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A System Performance and Economics Analysis of IGCC with Supercritical Steam Bottom Cycle Supplied with Varying Blends of Coal and Biomass Feedstock

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ABSTRACT

In recent years, Integrated Gasification Combined Cycle Technology (IGCC) has been gaining steady popularity for use in clean coal power operations with carbon capture and sequestration. Great efforts have been continuously spent on investigating various ways to improve the efficiency and further reduce the greenhouse gas (GHG) emissions of such plants. This study focuses on investigating two approaches to achieve these goals. First, replace the traditional subcritical Rankine steam cycle portion of the overall plant with a supercritical steam cycle. Second, add different amounts of biomass as co-feedstock to reduce carbon footprint as well as SO_x and NO_x emissions. Employing biomass as a feedstock to generate fuels or power has the advantage of being carbon neutral or even becoming carbon negative if carbon is captured and sequestered.

Due to a limited supply of feedstock, biomass plants are usually small, which results in higher capital and production costs. In addition, biomass can only be obtained at specific times in the year, meaning the plant cannot feasibly operate year-round, resulting in fairly low capacity factors. Considering these challenges, it is more economically attractive and less technically challenging to co-combust or co-gasify biomass wastes with coal. The results show that supercritical IGCC the net plant efficiency increases with increased biomass blending in the all cases. For both subcritical and supercritical cases, the efficiency increases initially from 0% to 10% (wt.) biomass, and decreases thereafter. However, the efficiency of the blended cases always remains higher than that of the pure coal baseline cases. The emissions (NO_x, SO_x, and effective CO_2) and the capital cost all decrease as biomass ratio increases, but the cost of electricity *increases* with biomass ratio due to the high cost of the biomass used.

Finally, implementing a supercritical steam cycle is shown to increase the net plant output power by 13% and the thermal efficiency by about 1.6 percentage points (or 4.56%) with a 6.7% reduction in capital cost, and a 3.5% decrease in cost of electricity.

NOMENCLATURE

ASU	Air Separation Unit
GT	Gas Turbine
ST	Steam Turbine
HRSG	Heat Recovery Steam Generator
IGCC	Integrated Gasification Combined Cycle
GHG	Greenhouse Gas(es)
AGR	Acid Gas Removal
HP	High Pressure (PSI)
IP	Intermediate Pressure (PSI)
DA	De-aerator
bmr	Biomass Ratio (biomass/feedstock mass) (wt%)
M.W.	Molecular Weight (lbs/lb-mol)
LHV	Lower Heating Value (Btu/lb)
HHV	Higher Heating Value (Btu/lb)

INTRODUCTION

In recent years, Integrated Gasification Combined Cycle Technology (IGCC) has been gaining steady popularity for use in clean coal power operations with carbon capture and sequestration. Great efforts have been continuously spent on investigating various ways to improve the efficiency and further reduce the greenhouse gas (GHG) emissions of such plants. This study focuses on investigating two approaches to achieve these goals.

To achieve the first goal of improving efficiency, this study investigates the feasibility of replacing the traditional subcritical Rankine steam cycle portion of the overall plant with a supercritical steam cycle because supercritical Rankine cycle is typically more efficient than the subcritical Rankine cycle and the Brayton cycle. To the authors' knowledge, there is currently no literature available for this type of steam system being used in an Integrated Gasification Combined Cycle (IGCC) system. To achieve the second goal of reducing GHG emissions, this study investigates adding biomass as a co-feedstock of coal to reduce carbon footprint as well as SO_x and

NO_x emissions. Employing biomass as a feedstock to generate fuels or power has the advantage of being carbon neutral or even carbon negative if carbon is captured and sequestered.

Raising the inlet temperature and pressure of the steam turbine in a traditional Rankine cycle is the most direct way to increase the operating efficiency of said cycle. As early as the 1950's, scientists and engineers have been highly focused on this area of potential steam cycle improvement. It was during this period where the maximum inlet pressure and temperature were raised from 2400PSI/1000^{o}F to near 4500PSI/1150^{o}F [1]. This was the onset of the first supercritical steam generation plant. The term "supercritical" comes from the idea that the steam running through the boiler or HRSG is *above* the "critical point" at the top of the vapor dome on a standard temperature-entropy diagram at around 3200PSI [2]. For reference, the typical efficiency of a standard subcritical Rankine (steam) cycle is around 30-38%, while a supercritical cycle under the same environmental conditions can achieve an efficiency of 42-45%. So far, all of the research and industrial efforts going into supercritical cycle design are meant for standard pulverized coal (PC) plants. To the authors' knowledge, there is currently no literature available documenting a supercritical bottom steam system being used in an IGCC system. This motivates the first goal of this study.

<u>To achieve the second goal of reducing emissions</u>, certain quantities of biomass were used in the existing coal plant's feedstock. The use of biomass in IGCC is not a new idea. The first pure biomass IGCC plant was constructed in Värnamo, Sweden 1993. As a demonstration plant, it provided roughly 6 MW of net electricity to the grid by using a fuel equivalent energy input of approximately 18 MW [3]. Several other biomass plants in the range of 40-100MW have been constructed, such as the Hawaiian biomass gasification experimental plant developed by Siemens-Westinghouse [4] and the McNeil Station in Burlington, Vermont [5]. In addition, other, more traditional plants have been modified for use with biomass and gasification processes, such as the Chowchilla I in California and the Lahti Co-firing Project in Finland, which both used syngas derived from biomass to run a Rankine cycle [5]. All of these plants, however, have either failed or been removed from the commercial power sector due to very similar problems associated with biomass.

The first and greatest challenge with utilizing biomass is associated with its availability, sustainability, and quantity. The supply of most biomass is seasonal and is limited by quantity. In addition, biomass cannot be economically transported over long distances due to its low mass density. A solution to some of these problems is by *co-feeding* biomass alongside coal in a larger plant. This allows biomass to be used whenever it is available and on the same economy of scale that coal is. Doing this also reduces fossil fuel consumption, which is a benefit both for the environment and for energy providers, since most of biomass wastes are either free or bear very low costs. Next, since biomass is cleaner than coal is, co-feeding results in lower emissions than a pure coal plant, and is able to provide much more power than a pure biomass plant. Furthermore, because there is coal mixed in with the biomass, corrosion is less of an issue than it is with plants that use purely biomass.

However, there are still operational problems that biomass can cause to co-fed systems. For one, biomass has very low energy density. Coupled with its low mass density, this means that the required volumetric flow rates for providing the required energy to run the plant are higher than those of coal. Limited biomass supplies and transport issues inhibit profitable operation of larger pure biomass plants, meaning that effectively utilizing pure biomass in any plant bigger than about 50-80MW is uneconomical at best [6]. Secondly, most types of biomass are very fibrous and tough, and tend to get stuck in various types of feeding machinery. Thirdly, biomass tends to contain many corrosive compounds that can damage other internal parts. Lastly, biomass has an expiration date: it cannot be stored for any extended length of time due to its tendency to rot and decompose, being rendered useless as a fuel in the process.

To overcome this new set of challenges of biomass feeding and long-term storage, one available solution is employing *pretreatment.* Various chemical, thermal, and biological processes are available to transform raw biomass into a form that makes it more suitable for power generation. The type of pretreatment taken into consideration for this study is *torrefaction.* Torrefaction is a thermal process, wherein raw biomass is heated to about 200-300^{o}C and essentially "cooked," removing a large portion of the moisture content, and altering the chemical structure of the biomass in such a way that it loses its tough, fibrous consistency, and "torrefied biomass," a reddish-brown, brittle, solid substance that has calorific properties that greatly approach those of low- to mid-grade coals [7]. During torrefaction, the biomass looses roughly 30% of its mass as torrefaction gases, and roughly 10% of its internal energy with them [8]. A simple algebraic calculation shows that this would result in about a 28% increase in the calorific value per unit mass for the feedstock [9].

