Clean Coal Feasibility Study

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Executive Summary

Senior design Team 16 is comprised of three mechanical engineers and one chemical engineering: Karl Falk, Isaac Kuiper, Chris Newhuis and Marc Loffert, respectively. We are one of three subteams looking into the feasibility of cleaner coal power generation.

With the world’s demand for electrical power at its greatest power plants are in high demand. This demand is often met with the construction of coal fired power plants because coal is both readily available and has a low cost. These plants are often contested because of growing concerns about their environmental impacts. With emerging clean coal technologies, newer plants have much lower emissions.

Team 16 is proposing that an economical, and environmental analysis be done on a standard coal power plant and compared against a clean coal power plant. We will compare the standard power plant to one of the following clean technology alternatives; an Integrated Gasification Combined Cycle with carbon sequestration or a Pulverized Coal Oxygen Fed plant with carbon sequestration.

Towards this purpose, we will identify the key components of each process. Physical components, such as the boiler, pulverizers, turbines, etc. will be analyzed to define key variables around them that will allow us to make informed estimates of dimensions and operating conditions. From this, we will be estimating costs of material, using values taken from current market values of commonly produced machinery or empirical estimates for construction of the system. Scale-up will be used to estimate costs of operating, installation, and other variable costs of construction.

Once costs are known, we will be performing a comparison between the different power plant varieties. It is assumed that the IGCC and the Oxygen Fed plants will be more expensive, but our study hopes to determine how much more it will cost the customer for a power plant to switch to an economically safe option.

Our subgroup (16) in particular is focusing on the energy cycles for the power plants: Boiler steam loops, turbines, pre-processing of the coal, etc. Equipment choices will be based on efficiency as well as cost, with the purpose of being economically friendly. We will then perform an exergetic analysis of the power cycles, so that we can produce optimizations based on both initial and long term costs. Once a final design is made, we will discuss the emissions, costs of this power plant.
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1 Introduction

1.1 Clean Coal Overview
According to the National Oceanic & Atmospheric Administration research lab at Mauna Loa the carbon dioxide levels in the atmosphere has been on the rise for the past fifty years. The current levels are at 388 ppm up from 315 ppm in 1960.

There are many contributing factors for this high level, but one of the largest factors is power production by coal fired power plants. According to the Environmental Protection Agency fossil fueled power plants are responsible for 40% of manmade carbon dioxide emissions in the United States. In the past, these emissions were just an afterthought but we are now beginning to understand that they are having a significant negative impact on the local and global ecosystems. In an effort to help reduce carbon dioxide emission by coal power plants, there are new clean coal technologies being developed. Some of these technologies are carbon dioxide scrubbers located within the flue stacks, syngas turbines and coal burned with an oxygen feed. Although these new technologies are effective at reducing emissions, they also have a higher cost due to additional processing in the plant. None the less, these technologies are still being considered when new power plants are being designed. This is because of the possible implementation of a carbon tax on large industries. These carbon taxes could quite possibly be very costly and expensive for any existing coal power plant. In order to help power plants to be as profitable as possible plant designers will have to weigh the costs of implementing technology to reduce emissions.

The goal of the Clean Coal project is to compare and contrast a Conventional Coal power plant with either an Internal Gasification Combustion Cycle power plant or an Oxygen Fed power plant on an economic and environmental basis. To keep the project to a reasonable size only one clean coal plant will be chosen to analyze. In order to achieve this goal a plant design will be made up for a standard coal plant and for the best option of the clean coal plants. These tasks were divided up into three different sub groups, each responsible for a different aspect of the designs. The first group, Team 14, is the environmental group. This group is in charge of capturing and sequestering the carbon dioxide, as well as removing other hazardous compounds. The second group, Team 15, is in charge of simulating the processes of the IGCC plant. Their main focus was to model the gasification process. Finally, our group is in charge of modeling the thermodynamic cycle for both the conventional coal and oxygen fed power plant.

We are also working with two geology students, who are our plant location consultants. These students will be researching coal varieties, to determine what type of coal we should use, and what impurities will be inherent in the fuel. They will also be informing us of possible locations for procuring the coal, viable areas for depositing the carbon dioxide, and where we can draw water for our processes from. This information will be vital for determining the final location of our power plant.

1.2 Overall Project Scope

1.2.1 Power Plant Design
We will be creating a design for two different types of power plants. The first power plant that we will model is a conventional coal power plant and the second will be a clean coal power plant. The

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1 (Tans)

2 (Environmental Protection Agency, 2007)
conventional plant will be our base case which we will compare either a conventional power plant with an oxygen feed or an IGCC power plant against.

1.2.1.1 Conventional
The purpose of designing the conventional coal fired power plant in this project is to use it as a basis of comparison to the clean coal plant option. For our conventional plant we will be designing two of the major components, the boiler and the cooling system as well as specifying other components such as the turbine and pumps. In order to create the best design of a conventional coal plant we will be analyzing many variations of the simple rankine cycle which can be seen in Figure 1. This rankine cycle shows the basic energy flow for our conventional plant. The coal is fed into a pulverizer and then burned in a boiler to create steam. This steam is sent to a turbine which turns a generator to create electrical power. The steam then exist the turbine into a condenser and cooling tower from where it is pumped back into the boiler to become steam again. Some variations of this basic cycle we will be considering are the possibility of multiple reheels within the turbine so we can operate at higher pressure and temperature. We will also be considering implementing a regeneration system which preheats the boiler feed water increasing the overall efficiency of the plant.

![Figure 1: Process Flow Diagram of Simple Rankine Cycle](image)

In order to find the most efficient setup for the rankine cycle, we will perform multiple iterations of our analysis. The cycle model will be modified and reanalyzed in order to determine cost effective methods to increase efficiency. We will analyze the effectiveness of reheels, where the steam is cycled through the boiler and sent through another turbine before it reaches the condenser. Also, a regenerative system will be modeled. This is where steam is removed from the turbine, and combined with the water that is exiting the condenser.

1.2.1.2 Conventional with Oxygen Feed
One form of clean coal technology stems from modifying a conventional coal power plant so that the coal is burned with an oxygen feed, instead of an air feed. This option will also use carbon capture technology in order to separate CO$_2$ from the flue gases, where it will then be stored underground. The process flow of this option will be very similar to the base case option. The differences arise in the design of the boiler, production of oxygen, operating temperatures, and the additional equipment required to separate oxygen from the air and to separate CO$_2$ from the flue gases.

This type of plant will assume the same process flow as the conventional option but with the exception of the addition of an oxygen feed. Certain components of the plant such as boiler, and sizing of various
components will be different but the overall energy flow will be the same as the conventional plant. The design of this power plant will also have to consider safety. The oxygen stream is much more reactive, and will produce hotter flames, so the design of the boiler will require measures to prevent failure or disaster.

