Final Technical Progress Report – Phase I

COOPERATIVE AGREEMENT
DE-FC26-00NT40899

Calla Energy Biomass Cofiring Project

September 2003

CONTRACTOR NAME
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PERIOD OF PERFORMANCE
From: September 25, 2000
To: September 30, 2001
Extended: September 30, 2003

CONTRACT PERIOD
From: September 25, 2000
To: September 30, 2001
Extended: September 30, 2003

ABSTRACT

The Calla Energy Biomass Project, to be located in Estill County, Kentucky is to be conducted in two phases. The objective of Phase I is to evaluate the technical and economic feasibility of cofiring biomass-based gasification fuel-gas in a power generation boiler. Natural gas and waste coal fines were evaluated as the cofired fuel. The project is based on the use of commercially available technology for feeding and gas cleanup that would be suitable for deployment in municipal, large industrial and utility applications. A design was developed for a cofiring combustion system for the biomass gasification-based fuel-gas capable of stable, low-NOx combustion over the full range of gaseous fuel mixtures in a power generation boiler, with low carbon monoxide emissions and turndown capabilities suitable for large-scale power generation applications.

Following the preliminary design, GTI evaluated the gasification characteristics of selected feedstocks for the project. To conduct this work, GTI assembled an existing "mini-bench" unit to perform the gasification tests. The results of the test were used to confirm the process design completed in Phase Task 1. As a result of the testing and modeling effort, the selected biomass feedstocks gasified very well, with a carbon conversion of over 98% and individual gas component yields that matched the RENUGAS® model.

As a result of this work, the facility appears very attractive from a commercial standpoint. Similar facilities can be profitable if they have access to low cost fuels and have attractive wholesale or retail electrical rates for electricity sales.

The objective for Phase II is to design, install and demonstrate the combined gasification and combustion system in a large-scale, long-term cofiring operation to promote acceptance and utilization of indirect biomass cofiring technology for large-scale power generation applications. Phase II has not been approved for construction at this time.

TABLE OF CONTENTS

List of Figures & Graphical Materials

List of Tables

INTRODUCTION

The Gas Technology Institute, GTI, has assembled a team to perform this project. The team includes Calla Energy Partners, who is providing cost sharing resources. Calla is a developer of energy projects, and plans to generate steam and electricity from the completed facility in an industrial park to be located in Estill County Kentucky. Biomass in the form of saw dust and wood chips can be acquired from lumber mills located in the region. Calla has also evaluated collecting railroad ties for a fee and using them to fuel the facility. This can be an attractive use for the facility. Coal waste from the impoundment ponds at the site as well as natural gas were investigated as a possible cofiring fuels for the facility. Calla plans to develop an energy facility in conjunction with the Estill County, Kentucky industrial park. This park sits on 600 acres of a former waste coal pond site. Figure 1 is an aerial view of the industrial park property. The site has access to highway, rail, and barge access. The developers plan to install a fluidized bed boiler that will use the waste coal as a fuel and will provide steam and electricity for sale to industrial customers and to a wholesale electricity provider for resale.

Figure 1. Estill County Industrial Park

The gasified biomass will produce a low calorific value gas (LCV) that can be used used in a manner similar to natural gas. GTI has evaluated the use of the gas for cofiring in either a fluid-bed boiler to reduce NOx emissions; or in a natural gas fired boiler as an alternative low cost fuel source. This is accomplished using GTI's low NOx emission burner technologies.

GTI has teamed with CARBONA and NEXANT to develop a design for a complete gasification facility capable of delivering LCV gas to a boiler to be provided by Calla. GTI shall also design a dual-fuel LCV gas burner to provide clean, high-efficiency combustion for the gas to be installed in Calla's boiler.

The design of the "gasifier island" to be employed at the Calla Energy Facility is a simple configuration, designed to provide gas of the quality needed for the end use application, cofiring in a natural gas-fired boiler. The RENUGAS® gasifier, Figure 2 design for the Calla Energy facility will use a gasifier designed to operate at 29 psia. Particulate exiting the gasifier will be captured in a cyclone. Gas is cooled to an appropriate temperature for metallurgical and other downstream equipment criteria.

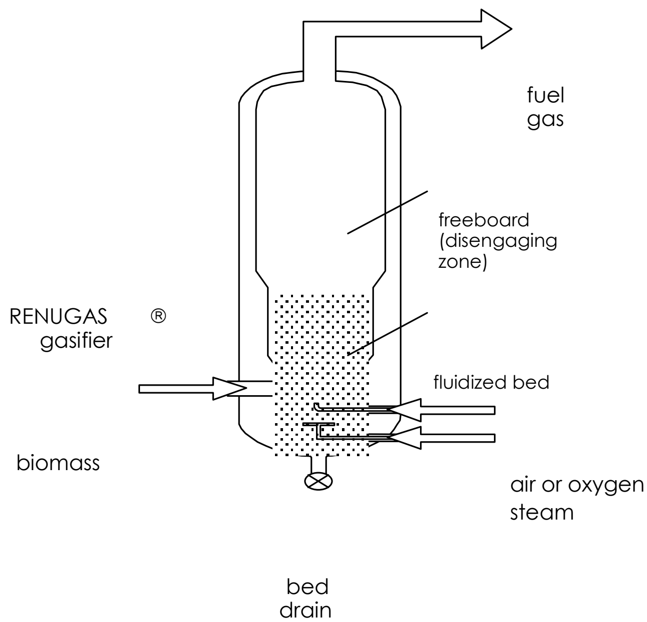


Figure 2. RENUGAS® Gasifier

The fuel gas produced from the gasifier will be burned in a natural gas-fired boiler. GTI evaluated the combustion for either a coal fired fluid-bed boiler or a natural gas fired boiler. Both options are technically viable, however the use of a separate natural gas fired boiler provides added backup capability to the project, which enhances its commercial reliability. GTI will determine the final location of the gas burners on the boiler to facilitate NOx emission reductions from the boiler during Phase II. For a natural gas package boiler application, GTI will apply their FIR burner design to ensure emissions on a par with natural gas low NOx burners.

The gasification facility will be fabricated on the site of an existing coal preparation plant. This is an old facility that Calla Energy plans to demolish. See Figure 3 and 4. The gasifier structure and fuel receiving and storage facilities will be located on the larger concrete foundations that previously supported the old prep plant equipment. Use of the existing foundation should save approximately $45,000 in construction cost. The boiler will be located near the gasifier to minimize the interconnection costs for the fuel gas.

Figure 3. Old Preparation Plant to be Demolished

Figure 4. Existing Conveyors and Material Storage Area

EXECUTIVE SUMMARY

Contract Objectives

This project is being conducted in two phases. The objective of Phase I was to evaluate the technical and economic feasibility of cofiring biomass-based gasification fuel-gas in a power generation boiler. Waste coal fines were evaluated as the cofired fuel. The project is based on the use of commercially available technology for feeding and gas cleanup that would be suitable for deployment in municipal, large industrial and utility applications. Define a combustion system for the biomass gasification-based fuel-gas capable of stable, low-NOx combustion over the full range of gaseous fuel mixtures, with low carbon monoxide emissions and turndown capabilities suitable for large-scale power generation applications.

The objective for Phase II is to design, install and demonstrate the combined gasification and combustion system in a large-scale, long-term cofiring operation to promote acceptance and utilization of indirect biomass cofiring technology for large-scale power generation applications.

EXPERIMENTAL

Project Tasks

Task 1.0 Phase I - Feasibility Study

The objective of Phase I was to evaluate the major technical and economic factors determining project viability and to define the specific fuel sources, fuel handling requirements, gasification system and combustion system configurations necessary to insure a successful biomass cofiring demonstration. This objective was accomplished through the following tasks:

Task 0.0. NEPA Information

Calla Energy Partners provided reports and documentation deemed necessary for DOE to prepare a NEPA review of the project. This information describes all anticipated environmental impacts of the proposed project. The NEPA review and approval process shall be completed by DOE before Phase II is initiated.

Task 1.1. Feedstock Evaluation

In this task, GTI and Calla identified and characterize the available economically viable biomass fuel resources for the plant. Fuel supply and transportation contracts will be negotiated during Phase II to insure adequate primary and backup feedstock supplies for the plant. In negotiating any contracts, realization will be made that the project may end at the completion of the feasibility study and not proceed further.

Based on the fuels identified, gasifier sizing, feed handling, feed preparation and gasifier feed system requirements will be defined for the process simulation modeling and the conceptual plant design.

Task 1.2. Process Simulation and Combustion System CFD Modeling
Based on the range of feedstocks identified in Task 1.1, the GTI Team modeled the plant process to evaluate and optimize plant configuration, reliability and efficiency. A proprietary gasification model was used to develop gasifier heat and material balances, perform gasifier sizing calculations, predict product fuel gas compositions, and define process input and output flow ranges for each feedstock identified and mixtures thereof. NEXANT modeled the remaining plant systems and components under consideration using information developed under previous and on-going studies for the US Department of Energy (DOE) to the extent possible, providing a consistent basis of information and methodologies with previous DOE efforts. GTI used special design software to perform modeling calculations for the low-NOx LCV gas burner design used in conjunction with the fluid bed boiler.

Task 1.3. Conceptual Plant Design
Based on the feedstock and design configuration modeling results from Tasks 1.1 and 1.2, the GTI team developed detailed flow sheets with heat and material balances, performance estimates, and total plant capital cost estimates for the design cases agreed upon. This information formed the basis for the technoeconomic study conducted in Task 1.4.

At the beginning of the conceptual design task, Calla Energy Partners prepared a project permitting study identifying all federal, state and local permits required for the entire project through demonstration operations. This study included a listing of all likely actions necessary to satisfy each permitting requirement, an approximate average time required to obtain the permit based on local experience with similar projects, the likely cost to the project, and the suggested project team member to be responsible for obtaining the permit.

Task 1.4. Technoeconomic Analysis
The capital costs at the total plant cost (IPC) level was determined for equipment, materials, labor, indirect construction costs, engineering, and contingencies. Operation and maintenance cost values were determined for the first-three year basis and subsequently levelized on the 3rd year basis of a 20-year plant book life to form a part of the economic analysis. Quantities for major consumables such as fuels and sorbent were taken from the technology-specific heat and material balance diagrams developed for each plant application. Other consumables were evaluated on the basis of the quantity required using reference data. Operation costs were determined on the basis of the number of operators. Maintenance costs were evaluated on the basis of requirements for each major plant section. The capital and operating cost results for each plant case are combined with plant performance in the comprehensive evaluation of the COE. Details of the plant design definition, capital cost estimate, operations, and maintenance cost estimate and economic analysis are reported herein:

- Plant Design
- Process Flow Sheets (heat and material balances)

- Performance Summary Table
- Overall efficiency and net plant heat rate (HHV basis)
- Summary Capital Estimate including detailed Code of Accounts
- Summary of production costs with details of the following sub-accounts: Fixed O&M, Variable O&M, Consumables, By-product Credit, and Fuel
- COE based on 15-year private sector financing based on 90% capacity factor

Task 1.5. Project Management – Phase I
Project review meetings were conducted as required. This report was prepared at the completion of Phase I to describe the findings of the study. A GO/NO-GO decision on Phase II must be received from DOE before initiation of detailed design and construction.

Task 1.6. Technology Conceptualization
GTI prepared a feasibility analysis of the advanced technology, based on their gasification experience. This report focuses on the potential future opportunities of the proposed technology and other related gasification opportunities for biomass.

Task 1.7 Gasification Characterizations of Selected Feedstocks
GTI determined experimentally the gasification characteristics of selected feedstock for the project. To conduct this work, GTI reassembled and refurbished an existing "mini-bench" unit to perform the gasification tests. The results of the test were used to confirm the process design completed in Phase Task 1.3. GTI worked with Calla Energy Partners to identify suitable materials for testing.

Subtask –1
GTI identified several feedstocks that are available for long-term supply to Calla Energy. GTI and Calla confirmed the availability of the feedstock and procured sufficient representative samples for biomass gasification tests at GTI. The samples were analyzed for their physical and chemical properties prior to testing.

Subtask –2
GTI assembled, refurbished, and pressure tested, the existing mini-bench scale gasification test unit. The instrumentation and data acquisition systems were calibrated. Test material was dried and readied for testing.

Subtask – 3
GTI conducted gasification tests of the selected feed materials. These characterized the gasification temperatures, steam/feed ratio, air/feed ratio, and other key process parameters. GTI conducted tests to optimize conversion efficiency and determine conditions that minimize oil/tar formation.

Subtask – 4
The results of Subtask 3 were used to update GTI's gasification computer model. The results of the testing were used to compare to the design basis used for Task 1.3 which verified the design basis.

Phase II Plant Design, Construction and Demonstration

Contingent on a decision to proceed based on the results of the Phase I feasibility study, detailed design, construction and demonstration of the biomass gasification–based fossil fuel cofiring facility will be completed in Phase II. This will be covered under a follow-on contract to this agreement.

RESULTS AND DISCUSSION

Task 0.0. NEPA Review

Calla Energy has met extensively with B&W to negotiate equipment costs for the ACFB. Based on the design specifications for the fluid bed boiler and its cleanup system to be supplied by B&W, the plant will be constructed to BACT standards. Calla Energy has submitted Air Permit applications to the Kentucky Department of Environmental Quality. These have been through preliminary review, Calla Energy has responded to questions posed by the agency, and they are waiting for permit approval, expected in October 2001.

Calla Energy has been negotiating the terms to a power purchase agreement with utilities in the area of the facility. These will be completed upon receipt of the permits.

Task 1.1 Feedstock Evaluation

Calla Energy conducted a survey of sources of wood waste material in the vacitity of the Estill County Facility. Approximately 1000 tons per day of sawdust is know to be available from 3 sawmills within eleven miles of the plant site. A representative sample of the material was provided to GTI for analysis. The analysis of materials for this project is listed in Table 1. One sample was of sawdust; the other was of "bark/slabs" generated when preparing lumber at the sawmills. The third sample was of coal product from the coal preparation plant at the Estill County Industrial Park. GTI also analyzed the fuel ash samples, Table 2. For the purposes of the plant design, it was determined that a 50/50 mixture of the two materials was a most likely from a convenience standpoint. The analysis determined that these materials require drying prior to feeding to the gasifier. GTI was also requested by Calla to evaluate the use of used railroad ties as a fuel. Calla would receive a tipping fee for accepting the railroad ties for disposal. GTI has not analyzed samples from a specific set of railroad ties to determine their effect on the plant design, but has generated "typical" data based on industry values.

Table 1. Fuel Analyses

Fuel	Estill County Saw Dust	Estill County Slabs/Bark	Estill County Prep Plant Product Coal
Sample Date	2/2/2001	2/2/2001	2/2/2001
Type	Typical	Typical	Typical
Air Dry Moisture	48.93	38.33	6.63
Proximate			
Moisture	50.52	40.55	7.62
Ash	0.46	6.49	5.56

Vol Matter			32.94
Fixed Carbon			53.87
Btu/lb			
Btu/lb MF	8,990	7,630	14,140
Sulfur			
(SO3 Corrected)			
Moisture	50.52	40.55	7.62
Ash	0.46	6.46	5.40
Vol Matter			32.94
Fixed Carbon			54.04
Ultimate			
C	49.07	46.34	78.83
H	6	5.38	5.3
O	43.61	36.97	7.24
N	0.27	0.4	1.83
S	0.13	0.03	0.96
Cl			
Ash	0.92	10.87	5.85

Table 2. Fuel Ash Analyses

Fuel	Estill County Saw Dust	Estill County Slabs/Bark	Estill County Prep Plant Product Coal
Sample Date	2/2/2001	2/2/2001	2/2/2001
Type	Typical	Typical	Typical
Ash Analsis			
% Element			
Na	0.17	0.09	0.41
Mg	2.35	0.68	0.85
Al	1.86	2.43	14.4
Si	10.3	15.6	24.6
P	1.06	0.3	0.21
Si	0.41	0.16	1.31
K	12.6	2.66	2.13
Ca	31.5	37.4	2.59
Ti	0.15	0.22	1.01
Fe	1.31	1.32	5.14
% Oxide			
Na2O	0.23	0.12	0.55
MgO	3.9	1.13	1.41
Al2O3	3.52	4.59	27.2
SiO2	22	33.4	52.6
P2O5	2.43	0.69	0.48
SO3	1.02	0.41	3.26

K2O	15.2	3.21	2.57
CaO	44.1	52.3	3.62
TiO2	0.25	0.37	1.68
Fe2O3	1.87	1.89	7.35
	94.52	98.11	100.72
Ash Fusion Temps			
Reducing			
IT	2540	2555	2485
ST	2555	2560	2515
HT	2570	2575	2570
FT	2585	2600	2610
Oxidizing			
IT	2565	2385	2640
ST	2580	2410	2675
HT	2600	2425	2700+
FT	2620	2440	2700+

Since the design basis fuel is nearly 50% moisture, and it is preferred that gasifier moisture content be limited to 20% moisture, alternative dryer designs were investigated. A steam driven dryer posed several technical and economic issues. A gas driven dryer posed environmental questions based on possible VOC emissions.

The GTI team decided to pursue a design that would use hot flue gas at 800 oF from the ACFB to dry the feed material. The exhaust from the dryer would be returned to the boiler, eliminating all environmental issues. Figure 5 is a flow diagram of the feed material dryer developed for the project. Figure 6 is a general arrangement drawing showing how the dryer and biomass feed system can be arranged.

