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Coal-Based Power Plants of the Future: Electricity and Ammonia Polygeneration Conceptual Design Report

Submitted To:

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1. Executive Summary

Team AST developed a coal-based power system for application in the evolving bulk power system. Specifically, the system is a polygeneration concept for the co-production of electricity and ammonia from coal in a system that can adapt to complex and shifting system dynamics. The initial performance evaluation of this conceptual design identifies a gap related to overall efficiency while meeting other objectives. Additionally, the process clarified risks to be worked in a subsequent pre-FEED study.

2. Business Case

The general business philosophy of the polygeneration conceptual design centers on offering multiple potential revenue streams, including (1) commercial electricity available for sale to the grid, (2) salable ancillary services (e.g., frequency stability, voltage regulation, etc.), (3) and NH_3 for commercial delivery. By combining these three different revenue streams with the conceptual design's emphasis on overall plant 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.

To maximize cross-comparison against existing studies, and to maintain full compliance with the terms of the awarded contract, site characteristics and ambient conditions are defined as follows[1]:

Exhibit 2-1 Site Characteristics

Parameter	Value
Location	Greenfield, Midwestern USA
Topography	Level
Size, Acres	300
Transportation	Rail or Highway
Ash Disposal	Off Site
Water	Municipal (50%) / Groundwater (50%)

Exhibit 2-2 Site Ambient Conditions

Parameter	Values
Elevation, m, (ft)	0, (0)
Barometric Pressure, MPa, (psia)	0.101 (14.696)
Design Ambient Temperature, Dry Bulb, °C, (°F)	15 (59)
Design Ambient Temperature, Wet Bulb, °C, (°F)	10.8 (51.5)
Design Ambient Relative Humidity, %	60
Cooling Water Temperature, °C, (°F)^	15.6 (60)
Air composition based on published psychrometric data, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076

[1] These exhibits correspond to Exhibit 1: Site Characteristics and Exhibit 2: Site Ambient Conditions found in Appendix B of the award document

Total	100.00

^The cooling water temperature is the cooling tower water exit temperature.
This is set to 8.5°F above ambient wet bulb conditions in ISO cases.

As assumed for gasification-based cases in the NETL baseline studies, the required land area is estimated as 30 acres for the plant proper with the balance providing a buffer of approximately 0.25 miles between the plant and the fence line. While this land area estimation is generous for this distributed small-scale concept, the 'extra land' provides for a potential rail loop, product storage and distribution, and a greenspace barrier between the facility and the surrounding community.

In all cases, it was assumed that the steam turbine is enclosed in a turbine building. The gasifiers, reformers, ammonia synthesis reactors, and the combustion turbines are not enclosed.

Allowances for normal conditions and construction are included in the cost estimates. The following design parameters are considered site-specific, and are not quantified for this study. Costs associated with the site-specific parameters can have significant impact on capital cost estimates.

- Flood plain considerations
- Existing soil/site conditions
- Water discharges and reuse
- Rainfall/snowfall criteria
- Seismic design
- Buildings/enclosures
- Local code height requirements
- Noise regulations – Impact on site and surrounding area

Additional market scenario assumptions that define the business case include:

Exhibit 2-3 Market Scenario Assumptions

Description	Values
Coal Type	Illinois #6
Coal Price, Current $'s per short ton	39.10
Natural Gas Price, Current $'s per million BTU's	4.21
Estimated Renewables Penetration, %	25
CO_2 Constraint and/or Price	95% Pre-Combustion Capture
Ammonia Contract Price, Gulf Coast, Current $'s per ton	$195
Ammonia Retail Price, Current $'s per ton	$551

The characteristics of the Illinois #6 coal used in the design basis may be found in Appendix B.

Preliminary estimates of high-level component costs were developed through a combination of subject matter expertise and application of QGESS scaling methods. The cost methodology used a "total plant costs" definition, including best initial estimates for materials, labor, engineering and construction management, and process and project contingencies in line with existing NETL and QGESS system analysis standards. The summary of these results by account area are presented below in Exhibit 2-4:

Exhibit 2-4 Representative Plant Costs

Account Area	TPC, 1,000's $
Coal Sorbent Handling	17,389
Coal Sorbent Prep & Feed	83,468
Feedwater System	32,208
Gasifier and Accessories Subtotal	403,587
Syngas Cooler and Gasifier System	267,998
ASU and Oxidant Compression	113,359
LT Heat Recovery & FT Saturation	11,023
Flare Stack System	1,496
Gasification Foundations	9,711
Gas Cleanup & Piping Subtotal	104,112
Selexol System	69,732
Elemental Sulfur Plant	16,264
Mercury Removal	1,941
Shift Reactors	6,939
Fuel Gas Piping	8,574
HGCU Foundations	662
Ammonia Production	107,365
CO_2 Compression and Drying	25,527
Combustion Turbine	38,292
Heat Recovery, Ducting, and Stack	22,102
Steam Turbine Generator	22,492
Cooling Water System	13,708
Ash & Spent Sorbent Handling Systems	18,208
Accessory Electric Plant	46,100
Instrumentation	26,425
Site Improvements	18,873
Buildings	31,830
Total Plant Costs	**1,011,686**

To assess the economic viability of this technology, these estimated total plant costs were combined with (1) the previously discussed market scenario assumptions, (2) identified plant performance characteristics (detailed in Section 3.2), and (3) the financing scenario details provided in Exhibit 2-5. These details were used with NETL's Power Systems Financial Model to estimate the cost of electricity (COE) required for the project to achieve the required internal rate of return on equity. This COE estimate represents the price required to achieve a zero net present value (NPV) based on the capital and operating expenditures, revenue, and financing assumptions just described at the required internal rate of return on equity of 10% (i.e. this is not a "profitless" or "breakeven price" but a price that yields a 10% return). These results are provided in Exhibit 2-6 on a 2011-dollar basis assuming a 30-year operational life. A 2011-dollar basis was chosen to facilitate crosschecking and benchmarking with relevant NETL systems analysis studies.

Exhibit 2-5: Power Systems Financial Model Details

Parameter	Value
Capacity Factor	85%, 90%
Debt/Equity Split	50%/50%
Interest Rate	4.5%
Financing Fee	2.7%
Repayment Term, years	15
Capital Cost Depreciation, years	20
Income Tax Rate	38%
Capital Expenditure Period, months	48
Required Internal Rate of Return of Equity	10%
Base Year	2011

However, estimation of such a COE for a polygeneration project requires careful use of such metrics. Specifically, wide-ranging assumptions that attempt to capture the price volatility of the ammonia market can result in product revenue that serves to skew the calculated COE. Specifically, one key advantage of this technology is the ability to provide distributed, close-to-end use ammonia such that a substantial portion of the standard market price driven by the significant transportation and distribution costs of ammonia can be captured as profit. This additional profit serves to effectively 'subsidize' the electricity production such that the COE required to meet a 10% return are significantly lowered.

A COE estimate was produced over the range from the current retail cost ($551/ton, representing the "high end" estimate) and the current United States Gulf Coast (USGC) contract price ($195/ton, representing the "low end" estimate). The retail price represents a reasonable upper bound estimate on potential ammonia revenue (full capture of the distributed ammonia production advantage), whereas the USGC contract price represents a reasonable lower bound estimate, at this stage, on the potential ammonia revenue (no capture of the distributed ammonia production advantage)[2]. An intermediate choice, such as 75% of the retail price, is a more plausible basis of evaluation. In practice, the plant would most likely capture a different level of locational advantage based on the geographical distribution of customers relative to the specific plant siting[3].

The choice of capacity factor used in the COE estimate also significantly impacts the results. However, a flat 'one point' choice of capacity factor undervalues the flexibility to shift production

[2] Historically, ammonia prices have been much higher, with an average price of $677/ton from 2008-2017, before reaching a low of $401 in September 2017. While it was decided not to include scenarios reflecting the much higher ammonia prices seen over the past decade, this could serve to increase revenue and lower the COE. Accurate forecasting of future ammonia prices would be an important area to investigate further in the FEED process.

[3] This can be modeled stochastically, with a non-trivial amount of effort, later in the FEED (Pre-FEED?) study process when the technology basis is more solidified.

between electricity generation and ammonia production, reducing the amount of non-performing capital periods where the plant is forced into curtailment by ISO/RTO dispatching decisions. Ideally, the various operation points would be stochastically modeled to represent and evaluate revenue generating activities. Unfortunately, this is difficult to implement within PSFM (applied here for consistency and benchmarking with other NETL systems analysis) and such non-trivial modeling would occur later in the FEED process when the technology basis is more solidified. Additionally, chemical production capacity factors are usually significantly higher than those typical of thermal electrical generation assets. To reflect this, COE estimates have been calculated using both 85% and 90% capacity factors. The results of these efforts are summarized in Exhibit 2-6.

Exhibit 2-6: Power Systems Financial Model Detail – Cost of Electricity Estimates

	COE in \$/MWh at 10% ROE		Assumed NH_3 Revenue \$/ton	Notes
	Capacity Factor 85%	90%		
AST Distrbuted Scale Polygeneration	\$ 86.25	\$ 66.28	\$ 551	Full Retail without Distrbution Costs
	\$ 174.87	\$ 154.90	\$ 413	75% of Retail
	\$ 263.49	\$243.53	\$ 276	50% of Retail
	\$ 315.28	\$ 295.31	\$ 195	Current USGC; No Locational Advantage Premium
Context				
IGCC (Shell Gasifier) With Capture	\$ 152.60			NETL Baseline Study (2011 \$); without T&S
IGCC (E-Gas) With Capture	\$ 141.90			NETL Baseline Study (2011 \$); without T&S
IGCC (GEE Quench) With Capture	\$ 138.70			NETL Baseline Study (2011 \$); without T&S

To provide context, the COE for NETL baseline studies of IGCC technologies that leverage carbon capture are also provided. The COE estimates for the process assuming partial but significant capture of the distributed ammonia production advantage (75%) at a reasonable capacity factor (90%) are similar to the COE estimates for IGCC with capture (not including transport and storage) in NETL baseline studies. This indicates a reasonable probability of profitable implementation of this process, but that detailed consideration of project specific factors and market dynamics needs to occur.

