodynamic equilibrium partial pressure for producing NH_3 is improved at low temperature, the N_2 triple bond is difficult to kinetically cleave at low temperature. Researchers have focused on catalysts that increase NH_3 yield at lower temperature and pressure, with the hope of reducing compression burden.

Catalyst research has shown large increases in rate of reaction with experimental materials, as compared with commercial magnetite.[14] However, rates of reaction must be compared at similar TRL's, since highly active catalysts may quickly deactivate or have significant performance reduction once commercially formulated or stabilized. Ruthenium catalysts have been in use for some time, most notably by KBR, who completed development of a combined magnetite and graphite-supported, Ru/Rb low-pressure ammonia process around 1990.[15] The graphitized-carbon-supported Ru catalyst enables 16% per pass conversion at 90 bar and is 10 to 20 times more active than magnetite. Since 2000, KBR has licensed 35 new grass root ammonia plants,[16] but applying these systems (or similar systems) across the broad operating window of the polygeneration process requires significant process development work.

Since the ammonia synthesis reaction is exothermic, development of a catalyst that could be used at even lower temperature could provide further benefits beyond the aforementioned process. In 2001, PDIL in India was able to achieve excellent catalyst activity at 100 ºC using a cobalt/ruthenium catalyst, but recent efforts have intensified to balance all the competing parameters of temperature, stability, pressure, manufacturability and capital expenditures. Recently, the Tokyo Institute of Technology studied, published, and patent-applied Ru/Ba-$Ca(NH_2)_2$ and found it is one hundred times more active than that of conventional ruthenium catalysts at < 300 °C and 9 bar,[17,18] and is considered to be TRL 3. Several experimental catalysts have are currently being tested, including Ru (10%)-Cs/MgO,[19] which is considered TRL 6-7.[20] These catalyst improvements can lead to significant advantageous changes in the ammonia synthesis train, although (again) careful engineering and targeted pilot plan studies would be required before commercial integration with the polygeneration platform.

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[14] 7.5 mmol/h•g (catalyst) at 260 °C and 9 bar in laboratory experimentation compared to commercial values of 2.2 mmol/h•g (catalyst) at 450 °C and 200 bar
[15] CEP, Sept. 2016, J. Richardson and V. Pattabathula
[16] Proceedings form Rotterdam NH3 2019, Summit D. Morris, G. Patel
[17] Angewandte Chemie International Edition (2018)
18 EP 2650047A1 (2011), Tokyo Institute of Technology
[19] Angew Chem Int Ed, 57 (10) (2018), pp. 2648-2652
[20] Energy Reviews, Vol 114, October 2019, Kevin H.R.Rouwenhorst, Guido Mul, Sascha R.A. Kersten

5.3 Potential NH_3 Separation Improvements

Absorbents may be used to capture ammonia after it is produced at elevated temperatures. This is in contrast to the current industry-standard refrigeration methods of separation, resulting in lower parasitic loads. This technique serves important purposes, including improving reactor performance as shown by Cussler[21], since most ammonia catalysts are kinetically NH_3 inhibited and the reaction equilibrium is inherently NH_3 inhibited.

Relevant absorbents[14] include: magnesium chloride ($MgCl_2$), calcium chloride ($CaCl_2$), strontium chloride ($SrCl_2$), zinc chloride ($ZnCl_2$), and zinc nitrate ($Zn(NO_3)_2$).[22] US20170152149 indicates an improvement in performance by strategic ammonia removal near autogenic (700 K reactor outlet, with 460 K $MgCl_2$ absorber) conditions. These absorbents typically range between TRL 3-5.

Applying the absorbents to ammonia production is anticipated to provide process advantages that may be applied to this polygeneration platform to lower pressure (10 – 30 bar), potentially lower capital expenses, improve operational safety, and replace refrigeration, resulting in lower costs and parasitic loads.[14,23,24] Incorporating these features in the polygeneration platform requires detailed techno-economic analysis, engineering analysis, and pilot plant validation of the altered system dynamics.

This short survey of innovation activity in the area of ammonia production establishes the potential technology lift to the polygeneration process that could be provided by external research and development. As such, these developments are being tracked for possible future incorporation to further improve the polygeneration platform.