1.2.1.3 Integrated Gasification Combined Cycle (IGCC)

The second clean coal technology considered for comparison is the Integrated Gasification Combined Cycle power plant (IGCC). The basis of this plant lies in the processing of the coal before it is burned. The coal is sent into a gasifier where it is turned into hydrogen gas, it is then burned in a gas turbine within a combined cycle. This clean option will also have a series of flue gas scrubbers that removes sulfur, carbon dioxide, and other pollutants before they are released into the air. Figure 2 depicts the process flow of the IGCC power plant.

![Figure 2: Process Flow Diagram of the IGCC Plant](image)

The IGCC option is expected to be much more effective in releasing cleaner emissions and operating efficiently, however, it will have a very high cost.

1.3 Variables for Comparison

1.3.1 Cost

Two cost comparisons will be made when comparing the conventional coal power plant to our cleaner alternative. First we will minimize cost without regard for efficiency or environmental impacts. This will determine whether or not our worst case is economically sustainable. Secondly, we will minimize fuel costs by obtaining high exergy efficient components. Components with high exergetic efficiency will result in low operating costs. This will be completed in order to minimize the pollutants associated with our plants. Our final product will be an optimized balance between pollutant levels and total cost. Our plants will be evaluated assuming a financial life of 20 years. All of our analyses will have a 20 year payoff period. The financial lifetime is not to be confused with the operating lifetime of the plant.
The cost comparisons that will be made can be broken into four subcategories: Purchased Equipment Costs including installation (PEC), Fuel Costs (FC), Operations and Maintenance (O&M), and Carrying Charges (CC). The sum of these costs represents the Total Capital Investment (TCI) or Total Revenue Requirement (TRR) needed in order for an economically sustainable power plant.

The most important factor in cost calculations is the cost of the final product; ours being cents per kilowatt-hour. Our final product must match or surpass the levelized total revenue requirement per Giga-Watt (This will be multiplied by the hours of operation in order to be converted to cents per kWh) and be below the average retail cost of electricity in order to be considered economically viable. A graph showing the average retail price of electricity for 2010 and 2011 is shown below in Figure 3.

![Figure 3: Average Retail Price of Electricity to Ultimate Customers](image)

The significance of this graph is that our final cost of electricity must be below 7.47 cents at the customer per kWh in order to be able to profit off of every sector that utilizes electricity. A plant cannot be operated at a profit with a cost of electricity above the market price unless customers agree to pay more for power coming from a clean coal plant. A government incentive could also be used to level the gap between the price of conventional coal power and clean coal power. It is also important to recognize that because this is a nationwide average certain states have lower costs per electricity. Once the location has been determined we will be able to evaluate whether or not our plant will be feasible on a state basis. (i.e. if our plant is in Washington, our cost per kWh must be below the cost of electricity in Washington for the industrial sector, which is 4.05 cents per kWh.) At this time it is unknown how much more expensive a clean coal plant will be to operate, but that is the essence of our proposal.

### 1.3.1.1 Purchase Equipment Cost

The PEC is comprised of the initial costs for all components in the power plant. The primary components of the system are the: compressor, boiler, turbine, cooling tower, generator, and pulverizer.

The PEC also accounts for piping, instrumentation and controls, and electrical equipment and materials. The PEC is highly dependent on both size and efficiency of the components. Because the size is predetermined by the power output of the plant, only the efficiency of the components can be varied. As previously stated our first cost optimization will minimize the PEC. The installation cost will be assumed

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1. (U.S. Energy Information Administration, 2011)
2. (U.S. Energy Information Administration, 2011)
to be 55% of the Purchased Equipment Cost. This is an average of typical installation cost percentage ranges.\(^1\)

### 1.3.1.2 Fuel Cost

The fuel cost is also highly dependent on size and efficiency, and again because size is pre-determined our only variable is efficiency. There will be a direct tradeoff between fuel costs and purchased equipment costs. The fuel costs account for only the cost of coal. We will be making the assumption that a contract will be made with a coal supplier in order to lock in the price of purchased coal.

### 1.3.1.3 Operations and Maintenance

Operations and Maintenance costs are split into two categories which are fixed costs and variable costs. The fixed costs are salaries, labor, and maintenance materials. The variable costs are costs associated with operation, other than fuel, such as cooling tower make-up water and waste disposal. Typically fuel costs are included in O&M, however because this is an entity we desire to minimize we separated it from operations and maintenance costs.

### 1.3.1.4 Carrying Charges

Carrying Charges are essentially every other costs associated with our plants. This includes land purchase, taxes, finance, setup costs, working capital, etc. We are assuming that the power plants will have one location therefore there will be no difference in land purchase cost between plants. There is no current nationwide carbon tax in the USA, but some states do enforce a carbon tax. If our plants are located in one of those states then carbon taxing will be a variable to consider. The financing and setup costs are dependent upon the components; we anticipate lower setup and financing costs for the conventional case in comparison with the clean coal alternative.

1.3.2 Environmental Impact

As coal power technology has progressed over the last hundred years, we have only recently become aware of our actions, and their effects on the environment. This is especially true in regards to what has been allowed to leave the smoke stacks of coal power plants. The average coal power plant in operation today generates 600 MW of power and produces around 3,700 kilotons of carbon dioxide, 10,000 tons of sulfur dioxide, and 10,200 tons of nitrogen oxide every year.\(^2\) There are several actions that can be done to reduce the amount of emission in a new power plant.

One way to help reduce the amount of pollutants emitted into the atmosphere is by building a power plant with an oxygen feed. This type of plant has several environmental benefits. By burning coal with an oxygen feed, the plant increases the concentration of carbon dioxide and other pollutants within its flue gas stream. In fact, the lack of nitrogen in the oxygen stream helps to increase the concentration of pollutants by a factor of 3.5.\(^3\) With this increased concentration of pollutants it makes it much easier to compressed and sequestrate them.

The IGCC power plant also helps to dramatically reduce the amount of pollutants emitted into the air, as well as achieving high efficiencies. This relatively new technology features higher than ever efficiency, with some plant designs reaching efficiencies around 45%\(^4\). Generally speaking, if you have a more

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1 (Bejan, 1996)
2 (Union of Concerned Scientists, 2009)
3 (D. McDonald and D. DeVault, 2007)
4 (World Coal Association)
efficient plant you will emit less pollution. In addition to this, studies have been performed on already existing small scale plants that have shown that these plants are able to capture up to 90-95% of mercury.\(^1\) Similar to the power plant with oxygen stream, IGCC can more easily capture its flue gasses and use various methods to safely and dispose of the carbon dioxide in an environmentally friendly way.