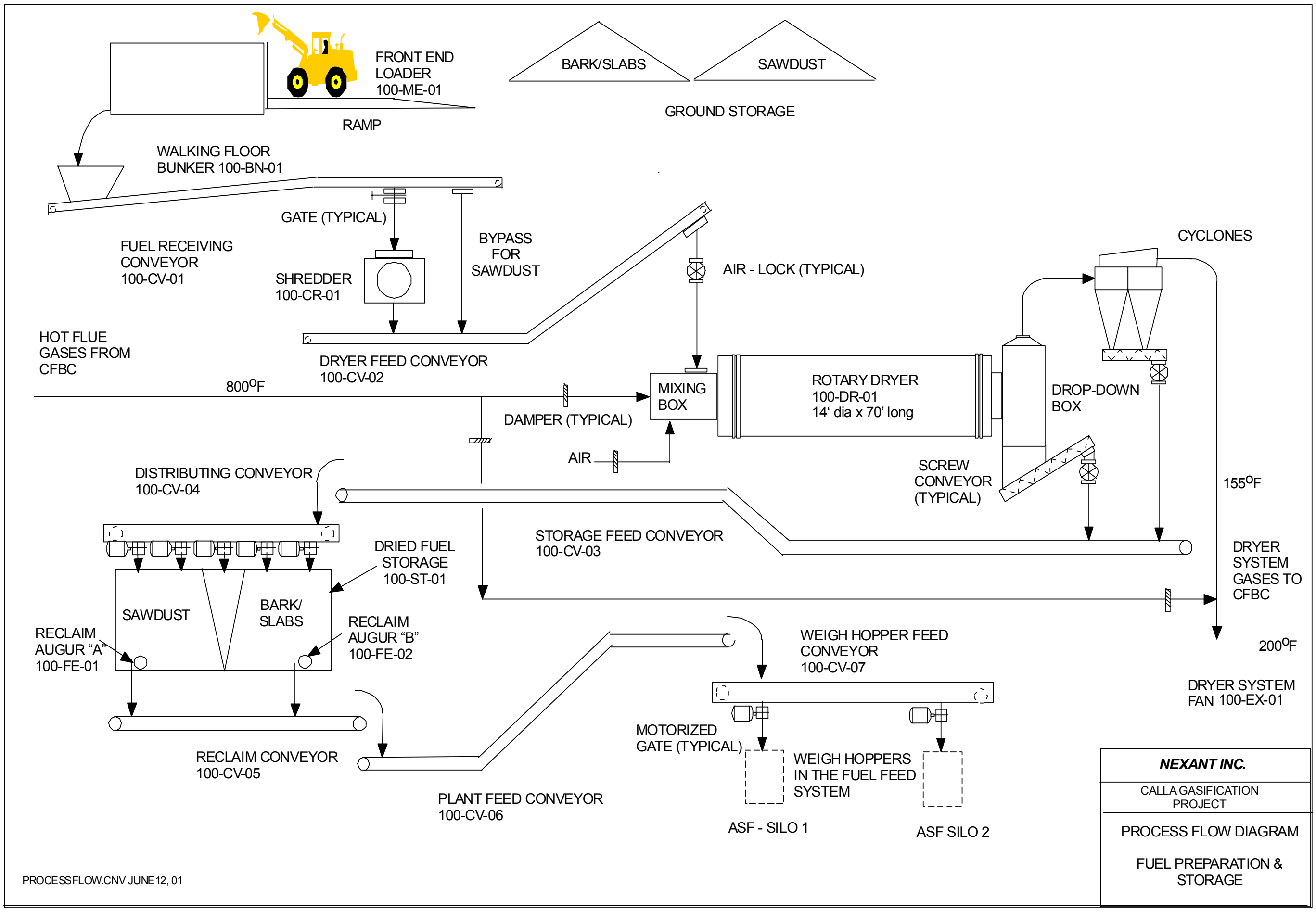


Figure 5. Fuel Preparation, Drying, and Storage

The dryer for sawdust constitutes nearly 30% of the total plant cost. The use of opportunity fuels that do not require drying can reduce capital costs by over $5 million. These two options were studied to ascertain the overall impact on project economics during Task 1.4.

Calla has determined that the conservative approach is best for this project. That is to design the project to accept the "wet fuels" such as saw dust and bark. Continue to explore opportunities to identify cost effective opportunity fuels and test them once the plant is completed to determine if there is an adverse impact on emissions or other issues. If those do not manifest themselves as a result of actual tests at the facility, then they will consider entering into a contract for fuels that provide income to the facility.

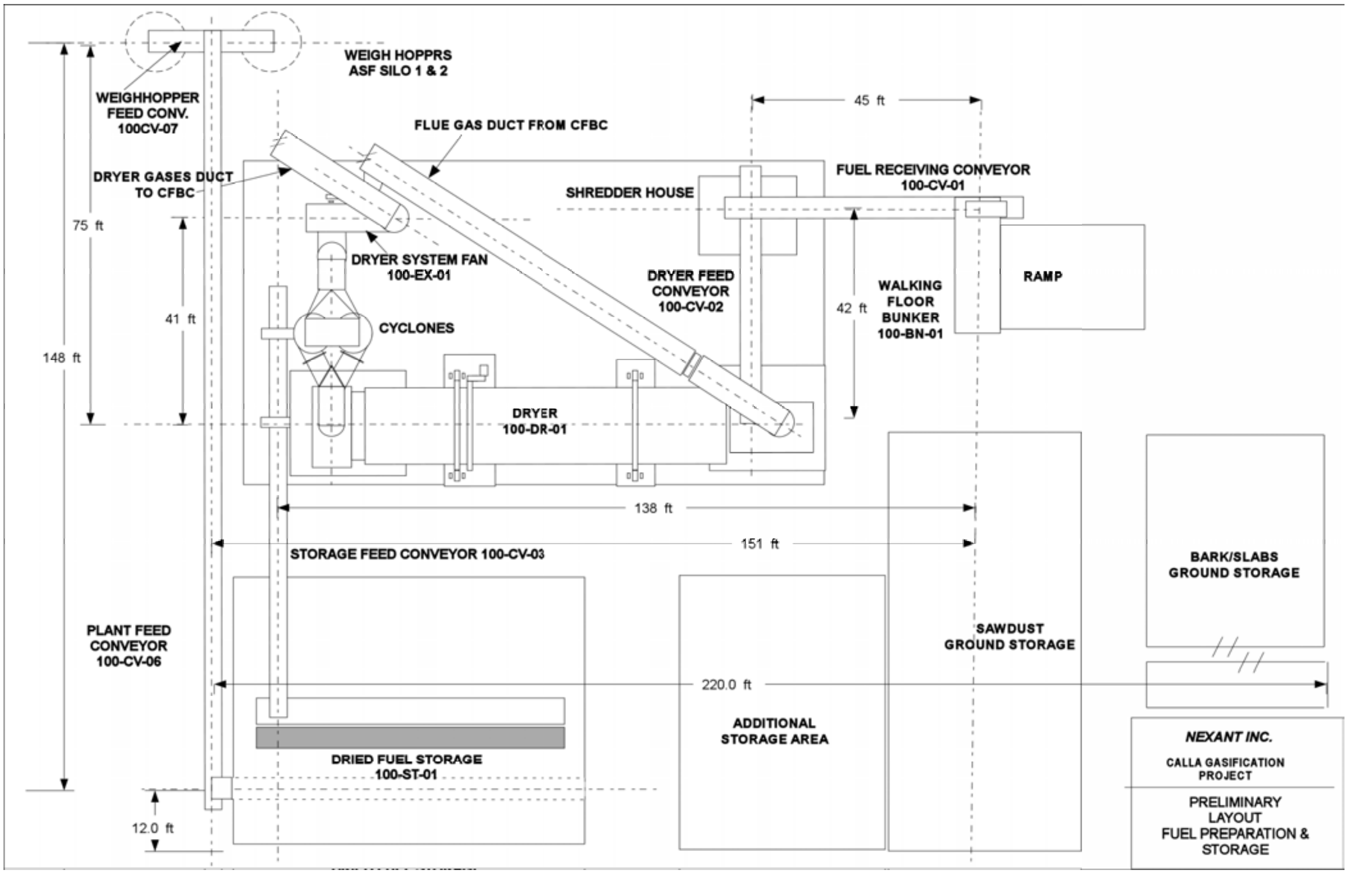


Figure 6. Fuel Preparation, Drying, and Storage Layout

Task 1.2. Process Simulation and Combustion System CFD Modeling

Combustion System

Early in the engineering evaluation of the project, Calla Energy reviewed the options associated with burning the LCV gas either in modified natural gas fired boilers, using GTI's FIR burner or in the coal-fired fluid bed boiler. The advantage of using the fluid bed boiler is that the gasification plant would not require desulfurization equipment if coal was used instead of biomass as a feedstock. Calla Energy has conducted preliminary discussions with B&W on providing a fluidized bed boiler for the Estill County project. B&W agreed that the concept was feasible, and GTI Proceeded on that basis.

Recent negotiations with B&W suggest that they may not warrantee a boiler if modified in the manner proposed, significantly increasing the risk of the project from a financial standpoint. Furthermore, they will not perform any engineering for this project until they have a firm equipment supply contract and the power purchase agreement is signed. This insures the viability of the project and allows them to concentrate their efforts on revenue guaranteed projects. For this reason, the design of the burners for the LCV to be used on a natural gas fired boiler was reconsidered.

GTI has also evaluated the use of their FIR burner to cofire the LCV fuel gas with natural gas in natural gas fired package boilers. This can be accomplished with emissions on a par with low-NOx combustion of natural gas. Detailed design of these burners will be completed once GTI receives detailed design information from Calla Energy on the natural gas fired boilers.

The Forced Internal Recirculation (FIR) burner concept as shown in Figure 7, was developed for low-NOx natural gas combustion without any degradation in boiler performance. The burner design combines two-stage combustion with premixed first stage gases and forced internal recirculation of products of partial combustion to reduce formation of "thermal NOx" as well as "prompt NOx." Secondary air enters the combustion chamber downstream of the primary combustion zone to complete combustion. Unlike conventional external flue gas recirculation, the FIR burner induces recirculation by harnessing the kinetic energy of a turbulent premixed jet. A recirculation insert is an integral part of the burner that provides recirculation of products of partial combustion to the root of the primary flame. Enhanced internal recirculation maximizes heat transfer to the process fluid surrounding the combustion space and lowers the flame temperature (both in the primary and the secondary combustion zones). The recirculation insert also radiates heat to the cold boiler walls and allows products of partial combustion to cool before flowing to the secondary combustion zone or back to the root of the primary zone flame.

FIR burners have been developed for firetube and package watertube boiler applications. When natural gas is fired, these burners have been shown to reduce NOx emissions from typical uncontrolled levels of 80-100 vppm to single-digit levels (9 vppm). This is done without the efficiency penalties incurred by alternative NOx control methods such as external flue gas recirculation and water injection. A 20 X 106 Btu/h FIR burner has been in continuous operation on an industrial watertube boiler in Monroe, Michigan since September 1997. More recently, a 2.5 X 106 Btu/h FIR burner has successfully met all its performance targets on a firetube boiler at Vandenberg Air Force Base in California, and has been in routine operation since May 1999. Finally, a 60 X 106 Btu/h burner has been in continuous operation on an industrial watertube boiler at a southern California brewery. These long-term demonstrations have helped to alleviate many concerns regarding burner reliability and deterioration of performance. GTI is continuing development of this burner for LCV applications.

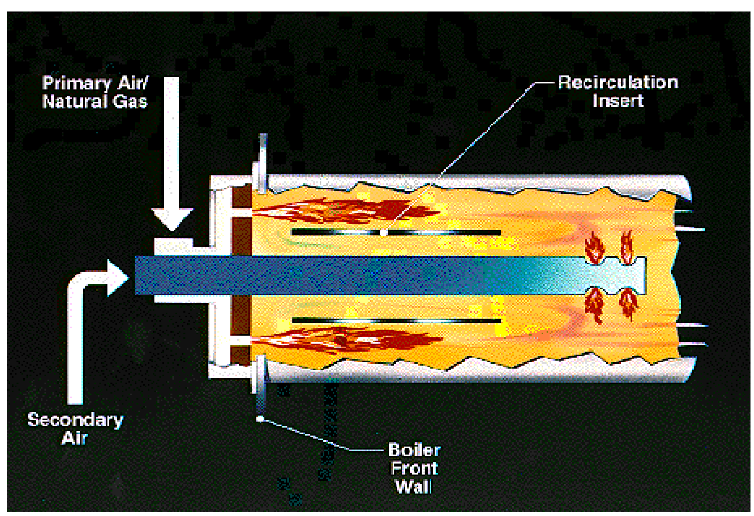


Figure 7. GTI's FIR Burner

Gasification System

The gasification system has been designed to operate at 29 psia. Figure 8 is a flow diagram of the gasification facility. A cyclone removes ash that is carried over from the gasifier. A gas cooler is provided to reduce the gas temperature to a level suitable for piping and control valves downstream. The gas is provided as a reburn fuel to the fluid-bed boiler.

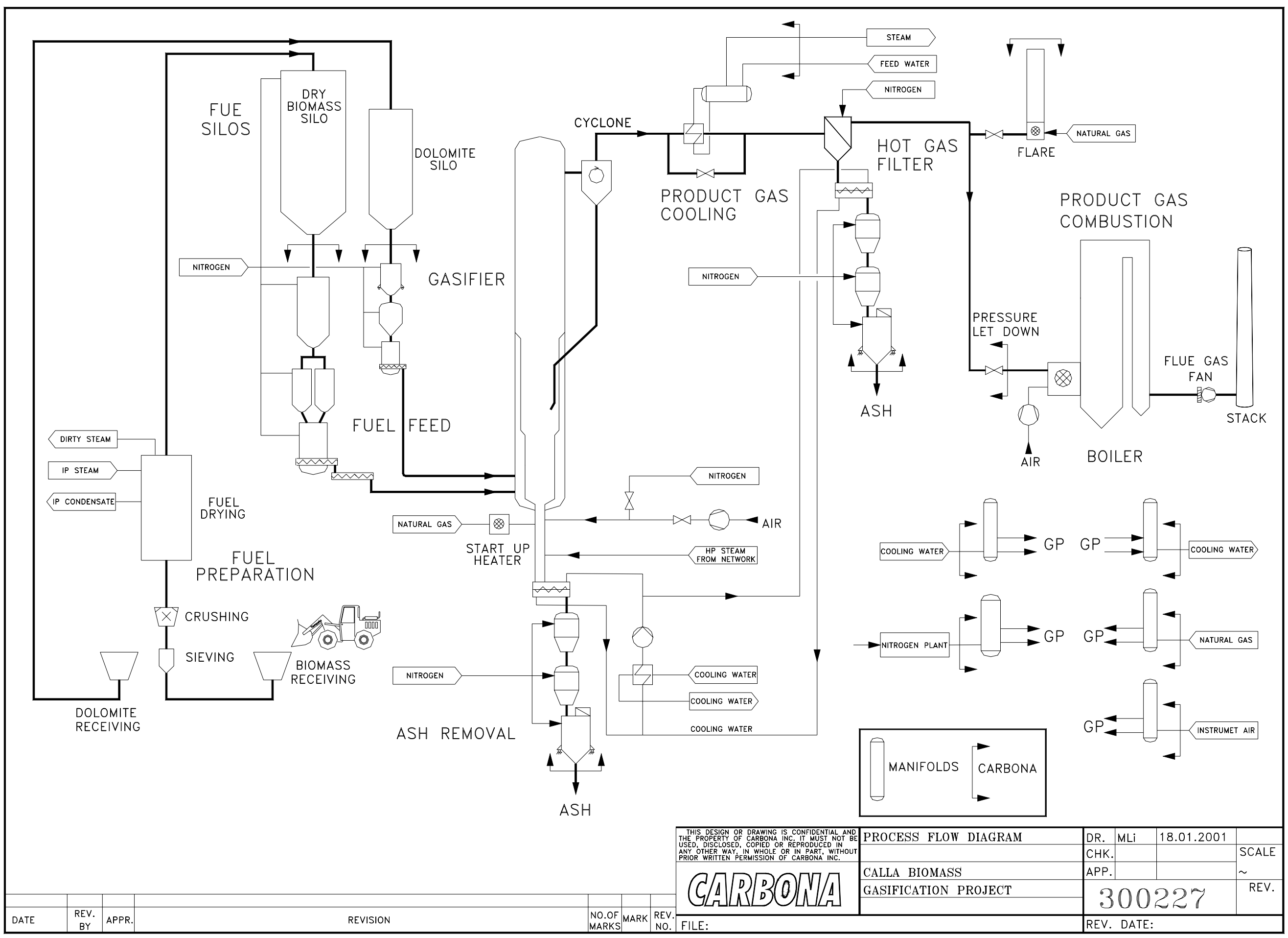


Figure 8. Flow Diagram of Gasification Facility.

The Gasifier is designed to operate with wood that is a moisture content of 20 percent. For the selected feedstocks: sawdust and wood/slabs, drying is required to reduce moisture to the desired level. Since coal is a fuel that is available on site, calculations of gasifier performance with 100 percent coal and a 50/50% mixture of coal and biomass were evaluated, Table 3. Gasifier output is reduced from the biomass gasification system when coal is cofired with the primary biomass fuel, Table 4. The quality of the gas for each case is presented in Table 5.

