Proceedings of ASME Turbo Expo 2011
GT2011
June 6-10, 2011, Vancouver, British Columbia, Canada

GT2011-45512

CASE STUDIES FOR BIOMASS/COAL CO-GASIFICATION IN IGCC APPLICATIONS

Henry A. Long, III and Ting Wang
Energy Conversion & Conservation Center
University of New Orleans
New Orleans, LA 70148, USA
E-mails: hlong@uno.edu; twang@uno.edu

ABSTRACT

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 sequestrated. However, there are challenges facing the effective utilization of biomass wastes: (a) biomass supply is limited and varies with the seasons, (b) biomass density is low and expensive for long-distance transportation, and (c) due to a limited supply of feedstock, biomass plants are usually small, which results in higher capital and production costs. Considering these challenges, it is more economically attractive and less technically challenging to co-combust or co-gasify biomass wastes with coal.

This paper focuses on discussing issues associated with coal/biomass co-gasification as well as an investigation into the effect of adding different amounts of biomass up to 50% (wt.) on a 250MW IGCC plant's performance, although a smaller plant of 75MW using 100% biomass is also included for comparison. The Siemens SGT6-6000G and Alstom GT8C2 gas turbines are used in the larger and smaller plants respectively. The results show the plant's efficiency increases first as 10% biomass is added; then decreases as the biomass is increased to 30%; and increases again once the biomass reaches 50%. The variation of efficiency is minor, only within one percentage between 38% and 39%. The advantage of adding biomass can be seen from the almost proportional reductions of SO_x, ash, energy for H_2S removal, water for scrubber, and the effective CO_2 emission. The effective CO_2 is calculated by subtracting the neutral CO_2 that is theoretically produced by burning the added biomass.

BACKGROUND AND MOTIVATION

With the public growing ever more environmentally conscious, the U.S. Government is taking steps to reduce the environmental impacts of human activities. In this day and age, a power company that utilizes commonly perceived "dirty" fuels like coal and oil is under heavy scrutinization to clean up its proceedings, especially through the use of taxes and fines. The pending discussions of the "carbon tax," which aims to charge power companies a fine for every ton of their annual carbon-based emissions every year, only serves to increase this burden on electrical power companies. Thus, it becomes ever more important politically, environmentally, and economically to reduce plant emissions to help make the environment cleaner and, in the meantime, to maintain a good public and political image.

Integrated Gasification Combined Cycle (IGCC)

Using IGCC technology results in lower emissions and more energy efficiency than a standard pulverized coal (PC) plant[1]. In addition, IGCC allows implementation of pre-combustion carbon capture and storage (CCS), which is typically much cheaper than post CCS for a PC plant. Furthermore, as this paper aims to demonstrate, using biomass in an existing coal IGCC plant will only further increase these benefits, albeit at a slight drop in gross power output. To avoid some of the added costs of bio-fuels, biomass waste products, bagasse in this instance, can be used for lower costs than biomass crops; and, in some cases, these costs can be turned into profits for removing materials that were going to be incinerated or thrown away to begin with.

In addition, from a biomass perspective, it is more economically feasible to co-gasify biomass with coal than to continue using biomass by itself. Because biomass availability is seasonal, cannot be transported over long distances ecomomically, has low energy density, and biomass itself is basically limited to smaller scale applications due to its limited supply. Thus, by mixing biomass with coal feedstocks, biomass can be used in much larger plants, allowing it to make use of the same economy and efficiency of scale that coal is. Also, seasonality would no longer be an issue because the larger plants could still function on coal alone for the seasons in which biomass availability is limited or nonexistant.

Ultimately, the goal of this study is to demonstrate the effectiveness of biomass and coal being gasified together; so that co-gasification can be devleoped into acost-effective and environmentally friendly source of electrical power, partly alleviating the effects of the energy-depency on foriegn oils/gas, increasing the process efficiency, and easing environmental concerns at the same time.

The objectives of this study are to (a) review the feedstock preparation for biomass and its integration with coal feeding, (b) examine potential issues related to the chemistry during biomass and coal gasification and their impact to the syngas, and (c) investigate the performance of IGCC power plants with different mass ratios of biomass/coal using the commercial software, Thermoflow.

AN OVERVIEW OF GASIFICATION

To begin, gasification is *not* combustion. Combustion involves blasting carbon-rich feedstock with large amounts of oxygen or other fuel-gas in order to release massive amounts of heat energy. In other words, it is an exothermic reaction. In a typical coal combustion power plant, the hot gases produced from combustion, since they cannot safely be put through a gas turbine as is, are used to heat up water/steam through a heat exchanger, which is then run through one or more steam turbines to produce electrical power. Typical products of combustion are H_2O, SO_x, NO_x, CO_2, and HCl. Combustion also tends to leave behind lots of ash that must, by law, be cleaned up and disposed of.

Gasification however, begins with an endothermic process known as *pyrolysis*, where the a small part of carbon-based feedstock is burned to provide heat that is needed to drive out moisture and volatiles, but in the absence or poor presence of oxygen. After pyrolysis, more heat is needed to thermally crack the volatiles to break the long hydrocarbonchains into lighter gases as well as to gasify the remaining carbon left in the feedstock into synthesis gases (or syngas in short).The chemical makeup of syngas tends to consistpredominantly of CO and H_2 with small amount of CH_4 as fuel and CO_2, N_2, and water vapor as non-combustable gases. The syngas also contains H_2S, COS, HCN, HCl, Hg, and other cotaiminants that will need to be removed before utilizing the syngas for power generation [2]. Unlike combustion, the goal of gasification is to produce these syngases, which can then be separated into components and used for different applications in a more efficient manner, which makes up for the initial energy investment necessary to produce the syngases.

All of this occurs within a single device, rightly called a *gasifier*. The most common fuel used in gasification, however, is coal. After the volatiles leave the feedstock, what is left in the gasifier is *char*, which is basically pure carbon. Once this occurs, the char is reacted using air/oxygen and steam to produce carbon monoxide (CO), carbon dioxide (CO_2), and diatomic hydrogen (H_2). These reactions are called Heterogeneous Phase Reactions, because they have a nonuniform reactant phase distribution: some reactants are solid and some are gaseous.

Heterogeneous Reactions

$$\mathbf{2C + O_2 \rightarrow 2CO} \qquad (R1.1)$$
$$\mathbf{2CO + O_2 \rightarrow 2CO_2} \qquad (R1.2)$$
$$\mathbf{C + H_2O \rightarrow CO + H_2} \qquad (R1.3)$$
$$\mathbf{C + CO_2 \rightarrow 2CO} \qquad (R1.4)$$
$$\mathbf{C + 2H_2 \rightarrow CH_4} \qquad (R1.5)$$

Using air for reactions 1.1 and 1.2 is an acceptable substitute for pure oxygen, but it introduces extra nitrogen to the process, which usually results in more NO_x emissions, a lower heating value for the syngas, and requires larger pipes and a larger clean-up system. Pure oxygen is preferred in this sense, but using oxygen requires the use of an air-separation unit (ASU), like a distillation tower, which comes with additional energy costs, and a subsequent loss in net power output. Which method to use is dependent upon the rest of the plant setup. Gasifiers that use unaltered air are called "air-blown" gasifiers, and those that use ASUs are likewise called "oxygen-blown" gasifiers.

From here, among other reactions between existing volatiles, an equilibrium reaction (called the Water-gas Shift Reaction, R1.6) is established, along with two other methane producing reactions, all of which are called *Homogenous Phase Reactions,* named so because all reactants involved are gases. In other words, the phase distribution is homogeneous.

Homogeneous Reactions

$$\mathbf{CO + H_2O \leftrightarrow CO_2 + H_2} \qquad (R1.6)$$
$$\mathbf{CO + 3H_2 \rightarrow CH_4 + H_2O} \qquad (R1.7)$$
$$\mathbf{2CO + 2H_2O \rightarrow CO_2 + CH_4} \qquad (R1.8)$$

Also, a few other reactions do occur, in which some carbon monoxide is converted further to carbon dioxide, and some hydrogen gets converted back into water. It is at this point that the concentrations of char, carbon monoxide, carbon dioxide, water, methane, and hydrogen achieve a degree of equilibrium. For most applications, a good gasifier design will allow for maximum production of carbon *mono*xide and hydrogen. In the case of IGCC, this should be supplemented by a copious amount of steam, but not enough to reduce the syngas's Lower Heating Value (LHV) below the gas turbine's requirements. Methane is not a major concern for most gasifiers used in providing direct electrical power, because its main use is as a substitute natural gas. In addition, most gasification conditions will deliver very small, inconsequential amounts of CH_4: not nearly enough for its presence to matter, even in the face of its high heating value. After leaving the gasifier, the syngases are separated from the other volatiles using *Gas Cleanup* Technologies. Processes like cyclone filters, misting technologies, and "scrubbers" are examples of such technologies. These Gas Cleanup systems "clean" the useable gases (namely CO and H_2) of their impurities, like COS, H_2S, and so on. The advantage of gasification is that many of these other impurities or contaiminants can be removed before combustion, so they will not be released to the atmoshpere through the exhaust. In addition, some of these contaiminants, when separated, can be used in other applications or sold for profit as such. For example, H_2S is used to denature proteins, and has use in other such chemical applications. COS is a primary ingredient in weed killers. Element sulfur and H_2SO_4 are valuable byproducts which can be sold on the market. Lastly, slag produced can be used in concrete applications.

There are many different types of gasifiers available, ranging from lower temperature and pressure, and larger grain size to larger body size and higher flow rate types. The next few sections discuss some basic strengths and weaknesses and design layouts of typical commercial gasifiers.

The Down-Draft Gasifier

The down draft gasfiter gets its name from the fact that the air or oxygen combusting agent is injected into the top of the gasifier and flows towards the bottom. Since the typical feedstock is also fed from the top of the gasifier (resulting in both the input air and feedstock flowing in the same direction), this model is also called the “co-current” or “co-flow” gasifier. Typically, the internal temperature of a typical down-draft gasifier is between about 800 and 1200°F. Because both streams flow in the same direction, the highest temperatures in the whole process occur during the combustion process.The pyrolysis and thermal cracking stages take place in this high-temperature zone. The result is that there is lower tar and ash production compared to other gasifier types, and, as such, there is less syngas cleanup necessary for this type of gasifier for the same type of feedstock. Because of its ability to eliminate tar from the resulting syngas, especially for biomass feedstock, this type of gasifier has been affixed to many existing combustion engines since early World War II [3].