[21] Converting Wind Energy to Ammonia at Lower Pressure, Mahdi Malmali, Alon V. McCormick, and E. L. Cussler
[22] US 20170152149 $MgCl_2$ Absorption System
[23] Palys M, McCormick A, Daoutidis P. Design optimization of a distributed Ammonia generation system. NH3 fuel conference. 2017. Minneapolis (MN). Retrieved from. https://nh3fuelassociation.org/2017/10/01/design-optimization-of-a-distributedammonia-generation-system/.
[24] Malmali M, McCormick A, Cussler EL, Prince J, Reese M. Lower pressure ammonia synthesis. NH3 fuel conference. 2017. Minneapolis (MN). Retrieved from. https://nh3fuelassociation.org/2017/10/01/lower-pressure-ammonia-synthesis/.

Appendix A: Major Equipment List

Exhibit A-1: Equipment Schedule

		PLANT AREAS						REMARKS
01		Air Separation Unit						
02		Coal Handling and Crushing						
03		Gasifier, HRSG & Quench						
04		Water Gas Shift						
05		Syngas Cooling						
06		Syngas Clean Up						
07		Ammonia Production						
08		Fuel Gas Conditioning						
09		Power Generation						
10		Utilities						

Exhibit A-2: Compressors[25]

ITEM NO.	No OFF	DESCRIPTION	TYPE	FLOW Am³/h	FLUID & Density kg/m³	PRESSURE SUCTION BAR(G)	PRESSURE DISCHARGE BAR(G)	ABSORBED POWER kW	MATERIAL C = Casing	MATERIAL I = Internals	Remarks
K-810	1	GT Feed Compressor	C	3688.0	Syngas 11.12	31.7	44.0	1380			
PK-650	1	CO2 Compressor Package (Booster)	C	25186.0	CO2 2.22	0.2	5.0	10630 (total)			Total Stages: 7 total (est) Includes Intercoolers (40°C) / Aftercooler (35°C)
		CO2 Compressor Package (Main Compressor)	C	16685.0	CO2 8.77	4.8	89.9				

Exhibit A-3: Heat Exchangers

ITEM NO.	No OFF	DESCRIPTION	TYPE	DUTY (kW)	DIMENSIONS DIAMETER m	DIMENSIONS LENGTH m	SURFACE AREA m^2	FLUID T = Tube S = Shell		MATERIAL	DESIGN CONDITIONS PRES BAR(G)	DESIGN CONDITIONS TEMP °C	Remarks
E-301	1	Oxygen Heater	S&T	1554	0.51	6.1	128	T	LP Steam	304 SS	6	182	BEU assumed
								S	Oxygen	304 SS	50	178	
E-302	1	Scrubber Blowdown Air Cooler	Air Cooler	449	N/A	N/A	26 (Bare)	T	Process Water	CS	41	209	
E-401	2	Shift Interchanger	S&T	9474 total	1.50 per shell	6.10 per shell	2779 total	T	Syngas	304 SS	42	332	AES assumed. HOLD may consider plate and frame
								S	Syngas	304 SS	42	318	
E-402	1	IP Boiler	S&T	23744	0.64	6.1	216	T	Syngas	304 SS	51	460	BEU assumed
								S	IP BFW / Steam	CS/3mm	51	287	
E-403	1	IP BFW Heater	S&T	8194	1.13	6.1	728	T	IP BFW	CS	68	258	AES assumed
								S	Syngas	304 SS	39	275	
E-411	1	Shift Start-Up Heater	S&T	663	0.16	6.1	10	T	HP Steam	CS/3mm	76	314	BEU assumed
								S	Syngas	304 SS	41	338	
E-501	1	Desaturator Air Cooler	Air Cooler	297	N/A	N/A	36 (Bare)	T	Process Water	304 SS	48	113	
E-502	1	Desaturator Water Cooler	S&T	6389	0.84	6.1	383	T	Cooling Water	CS	6	65	BEU assumed
								S	Process Water	304 SS	48	93	
E-510	1	IP BFW Heater	S&T	8194	0.88	6.1	424	T	Process Water	304 SS	50	222	BEU assumed
								S	IP BFW	CS	69	211	
E-511	1	LP Boiler	S&T	36471	1.55	6.1	1498	T	Process Water	304 SS	49	218	BEU assumed
								S	LP BFW / Steam	CS/3mm	10	181	
E-512	1	LP BFW Heater	S&T	10730	1.37	6.1	1114	T	LP BFW	CS	13	178	AES assumed
								S	Process Water	304 SS	49	191	
E-660	0	CO2 Chiller (Optional)						T	S. Critical CO2	SS			Not to be costed
								S	Refrigerant	SS			

[25] Code: A – Axial; C – Centrifugal; M – Metering; R – Reciprocating; S – Screw
All drives are electric motors unless specified otherwise.