Table 3. Alternative Fuel Case Studies Fuel Input

Fuel:	Case 1	Case 2	Case 3	
hard wood	0	0	0	%w
saw dust	50	25	0	%w
slabs/bark	50	25	0	%w
product coal	0	50	100	%w
carbon	47.71	63.27	78.83	% dry basis
hydrogen	5.69	5.50	5.30	% dry basis
nitrogen	0.34	1.08	1.83	% dry basis
oxygen	40.29	23.77	7.24	% dry basis
sulfur	0.080	0.520	0.960	% dry basis
clorine	0.00	0.00	0.00	% dry basis
ash	5.90	5.87	5.85	% dry basis
moisture	20.00	13.81	7.62	% dry basis
Total	100.00	100.00	100.01	% dry basis
moisture (as fed)	20.0	13.8	7.6	% dry basis
HHV dry basis	8,309.95	11,224.93	14,139.91	Btu/lb
HHV (as fed)	6,647.96	9,674.77	13,062.45	Btu/lb

Table 4. Gasifier Performance

Gasifier:	Case 1	Case 2	Case 3	
Gasification pressure	29.01	29.01	29.01	psia
Gasification temperature	1,562.00	1,742.00	1,742.00	°F
Gasification air temperature	194.00	194.00	194.00	°F
Gasification steam temp.	572.00	572.00	572.00	°F
Gas temperature after cooler	554.00	554.00	554.00	°F
Heat input to boiler	160.37	160.37	160.37	MBtu/hr
Gasifier Performance				
Fuel input	14.9	7.1	4.7	Tons/hr
Fuel heat input (HHV, as fed)	198.1	136.9	122.9	MBtu/hr
Gas production	35.4	25.6	22.9	Tons/hr
Gas heat to boiler (HHV @290C)	168.2	114.8	103.4	MBtu/hr

Table 5. Gas Composition

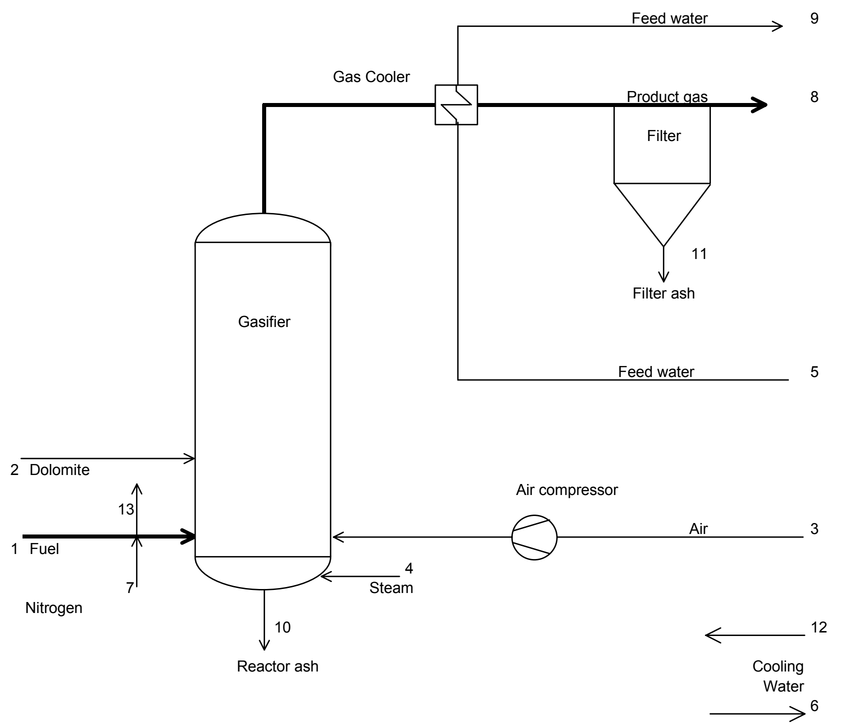
gas composition	Case 1	Case 2	Case 3	
CO	15.27	19.9	21.66	%-v
CO2	12.34	8.12	6.35	%-v
H2	14.77	13.48	14.2	%-v
H2O	13.89	8.66	6.56	%-v
CH4	2.62	1.86	1.52	%-v
N2	40.53	47.68	49.53	%-v
C6H6	1640	770	0	ppmv
C2H4	1474	700	0	ppmv
C2H6	0	0	0	ppmv
C7H8	0	0	0	ppmv
C10H8	510	240	0	ppmv
CxHy heavy tars	10	10	0	ppmv
H2S+COS	190	210	160	ppmv
NH3+HCN	2,000	1,220	1,630	ppmv
HCl	0	0	0	ppmv
tot	100.00	100.02	100.00	
gas dens,kg/m3	0.0684	0.0690	0.0682	lbs/cuft.
product gas heating value:				
HHV	144	140	138	BTU/cu.ft.
LHV	132	130	130	BTU/cu.ft.
HHV	2,100	2,030	2,040	BTU/lb.
LHV	1,930	1,890	1,900	BTU/lb
Cold gas efficiency	76.7	74.1	74.3	%

The flow diagram and material balance for the gasifier island is in Figure 9 depict the base case for operation of the plant with biomass as the primary feedstock.

Figure 9. Flow Diagram and Heat & Material Balance

CARBONA **GASIFICATION PLANT HEAT AND MATERIAL BALANCES**

Case 4: 100% biomass (Design Case)



Flow No.	Description	Temperature °F	Temperature °C	Pressure psia	Pressure bara	Mass flow lb/h	Mass flow kg/s	Energy MMBtu/h	Energy kJ/s
	IN								
1	fuel	59	15	15	1.0	29723	3.75	198.1	58055
2	limestone	59	15	15	1.0	183	0.02	0.0	0
3	air	59	15	15	1.0	41890	5.28	0.3	79
4	steam	572	300	435	30	0	0.00	0.0	0
5	feed water	320	160	1276	88	145796	18.37	42.6	12497
6	cooling water	77	25	73	5.0	11905	1.50	0.5	157
7	nitrogen	122	50	725	50	952	0.12	0.0	6
	electric power	-	-	-	-	-	-	2.7	800
	TOTAL IN					230449	29.04	244.3	71594
	OUT								
8	product gas	554	290	17	1.2	70858	8.93	168.2	49279
9	feed water	482	250	1262	87	145796	18.37	68.1	19946
10	reactor ash	482	250	15	1.0	968	0.12	0.4	113
11	filter ash	554	290	15	1.0	802	0.10	3.9	1148
12	cooling water	113	45	58	4.0	11905	1.50	1.0	283
13	nitrogen	122	50	15	1.0	119	0.02	0.0	1
	losses	-	-	-	-	-	-	2.8	824
	TOTAL OUT					230449	29.04	244.3	71594

NOTES:
- reference temperature 0 °C (+32 °F)
- water in liquid form at reference point (HHV basis)
- all calculation is done with SI-units, only results are converted to other units

Task 1.3. Conceptual Plant Design

Specifications for the gasifier island and other major cost components were developed and issued to manufactures and budget cost estimates were requested. The following is a list of the specific specifications issued for the project. Detailed specifications are ready for use to go out for bid during Phase II.

- Gasifier
- Fuel Feed
- Limestone Feed
- Gasifier Ash Removal
- Process Air
- Product Gas Ducting
- Product Gas Cooling
- Product Gas Filtering
- Filter Ash Removal
- Flare
- High Pressure Cooling Water
- Nitrogen Distribution
- Biomass Dryer Specification
- Biomass Feed Prep
- Inert Gas System
- Waste Heat Boiler
- Startup Gas Supply

The conceptual layout of the gasifier island was developed and is shown in Figures 10 and 11 to show the arrangement of the primary equipment. The primary equipment priced during the Techno-economic analysis, is shown in the Plant Equipment List, Table 6 A and B.

Table 6 A. Plant Equipment List

Equipment Number	Equipment Name
Biomass Preparation and Storage	
100-BN-01	Walking Floor Bunker
100-CR-01	Shredder
100-CV-01	Fuel Receiving Conveyor
100-CV-02	Drier Feed Conveyor
100-CV-03	Storage feed Conveyor
100-CV-04	Distributing Conveyor (in 100-CV-03)
100-CV-05	Reclaim Conveyor (in 100-CV-03)
100-CV-06	Plant Feed Conveyor
100-CV-07	Weigh Hopper Feed Conveyor
100-DR-01	Rotary Drier
100-EX-01	Drier Steam Fan (in 100-DR-01)
100-FE-01	Reclaim Auger A (in 100-DR-01)
100-FE-02	Reclaim Auger B (in 100-DR-01)
100-ST-01	Dried Fuel Storage

Table 6 B. Plant Equipment List

Gasification	
AHB-CNV1	Cooling Screw
AHB-LH1	Buffer Hopper
AHB-LH2	Lock Hopper
AHB-SILO1	Weigh Silo
DFS-SILO1	Weigh Silo
DFS-LH1	Lock Hopper
DFS-LH2	Surge Hopper
DFS-CNV1	Surge Hopper Metering Screw
DFS-EXHHDV1	Weigh Silo Top Bag filter
ASF-SILO1	Weigh Silo *
ASF-SILO2	Weigh Silo *
ASF-CNV7	Rotary Valve Feeding Screw
ASF-CNV8	Rotary Valve Feeding Screw
ASF-FDR2	Rotary Valve *
ASF-FDR5	Rotary Valve *
ASF-LH1	Surge Hopper
ASF-LH2	Surge Hopper
ASF-CNV3/6	Metering Screw
AFS-EXHHDV1	Weigh Silo Top Bag filter
AFS-EXHHDV2	Weigh Silo Top Bag filter
CGS-POX1	Gasifier System (incl CYC1+BURN1)
PAS-C1	Process Air Compressor
GCS-HXFT1	Product Gas Cooler (incl Spray)
AGS-STAK1	Flare (Incl. BURN1)
ACS-P1A/B	HP Cooling Water Pumps
ACS-E1	HP Cooling Water Cooler
ACS-TK1	HP Cooling Expansion Tank
N2-GEN	N_2 Gen incl. Air Compressor
N2-LPTK	LP Receiver Tank

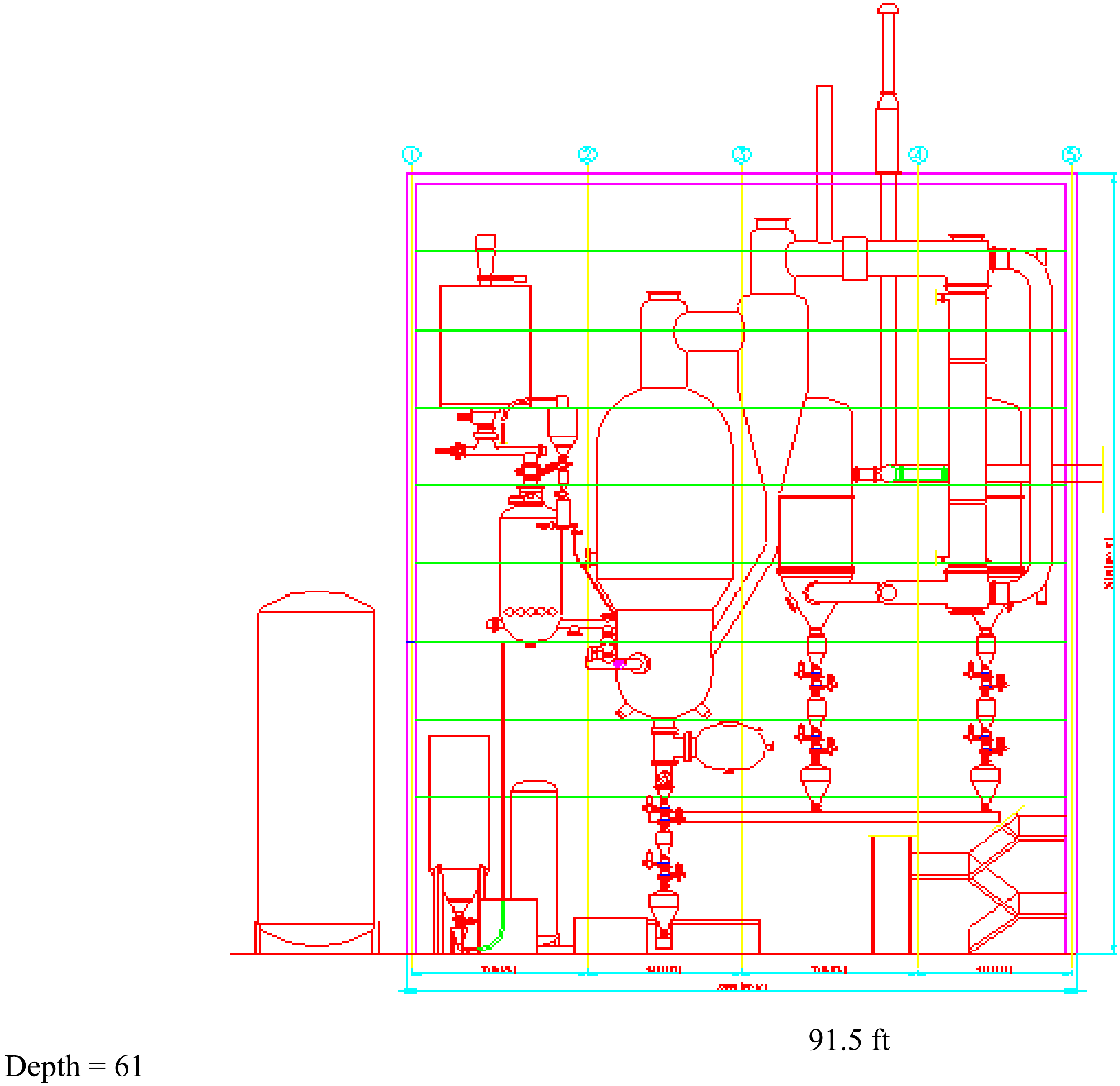
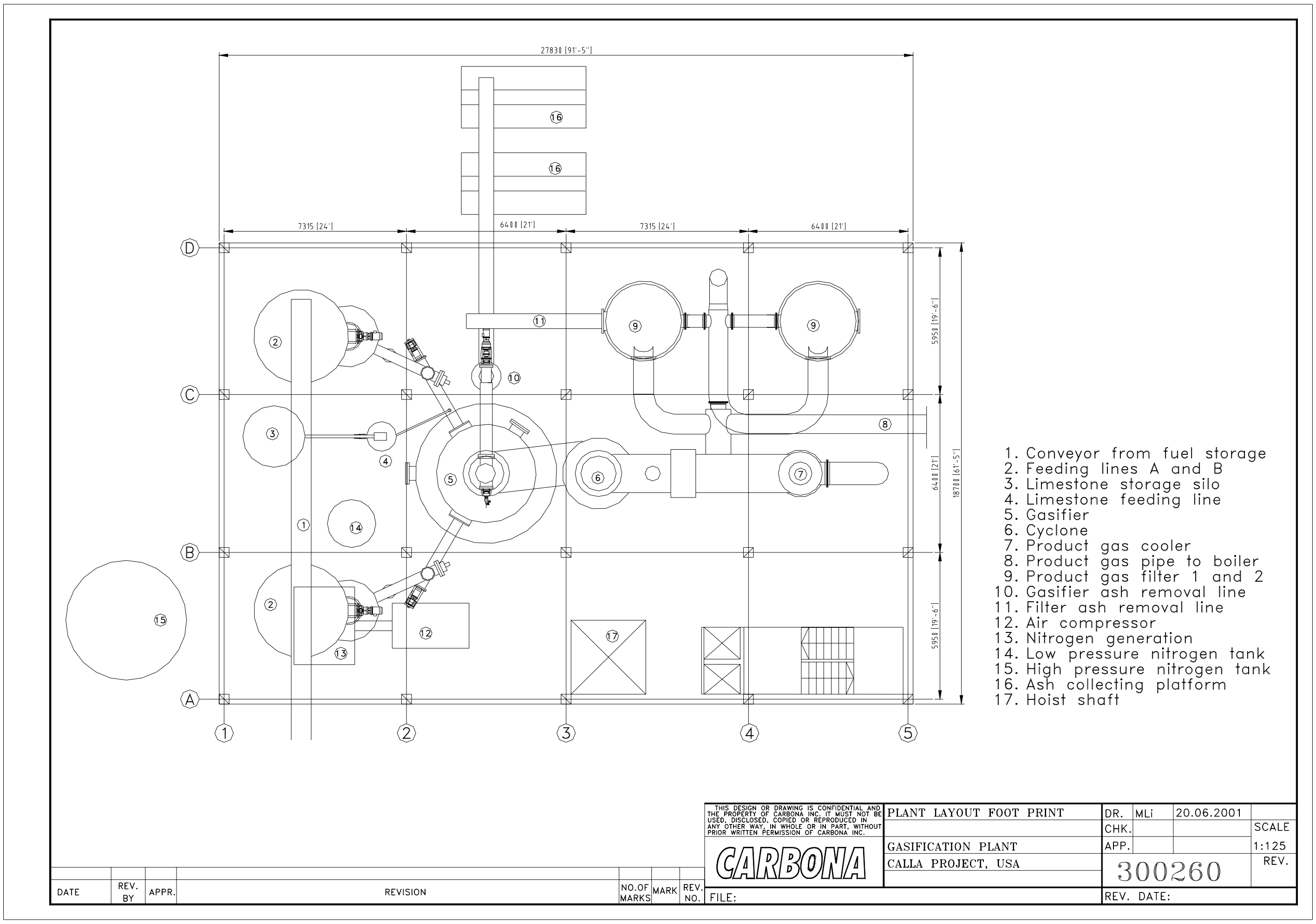


Figure 10. Gasifier Equipment Layout

Figure 11. Gasifier Island Equipment, Plan View



The equipment specifications and drawings developed during this contract are available to DOE in confidential form, if requested.

Task 1.4. Technoeconomic Analysis
Based on the specifications, budgetary quotations were received for major pieces of equipment. Once all quotations were received, a factored estimate of the installed plant costs was developed.

An economic assessment was performed for facilities that performed drying of the biomass feed material, as would be the case if wood chips, saw dust, etc. that had not been previously dried were planned as the primary fuel. A second estimate was prepared for a facility that was fed primarily with "dried" wood that did not require "pre-treatment" prior to gasification. Use of dried wood can reduce capital costs by 30% compared with "raw" wood. Examples of dried wood include used railroad ties, used utility poles and cross-arms, used pallets, wood waste from furniture manufacture, etc.

The cost analysis shows that the economic viability of a biomass facility for generation of a fuel gas is very dependent on the cost of the biomass and the comparable cost of competing fuels. Figure 12 shows the relationship fuel cost and product gas value that can be expected from a facility costing the same as the Estill County plant. From this figure, it can be observed that the value for gas from a facility such as this would be about $1.50/MMBtu where the cost of solid fuels to the facility are priced at zero. This is a very attractive price for clean fuel gas. Note that the costs shown do not reflect expected savings resulting from experience gained in the construction of this first plant.