A typical problem that occurs in this type of gasifier is that the input feedstock cannot have very high moisture content, so it is not possible to send in a slurry-based feedstock, nor is non-dried biomass a useable fuel source. Another disadvantage is that a decent portion of the char produced during pyrolysis (about 6% or so) is left completely unconverted. And, lastly, unlike its cousin, the up-draft gasifier, the down-draft gasifier expels syngas at fairly high temperatures, which will result in much wasted heat if it is not recovered in some way [4].

The Up-Draft Gasifier

A close relative of the down-draft gasifier is designed for the gasification agent (oxygen or air) to enter from the *bottom* of the gasifier (i.e. the “draft” blows *up* instead of down.) Since the feedstock is still fed from the top of the up-draft gasifier (as it is for this gasifier’s cousin, the down-draft gasifier), this gasifier is also called the “counter-flow” or “counter current” gasifier. Simply changing the flow direction and origin of the input air has drastic effects on gasifier performance. For one, since the input air(or oxygen) enters from the bottom of the gasifier, it acts as a cooling agent for the hotter syngases leaving from the same general location. In addition, after gasification and combustion, the leftover hot air, because it blows past the input feedstock entrance, may be used as a “built-in” dryer for the fuel. Thus, there is much less wasted heat, which grants this gasifier design an efficiency boost over its cousin. Lastly, because of the “drying” effect, fuels with much higher moisture content can be utilized in up-draft gasifiers, especially certain types of biomass[3].

The biggest drawback that is readily observable in up-draft gasifiers is that they lack the down-draft gasifiers’ abilities to eliminate tar. As such, there is a great loss in efficiency to offset the reduced wasted heat, as most biomass feedstocks will tend to produce a lot of tar that must be cleaned extensively before the resulting syngas mixture may be used in any sort of application, especially for traditional combustion engines and gas turbines. Lastly, the peak temperature inside the gasifier is much higher in an up-draft gasifier than in its down-draft cousin; so high, in fact, that in many cases there is applicable risk to the devices inside the gasifier. This means that these devices (such as the grate that holds the bulk of the unconverted char) must be either (a) made from stronger, less temperature-sensitive materials, or (b) protected by blowing in steam or some other coolant to maintain a more agreeable temperature in that area of the gasifier [4].

The Fluidized Bed Gasifier

A very interesting and intuitive gasifier design, this type of gasifier uses fluidization to move the feedstock particles. Basically, the gasifier is filled with a bed of solid, dry feedstock particles (which may or may not actually be fuel particles. Sometimes, sand or gravel forms the bed and the fuel enters the bed with the gasifying agent), which is then met with a moving stream of fluid particles (usually the gasifying agent) that are allowed to seep through the pores and cracks in the solid medium. When the fluid flow rate reaches a certain “critical point,” the solid particles become fully suspended in the fluid: they begin to levitate freely and essentially begin to behave as a fluid themselves; hence, they have been “fluidized.”

Fluidized bed gasifiers are not suitable for extremely small-scale applications (< 10MW) because of their high heat transfer rates, which results from the high amount of exposed feedstock surface area [4]. They are also very complicated to operate, as the entire gasification process is very dependent upon a highly complicated equilibrium state, which must be maintained at all times. One particular strength of fluidized bed gasifiers is the fact that they do not produce slag (more about slag later), so they can use certain types of fuels that would ordinarily corrode the walls of slagging gasifiers. Instead, the stray ash is agglomerated into heavy particulates that easily fall out of the fluidized mixture and are swept out of the bed. In addition, they can operate more readily at higher temperatures than any fixed-bed gasifier can, making them much more suitable for coal gasification, especially for high-ranking coals.

However, fluidized bed gasifiers do not fair very well with feedstocks that have low ash fusion temperatures. Fluidized bed gasifiers must operate at generally higher temperatures than fixed bed gasifiers to be effective, so, naturally, using a fuel where the ash fusion temperature is too low will not allow for proper gasification. If the fuel is gasified anyway, the feedstock ash will melt and begin to stick to the bed particles, resulting in rapid bed de-fluidization: a terribly undesirable effect. Second, despite its name, the fuel feedstock must be put in dry, as a slurry feedstock will only inhibit the gasifier’s ability to produce a fluidized bed.

The Entrained Flow Gasifier

This particular gasifier gets its name from the fact that the feedstock particles and the gasification agent are a part of the same stream once inside the gasifier. In other words, the solid particles or liquid droplets of feedstock have been entrained, or “trapped” inside the gas stream, forming what is called an entrainment. This allows for a much more even temperature distribution and a more steady reaction rate. Entrained flow gasifiers are very common in very big power plants (> 200 MW) because they can achieve very high syngas mass flow rates, higher than any other gasifier type: a necessity for large plants. All entrained flow gasifiers produce slag. Most of the slag that is produced forms a protective coating along the sides of the gasifier, which protects the walls from more corrosive substances that may form during gasification. Entrained flow gasifiers are capable of undergoing gasification at very high temperatures (> 2000 °F), meaning that virtually no tar will form inside the gasifier. The greatest strength of the entrained flow gasifier, though, is that it can accept a wide variety of feedstocks. Since the flow regime is basically just a gas with particles suspended in it, any liquid or powdered/pulverized solid is a viable fuel input for entrained flow gasifiers, regardless of its atomic makeup.

Although, for all of their strengths, entrained flow gasifiers have a few debilitating drawbacks. For one, the required average feedstock particle size is extremely small, on the order of tenths to hundredths of millimeters in diameter [2]. This is not a problem for liquid feedstocks, but solids like coal and biomass must be pretreated before they can be used in an entrained flow gasifier. This is usually not a problem for coal, because it can simply be ground down and pulverized mechanically. Second, most entrained flow gasifiers typically require the use of oxygen, not air, as the gasifying agent. Very few entrained flow gasifiers are capable of using air, because the conditions in the gasifier make the presence of nitrogen a problem for syngas production: the high temperatures and pressures can cause large amounts of unwanted NO_x production, rendering the resulting syngas mixture virtually unusable for power applications. Because of this strict oxygen requirement, most all entrained flow gasifiers require an ASU in order to operate. Finally, the syngas that leaves the gasifier will have an extremely high temperature compared to the other gasifier types, and there will be a resulting energy loss from this during the cooling stage before it enters the gas cleanup system.

Transport Gasifier

A recently produced model that has been under testing since 1996, this gasifier type utilizes a similar structure to Circulating Fluidized Bed gasifiers (CFBs), except with higher velocities, rizer densities, and circulation rates [5]. Because the device can be run as both a combustor and a gasifier, it is sometimes called the “Transport Reactor” rather than transport gasifier. It is unique in that there is no true “bed” in the gasifier itself, as the feedstock and gasifying agent are constantly in motion throughout the system, much like an entrained flow gasifier, but with larger particles, since making an entrainment is not necessary. Ash and unconverted char particles are filtered out via a gravity-driven “disengager” (for larger particles) and a high-temperature cyclone filter (for smaller particles.) Particles separated in this fashion are sent back to the “mixing zone” where the feedstock enters the device. Currently, this gasifier can operate at temperatures up to 1825˚F and gage pressures of up to 240 PSI. The transport gasifier is still in the developmental stages, and, as of 2001, there are no dedicated commercial plants using this gasifier type as of yet, though there are plant designs being tested for use with this gasifier [5].

Coal Gasification

Coal is the basis for a very large portion of the United State’s national energy supply. As such, it is vital that new technologies continuously develop to improve coal’s role in providing electrical energy. In doing so, the U.S.’s dependence upon foreign oil will decrease, which can also lighten National Security issues in addition to economic ones. However, coal-power has several problems with its implementation. First, coal contains higher levels of sulfur than most fuels, which is the leading cause of the acid rain phenomenon. Second, unlike oil, coal produces large amounts of ash, the content of which is mostly transition metal oxides. Third, coal-based power is not as efficient as some other processes, either. But, coal power has enormous energy density. And, also, coal is cheap and happens to be one of the most vast energy resources available in the United States [7-9].

There are several types of coal that are used as fuel in industry. The most commonly known type of coal is black coal, more scientifically referred to as bituminous coal (Known as such because they contain the chemical compound bitumen). Bituminous coals are the most common and complex variety of all coals. There are many different sub-types, all with various elemental contentsJust below bituminous and the loosely defined Sub-bituminous coals is lignite. Lignite, also called “brown coal,” has less energy-producing capability than the other coal ranks, but it is, in turn, easier to gasify due to its high volatile content.However, the presence and arrangement of these volatiles make lignite especially prone to spontaneous combustion, making its transport and handling very dangerous. Lignite is also very moisture-rich, which makes it valuable in IGCC applications. The highest rank of coal is called Anthracite, sometimes called “black diamond.” While anthracite possesses the largest energy-producing potential of all coals, it is expensive, and is reserved mainly for smaller-scale applications. Large power plants prefer to use bituminous coal or lignite.

The “ash” in the coal is all non-carbon content that remains solid and unconverted after combustion or gasification occur. Ash contains numerous metal oxides and non-metal oxides that typically do not wind up in any syngas mixture.

When coal is gasified, the “dirty” aspect of coal is much less of an issue. Gas cleanup technologies prevent almost all of the pollutants from coal power from entering the atmosphere by separating them and containing them before combustion. As previously stated, in some gasification applications, the volatiles captured are used in other industrial and commercial applications. As a result, the flue gas that leaves the clean-up system consists of virtually nothing more than hydrogen, carbon-dioxide, and water, possibly with some leftover sulfur output. Coal is typically gasified at high temperatures in excess of 1800°F and at high pressures over 20atm.

Because of coal’s high ash content, when it is gasified, it is prone to producing slag, which is basically a block of what would be considered a collection of ore impurities if found among pure metals. Slag is produced when the temperature inside the gasifier exceeds the fuel’s ash fusion temperature (AFT), causing the ash to melt. When this molten ash solidifies, what results is slag.Slag production can be controlled or prevented by manipulating the temperature and pressure conditions inside the gasifier, and also controlling the amount of water put through the gasifier. When slag is produced, it is “drained” through the bottom of the gasifier bed and collected outside. Slag is a valuable commodity in the construction and metal smithing industries for its use in purifying metals and as a common ingredient in certain types of concrete.

In general, coal is more efficient when used in large-scale power plants, typically over 200 Mega-Watts(MW). Gasification power plants are more than capable of providing this kind of output, and many existing plants around the world are a testament to this fact.

