Executive Summary

Testing and Feasibility Study of an Indirectly Heated Coal Gasifier - WYOIII

Prepared for

University of Wyoming

Clean Coal Technologies Research Program

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Submitted by:

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Introduction

The goal of this project was to assess the potential commercial benefits of an indirectly heated, non-slagging, fluidized bed coal gasifier against that of larger existing commercial directly heated, slagging, entrained-flow coal gasifiers for the production of liquid fuels and hydrogen. While all existing coal gasification technologies require pure oxygen to be co-fed with steam as the primary reacting agents, Emery has developed a design for an indirectly heated gasifier that uses only superheated steam as the direct reagent, while supplying additional process heat to the gasifier via hot flue gas in tubes in the gasifier. The heat in the tubes can be supplied from hot flue gas from the combustion of one or more of these sources:

- Coal Char (i.e. unconverted fixed-carbon) from the gasifier
- Natural Gas
- Raw Syngas

It was hypothesized that two primary benefits would result; reducing overall installed costs and lowering the operating costs – both contributing to reductions in the production costs of final products. These assumptions included:

1. Eliminating the need for an Air Separation Unit (ASU) to:
   a. Reduce parasitic electrical demand and/or costs associated with ‘over the fence’ oxygen supply
   b. Increase overall system reliability by decreasing unplanned outages related to the ASU
   c. Reduce the operation of compressors which are inefficient at higher altitude locations

2. Using a fluidized bed reactor, with lower overall operating temperatures and non-slagging environment would:
    a. Reduce capital costs
    b. Reduce maintenance costs related to refractory wear
    c. Reduce the costs of the downstream syngas cooler due to lower syngas exit temperatures

We also recognized that there would be potential economic penalties including:

1. The need to compress the syngas downstream for fuel synthesis applications, as our baseline case assumes the gasifier operating at 100 psia., which is necessary for proper heat transfer requirements
2. The need to potentially collect and capture CO_2 from both the syngas stream (as in other gasification plants) as well as from the combustion flue gas stream (if a given project aims for greater than 80% carbon capture)

Objectives

Emery had three primary objectives:

1. Perform experimental testing at the University of Utah test gasifier facility to obtain data from an existing indirectly heated gasifier using Powder River Basin coal.
2. Design a commercial scale plant at 500 tons per day or greater, to determine the cost of clean syngas production.
3. Apply this design to the production of:
    - Fischer-Tropsch fuels
    - Hydrogen production; and

- Niche chemicals such as fatty acids derived from emerging syngas fermentation techniques (this economic case was never fully developed nor concluded due to lack of findings or results provided the sub-contractor, Kiverdi, Inc.)

Changes from Original Proposal

During the course of the project we learned that we can also produce high-hydrogen outputs from the indirectly heated gasifier and as such, design cases were added for hydrogen production vs. strictly FT fuel production.

Methods

In order to develop the comparative cases, both technical and economic, Emery referenced existing reports about coal gasification design studies which were based on high-temperature entrained-flow, slagging gasifiers. Such reports included:

1) Technical Evaluation Studies by the Idaho National Laboratory (INL) and the University of Wyoming and provided to Emery under license by the Wyoming Business Council. This model was developed based on the Shell Coal Gasification technology (dry-feed, entrained-flow, slagging gasifier).

2) PARSONS Study "Capital and Operating Cost of Hydrogen Production from Coal Gasification". Technical and Economic Assessment of Small-Scale Fischer-Tropsch Liquids Facilities

DOE/NETL-2007/1253 Final 2007

3) CO_2 removal report by AspenTech and Energy & Environmental Research (EERC) called "Modeling and Cost Evaluation of CO_2 Capture Processes".

The former cases (INL) evaluate large-scale coal gasification projects under higher altitude conditions in Wyoming using Powder River Basin sub-bituminous coals. These cases were generally based on >30,000 tons/day of coal, and hence required the use of scale-factoring to develop comparisons against our considerably lower capacity plants (i.e. 500 tons/day).

