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CONCEPT BACKGROUND

8 Rivers is pursuing this Pre-FEED study for a 714 MWt (HHV) near zero emissions coal fired power plant located adjacent to Peabody's North Antelope Rochelle Mine (NARM). The power plant will receive coal directly from the mine and use that coal to generate syngas which will then be utilized in a syngas fueled Allam-Fetvedt Cycle power plant. The power plant will export about 287 MWe of power to the local network, yielding an efficiency of 40.2% (HHV). This will be via a dedicated switchyard or alternatively via the NARM switchyard subject to available capacity.

Because of the inherent low emissions nature of the Allam-Fetvedt Cycle the overall plant will have over 93% carbon capture. The various gases produced in the process will either be re-used within the process or will be sold for commercial use. Water will be cleaned and re-used within the process, with the facility operated on a zero liquid discharge basis.

Allam Cycle Coal is a syngas fired power generation cycle invented by 8 Rivers Capital, LLC. Simply stated, Allam Cycle Coal is an integration of commercially available coal gasification technology and the Allam Cycle natural gas (NG), as shown in Figure 1 below. The natural gas version of the cycle is being commercialized by NET Power, beginning with a 50 MWth plant currently operational in La Porte Texas. The Allam Cycle is essentially fuel agnostic. Based on "desk top" studies, engineering design and analysis the Allam Cycle can run on a wide range of fuels including but not limited to NG, coal syngas, tail gas, industrial off-gas, to name a few, by using the syngas combustor in development by 8 Rivers[i].

Work on the coal syngas-fueled Allam Cycle has advanced in a parallel program to the NG cycle. This program is focused on the coal-specific aspects of the Allam Cycle, building off of the advancement of the core Allam Cycle at the La Porte 50 MWth facility. The Allam Cycle coal program has been supported by several consortiums over the past 5 years. Activities have been centered on addressing key potential challenges specific to the coal syngas Allam Cycle, including corrosion testing, gasifier selection, impurity removal and syngas combustor development. This study contributes to advancing the technology towards a commercial 290 MW_e net output Allam Cycle plant. This study will be used by 8 Rivers, the technology and project developer, to support the development of a near zero emissions project with a goal to commission the commercial facility within 5 years.

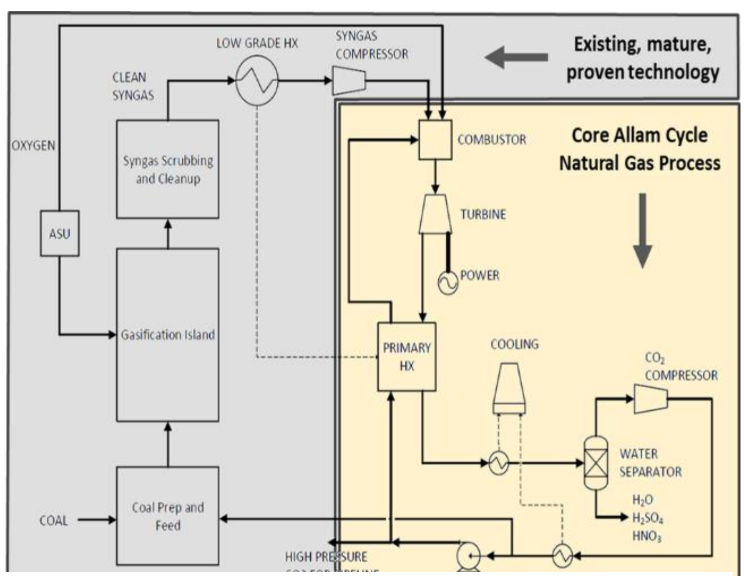

Figure 1 - Allam Cycle Coal Process Integration

The technology has the potential to enable new coal generation globally and domestically, using American technology and American coal. An

Allam Cycle coal power system has the potential to produce electricity at a lower cost than new natural gas combined cycle (CCGT), supercritical pulverized coal (SCPC) and integrated gasification combined cycle (IGCC) facilities. The system includes over 93% carbon capture and eliminates all other air emissions. The inherent emissions capture of the Allam Cycle provides an additional revenue stream,CO_2 for various uses including enhanced oil recovery and likely "proofs" it against future environmental regulations. Including revenue from CO_2, Ar, N_2 and tax credits, a first of a kind plant power price of $33 / MWH is expected.

An Allam Cycle coal plant will be the cleanest fossil fuel plant ever built with regards to Environmental Health and Safety since there is no vent stack in the system, all the combustion derived species will be captured in the system. The system removes nearly all NOx, SOx, and particulate emissions, while >93% of the CO_2 can be captured and stored permanently. Thus, there would be no air-born hazards or toxicological impacts from the Allam Cycle section of this plant, and to the degree that it displaces generation from neighboring fossil plants, it will actually reduce local air pollution. The "zero carbon" argon generated will be transported by truck or rail to existing industrial gas users, displacing argon that is generated with carbon-emitting power. The same industrial gas offtake will be used for nitrogen, but with a portion of the nitrogen potentially vented, given the large volumes over 4 MMT per year. Conventional black water treatment system and zero liquid discharge system are included in the system design in this study.

Plant production/facility capacity

The proposed Allam Cycle coal plant is designed to have 550MWt in LHV cleaned syngas fed into the Allam Cycle power island. Table 1 shows the plant's net and gross capacity with the Wyoming subbituminous coal chosen for the Pre-FEED study. The system efficiency and auxiliary load with selected site and Wyoming coal was updated with vendors' input in the Pre-FEED study.

Coal thermal input (MW in LHV)	676
Gross generator output (MW)	468.15
ASU load (MW)	-72.19
Total compression/pumping load in the Allam Cycle (MW)	-86.29
Gasification utility (MW)	-5.23
Cooling tower (MW)	-4.35
Miscellaneous BOP (MW)	-6.2
Net power output (MW)	286.7
Net efficiency (% LHV)	42.40%

Table 1 - Allam Cycle Efficiency With Wyoming subbituminous coal

In addition, the Allam Cycle coal plant produces CO_2, Argon, and Nitrogen for sale. At the 85% Capacity Factor modeled in the Conceptual design, the plant will produce 1.57 million tons of CO2 per year, 4.6 million tons of Nitrogen, and 71,000 tons of Argon.

Plant location consistent with the NETL QGESS

For the Pre-FEED study, 8 Rivers has selected to site the plant at Peabody's North Antelope Rochelle Mine (NARM), and to use Peabody's coal from that mine. Peabody submitted a Letter of Support to the original Coal FIRST application, and has provided all the necessary site and coal information for the Pre-FEED. Due to the large native power demand and the proximity to multiple CO_2 offtakes, this is a favorable location for siting an actual power plant.
When available, we have used NARM specific parameters. Otherwise, we have used NETL QGESS design parameters.

Parameter	Value
Location	Greenfield, Teckla, WY
Topography	Rolling
Transportation	Rail or highway
Ash/Slag Disposal	Off Site
Water	Ground water
Elevation, (ft)	4830
Barometric Pressure, MPa	0.101
Average Ambient Dry Bulb Temperature, °C	9
Average Ambient Wet Bulb Temperature, °C	5.2
Design Ambient Relative Humidity, %	61%
Cooling Water Temperature, °C	10
Air composition based on NETL QGESS, mass %	
N_2	72.429
O_2	25.352
Ar	1.761
H_2O	0.382
CO_2	0.076
Total	100.00

Table 2 - NARM Site Parametes

Business case from Conceptual Design

Allam Cycle Coal can create a business case for coal to thrive in the most difficult economic and regulatory conditions. The technology can enable new coal generation both globally and domestically, using American technology and American coal. This is because the Allam Cycle coal power system has the potential to produce electricity at the same or lower cost than conventional coal and natural gas plants, with natural gas seen as the key competitor for new-build dispatchable power. And, the system includes >93% carbon capture and eliminates all other air emissions. This inherent emissions capture provides an additional revenue stream to the Allam Cycle coal plant, and future-proofs it against environmental regulations.