This potentially high required electricity price indicates a closer look at ancillary services revenue (not included), sales of elemental sulfur or CO_2, reductions in construction cost from shop fabrication, and financing assumptions must be evaluated further. Additionally, this revenue model assumes a flat 50/50 split of the clean syngas distribution between power generation and chemical storage (discussed in more detail in Section 3.1.8). In a real-world deployment, the operation of the plant would shift away from that 50/50 baseline split in response to market conditions to maximize profitability.

Also, this assumes no technological advancements that would serve to lower the costs to build or operate the proposed plant design, nor technological advancements that would improve its performance.

3. Plant Concept and Important Traits

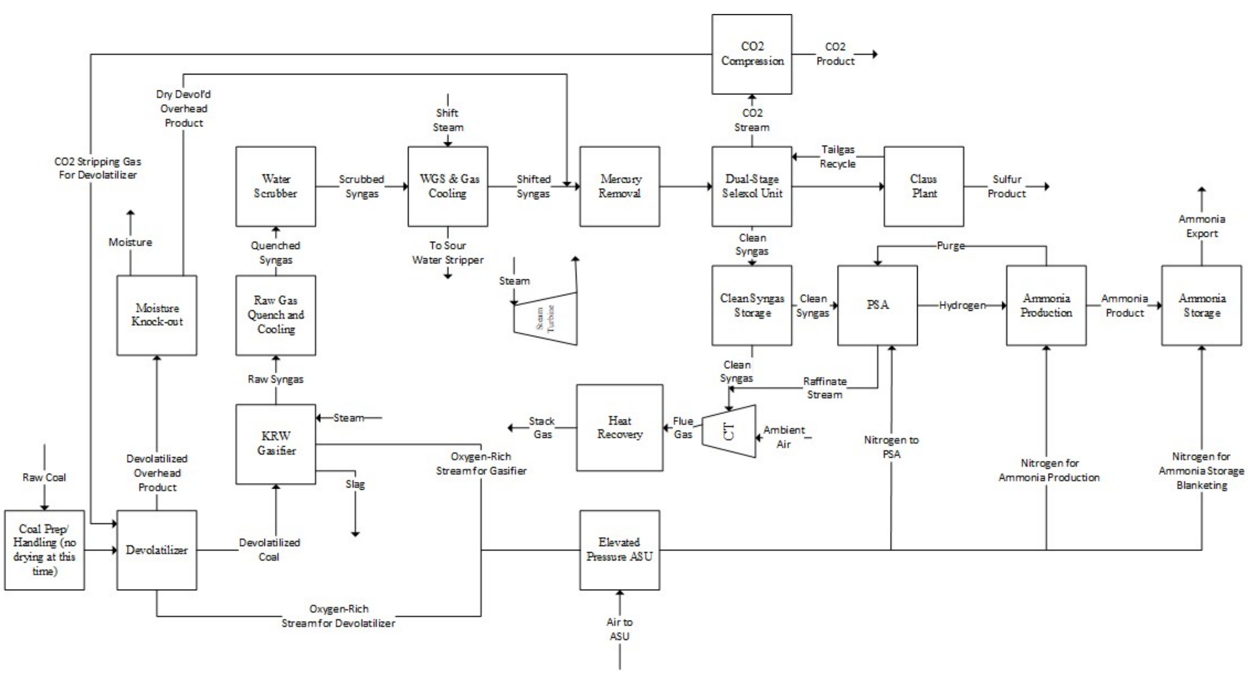
The overall plant concept it to apply innovative application of largely established technology components to design and develop a coal-based, polygeneration system that contributes to the modern bulk power system. Such a coal-based system functions at smaller scale to provide both distributed, dispatchable power and ancillary services to power systems that are stressed due to lower inertia and a more complex, geographically disjointed topology.

To do so, the system’s optimal scale must be smaller with a design philosophy that values operational response, adaptability, and resiliency in addition to the standard concerns of availability and efficiency. The subsequent conceptual design and pre-FEED studies will work through the details of transforming the proposed concept into a fully developed, robust option for meeting CFI’s objectives. The approach to meet these objectives is centered on intelligent and purposeful application of solid engineering and process development.

3.1 System Block Flow Diagram and Process Descriptions

At a high level, the conceptual design includes a coal gasifier to produce syngas that can be combusted in a conventional, simple cycle turbine as well as being used to produce ammonia for use as a chemical storage medium. A block flow diagram can be seen in Exhibit 3-1 followed by short process descriptions of each major subsystem.

Exhibit 3-1 Polygeneration Conceptual Design Block Flow Diagram



3.1.1 Coal Receiving and Handling

The operating section consists of two (2) primary unit operations:

- Handling systems designed to unload Illinois #6 coal and pile in yard stockpiles
- A storage area with active and inactive storage piles to service the plant

In the standard plant configuration, 8 cm x 0 (3" x 0) coal will be delivered to the site by 100-car trains comprised of 100-ton rail cars. Coal will be unloaded through the trestle bottom dumpster into two receiving hoppers and subsequently transported by a vibratory feeder and belt conveyor to either the long-term storage pile or the reclaim area. Iron will be removed by passing the coal under a magnetic plate separator prior to delivery to the reclaim pile.

Vibratory feeders, located in the reclaim hopper, and a belt conveyor transfer the coal to the coal surge bin located in the crusher tower. The coal is reduced to 3 cm x 0 (1 1/4" x 0) before a conveyor delivers it to the transfer tower and onto the tripper before being sent to the storage silos.

3.1.2 Coal Preparation and Feed Systems

The Coal Receiving and Handling subsystem ends at the coal silo. The Coal Preparation and Feed subsystem takes coal from the silo and performs four primary unit operations:

- Crushing the coal to a size suitable for use in the devolatilizer
- Transporting the coal from the coal silo to the devolatilizer
- Reducing the moisture content of the coal prior to delivery to the gasifier
- Reducing the overall volatile organic content (VOC) of the fuel feedstock

The crushed coal (roughly 0.125" x 0) is delivered to a surge bin before being transported to the devolatilizer through use of a lock hopper utilizing captured CO_2 as the transport gas.

3.1.3 Coal Devolatilization System

The purpose of the devolatilizer is to increase the overall system adaptability by facilitating a wider range of acceptable coal feedstocks and mitigate concerns of coal caking and swelling. Additionally, the application of this fluid bed system also creates the option to introduce limestone for scavenging sulfur evolved from the coal enabling the use of high sulfur coal sources that could overwhelm the fixed capacity of the acid gas removal system once the plant is built and commissioned. Similar to the ability of refineries to accept various qualities of crude oil feedstocks, this unit operation has utility for applications that envision arbitrage opportunities among different available coal feedstocks[4]. While this advantage is not captured in the business or technical merits of the baseline case examined in this conceptual design report, it is another factor that will improve system flexibility and modularity in real-world applications.

The devolatilizer 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

Through these functions, the devolatilizer assures a more consistent feedstock for the gasifier. Specifically, the wet coal (11.12% moisture content by weight) is dried within the devolatilizer through partial oxidization of the coal feed through use of an O_2-rich stream supplied by the Air

[4] While the current Conceptual Design efforts have focused on the use of Illinois #6 as the primary fuel feedstock, initial analysis suggests that the current design would support the use of additional coal feedstocks, including waste coal streams.

Separation Unit (ASU). CO_2 is additionally recycled from the syngas cleaning subsystem and introduced into the devolatilizer to gasifier to aid in the stripping the water and desorbed light hydrocarbons from the system.

A limited, partial oxidation of the coal produces creates the heat required to dry the coal and desorb light hydrocarbons. The extent of oxidation is controlled by limiting the feed of the O2-rich stream. The unit operation is aimed solely at conditioning the coal and does not have the burden of produce a specific fuel gas composition for the overhead, which would require more technology development. The resulting overhead stream from this drying and desorption process contains the stripping gas, by-products of the partial oxidation of the coal feed, the moisture driven off of the wet coal and the remnants of the O_2-rich, ASU stream. Water is knocked-out from the overhead stream by condensation through a transfer line exchanger prior to re-integration[5] with the post-water gas shifted, syngas stream just prior to the mercury removal bed.

The core product of the devolatilizer is the dried, devolatilized coal stream which containing solid by-products resulting from the partial oxidation. This solid stream is delivered to the gasifier for conversion to syngas.

3.1.4 Air Separation

An ASU will be included to create both oxygen-rich and nitrogen-rich streams for use in other system processes. Specifically, the oxygen-rich stream will be supply the oxidation reactions driving the core processes in the devolatilizer and gasifier while the nitrogen-rich stream will be used to supply (1) the ammonia synthesis loop, (2) the sweep gas required for the hydrogen-producing pressure swing adsorption (PSA) unit associated with the ammonia synthesis train and (3) product tank blanketing. Additionally, nitrogen may be used as a diluent for the combustion turbine, if needed

The sizing of the ASU is dominated by the oxygen requirements, with a total air flow rate to the ASU of ~240,000 lb/hr to support a demand of ~60,500 pounds per hour of oxygen required. This is in contrast to the 74,000 lb/hr of nitrogen required for system processes. The ASU represents significant parasitic loads on the system with the ASU auxiliaries and main compressor accounting for roughly 30% of the overall plant total.

3.1.5 Gasifier

The gasifier follows a KRW design with dimensions limited by the ability to shop fabricate and transport over-land to the site to ensure that modularity is maintained. It is believed that this limitation results in a maximum overall package size for the main gasifier section of 13.7 feet in diameter and 32 feet in length. Based on the known aspect ratios of the KRW gasifier, this will result in an inner reactor diameter of 9.1 feet with a reactor height of 27.4 feet, for an overall

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[5] The overhead stream is reintegrated after the water gas shift in order to limit variability in the water gas shift operating section as well as reduced the sizing of this section. Re-integration of this stream at this point may require particulate filter should our envisioned approach to handle such solids fails, however the mercury guard bed would serve as a point where the operational issues related to particulate solids in this overhead steam would manifest and could possibly be managed as necessary.

reactor volume of 1,800 cubic feet. As the plant design intends to include 2 gasifiers, the overall usable reactor volume will be 3,600 cubic feet.