Results

One of the key benefits realized during the design and overall analysis of the subject technology is that 'carbon conversion' in the gasifier is not as critical in the overall energy balance and economics as compared to other gasifiers. This is because unconverted carbon (i.e. coal char), is ultimately consumed in the combustor (or air-blown secondary gasifier) to generate heat for the gasifier, (resulting in 100% utilitzation of the coal energy). Furthermore, this allows the gasifier throughput (per unit volume) to increase because extended residence times of coal is not required to convert all of the fixed carbon.

Technical Information

Emery Activities

Emery purchased a copy of the report entitled "The Feasibility of Siting Coal Gasification and Synfuels Plants in Wyoming" published in 2011 by Idaho National Laboratory and the University of Wyoming. This report provided baseline economic information for a large-scale coal gasification (Coal-to-Liquids) plant in Wyoming. Emery also acquired a limited license to use the process simulation and cost estimating program "Aspen Plus". This was used in evaluating the capital and operating cost benefits of eliminating the use of oxygen and looking at different gas processing and conditioning systems. In addition, overall process simulations and process flow diagrams were done using ChemCad in order to quickly develop process schemes.

Emery evaluated the cost/benefits of using:

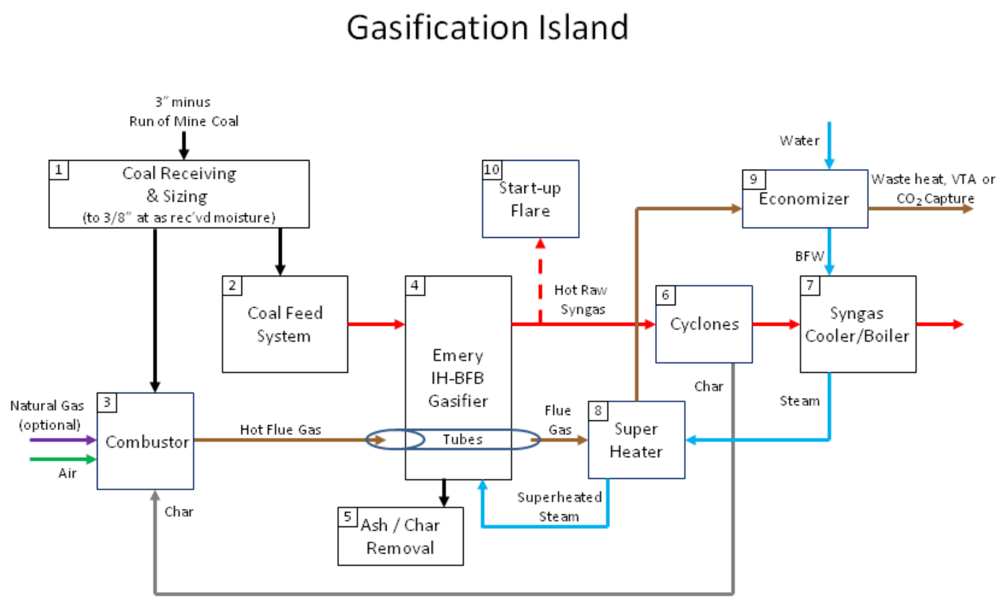
- Coal Char (un-converted fixed-carbon) from the gasifier
- Natural Gas

Emery also simulated and estimated the costs of CO_2 removal from both the syngas stream as well as from the combustion flue gas stream resulting from indirect heating. Emery also simulated the overall water requirements of the plant while considering emerging coal drying and water harvest concepts to minimize overall water requirements from ground or surface sources.

Gasifier Design Basis and General Process Description

The Emery IH-BFB uses in-bed heat transfer tubes to supply the energy needed to gasify coal or biomass. The use of in-bed tubes for heat transfer has been used in commercial scale fluidized bed boilers for generating steam.   In such cases, heat is transferred from the bed to the tubes carrying water, to generate steam. In the IH-BFB heat is transferred from the tubes to the fluidized bed coal materials.   This concept has also been demonstrated on biomass feedstocks in the MTCI Gasifier. The heat required to heat the bed is supplied by hot flue gas produced by burning fresh coal and/or coal char, natural gas and/or raw syngas. Oils recovered from gas cleaning can also be burned to supplement process heating. The choice of fuel will depend on factors related to each project and the availability and priced of natural gas vs. use of coal char.