Coal Type

For this Pre-FEED, we assume the use of the Wyoming subbituminous Coal from the NARM. The composition of the fuel is confidential and has been removed from the public report.

Table 3 - Analysis of Peabody North Antelope Rochelle Mine Coal

Given the abundance of natural gas, and a desire to be conservative, we used the High Oil and Gas Resource case from EIA, which projects a market average of \$2.90 / MMBTU gas in 2025, and \$1.62 /MMBTU coal at mine mouth and \$2.64 coal delivered cost.[ii] To adjust this projection for Wyoming subbituminous coal we assume that the mine mouth price remains at \$.70 / MMBTU for Wyoming subbituminous coal, given that EIA has mine mouth coal prices changing by <2%,while keeping 2025 delivery costs the same. This led to a net \$1.72/ MMBTU delivered coal cost for a generic project using Wyoming coal. For the specific NARM site at the mine mouth, we expect the cost provided by Peabody to be closer to the \$.70 / MMBTU mine mouth coal price, to be updated in the levelized cost analysis in the Cost Results Report. The cost of Wyoming subbituminous coal is in the process of being provided by Peabody for the Cost Results Report. We also show a case at \$2.68/MMBTU delivered cost, which uses the same methodology for Illinois Basin coal's 2019 price point.[iii]

Renewables Penetration

Using the EIA base case, renewables penetration is expected to grow from 18% to 31% of domestic power generation by 2050, with 73% of that power coming from intermittent solar and wind. The direct impact of renewables on Allam Cycle coal will be felt in terms of fluctuations in power prices and resulting dispatch of the plant. Our analysis doesn't attempt to predict future power prices and power market structure, and instead compares the price competitiveness of the facility to other dispatchable power plants. If Allam Cycle coal is the lowest marginal cost option for dispatchable power, it will be competitive.

The second related impact is capacity factor. Modeling of system economics shows that a minimum 40% capacity factor is required for an Allam Cycle Coal plant to remain economic, given its high relative CAPEX and reduced revenues at this level. However, given the lower marginal cost of production of the Allam Cycle due to additional byproduct revenues, we expect this plant to dispatch ahead of all other fossil plants, and to maintain a high capacity factor even with the 31% renewables projected by EIA, and above. As shown later in Figure 2, with current value of CO_2, Allam Cycle coal can bid into the dispatch order at \$0 / MWH, ensuring it runs at high capacity factor. With future plants that have lower byproduct revenues and only \$15 / MT from CO_2 (from EOR or a future carbon price), the marginal bid would be \$15 / MWH, which would still be low enough to be the first fossil source in the dispatch stack.

CO2 Constraint

We assume a base case CO_2 value of $48.6 / MT, which can be currently realized in the US market through the 45Q tax credit ($35 post-tax value) combined with $13.6 / MT CO_2 sales for enhanced oil recovery (EOR). Then we model a no 45Q case that models a $13.6 / MT CO_2 value. This value can be realized in the US or the Middle East with EOR, or through energy policy, like the industrial carbon price in Alberta ($15 / MT)[iv], the cap and trade system in Europe ($29 / MT)[v], or the Korean emission trading system ($20 / MT).[vi] The same CO_2 value could be achieved through policy schemes like clean energy standards or cap and trade, and have the same functional impact on the competitiveness of the Allam Cycle. This model doesn't include the cost of CO_2 transport and sequestration, which is expected to range from $5-$20 / MT depending on the specific site. But as will be shown, the economic advantage of Allam Cycle coal is large enough to withstand those additional CO_2 costs.

Note on Cost Modeling Methodology and NETL QGESS

As discussed with DOE, 8 Rivers plans to update our LCOE modeling to better match the NETL QGESS reports provided. However, 8 Rivers is waiting until the updated data from the Pre-FEED is available to revise the economic modeling, which will occur in the Cost Results Report. As such, the LCOE charts referenced herein all match the work from Conceptual Design, and will be updated later.

Domestic Market Applicability

As shown in Figure 2, Allam Cycle Coal's (AC Coal's) levelized cost of electricity in the US can out compete new combined cycle plants, which is the main competition for new dispatchable generation. The first-of-a-kind plant (FOAK) is projected to cost $33 / MWH after coproduct sales, lower than CCGT and half the price of an unabated supercritical coal plant. This is possible because of industrial gas sales, which amount to revenue of $68 / MWH: $41.5 of that

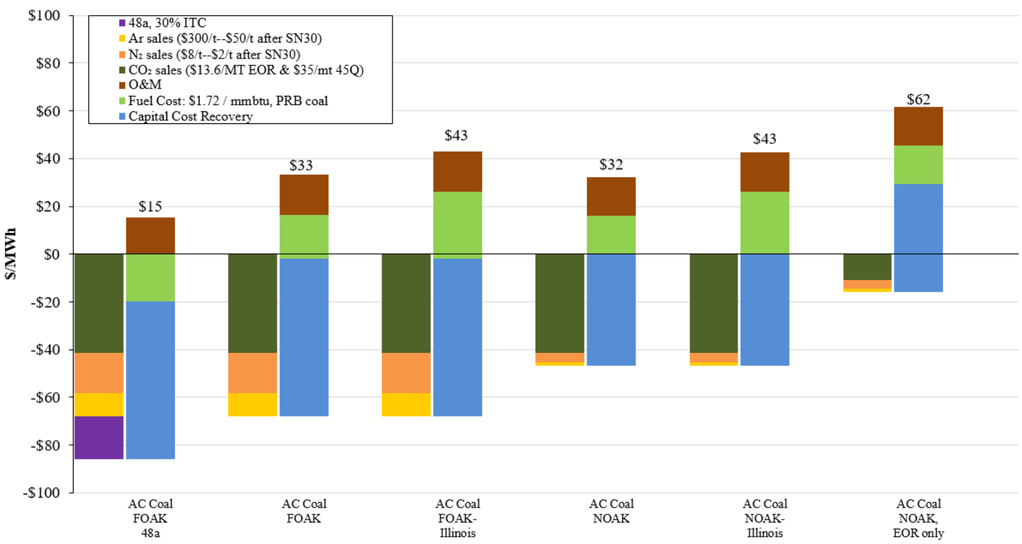

Figure 2 - Levelized Cost Comparison In The US Market

revenue from CO_2 sales, a quarter of which comes from sale of CO_2 for Enhanced Oil Recovery (EOR) and three quarters of which comes from the 45Q. The remaining $26.5 comes from Argon and Nitrogen from the air separation process, which are valuable industrial feedstocks for uses like arc welding and fertilizers.