The gasifier will be supplied with devolatilized coal, steam, and an oxygen-rich stream from the ASU, producing raw syngas and ash/slag. Upon exiting the gasifier, the raw syngas stream will combine with the overhead product from the gasifier before proceeding on to quenching, the water gas shift, and syngas cleaning processes. This integration of the overhead product at this point is critical to ensure that it is properly treated before reaching its final disposition in either the ammonia synthesis train or the combustion turbine.

It is anticipated that the gasifier will produce ~200,000 lb/hr of raw syngas from the coal feedstock, as well as ~11,000 lb/hr of slag. Parasitic loads are relatively light for the gasifier, accounting for ~1% of the total for the plant. Additionally, the gasifier allows for recovery of a significant amount of process heat, with roughly 11 MW energy that is used to meet other plant thermal loads and produced electricity via the steam turbine.

3.1.6 Water Gas Shift

Water gas shift (WGS) forms a central part of the plants emissions strategy by serving as a mechanism to maximize the amount of pre-combustion/pre-synthesis CO_2 capture This approach is synergistic to ammonia production as WGS increases the hydrogen content within the syngas stream. This shift is accomplished by reacting the raw syngas in the presence of steam and a catalyst in a fixed-bed reactor. Required cooling in this process will remove sensible heat that is generated in the shift reaction for use in other system processes.

The effluent of WGS operating section, after excess water is knocked out, is ~265,000 lb/hr comprised primarily of CO_2 (~233,000 lb/hr) and H_2 (~13,200 lb/hr).

3.1.7 Syngas Clean Up

The purpose of the syngas clean-up operation is to remove impurities from the shifted syngas stream (e.g., CO_2, sulfur, and mercury) to provide a hydrogen-rich, "pure" synthesis gas stream suitable for both power and chemical storage generation. The approach to syngas clean-up is as follows:

3.1.7.1 Mercury

Mercury removal will be accomplished through the inclusion of a sulfur-impregnated, activated carbon bed. A representative system is described in the *Cost and Performance Baseline for Fossil Energy Plants Volume 1b: Bituminous Coal (IGCC) to Electricity Revision 2b – Year Dollar Update* report.

3.1.7.2 Carbon Dioxide

CO_2 removal is accomplished through two primary steps. First, sour gas shift reactors are used to convert CO to CO_2, followed by application of a two-stage Selexol process with a targeted CO_2 removal efficiency of 95%, the maximum amount supported by public vendor quotes. The captured CO_2 is then compressed, with a portion recycled for use as a stripping gas in the devolatilizer while the bulk of the stream is routed to its final disposition.

3.1.7.3 Sulfur

The two-stage Selexol system that was implemented to facilitate capture of CO_2 also supports a very high level of sulfur removal (approximately 99.9%), negating the need for any additional sulfur mitigation technology.

The flowrate of the syngas stream sent to the two-stage Selexol process was ~320,000 lb/hr, containing ~290,000 lb/hr of CO_2 and ~2,800 lb/hr of sulfur (existing primarily as H_2S). After this process, ~45,000 lb/hr of clean syngas is available for use in the combustion turbine and ammonia synthesis train. While the overall removal efficiencies of the Selexol process are impressive, it does not come without cost as the parasitic loads of this subsection account for ~20% of the plant total.

3.1.8 Syngas Management

The purpose of the syngas management operation is to monitor and regulate the distribution of syngas (as well as relevant ancillary streams such as nitrogen, steam, etc.) between the various operating sections. This includes managing storage capacity to respond to changes in electrical load and extraction of hydrogen for ammonia synthesis. Primarily, this involves routing clean syngas between one of three (3) possible dispositions: (1) a tank for temporary storage, (2) the combustion turbine (CT), and (3) the hydrogen recovery pressure swing adsorption (PSA) unit.

While some deviation is expected to respond to changes and signals from the broader electrical grid, a nominal 50/50 split is expected for syngas between the CT and the PSA. The portion of clean syngas directed to the hydrogen recovery PSA is combined with the purge stream from the ammonia synthesis train. The hydrogen recovery PSA will extract pure H_2 from the cleaned syngas stream to feed the ammonia synthesis train, and will reject the hydrogen-deficient raffinate stream which is directed on towards the combustion turbine. A nitrogen-rich stream will be supplied by the ASU to serve as the sweep gas for this process.

The current baseline flowrate to the PSA is ~50,600 lb/hr (~22,500 lb/hr of clean syngas, ~10,700 lb/hr from the ammonia train purge stream, and ~17,000 lb/hr of sweep gas). Of that total, ~9,000 lb/hr is passed to the ammonia synthesis train, including ~7,800 lb/hr of H_2. The remaining ~41,600 lb/hr is re-integrated with the ~22,500 lb/hr of clean syngas that is destined for the CT.

3.1.9 Electrical Power Island

As previously noted, the fuel feed for the CT will consist of ~22,500 lb/hr of clean syngas combined with the ~41,600 lb/hr of the H_2-defficient raffinate stream from the hydrogen PSA for a total of ~64,100 lb/hr. This stream will have an HHV of ~155 MW, supporting gross CT output of ~60MW. Through engagement with relevant OEM's (General Electric (GE) and Siemens, specifically), a number of commercially available aeroderivative and heavy duty/frame turbines have been identified that are compatible with the projected syngas composition of this conceptual design.

In choosing between an aeroderivative and heavy-duty gas turbine, it is important to note a number of key tradeoffs. While aeroderivative turbines typically have superior ramp rates, throttle response, part load performance, and are both physically smaller and available in a larger number of capacities, heavy duty/frame turbines typically can achieve higher top-end efficiencies, have lower life-cycle costs, and superior performance in combined cycle operation.

In evaluation of specific options, one aeroderivative model of note is GE's LM2500 line. With base ratings between 24 and 37MW depending on the specific LM2500 model selected, two could be paired to meet the projected CT output of ~60MW while still allowing room for increased surge capacity. Additionally, these turbines exhibit other favorable characteristics including simple cycle efficiency between 34-37% on an LHV basis, and ramp rates of 30MW/min in simple cycle configurations (50MW/min in combined cycle applications).

Engagement with the turbine OEM, GE, confirms that the LM2500, LM2500+, and LM2500+ G4 models will all work with the projected syngas composition for this conceptual design. However, additional mitigation measures (e.g., water or steam injection) may be required for NOx compliance on these models.

As an alternative to the aeroderivative LM2500 line, GE has confirmed that the 6B.03 heavy duty gas turbine will also be compatible with the projected syngas composition. Unfortunately, the simple cycle net output for this model is only 44MW which would require a significant shift in the amount of syngas produced (either a ~25% reduction to support one 6B.03 turbine or a 45% increase to support two 6B.03's). Additionally, while heavy duty/frame engines can have simple cycle efficiencies as high as 44% on the 557 MW 9HA.02, the much simple cycle efficiency on the much smaller 6B.03 only reaches 33.5%, lower than all relevant LM2500 models. This efficiency comparison swings back in favor of the 6B.03 when a combined cycle configuration is considered (52.1% net efficiency for the 6B.03 in a 2x1 CC configuration compared to 50-51% for relevant LM2500's in a similar deployment).

In engagement with Siemens, the aeroderivative SGT-A45 and -A65, as well as the industrial SGT-600 and SGT-700 turbines were tentatively approved for use with this project's projected syngas composition with the understanding that natural gas blending may be required (particularly for the SGT-A65) dependent on final engineering analysis. Of these Siemens options, the most obvious fits given the projected syngas available for combustion are the 65 MW SGT-A65 and the 33 MW SGT-700 (employed in a two-turbine configuration). A summary of these two options, as well as the GE LM2500+, can be seen in Exhibit 3-2.

Exhibit 3-2 High Level Performance Summary of Relevant Combustion Turbines

Turbine	LM2500+	SGT-A65	SGT-700
Simple Cycle			
Configuration	Two turbines	One Turbine	Two Turbines
Type	Aeroderivative	Aeroderivative	Frame
Power Output, MW	63.6	64.9	65.6
Gross Efficiency	36.9%	43.3%	37.2%
Combined Cycle			
Configuration	2x1	1x1	2x1
Type	Aeroderivative	Aeroderivative	Frame
Power Output, MW	86.3	83	91.6
Net Efficiency	50.3%	54.2%	53.1%
Ratio of CC Output to SC Output	1.357	1.279	1.396

Of these available options, the SGT-A65 offers the highest efficiency in both simple and combined cycle operations. However, it has the lowest combined cycle output, the lowest operational flexibility by virtue of being one large turbine as opposed to two smaller turbines, and has the greatest questions surrounding acceptability of the generated syngas product without the need for natural gas blending.

The Siemens SGT-700 offers the second best simple and combined cycle efficiencies as well as the greatest room for handling surge capacity. Additionally, it will have the greatest efficiency gains of the three when moving from a simple cycle to combined cycle configuration, and is expected to be more compatible with the produced syngas than the Siemens SGT-A65.

Finally, the LM2500+ while offering lower efficiencies relative to the other highlight turbine options, does have the clear advantage of being the most compatible “out of the box” with the projected syngas composition.

A final determination of which turbine is best for this application will require a more detailed engineering assessment on the produced syngas by OEM counterparts as well as complex life-cycle analysis on the competing options. The Pre-FEED phase is suitable for completion of these efforts.

While the conceptual plant is nominally a simple cycle design, the plant will include a heat recovery system for producing steam to power a steam turbine. This ensures that any of the significant amount of unused heat generated from the gasifier, the ammonia synthesis train, or the simple cycle turbine can be captured to support supplemental electricity production.