By implementing these clean technologies, we will be able to dramatically reduce the amount of pollutants we put into the atmosphere. The amount of pollutants captured is dependent upon the process we choose, whether it is IGCC or Oxygen-Fed PC power plant.

### 1.4 Team 16’s Scope

Within the overall scope of the entire clean coal comparison, we will be focused on the energy balances, boiler design, and cost analyses for the power plants. This includes a design of the Rankine power cycle for the conventional power plant, and the conventional power plant with an oxygen feed.

For a fair comparison, it is important that we analyze state of the art designs for each of our power plants. This will require research on recently constructed power plants to learn about common practices, and industry standards. After sufficient research, we will model several power cycles in Engineering Equation Solver (EES) to make a decision on the most efficient Rankine cycle for our base case plant. This will narrow our selection to a few possible designs for the Rankine cycle.

No matter how efficient or environmentally friendly it may be, we cannot choose a power cycle setup for the conventional plant unless it is economically feasible. Throughout the entire process we will base our decisions on equipment costs as well as efficiency. We will then perform an exergetic analysis of the power cycles, so that we can produce optimizations based on both initial and long term costs.

It is our team’s responsibility to design a boiler for the conventional power plant in the base case option, as well as the oxygen feed option. This task begins with research on common practices. When an appropriate boiler design is chosen, we will modify the design and size to suit each power plant.

### 1.5 Constrained Variables

In order to make a fair and unbiased decision between the two plants, there are a few variables that will be kept the same when analyzing both of the designs. A major constrained variable is the location of the plant. The clean coal power plant requires a specific location that allows for carbon dioxide to be sequestered in rock formations below the earth. This location will most likely not be an ideal location, due to lack of cooling water, for a conventional power plant but was necessary to achieve a fair comparison between the two plants. This meant that other variables such as water availability and type of coal were also kept the same for both of the power plants. Another important variable that was kept the same is the amount of power that was generated for both plants. This was kept at 1 GW of power going to the grid. Coal type is the final constrained variable. It must be kept on an equal basis because of the different heating values, pollutants, moisture content, and char associated with different types of coal. Even though this isn’t a realistic assumption because the IGCC plant could possibly use a lower grade coal it must be made in order to help equalize some of the many differences in these plants.

#### 1.5.1 Location

In order to prepare a proper cost analysis we intend to pick a site location that provides a fair analysis of each option. The boiler designs and the IGCC have different methods of operation, giving different

\(^1\) (clean-energy.us, 2009)
variables of optimum performance. In addition, we will place the plant in a location which minimizes the costs or transportation, and other factors to which all designs are equally dependent on.

Primarily, a location for sequestration of carbon dioxide must be nearby. Both the IGCC and Oxygen fed plant will be removing carbon dioxide from the stack gas, and placing it either underground, or underwater. This process will be far too expensive if a site is not found near to the plant location. The construction of the base-case coal plant must also be located near a sequestration site despite not having carbon dioxide removal, in order to maintain a proper balance of variables. It should be noted that for our purposes the maximum sequestering distance is 100 miles. This is due to the cost of installing and operating a pipeline to a sequestration site. It is very expensive to install a pipeline that could provide sufficient flow for the purpose of transporting exhausts. In additions it would take a considerable amount of power to run a pipeline further than 100 miles.

Water availability, purity, and temperature will also factor into costs and design. As constant water flow will be necessary for plant operation, a reliable source must be nearby. Purity of available water will be factored into costs for boiler-feed water and condenser/cooling tower options.

We will be looking for a spot with a coal source located near the power plant, as a means of reducing costs of transportation. Coal composition is also a factor in the decision, and a decision as to available locations for mining coal will be solidified at a later point by geologists working in conjunction with the clean coal project.

Finally, we will take into consideration the major laws regarding the operation of power plants for our final location. There are a handful of states that charge large fees for the operation of power plants due to the amount of pollutants emitted by plants. We will be taking these types of fines into account when preforming cost analysis’s and will be including the cost savings that a clean coal plant would have by reducing its emissions.

1.5.2 Coal Type & Transportation

Our power plant design will be affected by the grade of coal used. The four major coal ranks are Bituminous, Subbituminous, Lignite, and Anthracite. All of these coal ranks vary in energy content, availability, price, and contaminant content.

<table>
<thead>
<tr>
<th>Coal Rank</th>
<th>Heating Value [Btu / lb_m]</th>
<th>Avg. Price [$ / Short ton]</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bituminous</td>
<td>10,500 - 15,500</td>
<td>55.44</td>
</tr>
<tr>
<td>Subbituminous</td>
<td>8,300 - 13,000</td>
<td>13.35</td>
</tr>
<tr>
<td>Lignite</td>
<td>4,000 - 8,300</td>
<td>17.26</td>
</tr>
<tr>
<td>Anthracite</td>
<td>≈ 15,500</td>
<td>57.1</td>
</tr>
</tbody>
</table>

Bituminous and Subbituminous coal make up 93% of the coal mined in the United States. \(^1\) Bituminous is mined in many mines to the East of the Mississippi River, while subbituminous is mined in large quantity mainly in the state of Wyoming.

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1. (Kentucky Educational Television, 2005)
2. (U.S. Energy Information Administration, 2011)
The decision between Bituminous and Subbituminous will be made when the location of the plant is decided. This decision is based on the cost of transporting the coal from the mine to the power facility, the energy content of the coal, and the cost of the coal itself.

1.5.3 Power Capacity
In order to begin the process of designing two different power plants, a realistic power capacity had to be chosen for both of the plants. As time progresses the average power capacity of coal power plants increases. Today coal power plants are the largest and most efficient they have ever been. To choose the power capacity for both of the power plants that were designed we looked at trends in coal power plants being currently built. The new trends show power plants being built with power production around 1 GW. To make the plants as applicable as possible, the size of the plants had to match current trends so they were set at 1 GW of power output. In Figure 4, below, it was determined that the average power plant capacity has been rising since about 1990. Although the average new coal power plant capacity is currently much lower than 1 GW. However, a plant of this size would fall towards the upper boundary of the range of new power plants, and would be a reasonable project despite its size.

1.5.4 Economic and Environmental Considerations
Economies are the driving force behind all businesses; because of this our power plant must be economically viable. When constructing our power plant we want it to produce as much as electricity at the lowest cost. Ideally but unrealistically, we would like to have no environmental constraints on our power plants because it is cheaper to construct and run a plant without them. However, in an attempt to be sustainable and good stewards of our planet, regulations have been added by governing bodies to power plants and many other industrial companies to help minimize the impact they have on the environment. As a result technology has been developed to help reduce the amount of pollution power plants emit.

1 (U.S. Energy Information Administration, 2011)
2 (U.S. Energy Information Administration, 2011)
This technology is expensive so we must take all the different financial aspects into perspective when making our decisions on what clean coal technologies to implement.