The Allam Cycle is modeled with a 36 month construction time compared to 31 months for CCGT. It's assumed to have a $4,328 / KW overnight capital cost, compared to $911 / KW for the H class CCGT. Total FOAK capital cost is $4,821 / KW. The FOAK has $105.7 / KW fixed O&M cost, and $1.8 / MWH variable O&M cost. Total NOAK capital cost is $3,286 / KW. Natural gas is priced at $2.90 / MMBTU and PRB coal at $1.72 / MMBTU.[vii] Cost data for other technologies is taken from NETL baselines 2011 Vol 3.[viii] The assumptions across cases are: A levelized capital recovery rate of 10.2%; effective tax rate of 25.7%; 45Q and 48A are not taxed; 8.3% nominal discount rate; no escalation or inflation except for 2% natural gas price escalation; 40 year economic life; and 85% capacity factor. 2018 is the cost reference year.

Allam Cycle coal outcompetes Supercritical Pulverized Coal (SC-PC in Figure 3) and H-class Combined Cycle Gas Turbines (CCGT) because of a mixture of its high inherent efficiency, manageable capital costs, and its multiple revenue streams. Figure 3 shows different sensitivity cases for CO_2 value, by product revenue, tax credit status, technology maturity, and coal price. As more plants are built, it is assumed that the revenues from Argon and Nitrogen sales will decline, as shown. Capital costs will also decline as learnings from early plants improve the overall design and constructability. Without 45Q, a Nth of a kind plant (NOAK) will produce electricity at $62 / MWH, cheaper than SC-PC, but more expensive than CCGT with $2.90 / MMBTU gas. It would still be extremely competitive when natural gas prices are above $5 / MMBTU as is common globally, and in any domestic scenarios when the total CO_2 value is greater than $30 / MT between EOR and carbon policies.

To further detail the competitiveness of Allam Cycle coal, Figure 2 also shows a case with a FOAK plant also claims the 48a tax credit and a two cases with $2.68 / MMBTU Illinois Coal. 48a is a 30% ITC available to power plants that use 75% coal feedstock and achieve 70% carbon capture with 40% HHV efficiency, a benchmark that Allam Cycle coal meets in all scenarios. It requires 400 MW total nameplate capacity. This Allam Cycle Coal design exports about 290 MW of electricity, but its nameplate capacity will be above 470 MW as shown later in Table 1A, and thus qualifies for 48a. For the purposes of 48a, IRS has defined nameplate capacity as "aggregate of the numbers (in megawatts) stamped on the nameplate of each generator to be used in the project."[ix] It can be claimed alongside 45Q, is already in statute, and has over $1 billion in credits currently claimable.[x] This 48a credit the higher CO_2 revenue per MWH of coal makes the Coal Allam Cycle competitive against the natural gas Allam Cycle being commercialized by NET Power. NET Power's LCOE is higher than the coal Allam Cycle with 48a.

Additionally, the US has over 5,000 miles in CO_2 pipelines connecting over 100 CO_2 offtakes, expanding the map of locations to build a CCS plant with minimal infrastructure required. The market for CO_2 for EOR is massive, with total potential demand enough to purchase 25 billion tons of CO_2 as the industry advances.[xi] In 2014, 3.5 billion cubic feet of CO_2 were injected for EOR. The natural supply of CO_2 is limited geographically and in total size, with only 2.2 billion metric tons of total natural reserves. This necessitates a supply of CO_2 for the EOR industry to grow, and guarantees a large and growing market for Allam Cycle coal CO_2.

The subsurface geology in the US is attractive for sequestration as well, with a number of pilot projects and one commercial scale injection well operating in Decatur, Illinois. Sequestration will be particularly important on the coasts and the Midwest where EOR is not an option. The DOE has estimated the total storage capacity in the United States ranges between 2.6 trillion and 22 trillion tons of CO2, enough for thousands of CCS plants running for thousands of years.[xii]

International Market Applicability

The Coal Allam Cycle's biggest international market is in fast growing economies where power demand is quickly increasing, and cheap natural gas is in short supply. This encompasses parts of India and China as well as much of eastern Asia. This region also has the most experience in constructing the coal gasifiers needed for this system. We have modeled further sensitivities for the global market: the nth-of-a-kind Allam Cycle with \$0-\$13.6 value per MT of CO_2, compared against conventional coal (SC-PC) and a CCGT with \$8 / mmbtu imported liquefied natural gas, as shown in Figure 2.[xiii] Capital costs are not adjusted internationally. We expect capital cost decreases to be roughly proportional across technologies, and thus not greatly impact relative competitiveness.

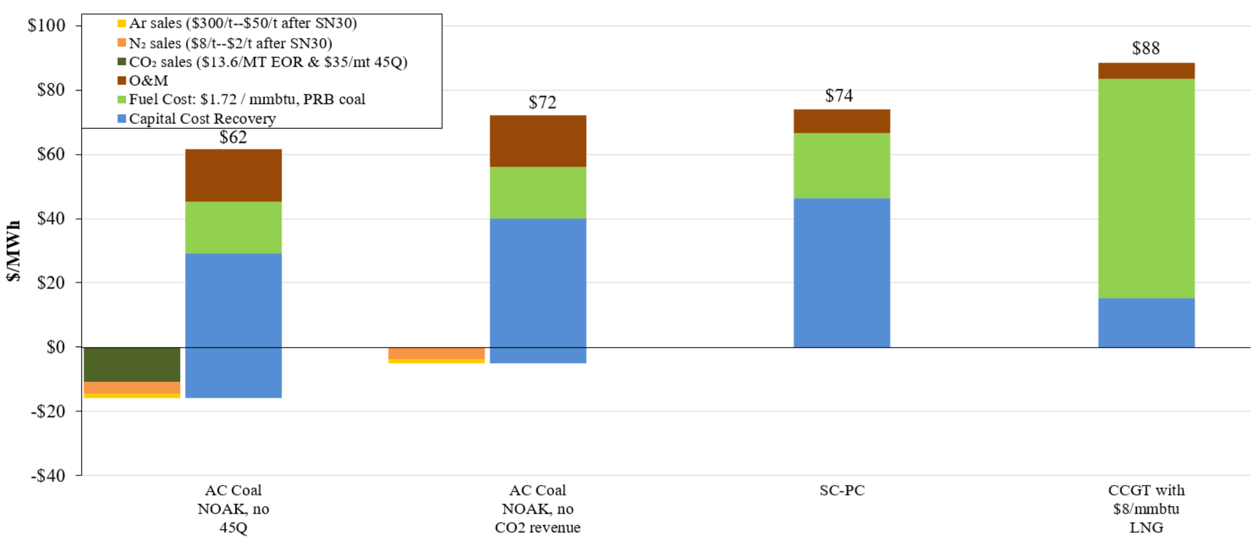

Figure 3 - Cost of Allam Cycle Coal in Global Market

We expect the initial FOAK Allam Cycle plants to be built in the US, as with 45Q it is the most attractive place for CCS in the world for initial deployment. The deployment of both coal- and gas-based Allam Cycle plants will bring down the cost for the core cycle agnostic of fuel source. This is key: deployment of the natural gas Allam Cycle will have a direct impact on lowering the cost of the Coal Allam Cycle, since the core Allam Cycle is common and nearly identical in each system. Thus we expect to deploy the Allam Cycle at scale globally with nth-of-a-kind costs. As shown above with conservative industrial gas prices, this system will be cheaper than conventional coal with \$13.6 CO_2 and at cost parity with \$0 CO_2. After economics, the zero air pollution profile of this cycle may drive deployments globally, particularly in countries like

Korea and China and India where air pollution is a top domestic issue. Allam Cycle may even be deployed without carbon capture initially, venting the CO_2 until an offtake is fully developed, and in the meantime delivering power at the same price with zero other air emissions.