Exhibit A-4: Heat Exchangers (continued)

ITEM NO.	No OFF	DESCRIPTION	TYPE	DUTY (kW)	DIMENSIONS DIAMETER m	LENGTH m	SURFACE AREA m^2		FLUID T = Tube S = Shell	MATERIAL	DESIGN CONDITIONS PRES BAR(G)	TEMP °C	Remarks
E-801	2	GT Feed Preheater	S&T	1179	0.38 per shell	6.1 per shell	68 per shell	T	Process Water	304 SS	50	191	BEU assumed
								S	Fuel Gas	CS/3mm	50	149	
E-802	1	GT Feed Compressor Spillback Cooler	S&T	898	0.37	6.1	62	T	Cooling Water	CS	6	65	BEU assumed
								S	Fuel Gas	CS/3mm	50	103	
E-901	1	Steam Turbine Condenser	S&T	94622		9.40	3600	T	Cooling Water	304 SS			Part of HRSG
								S	Steam / Cond	CS/3mm			
E-902	2	DMW Preheater	S&T	20467	0.83 per shell	6.1 per shell	379 per shell	T	Process Water	304 SS	50.0	149.0	BEU assumed
								S	DMW / Condensate	CS/3mm	10.0	112.0	
E-903	1	LLPS Boiler	S&T	2959	0.40	6.1	74	T	Process Water	304 SS	50.0	177.0	BEU assumed
								S	LLP BFW / Steam	CS/3mm	10.0	131.0	
E-911	1	Steam Turbine Condenser 2	S&T	48193		9.40	1800	T	Cooling Water	304 SS			Part of HRSG
								S	Steam / Cond	CS/3mm			
								T					
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Exhibit A-5: Pumps[26]

ITEM NO.	No OFF	DESCRIPTION	TYPE	FLOW m³/h	FLUID & Density (kg/m3)	PRESSURE SUCTION BAR(G)	PRESSURE DISCHARGE BAR(G)	ABSORBED POWER kW	MATERIAL C = Casing I = Internals		Remarks
P-301	2	Scrubber Blowdown Pump	C	10.2	Water	0.6	7.2	4.1	C	CS/3mm	
					955.9				I	12% Cr	
P-501	2	Desaturator Circulation Pump	C	1561.0	Water	33.4	46.4	726.3	C	304 SS	
					809.8				I	12% Cr	
P-650	2	CO2 Condensate Pump	C	0.3	Water	4.0	37.2	0.37	C	304 SS	
					997.0				I	12% Cr	
P-660	2	CO2 Pump	C	303.2	Supercrit CO2	89.6	148.2	683.2	C	304 SS	
					530.6				I	12% Cr	
P-901	2	Steam Turbine Condensate Pump	C	314.4	Water	-0.6	4.0	55.7	C	CS/3mm	Part of HRSG
					993.0				I		
P-902	9	IP BFW Pump 1	C						C		Part of HRSG
									I		2 operating / 1 stand-by per HRSG
P-903	9	HP BFW Pump	C						C		Part of HRSG
									I		2 operating / 1 stand-by per HRSG
P-905	6	GT BFW Pump	C						C		Part of HRSG
									I		1 operating / 1 stand-by per HRSG
P-911	2	Steam Turbine Condensate Pump 2	C	160.1	Water	-0.6	4.0	29.3	C	CS/3mm	Part of HRSG
					993.0				I		
P-1001	2	LP BFW Pump	C	235.9	Condensate	0.2	10.5	94.8	C	CS/3mm	
					954.6				I		
P-1002	2	IP BFW Pump 2	C	169.1	Condensate	8.0	63.4	374.0	C	CS/3mm	
					920.2				I		
P-1003	2	LP Condensate Pump	C	5.4	Condensate	1.0	7.8	3.07	C	CS/3mm	
					916.0				I		