In addition, torrefied biomass has a higher mass density than untreated biomass, is less corrosive, has higher grindability, and is much easier to store and transport. Despite these benefits, using torrefaction at all requires that a separate, torrefaction plant be constructed on-site, which is a significant investment for most plants, especially the smaller ones. In fact, in one 1999 study done on a failed test plant by Siemens-Westinghouse in Maui, Hawaii, the researchers speculated that, while torrefaction itself is very effective at solving virtually all the feeding problems they'd been having, investing in one might not be economically viable [4]. However, a 2005 study by P.C.A. Bergman of the Netherlands showed that torrefaction when combined with Pelletization (another process that increases the mass density of the biomass), showed that using torrefaction was not only viable in Europe, but perhaps *profitable* as well, albeit with a high dependency upon the price of the biomass feedstock and other factors [8].

While some biomass-coal co-feeding studies have been done in the realm of *co-combustion* of biomass with coal [10,11] they were mainly based on subcritical PC plant designs. In IGCC plants, the biomass and coal are *co-gasified* instead of co-combusted. For instance, the Polk IGCC plant performed several experiments in which a wood-based eucalyptus biomass feedstock was co-fed into an existing IGCC coal plant, in Tampa, Florida. The results showed that the existing Coal/Petcoke fed IGCC system was feasible to feed biomass, and the emission of NO_x and SO_x was reduced about 10% [12]. The Buggenum IGCC plant in Netherlands also successfully co-gasified biomass (50% wt) with coal using 3 major biomass sources: wood, sewer sludge, and manure, using about 300 tons of feedstock per year [13].

This study only focuses on investigating *co-gasification* of biomass and coal for application in IGCC systems with both subcritical and supercritical bottom Rankine cycle systems.

DESIGN METHOD

The overall study was performed using the Thermoflow® suite's GTPro® software. Two baseline cases were constructed: one with a subcritical steam turbine design, and one with a supercritical steam turbine design, both using pure coal as the feedstock. From these setups, an amount of biomass was added to the coal based on a weight ratio. The ratios investigated were 10%, 30%, and 50%, for a total of 8 cases. The studied plants were assumed to have been built in southern Louisiana, using Texas Lignite and Sugarcane Bagasse as the feedstocks, and do not include any actual form of integration between the gas turbine compressor and the Air Separation Unit (ASU). The ultimate analyses for both of these fuels are given in Table 1.

Table 1 Fuel Ultimate Analysis (molecular basis)

Component	S. Hallsville Texas Lignite (wt%)	Sugarcane Bagasse (wt%)
C	41.3	43.59
H_2	3.053	5.26
N_2	0.623	0.14
S	0.7476	0.04
O_2	10.09	38.39
Cl_2	0	0
H_2O	37.7	10.39
Ash	6.479	2.19
LHV (Btu/lb)	6398	6714

Taken from: GTPro® internal fuel library

This study includes price and energy consumption on the *pretreatment* of both fuels. Due to limitations in the software, the actual pretreatment process cannot be modeled directly, so to make up for this, a certain "fuel preparation" cost (200kW-hr/ton of fuel for biomass, 40kW-hr/ton for coal) was added to the fuel inputs and the cost of constructing a torrefaction facility on-site was included based on information given in Bergman's data for torrefaction [8].

The plant's steam cycle is a condensing, single-reheat cycle for both sets of cases. This was done to maintain a higher efficiency over air-cooled condensing systems and non-reheat cycles. The cooling system used for this was a standard natural-draft cooling tower. It uses two main pressure streams (HP and IP,) both of which provide steam directly to the ST (HP provides main source of steam for the whole turbine, IP provides supplementary steam for second casing), with the IP stream also providing the steam needed for Acid Gas Removal, and a standalone deaerator to help with removing the impurities from the water source.

The gasifier is modeled after the GE/Texaco gasifier. It is slurry-fed (35% water by weight), oxygen-blown with an ASU pressure of 147PSI (10 bar), and no coolers at all. The raw syngas is *quenched* with water at 300°F (149°C), up to a relative humidity of 50%. This selection of quench-type gasifier will allow for a more direct comparison when carbon capture is introduced to the design in the future. Figure 1 shows the basic gasifier layout, with the numbers shown being representative of the pure coal, subcritical case. For both sets of cases (sub- and supercritical,) the GT used was a Siemens SGT6-4000F with steam injection, and the ST inlet temperature and pressure are fixed at 1100PSI/1000F (76 bar/538°C) for the subcritical plant, and 2400PSI/1200F (165.5 bar/650°C) for the supercritical plant.

Both sets of cases make use of a natural-draft cooling tower in the condenser, and all process water is returned to the deaerator (DA) after usage. Due to the immense increase in temperature from the subcritical case to the supercritical case, a duct burner is necessary to raise the temperature of the steam entering the steam turbine to the appropriate level. Therefore, the plant must make use of natural gas as a substitute fuel in order to achieve this high temperature. Both cases are shown in Figures 2 and 3, respectively, both using 0% biomass in the feedstock.

For all the cases, the turbine inlet temperature of GT is fixed and the total mass flow rate to the GT is also fixed. There are two options for designing the systems: for higher efficiency or lower costs. The option of *lower costs* was selected for this study. This was also part of the reason that a quench-type gasifier was selected instead of a radiant-cooled gasifier.

The cleanup system consists of a particulate scrubber supplied with water at 215°F (102°C) for the procedure, a section for Carbonyl-Sulfide (COS) Hydrolysis, a series of coolers and water "drains," and Acid Gas Removal (AGR). The AGR unit is an amine-based system (single-stage), which operates at 90% removal efficiency. No CO-shift or carbon capture systems were modeled for this study, but a parallel study was undertaken to incorporate carbon capture. Figure 4 shows the overall plant layout for the subcritical, pure coal case.

The NO_x production was based on the emissions specifications from the gas turbine manufacturer. During the course of this experiment, it was discovered that the emissions data for the SGT6-4000F was no longer available from the Siemens company, so the NO_x specification used was instead based upon a similar model, the SGT6-*5000*F, since both GTs have similar combustors and the same NO_x control unit installed. The NO_x data was specified to be 9ppm at a 15% O_2 reference content [14].