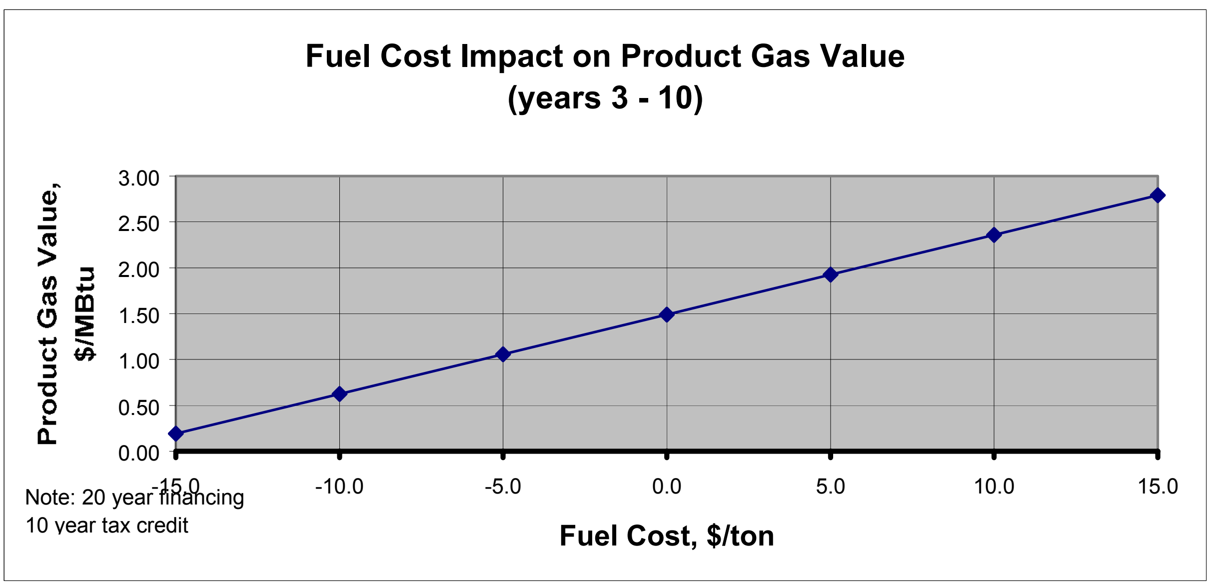


Figure 12. Relationship Between Fuel Cost and Product Gas Value

Task 1.5. Project Management – Phase I
GTI has continued to manage the work activities to keep the project on schedule.

GTI continues to maintain close contact with Calla Energy and their progress in developing the power plant at the Estill County Industrial Park. Currently Calla has received a draft permit with proposed emission levels that are acceptable to the State of Kentucky. In this permit, the State prefers that Calla only submit for the coal fired fluid bed boiler, which is the primary generation source for the project. They prefer that the biomass gasification plant be permitted separately as an amendment to the permit, once all funding is established. Calla is now working with two separate boiler vendors to develop detailed design data that will comply with Kentucky emission criteria established in the draft permits. They anticipate that all permits, air, water, land and siting, will be submitted by year end, or sooner. Calla is working with Kentucky Utilities to develop a cost estimate for an interconnection from the utility to the site. Financing for the project is favorable, and is awaiting issuance of final permits.

Calla remains interested in demonstrating biomass gasification in conjunction with the coal fired boiler, as developed in the Phase I cost study. They will explore means to proceed with this project once the initial coal boiler work has begun.

Task 1.6. Technology Conceptualization

GTI participated in several meetings and making contributions towards the development of U.S. DOE's draft Strategic Plan for Biomass Gasification. The final Biomass Program report was submitted by Antares to U.S.

Task 1.7 Gasification Characterizations of Selected Feedstocks

Subtask 1 – Identify Feedstocks
On August 29th, GTI conducted a status review meeting with Calla Energy and visited the project site in Irvine, KY. GTI collected biomass samples to be tested in the mini-bench unit from two saw-mills located within 3 miles of the site.

GTI also received two sources of pelletized biomass feedstocks that had very similar chemical properties to the saw-mill samples. One was received from Bush Industries, which manufactures furniture. They have factories in western Virginia and western New York. They manufacture fuel pellets and also have chip board waste from their factories for which they are looking for outlets.

The second sample came from Menard's lumber store in the Chicago area. They purchased fuel pellets that are sold at retail for use in wood stoves. GTI contacted the manufacturer of these pellets, Pennington Seeds located in Greenfield, MO. The company representative, Dan Pennington agreed to donate several bags of wood fuel pellets for testing. The wood fuel pellets are manufactured from the chip and saw dust waste of furniture manufacturing. The primary wood in the pellets is oak, with small amounts of other hardwoods mixed in. The wood pellet manufacturing facility is located in Kenbridge, VA.

The advantage of testing pellets is that they have superior handling characteristics compared to saw dust, particularly in a small-scale system. The wood pellets were analyzed and compared with the wood samples provided by sawmills in the Irvine, Kentucky, Table 7. The results showed that they were very similar except for lower moisture, which is preferred for gasification, and would eliminate the need to dry test materials.

Table 7. Chemical Properties of Feedstock

Component	Mill Saw Dust	Bush Ind. Chip Board Waste	Bush Ind. Wood Pellets	Menard's Wood Pellets
Proximate Analysis				
Moisture %	39.23	35.96	5.53	<0.05
Volatile Matter %	49.35 (81.2 d.b.)	53.21 (83.09 d.b.)	74.85 (79.23 d.b.)	80.61 d.b.
Ash %	0.39	0.27	0.73	0.46
Fixed Carbon %	11.03	10.56	18.89	18.93
Ultimate Analysis				
Ash %	0.63	0.71	0.82	0.44
Carbon %	49.51	48.90	48.65	47.84
Hydrogen %	5.88	6.04	6.03	6.14
Nitrogen %	0.11	3.02	3.75	0.10
Sulfur %	0.02	0.07	0.08	0.01
Oxygen %	43.85	41.27	40.66	45.47
BTU/lb.	8,440	8,480	8,540	8,060

d.b.- dry basis

Due to the low ash content of the biomass feedstocks an inert bed must be added to the gasifier reactor. The alumina beads provide an inert bed material for heat transfer in the fluid bed. There are several choices for bed materials and each has its advantages and drawbacks. Often times dolomite or limestone is used because it will aid in the cracking of tars and oils to lighter hydrocarbons. The disadvantage of dolomite is attrition; the material will begin to disintegrate. For the setup of the mini-bench unit, this attrition would quickly plug the filter and result in excessive downtime. In previous experiments with biomass gasification GTI has used alumina proppants to act as bed material. The proppants are used in the oil recovery industry to fill voids and to support the voids created by the extraction of oil. The proppants make an excellent bed material due to the uniformity of size and the toughness of the material. What is lost with the use of alumina is that it does not have the cracking properties of the dolomite.

GTI contacted Carbo Ceramics Inc. McIntyre Operations in McIntyre, GA about obtaining some material to use in the gasification tests. The previous gasification tests used alumina in the –40+70 mesh range. The proppant obtained from Carbo Ceramics was an alumina material in the –30+60 mesh range. The sieve distribution put the material at 80.9% 40 mesh, 18.6% 50 mesh and 0.5% at 60 mesh. Carbo Ceramics supplied roughly 125 pounds of material to GTI. This allowed new bed material to be used in each run.

Subtask 2 – Assemble Mini-Bench Gasifier

GTI conducted an equipment inventory of existing hardware available for construction of the “mini-bench” facility. Based on the inventory, supplemental equipment needed for completion of the test unit was purchased.

GTI developed a material and energy balance based on the Calla Energy Phase I design for the operation of the mini-bench facility. The mini-bench system installed is capable of testing to a maximum pressure of 75 psia. This was sufficient for the purposes of validating the Calla Energy design basis.

Preliminary Process Flow Diagrams (PFDs) and Process and Instrument Diagrams (P&IDs) of the Mini-Bench unit were prepared. A copy of the PFD for the mini-bench facility is shown in Figure 13. Figure 14 is a picture of the mini-bench unit prior to complete assembly for testing.

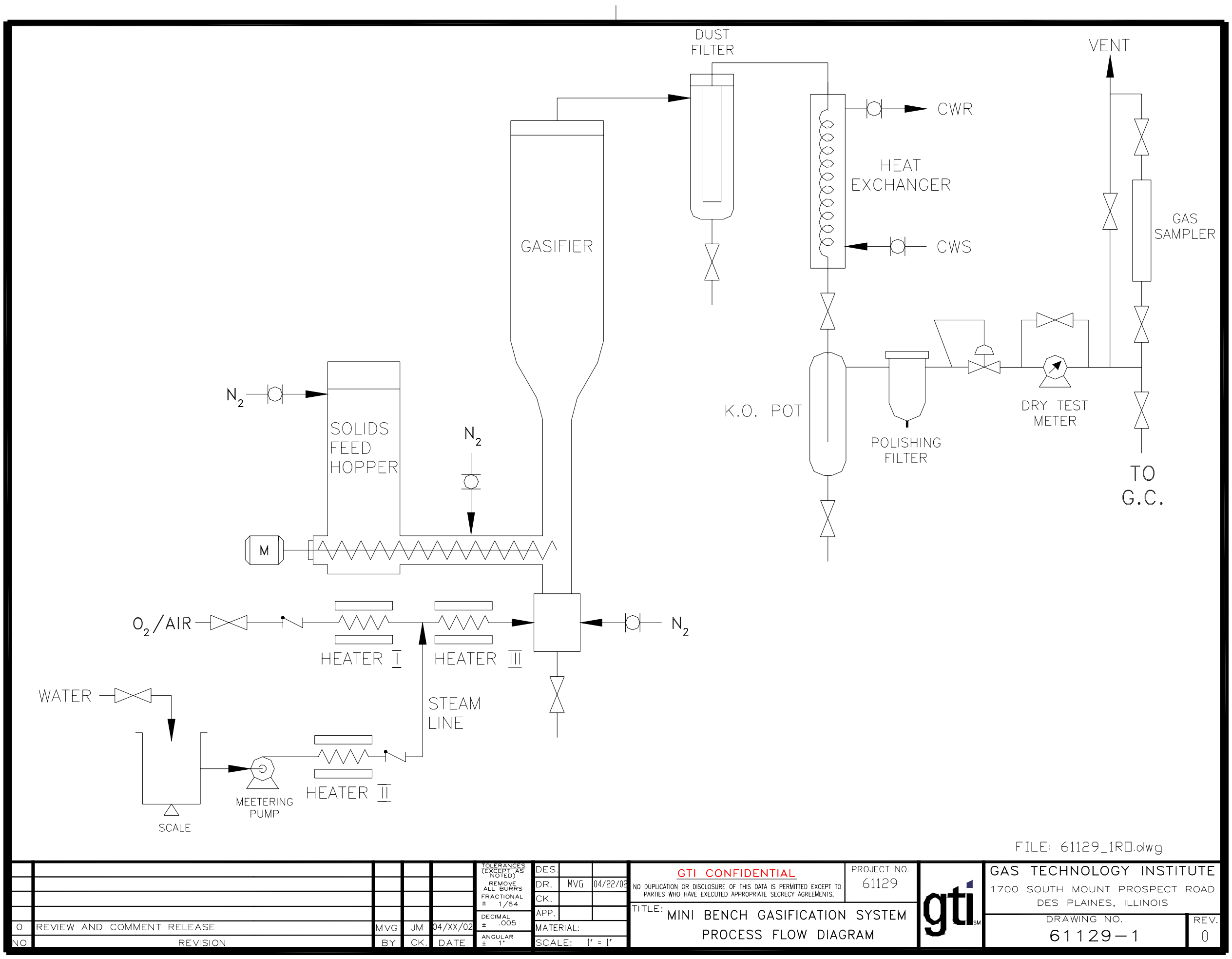


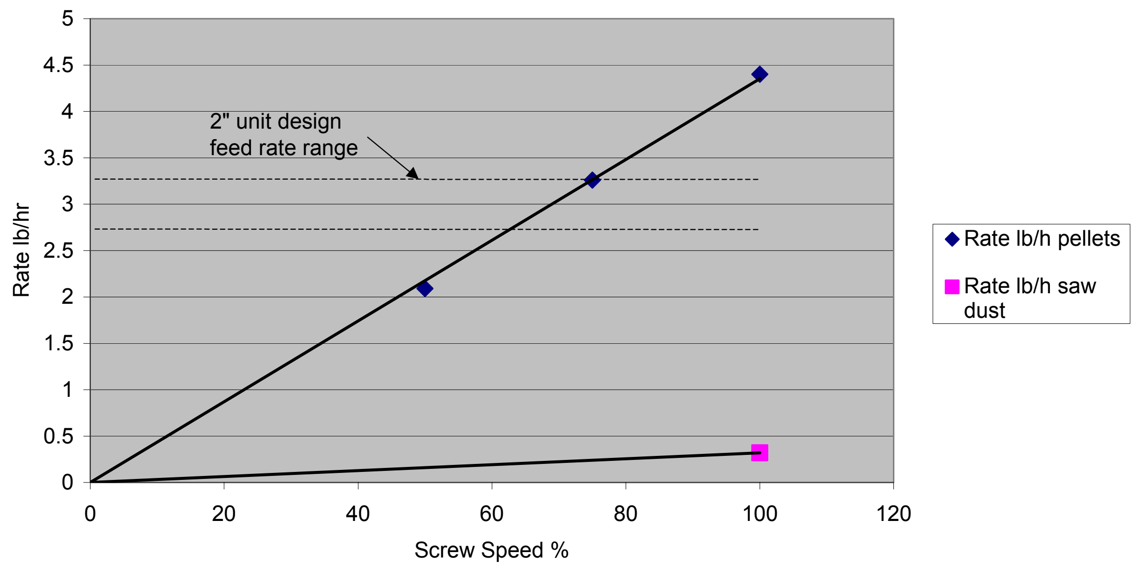
Figure 13. Mini-Bench Gasification System – Process Flow Diagram

Figure 14. Mini-Bench Gasification Hardware

As part of the "shakedown process" initial tests were conducted using each of the biomass samples available in a "cold" state to calibrate feed systems and ensure the operability of all the equipment.

Early cold tests were performed with a variety of material to determine the ability of the feed system (originally designed for coal) to handle saw dust and other raw products. These materials could not be fed reliably into the gasifier with the existing feed system. A maximum feed rate of only 0.3 lb per hour was achieved, Figure 15. This is due to the small-scale of the test unit, which poses some restrictions on the types of material that can be tested and the conditions under which the tests can be run. GTI determined that only pelletized biomass material would reliably be fed to the system properly. A feed rate of up to 4.5 lb per hour was demonstrated with pellet feeding.

Figure 15. Feed System Calibration Test Results



Following the cold testing, several proving test runs were made with coconut charcoal to test the system at operating temperature and pressure conditions consistent with the Calla design. The coconut charcoal is used because of its ready ability to be gasified, and its low tar/oil content. GTI has used this method to establish base line data that is comparable with past test operations. A few minor mechanical and electrical problems were discovered and fixed.

Subtask 3 – Test Feedstocks in Mini-Bench Gasifier

Preliminary data from two of the 2" unit test runs is contained in the Table 8 (moisture free basis). A complete listing of test data from the material and energy balance calculations is in Table 11. The test data was compared to gas compositions predicted using the GTI U-GAS® model, data summarized in Table 12.

Table 8. Test Run Raw Data

Test No.	WP-041703	WP-020403
Component	Measured Mol% mf basis	Measured Mol% mf basis
Hydrogen	13.7%	13.7%
Carbon Monoxide	11.6%	11.4%
Carbon Dioxide	17.8%	17.3%
Nitrogen	50.4%	52.4%
Methane	4.57%	3.35%
Others (Argon, higher hydrocarbons)	1.93%	1.85%
H2S (other sulfur compounds)	161 ppm	not analyzed

GTI established a test protocol for pressure and temperature that would simulate the design of the Calla Energy commercial-scale plant. This was used to establish the test matrix around a nominal 15 psig operating pressure and a design temperature of 1562 ^{o}F (850 ^{o}C). The test unit was operated within a window of test temperatures for model verification. Due to the small size of the unit the reactor, a temperature drift ±10 degree Fahrenheit is typical. Gasifier air feed rate is adjusted to keep the temperature at the test value.

The planned test matrix for the feedstocks over a variety of conditions is outlined in Table 9, below.

Table 9. Planned Test Matrix Overview

Condition	Carbona Design	Minimum	Maximum
Temperature	1562 F	1450	1650
Pressure	15 psig	12 psig	25 psig
Steam: Carbon	0.35 mole: mole	0.2	0.6

Test Procedure

For each test run inert material – alumina beads - was loaded into the gasifier. Then the feed hopper was filled with a measured amount of startup material, primarily charcoal. The unit was preheated using hot nitrogen to heat the bed and reactor. When the reactor reached a set temperature, the feed material and air were fed to the reactor. Charcoal was burned as a startup material to bring the gasifier up to reaction temperature. The alumina beads provide an inert bed material for heat transfer in the fluid bed.

Once near gasification temperature the feed hopper was opened and the full batch of pelletized biomass feed was charged to the feed hopper. Approximately 6 pounds of material was loaded in the hopper for each test. The conditions of the run were established by adjusting the fuel feed rate, steam rate, and airflow to meet the gasifier test temperature. The reactor was then allowed to reach a steady state. This usually took about 30 minutes before the reactor temperature would become steady. During steady state, the feed rates and reactor temperature did not fluctuate significantly.

Once the feed rates, product gas rates, and temperature were deemed steady, the product gas was sampled. Reactor conditions of temperature, pressure, and flow rates were continuously monitored by the data acquisition system and manually recorded every ten minutes. Another gas sample was taken before the end of the steady state period. The steady state testing was conducted for periods of up to 1 hour.

To shut the Mini-Bench unit down, fuel feed was stopped and the air was replaced with nitrogen. The unit was allowed to cool under a nitrogen atmosphere to stop all of the gasification and combustion reactions. The next day the unit was cleaned, all of the bed material was removed, and samples were taken to the lab and the unit prepared for the next run.

Twenty-nine test runs were conducted in this program beginning in December 2002. The first seven runs were performed as shakedown runs to prove the system and to allow the operators to gain experience with the equipment. This was conducted in January and February of 2003. Of the remaining 17 runs 9 were chosen for modeling comparisons. These runs were chosen on the basis of overall mass balance closure requiring little adjustment.

Each test collected an array of test data for each key data location. The data was logged as described above and analyzed to develop the material and energy balances. A typical material and energy balances for a test run is included in Appendix D. A typical sample of a steady state period data is included in Table 10. This table indicates how conditions were maintained at steady conditions. Figures 16 – 21 show steady state data collected for three of the test periods to indicate the relative stability of test data comprising each test. Temperatures during a steady state period were maintained within ± 10 ^oF. Air flow was used to control temperature for each test period. The pressure in the gasifier tends to fluctuate or increase during the test as the filter accumulates solids.

The pressure in the gasifier tends to build during a test period due to particulate accumulation on the dust filter.