Figure 1. Block Diagram of Gasification Island



Coal Prep

Coal is prepared by milling to produce 1 inch minus material. It is then dried to 10% moisture by weight. Drying is required to reduce the heat load on the gasifier and hence the number of heat transfer tubes required in the bed. Each pound of water requires around 1500 Btu/# to heat the water from 70 degrees Fahrenheit to the bed temperature of around 1500 Fahrenheit.

Gasifier & Gas Cleaning Description: Quench Process Approach & Tar Reforming Process Approach

The dried coal and steam are fed to the fluidized bed gasifier to produce a syngas mixture comprised mainly of H2, CO, CO2, and CH4. The final gas composition depends on the feed composition, the steam feed rate, and the bed operating temperature. The hot raw syngas is then fed to cyclones in series which reduce the particulate content of the syngas by 99+%. The syngas is then passed through a venturi scrubber which cools the gas and removes any remaining particulates and any tar/oil in the syngas. An oil/water stream from the venturi scrubber is sent to an oil/water separator which removes the oil from the water stream. The oil recovered is recycled to the gasifier or combusted (with either the natural gas or coal char) as part of the heat input to the tubes. The clean syngas is fed to a caustic scrubber to remove ammonia and some of the H2S. After scrubbing the gas enters an electrostatic precipitator which removes any remaining particulate and oil mist. The syngas is compressed and the gas is sent to a Selexol unit which removes the H2S and a portion of the CO2. The amount of CO2 removed can be adjusted by changing the Selexol units operating conditions and using a subsequent water-gas shift reactor to achieve the desired ratio of H2:CO. The above process description is consider a 'wet quench' approach. Alternatively, the raw syngas could go immediately to high-temperature sulfur removal technology followed by a tar reformer. From there it would go to the water-gas shift reactor for final ratio adjustments, then to the Selexol unit for CO2 removal. The clean, shifted, syngas is then sent to a Fischer Tropsch catalytic conversion unit. The bulk liquids and waxes produced by the FT unit are further upgraded to produce Diesel, Naphtha, and LPG. In the case of hydrogen production, the water-gas shift step is maximized to increase hydrogen production.

U of U Testing

The fluidized bed test gasification system is located in the University of Utah's (U of U) Industrial Combustion and Gasification Research Facility (ICGRF). The system comprises the fluidized bed reactor plus associated feed and product handling systems. The gasifier utilized for this project is a 200 kW, bubbling fluidized bed steam reformer. The gasifier itself is a refractory-lined pressure vessel capable of maintaining a reactive environment with temperatures up to 870°C (1600°F) and pressures up to 7 bar (100 psi).

As the testing progressed it was determined that there were several inherent problems with delivering crushed coal to the gasifier using a feeder designed for woody biomass. Two of these issues were critical and despite the extensive efforts to overcome them, the feeding system ultimately constrained the conditions that could be tested in the gasifier. The first critical problem was that the metering screws were not able to deliver the coal to the injector screw at a controllable rate. The second critical feeding issue was that c-ball valves (most significantly the lower) were not able to seal and hold pressure due to fines in the crushed coal.

Laboratory-scale measurements of fuel char yields and reactivity

To complement the fluidized bed experiments in the process development unit (PDU) UofU performed experiments in a lab-scale pressurized thermogravimetric analyzer to measure char yields and reactivity of char under conditions representative of the fluidized bed system. The PTGA data was acquired under controlled conditions and allowed for identification of reaction rates over the entire range of conversion, making it suitable for fluidized bed gasifier models.

Pilot-scale Gasification Experiments

The coal that was used for these tests was a Powder River Basin (PRB) coal from the Black Thunder mine in Wyoming. For each of the test conditions shown in Table 1, the gas composition was measured using a gas chromatograph and a NOVA analyzer. Gas phase tar and bed solids samples were collected at the location detailed.