Bio-Gasification

The use of biomass as an alternative energy source can be traced back to the first wood-fueled fire. Biomass is any material that is derived directly from living or previously living things. Examples include wood products, animal and plant waste, and biodegradable waste. In gasification, biomass produces more highly corrosive ingredients, because it has a much higher metallic ion content and produces higher levels of acidic substances than coal. It also has a much lower energy density. The most limiting factor in using biomass as a fuel, though, is its limited availability: it is not available year-round, it cannot be stored for extended periods of time because it can rot or decay, and there isn't much of it being produced. This means that using biomass for almost anything bigger than 50-80 MW is at best uneconomical. However, biomass produces cleaner syngases than coal does because of it's lower sulfur and ash contents and neutral carbon footprint [6].There's also a greater degree of complexity involved in processing biomass before gasification begins, given its highly complex structure and chemical makeup. Likewise, there are many more types of biomass available for use in gasification.

Biomass and coal are essentially chemical opposites: while coal contains a lot of sulfur and ash, biomass contains more oxygen and nitrogen and is more prone to producing tar. Coal contains many transition metals, while biomass contains more alkali and alkaline-earth metals [7], usually in the form of salts (especially sodium and potassium.) Biomass is also more likely to produce ammonia, which is useful as a cleaning agent, but can be emitted as a deadly pollutant if not properly contained. Biomass also has generally higher volatile content than coal, but coal has more fixed carbon and ash content [6,7].Of particular note is biomass's tendency to produce tar. Tar can be very damaging to the gasifier, as it tends to stick to the walls and clog the entrance and exit ports, especially when it is produced alongside slag. (As in, during Co-gasification discussed later.) Tar itself is also not useful as a fuel aside from its high carbon content. The solutions to this are to either (a) prevent tar build-up by manipulating the internal gasifier conditions (like in fluidized bed gasifiers) or (b) burn or thermally crack the tar as it forms in the gasifier so that it is no longer an issue (like in entrained flow and down-draft gasifiers.) Coal gasifiers can also produce tar, but the frequency and the amount are much less when biomass is not involved.

Biomass is typically gasified at lower temperatures than coal. And, also unlike coal, bio-gasification typically occurs at atmospheric pressure. This is because raising the pressure inside an enclosed space requires some degree of work or expense of energy, and, biomass can easily be gasified at atmospheric pressure, unlike coal, which requires much higher pressures to undergo efficient devolatization and gasification. It is therefore, usually, more efficient to gasify biomass at atmospheric pressure at no cost than to waste energy in raising the internal gasifier pressure. When gasified alongside coal, however, increased pressure becomes a necessity, so the argument over the expected efficiency of the biomass/coal co-gasification process is moot in that regard.

Biomass Pretreatment

Something worthy of note about biomass is the fact that it is very difficult to transport and use as feedstock. Biomass cannot be easily pulverized or slurried like coal can, so continuous feeding tends to be an issue. The biggest problem in this regard is that biomass has a highly fibrous, sinewy structure, making it hard to tear up and very easy to get stuck in most machines, especially between gears and in conveyor belt drives. A few steps to alleviate this issue have been taken through several technologies, In particular, torrefaction and flash pyrolysis, among others [7, 10-12].

As has already been discussed, pyrolysis is the first phase of the overall gasification process. Flash pyrolysis is performed before the biomass enters the gasifier so that it is converted into both char and a substance that can easily be poured into the gasifier bed like typical coal feedstock. This substance is usually called "bio-oil," and also has its uses outside of gasification [10]. This is very beneficial for biomass, as liquids are usable feedstock in just about every type of gasifier (except, perhaps, for down-draft gasifiers).

Flash pyrolysis is referred to as such because it occurs at a very fast rate. Typically, the biomass is able to reach temperatures of about 1200 °F in less than 1 second. In addition to this, there is another, higher temperature flash pyrolysis that mainly results in gaseous material, rather than a liquid. This readily produces a highly reactive syngas that is about 80% carbon monoxide and hydrogen by weight. Many other forms of pyrolysis at various max temperatures, heating rates, and miscellaneous conditions are used, each with markedly different resulting compound compositions and heating values.

Torrefaction is a process which converts biomass into a denser, more brittle, solid form. Torrefaction can be called a sort of mild pyrolysis, which occurs at temperatures of around 500°F over an extended period of about 5-10 minutes [11,12]. This process, like all types of pyrolysis, occurs in the absence of oxygen. During this process, the biomass releases most of its water content. There is an energy loss during this process, but the loss of mass is greater than the loss of energy, theoretically increasing the heating value (energy/mass) of the biomass [11, 12]. The end result is a conglomeration of pellet-like chips called torrefied biomass, also sometimes called "bio-coal." In fact, torrefied biomass very closely resembles coal in appearance, and greatly approaches its properties, as well.

Torrefaction is an available option to most types of biomass, especially those involving wood or wood products. The majority of reactions that occur are the same from one type of biomass to the next. However, the resulting compositions and mass and energy losses are much different from type to type.

Finally, torrefaction's most suitable usage is in pre-preparation for use with entrained flow gasifiers. The reason is because entrained flow gasifiers, as mentioned previously, require the feedstock input to essentially be a powder. (<0.15 mm grain size) Torrefied biomass is extremely brittle and can quite easily be crushed into whatever grain size is necessary, especially after pelletization, another process that increases biomass's density through the removal of further moisture [11].

IGCC – Integrated Gasification Combined Cycle

IGCC is an appropriate use for existing coal gasification plants. It is capable of producing electrical power with a total output efficiency of near 55% [13].The basic outline of IGCC (Fig. 1) is as follows:

1.) Raw feedstock enters the gasifier and undergoes gasification.

2.) Syngas is extracted and particulates are removed.

3.) The syngas is cooled so it canbe “cleaned.” (Syngas can theoretically be cleaned at higher temperatures, but that technology is still under development.)

4.) The syngas is cleaned in a series of devices that remove particulates, COS, H_2S, SO_x, NO_x, and halides from the mixture.

5.) The gas is then burned in a combustor and run through a gas turbine.

6.) The turbine exhaust is then run through a heat recovery steam generator (HRSG), where the waste heat is used to generate steam .

7.) The steam is run through a steam turbine, where additional electrical power is generated from the recovered waste heat.

IGCC was chosen for this study because of its readiness to accept a large variety of feedstock, making it highly desirable for co-gasification. Also, it has an innate high combined cycle efficiency due to the advancement of high-performance gas turbine and steam turbine systems . Lastly, since IGCC requires that the gases be cleaned up before they are burned in the turbine’s combustor, the process results in very low emissions.

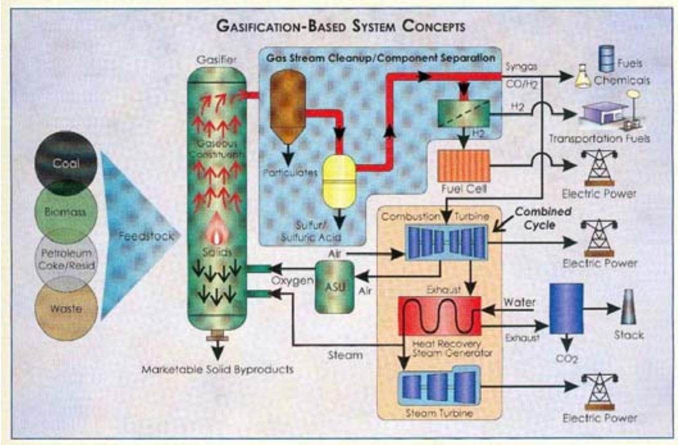


Figure 1 Typical IGCC plant using biomass feedstock (Source: U.S. Department of Energy)

There are severalsucessful commercially functioning IGCC plants in the world such as the Wabash River Station in West Terre Haute, Indiana and the Polk County Power Station in Tampa, Florida, the Buggenum plant in the Netherlands; and , the ELCOGAS plant in Puertollano, Spain [13].

Co-Gasification

It is the primary focus of this paper to determine the merits of mixing coal gasification with biomass. Specifically, to answer the question: “What happens when coal and biomass are mixed together?” In theory, the results are:

1.) Higher Energy Syngas
2.) Reduced Emissions, especially hazardous pollutants
3.)Lower gross power output, but higher themal efficiency

As discussed later, coal and biomass seem to share a **synergistic** relationship when used together. **Synergism**is defined in the paper as when two or more causes combine together to produce a result that is greater than the sum of its parts. i.e., if an amount of coal produces syngas with a certain heating value, and an amount of biomass produces synags with a different heating value, to say that the two are in synergism with regards to syngas production means that the heating value reached by the combination of both amounts is greater than it would have been if they were gasified apart and both streams of syngases are collected together afterwards. (i.e. larger than the average of the heating values of the separate streams.)

Co-gasification is seen as a feasible process because of coal and biomass’s synergism in key areas. It would be highly beneficial to take existing gasification plants that use coal as fuel, IGCC plants in particular, and supplement them with biomass feedstock. In areas especially where lots of biomass waste is produced, this becomes a good economic endeavor, considering the close proximity of supply and the cheap costs.

One interesting way in which coal and biomass are synergistic is involving reaction rates.A 50-50 blend by weight of coal and biomass results in a lower activation energy than either if they were apart, as seen in Table 1. The numbers in each box indicate the average activation energy of each substance at different temperature ranges. When added together, notice that the total activation energy (E1 + E2 +E3) needed is nearly always less for the blend than it is for either substance by itself. This means that blending biomass and coal together results in a faster reaction time than coal or biomass alone, and requires less gasification agent(i.e. oxygen or air) to complete the reactions. Thus, synergism applies. Finally, placing coal and biomass together, as will be seen later, results in different syngas compositions than those of either by itself.