Table 10. Typical Raw Test Data (from steady state period)

Time	air	nitrogen	steam	Reactor Temperature (^oF)					Pressure	Product Flow	
	SLM	SLM	grams/min	1	2	3	4	5	psig	CFM	
15:50	28	2.4		1453	1458	1452	1450	1446	24	1.9	
16:00	28	2.2	6.1	1453	1455	1449	1450	1444	24.6	1.8	sampled
16:10	28	2.3	6.1	1450	1454	1449	1446	1443	25.4	1.8	
16:20	28	2.2	6.1	1450	1454	1448	1445	1441	26.6	1.8	
16:30	28	2.3	6.1	1448	1451	1448	1445	1442	25	1.8	
16:40	28.5	2.4	6.1	1454	1458	1456	1451	1448	25.8	1.8	sampled
16:50	28	2.4	6.2	1453	1457	1451	1448	1446	24.4	1.8	
17:00	28	2.4	6.1	1448	1449	1446	1445	1442	25.5		

Figure 16. Process Data From Test Period 4/15/03

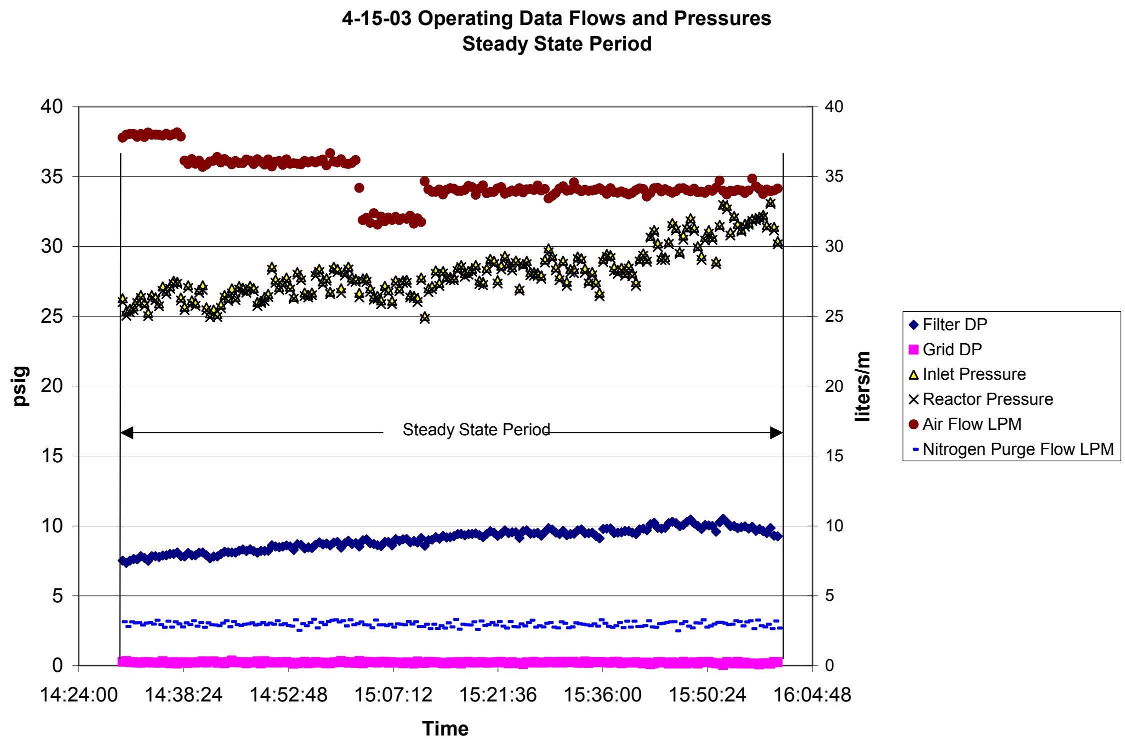


Figure 17. Temperature Data From Test Period 4/15/03

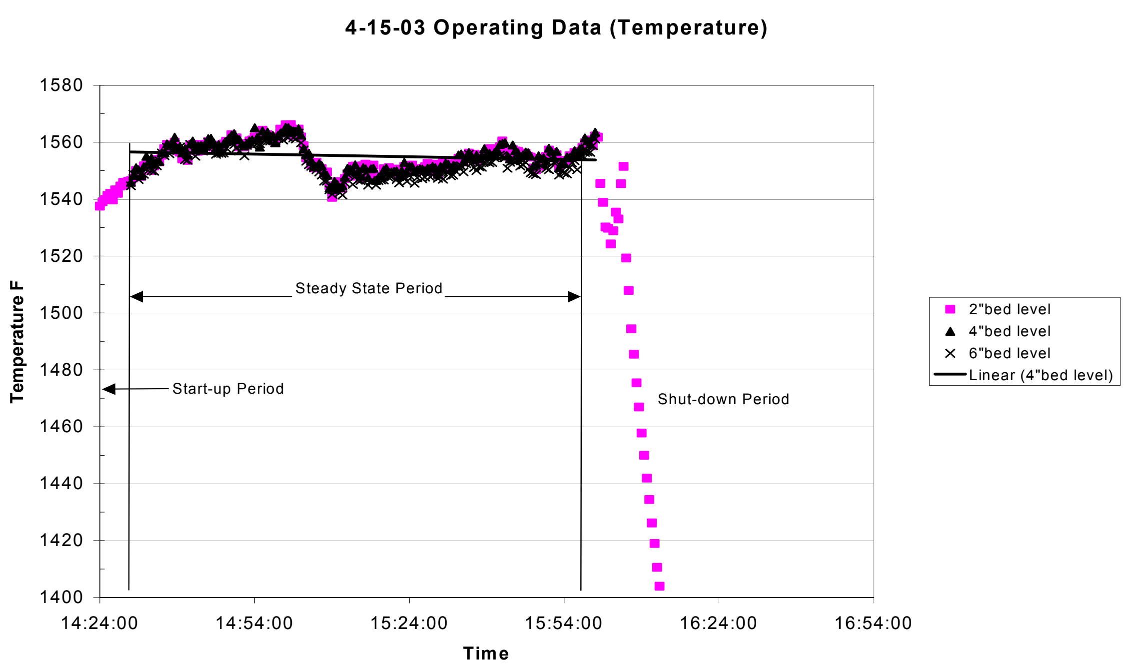


Figure 18. Process Data From Test Period 6/26/03

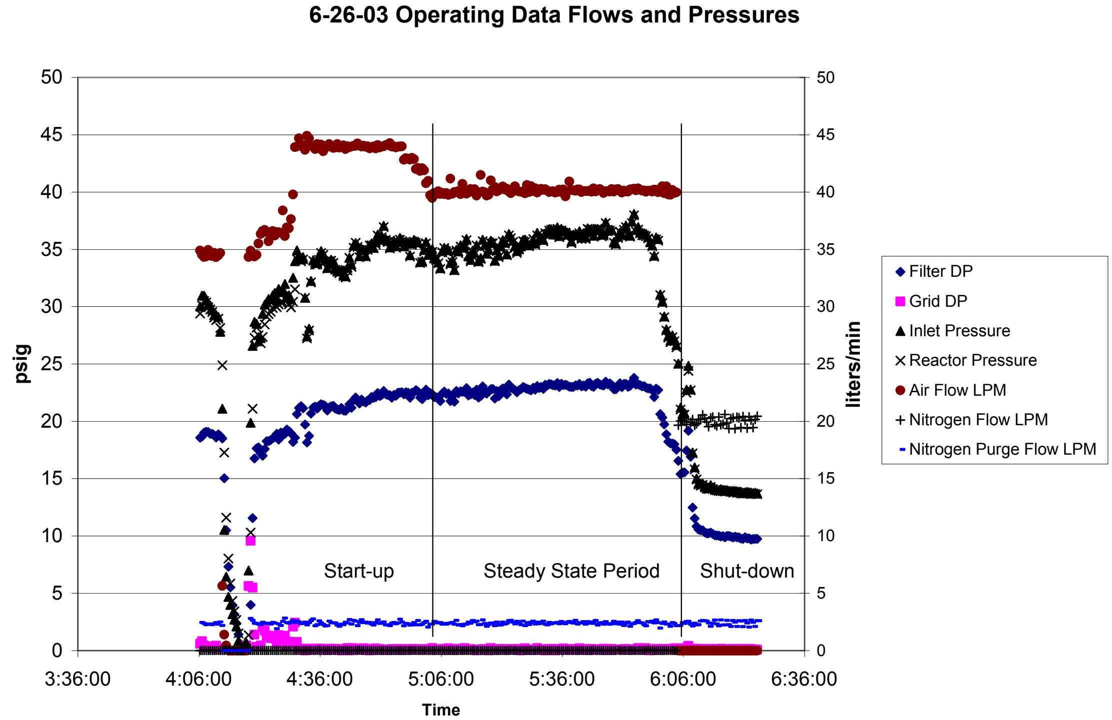


Figure 19. Temperature Data From Test Period 6/26/03

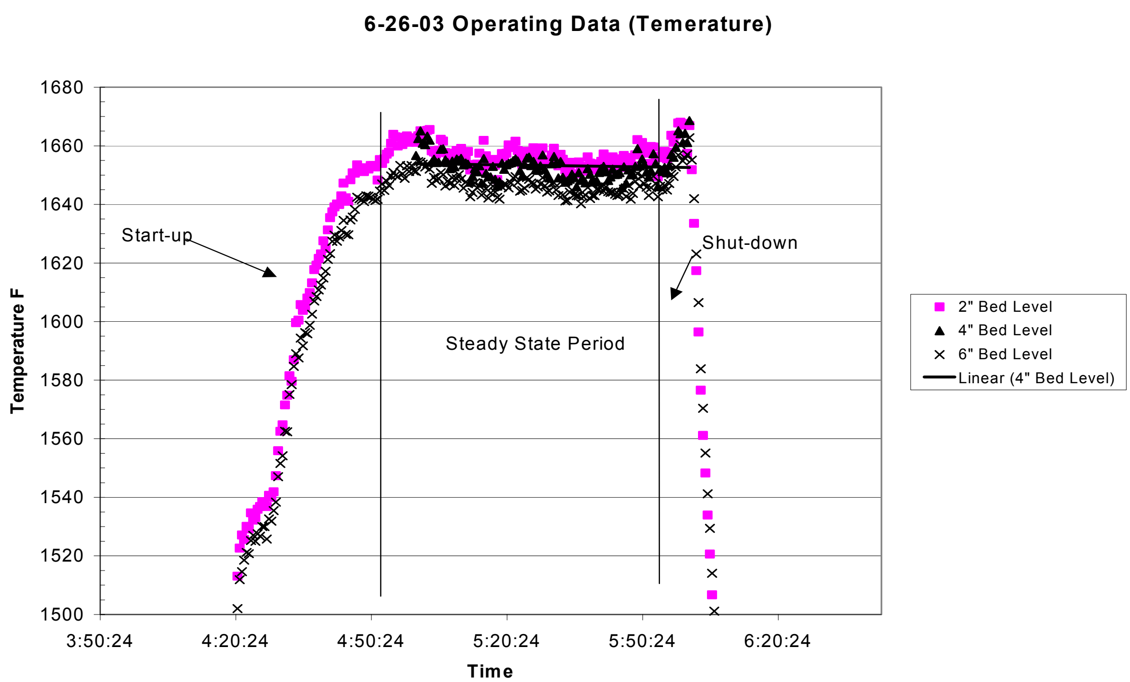


Figure 20. Process Data From Test Period 6/30/03

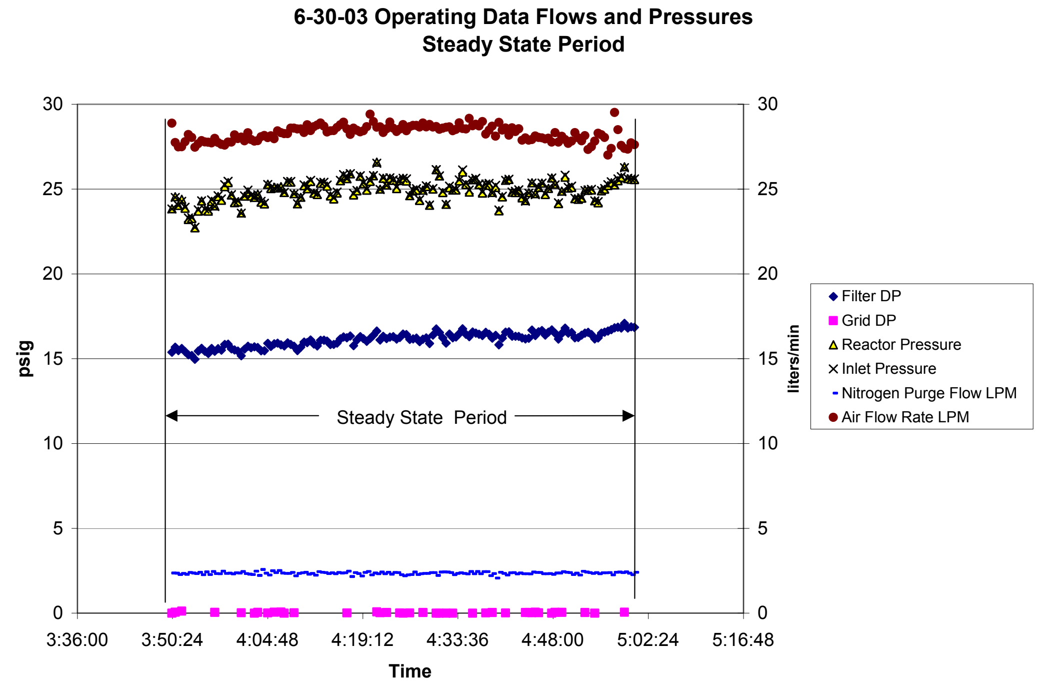
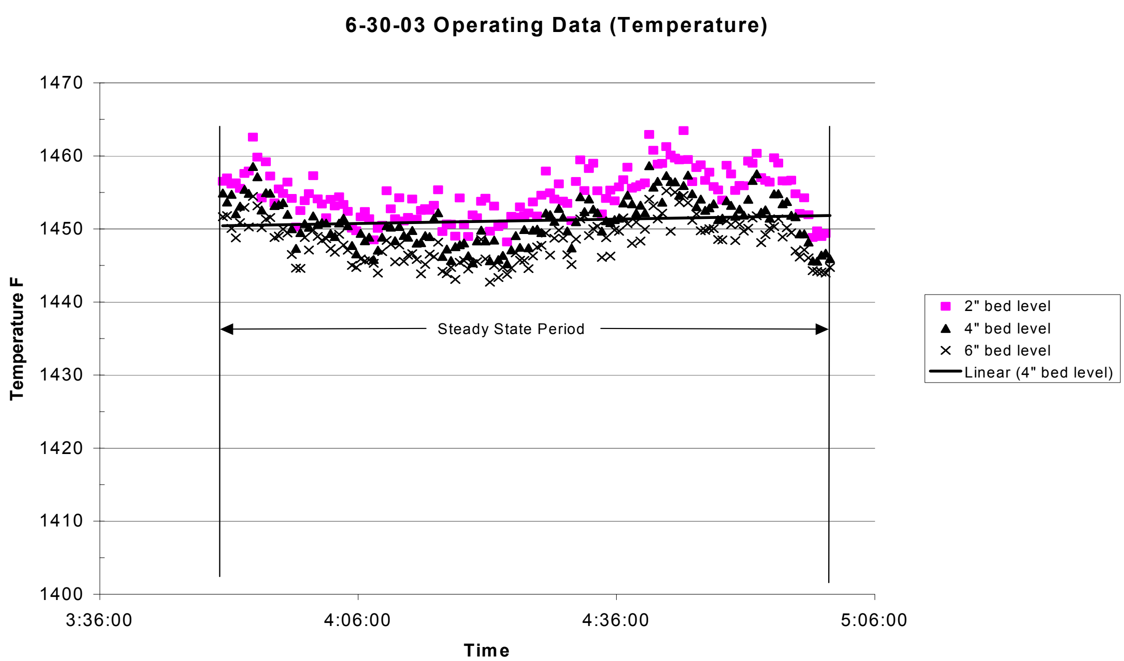


Figure 21. Temperature Data From Test Period 6/30/03



Grab samples were collected at the beginning and end of the steady state period and taken to GTI's laboratory for detailed analysis of the gas stream. Table 11, summarizes the material and energy balance developed for test runs with sufficient data for characterization. These tables list the input and output mass collected during each test (corrected as necessary), the gasifier temperature and pressure conditions for the test, the gas composition measured during the test and provides key parameters used to evaluate test data. This includes the gas yield on a scf/lb biomass feed basis and heavy hydrocarbon production values on a weight % of biomass feed basis.