Canada and the EU are also attractive international markets given their CO_2 policies, as are Middle Eastern countries like Saudi Arabia and UAE that have large demand for CO_2 for their oilfields, though the potential for Allam Cycle plants may be limited by power demand not CO_2 demand. And Middle Eastern coal power is still being built despite massive gas supplies. In UAE, for example, 2.4 GW of coal are currently under construction and UAE is targeting 11.5 GW of new coal by 2050.[xiv]

The basic economic proposition for these countries is similar to the 45Q and EOR LCOE's shown in Figure 2, and so have not been broken down specifically here.

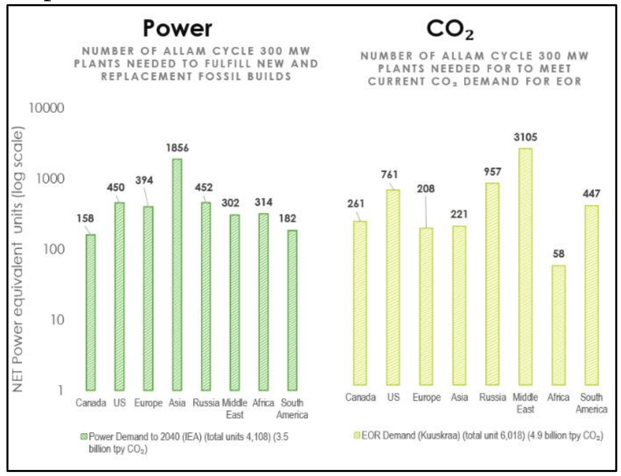

Figure 4 - Global Power and CO2 Demand

The scale of the global region is broken down in Figure 4 by power demand and CO_2-EOR demand. CO_2 sequestration and utilization are not included, which greatly increases the CO_2 offtake potential and opens up regions without EOR for CCS.

Estimated cost of electricity (and ancillary products)

As shown above, the cost of electricity is estimated at \$15-\$43 per MWh with 45Q, across various scenarios. Without CO_2 incentives, the price rises to \$62-\$72 per MWh. Byproduct revenues are modeled as inputs to this power price output. Internal research and industry quotes led to our conservative estimate of \$13.6 / MT CO_2 for EOR, and our range of estimates for Nitrogen at \$2-\$8 per ton, and Argon at \$50-\$300 per ton. Byproduct values are uncertain and site specific. The Nitrogen value is an average value, assuming a combination high purity sales, low purity sales, and venting. For the FOAK each year, 2,190,623 MWH of power, 1,572,210 tons of CO_2, 70,773 tons of Argon, and 4,605,832 tons of Nitrogen will be produced.

Market advantage of the concept

By producing power that is cheaper and has zero emissions, the Allam Cycle applied to coal as well as gas can become the new standard for power generation worldwide. Never have clean and cheap and dispatchable all coincided. Additionally, the power island has a much smaller footprint compared to conventional fossil fuel power plants given that the supercritical CO_2 working fluid has a very high density heat capacity, hence reduce the size of the power plant equipment, including gas turbine, heat exchanger, compressor and pumps. The compact design heat exchangers currently tested in the NET Power demo plant has much smaller footprint compared to the commercial heat recuperator. The smaller material needs of this equipment reduces construction costs, and most of the equipment in the power cycle can be built as modular, factory assembled skids. As an oxy-fuel cycle, the core cycle equipment, gas turbine, is not dependent on ambient conditions and is nearly identical from plant to plant. This will help to enable an assembly line, modular approach for construction, and also make sure the gas turbine can have a constant power output with site conditions. In general, only the cooling water system and the first stage of the main air compressor in Air Separation Unit experience ambient conditions. Design of the transition points between compressors and pumps will also minimize the impact of the cooling water temperature change. Therefore, the impact of ambient conditions on the Allam cycle efficiency is much smaller than its impact on CCGT system. Finally, CO_2 is generated at high purity and pressure, reducing the cost of getting the CO_2 pipeline ready, and virtually eliminating the penalty of capturing CO_2 instead of venting it.

PERFORMANCE RESULTS

Aspen Plus was used for the process modeling of the coal based Allam Cycle system. The model is a combination of proprietary models and know-how developed by 8 Rivers during the invention, optimization, and demonstration of the NET Power demonstration plant. When available, vendor provided information was incorporated into the model. In some cases, vendors provided detailed information. In other cases, the vendor supplied equipment has to be "black-boxed" inside of Aspen Plus. This model will continue to evolve and change as more information is obtained from the equipment suppliers as the pre-FEED continues. A process block flow diagram is presented in Figure 5. The data for the numbered streams is provided in tables that are confidential and have been removed from the public report.

Aspen 11.0 was used for the process modeling of the coal based Allam Cycle. RK-SOAVE and Peng-Robinson were used as the Equation of State. Peng-Robinson was used to simulate the process at the conditions close to the critical point of CO2. Vendor data were used for the simulation of each sub-process in the system, which includes ASU, coal milling, coal drying, coal gasification process with quench and scrubbing system, Acid Gas Removal, Sulfur recovery, and the entire Allam Cycle power island. The vendor data includes heat and mass balance of the entire coal gasification system, inlet/out let conditions as well as utility consumption for each process, turbomachinery efficiency, heat exchanger minimum temperature approach and detailed combustor/turbine design conditions and efficiency. Low to mid 80 percent efficiency were assumed for the compressors without getting vendor data, and 3% motor driven mechanical loss were considered.