Table 1 Average activation energies for biomass and coal at various heating rates (Aghalayam et. al, 2008 [14])

	E1 kJ/mol	E2 kJ/mol	E3 kJ/mol
	380-450K	*450-720K*	*720-990K*
100 K/min			
Biomass	70.1	40.5	–
Blend	55.5	33.9	5.0
Coal	76.6	20.1	14.7
20 K/min			
Biomass	58.3	53.8	–
Blend	56.5	36.3	–
Coal	49.7	17.7	14.1
10 K/min			
Biomass	85.0	46	–
Blend	68.2	39.3	–
Coal	77.6	18.2	19.4

DESIGN APPROACH

Six scenarios are investigated using GTPro®, part of Thermoflow® program suite. The cases are set up to determine the effects of the biomass on the overall coal plant performance. A theoretical250MW coal IGCC power plant and a smaller 75MWbiomass IGCC power plant with the similar layout aredesigned first as the baseline cases for the 100% coal and 100% biomass plant, respectively. These plants are created using ThermoflowGTPro® software. After creating the baseline plants, the feedstock of the larger plant is varied further by replacing different amounts of the coal feedstock (by weight) with biomass. The various plant cases studied are: 100% coal, 100% biomass, and various biomass-coal blends composed of 10%, 30%, and 50%(wt.) biomass, respectively.

The location of the plant was chosen to be in Southern Louisiana, specifically around New Orleans, LA, meaning temperatures routinely near 85°F and a relative humidity index of about 90% in early summer, and having an overall elevation of 7-10 feet above sea level. The completed baseline IGCC power plant is shown in Fig. 2, which shows the basic layout of all power plant cases listed from here on. It is important to note that the numbers on the figure represent the end results of the 0% biomass or pure coal case. The plant layout and operating conditions are kept constant through user input throughout the design process. The only thing that differs from case to case is the gasifier feedstock, and, in the case of the smaller biomass plant, the gas turbine used. The gasifier(shown in Fig. 3)used in the plant is an entrained flow gasifier with both radiant and convective syngas coolers built-in, with internal conditions set at a temperature of 2500 ˚F and absolute pressure of 642.7 psi. The large plant uses a Siemens GT6-6000G gas turbine in the power block(Fig. 3), and the smaller plant uses an Alstom GT8C2 in the same arrangement. The turbine inlet temperature (TIT) is fixed for all cases. The steam turbine used is non-condensing to reduce water consumption and the HRSG does not include any accessories like burners or deaerators.

The gasifier chosen is a slurry-fed, oxygen-blown entrained flow gasifier. As discussed earlier, it requires an Air-Separation Unit (ASU), which operates at around 75 PSI and is not integrated with the gas turbine compressor. The gas cleanup system for all plants enforces the same cleanup efficiencies of 98% and the same output temperature of about 400°F. Again, for the sake of simplicity, NO_x and Argon levels present in the syngas are deemed to be negligible and are not analyzed or discussed.

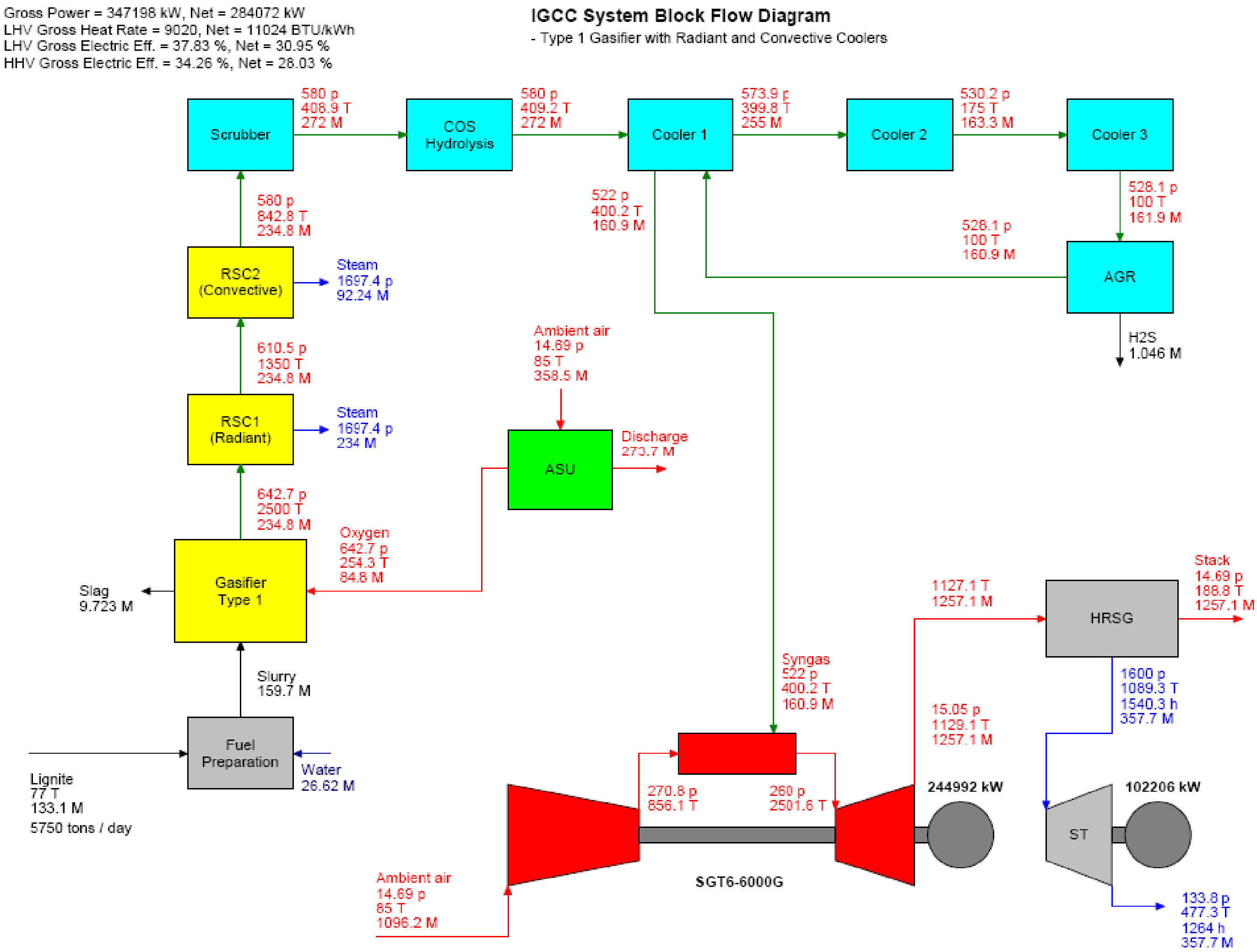


Figure 2 IGCC baseline plant design. Parametes in the figure: P(psia), T (°F), h(Btu/lb), M(lb/s).