In addition to the fuel feed, ambient air will be supplied to the CT as well as third stream meant to lower the firing temperature of the CT as a means of NOx control, if needed. It is anticipated that excess nitrogen produced by the ASU will be used as the diluent of choice. However, syngas humidification could prove to be a preferable alternative with the final determination based on continued interaction with OEM.

3.1.10 Ammonia Synthesis

The primary goal of the ammonia (NH_3) synthesis train is to provide a chemical storage medium to support overall system reliability, availability, and modularity with the additional opportunity to provide a supplemental value stream for the polygeneration plant. Based on the nominal amount of hydrogen available in the plant, a scale-down of the conventional, existing Haber-Bosch approaches is believed to be most applicable.

The H_2-rich stream from the hydrogen PSA will be combined with a nitrogen pure stream from the ASU to supply the ammonia synthesis train with the components necessary to create a capture-ready ammonia product. It is estimated that at baseline operating conditions, the ammonia train will generate ~30,000 lb/hr of ammonia.

The ammonia synthesis process will generate significant usable process heat that will be recovered to produce steam for use in electricity generation or to meet the thermal loads of other plant processes.

3.2 Target Level of Performance

Exhibit 3-3 below provides the high-level performance summary for the current conceptual design:

Exhibit 3-3 Summary Performance Characteristics

Performance Summary	
Combustion Turbine Power, MWe	61
Steam Turbine Power, MWe	35
Total Gross Power, MWe	96
Total Energy Chemically Stored as NH_3, MW	84
Combined Gross Power and Chemical Storage	180
Coal Handling, kWe	114
Slag Handling, kWe	131
ASU Auxiliaries, kWe	293
ASU Main Compressor, kWe	17,501
Oxygen Compressor, kWe	2,917
Nitrogen Compressor, kWe	9,553
Ammonia Plant Compressors, kWe	4,236
Ammonia Plant Refrigeration System, kWe	2,512
CO_2 Compression, kWe	8,455
Feedwater Pumps, kWe	1,691
Condensate Pumps, kWe	163
Quench Water Pumps, kWe	143
Circulating Water Pumps, kWe	2,034
Ground Water Pumps, kWe	222
Cooling Tower Fans, kWe	1,184
Scrubber Pumps, kWe	327
Acid Gas Removal, kWe	4,384
Combustion Turbine Auxiliaries, kWe	13
Steam Turbine Auxiliaries, kWe	17
Syngas Recycle Compressor, kWe	186
Claus Plant Auxiliaries, kWe	62
Claus Plant Recycle Compressor, kWe	452
Miscellaneous Balance of Plant, kWe	3000
Transformer Losses, kWe	413
Total Auxiliaries, MWe	60
Combined Net Power and Chemical Storage	120
HHV Net Plant Efficiency	30.6%
As-Received Coal Feed, kg/hr (lb/hr)	51,951 (114,532)
HHV Thermal Input, MWt	392
LHV Thermal Input, MWt	379
CO_2 Emissions, lb/MMBtu	22
Raw Water Consumption, gallons/MWh	882

3.3 Ability of the Proposed Plant to Meet Coal First Design Criteria

3.3.1 High overall plant efficiency

Initiative Objective: High overall plant efficiency (40%+ HHV or higher at full load, with minimal reductions in efficiency over the required generation range).

Status: *Partially met - System will have minimal reductions over the operating range but is below the target.*

The current estimate of net plant efficiency at the central design point is 30.6%. This is below the 40% target that seemed achievable in the proposal stage. The conceptual design system pays an efficiency price due to (1) a 95% carbon capture goal (post-shifting our synthesis gas for maximum emissions reduction), (2) decoupling the combustion and steam turbine cycles to improved ramp rate, and (3) making design choices intended to balance a high overall efficiency with respectable efficiencies across a broad window of operating characteristics (i.e. different splits of electricity and energy storage by chemical production). The detailed work of the conceptual design process indicates the efficiency cost of these desired design characteristics are higher than the preliminary assessment. By reducing the goal from the aggressive 95% to a less aggressive 'natural gas-like' emissions total, overall efficiency in the 33-34% range could be achieved More detailed assessment of both the magnitude and shape of the efficiency curves will be developed during the pre-FEED study with the intent of refining the operating window of the system to reduce the efficiency penalty without significant adverse impacts to other desired design attributes inherent in a flexible coal-based energy system designed to be responsive to the more dynamic needs of the modern bulk power system.

The current efficiency is maximized through the combination of electrical generation and chemical storage of energy via ammonia This is a key component providing a wider band of efficient operation, allowing for greater overall time averaged energy conversion performance than can be achieved by a design focused solely on optimization of "point-in-space" operation. A simple cycle combustion turbine system has been initially selected rather than a combined cycle system due to their superior turn-down characteristics. This allows the proposed system to operate efficiently across a broader range of operating conditions, allowing improved average efficiencies while effectively following constantly changing load demands. By combining multiple systems whose design choices will be guided by establishing broader, flatter efficiency curves (e.g., syngas production, syngas combustion turbine for electrical generation, synthesis gas to fuel conversion, and fuel combustion turbine), an overall system with a broadly efficient operating window that is robust to both operational upsets and widely varying load requirements was developed.

The system currently leverages significant heat integration between unit operations to maximize the advantages offered by the various exothermic and endothermic chemical processes as well as the residual heat from the combustion turbine outlet. Additionally, the current design basis minimized parasitic loads to the minimum needed to meet performance targets. Consequently, further improvements in efficiency will require either tradeoffs in performance on other initiative objectives or significant improvements in the energy efficiency of components systems. While these component system efficiency gains are not anticipated in the near-term, later generations of this technology platform should have process intensification options (particularly ammonia synthesis) that should help increase overall efficiency.

3.3.2 System modularity.

Initiative Objective: Modular (unit sizes of approximately 50 to 350 MW), maximizing the benefits of high-quality, low-cost shop fabrication to minimize field construction costs and project cycle time

Status: *Met - system capacity chosen such that significant modular construction is anticipated and provides ~120 MW of net energy production.*

The designed system is a smaller generation asset capable of serving the spatially diverse requirements for ancillary services (which do not 'travel well' across the grid) and to function competently as a component of a larger distributed system. Due to the modest scale generation systems considered in this concept, the systems may be designed to allow for shop fabrication and use of more standardized components, providing advantages in terms of capital costs, maintenance cost and response, as well as lowered construction times to facilitate limited asset redeployment (i.e. 'semi-mobile'). Specifically, the modularity of the design is based on the premise that the gasifier would constitute the largest plant system that would need to be fabricated off-site. If this system is sized such that it could be shop fabricated (based on Worley experience), then modularization of the other major systems of the plant should also be possible.

The gasifier follows a KRW design with dimensions limited by the ability to shop fabricate and transport over-land to the site to ensure that modularity is maintained. It is believed that this limitation results in a maximum overall package size for the main gasifier section of 13.7 feet in diameter and 32 feet in length. Based on the known aspect ratios of the KRW gasifier, this will result in an inner reactor diameter of 9.1 feet with a reactor height of 27.4 feet, for an overall reactor volume of 1,800 cubic feet. As the plant design intends to include 2 gasifiers, the overall usable reactor volume will be 3,600 cubic feet. The KRW gasifier has been demonstrated successfully at this scale (when it was part of development for a larger scale process).

Additionally, ammonia was chosen as a chemical storage medium as its current state of the art is able to be more efficiently scaled down than methanol synthesis. Additionally, active process intensification research targeting ammonia provides a path for an even more modular system in subsequent generations.

3.3.3 Carbon capture and low emissions

Initiative Objective: Near-zero emissions, with options to consider plant designs that inherently emit no or low amounts of carbon dioxide (amounts that are equal to or lower than natural gas technologies) or could be retrofitted with carbon capture without significant plant modifications).

Status: *Preliminarily met - would want to incorporate a more standard life cycle analysis as part of the pre-FEED process.*

Team AST's approach uses a water-gas shift reactor to make the option to implement pre-combustion capture inherent in the proposed approach. The current design leverages an established solvent-based acid gas removal/carbon capture system as it was determined to have simpler logistics compared to the significant amount of solid material required for a sorbent or Skyonic-like system. Currently, the system is using an aggressive 95% pre-combustion carbon capture target. Ammonia, as the chemical storage component, has potential for power generation with limited emissions impact. Specifically, ammonia-based power options have been an area of highly active R&D activities (fuel cell, internal combustion engines, turbines, and microthrusters) for extracting energy stored in the chemical bonds of ammonia with minimal environmental impact. The proposed approach enables the potential for the specified coal-based generation system to take advantage of complimentary innovations in this space. The current estimate of CO_2 emission is 22 lb/MMBtu of coal processed in the system, which is similar to the emissions performance of large baseload, IGCC plants modeled in the NETL baseline studies.

3.3.4 High ramp rate characteristics

Initiative Objective: The overall plant must be capable of high ramp rates and achieve minimum loads commensurate with estimates of renewable market penetration by 2050

Status: Met - requires more detailed assessment during the pre-FEED stage.

The current design combines several systems that provide operational flexibility in order to generate a wide window of operations at reasonable efficiency to facilitate the ability of the plant to absorb grid disturbances and complex market dynamics. Specifically, the syngas production will couple to storage capacity, allowing for adjusted final disposition between the power generation and ammonia production (chemical storage/fuel) options, resulting in the ability to vary the power output without requiring that the entire plant be operated at partial load. The synthesis gas power production will be accomplished by a simple cycle turbine due to its flatter efficiency curve and better response characteristics relative to combined cycle operations. Heat recovery throughout the plant will generate steam for a decoupled steam cycle to enable reasonable efficiency and overall responsiveness. Additional, surge capacity for electricity production can be achieved through combustion of the energy stored as ammonia. This can be accomplished either through blending of ammonia in to the feed of the combustion turbine (as needed, on a limited basis) to allow other parts of the system to adjust to demand-load and system upsets or, in specific cases, through deployment of an additional, dedicated ammonia-based power system. The use of ammonia for electrical power generation at small-scale is an active area of research which hopefully can be leveraged in later technology generations.