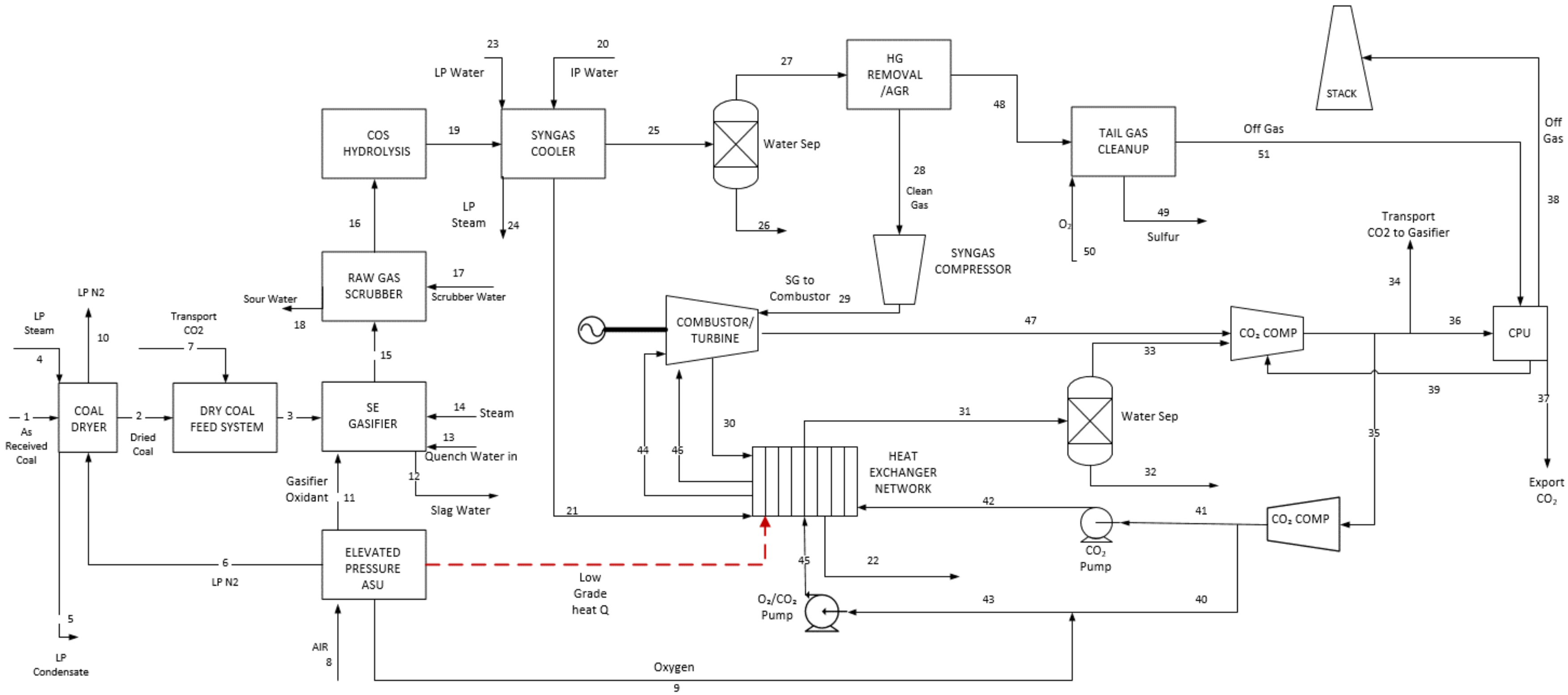

Figure 5 – Process Block Flow Diagram

Plant performance results

The overall performance of the plant is summarized in

Table *4*, which includes auxiliary power requirements. The ASU accounts for approximately 41% of the auxiliary load, with a further 52% of the auxiliary load being consumed by the motor driven pumps and compressors specific to the power island and the Allam Cycle process. Motor efficiencies are included in efficiency calculations for the rotating machinery. Some gasifier auxiliaries are separated out and listed individually, as are the transformer losses.

Coal Thermal Input (MW in HHV)	**713.60**
Coal Thermal Input (MW in LHV)	**676.00**
Gross Turbine Shaft Power Output (MWe)	**472.88**
Gross Generator Power output (MWe)	**468.15**
Auxiliary Load Summary (MWe)	
Coal Handling and Crushing	*1.27*
Coal Drying	*0.41*
Air Separation Unit	*72.19*
Grey Water Pump	*0.99*
Waste Water Pump	*0.51*
Quench Water Pump	*0.19*
Filter Vacuum Pump	*0.26*
Gasifier Auxiliaries	*0.593*
Acid Gas Removal	*0.37*
Sulfur Recovery	*0.34*
Zero Liquid Discharge	*0.30*
Cooling Tower Pump	*1.13*
Cooling Tower Fan	*3.22*
Syngas Compressor	*18.45*
CO2 Compressor	*38.13*
CO2 Pump	*28.14*
Oxidant Pump	*7.79*
CO2 Purification Unit	*1.57*
Miscellaneous Power Island	*0.83*
Miscellaneous Balance of Plant	*1.00*
Transformer loss (1.5% of power output)	*4.37*
Total Auxiliary Load (MWe)	177.09
Net Power Output (MWe)	**286.7**
Net Plant Efficiency, % (HHV)	**40.18%**
Net Plant Efficiency, % (LHV)	**42.41%**

Table 4 - Plant Performance Summary

Carbon balance

The carbon balance for the plant is shown in Table 5. The carbon input to the plant consists only of carbon from the coal. The ASU rejects the CO_2 in the air as part of the input stream treatment, since this is immediately returned to the environment, it is not accounted for in the carbon balance. Carbon in the plant leaves as unburned carbon in the slag, in the CO_2 outlet stream from the plant, acid gas vented from black water/ZLD system, and the off gas from the CO_2 purification unit.

Carbon In (kg/hr)		**Carbon Out (kg/hr)**	
Coal	63852	Stack (stream 38)	3819.0
		CO2 Product (stream 37)	58999.8
		Slag	1033
		Acid Gas	0.8
Total	**63852**		**63852**

Table 5 - Plant carbon balance

Sulfur Balance

Table 6 shows the sulfur balance for the plant. The sulfur input comes solely from the sulfur in the coal feedstock. The main output is elemental sulfur from the sulfur recovery unit. There is also sulfur leaving the system as sulfuric acid from turbine exhaust condensate and being neutralized in the ZLD.

Sulfur In (kg/hr)		**Sulfur Out (kg/hr)**	
Coal	236	Sulfur to ZLD	0.77
	0	Solid S	235.23
Total	**236**		**236**

Table 6 - Plant sulfur balance

Water Balance

In this pre-FEED study, a mechanical draft hybrid cooling tower is used to provide the cooling and a reverse osmosis (RO) unit and zero liquid discharge (ZLD) system is used for process water treatment to allow water to be reused within the plant. The water balance calculation is performed for both wet cooling design and dry cooling design. A wet cooling design water balance schematic has been included in Figure 6 and an overall plant water balance has been shown in Table 17. A dry cooling design water balance schematic has been included in Figure 7 and an overall plant water balance has been shown in Table 18.

With the dry cooling, there is no requirement for raw water withdrawal, since all process waste water is of suitable quality to be recycled in the syngas scrubber or it is suitably treated within the RO or ZLD to be reused elsewhere within the plant. In the dry cooling design, the plant is actually a net water production, with raw water production being approximately 1.46 gpm/MWe. For the wet cooling design, the raw water consumption is 7.2 gpm/MWe, which is less than the typical water consumption in the IGCC/CCS systems in DOE reference reports.

Inclusion of RO and ZLD process waste water treatment means that there is no process water discharge at the plant battery limits. Where the composition has been determined as part of the process modelling, the process water stream quality has been provided in Table 4 to Table 13.