Table 11. Material & Energy Balance for Selected Test Runs

Run #	15	22	23	24	25	26	27	28	29
Feedstock	Menards	Bush	Bush	Bush	Menards	Bush	Menards	Menards	Menards
Pressure, psig	26	17	13	25	27	25	30	36	26
Temp ^{o}F	1550	1550	1550	1550	1650	1450	1550	1650	1450
Input, lbs									
Biomass	2.87	2.41	2.75	3.58	2.94	2.73	3.44	3.65	3.05
Moisture	0.00	0.19	0.19	0.25	0.20	0.19	0.00	0.00	0.00
Steam	0.94	0.83	0.82	0.78	0.80	0.82	0.82	0.84	0.81
Air	6.06	7.59	7.85	7.42	6.40	5.37	6.65	7.25	5.54
Nitrogen (purge)	0.66	0.20	0.17	0.50	0.21	0.47	0.35	0.40	0.12
C	1.373	1.172	1.338	1.742	1.430	1.328	1.646	1.746	1.459
H	0.281	0.258	0.279	0.330	0.289	0.276	0.303	0.318	0.277
O	3.555	3.656	3.851	4.098	3.582	3.257	3.850	4.103	3.401
N	5.315	6.119	6.295	6.329	5.238	4.700	5.460	5.968	4.385
S	0.000	0.002	0.002	0.003	0.002	0.002	0.000	0.000	0.000
Ash	0.013	0.020	0.023	0.029	0.024	0.022	0.015	0.016	0.013
Total Input	10.54	11.23	11.79	12.53	10.57	9.59	11.27	12.15	9.54
Btu	26,411	24,180	27,159	34,045	24,867	26,197	31,023	26,656	27,508
Output, lbs									
Solids	0.032	0.049	0.056	0.073	0.049	0.062	0.055	0.059	0.034
Oils/Tars	0.015	0.036	0.041	0.054	0.013	0.029	0.055	0.055	0.062
Condensate	1.23	1.54	1.54	1.38	1.21	1.44	1.46	1.45	1.14
Total Gas	9.28	9.61	9.61	10.45	9.16	8.06	9.71	10.60	8.28
Total Output	10.56	11.24	11.69	11.96	10.56	9.59	11.28	12.16	9.52
C	1.375	1.172	1.342	1.734	1.433	1.331	1.647	1.749	1.462
H	0.280	0.260	0.281	0.329	0.288	0.276	0.303	0.317	0.278
O	3.565	3.668	3.849	4.099	3.584	3.248	3.852	4.099	3.396
N	5.319	6.117	6.186	5.768	5.234	4.702	5.468	5.981	4.451
S	0.002	0.001	0.001	0.000	0.002	0.001	0.000	-	0.000
Ash	0.013	0.020	0.023	0.029	0.024	0.022	0.015	0.016	0.013
Btu	30,019	23,304	32,752	34,890	29,792	26,967	31,794	34,519	27,390
C_6H_6+, wt	0.034	0.022	0.028	0.038	0.039	0.039	0.059	0.065	0.047
Oils/Tars, wt% Feed				1.50%	0.45%	1.07%	1.60%	1.50%	2.04%
C_6H_6+, wt% Feed	1.19%	0.93%	1.02%	1.06%	1.31%	1.41%	1.72%	1.79%	1.55%
Sum O,T, C_6+ wt%	1.71%	2.43%	2.52%	2.56%	1.76%	2.48%	3.32%	3.29%	3.59%
Gas scf/lb Feed	43	51	47	39	42	39	36	38	36
Carbon Conversion	98.62%	97.52%	97.53%	97.47%	98.25%	96.98%	97.57%	97.54%	98.56%
Gas Comp, Vol%									
H_2	11.95%	8.40%	8.60%	12.35%	12.25%	10.00%	7.00%	8.10%	11.15%
CO	10.11%	7.02%	8.22%	12.40%	10.49%	9.60%	12.50%	12.00%	10.60%
CO_2	17.00%	17.05%	16.90%	16.65%	17.65%	18.20%	16.20%	16.40%	18.85%

Run #	15	22	23	24	25	26	27	28	29
CH_4	3.59%	1.68%	2.42%	3.55%	3.52%	3.74%	4.52%	4.57%	4.54%
C_2H_4	0.46%	0.36%	0.65%	0.61%	0.60%	0.92%	1.30%	0.92%	1.12%
C_2H_6	0.11%	0.04%	0.06%	0.36%	0.07%	0.21%	0.16%	0.11%	0.23%
C_3H_8	0.02%	0.02%	0.02%	0.02%	0.01%	0.12%	0.03%	0.01%	0.12%
C_6H_6 plus	0.13%	0.08%	0.10%	0.13%	0.15%	0.17%	0.22%	0.22%	0.20%
N_2	55.45%	64.05%	61.70%	53.15%	54.25%	56.15%	56.50%	56.20%	51.90%
Ar & O_2	0.45%	0.47%	0.61%	0.31%	0.28%	0.08%	0.65%	0.70%	0.51%
H_2S	0.0154%	0.0117%	0.0112%	0.0133%	0.0151%	0.0101%	0.0023%	0.0018%	0.0024%
COS	0.0009%	0.0009%	0.0013%	0.0012%	0.0013%	0.0010%			
N_2 & Ar Free Basis									
H_2	27.1%	23.7%	22.8%	26.5%	26.9%	22.8%	16.3%	18.8%	23.4%
CO	22.9%	19.8%	21.8%	26.6%	23.1%	21.9%	29.2%	27.8%	22.3%
CO_2	38.6%	48.1%	44.8%	35.8%	38.8%	41.6%	37.8%	38.1%	39.6%
CH_4	8.1%	4.7%	6.4%	7.6%	7.7%	8.5%	10.5%	10.6%	9.5%

Carbon Conversion. The carbon conversion is defined here as the amount of carbon leaving the reactor as gas or liquids divided by the carbon fed to the reactor. The Calla design does not contain equipment that will condense any of the heavier hydrocarbons or water vapor. These components will contribute to the heating value of the gas stream. The carbon conversions ranged from 96.98% to 98.62%. This conversion is typical of biomass systems.

Mass Balance. Table 11 shows a typical material balance based on individual components (C, H, O, N, S, ash). The inlet stream consists of biomass, steam, air and purge nitrogen. The outlet stream consists of ash collected off of the filter, oils and tars collected, steam condensed, and gaseous components. The steady state values in lbs/hr for these components are reported in the table. Outlet gas flow rate is measured by a "dry air meter," which is calibrated with more than 99.9% accuracy. The ideal gas law was used to calculate the flow rate of outlet gas in lbs/hr. The mass rate of gaseous components was then calculated from lab GC analysis of the collected gas samples.

In order to close the overall mass balance for each component, an adjustment is made to the flow rates for some of the experimentally measured parameters. These include: inlet biomass feed rate, inlet air and purge-nitrogen flow rates, and outlet steam condensate rate. The procedure used to close the component mass balance is given below:

(1) Adjust the biomass feed rate closed carbon balance. It was found that small variation in biomass feed rate occurs over time due to problems in the biomass feeder.
(2) Next, adjust the amount of steam condensed at the outlet to close the hydrogen balance. It was observed that a significant amount of water escapes the knockout condenser during some experiments.
(3) Oxygen balance is closed next by adjusting the inlet air flow rate.
(4) Finally, adjusting the inlet purge nitrogen rate closed nitrogen component balance.
(5) The amount of ash in the outlet solids is assumed to be equal to that in the incoming biomass.

(6) Sulfur was not balanced, since it is not a major component in the gas and was not a primary factor for this study.

The mass balances must be closed for the purposes of modeling. The model takes the inputs of biomass composition and feed rate, steam flow, and the operating conditions of temperatures and pressures and calculates the needed oxygen and the gas composition and yield. If the mass balance is not closed, the model predictions can not be used to compare against the experimental yields.

Yield Data. The production of syngas is effected by temperature and pressure. With increasing pressure and temperature, an increase in throughput is possible. This is shown in the next three graphs. Figure 22 shows how the biomass feed rate increases with corresponding increases in pressure.

Examining the normalized gas production rate, scf of product gas per pound of biomass feed, there is not much influence of pressure (temperature constant) on the gas production over the range studied, Figure 23.

Temperature does increase gas production, at constant pressure. This is a result of the cracking of heavier hydrocarbons and the increase in methane production, Figure 24. The correlation is better when viewed on a nitrogen free basis, Figure 25. This is expected and the relative increase is close to what would be expected as shown in the modeling correlation Figure 32, 35.

Figure 22. Correlation of Biomass Feed with Pressure (Temperature = 1550 ^{o}F)

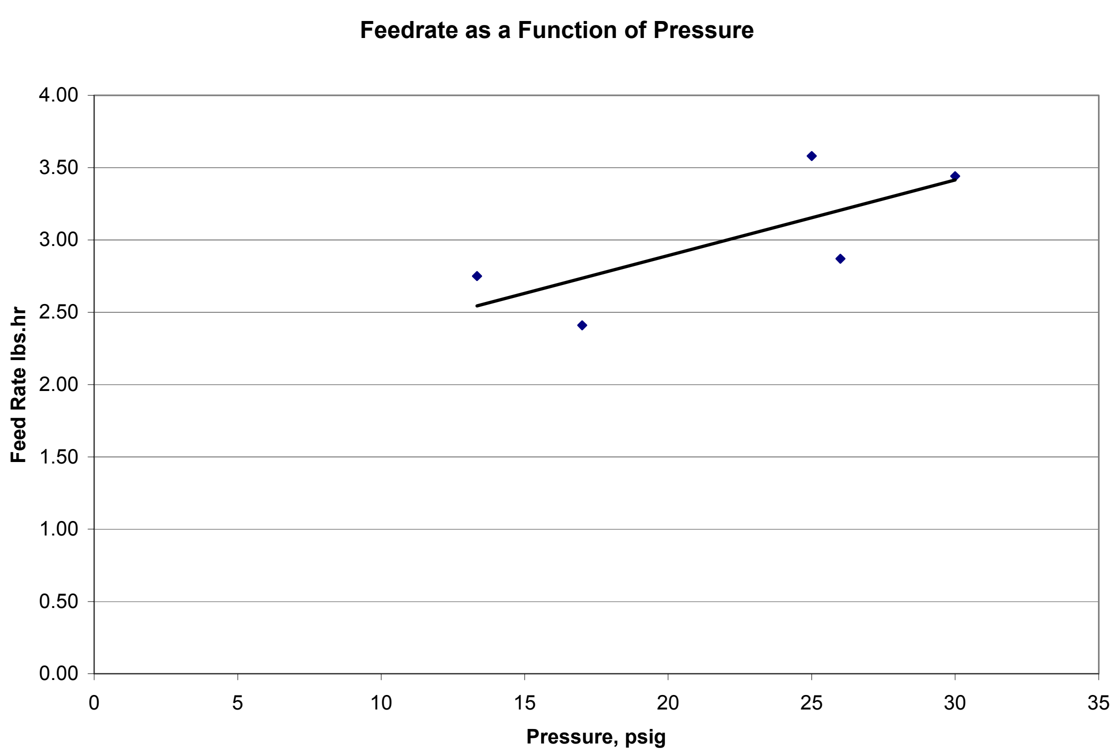


Figure 23. Correlation of Gas Yield with Pressure (Temperature Constant)

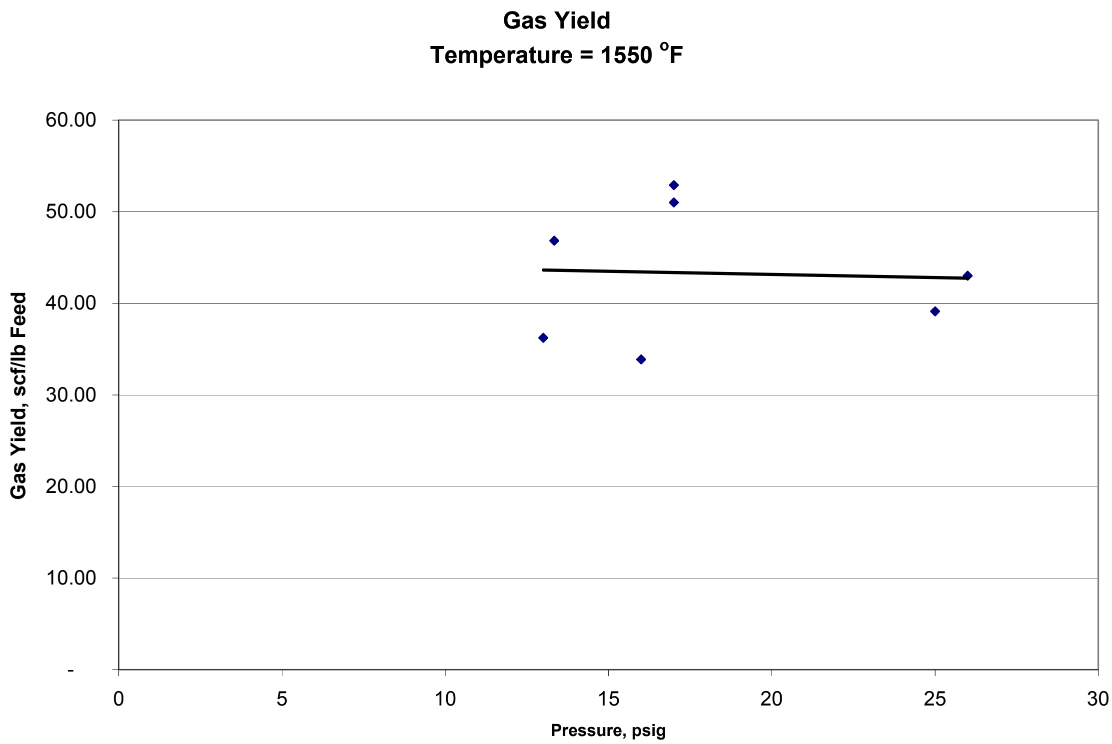


Figure 24. Correlation of Gas Yield with Temperature (Pressure Constant)

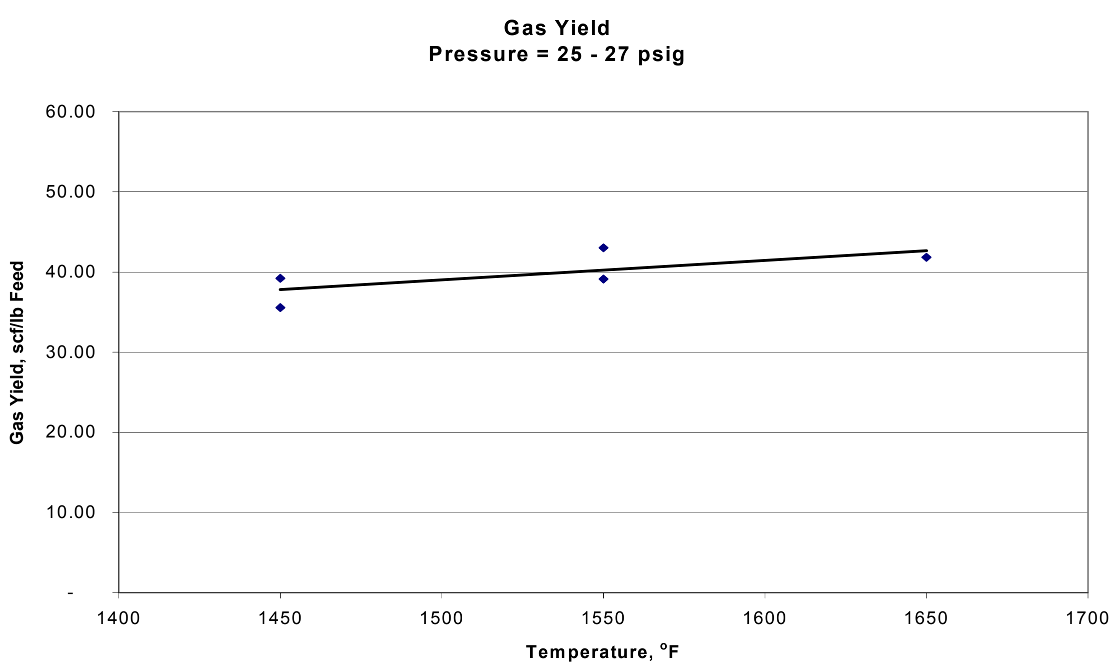
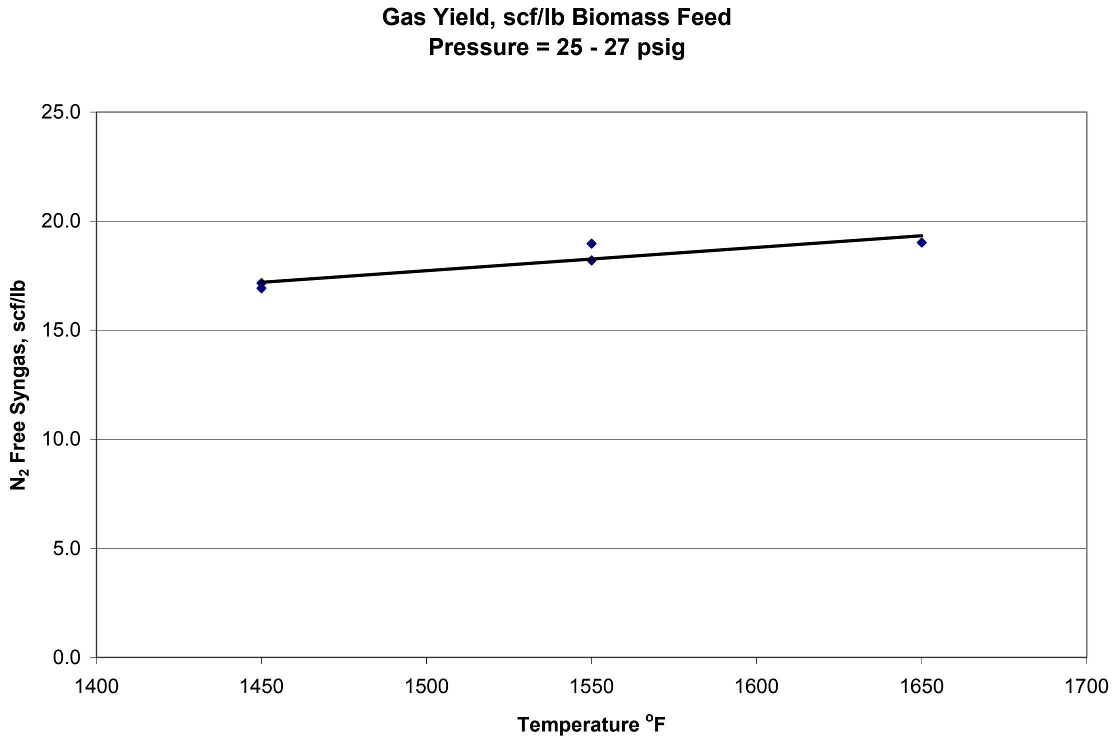


Figure 25. Correlation of Gas Yield/N_2 Free with Temperature (Pressure Constant)



Gas Composition. Examination of the primary gas compositions from the test runs for the effect of temperature and pressure was performed focusing on a group of test comparing data for constant temperature and at constant pressure. These results were also examined on a nitrogen free basis. Figure 26 and 27 examine the gas composition as a function of pressure at a constant temperature of 1550 ^{o}F. Examination of data on a nitrogen free basis reduces the influence of nitrogen variation on interpretation of the results. The concentration of methane in the syngas increases with pressure and temperature. This is due to cracking of heavier hydrocarbons and preferred equilibrium.