Table 1 Test Conditions for the Fluidized Bed Gasifier

Test #	**Date**	**Temp**	**Coal**	**Steam**
		°F	**lb/hr**	**lb/hr**
1	10/4/2013	1250	20	40
2	10/3/2013	Max*	20	40
3	8/21/2013	1250	30	40
4	9/27/2013	Max*	30	40
5	9/26/2013	1250	20	60
6	10/3/2013	Max*	20	60
7	10/4/2013	1250	30	60
8	10/3/2013	Max*	30	60
9	9/30/2013	1250	40	35

* *The maximum temperature varied between 1325 and 1400 °F, dependent on steam and coal flow rate*

Results

The data resulting from the tests detailed in Table 2 were analyzed and a summary is presented here. The gas chromatograph data was combined in a spreadsheet with the operating data collected by the FBG control computer.

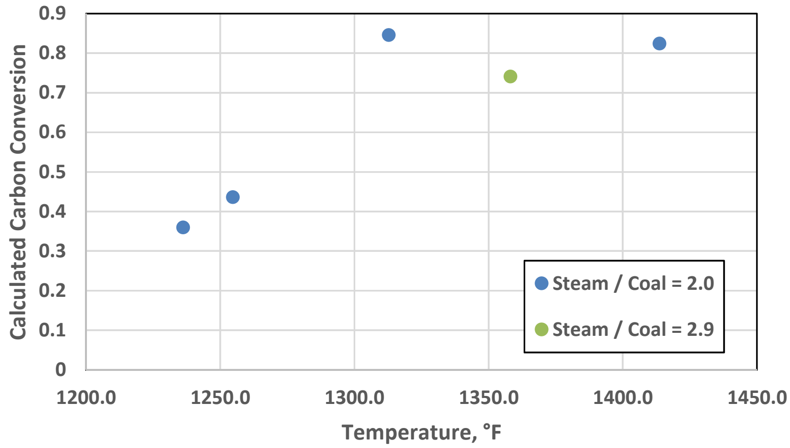
Table 2. Summary of averaged data for each test condition

		TEMP	COAL*	STEAM	GAS CHROMATOGRAPH % (NO N2)					LOI		CARBON
TEST	Date	°F	lb/hr	lb/hr	H2	O2	CH4	CO	CO2	Bed	Char	Conversion
1	10/4/2013	1255	20	41.0	61.7%	0.8%	6.6%	4.6%	26.2%	3.2%	5.8%	43.6%
2	10/3/2013	1414	20	40.1	60.9%	0.8%	3.8%	10.9%	23.6%	0.7%	7.7%	82.4%
3	8/21/2013	1247	30	39.9	52.9%	0.4%	10.0%	5.8%	31.0%	4.6%	80.4%	
4	9/27/2013	1343	30	38.5	55.7%	6.3%	3.9%	10.5%	23.6%	1.1%	17.1%	
5	9/26/2013	1218	20	57.5	54.4%	0.3%	6.8%	3.9%	34.7%	0.8%	4.3%	
6	10/3/2013	1358	20	57.9	62.3%	0.4%	3.5%	8.6%	25.2%	14.1%	3.0%	74.1%
7	10/4/2013	1236	30	58.7	61.9%	0.7%	7.5%	3.9%	26.0%	3.0%	15.7%	35.9%
8	10/3/2013	1313	30	58.6	59.3%	1.9%	5.4%	6.7%	26.7%	0.4%	11.1%	84.5%
9	9/30/2013	1251	40	35.0	48.5%	2.0%	10.7%	6.7%	32.1%	4.5%	22.4%	

*The reported coal rate is the set point on the external Acrison feeder

The carbon conversion was calculated for the tests performed on 10/03 and 10/04 where the mass balance closure was very good. These data points are available for tests 1, 2, 6, 7 & 8 and are plotted as a function of temperature in Figure 2. These data show that the carbon conversion is a strong function of temperature. The shape of the curve suggests that at low temperatures, < 1250 °F, there is likely little gasification of the solid material and the species in the gas phase are likely due to volatiles in the coal. The conversion increases strongly in the temperature range from 1250 °F to 1300 °F. A maximum conversion between 75 and 85% is reached at temperature above 1310 °F.