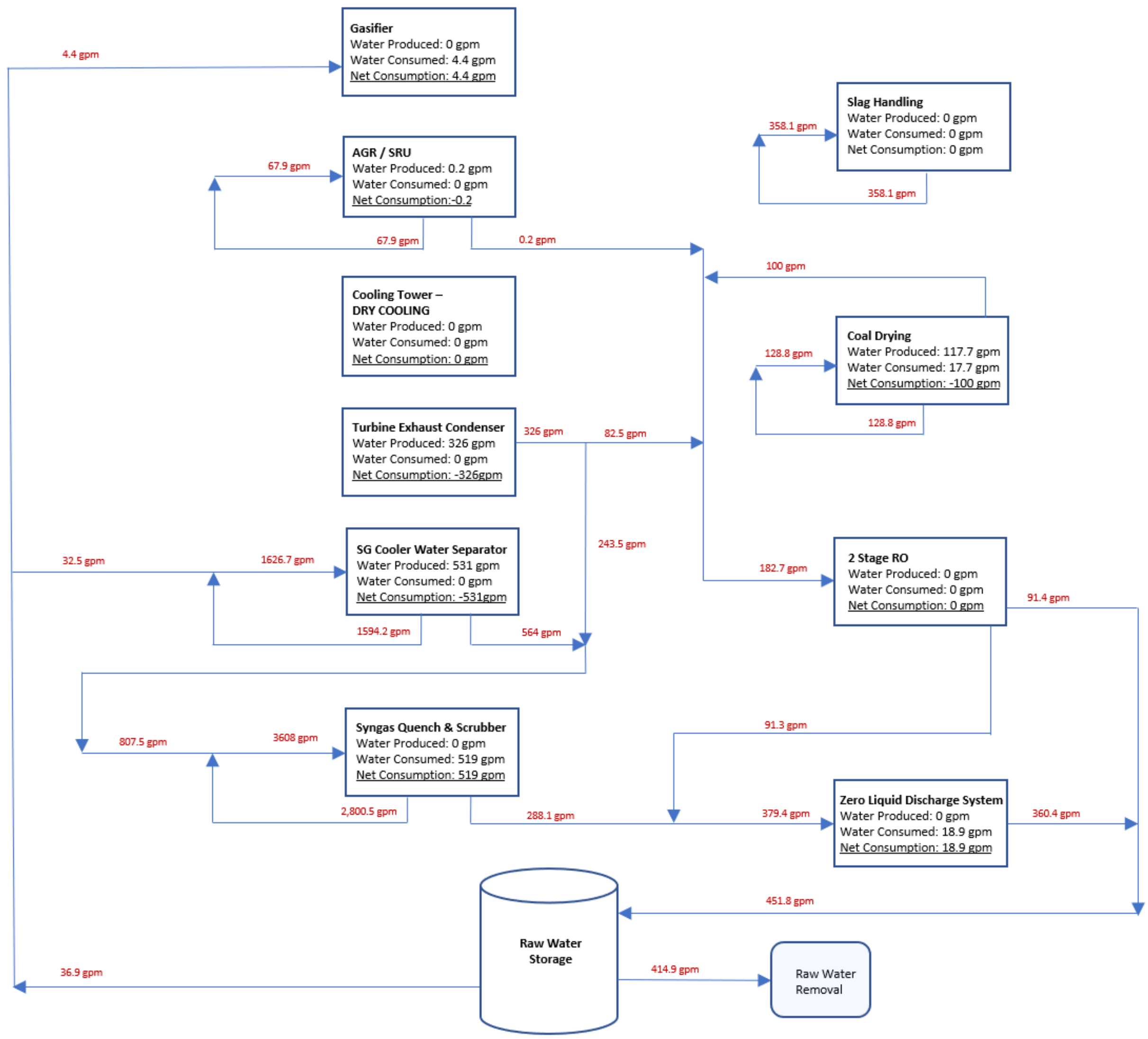

Figure 6 – Dry Cooling Water Balance Schematic

Dry Cooling Water Use	Water Demand	Internal Recycle [1]	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	5793.9	6208.8	-414.9	0	-414.9

[1] Internal Recycle is plant internal recycle and includes internal recycle within components, recycle of process waste water into the syngas scrubber and discharge from the 2 stage RO and ZLD.

Table 7 – Overall Plant Water balance - dry cooling operation

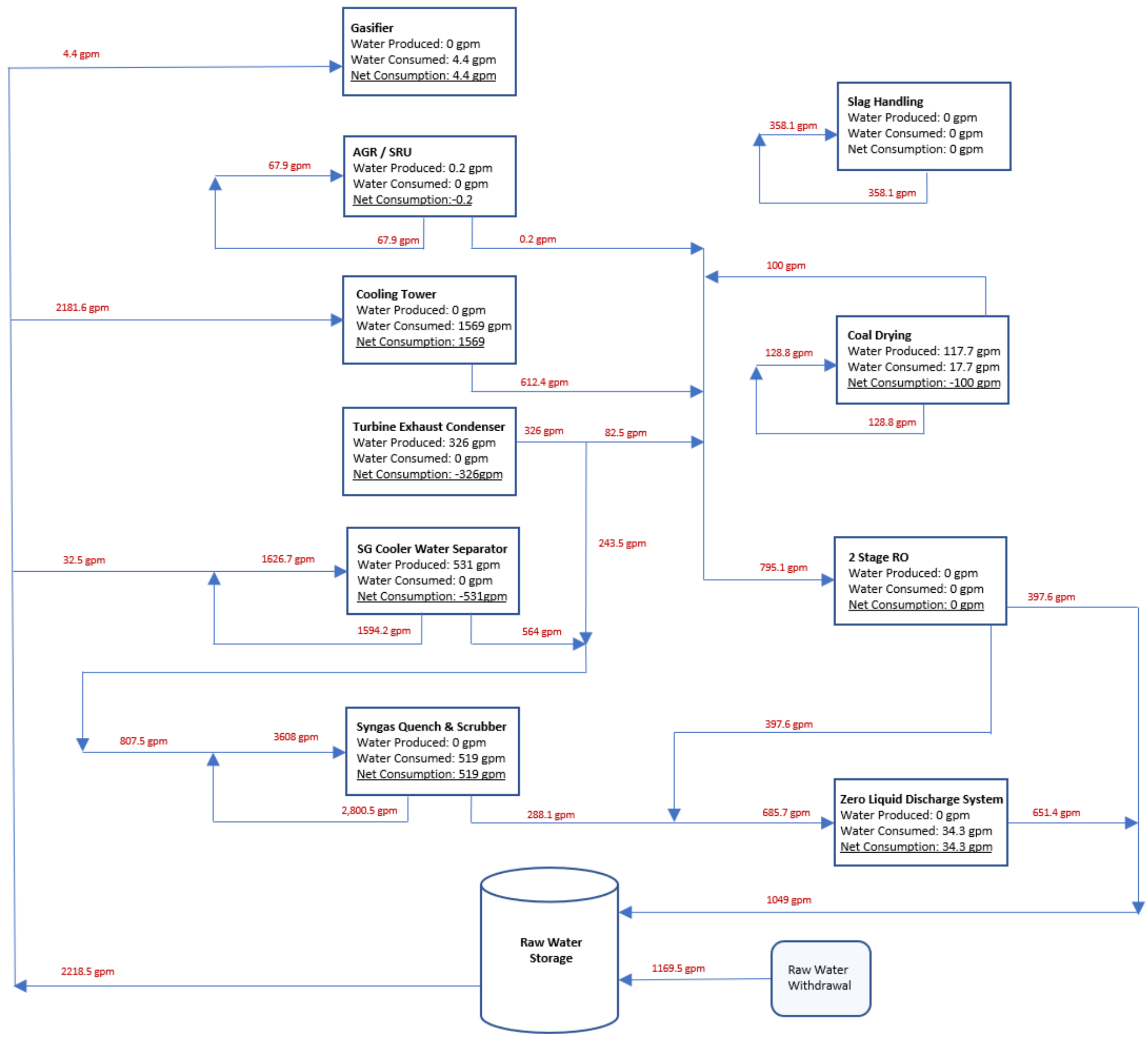

Figure 7 –Wet Cooling Water Balance Schematic

Wet Cooling Water Use	Water Demand	Internal Recycle [1]	Raw Water Withdrawal	Process Water Discharge	Raw Water Consumption
	gpm	gpm	gpm	gpm	gpm
Overall Balance	7975.5	6806.0	1169.5	0	1169.5

[1] *Internal Recycle is plant internal recycle and includes internal recycle within components, recycle of process waste water into the syngas scrubber and discharge from the 2 stage RO and ZLD.*

Table 8 – Overall Plant Water balance - wet cooling operation

Plant Emissions

The low level of SO2 emissions is achieved by capturing the sulfur in the gas by the AGR process. The AGR process removes over 99 percent of the sulfur compounds in the fuel gas down to a level of less than 2 ppmv. The tail gas from AGR goes to tail gas treatment unit where using liquid redox, all of the sulfur gets converted into elemental form. The other source of SO2 will be from sour acid gas vented from black water treatment on continuous basis.