Figure 26. Variation of Gas Composition at Constant Temperature

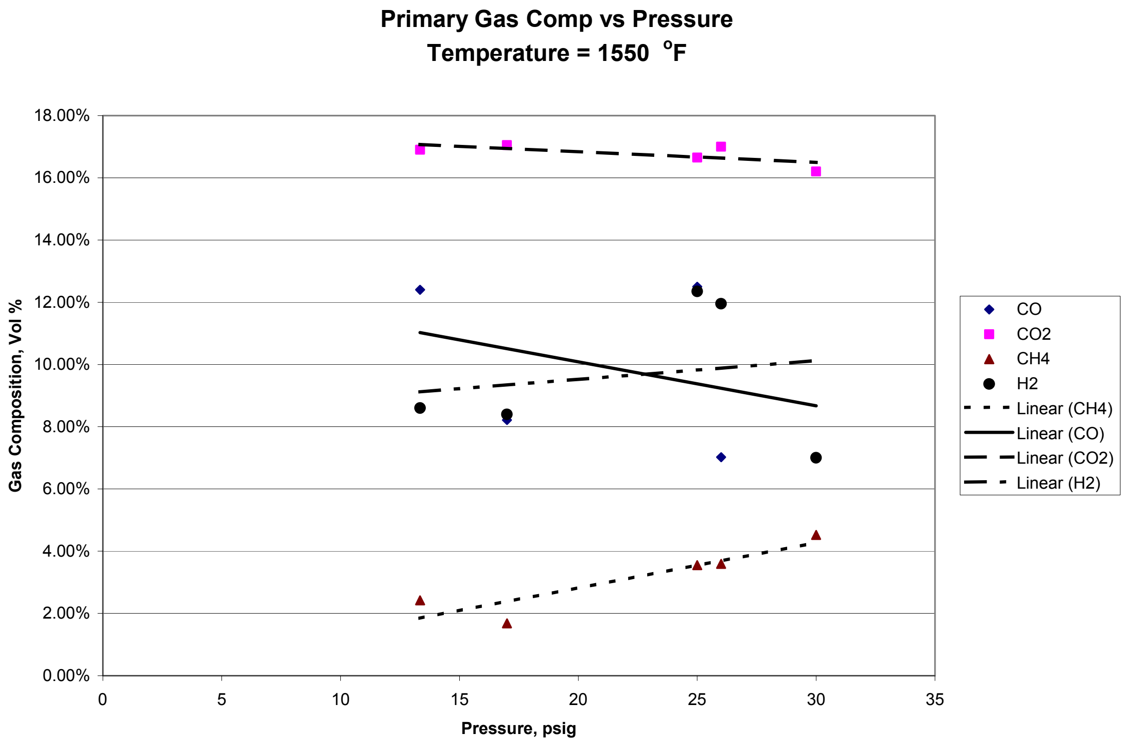
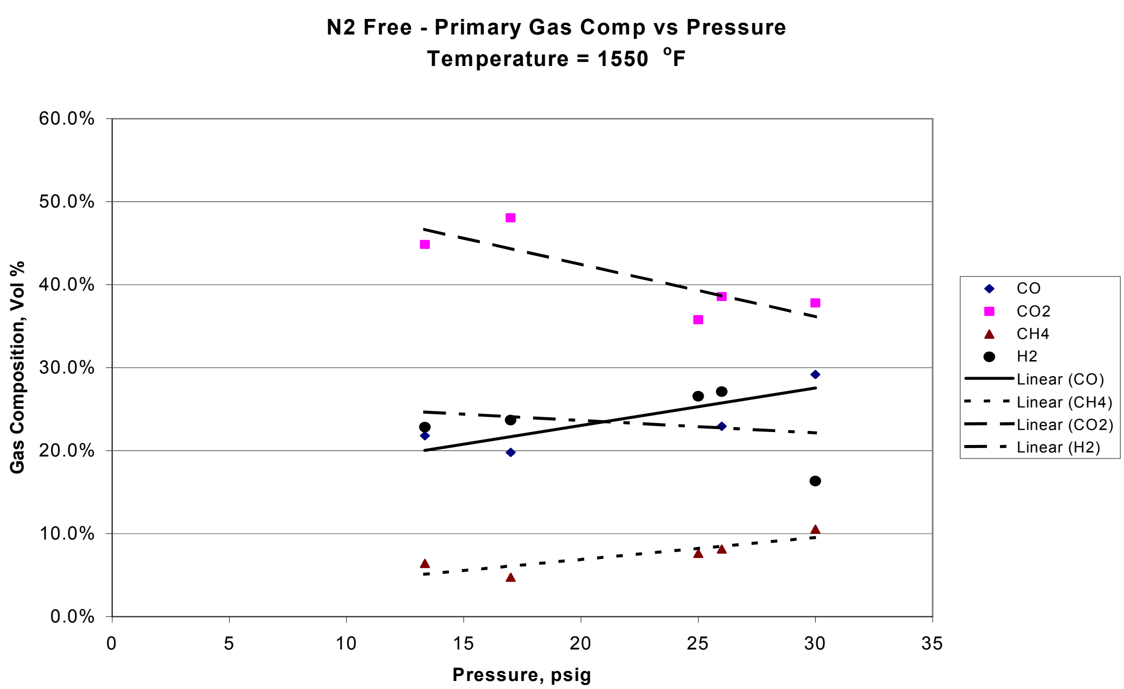


Figure 27. Variation of N_2 Free - Gas Composition at Constant Temperature



The effect of temperature on the primary gas compositions from the test runs was examined at a relatively constant pressure of 25 – 30 psig. Temperature was varied over the range of 1450 – 1650 ^oF. These results were also examined on a nitrogen free basis, Figure 28 and 29. It is clear that pressure will increase the methane concentration of the gas. Pressure also improves CO production and decreases CO_2 formation. Examination of data on a nitrogen free basis reduces the influence of nitrogen variation on interpretation of the results.

Figure 28. Variation of Gas Composition at Constant Pressure

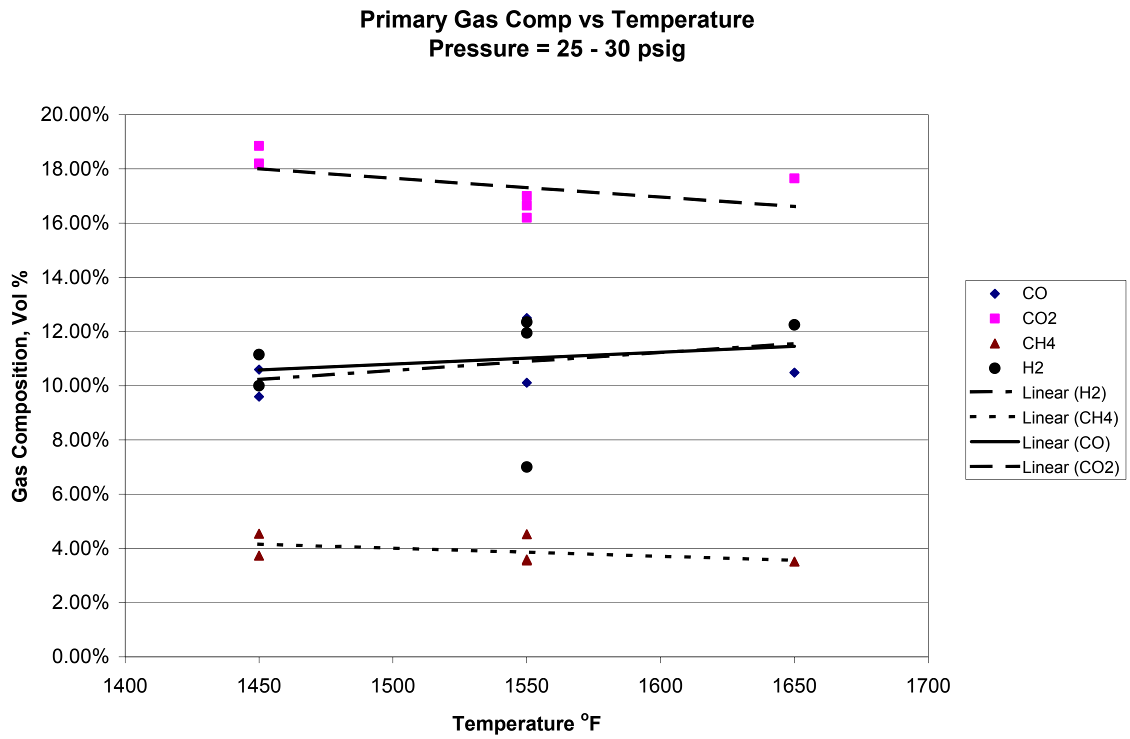
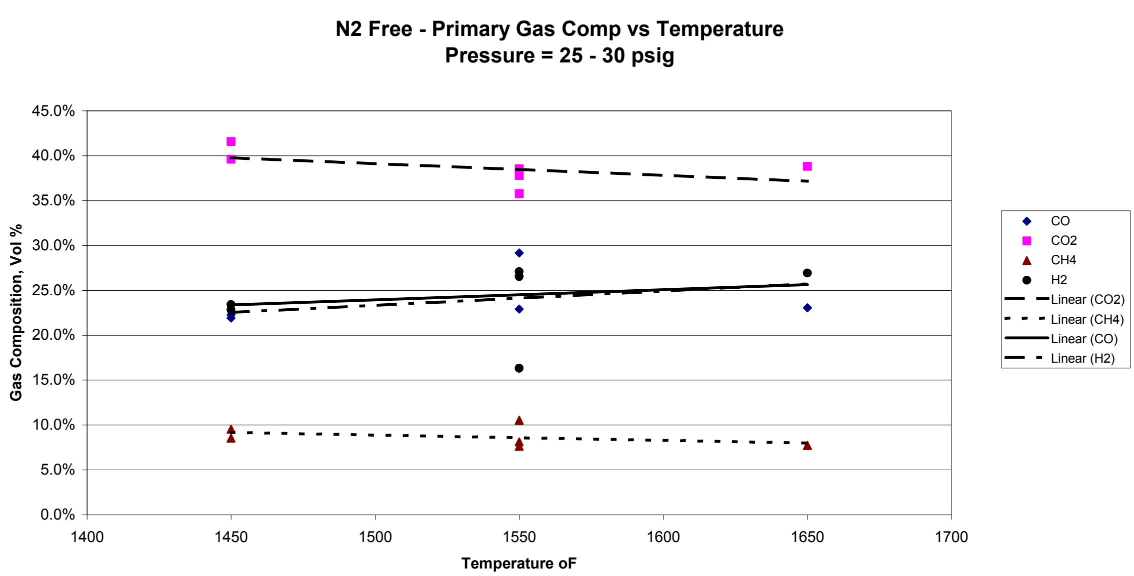


Figure 29. Variation of N_2 Free - Gas Composition at Constant Pressure



Tars and Oils. A key objective of the testing was to determine the effect of temperature and pressure on the tar/oil and heavy hydrocarbon production. Figure 30 provides a graphical indication of the relationship associated with varying pressure at constant temperature of total heavy hydrocarbon production. Examination of the data suggests total heavy hydrocarbon production increases with pressure (at constant temperature) but the material is lighter in molecular weight as there are more light ends due to cracking of the heavier fractions. When pressure is constant and temperature is varied, the total production of heavy hydrocarbons is reduced as expected. There are more light ends and less of the heavier tars and oils, Figure 31. This shows that both higher pressure and temperature favor cracking of the heavier materials into lighter fractions. Detailed analysis was performed of the condensate and tar/oil samples for selected test runs. This data is contained in Appendix C.

Figure 30. Summary of Tar/Oil/C6 + Production at Constant Temperature

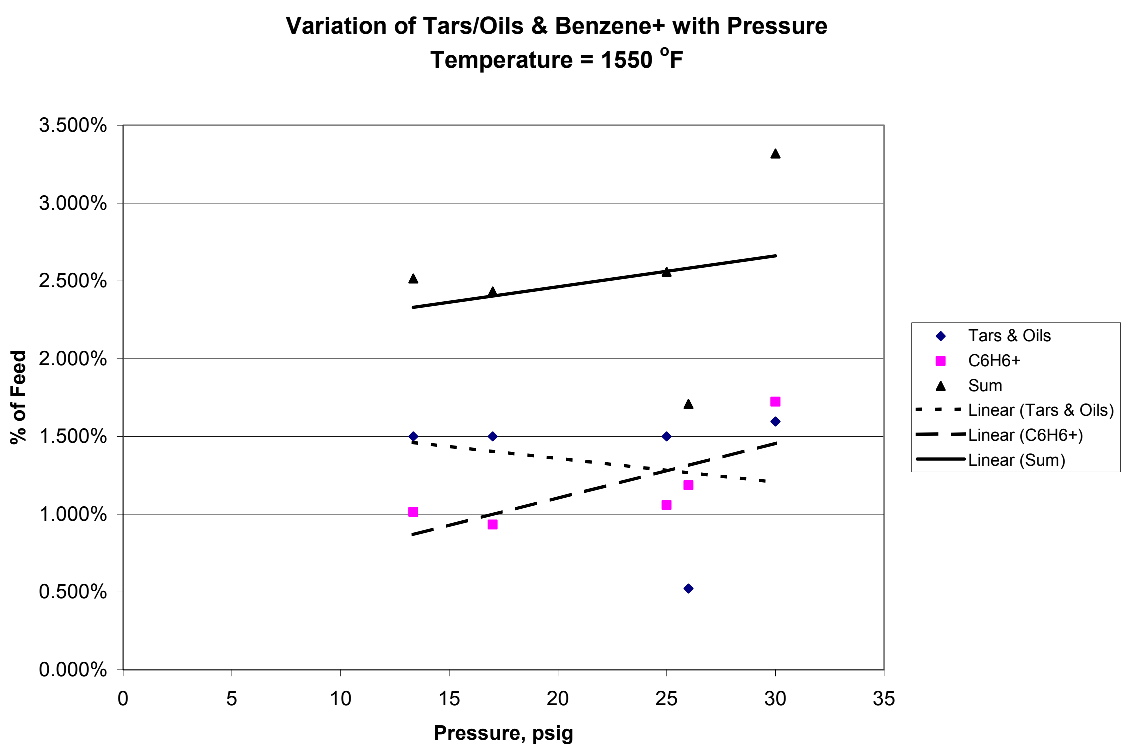
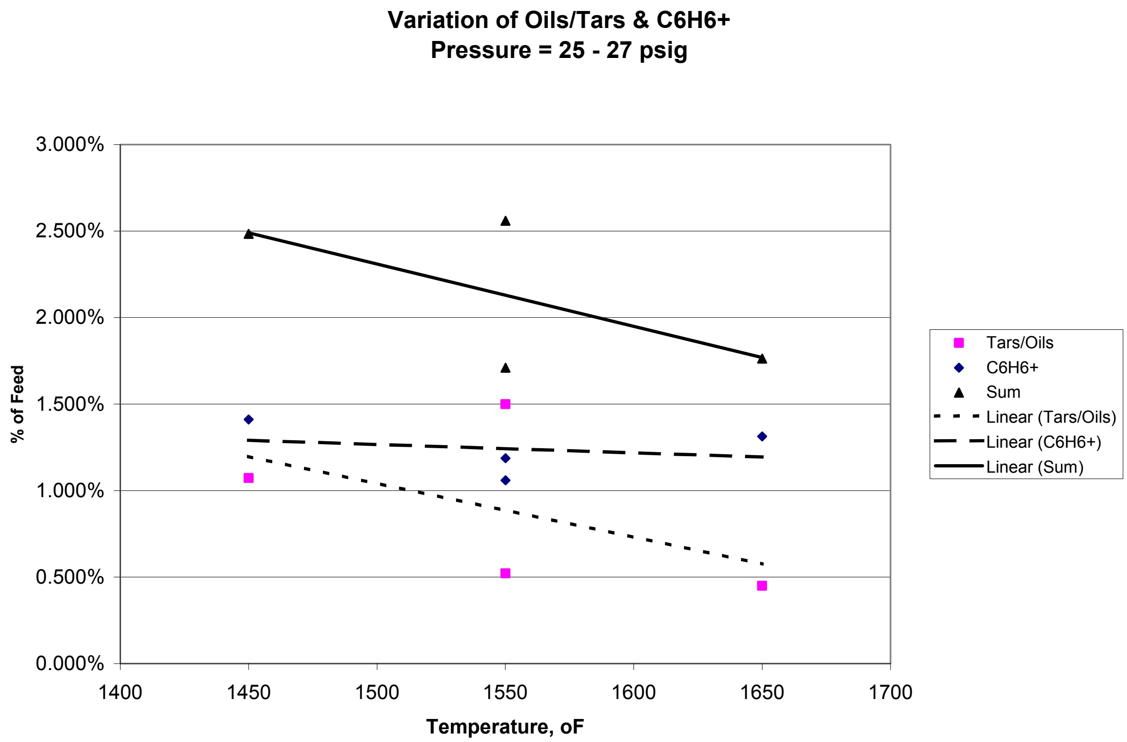


Figure 31. Summary of Tar/Oil/C6 + Production at Constant Pressure



Subtask 4 – Validate GTI's RENUGAS® Model

GTI has a model of the fluidized bed gasifier that uses performs material and energy balances over the gasifier applying global reaction equilibrium conditions to the feedstock material. The model is run assuming a 100 ^{o}F approach to equilibrium for the shift reaction in the gasifier. When biomass is applied, the model provides a prediction of the performance of the RENUGAS® gasifier. When coal is applied, the model predicts the results for the U-GAS® gasifier. The model is adjusted for the reactivity of different feedstocks. This model has been validated over several years for various pilot plant and commercial projects. The purpose of this project was to gather data to validate the model for the feedstock materials and conditions used for the preliminary design study conducted for Calla Energy.

The GTI RENUGAS® model was applied to a selection of the test data. Table 12 compares the results of the model as with the test run data. The data from the model approaches the results of the experimental tests in most cases. Input to the model were gasifier size, biomass feed rate, gasifier outlet temperature, and operating pressure. The output of the model includes the airflow, steam flow, and product gas composition. There can be peculiarities of certain test runs that will affect test results, such as the temperature of the preheated feed gas, heat loss, that can be adjusted based on observed results.