The first financial aspect to consider is the capital cost of clean coal. To build a brand new IGCC power plant is 30% more expensive than a traditional power plant. Oxygen feed plant and IGCC plants use capturing systems to help reduce their emissions but this technology is expensive. According to the EPA estimates in 2006, using capturing technology increased the capital costs by 47%.

The second financial aspect is operating costs. Running a clean coal plant is more expensive because energy has to be taken from the output to run the clean coal equipment. This can play a huge role in the overall cost of producing electricity. One example is of an IGCC plant in Minnesota where the capturing process added 5 cents/kWh. This increase was so drastic the project was canceled.

However there are some financial incentives to use clean coal technologies. One of these is in the form of government subsidies. In order to help speed along the advancement in technology and to help implement the use of clean coal, the government has given billions of dollars to companies to encourage them. For example in 2005 the Bush administration’s Energy Policy Act gave $1.8 billion for clean coal. They also gave large federally guaranteed loans towards the construction of IGCC power plants.

Another financial incentive is the possibility of a nationwide carbon tax in the future. A carbon tax would charge an industry a certain amount of money per ton of CO₂ or other pollutant emitted. This idea has already been implemented in several places in the United States. For example, Maryland charges five dollars per ton of carbon dioxide emitted for a stationary source emitting more than a million tons of carbon dioxide a year. Coal plants generally have a life span of several decades, so a plant could save a considerable amount of money if a carbon tax would be implemented.

Taking all of these financial considerations into account we will have to decide on what type of clean coal will be justifiable in designing our clean coal power plant. Even though the capital and running costs are high the help of the government and the impending passing of a carbon tax may make the use of clean coal technologies worth it in the future.

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1 (Energy Justice, 2007)
2 (Energy Justice, 2007)
3 (Energy Justice, 2007)
4 (Energy Justice, 2007)
5 (McGowan, 2010)
2 Conventional Coal Plant

2.1 Overall Block Diagram/Energy flow

It is important that we design the base case power plant to be representative of the state of the art conventional Rankine cycle power plants. Throughout this design process we must continually research common designs of high efficiency power plants, as well as design techniques.

We will look into the techniques of implementing reheat, regeneration, and the use of supercritical boiler pressures to increase the efficiency of the power plant. First, several simple options were simulated in EES in order to compare the effectiveness of each modification. This allows us to compare how effective each method is in increasing the thermal efficiency of the plant. When we determine which methods are most effective we can combine each improvement into the final design for the base case plant. The first modification option that we analyzed was the reheat rankine cycle, as seen below in Figure 5.

![Figure 5: Block Diagram of Reheat Rankine Cycle](image)

After the simple Rankine cycle was analyzed, the next step was to incorporate reheat and regeneration into the cycle. It was determined that it would be profitable to add both regeneration, and reheat into the cycle to improve the overall process efficiency. The regeneration and reheat were incorporated into the process flow of the simple rankine cycle as depicted below, in Figure 6.
This option for the process flow increases the efficiency, because the open feed-water heater and the closed feed-water heater utilize the heat before it is removed in the condenser.

Our next steps in choosing a final design include implementing a supercritical phase into the process. This means that the boiler pressure and temperature will bring steam above the critical point of water, which shows a large improvement in efficiency. This involves research on the temperature limits of the equipment, additional costs of running the cycle with a higher boiler pressure, and the added efficiency of using this technique. Once a final decision is reached, we will then optimize the variables of the final design to reach several goals. We will have a scenario to maximize the efficiency of the plant, and another to minimize the cost of the plant.

2.2 Design Specifications

2.2.1 Coal Pulverizer

In order to burn the coal received as thoroughly as possible the coal must be pulverized such that at least 70 percent of the particles will pass through a 200-mesh sieve.\(^2\) Pulverization of the coal allows for all the carbon particles to be exposed to oxygen thus burning completely as possible. Three types of coal pulverizers were analyzed in order to determine which pulverizer will work best for our conventional coal fired base case power plant.

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1. (Cengel, 2011)
2. (EPA, 1993)
The first type of pulverizer analyzed was the “Ball Tube Mill” pulverizer. The main component of a ball tube mill pulverizer is a large drum with an extended hollow section at each end. The extended hollow sections, called trunnions, allows for the inflow and outflow of the coal chunks and pulverized coal respectively. The trunnions also provide a bearing surface for which the drum can be rotated on. The drum is then filled with steel balls nearly up to the base of the trunnions. The coal is pulverized when the drum is rotated and the balls are allowed to be continuously lifted and dropped on the coal. The pulverized coal is extracted by forcing air through the pulverizer which carries the dust like pulverized coal into the boiler. Typically, classifiers are located on each end of the mill which act as size separators in order to ensure the exit stream is completely pulverized. Coal particles that are too big are separated out gravitationally and are added to the inlet stream to be re-processed. It should also be noted that the drum is pressurized. The pressure will be determined based on required inlet boiler pressure. This is in order to minimize the wear on the mill typically found in exhausters on suction mills.¹

There are several advantages and disadvantages to the ball tube mill pulverizer. The ball tube mill has a high throughput capability which minimizes the total number of mills required per plant. It also features the lowest maintenance cost in comparison to other types of pulverizers. This can be attributed to the lifespan of the mill liners which typically last from 15-20 years. Some other significant advantages are that the balls can be replenished during operation (due to its slow operating speed) and foreign metals in the coal can be ignored. Units also include two feeders and two crusher dryers which allows for full production should one side (one feeder and one dryer) fail.²

Disadvantages of using a ball tube mill pulverizer include “high initial cost, high power input, and large floor-space requirements…”³

Another type of pulverizer we analyzed was a high speed impact mill. It is the most basic type of coal pulverizer. The coal is crushed by hammers mounted on a shaft and then sent into a grinding chamber. A major advantage of this type of mill is the low initial cost of the units. A disadvantage of this type of mill is its “susceptibility to damage by foreign materials.”⁴

The final type of pulverizer analyzed is a medium speed roller type. Coal is fed at the top dead center of the mill and allowed to fall in the center of a rotating grinding plate. The rotating action of the plate forces the coal to the outside of the plate. Positioned over the grinding plate are series of rollers that crush the coal as they move outward. Dense foreign materials are allowed to fall through a nozzle ring and are continuously scraped into a chamber for disposal.⁵

A main advantage of the roller type pulverizer is its relatively low energy consumption. “The roller can grind material on the pulverizerstones directly, so the consumption of powder is only 30%-40% of ball pulverizers.”⁶ Another advantage is the small space requirement of the roller mill. Due to its vertical design the vertical pulverizer uses only 50% of the floor space required for a ball tube mill pulverizer.