NOx emissions are negligible as we are using 99.5% pure oxygen going to gasifier, combustor and tail gas treatment unit. N_2 from the fuel which makes it into the system is converted to NOx in the combustor and removed as HNO_3 in the water separator.

Particulate discharge to the atmosphere is extremely low values by the use of a total quench gasifier, cyclone separator with in addition to the syngas scrubber with venturi and the gas washing effect of the AGR absorber. The particulate emissions are negligible from gasifier. The other particulates emitted will be from coal handling and dry coal feed preparation and delivery systems

Approximately 97 percent of the mercury is captured from the syngas by dual activated carbon beds. CO_2 emissions represent the uncontrolled discharge from the process.

Steady State Emissions

The steady state emissions are shown in Table 20.

	kg/GJ[C]	lb/MMBtu[C]	Tonne/year	ton/year	kg/MWh [B]	lb/MWh [B]
SO2	n/a	n/a	n/a	n/a	n/a	n/a
NOx	n/a	n/a	n/a	n/a	n/a	n/a
Particulate[D]	0.0005	0.0012	9.515	-10.48	0.0027	0.006
Hg	9.22941E-11	2.14615E-10	0.002	0.002	4.82614E-10	1.06368E-09
HCl	n/a	n/a	n/a	n/a	n/a	n/a
CO2	5.72	13.31	104,310	114,949	29.92	65.95

A – Calculations based on 85% capacity factor
B – Emissions based on gross generator output power, except where noted
C – Heating value based on LHV
D- particulates not captured by bag filters

Table 20 - Steady-state plant emissions

Start-Up Emissions

According to the gasifier vendor, 2 start-ups per year are considered while utilizing a lower coal feed rate. The start-up will last for 2 hrs, during which all the syngas generated will be flared downstream of syngas scrubber. Alternate locations for the vent, including the possibility of taking the gas into the power cycle, will be determined and investigated during the FEED stage. Table *9* provides emissions expected during these two gasifier starts.

	tonne/year	ton/year
SOx	0.371	0.408
NOx	n/a	n/a
Particulate	n/a	n/a
Hg	1.80749E-05	1.99E-05
HCl	n/a	n/a
CO2	254	280

Table 9 *- Start-Up Emissions*

Open Loop Fluidized Bed Dryer With No Water Recovery

Wet coal is conveyed to feed distribution screw conveyor that discharges the feed material to feed rotary air locks. The introduced feed is allowed simply to fall by gravity into the area of the feed zone where it can back-mix with dry material before migrating in the main drying area. Inert gas nitrogen is used as a fluidizing and drying media for this dryer.

LP Nitrogen from ASU unit is directed to supply fan which is intended to increases static pressure of nitrogen to use in the system. This nitrogen is heated to 295° F by LP steam. This LP steam (~5 bar) is generated by syngas cooler block, which is used to heat the LP N2.

Fluidization and direct contact drying of the coal is accomplished via inert fluidizing heated nitrogen gas stream. The fluidic behavior of the material itself, volumetric displacement of the fluidized material within the unit due to additional material feed and the inclusion of a special, directional-flow gas distribution plate create conditions within the fluid bed wherein material is conveyed through several drying “zones.” The heated fluidizing gas entering the fluid bed unit passes through specially-designed gas distribution plate to ensure proper distribution of the fluidizing gas across the fluidized surface. The gas passes through the fluidized layer and provides a portion of the necessary drying energy to coal during fluidization.

The dried material is discharged from the fluid bed unit via a “discharge boxes” / chutes located at the end of the fluid bed dryer unit. Material discharge from each of these discharge boxes is accomplished via two means - a fixed-height overflow weir and an integrally-constructed underflow discharge screw. The main portion of the material discharged from the unit is via the fixed-height overflow weir. A small portion of the material is discharged via the integrally-constructed underflow screw. The moisture- and fines-laden exhaust gas is then carried via ducting to the inlet of the dust-recovery cyclone unit or bag house filter system. The recovered fines can then either be mingled with the material exiting the dryer or handled separately. After flowing through the dust-recovery cyclone or bag filters, the exhaust gas is vented to safe location. If there is limitation of fluidization LP N2 gas, then provision can be made for vented gas to be recycled

Closed Loop Fluidized Bed Dryer With Water Recovery

Wet coal is conveyed to feed distribution screw conveyor that discharges the feed material to feed rotary air locks. The introduced feed is allowed simply to fall by gravity into the area of the feed zone where it can back-mix with dry material before migrating in the main drying area. Inert gas nitrogen from ASU is used as a fluidizing media. LP steam (~5 bar) generated by syngas cooler block is used as heating media. The necessary thermal energy for accomplishing drying of the material is imparted through convective and conductive heat transfer means. Convective heat transfer is accomplished via heating of the fluidizing gas entering the dryer, which then comes into direct contact with the fluidized material within the dryer - imparting a portion of the required heating / drying energy. Conductive heat transfer is accomplished via the use of steam passing through the tubes of the dryer's in-bed heat exchangers. As the material comes in contact with the outer surfaces of the in-bed heat exchanger tubes, heating / drying energy is transferred from the in-bed heat exchanger units to the fluidized material via tube-side condensation of the steam. Heating will be controlled precisely to deliver only the necessary energy required to reach the target moisture specification for the product exiting the fluid bed. The fluidic behavior of the material itself, volumetric displacement of the fluidized material within the unit due to additional material feed and the inclusion of a special, directional-flow gas distribution plate create conditions within the fluid bed wherein material is conveyed through several drying "zones." The heated fluidizing gas entering the fluid bed unit passes through specially-designed gas distribution plate to ensure proper distribution of the fluidizing gas across the fluidized surface. The gas passes through the fluidized layer and provides a portion of the necessary drying energy to coal during fluidization.

The dried material is discharged from the fluid bed unit via a "discharge boxes" / chutes located at the end of the fluid bed dryer unit. Material discharge from each of these discharge boxes is accomplished via two means - a fixed-height overflow weir and an integrally-constructed underflow discharge screw. The main portion of the material discharged from the unit is via the fixed-height overflow weir. A small portion of the material is discharged via the integrally-constructed underflow screw. The moisture- and fines-laden exhaust gas is then carried via ducting to the inlet of the dust-recovery cyclone unit or bag house filter system. The recovered fines can then either be mingled with the material exiting the dryer or handled separately. After flowing through the dust-recovery cyclone or bag filters, the exhaust gas is then carried scrubber-condenser unit. Prior to its entry into the scrubber-condenser unit, a small portion of the exhaust gas is "purged" from the exhaust air stream, carrying with it a small portion of the water vapor that was evaporated from the material in the dryer unit. This purge gas stream is removed from the closed-loop gas stream to provide pressure control for the dryer unit's exhaust gas and is approximately the equivalent volume of air entering the drying system with the feed material. In this manner, the overall water-condensing requirement for the scrubber-condenser unit is slightly lowered, relative to its duty without purging the excess gas volume prior to the unit. The remaining exhaust gas then enters the scrubber-condenser unit via an integral venturi scrubbing section for further particulate removal. After passing through the scrubbing section of the unit, the gas then enters the integrally-constructed condensing section of the unit where it comes in contact with recirculated cooling water and further cooled. As the exhaust cools, moisture is removed from the gas stream (i.e. the gas stream is dehumidified). The condensed moisture is continually discharged from the scrubber-condenser unit as a “recover” water stream.