Figure 2. Calculated Carbon Conversion for Experiments 1,2,6,7 & 8



The samples of bed and char material were analyzed to calculate the carbon content by Loss in Weight Analysis (LOI). The data indicates that the carbon present in the bed material generally decreases with an increase in temperature. The amount of carbon in the filter material does not seem to be a strong function of temperature. This is an indication of the composition of the filter material, but the amount of carbon carried out of the bed for each of the test conditions was not measured. The carbon in the bed material seemed unusually high for test # 6 and the amount of bed material in the filter sample was unusually low for test #3.

Emery Analysis of U of U Data

The U of U data analysis is based on using the average values for each run. Emery has performed a linear regression analysis using 357 data points which gives much better accuracy than only using averages. Based on this analysis Emery obtained the following equation for the effect of steam feed rate and temperature on the H2/CO ratio: H2/CO = .206 #/hr of steam + .001*average bed Temperature. This equation is valid for the range of test conditions in the U of Utah experimental runs. The main objective of the U of U test program was to show that the

H2/CO ratio was a function of steam feed rate and bed temperature which this equation demonstrates. The range of H2/CO ratios in the test runs varied from 1.5 to 16.

Kiverdi

Kiverdi, Inc. was a sub-contractor to Emery and project participant with an early stage technology which is aimed at producing higher value niche chemicals by producing fatty acids (and their derivatives) via fermentation of syngas. Kiverdi's proprietary bioprocess and microbes as a back end to Emery's gasification technology has the potential to create an economical solution to convert syngas obtained from agricultural waste blended with coal into high value oils and chemicals used in every day products such as detergents, packaging and fuels.

For this project, Kiverdi's goal was to demonstrate the conversion of bottled syngas components into chemicals. The bioprocess has 2 major components which include gas fermentation to convert syngas components into chemicals and extraction of the chemicals from the cell mass. Kiverdi performed their two part bioprocess of gas fermentation to convert syngas components into chemicals and extraction of the chemicals form the cell mass by completing the tasks below.

Task 1: Experiments
Task 2: Bench Scale Demonstration
Task 3: Data Collection & Analysis (Wet vs. Dry Extraction)
Task 4: Parallel Bioreactor Runs
Task 5: Determining SOP for Larger-Scale Extraction
Task 6: Performing GS-MS Analysis on Extracted Chemicals

Towards the end of the project, Kiverdi failed to provide detailed data to support their claims in their reports. Therefore Emery was forced to make assumptions based on Kiverdi's very basic information provided about their projected yield and value of resultant products.

Resulting Basic Commercial Plant Schemes

Emery elected to evaluate only the production of FT fuels and Hydrogen. This was due to the fact that there is so much more information available in the public domain regarding syngas processing to produce these product streams. Furthermore, this enabled Emery to isolate the benefits of the proposed indirectly heated gasifier, against a baseline case of an Entrained-flow slagging gasifier simulated and modeled in ASPEN by the Idaho National Laboratory (INL). The INL data was then scaled down to an equivalent smaller design target of 500 tons/day of coal input equivalent. From this, we were able to identify the major cost savings (capital and operating) in the Emery technology against a scaled down version of the INL-Shell Gasifier model. Additionally, doing so enabled us to leverage much of the cost information for syngas processing and upgrading to Hydrogen and FT Fuels while keeping many of the costs identical, unless specific areas required upward or downward adjustments. In each of the Emery cases described below, we require 600 tons/day of coal (vs. the 500 tons/day fed to the INL/ Shell Gasifier case), due to the need to supply heat to the Emery gasifier. However, it is important to point out that the INL-Shell Gasifier (which requires oxygen) still has an 'offsite' energy penalty associated with electricity production necessary to operate the cryogenic air separation unit.

Below are the eight (8) cases using the Emery indirectly heated gasifier; four based on the production of Fischer Tropsch fuels and four based on Hydrogen production. Each set of four schemes are further divided into gasifiers that used either coal char or natural gas (CH4) as the heat source, and then each had a case where CO2 was vented to the atmosphere or CO2 was captured.