¹ (Norman K. Trozzi, 1991)
² (D. McDonald and D. DeVault, 2007)
³ (Integrated Publishing)
⁴ (Integrated Publishing)
⁵ (Schumacher)
⁶ (BinQ, 2010)
A disadvantage of the roller type pulverizer is its high initial cost. Operations and Maintenance costs are also comparatively high due to the uneven wear of grinding parts and the complexities of the system.\(^1\)

A decision matrix will be constructed as part of our final deliverable.

### 2.2.2 Boiler

Steam production and pulverized coal flow rate are the fundamental entities that drive the design of our Boiler. In order to maximize steam production and minimize fuel requirements an efficient burner is needed. There are several types of burners, and several burner arrangements, that will be considered for both the conventional coal base case and the oxygen fired plant.\(^2\)

The first type of burner analyzed is a conventional circular burner. The burner’s main component is a nozzle with an impeller attached in order to disperse the pulverized coal. Supplementary air is added via a register, which is controlled with interlinked doors in a circular pattern. Air distribution must be uniform in order to achieve high combustion efficiency. For that reason the register is typically set in a position that allows for uniform air distribution (except during start up where less air is used.) All of the air in a conventional burner is added at the same time as the coal air stream from the pulverizer; because of this high flame temperatures are reached thereby producing high levels of NO\(_x\).

By controlling the supplementary air and swirl we arrive at the second type of burner to be analyzed. The S-type burner is a conventional circular burner in which the secondary air is controlled by a sliding disk that moves up and down the barrel of the burner. Swirl is independently controlled by spin vanes in the burner, rather than being dependent on the supplementary air added by a register in a conventional circular burner. The S-type burner features higher efficiency then the conventional burner, due to better flame and swirl control, however it also features high NO\(_x\) production rates.

The third type of burner examined is a dual register 4Z burner. This burner was invented in order to reduce maximize NO\(_x\) reduction while maintaining a high efficiency. Similar to the S-type burner, air is controlled by a sliding disk. A pitot tube grid is located in the burner barrel in order to measure air flow, which is necessary for equal flame distribution. The DRB-4Z achieves higher NO\(_x\) reduction rates by introducing the supplementary air on the outer edge of the burner (outside the flame wall). All air, both main and supplementary, are independently controlled with sliding dampers. This burner also features an inner spin vane and an outer spin vane in order to maximize swirl control. Figure 7 depicts the previously discussed DRB-4Z burner.

The DRB-4Z burners feature approximately a 70% reduction in NO\(_x\) emissions from fuel in comparison to a conventional burner.\(^3\)

Burner location in the boiler plays an important role in efficiency and NO\(_x\). There are four primary types of boilers: Wall-Fired, Tangentially Fired, Cyclone-Fired, and Stoker-Fired. A wall fired boiler features burners mounted along one or two opposing walls. This type of boiler layout leads to high peak flame temperatures therefore producing high quantities of NO\(_x\).

A tangentially fired boiler features burners located at the four corners of the boiler structure. The burners are individually focused on the tangent of an imaginary circle in the center of the boiler creating a rotating

---

1 (Chattopadhyay, 2004)

2 (Kitto, 1992)

3 (Babcock & Wilcox a McDermott company)
fireball in the center. This allows for stratified fuel-rich and fuel-lean regions (i.e. offers similar NO\textsubscript{x} reduction benefits as a DRB-4Z).

Figure 7: Mechanical Layout and Combustion Zones of a DRB-4Z Burner

A cyclone fired boiler use crushed coal rather than pulverized; they are generally small which produces high peak flame temperatures, again resulting in high NO\textsubscript{x} emissions. For these reasons the cyclone fired boiler will not be considered an option.

Stoker-Fired boilers are essentially a grill. Coal is dumped onto a shaking grate and burned. Primary combustion air is added underneath the grate, and supplementary air is added at the top of the system (providing 15-20% of air required for stoichiometric combustion). The “overfire” air leads to relatively low NO\textsubscript{x} emissions.\footnote{(Babcock & Wilcox, 1993)}

Boiler design is dependent on the fuel used and on the required steam temperatures and pressures necessary for power production. Many options for boiler layout will be considered for the conventional coal power plant, and the cleaner alternative. Boiler layout will be determined by optimizing for a balance of the most efficient heat transfer rates possible and capital and operating cost.

The materials of construction are dependent on the components function within the boiler. More specifically the material will be determined by the surrounding temperature of the component. For instance, the steam drum undergoes relatively low operating temperature, so carbon steel would be sufficient as creep is not a significant issue.\footnote{(Babcock & Wilcox, 1993)} Conversely the boiler tubing undergoes high temperatures which means creep is a significant problem and a metal with a slower rate of creep must be selected. All surfaces inside the boiler will be affected by erosion and corrosion. A coating may be necessary in order to deter deposit accumulation. Because the boiler tubes must be internally cleaned, erosion inside the boiler tubes will also be an issue. The most important aspect when specifying the correct material for the

\begin{itemize}
\item\footnote{(Utility Boilers)}
\item\footnote{(Babcock & Wilcox, 1993)}
\end{itemize}
The heat transfer coefficient is directly related to the conductive heat transfer coefficient which is specific per material and varies with temperature. It is also dependent on pipe thickness and the surface area, as well as the temperature difference between the wall and the inside of the boiler. In order to minimize surface area a material with a high conductive heat transfer coefficient must be selected.

Thinner pipes have a heat transfer coefficients higher than thicker pipes, however they also present several concerns. The amount of corrosion and erosion that thin pipes can withstand without maintenance is lower than that of thicker pipes. Pipe thickness is also very important when dealing with internal pipe pressure. There are also several monetary reasons for selecting pipe thickness. Having pipes that are too thick will decrease heat transfer rates as well as increase. Contrastingly, having pipes that are too thin could yield a higher maintenance cost.

There are many safety issues concerning boilers. Boiler feed water treatment is essential for the prevention of catastrophes. Corrosion inside the boiler wall pipes can lead to reduced efficiency, as well as a shorter plant life. If internal pipe corrosion goes unchecked the pipes could undergo catastrophic failure.\(^1\) Coal dust is also a major issue concerning a boiler. If coal dust levels in the plant go unchecked they can lead to explosion. Similarly, operating the boiler without adequate air for complete combustion will create a fuel-rich mixture that can sometimes create explosive conditions within the combustion chamber.\(^2\)

### 2.2.3 Turbines

We will not design a turbine because it falls outside of the scope of the project and our capabilities. Instead we will specify one from a company that already produces them. The turbine will be chosen to match the specification of the power output and emissions performance, but it also set some of its own parameters such as fuel flow rate and operating temperatures and pressures. Before a turbine can be specified we had to gain a better understanding on what design considerations we should take into account for a steam turbines for the conventional coal power plant and internal combustion turbines for the IGCC power plant.