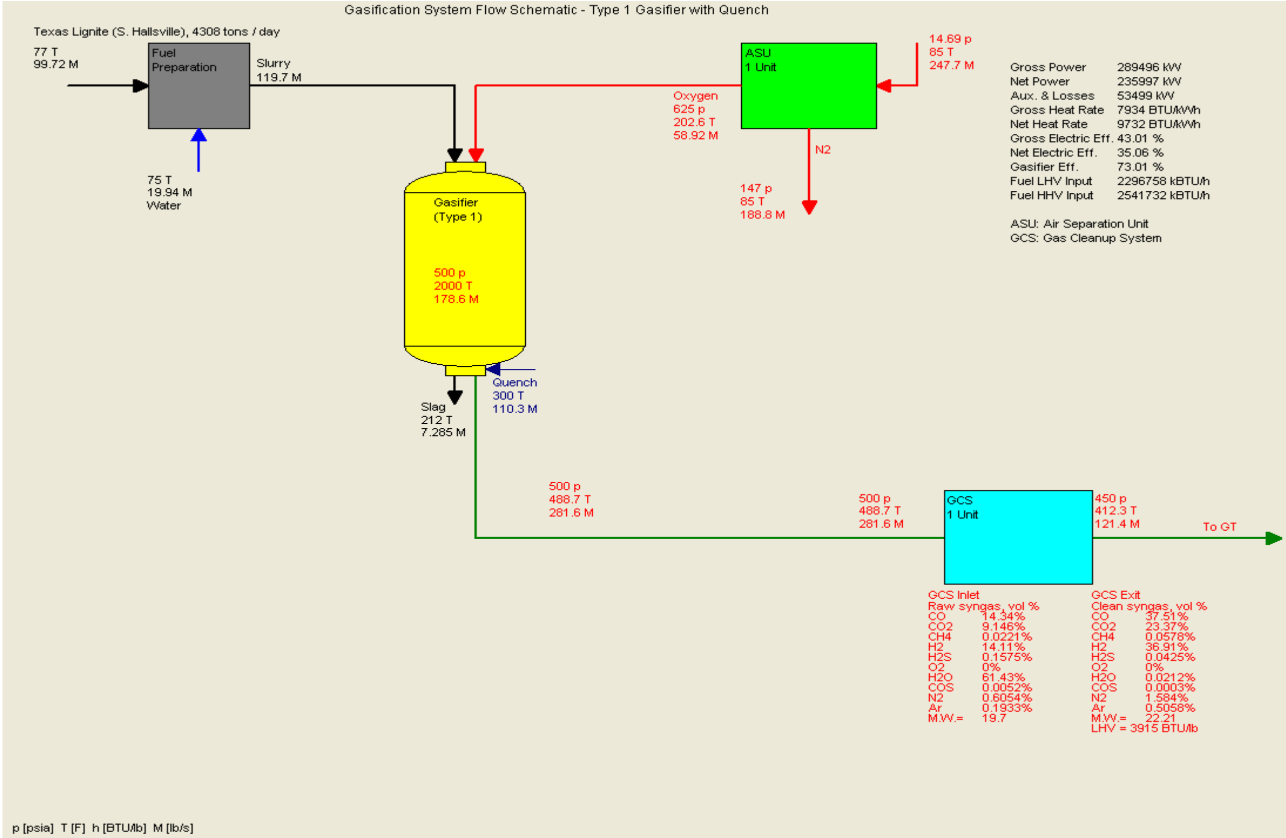

Figure 1 Gasifier Design (0% biomass, subcritical case)

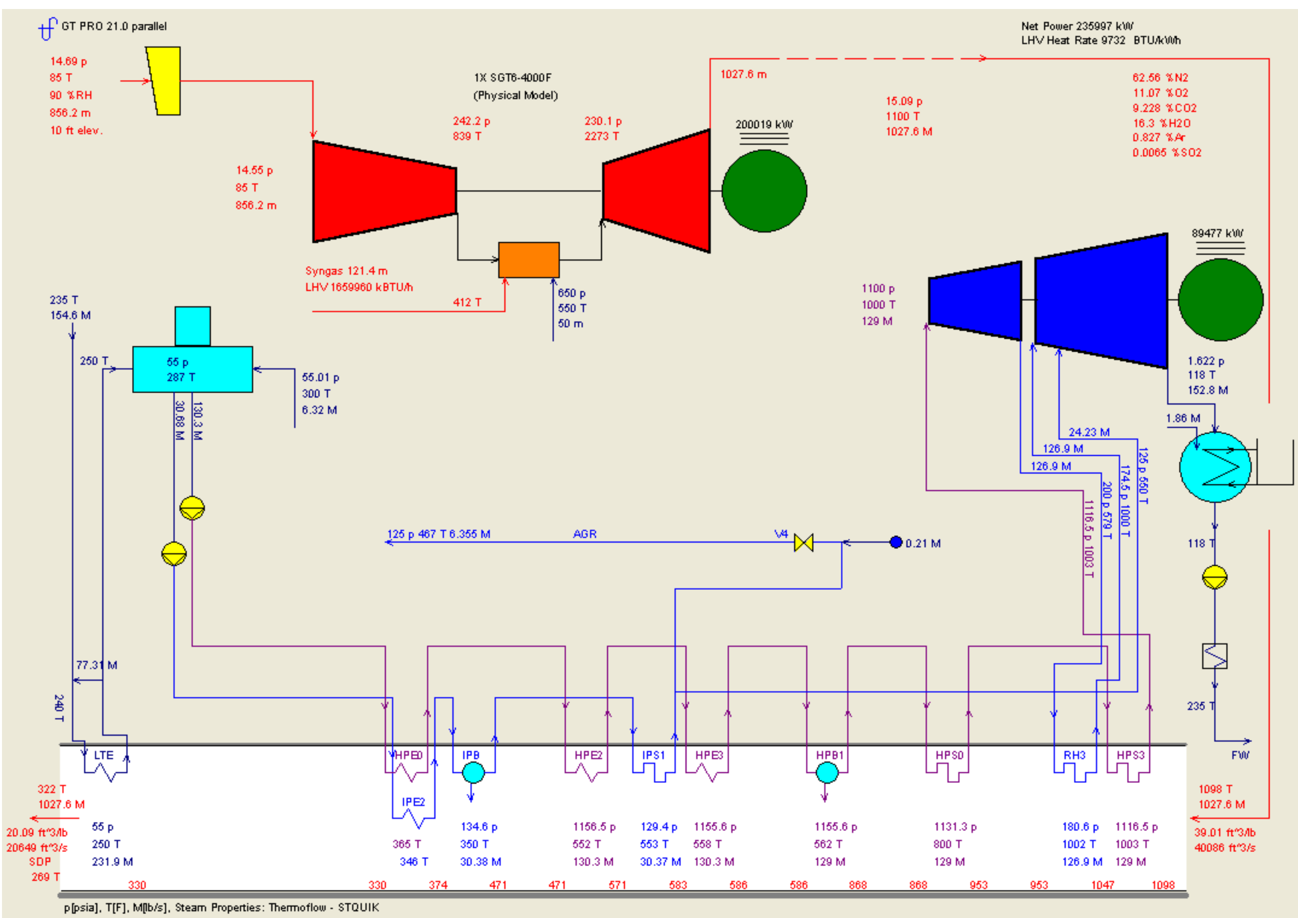

Figure 2 System Design (0% biomass, subcritical steam cycle case)