3.3.5 Integration of coal-based electricity generation with storage

Initiative Objective: Integration with thermal or other energy storage to ease intermittency inefficiencies and equipment damage.

Status: *Met - inherent in the polygeneration approach.*

Polygeneration (co-production with ammonia) was selected so that readily accessible, chemical storage of the energy from coal is inherent in Team AST's design. This choice allows the system to ramp up and down in response to the varying load demands and intermittent power supplied to the grid system without placing unneeded mechanical and/or metallurgical stress on system equipment. The chemical storage options considered in the proposed approach can handle transients in the system. Additionally, the selected option for chemical storage, ammonia, has multiple disposition options (e.g., combustion for power, readily transported fuel, combined heat and power, vehicle fuel, and/or localized fertilizer production). These multiple dispositions allow specific project implementations to leverage various potential value streams to facilitate a greater range of economically viable implementations and/or meet mission requirements (e.g., DoD energy and mission resilience options) if the system is deployed in a microgrid or related approach.

The chemical storage medium of ammonia was selected due to it being better aligned with the performance targets of the Coal FIRST initiative. Specifically, overall systems efficiency is enhanced relative to a methanol system due to the higher separation energy (two distillation columns rather than a refrigeration-based system) and lower quality heat recovery from a methanol-based system. Current synthesis process technology is known to scale down better for ammonia than methanol. Additionally, developments in the area of renewable energy-derived ammonia are driving process intensification innovation in ammonia synthesis that later generations of this technology platform may leverage. This also indicates that ammonia production is more complimentary to reduced design, construction, and commissioning efforts. Carbon is rejected at a point source in ammonia production allowing more efficient life-cycle carbon dioxide capture (compared to distributed carbon dioxide emissions after methanol end use). Methanol production requires more water than ammonia synthesis. Additionally, ammonia transport costs create acts as a protective buffer to potential disruptions caused by cheap natural gas-derived mega-plants (cf. methanol), making the ammonia market inherently distributed which is complimentary to a distributed power system.

3.3.6 Minimized water usage

Initiative Objective: Minimized water consumption.

Status: *Preliminarily met - requires more detailed utility assessment during pre-FEED*

Water usage was minimized throughout the conceptual design development with optimistic targets for extensive re-use of process water. More detailed evaluations of the suitability of process water for reuse will occur in the pre-FEED stage; aimed at careful consideration of the trace components in the water. Additionally, ammonia was chosen as the chemical energy storage medium partially based on the reduced water and steam requirements relative to methanol synthesis and product recovery. Current estimates of water consumption are 882 gallons/MWh.

3.3.7 Reduced design, construction, and commission schedules

Initiative Objective: Reduced design, construction, and commissioning schedules from conventional norms by leveraging techniques including but not limited to advanced process engineering and parametric design methods.

Status: *Preliminary met - impact will be seen in the pre-FEED study and incorporation of external technology development in subsequent generations of this technology platform (i.e. incorporation of process intensification).*

The conceptual design approach was selected so that one could rationally select unit operation scales that allow for standardization and parametric design. Additionally, the intention is to leverage advances in process intensification such as those being driven by the American Institute of Chemical Engineers RAPID Manufacturing Institute. The pre-FEED section of Team AST's study will include a sourcing and manufacturability analysis aimed at establishing the most standardized version of the concept so that it can be replicated with minimum re-engineering and re-specification of equipment. The intent is to have a system that is deployable on timescales similar to those seen by deployment of natural gas combined cycle generation assets rather than the lengthy timelines of baseload coal or nuclear power plants.

3.3.8 Improved maintainability

Initiative Objective: Enhanced maintenance features including technology advances with monitoring and diagnostics to reduce maintenance and minimize forced outages

Status: *Preliminarily met - requires further articulation and assessment during pre-FEED.*

The approach is designed to respond to curtailed (or even fully reduced) demand for electrical generation capability while remaining on 'warm stand-by.' Specifically, the design leverages the intelligent incorporation of storage (synthesis gas and ammonia) capacity in the system. The storage capacity provides the capability to run for a limited time off stored synthesis gas in the event of gasifier curtailment or store produced synthesis gas for future use if the combustion turbine or the ammonia (chemical storage) production train(s) are curtailed. Note that ammonia can be used to augment reduced synthesis gas availability when required to perform both scheduled or unplanned maintenance. Additionally, multiple trains have been employed, when practical (gasifier and turbines). This allows the ability to respond quickly, minimizes wear and tear on equipment, maximizes utilization of deployed capital and allows for maintenance on various trains within the system while continuing to provide value. Accomplishing this requires advanced controls and edge computing-enabled asset optimization (such as that deployed in microgrids). The pre-FEED study will specify advances in sensors, monitoring, and condition-based maintenance appropriate for these scales.

3.3.9 Integration with other plant value streams

Initiative Objective: Integration with coal upgrading, or other plant value streams (e.g., co-production)

Status: *Met*

The polygeneration approach inherently links coal-based electricity generation with other value streams (production of ammonia as a chemical fuel or for other beneficial use). These unit operations create multiple options for effective heat integration and dispositions of intermediate streams produced in various operating sections.

3.3.10 Potential for natural gas integration

Initiative Objective: Capable of natural gas co-firing

Status: *Met*

Natural gas can be incorporated into this approach in a variety of ways to increase reliability, resiliency, and reduce the risks associated with the gasification process. Specifically, natural gas can be used to produce make-up synthesis gas as needed through either a steam methane or autothermal reformer. Natural gas may also be blended with a portion of the water gas shift reactor effluent directed to the combustion turbine to optimize the energy content of the fuel combusted in the turbine (in terms of quality and consistency of the turbine fuel's heat content). Natural gas can also complement the heat requirements of the system as needed.

4. Technology Development Pathway

This conceptual design employs the innovative deployment of proven foundational components. This, combined with the subsequent application of a sound engineering (pre-FEED and FEED) and process development methodology, will ensure the system meets the technical requirements for a component of a modern, highly distributed power system. As such, the needs for driving this proposed approach to the next stage are more focused on sound development work rather than inventive, higher risk research work. This approach lowers risks and focuses on system needs rather than becoming experimental in nature.

4.1 Current State of the Art

All of the operating sections of this conceptual design are based on mature technology. However, some of the unit operations leverage technology that has not been widely applied recently. Specifically, the devolatilizer bubbling bed is similar in scale and function to the carbonizer unit operation demonstrated as a pre-process step for pressurized fluid bed combustor technology in prior deployments. The KRW gasifier was demonstrated successfully in the 1970's and 1980's at the scales that this conceptual design intends to use. Process development and demonstration of this unit operation will need to spend considerable time assuring known technology lessons are appropriately considered and transferred.

The cautionary tale of the commercial deployment of the KRW gasifier by the Sierra Pacific Power Company, as part of the Pinon Pines IGCC Power Project, should provide guidance in the pre-FEED study. However, this project was scale up of the KRW gasifier to larger scales than those envisioned by this design which have been demonstrated. Additionally, the Pinon Pines project suffered from multiple applications of new technology compounding its technology risks.

The unit operations have also been, essentially, demonstrated at the scales of this project.

Specifically, the Waltz Mill, PA demonstration of the KRW gasifier ran, at a minimum, of 35 MW capacity which is greater than the capacity needed per gasifier train in this project. The devolatilizer unit operation has a broad basis of commercial practice (e.g. the ubiquitous use of fluid bed for complex commercial drying operations ac

Bubbling-bed coal drying (and associated desorption) has been demonstrated at scale (cf. Great River Energy's Coal Creek Unit 2 station ~600 MW demonstration); augmented by ubiquitous application of fluid beds in drying operations. The 'carbonizer' unit operation of the Foster-Wheeler/Westinghouse second generation pressurized fluid bed combustion process, while having more complex technical objectives (production of fuel gas) compared to the devolatilizer's drying and desorption objectives, serves as a reasonable basis equipment required for such fluidization and solids handling.(e.g. sizing, cost, and parasitic loads) for the During the conceptual design process (i.e. prior to detail design in a FEED study).The 'carbonizer' was deemed 'commercially available' in Clean Coal Technology Program literature. However, as best as can be determined in the open literature the largest demonstration of a carbonizer operation was ~ 7 MW at Wilsonville, AL.

The other unit operations are well-established placing the requirements on overall flowsheet optimization. Additionally, ammonia production at small-scale, including in highly intensified options, is an active area for technical development that may be incorporated into later generations of this platform. The technical readiness of the processes operating sections is summarized in Exhibit 4-1.

Exhibit 4-1 Technical Readiness of Operating Sections

Operating Section	Status	Pathway Forward
Coal Preparation and Handling	Mature, stable	Established technology.
Air Separation Unit	Mature, stable	Established technology; pressure swing adsorption options should be reconsidered if the process scaling changes or as a means for reducing parasitic load.
Devolatilizer	Demonstrated, engineering design	Bubbling bed drying and desorption established. Disciplined detailed engineering and scale-up of this bubbling bed (c.f Kunii and Levenspiel text) is required. This process will require supporting experimentation (cold flow) and modeling (e.g. CFD)
Gasifier (includes particulate handling and cooling)	Demonstrated, engineering design	Detailed analysis of previous design basis of the KRW and other fluid bed gasifiers should be used to inform the detailed design during the FEED stage. This design process must leverage supporting experimentation (cold flow) and modeling (e.g. CFD, kinetics), fluid bed design and scale-up principles (Kunii and Levenspiel), as well as multiphase reactor design methods (Chapters 7 and 14 of

		Froment and Bischoff text).
Syngas Cleanup (includes carbon capture and sulfur recovery) and Management	Mature, potential innovation impact	Established options, potential to integrate improvements in pre-combustion capture
Ammonia Synthesis Train and Product Storage	Mature, significant potential innovation impact	Established options at relevant scale; active R&D in process intensification that may improve performance
Electrical Power Island	Mature, engineering optimization	Established options, turbine choice and integration will be iteratively optimized during the FEED process. Potential efficiency gains by switching to a combined cycle process with a separate decoupled process (gasifier, ammonia, etc.) heat recovery steam turbine should be considered in conjunction with ramping characteristics.