Steam turbine technology has been around for more than a hundred years. As a result there are many different types of steam turbines to choose from. The most important factor in choosing a steam turbine for our senior design project is that it must match the power output specifications for our plant. After choosing a turbine that would create enough power, the rest of the plant could be made to work around the specific specifications of the particular turbine. A list of different steam turbines, that meet this criterion, will be compared against each other.

In the list of different steam turbines the two turbines that were chosen to be analyzed for the conventional plant are the Siemens SST-9000 and the GE G-Series steam turbines. These turbines where chosen for several different reasons.

The first steam turbine selected was the SST-9000 steam turbine. This turbine was selected as a possible candidate for the conventional plant for several reasons. First it can produce the 1 GW of power that is needed to run the plant. The second is that the turbine has high element efficiencies between 25-30%.

---

1. (Feedwater, 2011)
2. (Oland, 2002)
efficient. By choosing a turbine with high element efficiency it will help the plant to produce the most amount of work from the least amount of coal. It will also help to reduce the amount of pollutants put into the atmosphere. This turbine was also chosen because it can be set up to run with any cooling condition. This is important because the final location of the plant will determine the type of cooling system used. It could potentially be one of several different types of cooling system and this turbine can designed to handle a wide variety of them. This is done by changing the running parameters of the high and lower pressures sections of the turbine. High pressures sections of the turbine require more cooling than low pressure sections so if a turbine were setup with more low pressure setups it could be made to work well with a cooling tower, air cooling tower and other low water usage cooling methods. The final aspect that makes this turbine a good choice is that it has an extended lifetime of up to sixty years.¹

The second turbine selected was the GE G-Series steam turbine. This turbine was chosen as an option for the conventional plant because it has many positive qualities like the Seiemens turbine. This turbine can produce the 1 GW of power output required by the plant specifications. This turbine can be designed to operate with one high pressure and two low pressures sections of a turbine. There is very little other information about this turbine without contating the sales representative but sense it does have the capability to reheat and can run at different steam condidtion it can be assumed that it could be designed to operate with different types of cooling systems.

We will also consider the option of using two smaller turbines to combine to our 1 GW of power output. This has several advantages such as this plant could baseload with one turbine and peak load with the other, and one turbine can operate while the other is being repair. The disadvantages of this type of turbine is that there is a high capital cost involved because you have to buy two of everything, it requires much more room and there is more inefficiencies. For these smaller turbines we will be looking for a turbine that has the option of high and low pressuer turbines to reduce cooling water needed, efficiencies or turbine, and capital cost.

2.2.4 Pumps

There are many different types of pumps that are used in power plants. There is the boiler circulating pump that circulates water in the heat exchanger of the boiler, the boiler feed water pump that that can send high pressure and temperature fluid to and from the boiler and turbines and the circulating water pump that sends water to the condenser. Because of the wide use of all these pumps there are many different styles and models to choose from. However there are two important features to consider when picking a pump. The first is that it can supply sufficient flow to the designated component. The second is that it can handle the temperature of the liquid that it will be pumping.² Both of these aspects will be considered when specifying pumps for our power plants.

Some examples of pumps that we are considered can be found in the following table which shows several different high, medium, and low pressure pumps, their operating conditions, and their flow rates.

<table>
<thead>
<tr>
<th>Pump</th>
<th>Pressure Rating</th>
<th>Max Temperature (°C)</th>
<th>Flow Rate (m³/hr)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HPK</td>
<td>25 and 40</td>
<td>240 - 400</td>
<td>3500</td>
</tr>
</tbody>
</table>

¹ (Siemens)
² (Filter)
These are just a few examples of possible pumps that we can use at different points in the plant.

2.2.5 Condenser

Boiler-feed water will need to be condensed after running through the turbines. Assuming a counter-current set up for the heat exchanger, we can determine the $\Delta T_{lm}$, the log mean of the temperature differences in and out.

$$\Delta T_{lm} = \frac{(\Delta T_{in} - \Delta T_{out})}{\ln \left( \frac{\Delta T_{in}}{\Delta T_{out}} \right)}$$  \hspace{1cm} (1)

Temperature for the cooling water is given in the following section, and the boiler-feed water is assumed to be at 383 K, condensing isothermally. Figure 8 shows temperatures in and out of the condenser.

We can then use the equation for heat transfer via conduction:

$$Q = (U)(A)(\Delta T_{lm})$$  \hspace{1cm} (2)

This allows us to calculate an area for the heat exchanger, as $Q$ (Heat transferred) is known from the enthalpy of condensing, as well as the flow rate of boiler feed water. $U$, the overall heat transfer coefficient, is estimated from common values of condensing steam run against cooling water in tubular
heat exchangers\(^1\). With the area, we can use Seider\(^2\) to estimate a cost of the heat exchanger as a function of area. Final cost of the heat exchanger is also a function of the materials used to construct the exchanger, as well as a pressure factor:

\[
C_F = (F_P)(F_M)(C_B)
\]

\[
C_B = e^{(7.1460+0.16\ln(A))}
\]

Where \(F_P\) is the pressure factor, and \(F_M\) is the materials factor.

Next semester, when final temperatures have been acquired, an effectiveness factor, \(F\), can be determined for the heat exchanger, which will affect the true area required for heat transfer. Additionally, \(U\) is merely an estimate at this point, and further studies should present a more accurate value for the heat transfer coefficient. Depending on what is found, area required may increase or decrease. Finally, a material for construction must be chosen that can withstand the temperature range through the condenser. Material factors given in Seider provide an empirical assessment of the cost increase for different materials of construction.

2.2.6 Cooling Tower

We will utilize a cooling tower in conjunction with the condenser, in order to minimize the feed water required for cooling. Preliminary costs estimates have shown that capital purchasing costs for a cooling tower will be much more effective than costs of purchasing greater quantities of feed water:

<table>
<thead>
<tr>
<th>Table 2: Cost Estimation of Cooling Tower Options</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cooling tower water make-up (kg/s)</td>
</tr>
<tr>
<td>Capital cost of cooling tower ($)</td>
</tr>
<tr>
<td>Cost of make-up water ($/yr)</td>
</tr>
<tr>
<td>Water flow rate, no cooling tower (kg/s)</td>
</tr>
<tr>
<td>Cost of water, no cooling tower ($/yr)</td>
</tr>
</tbody>
</table>

Designs for the cooling tower calculations are stated below. For the non-cooling tower option, a water flow rate was minimized so that there would still be a temperature differential through the condenser.

In addition, the location of the plant may not be in a favorable area for feeding water, so flow rate should be kept to a minimum. Additional studies may consider an air cooler in place of the water evaporating cooling tower.