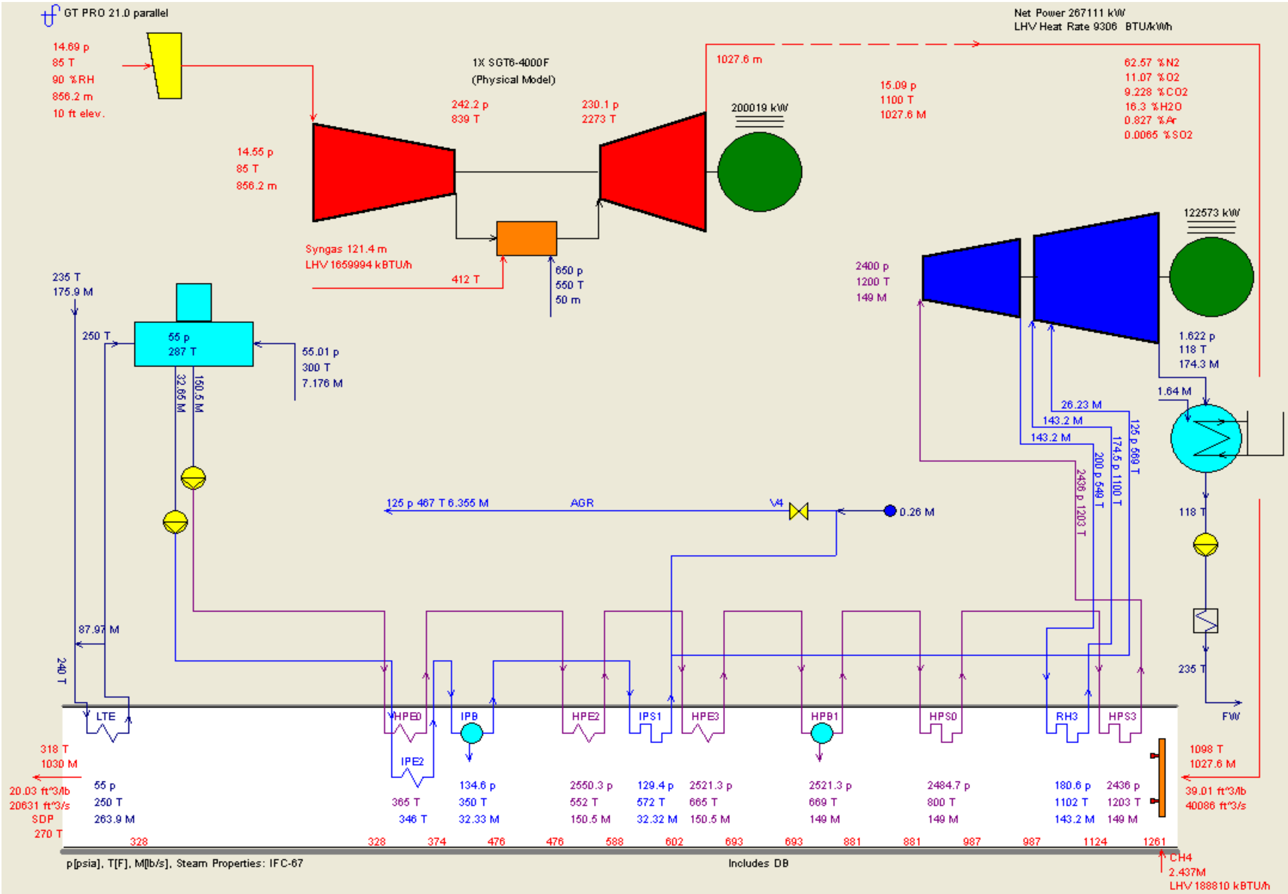

Figure 3 System Design (0% biomass, supercritical steam cycle case)

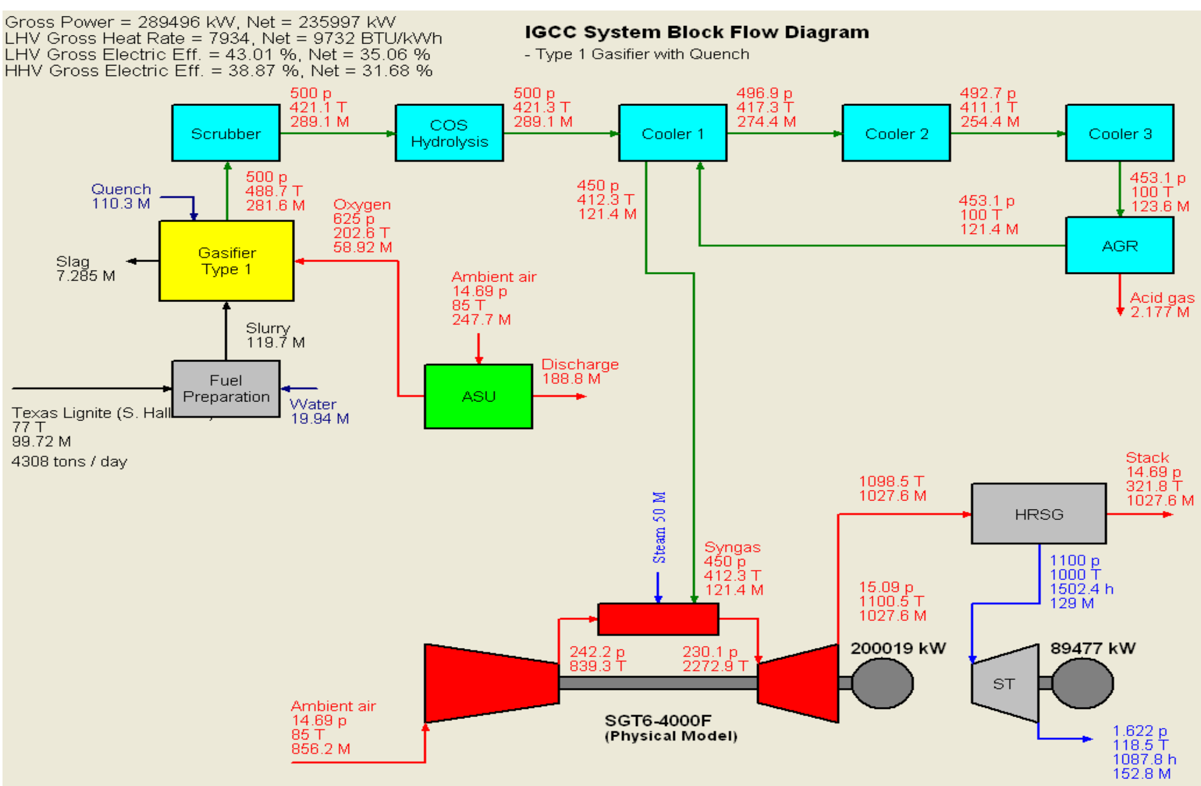

Figure 4 IGCC overall plant layout (0% biomass, subcritical steam cycle case)

ECONOMICS ANALYSIS

For the economics aspect of this study, the price of lignite was set at $19.00 per short ton [15]. Bagasse, as a waste product, is usually free for the sugarcane farmers. Considering the costs for transportation and storage of the shear amount of it, its price was taken to be 1/3 ($10) of the typical market price of the sugarcane plant itself: about $30.00/ton [16]. However, this is based on a per ton basis of *sugar cane*, not bagasse. A typical 1 ton supply of sugar cane will only yield about 0.2 tons of bagasse. Added to that is the fact that most sugar cane refineries will use the bagasse as a source of energy by burning it; the energy from which will be used to refine the sugar within the cane. When taking this into account, it means that the actual price per ton of bagasse will be more than 5 times the amount shown. The final price of the (wet) bagasse is about $65/ton in Louisiana [17]. Lastly, for the supercritical plants, the duct burner fuel is natural gas, which rates in at $4.10 per million Btu [18].

Operations and Maintenance (O&M) costs were estimated at $60/kW-hr/year (fixed), and 0.6 cents/kW-hr/year (variable). The cost of water was assumed to be approximately $2.00 per thousand gallons *utility* (very much subject to local conditions and regulations.)

In this study, no carbon tax or carbon credit was taken into account, since there is no strict tax in place in the U.S. yet. Since there is no indication of this being the case anytime soon, carbon taxes/credits were not considered for this study. Also, since the primary goal of this plant is *power*, there is no price set for exporting any bi-products, such as H_2S or N_2 from air separation.

Lastly, for the analysis, an overall plant life of 30 years is assumed, with total operational capacity of 8,000 hours per year. In addition, 30% of the total initial investment is to be taken on *equity,* meaning that the plant owner must pay for these commodities out of his/her own pocket. Taxes on the plant were taken to be around 35%, with 10% flat-interest rates for all plant features. No inflation was considered for this study, so the analysis is based on 2011 USD. Lastly, the total package uses straight-line depreciation, but it was assumed that only 75% of the total investment is available for depreciation for tax purposes.

The fuel cost of coal is converted from $/ton to $/mmBtu by Eq. 1:

$$\frac{\$}{mmBtu(coal)} = \frac{\$}{ton} * \frac{1\,ton}{2000\,lbs} * \frac{1}{LHV_{coal}} * \frac{10^6 Btu}{1 mmBtu} \quad (1)$$

which comes out to about $1.48/mmBtu for lignite. For the biomass, however, this becomes difficult, because biomass is <u>purchased wet,</u> i.e. untreated, but it is <u>utilized dry</u>. Therefore, an additional conversion must be taken into account using the loss of mass during torrefaction (assumed to be 0.3 pounds lost per wet pound) as well as the gain in heating value. After conversion, the biomass dry LHV comes out to be $6.92/mmBtu. The cost of the blended biomass/coal feedstock is calculated under the assumption that it is linearly proportional to the biomass ratio (bmr). The energy consumption for coal grinding and drying was estimated to be 40kW-hrs/ton, while biomass, which must undergo torrefaction as well as grinding and drying, was estimated to be 200kW-hrs/ton. The average processing cost for each biomass case was also calculated linearly proportional to the bmr.

RESULTS AND DISCUSSIONS

The results are summarized in Tables 2 and 3 and are analyzed in two parallel paths: the effect of supercritical bottom cycle and the effect of biomass blending with coal on power output, and efficiency. More detailed data for select subcritical plants and the baseline supercritical plant is shown in the appendix.