Sparing philosophy

For this process, single units are utilized throughout the facility with exceptions when equipment limitations require additional trains. Normal industry spares for rotating equipment may also be considered.

The major subsystems of the plant are:

- One ASU (1 x 100%).
- Two trains of coal milling and pulverizer systems (2 x 50%).
- One fluidized bed coal dryer system (1 x 100%).
- One train of gasification, including gasifier, cyclone and syngas scrubber (1 x 100%).
- One black water system and ZLD(1 x 100%).
- One COS Hydrolysis Reactor (1 x 100%).
- One Hg removal unit (1 x 100%).
- One AGR unit (1 x 100%).
- One tail gas clean up for sulfur recovery unit (1 x 100%).
- One syngas combustor (1 x 100%)
- One syngas compressor (1 x 100%)
- One CO2 compression and pumping system (1 x 100%)
- One turbine (1 x 100%).

Equipment list

The following tables show the major equipment in the facility, broken into sections by operation.

No	Description	Type	Operating Quantity	Spares
1	Feeder	Vibratory	1	0
2	Conveyor	Belt	1	0
3	Roller Mill Feed Hopper	Dual Outlet	1	0
4	Roller Mill & Pulverizer	Rotary	2	0
5	Weigh Feeder	Belt	1	0
6	Coal Dryer	Fluidized Bed	1	0
7	Coal Dryer Feed Hopper	Vertical Hopper	1	0
8	Scrubber Condenser	Packed Tower	1	0
9	Vent Filter	Hot Baghouse	1	0
10	Low pressure Coal Feed stock Bin	Vertical Hopper	1	0
11	Coal Lock Hoppers	Vertical Hopper	2	0

12	High Pressure Feeder	Vertical Hopper	1	0

Table 10 - Coal Preparation and Feed

No	Description	Type	Operating Quantity	Spares
1	Gasifier	Pressurized Entrained Flow Dry Feed	1	0
2	HCL Scrubber with Venturi	Tray Column	1	0
3	Synthesis Gas Cyclone	High Efficiency	1	0
4	Steam Drum	NA	1	0
5	Coolant Drums	NA	1	0
6	Flare Stack	Self-supporting, carbon steel, stainless steel top, pilot ignition	1	0
7	Pumps	Centrifugal	2	2

Table 11 - Gasifier and Accessories

No	Description	Type	Operating Quantity	Spares
1	COS Hydrolysis Reactor	Fixed Bed, Catalytic	1	0
2	Hg Removal Unit	Carbon Bed	1	0
3	Acid Gas Removal Plant	Sulfinol-M	1	0
4	Auto circulation Oxidizer Vessel Sulfur Recovery	N/A	1	0
5	Vacuum Belt Filter Sulfur Cake separator	N/A	1	0
6	Syngas Cooler	Shell and tube	1	0
7	K.O.Drums	Vertical with mist eliminator	1	0

Table 12 - Syngas Cleanup:

No	Description	Type	Operating Quantity	Spares
1	Process Water Treatment	Vacuum flash, brine concentrator, and crystallizer	1	0
2	Primary Sour Water Stripper	Counter-flow with external reboiler	1	0
3	De-aerator	N/A	1	0
4	Low Temperature Heat Recovery Coolers	Shell and tube	4	0
5	Black Water Filter	Pressurized Filter	1	0
6	K.O.Drums	Vertical with mist eliminator	2	0
7	High and LP Flash	Vertical	2	0
8	Milling Water Tank	Tank with motor rotator	1	0
9	Gray Water Tank	Storage Tank	1	0
10	Pumps	Centrifugal	5	5

Table 13 - Water Treatment and ZLD

No	Description	Type	Operating Quantity	Spares
1	Slag Crusher	Roll	1	0
2	Slag Quench Tank	Water Bath	1	0
3	Slag Depressurizer	Lock Hopper	1	0
4	Slag Receiving Tank	Horizontal, weir	1	0
5	Slag Conveyor	Drag Chain	1	0
6	Slag Separation Screen	Vibrating	1	0
7	Pumps	Centrifugal	2	2

Table 14 - Slag Recovery and Handling System

No	Description	Type	Operating Quantity	Spares
1	Circulating Water Pumps	Vertical, wet pit	2	2
2	Cooling Tower	Hybrid, mechanical draft, multi-cell	1	0

Table 15 - Cooling Water System

No	Description	Type	Operating Quantity	Spares
1	Syngas compressor	Reciprocating	2	0
2	Combustor(s) and turbine	Proprietary	1	0
3	Recuperative Heat Exchanger	Printed Circuit	1	0
4	Direct Contact Cooler	Vertical Column	1	0
5	Main CO2 Compressor	Centrifugal	4	0
6	Compressor After-cooler	Printed Circuit	1	0
7	Main CO2 Pump	Centrifugal	3	0
8	Oxidant Pump	Centrifugal	1	0

Table 16 - Allam Cycle Power Island

Additional Equipment Information

Some additional equipment information is provided below to add further context to these performance results.

Heat Exchangers: The heat exchanger network includes multiple heat exchangers to deal with multiple hot and cold fluids, not a single unit. The minimum temperature approach of the heat exchanger network is 3°C, and it is at the low end of the heat exchanger which is made by stainless steel. Additionally, low grade heat taken from the main air compressor is used to preheat the recycle CO_2 stream to close to 200C. The total amount of the low grade heat from ASU is around 34 MWt.

CPU: The CPU is an auto-refrigeration cryogenic process with one flash and a distillation column for liquid CO_2 and contaminants (N_2, Ar, O_2) separation. Water is removed from a conventional molecular sieve desiccant to prevent ice formation in downstream equipment. Given that the feed pressure is 65bar with 98% CO_2 purity, there is no need for compression to provide any additional cold energy, and the oxygen concentration can be reduce down to less than 0.5ppmv based on the Aspen modeling. However, there is some CO_2 loss in the CPU to ensure the low oxygen concentration, which leads to about 94% CO_2 capture rate of the overall system. CO_2 capture rate can be higher by relaxing the oxygen concentration requirement. If export CO_2 is for sequestration or other chemical use which does not require oxygen removal, then CPU can be fully eliminated to reduce the cost and increase the CO_2 capture to almost 100%.

The major equipment within the CPU are listed below:

- Molecular sieve desiccant
- Plate and fin heat exchanger
- Pressure reducing valve
- Flash column;
- Distillation column with reboiler
- Liquid CO_2 pump
- Off gas compressor

Combustor: Siemens has calculated combustor exit gas composition using in-house tools previously verified for other mixtures. Additionally, 8 Rivers has reduced reaction kinetic modeling validated by the shocking tube testing data done by University of Central Florida, which shows complete combustion of syngas under the Allam Cycle condition (Samuel Barak, 2020).[xv]

Oxygen in the recycled CO_2 is injected back to the combustor with recycled CO_2, to ensure a complete combustion in an oxygen rich combustion mode. CPU is included in the system design to remove the excess oxygen from the export CO_2. The oxygen in the recycled CO_2 stream is 0.6832% in volume at the steady state, which is 6832ppmv.

Turbine: The turbine need be cooled, and the cooling information is provided by Siemens. The cooling flow is pulled from the middle of the heat exchanger network. However, given that it's vendor confidential information, it is not shown in the PFD.

Turbomachinery: Turbomachinery efficiency of CO_2 compressors and pump in the Allam Cycle is taken from vendor data. Low to mid 80 percent efficiency were assumed for the compressors without getting vendor data, and 3% motor driven mechanical loss were considered.

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