[26] Code: C – Centrifugal; D – Diaphragm; M - Metering

Exhibit A-6: Pressure Vessels

ITEM NO.	No OFF	DESCRIPTION	ORI.	SECTION	DIMENSIONS		DESIGN CONDITION		MATERIAL		Remarks
					DIAMETER m	LENGTH m	PRES BAR(G)	TEMP °C	SHELL	INTERNALS	
R-401	1	Shift Reactor 1	V		3.4	7.30	40.0	475	CS SS Lined		Catalyst Bed Volume = 46 m³
R-402	1	Shift Reactor 2	V		3.5	7.30	40.0	330	CS SS Lined		Catalyst Bed Volume = 48 m³
T-501	1	Desaturator	V	TOP BOTTOM	3.14 4.69	13.1 15.2	45.0 47.0	200 215	CS 3mm SS Lined	SS Packing	Stainless Steel Packing Total T/T = 31.5 m including transition height
V-301	1	Scrubber Blowdown Separator	V		1.10	3.00	3.5	180	CS 3 mm CA		
V-501	1	Mercury Guard Bed	V		By Vendor		45.0	200	CS 3mm SS Lined	SS	Flow: 6713 m³/h, 171,800 kg/h; Inlet Hg : 55 ppbm; Mercury Removal: 95%
V-901	1	Deaerator	H		By Vendor						Flow: 467,100 kg/h
V-902	1	LLP Steam Drum	H								Included in HRSG Package
V-903	1	IP Steam Drum	H								Included in HRSG Package
V-904	1	HP Steam Drum	H								Included in HRSG Package
V-1001	1	IP Steam Drum (Shift)	H		2.1	8.40	51.0	287	CS 3 mm CA		
V-1002	1	Continuous IP Boiler Blowdown Drum	V		1.00	2.60	7.5	180	CS 3 mm CA		
V-1003	1	Intermittent IP Boiler Blowdown Drum	V		1.00	2.60	7.5	180	CS 3 mm CA		
V-1005	1	LP Steam Drum	H		2.0	6.00	6.0	182	CS 3 mm CA		

Exhibit A-7: Packaged Equipment

ITEM NO.	No OFF	DESCRIPTION	DUTY SPECIFICATION	REMARKS
PK-101	1	Air Separation Unit	Air Flow: 210,000 kg/h @ 0 barg; O2 Flow: 50,000 kg/h; O2 Press: 44 barg; O2 Purity 99.5%; Nitirogen Product: 44 barg; Power Cons (est): 20.62 MW	Includes N2 (NH3 / Diluent) Compessor
PK-201	1	Coal Handling and Crushing Package	Delivery 100 x 100 ton Trains, 8 cm x 0; Initial Crushing to Storage Silo: (3 cm x 0); Final Crushing 70,900 kg/h, Moisture 11.12 wt%, Size 1/8" x 0	Based on Illinois #6 coal Refer to Process Description for scope.
PK-301	2	SES U-Gas Gasification & HRSG	Raw Syngas Output (each identical train): 85,900 kg/h ea., 4525 m³/h ea.; Outlet Pressure: 35 barg;	SES U-Gas Process Includes Lock Hoppers, HRSG, & Scubber
PK-501	1	Sour Water Stripper Package	Total Feed Flow: 106,400 kg/h; MOC: 304 SS, Pump Impeller 12% Cr	
PK-601	1	Acid Gas Removal Unit (SELEXOL)	Feed Flow Rate: 171,500 kg/h; Volumetric Flow (actual): 6713 m³/h; Inlet Pressure: 33 barg; Inlet Temperature; 40 °C	Selexol Process
PK-602	1	Sulfur Recovery Unit (Super Claus)	Acid Gas Flow: 9,600 kg/h; Recoverd Sulfur: 1,800 kg/h	Super Claus Process
PK-603	1	Tail Gas Treatment Unit (SCOT)	Feed Flow Rate: 7,800 kg/h;	
PK-604	1	PSA Unit	Feed Flow Rate: 11,700 kg/h; Volumetric Flow (actual): 2213 m³/h; Inlet Pressure: 32 barg; Hydgrogen Flow: 4400 kg/h (86% Recovery)	
PK-651	1	CO2 Drying Package	Total Gas Flowrate (wet): 146,500 kg/h; Dried Gas Flowrate: 146,200 kg/h; Pressure: 4 barg; Temperature: 21.6 °C	
PK-701	2	Ammonia Loop & MUG	300 MTPD Ammonia Production/train; Power Cons (est): 4.07 MW/train	Includes Makeup Gas Compressor
PK-901	3	HRSG	HRSG Duty: 46,440 kW; Duct Burner Duty HHV (norm/max): 14,000/41,500 kW; Pressure Levels: 3; HP Steam Flow: 79,000 kg/h @ 65 barg & 500°C	Duty Specifications are per HRSG
PK-902	3	SCR Package	Feed Rate: 330,000 kg/h ea; SOx Inlet 2 ppmvd; NOx Inlet: 25 ppmvd; NOx Outlet: 5 ppmvd	Integrated with HRSGs