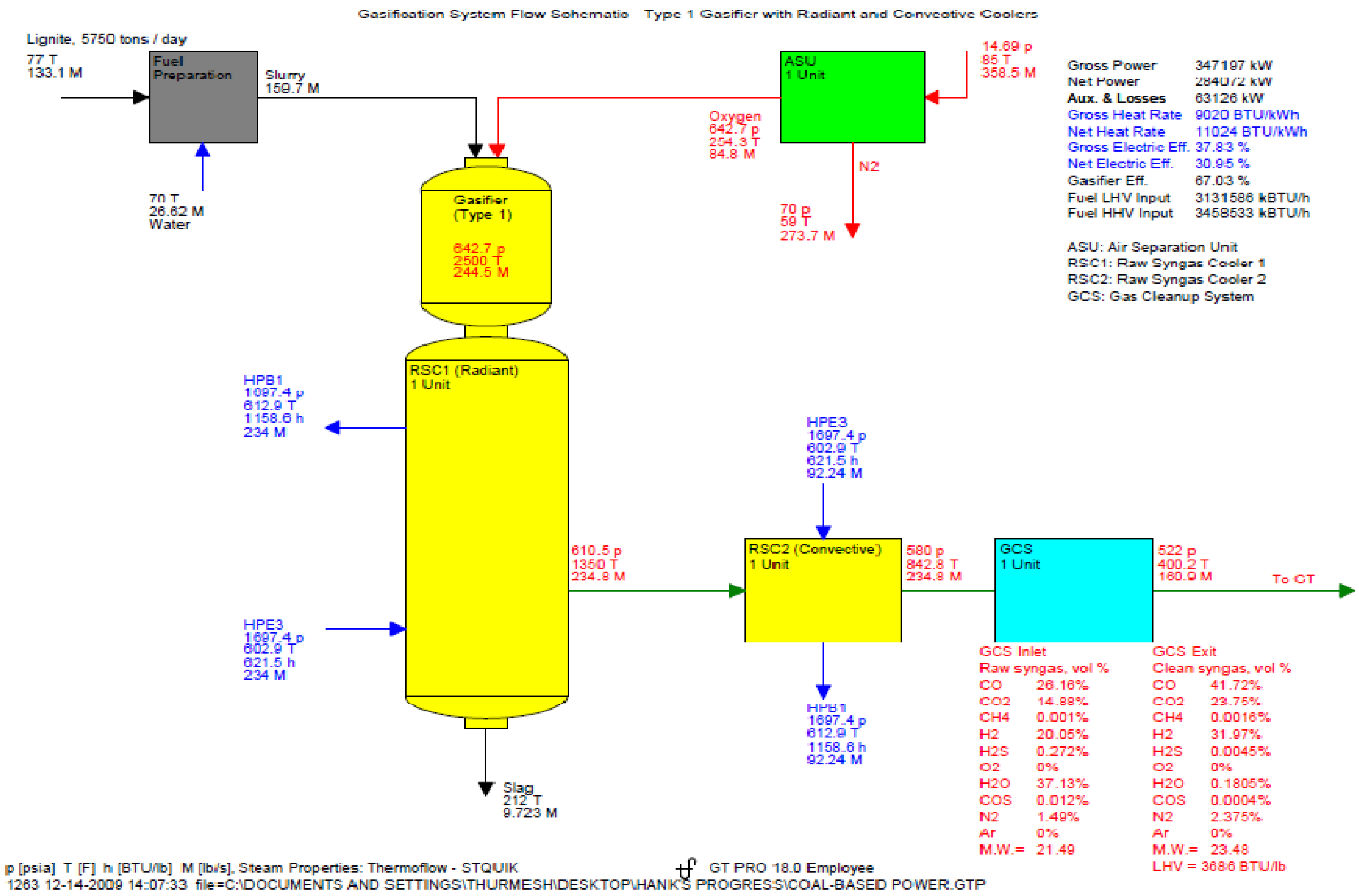


Figure 3 The slurry-fed, oxygen-blown, entrained-flow gasifier design layout

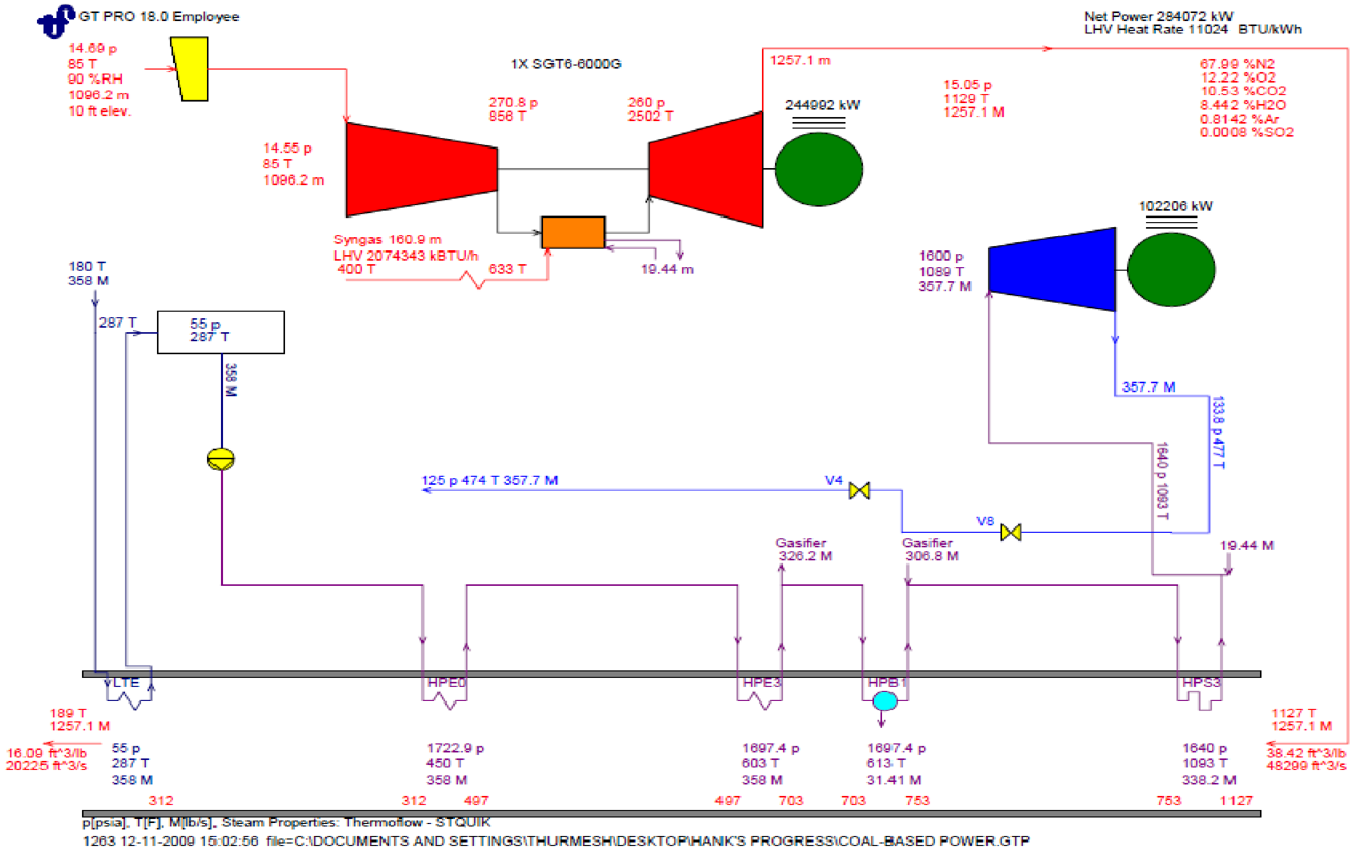


Figure 4 Pure coal (0% biomass) plantpower bloack specifics

The coal portion of the fuel is chosen to be Texas Lignite, because, given the plant location, lignite is a very popular choice; not without merit, since Louisiana is situated directly between two very large producers of lignite ore: namely, Texas and Mississippi. For biomass, since it's Louisiana, the most obvious choice is sugar cane bagasse. Since Louisiana isone of the largest producers of sugar cane in the mainland United States, using the residue from processing this crop only seems like the natural choice for biomass feedstock. Table 2 shows the ultimate analyses for both of these fuels.

Table 2 Ultimate analyses of lignite and bagasse fuels (molecular basis)

Component	S. Hallsville Texas Lignite	Sugarcane Bagasse
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%

(Source: GTPro built-in fuel library.)

Upon the creation of the baseline plants, the larger plant is duplicated exactly in a separate GTPro file, whereupon its feedstock is changed to be a mix of the Lignite and the Bagasse fuel feedstocks. This procedure is repeated for different amounts of biomass. Each case is classified by the biomass/coal mass ratio in the feedstock. All feedstocks are assumed to be slurry-fed with 35% water, by mass, at 70 ˚F. Since different ratios would result in different heating values for the syngas, this would result in significant changes in the results. To at least keep the total power output reasonably constant, the turbine inlet temperature is fixed.A partial summary on the overall plant operating data for three plants (100% coal, 30% biomass, and 100% biomass) are given in the Appendix.

RESULTS AND DISCUSSIONS

Starting from the source of the case differences, the most pertinent thing to observe is the gasifier syngas compositions. Table 3shows the data on syngas composition for each case's fuel input under the same gasifier conditions. What should be noted is the fairly consistent trend of increasing CO and H_2 levels and decreasing CO_2, N_2, and Sulfur levels. As evidence of the similarity between the Lignite and Bagasse, note the changes in overall LHV.

Even if the rest of the plant is slightly different, the gasifier used in both reference plants is exactly the same. The only thing that is different is the mass flow rate, which is already taken into account by viewing the composition as a percentage and taking the LHV on a per pound basis. As such, if there were no synergism between coal and biomass, we would see a direct relation of the syngas's overall LHV, with coal's syngas LHV at the highest value, and biomass's at the lowest. What we see instead, is that the LHV actually *increases* when the two are mixed together. The average LHV value between pure coal and pure biomass is around 2350 Btu/lb. Even only 10% biomass results in syngas with an LHV significantly greater than this amount. As such, there is definitely something occurring between the coal and biomass within the gasifier that results in syngas of much greater quality.

Table 3 Syngas compositions of various feedstocks by volume % (Argon negligible)

Case	0% biomass	10% biomass	30% biomass	50% biomass	100% biomass*
CO %	26.16	27.68	27.41	28.93	23.59
CO_2%	14.88	13.76	14.73	13.97	16.18
CH_4%	0.0010	0.0015	0.0012	0.0016	0.0006
H_2%	20.05	21.74	20.47	21.65	18.28
H_2S %	0.2720	0.2475	0.1965	0.1465	0.0134
O_2%	0	0	0	0	0
H_2O %	37.13	35.18	35.81	34.03	40.83
COS %	0.0120	0.0107	0.0089	0.0066	0.0006
N_2%	1.490	1.386	1.382	1.269	1.108
LHV,77F (Btu/lb)	2483.4	2701.9	2566.5	2736.8	2194.5

*100% Biomass plant is only 75MW, all others are 250MW.

Beyond the gasification stage is the power block. Table 4 describes the overall plant power outputs and net efficiency of each case. Note what happens to the required mass flow rate as the total power output changes.

Table 4 Power block data

Case	0% biomass	10% biomass	30% biomass	50% biomass	100% biomass*
GT mass flow (lbs/s)	1257	1245	1254	1246	443
ST mass flow (lbs/s)	357.7	355.5	356.9	352.5	112.5
Gross GT output (kW)	244,992	242,485	243,912	242,003	56,042
Gross ST output (kW)	102,206	101,567	101,980	100,670	32,084
Overall Elect. Efficiency (LHV)	37.83%	38.67%	38.35%	38.98%	34.20%
Total Net Power (kW)	284,072	287,703	286,412	288,612	71,788

*100% Biomass plant is only 75MW, all others are 250MW.

This suggests that Co-Gasification is more efficient overall than either case of single gasification. However, note that the 100% biomass plant has a lower efficiency because it is only about 30% as large as the coal/biomass co-gasification plants. Typically, power plants tend to be less efficient in smaller capacities. How the plant will actually compare if it were the same size as the coal plant cannot be determined without further investigations. But, as mentioned previously, actually building a pure biomass plant as large as 250MW is not practical in Lousiana due to limited supply and feeding problems.

But, where does this enhanced efficiency come from? A first guess might be that there must also be reduced energy consumption somewhere to achieve this result. Table 5contains data showing the slected major sources of heatlosses and power consumptions at various places in the plant for each case.

Table 5 Comparison of selected major heat losses and energy consumptions in plant auxiliaries

Case	0% biomass	10% biomass	30% biomass	50% biomass	100% biomass*
ASU input (kW)	45,706	39,611	42,301	37,413	11,605
Feedstock Mill (kW)	4,791	4,476	4,656	4,419	1,294
HRSG feed pumps (kW)	244,992	242,485	243,912	242,003	56,042
Heat Loss from Slag (Btu/s)	102,206	101,567	101,980	100,670	32,084
Syngas Water Condensed (Btu/s)	19,594	15,716	17,413	14,856	5,415
Transformer Losses (kW)	1,736	1,720	1,729	1,713	440

*100% biomass plant is only 75MW, all others are 250MW.

The power consumed in the feedstock mill only includes the mechanical work. In this study, the biomass is assumed chopped and mixed with coal in a slurry form.No torrefaction or other forms of biomass preparation which require heat input are implemeted in this study..

Further evidence of synergism can be seen in this data as well. The total energy input of the ASU (directly linked to the amount of oxygen supplied to the gasifier) is **lower**for all the co-gasification cases. In addition, less slag is produced and hence less energy is lost due to slag production. There is generally less moisture removed during syngas cooling and less energy used for the HSRG feed pumps. The emissions data recorded for the plant are shown in Table 6.

Table 6 Cleanup System and Emissions Data

Case	0% biomass	10% biomass	30% biomass	50% biomass	100% biomass*
Scrubber Water (Btu/s)	6,761	4,124	5,319	3,860	1,220
H_2S removal losses (Btu/s)	7,449	6,301	5,183	3,619	107
Cooler Heat Rejection (Btu/s)	118,180	92,769	103,634	87,127	32,487
SO_x output (tons/year)	281.2	237.4	196.0	136.9	7.5
CO_2 output (tons/year)	2,576,385	2,420,106	2,545,358	2,442,023	734,390
Effective CO_2 output (tons/year)	2,576,385	2,084,662	1,539,028	76,4807	0*

*100% biomass assumed to be completely carbon neutral.
100% biomass plant is only 75MW, all others are 250MW.