Table 2 Work and Efficiency Data for Subcritical Plants

Biomass/Coal Ratio	0%	10%	30%	50%
Gross GT Power (kW)	200,019	200,018	200,017	200,017
Gross ST Power (kW)	89,477	89,790	90,191	90,551
Auxiliary Losses (kW)	53,499	52,451	55,913	59,277
Total Net Power (kW)	**235,997**	**237,356**	**234,296**	**231,291**
Gross Efficiency (LHV)	43.01	43.59	43.96	44.31
Net Efficiency (LHV)	**35.06**	**35.70**	**35.49**	**35.27**

In the subcritical IGCC system, blending biomass results in reduced output power but slightly increased net efficiency with the highest net efficiency achieved at 10% bmr. It is not clear in the first glance why reduced net output power results in increased efficiency. This is caused by two of the design choices: (a) the inlet temperatures at both the gas and steam turbines are fixed and (b) the total mass flow rate to the GT is also fixed. The details are explained below.

After torrefaction, the biomass's energy density becomes higher than the lignite coal used, so the syngas produced by blending biomass with coal produces higher energy density syngas. To maintain the turbine inlet temperature at the fixed maximum value as in the pure-coal case, either the fuel flow rate must be reduced or the air flow from the compressor must be increased to dilute the higher energy stream. However, since the *mass flow* through the GT must also be preserved, the only way to satisfy both criteria is to both reduce the fuel flow rate *and* raise the air flow in such a way that the TIT will be the same as previous cases. This means that the compressor is more taxed from each increased biomass amount. Reducing the feedstock's mass flow rate, in turn, reduces the size of the gasification and cleanup islands.

Under the above two design approaches, the GT power is maintained as near-constant for all biomass blending cases, while the ST output power increases from the additional mass flow of the water saved due to the reduced cleaning requirements of the biomass-derived syngas. This water conserved from cleaning the syngas makes up for the fact that the water that is condensed from the syngas and added to the steam cycle decreases with increasing bmr (see tables 4 and 5.) This occurs because the dried and torrified biomass used actually contains less water than the type of coal chosen (see table 1.) The net output power is therefore dependent on the auxiliary (parasitic) power consumptions, including the energy needed for biomass pretreatment. Among three biomass blending cases, the 10% bmr case uses the least amount of parasitic energy and therefore produces the largest net output power and the highest net plant efficiency. However, notice that, even though the 30% and 50% bmr cases are less efficient than 10% bmr case, they are still more efficient than the corresponding pure coal case. For gross efficiency, the reduced heat losses are more than enough to keep the efficiency above that of pure coal. However, the greater burden on the auxiliary (parasitic) loads forces a clear, gradual reduction in net efficiency as the bmr increases beyond 10% for both the subcritical and supercritical cycles.

The baseline efficiency seems low at first. However, this is because lignite, which has a very low heating value, was chosen as the main fuel. Using a higher-rank coal, such as Illinois #6 or Pittsburgh #8, can increase the efficiency by as much as 3 and 4.5 percentage points (not shown), respectively.

Table 3 Work and Efficiency Data for Supercritical Plants

Biomass/Coal Ratio	0%	10%	30%	50%
Gross GT Power (kW)	200,019	200,017	200,017	200,017
Gross ST Power (kW)	122,573	122,602	122,946	123,262
Auxiliary Losses (kW)	55,481	54,413	57,873	61,235
Total Net Power (kW)	**267,111**	**268,207**	**265,090**	**262,043**
Gross Elect. Efficiency (LHV)	44.29	44.84	45.18	45.52
Net Elect. Efficiency (LHV)	**36.67**	**37.28**	**37.08**	**36.89**

The heat loss data for all cases is presented in Tables 4 and 5. For clarification, "Acid Gas Removal" is the heat needed to activate the thermochemical process of desulfurization while "AGR heat loss" is the actual heat lost during the process due to irreversibilities and piping heat losses. Next, looking at the heat loss data, it is discovered that syngases coming from higher bmr blends universally lose less heat from cleanup than syngases from lower bmr blends. Yet, the supercritical cycle's losses are nearly identical to those of the subcritical cycle. Looking at the syngas compositions in Tables 4 and 5, it is easy to see that the raw syngas from the supercritical plants' gasifiers have almost the same composition as those of the subcritical plants, with any differences able to be attributed to round-off error. This would make sense, since the gasification block should not change from plant to plant: only the steam cycle design and the mass flow rates through it. It thus makes sense that the cleanup system for both sets of plants should be similar as well. Of interesting note is the fact that the supercritical plants require more water to be drained from the raw syngas before cleaning. This is probably due to the increased demand of water from the steam cycle. Appropriately enough, this means that the coolers in place before acid gas removal will need to reject less heat to the surroundings since the syngas mixture at this point will have a lower specific heat.

Tables 5 and 6 show the raw syngas compositions and the volume fractions of H_2S and COS that must be removed before feeding the syngas to GT combustor.

Table 4 Heat Loss Data for Subcritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
Acid Gas Removal (Btu/s)	5,197	4,532	3,534	2,562.9
Syngas Water Condensed (Btu/s)	22,445	21,584	21,168	20,765
AGR heat loss (Btu/s)	611.2	533.0	415.6	301.5
Slag Production (Btu/s)	14,473	13,843	13,451	13,071
Cooler Heat Rejection (Btu/s)	167,317	156,460	151,001	145,686

Table 5 Heat Loss Data for Supercritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
Acid Gas Removal (Btu/s)	5,197	4,532	3,534	2,563
Syngas Water Condensed (Btu/s)	23,284	22,402	21,979	21,569
AGR heat loss (Btu/s)	611.2	533.1	415.6	301.5
Slag Production (Btu/s)	14,473	13,843	13,452	13,072
Cooler Heat Rejection (Btu/s)	164,001	153,195	147,746	142,441

Table 6 Raw syngas compositions (vol%) for subcritical IGCC plants

Biomass/Coal Ratio (vol%)	0%	10%	30%	50%
CO	14.34	14.98	15.47	15.97
CO_2	9.146	8.776	8.726	8.670
CH_4	0.0221	0.0274	0.0299	0.0327
H_2	14.11	14.76	14.91	15.06
H_2S	0.1575	0.1434	0.1142	0.0846
H_2O	61.43	60.56	60.03	59.51
COS	0.0052	0.0047	0.0038	0.0029
N_2	0.6054	0.5726	0.5374	0.5016

Table 7 Raw syngas compositions (vol%) for supercritical IGCC plants.

Biomass/Coal Ratio (vol%)	0%	10%	30%	50%
CO	14.32	14.98	15.47	15.97
CO_2	9.147	8.776	8.726	8.670
CH_4	0.0221	0.0274	0.0299	0.0327
H_2	14.11	14.76	14.91	15.06
H_2S	0.1575	0.1435	0.1142	0.0846
H_2O	61.42	60.55	60.03	59.51
COS	0.0052	0.0047	0.0038	0.0029
N_2	0.6054	0.5727	0.5374	0.5016

The emissions data in Tables 8 and 9 shows that the overall emissions for each type of pollutant (NO_x, SO_x, and CO_2) universally decreases with increasing biomass ratio. In the supercritical cases, the CO_2 output for each supercritical case is greater than the corresponding subcritical case by about 90,000-100,000 tons/year, due to the presence of the duct burner mentioned earlier. However, on a per unit output power basis (ton/MW-year), the CO_2 emissions actually *increase* for increasing bmr in the supercritical IGCC cases, albeit by a very small amount. The only exception is from 0% to 10% bmr, where there is a sharp decrease just for adding biomass to the feedstock. While the CO_2 emissions beyond this point do increase, note the fact that the emissions for the biomass blends are still *always lower* than they are for pure coal.

The *effective* CO_2 on the other hand always decreases with increasing bmr. The effective CO_2 is determined by calculating the neutral CO_2 from biomass and subtracting it from the gross CO_2.