4.2 Technology Advancement by this project

This project advances the responsive coal-based technology through integration and through capturing neglected technology options. Specifically, high quality, relevant technology development from a generation ago is at high risk of being lost due to its lack of initial deployment and workforce demographics (retirements). The conceptual design study made it apparent that documentation of such technologies is not as well-preserved nor as accessible as desired. While these technologies were initially aimed at large-scale, carbon-capture agnostic applications, further detailed engineering work is warranted to unlock their potential to develop a coal-based system optimized for the power system anticipated in 2050.

Continuing this project through the pre-FEED (and additional engineering steps) study will advanced the technology platform by integrating components and incorporating adjacent space innovation (such as process intensification, as they become available). This technology foundation has great potential to be a large platform to more safely deploy such adjacent space innovations as lower risk enhancements before attempting to have them support themselves technical and economically on their own.

4.3 Technical Risks Relevant for the Proposed Design

They key risks on this project are:

1) Inability to further improve overall system efficiency while maintaining compliance with other initiative goals
2) Technology knowledge erosion
3) Adherence to a disciplined, process development process

As discussed in the section on the design's ability to meet the Coal FIRST Initiative's objectives and in the technical gaps below, the largest issue is the overall efficiency and if more adjustments can be made without losing the performance on other objectives. Technical knowledge erosion refers to the risk of resurrecting core components from decades ago. During the conceptual design process, finding old 'standard' handbooks and reports has been difficult and documentation is never as detailed as desired. More importantly, the engineers and scientists the developed some of the core components of this design have finished or will soon finish their careers, limiting the amount of 'full context' that can be given to the demonstrated technology components.

The success of fast-cycle technology development in the microelectronics and software industry has increased the risk that disciplined process development process will be short cut. The lack of "new" components on this conceptual design flowsheet can confuse planners into thinking process development can be "accelerated". The Pinon Pines experience (cf. 2002 NETL report: *Piñon Pine IGCC Power Project A DOE Assessment),* where reliability issues were largely caused by failures in the implementation of a novel filter-fines removal system, underscores the need for any proposed technology development to outline the integration and mitigation of risk in detail rather than assume that these novel components are actually stable technology components that can be implemented without cause for concern.

The previous demonstration of the unit operations analogous to the devolatilizer at relevant scales limits the technical risk associated with its deployment. However, careful application of the design and scale-up of such a bubbling-bed need to be carefully followed and needs to be supported by complimentary computational fluid dynamics modeling and cold flow experiments. These processes will form the core of the pilot plant planning and objectives for this portion of the plant. Additionally, there is a reasonable concern related to tars and heavies dropping out during the condensation of the moisture out of the devolatilizer overhead leading to blockages of the transfer line, as well as other operational issues. The formation of these species (atomized or vapor phase tars and heavy hydrocarbons) are not anticipated at the temperatures and short-residence time distributions of this unit operations. However, the devolatilizer design will include sufficient transport disengaging height to prevent carry over of atomized heavy hydrocarbons. Additionally, the technology basis envisions leveraging saltation velocity to drop out any potential atomized heavies that do carry over, complimented with periodic line sweeps. Should these techniques fail, the process will route the devolatilizer overhead into the gasifier outlet quench system to handle tars and heavy hydrocarbons and will explore adjusting the temperature and residence time profiles of the devolatilizer to reduce their initial formation. This issue will be included in a pilot plant objectives and operations plan to assure the technology development pathway is clear.

Additional technical risks include the development and sourcing of both the devolatilizer and the KRW gasifier. While the theory behind both of these pieces of equipment is sound, neither one is currently being commercially produced. Failure to find an OEM willing to manufacture them, or only finding ones that are unwilling to manufacture them to acceptable specifications for the proposed application, will present a technical challenge which must be managed and mitigated.

The final primary technical risk involves final selection of an acceptable combustion turbine. While there are many commercial CT's that advertise the ability to run on syngas, there are often tight specifications that the syngas must meet for the CT to operate effectively. As this information is not often publicly available, it is important to continue productive engagement with turbine manufactures (especially as design and Pre-FEED study adjustments alter the composition of fuel sent to the combustion turbine).

The final primary technical risk involves final selection of an acceptable combustion turbine. While there are many commercial CT's that advertise the ability to run on syngas, there are often tight specifications that the syngas must meet for the CT to operate effectively. As this information is not often publicly available, it is important to be able to engage positively and fruitfully with OEM's to obtain accurate vendor quotes. Initial vendor quotes have been obtained regarding a number of GE and Siemens options. While feedback is promising and it is believed that an acceptable turbine can be selected without significant issue, additional engineering analysis by OEM points of contact will be required during the pre-FEED phase for final confirmation. It is expected that the worst-case scenario will involve some turbines requiring natural gas blending or additional emissions control measures.

Overall, the technical risk of the project should be fairly low as the overall design process has been focused on application of proven, commercially-existing technologies whenever possible to facilitate rapid deployment of a pilot program.

4.3 Overcoming Existing Shortcomings and Identified Risks

The subsequent application of further engineering process to this conceptual design will focus on overcoming previously identified shortcomings (overall efficiency) and the risks mentioned above. The pre-FEED study will be the initial attempt at closing the performance gap and mitigating risk. A key part of the pre-FEED study is to outline a detailed process development and process piloting plan that actively explores these areas and solidifies the technical basis. One part of the plan will focus on incorporation on adjacent space innovation and OEM suggestions to improve performance. The other main component of the plan will assure the technology applied such that is demonstrates that mitigation plans for the risks are handled.

Performance improvement pathways will focus on the lone identified performance gap relative to the CFI's guidelines: efficiency. Primary pathways include soliciting, testing, and incorporating OEM feedback that can improve performance and scouting of adjacent space applications (such as process intensification) that can rescue parasitic loads. However, the main activity for closing this performance gap will be investigating the detailed assessment of system dynamics to see if adjustments can be implemented to improve efficiency while still having an acceptably flat response curve. The cycles of the combustion turbine and steam turbine are fully decoupled in this current iteration, but there may be an opportunity to couple the cycle of a steam turbine to the combustion turbine (i.e. via direct routing of flue gas heat) to improve efficiency, while using other system dynamics to still meet required ramping characteristics.

The risk mitigation portion of the technology development will focus on the actual work of building components and exploring a wider range of potential combustion turbine feed compositions in conjunction with OEMs. Our initial OEM assessment conducted as part of this process and relevant relationships to enable such activity are described in the next section.

5. Technology Original Equipment Manufacturers (OEM)

5.1 List of Commercial Power Generation and Gasification R&D Equipment

Exhibit 5-1 provides a list of the major equipment in the AST Polygeneration System. This exhibit includes the current commercial status of the equipment.

Exhibit 5-1 List of Major Equipment Polygeneration Conceptual Design

Power Generation / Gasification Process System Block	Power Generation / Gasification Process Equipment	Commercial/R&D Status
Air Separation Unit (ASU)	ASU / Oxygen Separator	Commercially Available
Coal Feed Preparation	Coal Conveyors	Commercially Available
	Coal Pulverizers, Dryers	Commercially Available
Char Preparation	Devolatilizer	R&D
Gasifier Island	Gasifier	R&D
Syngas Cooler	Spray Quench or Boiler type SynGas Cooler	Commercially Available
Syngas Filters	Syngas Filter	Commercially Available
Sulfur Recovery	Wet Sulfuric Acid/ Solid Sulfur	Commercially Available
CO_2 Compression	CO_2 Compressors	Commercially Available
Electrical Power Island	Gas Turbine with high Hydrogen Firing Capability	Commercially Available – confirmation of fuel gas suitability required.
	Heat Recovery	Commercially Available
	Steam Turbine Generators	Commercially Available

Worley project engineers have designated the devolatilizer and gasifier equipment as “R&D” status due to the design and construction list inherent in there not being recent orders of this specific equipment. Specifically, while both unit operations have been procured, constructed, and demonstrated at the scale of this project, the pause in active use of these components create the risk that the context behind the current detailed design may be lost in workforce turnover and incomplete or not properly preserve archived design documentation. However, the experience of the AST team in scale up and design of fluid beds makes developing these components an application of engineering best practices rather than a risky set of technology development issues.

5.2 Worley’s Experience Working with Relevant OEMs

Worley Group Inc. (formally WorleyParsons Group, Inc.) is working with AST as the Architecture and Engineering firm to develop designs that reflect state of the art commercial practice. 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 AST’s experience with OEMs for the critical equipment in the gasification process.

5.2.1 Gasifier

Worley has work with fabricators and refractory suppliers to develop the capital costs for this equipment.

5.2.2 Gas Turbine & Steam Turbine

Worley is one of the leading engineering firms in the world specializing in power, energy, chemicals, hydro-carbon upstream and downstream projects. The Reading office is the center of excellence for all types of power projects including gasification, gas turbine combined cycle projects and various special power generation projects.

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 during the conceptual design process discussed above.

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.

5.2.3 Syngas Cooler

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

5.2.4 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 etc. The CO_2 compressor inquiries were pursued with these OEMs as a part of various feasibility and pre-FEED and FEED studies performed for post combustion CO_2 Capture projects.

5.3 Equipment Information Resources

For further development of the process during the Pre-FEED study, Worley's and AST's resources for equipment information includes Vendor Data & Interfaces, the Worley Project Library, budgetary quotes, and past reference projects.