Calculations for the cooling tower were performed using Microsoft Excel (see Table 3). We assumed a temperature for the process feed water, and given a heat transfer from the condenser, we calculated a temperature into the cooling tower. As the heat transfer through the condenser will be known, the heat removed by evaporating water must be equal in order to bring the flow back down to feed temperature:

---

\(^1\) (The Engineering ToolBox)

\(^2\) (Seider, 2009)
Using this equation, we can calculate the mass of water evaporated. Since the water will have some impurities, evaporating the water necessitates the removal of a concentrated water stream through a blowdown. We used an estimate of 3 cycles of concentration (ratio of impurity in blowdown to feed) as the actual feed concentration is not yet specified. This value was taken from heuristic assumptions\textsuperscript{1}. Using this value, the blowdown flow is half of the total evaporated, and we determined a make-up rate by summation of the two leaving streams. From this we can easily determine the cost of make-up water per year, using cost estimates for cooling water from Seider\textsuperscript{2}.

\[
Q_{\text{cond}} = \Delta H_{\text{tower}} = (h_{\text{vap}})(\text{Mass evaporated})
\]

<table>
<thead>
<tr>
<th>Temperature in (C)</th>
<th>39.8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temperature out (C)</td>
<td>30</td>
</tr>
<tr>
<td>Condenser Duty (kJ/s)</td>
<td>123000</td>
</tr>
<tr>
<td>Make-up water (kg/s)</td>
<td>73.76</td>
</tr>
<tr>
<td>Water Cost ($/gallon)\textsuperscript{1}</td>
<td>.000075</td>
</tr>
<tr>
<td>Flow Cost ($/year)</td>
<td>42100</td>
</tr>
</tbody>
</table>

Heat duty through the condenser is an estimate taken from the boiler Rankine cycle (see appendix A). We used data from Peters\textsuperscript{3} to model the capital cost of the cooling tower as a function of the water flow rate and the temperature range through the reactor, as seen in Figure 9, below. This graph represents a temperature range of 5.5 °C. This is modeled by adjusting the total flow rate of water through the loop, as increasing the water flow will decrease the temperature differential through the condenser. Once we have solidified variables, an optimized flow rate can be determined.

\[
y = 0.71x + 12.2
\]

![Graph of flow rate and capital cost](image)

\textbf{Figure 9: Correlation of Flow Rate in Cooling Tower to Capital Purchase Cost}\textsuperscript{4}

\textsuperscript{1}http://www1.eere.energy.gov/femp/program/waterefficiency.bmp10.html
\textsuperscript{2} (Seider, 2009)
\textsuperscript{3} (Peters, 2003)
\textsuperscript{4} (Seider, 2009)
A parallel pumping system was suggested for controlling the flow through the cooling tower, as a precaution against pump failure. If one pump fails, the other will still be able to maintain cooling on the reactor flow, to prevent catastrophic failure. We will be researching additional cost estimates for the pumps at a later time. Each pump must be able to withstand the full flow through the cooling tower.

In the following semester, information will be taken from the boiler loop to complete variable analysis of the system. Heat transfer through the condenser will determine how much water will be flowing through the loop, and a preliminary cost can be determined. This can then be scaled up with regards to operating and instillation costs.

2.2.7 Pre-feed processing
Boiler-feed water needs to be exceptionally clean, to prevent system failure. Entrained CO$_2$, O$_2$, or mineral deposits will cause corrosion or buildup inside of the boiler loop. To prevent this, we will have to use extra purified Boiler-feed water for our system.

One option, as used by Siemens\textsuperscript{1}, involves using a chemical treatment called coagulation to remove larger pieces of suspended solids in the water. Molecules involving aluminum and sulfates tend to be used for these purposes. Additional chemicals are then added to precipitate out the dissolved solids, as well as reduce the hardness and alkalinity. This step can be combined with the coagulation step, as both byproducts can be removed together. This is performed through a filtration, either ultrafiltration or membrane technologies. Finally, and ion exchange system will be used to remove ions from the flow stream.

Another option, Reverse Osmosis, can be used. This process should provide higher removal of solids, for more cycles of concentration, reducing blowdown and makeup streams. This comes with a downside of higher operating costs. In addition, Reverse Osmosis does not remove dissolved oxygen and other gases, so it will have to be passed through a degasifier afterwards.

The choice of process has not yet been finalized. We will have to determine the costs of running each system, as well as doing a comparative analysis on how much purity is needed, to determine an optimal choice for cleaning the stream. In addition, study will go into how much feed water is necessary and how frequently it must be replaced. It is possible that we will buy a pre-fabricated boiler-feed water treater from an existing company, as opposed to creating a new system from scratch.

\begin{figure}
\centering
\includegraphics[width=\textwidth]{PFD_of_Cooling_Tower_Segment.png}
\caption{PFD of Cooling Tower Segment}
\end{figure}

\textsuperscript{1} http://www.water.siemens.com/en/applications/industrial_process_water/boiler_feedwater/Pages/default.aspx
3 Conventional Coal Plant with Oxygen Feed

3.1 Overall Block Diagram/Energy flow
For the purpose of maintaining a fair comparison, the coal plant with oxygen will assume the same process flow as the base case plant, that is, a regenerative-reheat rankine cycle. This implies that the plant can be generalized with the same block diagram, but the components will be different. The overall process must produce more power in order to provide work to the oxygen separation process. The most dramatic difference between the two processes is the design of the boiler. The boiler will be designed to deliver the same amount of heat into the water stream using the combustion properties of oxygen, rather than air. However, once the heat is delivered into the water stream, the power plant will have a much similar process flow.

3.2 Design Specifications

3.2.1 Boiler
Air is comprised of approximately 78% Nitrogen and 21% Oxygen, with the remaining 1% being various gases (on a volume basis).\(^1\) Because nitrogen is an inert gas it absorbs heat when the coal is combusted, and invariably some of the nitrogen does react and produces NO\(_x\) gases. A way to reduce these losses is to fire the coal with oxygen. Typically oxygen coal combustion features a flue gas recycler in order to better control the flame temperature and to minimize NO\(_x\) production.\(^2\) Oxygen coal combustion replaces nitrogen found in air with flue gas, which is predominately CO\(_2\). This is done to increase the CO\(_2\) concentration in order to make it easier to remove.\(^3\) Pure oxygen input at the burners could achieve stoichiometric combustion, however it doesn’t necessarily provide the mass and volumetric flow rate required to mix the fuel and oxygen in order to achieve required heat transfer rates.\(^4\) Burning coal with oxygen, instead of air, removes the possibility of nitrogen gas found in air from reacting. A case study shows the O\(_2\)-PC boiler can reach fuel efficiencies near 95%, as opposed to an air-fired boiler whose efficiency is around 88%.\(^5\) This increase in efficiency is due to the decrease of nitrogen, which absorbs significant amounts of heat during the combustion process. Due to conflicting research the flue gas recycle rate will need to be optimized. The flue gas recycle rate will be optimized in order to maximize the efficiency of the boiler.