Table 8 Emissions Data for Subcritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
NO_x (tons/year)	234.7	232.5	232.1	231.8
SO_x (tons/year)	2,157.5	1,869.6	1,457.7	1,057.3
Gross CO_2 (tons/year)	2,110,246	2,045,916	2,042,789	2,039,757
Eff. CO_2 (tons/year)	2,110,246	1,824,817	1,388,924	965,167
Gross CO_2 (tons/MW-year)	8,942	8,620	8,719	8,819
Eff. CO_2 (tons/MW -year)	**8,942**	**7,688**	**5,928**	**4,173**

Table 9 Emissions Data for Supercritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
NO_x (tons/year)	234.7	232.5	232.1	231.8
SO_x (tons/year)	2,157.6	1,868.7	1,457.7	1,057.3
Gross CO_2 (tons/year)	2,220,582	2,141,202	2,137,838	2,134,566
Eff. CO_2 (tons/year)	2,220,582	1,920,103	1,483,973	1,059,975
Gross CO_2 (tons/MW-year)	8,313	7,983	8,064	8,146
Eff. CO_2 (tons/MW -year)	**8,313**	**7,159**	**5,598**	**4,045**

Lastly, for the economic impact of these plants, see Tables 10 and 11. Note that, the additional \$10,000,000 for a torrefaction plant is ~1% of the total capital cost, meaning that it is insignificant compared to the total plant cost. Not to mention, co-gasifying biomass with coal actually *reduces* the total investment by a significant amount. The cost analysis program report (not shown) showed that the biggest saving is in the piping system and the gasifier itself. Not entirely clear at first, but looking back at the work data, the gross GT work is constant. Based on the design criteria, this leads to the discovery that using biomass in the gasifier means that *a smaller gasifier can be used* and the plant will still get the same net power output. As explained earlier, this is possible because of the reduced necessary syngas flow rate to the GT. This difference alone accounts for nearly 80% of the price reduction seen in the tables. This results in reductions of the capital cost for both subcritical and supercritical IGCC plants.

The cost of electricity (CoE) actually decreases from 0% to 10% bmr due to the reduced size of the cleanup and gasification islands for both sets of cases. However, it rises again beyond 30% due to the added extra cost of the biomass. CoE is calculated based on levelized capital cost, O&M costs, interest, and the costs of water and fuel.

Table 10 Economic Analysis for Subcritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
Total capital cost (millions of $)	1,029.75	926.74	911.62	897.44
Capital cost ($/kW)	4,363	3,904	3,891	3,880
CoE ($/kW-hr)	0.1008	0.0979	0.1084	0.119

Table 11 Economic Analysis for Supercritical IGCC Plants

Biomass/ Coal Ratio	0%	10%	30%	50%
Total capital cost (millions of $)	1,087.58	983.83	970.95	956.03
Capital cost ($/kW)	4,072	3,668	3,663	3,648
CoE ($/kW-hr)	0.0972	0.0947	0.1041	0.1133

The Energy Information Administration's (EIA) data for 2010 has stated that the average capital cost for a typical IGCC plant is around $3,200-$3,500/kW [19], which is about 25% lower than the baseline case for this study. This is mostly because the EIA's data is based on a system that is over 600MW, and larger plants will always be cheaper on a per unit power basis than smaller ones like this. However, the ongoing 630 MW IGCC construction project of Duke Energy's Edwardsport Station in Knox County, Indiana recently reported a cost overrun [20]. A new cost cap of $2.987 billion was imposed, which translates to a capital cost of $4,741/kW or 9% above the price of the baseline case of this study. Therefore, it is believed the cost analysis of this study is more in line with the actual expenses based on 2011 economic conditions.

As mentioned earlier, lignite was chosen as a fuel due to its cheaper price tag. Illinois #6 and Pittsburgh #8 are higher-rank coals, but they are also more expensive. For a subcritical, pure coal plant, the capital cost for Illinois #6 and Pittsburgh #8 (not shown) are lower than that of the baseline shown: $3,750/kW and $3,534/kW, respectively. The lower cost results from a reduced gasifier and cleanup system size due to the increased heating value of the alternative coals. The CoE (not shown) for both of these coals is also slightly lower: $0.0996/kW-hr for Illinois #6 and $0.0926 for Pittsburgh #8.

For qualitative differences between the cases, see Figs. 5-11 for further examination. In Figs. 9-10, even though the supercritical gross CO_2 emissions are approximately 90,000 tons/year greater than the data plotted, the differences between individual cases is still about the same. Therefore, only the data for the subcritical plants is shown in this figure.

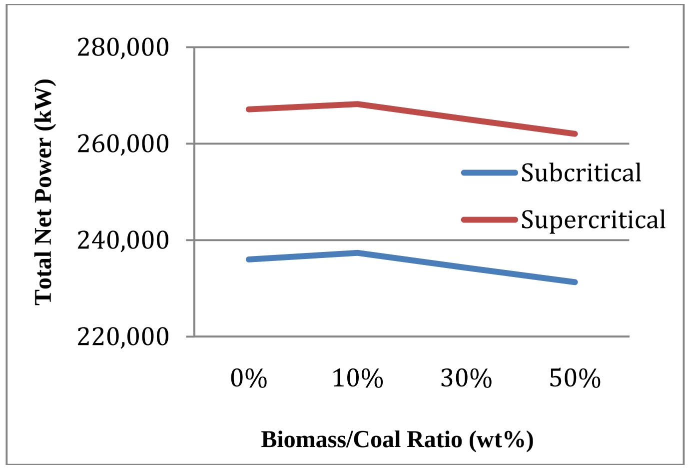

Figure 5 Total net power for various amounts of biomass

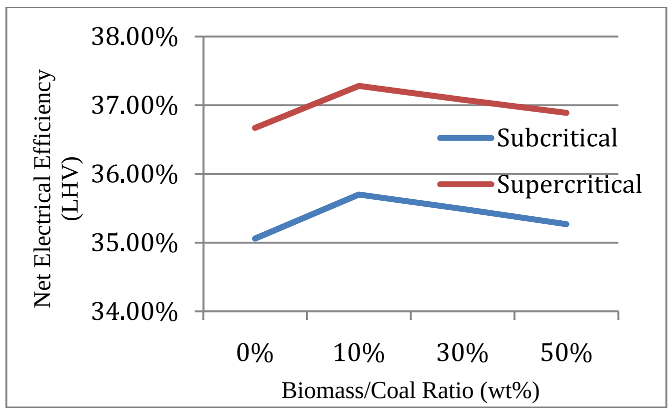

Figure 6 Net efficiency for various amounts of biomass

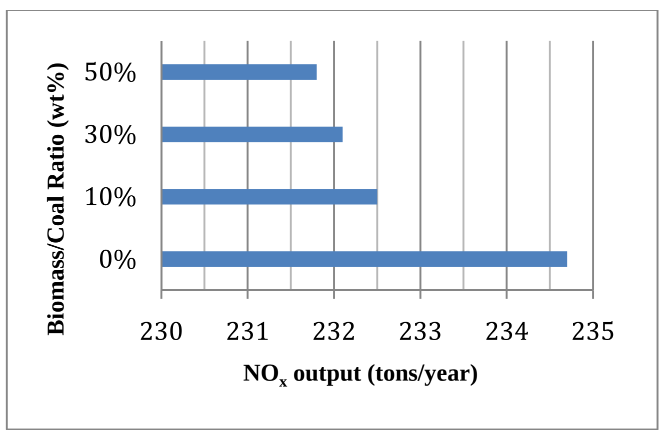

Figure 7 NO_x emissions for various amounts of biomass blending (both plants nearly identical)