5.3.1 Vendor Data & Interface

Worley has direct key vendor contacts for major critical equipment in the gasification process. For Worley, we interface 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. On some projects where the emission performance needs to be calculated by OEMs, OEMs may provide the emission and performance estimates for given ambient conditions, fuel types, various load points and different cooling system configurations.

5.3.2 Worley Project Library

Worley maintains an electronic repository of all design information on major projects that were either built by Worley (or) involved as Owner's Engineer or prepared the feasibility, Pre-FEED and FEED studies on behalf of the Owners. This information including performance data, drawings, calculations, Process & Instrument Diagrams (P&IDs), system descriptions and calculations are stored in Worley's Database which are accessible this team.

5.3.3 Budgetary Quotes

Worley can obtain budgetary quotes for major and critical equipment based on mini-specification or email inquiries. Typically, OEMs provide a budgetary quote within a three-week time period.

5.3.4 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.

5.4 Experience with OEM's for Commercial Ammonia Equipment and R&D

Worley and AST's lack of direct experience with commercial ammonia process and catalyst equipment and technology licensors is complemented by additional subject matter experts on Team AST who are actively engaged in this area.

Appendix A: Unit Operation Details

A-1 Solids Prep and Devolatilization

The block flow diagram for Solids Prep and Devolatilization, as well as the relevant input and output streams, can be seen below in Exhibits A-1 and A-2, respectively.

Exhibit A-1 Block Diagram of Solids Prep and Devolatilization

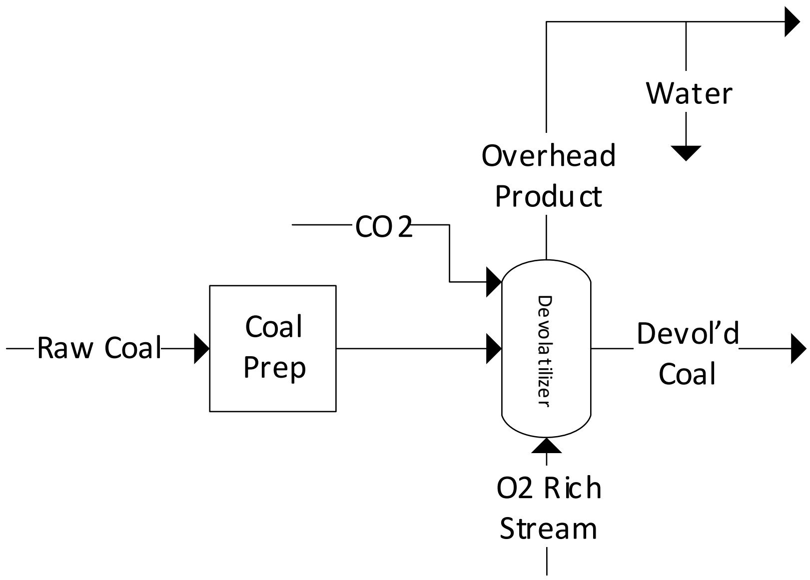

Exhibit A-2 Relevant Stream Composition for Solids Prep and Devolatilization

VARIABLE	UNIT	INPUTS			OUTPUTS		
		Raw Coal	CO_2	O_2-Rich Stream	Overhead Product	Water	Devol'd Coal
Total	lb/hr	114,532	35,127	18,839	73,902	16,801.51	95,088
N_2	lb/hr	1,435.32	0.00	0.00	106.21	0.00	1,329.11
O_2	lb/hr	7,889.17	0.00	17,323.20	661.60	0.00	7,309.44
Ar	lb/hr	0.00	0.00	1,203.30	1,203.30	0.00	0.00
H_2O	lb/hr	12,735.95	0.00	261.02	16895.00	16,801.51	0.00
CO	lb/hr	0.00	0.00	0.00	681.04	0.00	0.00
CO_2	lb/hr	0.00	35,126.90	51.93	53,904.60	0.00	0.00
Ash	lb/hr	11,105.90	0.00	0.00	0.00	0.00	11,105.90
S	lb/hr	2,870.64	0.00	0.00	0.00	0.00	2,658.21
COS	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
NH_3	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00

H_2S	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
SO_2	lb/hr	0.00	0.00	0.00	424.41	0.00	0.00
SO_3	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
H_2	lb/hr	5,150.87	0.00	0.00	0.00	0.00	4,769.00
CH_4	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
C	lb/hr	73,007.90	0.00	0.00	0.00	0.00	67,605.40
Cl_2	lb/hr	335.93	0.00	0.00	0.00	0.00	311.07
C_6H_6	lb/hr	0	0.00	0.00	0.00	0.00	0.00
HCl	lb/hr	0	0.00	0.00	25.57	0.00	0.00
Methanol	lb/hr	0	0.00	0.00	0.00	0.00	0.00

A-2 ASU, Gasifier, and Quench

The block flow diagram for ASU, Gasifier, and Quench, as well as the relevant input and output streams, can be seen below in Exhibits A-3 and A-4, respectively.

Exhibit A-3 Block Flow Diagram of ASU, Gasifier, and Quench

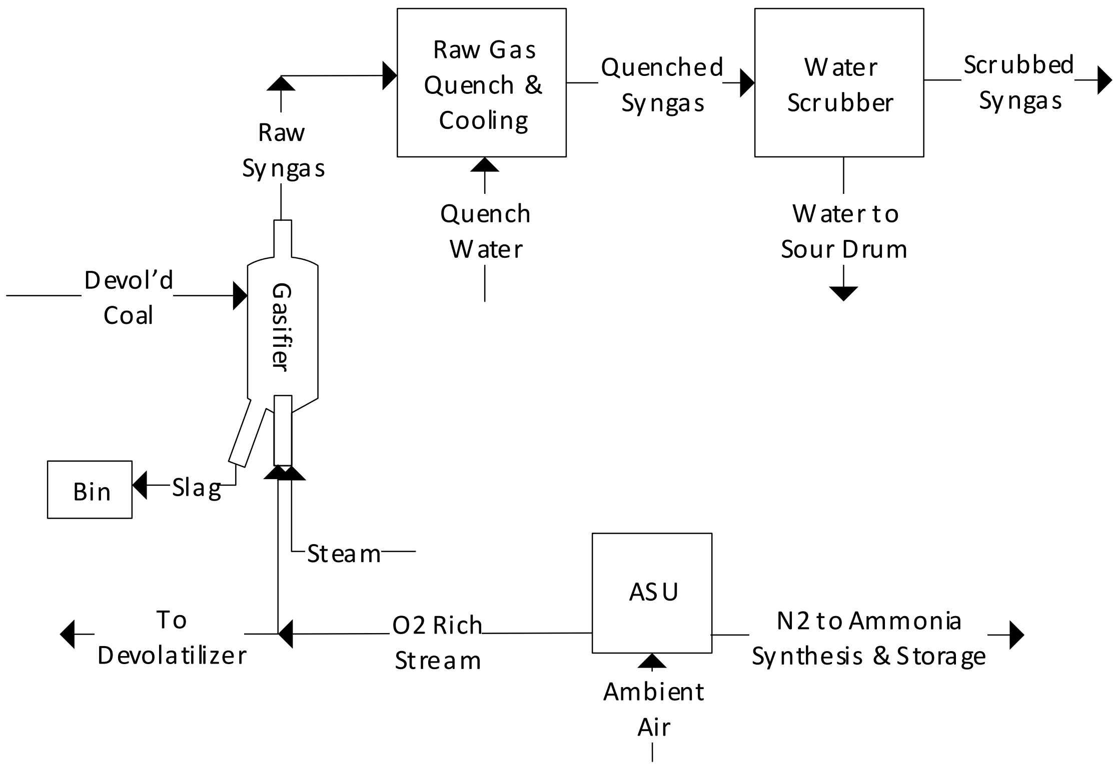

Exhibit A-4 Relevant Stream Composition for ASU, Gasifier, and Quench

VARIABLE	UNIT	INPUTS			OUTPUTS		
		Devol'd Coal	Ambient Air	Steam	N_2 to Ammonia Synthesis and Storage	O_2-Rich Stream to Devolatilizer	Scrubbed Syngas
Total	lb/hr	95,088	238,506	20,215	53,683	18,839	201,345
N_2	lb/hr	1,329.11	172,711.39	0.00	53,683.12	0.00	1,322.72
O_2	lb/hr	7,309.44	60,453.40	0.00	0.00	17,323.20	0.00
Ar	lb/hr	0.00	4,199.21	0.00	0.00	1,203.30	6,204.96
H_2O	lb/hr	0.00	910.90	20,215.18	0.00	261.02	14,177.44
CO	lb/hr	0.00	0.00	0.00	0.00	0.00	122,907.42
CO_2	lb/hr	0.00	181.23	0.00	0.00	51.93	45,496.43

Ash	lb/hr	11,105.90	0.00	0.00	0.00	0.00	0.00
S	lb/hr	2,658.21	0.00	0.00	0.00	0.00	0.00
COS	lb/hr	0.00	0.00	0.00	0.00	0.00	400.22
NH_3	lb/hr	0.00	0.00	0.00	0.00	0.00	7.77
H_2S	lb/hr	0.00	0.00	0.00	0.00	0.00	2,598.28
SO_2	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
SO_3	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
H_2	lb/hr	4,769.00	0.00	0.00	0.00	0.00	4,599.39
CH_4	lb/hr	0.00	0.00	0.00	0.00	0.00	3,310.28
C	lb/hr	67,605.40	0.00	0.00	0.00	0.00	0.00
Cl_2	lb/hr	311.07	0.00	0.00	0.00	0.00	0.00
C_6H_6	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
HCl	lb/hr	0.00	0.00	0.00	0.00	0.00	319.91
Methanol	lb/hr	0.00	0.00	0.00	0.00	0.00	0.03

A-3 Syngas Cleaning

The block flow diagram for Syngas Cleaning, as well as the relevant input and output streams, can be seen below in Exhibits A-5 and A-6, respectively.