As expected, biomass requires less cleaning than coal does, and appropriately has less energy losses related to gas cleanup, lower scrubber water consumption, and lower emissions overall. The heat loss in the “cooler” heat exchangers within the gas cleanup system, (NOT the ones built into the gasifier) shows the largest reduction with biomass blending among all the losses presented in Tables 5 and 6. Figures 5 through 9 that follow contain graphical representations of the important data in Tables 4, 5,and 6.

Regarding CO_2 emissions, it needs to be pointed out that the amount of total CO_2 reduction doesn't seem to be much with biomass blending. However, when the neutral CO_2 is subtracted , the net **"effective"** CO_2 emissions are significantly reduced as more biomass is added (Table 6 and Fig. 6). It isn’t a direct linear relationship, but a clear inverse trend can be observed.

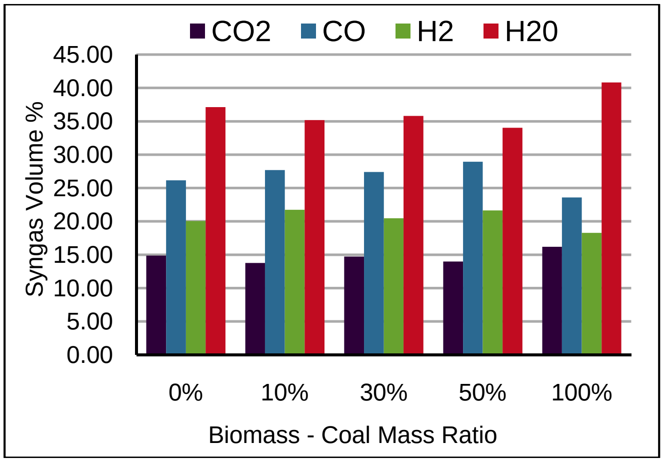


Figure 5 Syngas compositions for various amounts of biomass blending

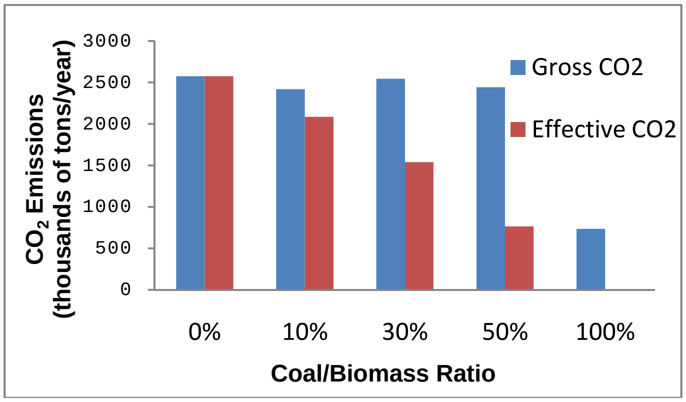


Figure 6 Gross and effective CO_2 emissions for various amounts of biomass blending

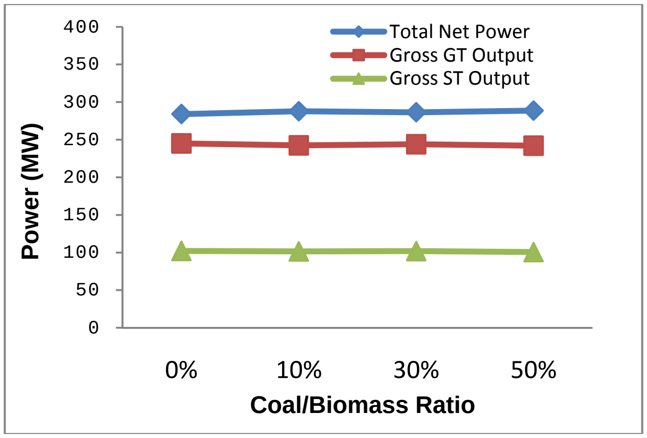


Figure 7 Power output data for various amounts of biomass blending

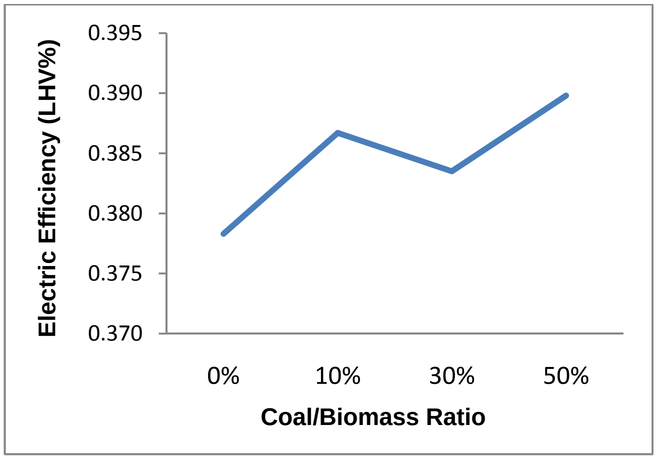


Figure 8 Electrical efficiency for various amounts of biomass blending

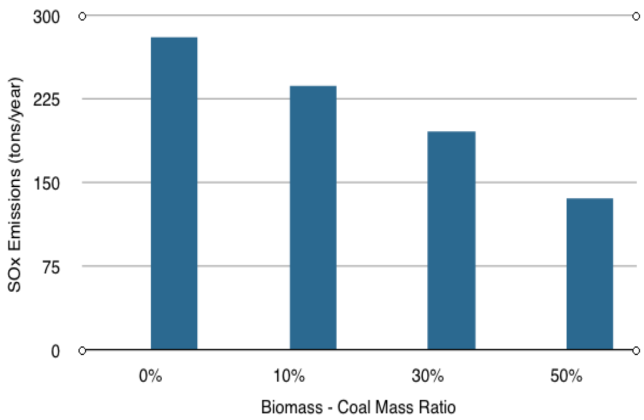


Figure 9 SO_x emissions for various amounts of biomass blending

Conclusions

Based on these results, there is evidence to suggest that gasifying biomass with coal will raise the efficiency of the studied IGCC plant. While, when compared with the pure coal baseline case, the following expected results do occur for blending biomass: the net power output increases, the emissions go down, and the efficiency improves, albeit by a very small amount. What was *not* expected, though, was the fact that a mere 10% biomass, one-third of the target amount, yielded even better results. Not only is there an efficiency gain compared to the pure coal baseline plant, the total carbon dioxide emissions are actually lower than the 30% case. This is because a very low-carbon coal and a fairly high-carbon biomass specimen are chosen as feedstocks. However, once the “neutral” CO_2 is removed from the calculations, a “net” or “effective” CO_2 outputcan be found which is more in-line with the theory. While the total, “absolute” CO_2 output shows virtually no trend from case to case, the **effective**CO_2 is approximatly linearly proportional to the amount of biomass.The reducedauxiliary power consumptions are mainly a result of the reduction of substances that require energy to be removed from the syngas, particularly those containing sulfur (like COS, and H_2S for example.)Also interesting to note is the reduced energy needed for the scrubber water. The “scrubber” in this case is the particulate scrubber, which removes fly ash and solid particles that make their way to the gas cleanup system. This would suggest that the increasing levels of biomass result in less fly ash as well as less slag output.

The result seems to suggest that the overall behavior of the system’s efficiency, emissions, and power output are not linear functionswith biomass blending ratio. The optimum operating point for this setup appears to be a 50-50 blend. These results also agree with those achieved in the study by Kezhong Li et. al. (2008), which found that blended coal and biomass were more efficient than coal alone and that a 50%-by-mass ratio was the highest proportion that was thermodynamically feasible, and also the one that produced the most significant results.

In summary, this study is performed using the commercial code GT Pro of the Thermoflow program suite. The Siemens SGT6-6000G and Alstom GT8C2 gas turbines are used in the larger and smaller plants, respectively. The results show the plant's efficiency increases first as 10% of the coal feedstock is replaced with biomass; then decreases as this amount is increased to 30%; and increases again once it reaches 50%. The variation of efficiency is minor, only within one percentage point between 38% and 39%. The advantage of adding biomass can be seen from the almost proportional reductions of SO_x, ash, energy loss for the H_2S removal system, water for the scrubber, and, of course, the **effective** CO_2 emissions. The effective CO_2 is calculated by subtracting the neutral CO_2 that is produced by the added biomass.

ACKNOWLEDGEMENTS

This study was supported by the Department of Energy contract NO. DE-FC26-08NT01922 and the Louisiana Governor's Energy Initiative via the Clean Power and Energy Research Consortium (CPERC), administered by the Louisiana Board of Regents.

REFERENCES

[1] U.S. Department of Energy, 2009, “Gasification Technology R&D,” Public Company Papers. http://www.fossil.energy.gov/programs/powersystems/gasification/index.html

[2] Rezaiyan, J., and Cheremisinoff, N. P., 2005, *Gasification Technologies: A Primer for Engineers and Scientists*. Taylor and Francis, New York, NY.

[3] Turare, C., 2002, “Biomass Gasification – Technology and Utilisation.” ARTES Institute, Glucksburg, Germany.

[4] Reed, T. B., Gaur, S., 2001, “A Survey of Biomass Gasification,” 2nd Ed, The National Renewable Energy Laboratory and The Biomass Energy Foundation, Golden, CO.

[5] Benabithe, Z., Castiblanco, E. A., Janna, F. C., 2008, “Fluidized-bed Co-Gasification Process of Colombian Coal and Biomass Wastes,” *25th International Pittsburgh Conference*, Pittsburgh, PA.

[6] Loganbach, J., Smith, P.V., Leonard, R., Rogers, L., Vimalchand, P., Liu, G., 2001, “Development Status of the Transport Gasifier at the PSDF,” *Gasification Technologies 2001*, National Energy Technology Laboratory, Southern Company Services, and Kellogg Brown & Root, Inc., San Francisco, CA.

[7] Bain, R., Craig, K., Comer, K., 1997, “Gasification-Based Biomass,” *Renewable Energy Technologies Characterizations*, U.S. Department of Energy and Electric Power Research Institute., Washington, D.C. and Palo Alto, CA., Chap. 2, pp. 7-17. http://www.nrel.gov/docs/gen/fy98/24496.pdf

[8] Morreale, B. D., 2008, “Thermochemical Conversion of Coal and Biomass Mixtures,” *25th International Pittsburgh Conference*, Pittsburgh, PA.