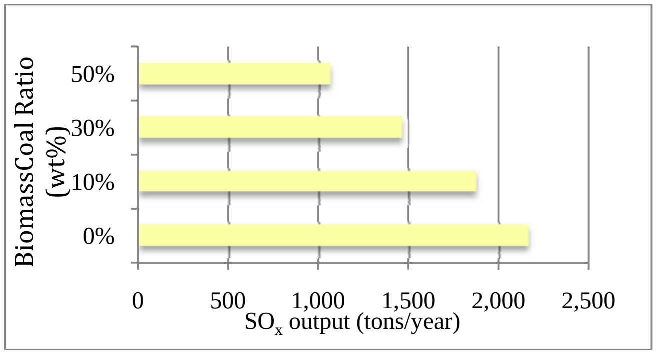

Figure 8 SO_x emissions data for various amounts of biomass (both plants nearly identical)

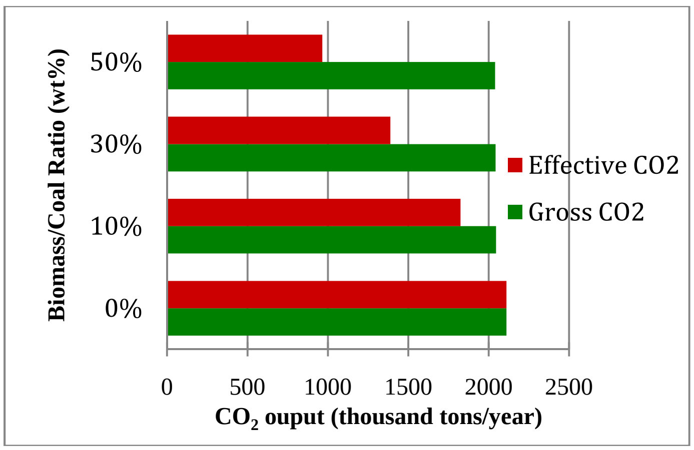

Figure 9 CO_2 output for various amounts of biomass (subcritical only)

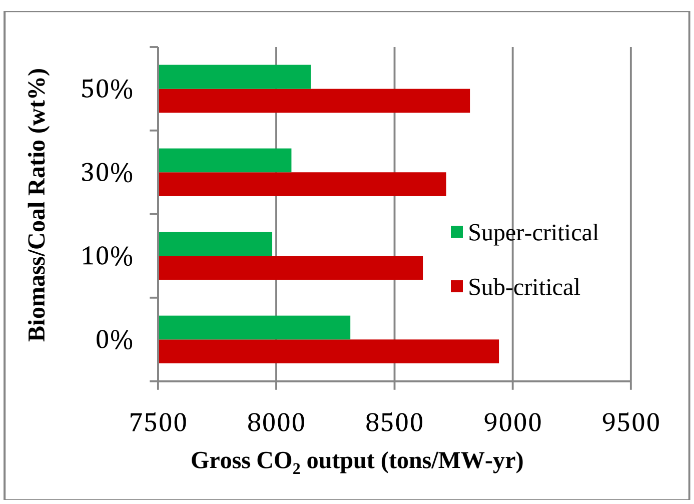

Figure 10 Gross CO_2 output for various amounts of biomass, per MW basis.

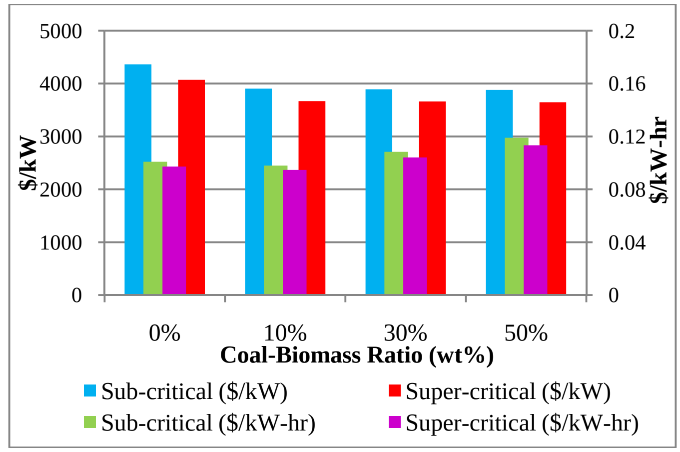

Figure 11 Average costs for sub- and supercritical IGCC cycles with varying amounts of biomass.

CONCLUSIONS

In summary, this study was performed using GTPro®, a program from the Thermoflow® software suite. It was implemented with a GE/Texaco gasifier and Siemens-Westinghouse SGT6-4000F gas turbine, and the plant was assumed to be constructed in southern Louisiana using Texas Lignite and sugarcane bagasse as fuels. The results show that the net plant efficiency increases at 10% bmr for both sets of cases, but decreases thereafter. However, the efficiency of the blended cases remains higher than the baseline, pure coal cases for *all blend ratios*. The baseline efficiency seems low at first. However, this is because lignite, which has a very low heating value, was chosen as the studied main fuel. Using a higher-rank coal, such as Illinois #6 or Pittsburgh #8, can increase the efficiency by as much as 3-4 percentage points alone and actually reduce the capital cost and CoE due to a reduction in required gasifier size. The emissions (NO_x, SO_x, and effective CO_2) and the capital costs all decrease as the biomass ratio increases. However, the cost of electricity increases with bmr due to how expensive obtaining the biomass is. With these results in mind, the following conclusions can be drawn:

- Adding biomass to a lignite plant's design is always beneficial to the efficiency of said plant if the plant is designed with the use of biomass in mind for a specific GT and ST. The efficiency improvement will vary based on different coals and biomass used.

- 10% biomass appears to be the optimal point of operation, since beyond this amount, the cost of using such a valuable type of biomass quickly becomes significant, and may in fact hinder the plant's economic sustainability. In addition, a bmr of 10% boasts the highest efficiency within each set of cases due to a reduction in the sizes of the cleanup and gasification islands. 50% biomass, however, does not appear to be an attractive economic option due to the high CoE.

- Factoring in biomass's neutral CO_2 shows that using biomass will always result in lower CO_2 output than pure coal plants, and also has a significant (reduction) effect on NO_x production.

- Implementing a supercritical steam cycle is shown to increase the net plant output power by 13% and the thermal efficiency by about 1.6 percentage point (or 4.56%) with 6.7% reduction of the capital cost and 3.5% reduction of COE.

Implementing a supercritical steam cycle in an IGCC system is feasible, but requires additional equipment and considerations before it should be attempted. At the very least, a duct burner must be added, or a larger GT with a potentially higher exit temperature must be used. Again, to the authors' knowledge, no power generation system of this type has been documented, much less actually constructed. It is highly recommended that a test plant be constructed in the future to determine the viability of such a system.

ACKNOWLEDGMENTS

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Appendix (Energy and Efficiency reports for Select Plants)

0% bmr, subcritical

System Summary Report

GT PRO 21.0 parallel

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RK\THERMOFLOW\BETTER PLANT DESIGN\SUBCRITICAL QUENCH - 0% BIOMASS.GTP

Plant Configuration: GT, HRSG, and condensing reheat ST

One SGT6-4000F Engine (Physical Model), One Steam Turbine, GT PRO Type 10, Subtype 2

Steam Property Formulation: Thermoflow - STQUIK

SYSTEM SUMMARY

	Power Output kW		LHV Heat Rate BTU/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	200019		8299		41.12	
Steam Turbine(s)	89477					
Plant Total	289496	235997	7934	9732	43.01	35.06

PLANT EFFICIENCIES

PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, BTU/kWh
29.58	24.10	31.36	8336

GT fuel HHV/LHV ratio =	1.083			
DB fuel HHV/LHV ratio =	1.083			
Total plant fuel HHV heat input / LHV heat input =	1.107			
Fuel HHV chemical energy input (77F/25C) =	2541736	kBTU/hr	706038	BTU/s
Fuel LHV chemical energy input (77F/25C) =	2296762	kBTU/hr	637989	BTU/s
Total energy input (chemical LHV + ext. addn.) =	2548619	kBTU/hr	707950	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	2567576	kBTU/hr	713216	BTU/s

GAS TURBINE PERFORMANCE - SGT6-4000F (Physical Model)