Exhibit A-5 Block Flow Diagram of Syngas Cleaning

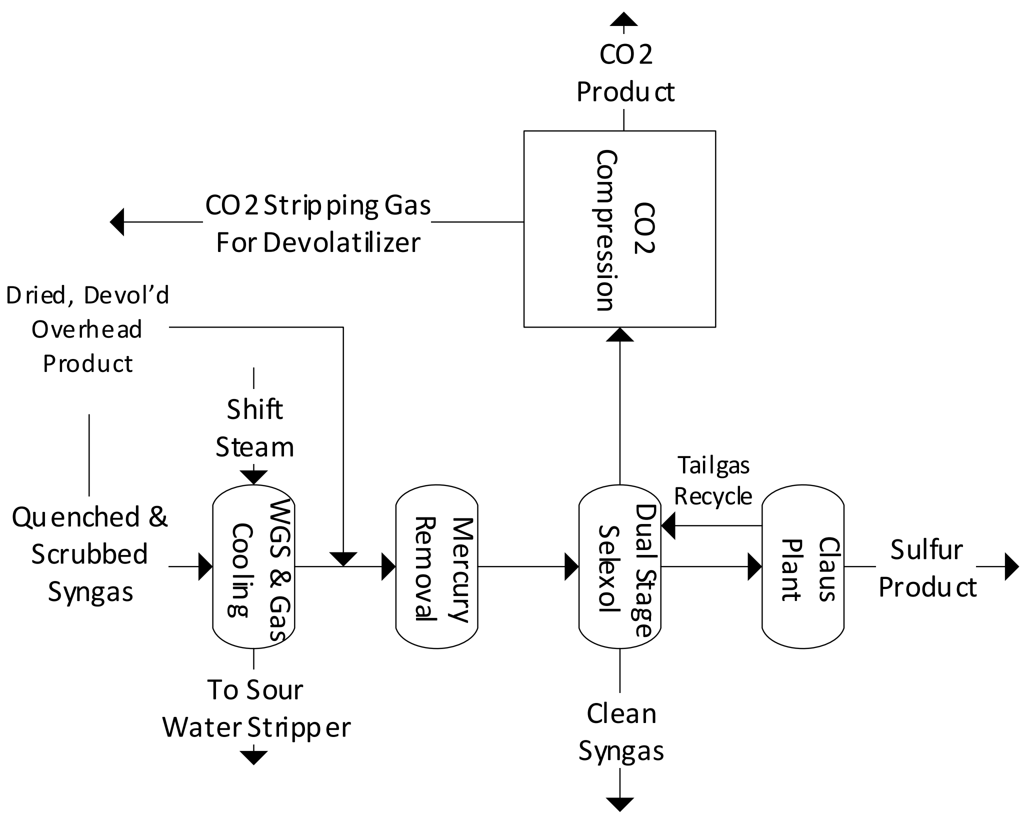

Exhibit A-6 Relevant Stream Composition for Syngas Cleaning

VARIABLE	UNIT	INPUTS			OUTPUTS		
		Quenched and Scrubbed Syngas	Shift Steam	Dried, Devol'd Overhead Product	CO_2 Stripping Gas for Devolatilizer	CO_2 Product	Clean Syngas
Total	lb/hr	201,345	143,877	57,100	35,127	237,478	45,128
N_2	lb/hr	1,322.72	0.00	106.21	0.00	0.00	1,428.93
O_2	lb/hr	0.00	0.00	661.60	0.00	0.00	661.60
Ar	lb/hr	6,204.96	0.00	1,203.30	0.00	0.00	7,408.25
H_2O	lb/hr	14,177.44	143,877.29	93.49	0.00	0.00	495.98
CO	lb/hr	122,907.42	0.00	681.04	0.00	0.00	4,367.49
CO_2	lb/hr	45,496.43	0.00	53,940.60	35,126.90	237,478.16	14,347.63

Ash	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
S	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
COS	lb/hr	400.22	0.00	0.00	0.00	0.00	0.00
NH_3	lb/hr	7.77	0.00	0.00	0.00	0.00	7.77
H_2S	lb/hr	2,598.28	0.00	0.00	0.00	0.00	0.00
SO_2	lb/hr	0.00	0.00	424.41	0.00	0.00	0.00
SO_3	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
H_2	lb/hr	4,599.39	0.00	0.00	0.00	0.00	13,099.91
CH_4	lb/hr	3,310.28	0.00	0.00	0.00	0.00	3,310.18
C	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
Cl_2	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
C_6H_6	lb/hr	0.00	0.00	0.00	0.00	0.00	0.00
HCl	lb/hr	319.91	0.00	25.57	0.00	0.00	0.00
Methanol	lb/hr	0.03	0.00	0.00	0.00	0.00	0.03

A-4 Electricity Generation and Product Synthesis

The block flow diagram for Electricity Generation and Product Synthesis, as well as the relevant input and output streams, can be seen below in Exhibits A-7 and A-8, respectively.

Exhibit A-7 Block Flow Diagram of Electricity Generation and Product Synthesis

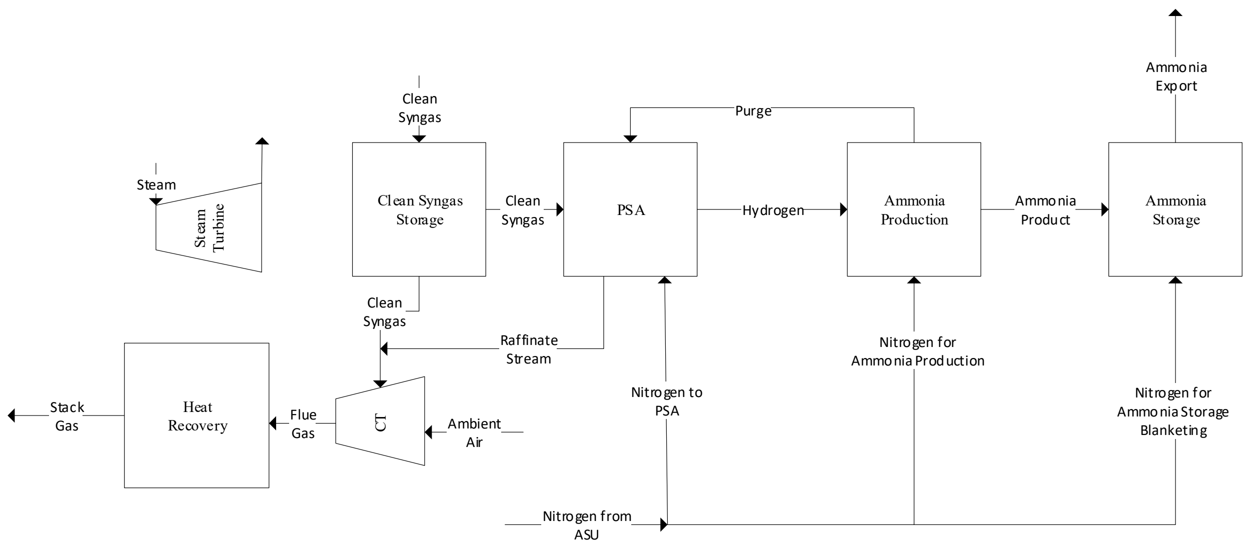

Exhibit A-8 Relevant Stream Composition for Electricity Generation and Product Synthesis

VARIABLE	Unit	INPUTS		OUTPUTS	
		Clean Syngas	N_2 from ASU	CT-Ready Fuel Stream	Ammonia Product
Total	lb/hr	45,128	53,683	64,209	29,542
N_2	lb/hr	1,428.93	53,683.12	26,205.68	0.00
O_2	lb/hr	661.60	0.00	661.60	0.00
Ar	lb/hr	7,408.25	0.00	7,369.28	0.00
H_2O	lb/hr	495.98	0.00	495.98	0.00
CO	lb/hr	4,367.49	0.00	4,367.49	0.00
CO_2	lb/hr	14,347.63	0.00	14,347.63	0.00
Ash	lb/hr	0.00	0.00	0.00	0.00
S	lb/hr	0.00	0.00	0.00	0.00
COS	lb/hr	0.00	0.00	0.00	0.00
NH_3	lb/hr	7.77	0.00	400.98	29,542.27

H_2S	lb/hr	0.00	0.00	0.00	0.00
SO_2	lb/hr	0.00	0.00	0.00	0.00
SO_3	lb/hr	0.00	0.00	0.00	0.00
H_2	lb/hr	13,099.91	0.00	7,050.64	0.00
CH_4	lb/hr	3,310.18	0.00	3,310.18	0.00
C	lb/hr	0.00	0.00	0.00	0.00
Cl_2	lb/hr	0.00	0.00	0.00	0.00
C_6H_6	lb/hr	0.00	0.00	0.00	0.00
HCl	lb/hr	0.00	0.00	0.00	0.00
Methanol	lb/hr	0.03	0.00	0.03	0.00

Appendix B: Coal Feed Details

The characteristics of the Illinois #6 design coal are as follows:

Exhibit 2-4 Design Coal - Bituminous (Illinois No. 6, Herrin)

Rank	**Bituminous**	
Seam	**Illinois No. 6 (Herrin)**	
Source	**Old Ben Mine**	
Proximate Analysis (weight %)[A]		
	As Received	**Dry**
Moisture	11.12	0.00
Ash	9.70	10.91
Volatile Matter	34.99	39.37
Fixed Carbon	44.19	49.72
Total	100.00	100.00
Sulfur	2.51	2.82
HHV, kJ/kg (Btu/lb)	27,113 (11,666)	30,506 (13,126)
LHV, kJ/kg (Btu/lb)	26,151 (11,252)	29,544 (12,712)
Ultimate Analysis (weight %)		
	As Received	**Dry**
Moisture	11.12	0.00
Carbon	63.75	71.72
Hydrogen	4.50	5.06
Nitrogen	1.25	1.41
Chlorine	0.29	0.33
Sulfur	2.51	2.82
Ash	9.70	10.91
Oxygen[B]	6.88	7.75
Total	100.00	100.00