[9] Biofuel Industries, Cogeneration Technologies, Renewable Energy Technologies, Trigeneration Technologies, 1999, “Coal Gasification,” Renewable Energy Institute, Houston, TX. http://www.cogeneration.net/Coal-Gasification.htm

[10] Hanssen, J. E., 2007, “Co-Gasification of Biomass with Coal: A Fast Track to Renewable Hydrogen,” *3rd International Conference on Clean Coal Technologies for Our Future*, Cagliari, Sardinia, Italy.

[11] Bergman, P. C. A., Kiel, J. H. A., 2005, “Torrefaction for Biomass Upgrading,” *14th European Biomass Conference and Exhibition*, Paris, France.

[12] Richards, G., 2008, “Co-Gasification: An Introduction,” National Energy Technology Laboratory, Pittsburgh, PA. http://www.mcilvainecompany.com/NOx_Decision_Tree/subscriber/Tree/DescriptionTextLinks/George Richards - NETL DOE.pdf

[13] Jenkins, S., 2008, “Gasification 101,” Gasification Technologies Council Workshop, Tampa, FL.

[14] Aghalayam, P., Baretto, J., Ganesh, A.; Kauchali, S., 2008, “Pyrolysis of Sawdust-Lignite Blends,” *25th International Pittsburgh Conference*, Pittsburgh, PA.

[15] Li, K., Zhang, R., Bi, J., 2008, “Process Development on Co-Gasification of Coal and Biomass in a Fluidized Bed,” *25th International Pittsburgh Conference*. Pittsburgh, PA.

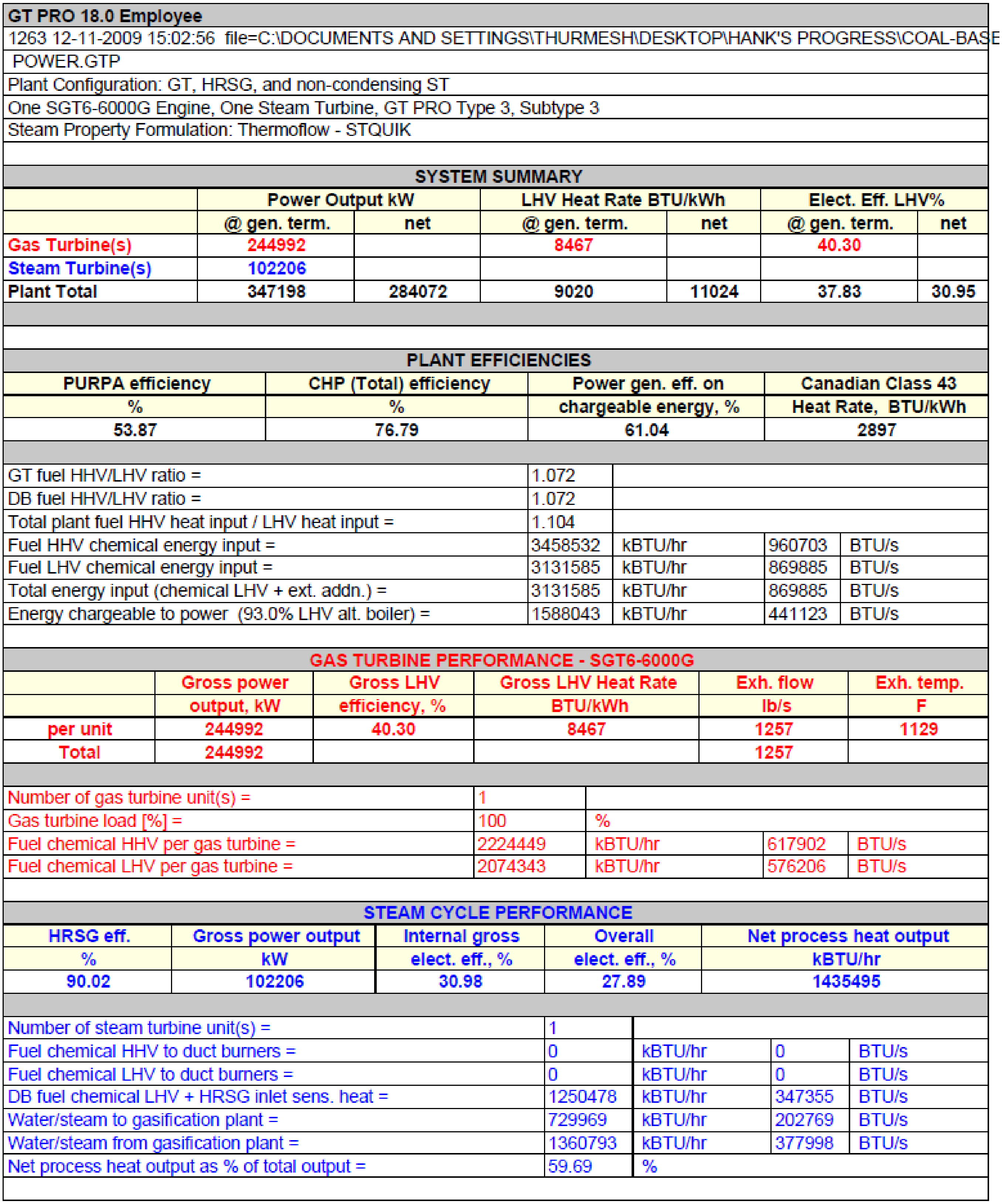
[16] Li, X., Wang, T., 2009, “A Parametric Investigation of Various Integrated Gasification Combined Cycles With Carbon Capture,” Master’s Thesis. University of New Orleans, New Orleans, LA.

[17] McDaniel, J., Hornick, M., Webb, L., Boddiford, D., Davis, T., Pedro, T., Valentine, M., Hall, B., 2002, “Tampa Electric Polk Power Station Gasification Combined Cycle Project,” *Final Technical Report*, Tampa Electric Company. http://www.tampaelectric.com/data/files/PolkDOEFinalTechnicalReport.pdf

Appendices (Selective System Summary Report)

Pure coal

System Summary Report



GT PRO 18.0 Employee

1263 12-11-2009 15:02:56 file=C:\DOCUMENTS AND SETTINGS\THURMESH\DESKTOP\HANK'S PROGRESS\COAL-BASE POWER.GTP

Plant Configuration: GT, HRSG, and non-condensing ST

One SGT6-6000G Engine, One Steam Turbine, GT PRO Type 3, Subtype 3

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)	244992		8467		40.30	
Steam Turbine(s)	102206					
Plant Total	347198	284072	9020	11024	37.83	30.95

PLANT EFFICIENCIES

PURPA efficiency %	CHP (Total) efficiency %	Power gen. eff. on chargeable energy, %	Canadian Class 43 Heat Rate, BTU/kWh
53.87	76.79	61.04	2897

GT fuel HHV/LHV ratio =	1.072			
DB fuel HHV/LHV ratio =	1.072			
Total plant fuel HHV heat input / LHV heat input =	1.104			
Fuel HHV chemical energy input =	3458532	kBTU/hr	960703	BTU/s
Fuel LHV chemical energy input =	3131585	kBTU/hr	869885	BTU/s
Total energy input (chemical LHV + ext. addn.) =	3131585	kBTU/hr	869885	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	1588043	kBTU/hr	441123	BTU/s

GAS TURBINE PERFORMANCE - SGT6-6000G

	Gross power output, kW	Gross LHV efficiency, %	Gross LHV Heat Rate BTU/kWh	Exh. flow lb/s	Exh. temp. F
per unit	244992	40.30	8467	1257	1129
Total	244992			1257	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV per gas turbine =	2224449	kBTU/hr	617902	BTU/s
Fuel chemical LHV per gas turbine =	2074343	kBTU/hr	576206	BTU/s

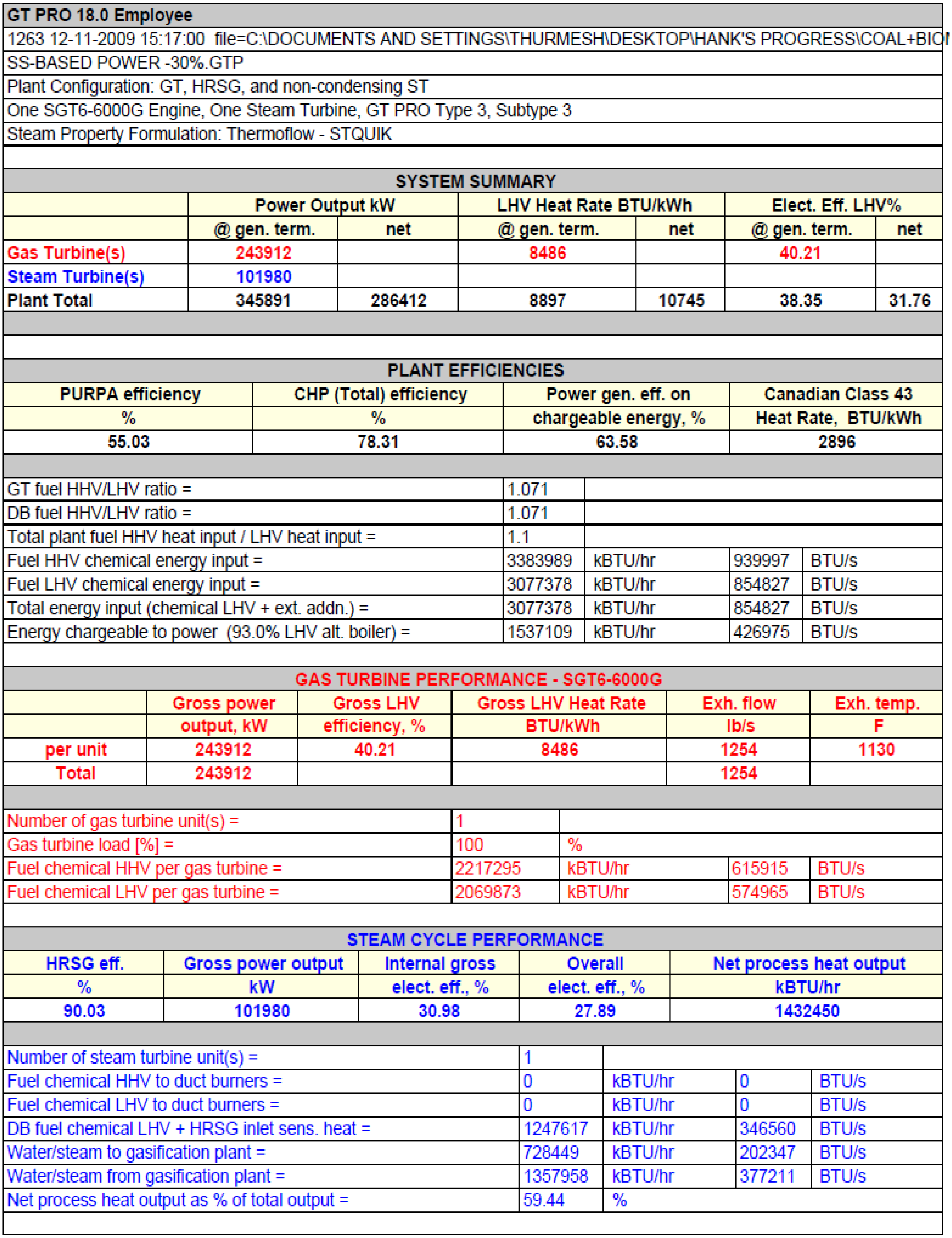
STEAM CYCLE PERFORMANCE

HRSG eff. %	Gross power output kW	Internal gross elect. eff., %	Overall elect. eff., %	Net process heat output kBTU/hr
90.02	102206	30.98	27.89	1435495