Figure 3. Case Matrix

		CO_2	
Heat Source ↓	Final Products ↓	Vent	Capture/Sell
Coal Char Heat	FT Fuels	Case 1	Case 3
	Hydrogen	Case 2	Case 4
CH_4 Heat	FT Fuels	Case 5	Case 7
	Hydrogen	Case 6	Case 8

Economic Analysis

For the gasification including the coal feed system, indirectly heated fluidized bed, cyclones, venturi scrubber and selexol system to remove H2S and CO2 Emery has used cost estimates based on Vendor quotes and the Aspen Economic Evaluation program. INL (Icaraus) used a factor of 1.5 to calculate plant installed costs from plant equipment costs, with separate estimates for piping, electrical and control equipment. Emery has also used the itemized costs and selling prices for the plant raw materials and the plant product pricing.

Emery has scaled costs from an INL and Aspen report to calculate the capital costs and operating costs for CO2 recovery in the high H2/CO(7/1) cases where CO2 is produced in the water gas shift reactors which convert CO + H2O to CO2 + H2. Emery has also compared its cost estimate with a report by Parsons for NETL and found that the costs agreed within 10% when corrected for inflation and adjusted to a capacity of 500 TPD of coal. The total installed cost of the Emery system to produce clean syngas is around $34 million and the INL system is around $157 million. The total INL investment including the Fischer Tropsch system is around $277 million and the Emery cost of coal to liquids is $153 million. The total Emery capital cost of a coal to hydrogen plant is $144 million.

Conclusions/Recommendations

After evaluating the side-by-side economics between the Emery IH-BFB Gasifier compared to the scaled-down figures from the Shell commercial entrained-flow gasifier, it was concluded that potential significant economic value can be derived using by the Emery IH-BFB Gasifier. The cost advantage comparison was only evaluated for the FT fuels production case. This is because this was the basis for the INL/Shell case, as they did not have a Hydrogen equivalent. The results showed a capital cost savings of at least 42% and an operating cost savings of 13%. These both contribute to a capital payback of ½ the time compared to the INL/Shell case and/or a simple return on investment of 12% (vs. only 6% for the INL/Shell case).

Simplified Business Plan for Commercialization

In order to advance this technology toward commercialization, we must first take into consideration all that is already known and tested (i.e. existing technology) vs. new areas of the technology that have more development risk. First and foremost, the primary design basis of the technology (a fluidized bed), has significant history of commercial deployment in both combustors and gasifiers. This fact alone greatly reduces the overall risk typically associated with new technology development, because the fundamentals of fluidization in gasification environments are well understood. The newer areas of development primarily come from the use of tubes inside the bed of the gasifier to act as the primary heat input and their ability to properly transfer such heat to the feedstocks inside the gasifier. However, this feature has been demonstrated to a limited extent, in the MTCI or TRI gasifier technology on biomass feedstocks. The third aspect, the combustion of coal or natural gas to produce hot flue gas into the tubes, is of course, also a low-risk, well proven area. Below is our preferred course in which to commercialize the technology and demonstrate potential benefits versus the actual costs.

Step 1: Build a Process Development Unit in the 10 to 20 TPD range. This is large enough to obtain key data on heat transfer, fluidization, carbon conversion, resulting char for combustion, etc. that will aid key heat/mass/energy balances necessary for subsequent reactor design as well as the influence on 'balance of plant' areas. Operate for a minimum of 2,000 hours to obtain sufficient operational data and enable parametric variations. From this develop a detailed process model in ASPEN to form the design basis for the next scale up.

Step 2: Phase 1 - Complete detailed design and engineering for a 200 TPD demonstration plant. Phase 2 - Implement the 200 TPD demonstration plant preferably at a brown-field site so the syngas can be combusted in the boiler during the first 2 years of operations. Phase 3 – add the chemical production island of FT Fuels and/or a Hydrogen/CO2 production facility to produce final products and operate the plant as a commercial asset.

Step 3: Develop subsequent scaled-up version of the reactors to modules of 500 TPD or 1,000 TPD. Install individually in a distributed fashion or use multiple units for larger production applications.

Table 3. Preliminary Commercialization Schedule

	Year 1	Year 2	Year 3	Year 4	Year 5
Step 1 - Build / Operate PDU					
Step 2 - Build Demonstration Plant					
Phase 1 - Detailed Engineering and Design					
Phase 2 - Implement Demonstartion Plant					
Phase 3 - Add Chemical Production					
Step 3 - Develop 500 or 1000 tpd Modules					