	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	BTU/kWh	lb/s	F
per unit	200019	41.12	8299	1028	1100
Total	200019			1028	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV (77F/25C) per gas turbine =	1798009	kBTU/hr	499447	BTU/s
Fuel chemical LHV (77F/25C) per gas turbine =	1659960	kBTU/hr	461100	BTU/s

STEAM CYCLE PERFORMANCE

HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kBTU/hr
77.34	89477	38.11	29.47	-251857

Number of steam turbine unit(s) =	1			
Fuel chemical HHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1035892	kBTU/hr	287748	BTU/s
Water/steam to gasification plant =	28819	kBTU/hr	8005	BTU/s
Water/steam from gasification plant =	70329	kBTU/hr	19536	BTU/s
Net process heat output as % of total output =	-45.51	%		

0% bmr, supercritical

System Summary Report

GT PRO 21.0 parallel

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rk\Thermoflow\Better Plant Design\SUPERCRITICAL QUENCH - 0% BIOMASS.GTP

Plant Configuration: GT, HRSG, and condensing reheat ST

One SGT6-4000F Engine (Physical Model), One Steam Turbine, GT PRO Type 10, Subtype 2

Steam Property Formulation: IFC-67

SYSTEM SUMMARY

	Power Output kW		LHV Heat Rate BTU/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	200019		8299		41.12	
Steam Turbine(s)	122573					
Plant Total	322592	267111	7705	9306	44.29	36.67

PLANT EFFICIENCIES

PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, BTU/kWh
31.53	26.39	33.02	8104

GT fuel HHV/LHV ratio =	1.083			
DB fuel HHV/LHV ratio =	1.11			
Total plant fuel HHV heat input / LHV heat input =	1.107			
Fuel HHV chemical energy input (77F/25C) =	2751301	kBTU/hr	764250	BTU/s
Fuel LHV chemical energy input (77F/25C) =	2485624	kBTU/hr	690451	BTU/s
Total energy input (chemical LHV + ext. addn.) =	2741115	kBTU/hr	761421	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	2760346	kBTU/hr	766763	BTU/s

GAS TURBINE PERFORMANCE - SGT6-4000F (Physical Model)

	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	BTU/kWh	lb/s	F
per unit	200019	41.12	8299	1028	1100
Total	200019			1028	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV (77F/25C) per gas turbine =	1798046	kBTU/hr	499457	BTU/s
Fuel chemical LHV (77F/25C) per gas turbine =	1659994	kBTU/hr	461109	BTU/s

STEAM CYCLE PERFORMANCE

HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kBTU/hr
80.94	122573	42.19	34.15	-255492

Number of steam turbine unit(s) =	1			
Fuel chemical HHV (77F/25C) to duct burners =	209505	kBTU/hr	58196	BTU/s
Fuel chemical LHV (77F/25C) to duct burners =	188309	kBTU/hr	52447	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1221701	kBTU/hr	340195	BTU/s
Water/steam to gasification plant =	28818	kBTU/hr	8005	BTU/s
Water/steam from gasification plant =	79225	kBTU/hr	22007	BTU/s
Net process heat output as % of total output =	-38.95	%		

10% bmr, subcritical

System Summary Report

GT PRO 21.0 parallel
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rk\Thermoflow\Better Plant Design\SUBCRITICAL QUENCH - 10% BIOMASS.GTP
Plant Configuration: GT, HRSG, and condensing reheat ST
One SGT6-4000F Engine (Physical Model), One Steam Turbine, GT PRO Type 10, Subtype 2
Steam Property Formulation: Thermoflow - STQUIK

SYSTEM SUMMARY						
	Power Output kW		LHV Heat Rate BTU/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	200018		8307		41.08	
Steam Turbine(s)	89790					
Plant Total	289807	237356	7827	9557	43.59	35.70

PLANT EFFICIENCIES			
PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, BTU/kWh
30.15	24.60	31.90	8333

GT fuel HHV/LHV ratio =	1.083			
DB fuel HHV/LHV ratio =	1.083			
Total plant fuel HHV heat input / LHV heat input =	1.103			
Fuel HHV chemical energy input (77F/25C) =	2501652	kBTU/hr	694903	BTU/s
Fuel LHV chemical energy input (77F/25C) =	2268428	kBTU/hr	630119	BTU/s
Total energy input (chemical LHV + ext. addn.) =	2520301	kBTU/hr	700084	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	2539259	kBTU/hr	705350	BTU/s

GAS TURBINE PERFORMANCE - SGT6-4000F (Physical Model)					
	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	BTU/kWh	lb/s	F
per unit	200018	41.08	8307	1026	1102
Total	200018			1026	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV (77F/25C) per gas turbine =	1799918	kBTU/hr	499977	BTU/s
Fuel chemical LHV (77F/25C) per gas turbine =	1661637	kBTU/hr	461566	BTU/s

STEAM CYCLE PERFORMANCE				
HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kBTU/hr
77.38	89790	38.22	29.57	-251873

Number of steam turbine unit(s) =	1			
Fuel chemical HHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1036152	kBTU/hr	287820	BTU/s
Water/steam to gasification plant =	25133	kBTU/hr	6981	BTU/s
Water/steam from gasification plant =	69632	kBTU/hr	19342	BTU/s
Net process heat output as % of total output =	-45.13	%		

50% bmr, subcritical

System Summary Report

GT PRO 21.0 parallel
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rk\Thermoflow\Better Plant Design\SUBCRITICAL QUENCH - 50% BIOMASS.GTP
Plant Configuration: GT, HRSG, and condensing reheat ST
One SGT6-4000F Engine (Physical Model), One Steam Turbine, GT PRO Type 10, Subtype 2
Steam Property Formulation: Thermoflow - STQUIK

SYSTEM SUMMARY						
	Power Output kW		LHV Heat Rate BTU/kWh		Elect. Eff. LHV%	
	@ gen. term.	net	@ gen. term.	net	@ gen. term.	net
Gas Turbine(s)	200017		8316		41.03	
Steam Turbine(s)	90551					
Plant Total	290567	231290	7701	9675	44.31	35.27

PLANT EFFICIENCIES			
PURPA efficiency	CHP (Total) efficiency	Power gen. eff. on	Canadian Class 43
%	%	chargeable energy, %	Heat Rate, BTU/kWh
29.64	24.01	31.46	8298

GT fuel HHV/LHV ratio =	1.081			
DB fuel HHV/LHV ratio =	1.081			
Total plant fuel HHV heat input / LHV heat input =	1.097			
Fuel HHV chemical energy input (77F/25C) =	2453744	kBTU/hr	681595	BTU/s
Fuel LHV chemical energy input (77F/25C) =	2237765	kBTU/hr	621601	BTU/s
Total energy input (chemical LHV + ext. addn.) =	2489670	kBTU/hr	691575	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	2508630	kBTU/hr	696842	BTU/s

GAS TURBINE PERFORMANCE - SGT6-4000F (Physical Model)					
	Gross power	Gross LHV	Gross LHV Heat Rate	Exh. flow	Exh. temp.
	output, kW	efficiency, %	BTU/kWh	lb/s	F
per unit	200017	41.03	8316	1026	1103
Total	200017			1026	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV (77F/25C) per gas turbine =	1798486	kBTU/hr	499579	BTU/s
Fuel chemical LHV (77F/25C) per gas turbine =	1663295	kBTU/hr	462026	BTU/s

STEAM CYCLE PERFORMANCE				
HRSG eff.	Gross power output	Internal gross	Overall	Net process heat output
%	kW	elect. eff., %	elect. eff., %	kBTU/hr
77.41	90551	38.50	29.80	-251904

Number of steam turbine unit(s) =	1			
Fuel chemical HHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV (77F/25C) to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1036831	kBTU/hr	288009	BTU/s
Water/steam to gasification plant =	14213	kBTU/hr	3948	BTU/s
Water/steam from gasification plant =	67494	kBTU/hr	18748	BTU/s
Net process heat output as % of total output =	-46.88	%		