Table 12. Comparison of Model Data with Test Run

Run #	**15**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**
Test Date	4/15/03	6/9/03	6/10/03	6/18/03	6/20/03	6/24/03	6/26/03	6/26/03	6/30/03
Temperature F	1553	1546	1547	1540	1649	1450	1550	1649	1448
Pressure psig	27.64	16.72	17.72	23.44	26.33	25.25	28.87	35.67	25.5
Pressure Abs psia	42.34	31.42	32.42	38.14	41.03	39.95	43.57	50.37	40.2
Feed Rate lb/hr	2.87	2.59	3.59	3.583	3.16	2.932	3.44	3.85	3.05
Model									
CO	23.70	19.66	19.53	24.43	28.08	17.45	26.34	30.68	20.49
CO2	32.83	34.12	47.43	30.91	28.29	35.52	31.08	28.31	35.37
H2	28.35	24.58	23.37	23.56	26.15	23.31	27.04	27.64	25.48
CH4	10.52	10.10	4.67	10.42	10.06	10.55	10.86	11.03	10.78
Dry Syngas Rate scfh	95.74	73.11	122.94	111.62	100.93	80.31	105.59	121.92	89.60
Dry Syngas/lb Biomass scf/lb	33.36	28.23	47.47	31.15	31.94	27.39	30.69	33.40	29.38
H2 Yield scf/lb biomass	5.32	4.30	3.99	4.43	5.02	3.90	4.93	5.30	4.39
CO Yield scf/lb biomass	4.45	3.44	3.33	4.59	5.39	2.92	4.80	5.88	3.53
CH4 Yield scf/lb biomass	1.97	1.77	0.80	1.96	1.93	1.76	1.98	2.12	1.86
CO2 Yield scf/lb biomass	6.16	5.96	8.09	5.81	5.43	5.94	5.67	5.43	6.10
N2 Free Syngas Rate, scfh	53.85	45.27	44.20	67.32	60.67	49.00	62.75	70.00	52.56
N2 Free Syngas scf/lb Biomass	18.76	17.48	12.31	18.79	19.20	16.71	18.24	18.18	17.23

Run #	15	22	23	24	25	26	27	28	29
Experimental Data									
CO	22.69	19.53	21.46	26.47	22.93	21.89	28.74	27.40	22.04
CO2	38.16	47.43	44.13	35.54	38.58	41.51	37.24	37.44	39.19
H2	26.82	23.37	22.45	26.36	26.78	22.81	16.09	18.49	23.18
CH4	8.06	4.67	6.32	7.58	7.69	8.53	10.39	10.43	9.44
Dry Syngas Rate scfh	123.48	122.94	128.76	140.06	123.00	107.07	124.50	136.93	108.50
Dry Syngas/lb Biomass scf/lb	43.02	47.47	43.56	39.12	38.92	36.52	36.19	37.51	35.57
H2 Yield scf/lb biomass	5.14	3.99	3.75	4.83	4.77	3.65	2.53	3.04	3.97
CO Yield scf/lb biomass	4.35	3.33	3.58	4.85	4.08	3.51	4.52	4.50	3.77
CH4 Yield scf/lb biomass	1.54	0.80	1.05	1.39	1.37	1.37	1.64	1.71	1.62
CO2 Yield scf/lb biomass	7.31	8.09	7.36	6.51	6.87	6.65	5.86	6.15	6.71
N2 Free Syngas Rate	55.01	44.20	49.32	65.62	56.27	46.95	54.16	59.97	52.19
N2 Free Syngas scf/lb Biomass	19.17	17.06	16.68	18.31	17.81	16.01	15.74	15.58	17.11

A key aspect of the model is predicting the output of the gasifier over a variety of gasifier conditions. Figure 32, 33, and 34 examine the overall precision of the model by comparing predicted versus experimental data for the total output. Perfect correlation occurs when test data line up on a perfect 45^o line for matching model data.

Examination of the syngas yield versus model yield was performed in Figure 32, which compares the dry syngas for each test. The total test gas is somewhat higher than the model; this is a result of the additional nitrogen present in the gas compared to typical operation. Similarly comparison of the syngas yield per pound of biomass also shows a test result higher than the model by about 10 percent, Figure 33. However the results are very close when examined on a nitrogen-free basis. Normalized syngas yield on a nitrogen-free basis is is examined in Figure 34. This data shows that the model can provide an excellent indication of gasifier results. Operation of a small gasifier of this type will typically have a higher nitrogen purge than would be common on a commercial gasifier.

The yield of methane was examined at constant pressure and constant temperature, Figures 35 and 36. As expected, the yield increases at constant temperature with increasing pressure for both the model and the experimental data. However, the model and the data are somewhat divergent for tests at constant pressure. Since both data sets are nearly horizontal, there may not be sufficient data to fully characterize this trend.

Figure 32. Syngas Yield Comparison for Model & Experimental Data

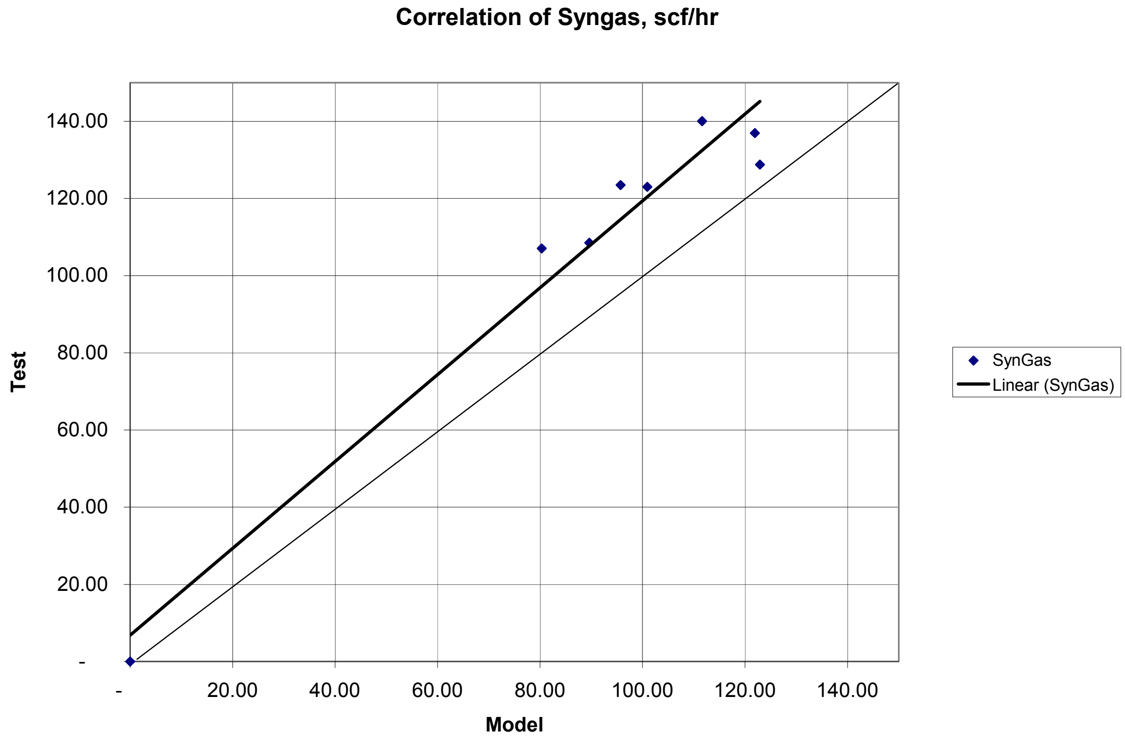


Figure 33. Normalized Syngas Yield scf/lb for Model & Experimental Data

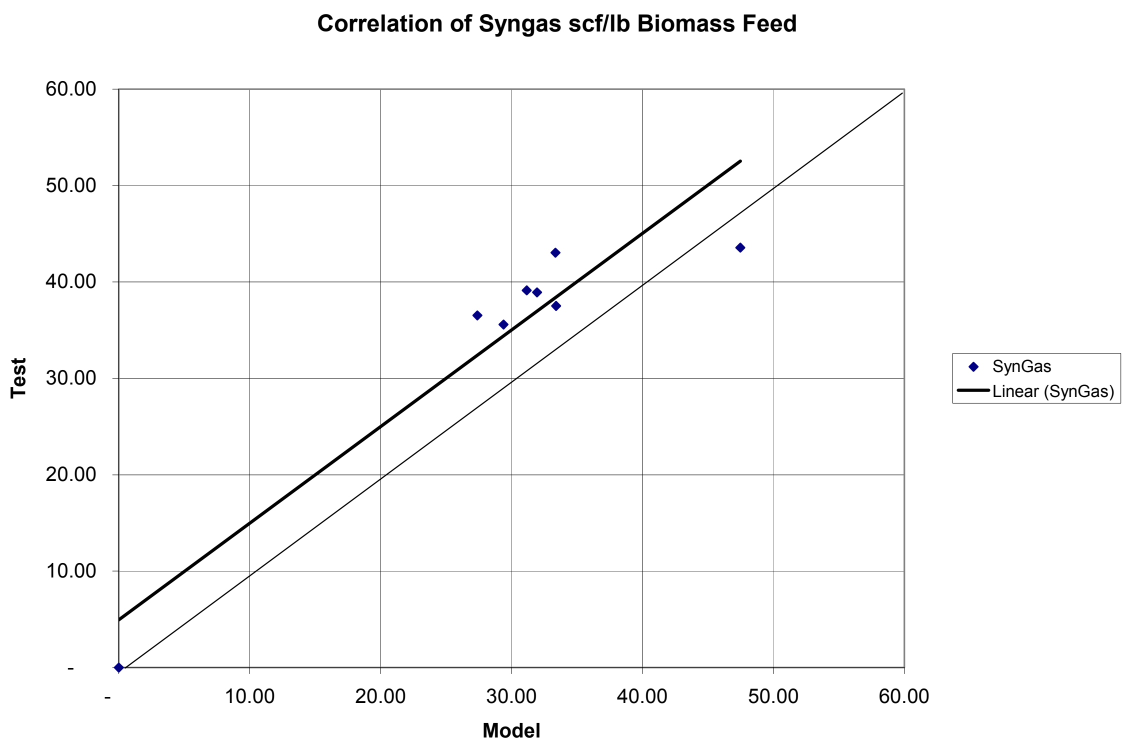


Figure 34. Normalized Syngas Yield – N2 Free - scf/lb for Model & Experimental

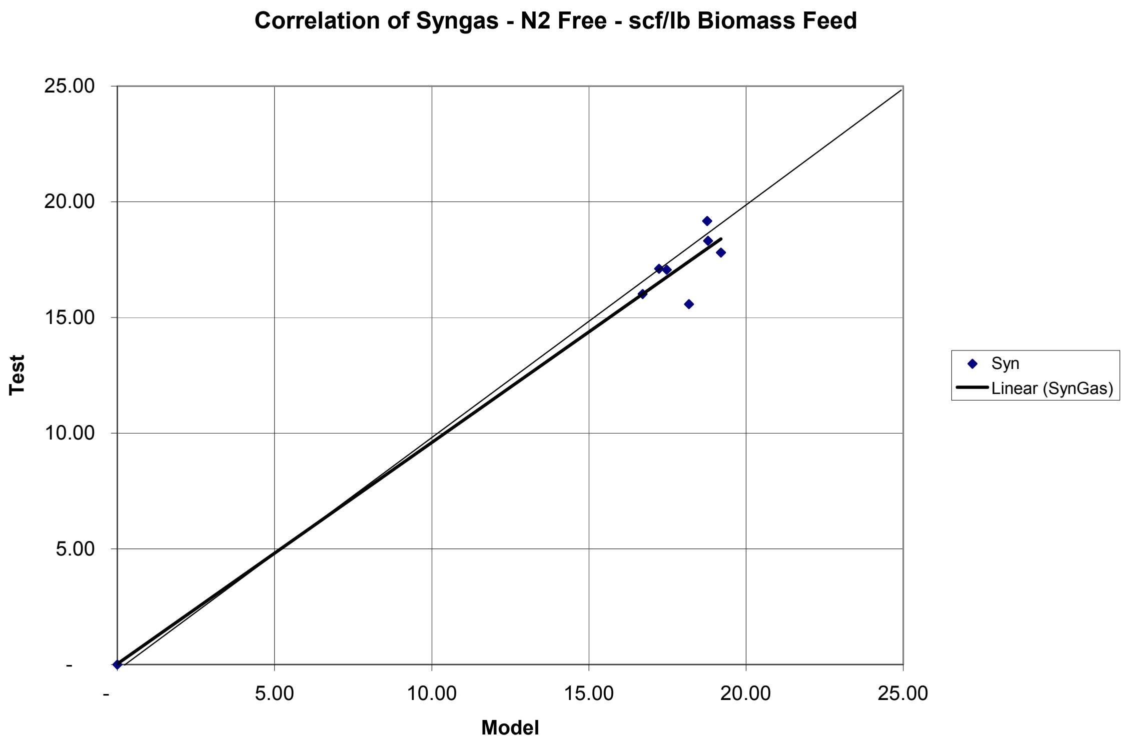


Figure 35. Methane Yield Comparison for Constant Pressure

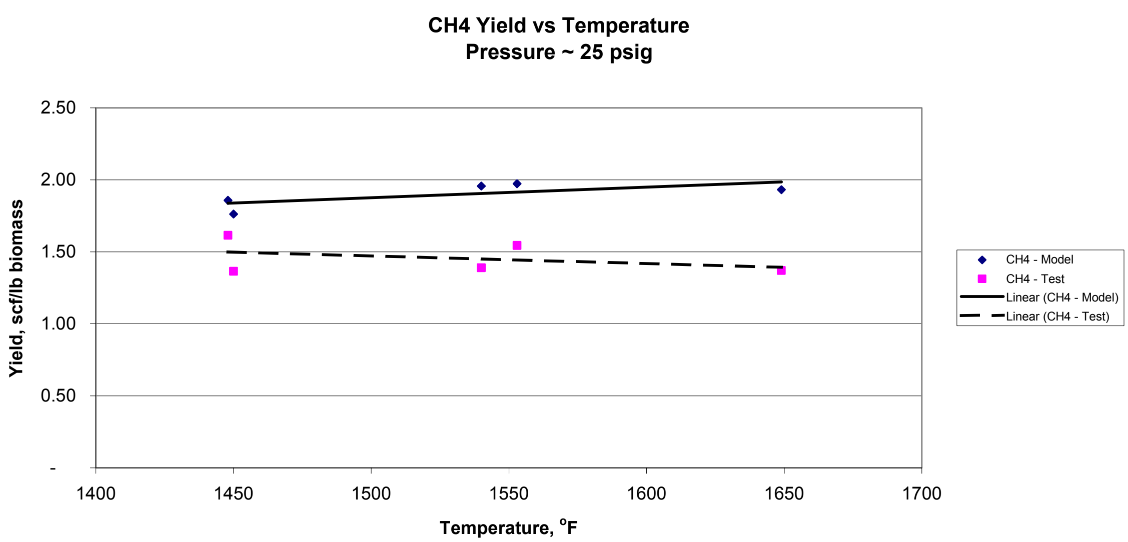
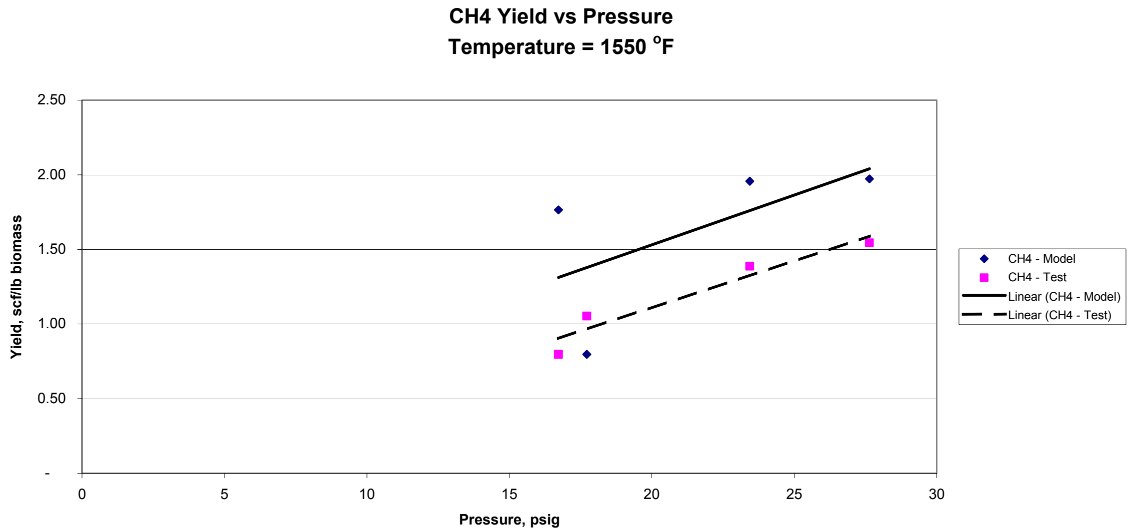


Figure 36. Methane Yield Comparison for Constant Temperature



CONCLUSION

The design and techno-economic study completed during Phase I confirms that biomass can be economically gasified to provide a fuel gas that completes with natural gas as a fuel when the biomass fuel is available at a reasonable price. The economics become significantly compelling when opportunity fuels are available for a tipping fee (negative fuel cost). The production tax incentives are imperative for the economics to drive these projects forward.

The facility design is relatively simple and straightforward. There appear to be several areas where costs on future facilities can be lowered once first-of-a-kind engineering costs are recovered from early demonstration units, and vendors become accustomed to this type of equipment fabrication and design.

Calla Energy is committed to proceeding with the construction of the facility based on receipt of all necessary permits, financing, and support from DOE. Comments to permits for the coal-fired boiler are have been received and full submittal to the State of Kentucky is planned before the end of the calendar year. Once work is initiated on the coal plant, Calla hopes to proceed with biomass gasification as designed in the phase one study.

The testing conducted on the 2" mini-bench unit has verified that the model is an excellent tool for predicting the performance of a fluid-bed gasifier. Results of the testing showed that:

- Model results are close to experimental results, even with equipment as small as 2" in diameter
- Tars, oils and other heavy hydrocarbons tend to crack at higher temperatures, but a commercial facility design will need to accommodate quantities that remain in the gas
- Production of tars, oils, and heavy hydrocarbons increases somewhat with increasing pressure
- Biomass throughput increases at a predictable rate with increasing pressure
- Methane production increases with increasing pressure as expected, due to cracking of heavy hydrocarbons
- The model correlates well on overall throughput of the gasifier with experimental results