Number of steam turbine unit(s) =	1			
Fuel chemical HHV to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1250478	kBTU/hr	347355	BTU/s
Water/steam to gasification plant =	729969	kBTU/hr	202769	BTU/s
Water/steam from gasification plant =	1360793	kBTU/hr	377998	BTU/s
Net process heat output as % of total output =	59.69	%		

30% biomass and 70% coal

System Summary Report



GT PRO 18.0 Employee
1263 12-11-2009 15:17:00 file=C:\DOCUMENTS AND SETTINGS\THURMESH\DESKTOP\HANK'S PROGRESS\COAL+BIO
SS-BASED POWER -30%.GTP
Plant Configuration: GT, HRSG, and non-condensing ST
One SGT6-6000G Engine, One Steam Turbine, GT PRO Type 3, Subtype 3
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)	243912		8486		40.21	
Steam Turbine(s)	101980					
Plant Total	345891	286412	8897	10745	38.35	31.76

PLANT EFFICIENCIES

PURPA efficiency %	CHP (Total) efficiency %	Power gen. eff. on chargeable energy, %	Canadian Class 43 Heat Rate, BTU/kWh
55.03	78.31	63.58	2896

GT fuel HHV/LHV ratio =	1.071			
DB fuel HHV/LHV ratio =	1.071			
Total plant fuel HHV heat input / LHV heat input =	1.1			
Fuel HHV chemical energy input =	3383989	kBTU/hr	939997	BTU/s
Fuel LHV chemical energy input =	3077378	kBTU/hr	854827	BTU/s
Total energy input (chemical LHV + ext. addn.) =	3077378	kBTU/hr	854827	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	1537109	kBTU/hr	426975	BTU/s

GAS TURBINE PERFORMANCE - SGT6-6000G

	Gross power output, kW	Gross LHV efficiency, %	Gross LHV Heat Rate BTU/kWh	Exh. flow lb/s	Exh. temp. F
per unit	243912	40.21	8486	1254	1130
Total	243912			1254	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV per gas turbine =	2217295	kBTU/hr	615915	BTU/s
Fuel chemical LHV per gas turbine =	2069873	kBTU/hr	574965	BTU/s

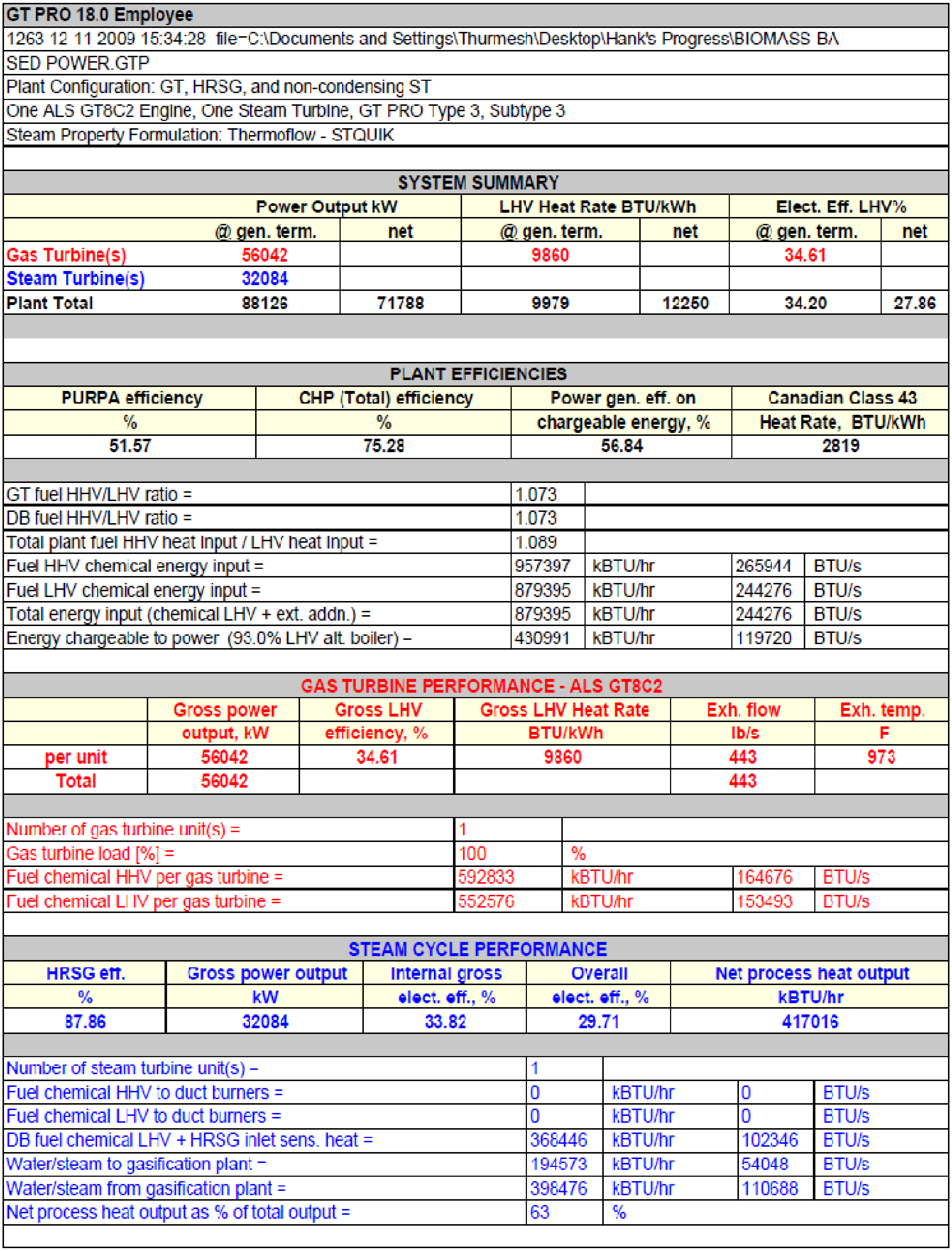
STEAM CYCLE PERFORMANCE

HRSG eff. %	Gross power output kW	Internal gross elect. eff., %	Overall elect. eff., %	Net process heat output kBTU/hr
90.03	101980	30.98	27.89	1432450

Number of steam turbine unit(s) =	1			
Fuel chemical HHV to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	1247617	kBTU/hr	346560	BTU/s
Water/steam to gasification plant =	728449	kBTU/hr	202347	BTU/s
Water/steam from gasification plant =	1357958	kBTU/hr	377211	BTU/s
Net process heat output as % of total output =	59.44	%		

Pure biomass

System Summary Report



GT PRO 18.0 Employee
1263 12 11 2009 15:34:28 file=C:\Documents and Settings\Thurmesh\Desktop\Hank's Progress\BIOMASS BA
SED POWER.GTP
Plant Configuration: GT, HRSG, and non-condensing ST
One ALS GT8C2 Engine, One Steam Turbine, GT PRO Type 3, Subtype 3
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)	56042		9860		34.61	
Steam Turbine(s)	32084					
Plant Total	88126	71788	9979	12250	34.20	27.86

PLANT EFFICIENCIES

PURPA efficiency %	CHP (Total) efficiency %	Power gen. eff. on chargeable energy, %	Canadian Class 43 Heat Rate, BTU/kWh
51.57	75.28	56.84	2819

GT fuel HHV/LHV ratio =	1.073			
DB fuel HHV/LHV ratio =	1.073			
Total plant fuel HHV heat input / LHV heat input =	1.089			
Fuel HHV chemical energy input =	957397	kBTU/hr	265944	BTU/s
Fuel LHV chemical energy input =	879395	kBTU/hr	244276	BTU/s
Total energy input (chemical LHV + ext. addn.) =	879395	kBTU/hr	244276	BTU/s
Energy chargeable to power (93.0% LHV alt. boiler) =	430991	kBTU/hr	119720	BTU/s

GAS TURBINE PERFORMANCE - ALS GT8C2

	Gross power output, kW	Gross LHV efficiency, %	Gross LHV Heat Rate BTU/kWh	Exh. flow lb/s	Exh. temp. F
per unit	56042	34.61	9860	443	973
Total	56042			443	

Number of gas turbine unit(s) =	1			
Gas turbine load [%] =	100	%		
Fuel chemical HHV per gas turbine =	592833	kBTU/hr	164676	BTU/s
Fuel chemical LHV per gas turbine =	552576	kBTU/hr	153493	BTU/s

STEAM CYCLE PERFORMANCE

HRSG eff. %	Gross power output kW	Internal gross elect. eff., %	Overall elect. eff., %	Net process heat output kBTU/hr
87.86	32084	33.82	29.71	417016

Number of steam turbine unit(s) =	1			
Fuel chemical HHV to duct burners =	0	kBTU/hr	0	BTU/s
Fuel chemical LHV to duct burners =	0	kBTU/hr	0	BTU/s
DB fuel chemical LHV + HRSG inlet sens. heat =	368446	kBTU/hr	102346	BTU/s
Water/steam to gasification plant =	194573	kBTU/hr	54048	BTU/s
Water/steam from gasification plant =	398476	kBTU/hr	110688	BTU/s
Net process heat output as % of total output =	63	%		