Exhibit A-8: Miscellaneous Equipment

ITEM NO.	No OFF	DESCRIPTION	DUTY SPECIFICATION	REMARKS
U-201	1	Fluid Bed Dryer Package	Flowrate: 62,984 kg/h (dry); Size 1/8" x 0; Moisture in/out: 11.12 wt%/ 5 wt%; Nitrogen Flow (est): 30,000 kg/h; N2 Temperature 140 °C; MOC: 316H; Dryer Size: 2.5 m ID x 9.0 m T/T (Preliminary); DP: 50 barg; DT: 700 °C Internal Tube Bundle; Dryer Duty (est): 3.2 MW	Includes associated auxiliary equipment, Nitrogen Heater, vent condenser, water and particulate removal, recycle blower, booster compressor (suplemental info below)
U-201-K1	1	Drier Vent Booster Compressor	Centrif. Compressor - Flowrate: 22600 am³/h; Suction Pressure: 0.1 barg; Discharge Pressure: 32 barg; Absorbed Power: 3.8 MW; Stages: 4; Intercooling and aftercooling Duty (Total) 3800 kW	Part of U-201
U-201-E1	1	Drier Vent Condenser	Type: S&T HX; Duty: 2900 kW; Area: 193 m²; Tube Side: DP: 6 barg, DT: 65°C, MOC: SS; Shell Side: DP: 6 barg, DT: 150 °C, MOC: SS	Part of U-201
U-201-E2	1	Nitrogen Heater	Type: S&T HX; Duty: 800 kW; Area: 44 m²; Tube Side: DP: 6 barg, DT: 155°C, MOC: SS; Shell Side: DP: 6 barg, DT: 170 °C, MOC: SS	Part of U-201
U-201-V1	1	Drier Vent Condensate Drum	Type: Vertical Pressure Vessel; MOC: SS; Diameter: 2.4 m; T/T: 2.4 m; Design Pressure 6 bar g; Design Temperature: 150 °C	Part of U-201
U-201-K2	1	Drier Recycle Blower	Centrif. Compressor - Flowrate: 19800 am³/h; Suction Pressure: 0.1 barg; Discharge Pressure: 1.4 barg; Absorbed Power: 0.7 MW; Stages: 1;	Part of U-201
U-201-U1	1	Dryer Vent Particulate Removal	Flow (est): 35,000 kg/h; Temperature 75 °C; MOC: 316H; Pressure 0.4 barg	Part of U-201
U-901	3	Stack	Flowrate: 330,000 kg/h ea; 105 m³/s; Temperature: 105 °C; MW: 27; Height: 22.9 m; Diameter: 2.7 m;	
U-1001	1	IP Steam Desuperheater	Steam Inlet: 72.5 Mt/h @ 413°C & 39.26 barg; BFW: 60 barg & 228 °C Steam Outlet: 79 Mt/h @ 336°C & 39 barg	
K-901	3	Gas Turbine	Output: 30.18 MW ea / 90.53 MW Total	Model: GE
K-902	1	Steam Turbine	Output: 47 MW; HP Steam Flow: 155,500 kg/h @ 63 barg / 500 °C	
K-912	1	Steam Turbine 2	Output: 25 MW; HP Steam Flow: 79,200 kg/h @ 63 barg / 500 °C	