A significant difference between an oxygen feed plant and an air feed plant is the size requirement. The previously mentioned case study showed that an oxygen feed boiler requires only 65%\(^6\) of the surface area and 45%\(^7\) of the volume required for an air feed boiler. This is a result of the higher flame temperatures achieved when combusting a mixture of oxygen and flue gas. This means the component cost for a boiler will be lowered, thereby offering some cost benefits. However because heat is not

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1 (The Engineering ToolBox)
2 (Woycenko, Ieda, Van De Kamp)
3 (McDonald, 2007)
4 (McDonald, Zadiraka, 2007)
5 (Andrew H. Seltzer)
6 (Andrew H. Seltzer)
7 (Andrew H. Seltzer)
transferred to nitrogen the maximum heat flux through the walls is approximately 2.5 times greater than that of the air fired boiler.\textsuperscript{1} This will mean we may have to upgrade the material used for the walls in the oxygen coal combustion plant.

3.2.2 Turbines
A conventional coal plant with oxygen feed and a conventional coal power plant work in a very similar way when it comes to power generation. They both have a boiler that heats steam that goes to a steam turbine to produce work. The only difference is the type of combustion reaction that happens within the boiler. Because there is no difference in steam heating by different methods the same turbines that were recommended for the conventional coal power plant with oxygen feed will be a scaled up model of the turbines considered for the conventional coal plant. To see what these turbines are reference the turbine section in the conventional coal plant.

\textsuperscript{1} (Andrew H. Seltzer)
4 Integrated Gasification Combined Cycle

4.1 Design Specifications

4.1.1 Gas Turbines

Gas turbines, like steam turbines, come in all different shapes, sizes and power generating capabilities. There are several different operating conditions that were investigated in order to choose the best gas turbine to be used in the IGCC power plant. The first thing considered was whether or not the power plant was going to be a single shaft or a multi shaft system. A single shaft system is exactly as it sounds. It only has one shaft that connects the entire system. On this shaft lie a single gas turbine, steam turbine, and generator. By consolidating all of these components to a single shaft it increases the efficiency of the unit by reducing energy loss through mechanical and thermal system. Other benefits are that these types of systems are small in size and they require less cooling water because the low pressure steam turbine and gas turbine are the only components that need to be cooled. However there is one major drawback to the single shaft system. These types of power plants are generally small in power output and only produce somewhere between 100 – 650 MW of power. If this type of system was used we would have to use multiple setups in order to achieve the amount of power we are looking to produce. The second type of system is the multi shaft system. Multi shaft power plants work in a very similar way to single shaft but they are configured a little differently. Instead of only having one gas turbine to heat water that runs the steam turbine these power plants have several gas turbines. These gas turbines do not lie on the same shaft but they all end up producing steam for a single steam turbine. Because of the increased exhaust that can be used, steam can be heated to high temperatures and pressures. There are several benefits to this type of system. First, because of the increased quality of the steam being produced, a higher pressure steam turbine can be used which further increases the power output of the power plant. Second there are fewer steam turbines that are in the system which increases the efficiency because gas turbines tend to be more efficient than steam turbines. By using a combination of several gas turbines and a large steam turbine the desired 1 GW of power output could be achieved.

The second characteristic that was consider when selecting the gas turbines for the IGCC power plant was the efficiency of the gas turbine while operating in a combined cycle system. Because the goal of the project is to try and reduce the emissions of the power plant it only made sense to try and choose a turbine that has the highest efficiency.

The third characteristic that had to be addressed when searching for a gas turbine was the fuel that it used. In the past, the two major fuels used to power gas turbines were methane or natural gas. This presented a problem because the fuel that the power plants are going to use is coal. Thankfully new technology has been developed that allows turbines to run off of syngas which is the gasification of pulverized coal. Even though these syngas turbines are a relatively new technology there is still a wide variety to choose from.

From all the gas turbines research the two turbines that were chosen to be possibly analyzed for the IGCC plant are the Siemens SGT5-400F and the GE 9FA gas turbines. These turbines where chosen for several different reasons.

The Siemens SGT5-4000F gas turbine is one option for the IGCC power plant. Some of the operating conditions can be found in Table 4. This turbine is a medium sized turbine and as a result would need three of these turbines and one steam turbine to generate enough power to meet the plants power output. The relatively high efficiency makes it desirable in respect to coal consumption and exhaust emissions.
Table 4: SGT5-4000F Gas Turbine\(^1\)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Grid Frequency (Hz)</td>
<td>50</td>
</tr>
<tr>
<td>Gross Power Output (MW)</td>
<td>292</td>
</tr>
<tr>
<td>Gross Efficiency (%)</td>
<td>39.8</td>
</tr>
<tr>
<td>Gross Heat Rate (kJ/kWh)</td>
<td>9,038</td>
</tr>
<tr>
<td>Exhaust temperature (°C)</td>
<td>577</td>
</tr>
<tr>
<td>Exhaust Mass Flow (kg/s)</td>
<td>692</td>
</tr>
<tr>
<td>Pressure Ratio</td>
<td>18.2</td>
</tr>
</tbody>
</table>

The GE 9FB gas turbine is another option for our IGCC plant because it fulfills many of the design specifications of the plant. Table 5 shows a list of the most important factors regarding this turbine. Some key elements of this list are the power output, the high efficiency, and the low emissions. This is a high power output gas turbine and would only need two of these turbines to run the IGCC plant. By only needing two it helps to reduce the initial equipment costs for the plant.

Table 5: GE 9FB Gas Turbine\(^2\)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>9FB Combined Cycle Performance</td>
<td></td>
</tr>
<tr>
<td>Net power output</td>
<td>510 MW</td>
</tr>
<tr>
<td>Combined cycle efficiency</td>
<td>60%</td>
</tr>
<tr>
<td>NOx emissions</td>
<td>30 to 50 mg/Nm3</td>
</tr>
<tr>
<td>CO emissions</td>
<td>30 mg/Nm3</td>
</tr>
<tr>
<td>Start time</td>
<td>less than 30 minutes</td>
</tr>
<tr>
<td>Ramping rate</td>
<td>greater than 50 MW/minute</td>
</tr>
<tr>
<td>Gas turbine turndown</td>
<td>30% base load</td>
</tr>
<tr>
<td>Plant turndown</td>
<td>40% base load</td>
</tr>
</tbody>
</table>

4.1.2 Steam Turbines

In addition to the gas turbines, the IGCC plant will also use a steam turbine to generate power. This steam turbine will run off of steam heated by the exhaust from the gas turbines. Depending on the size and quantity of the gas turbines will determine the size of the steam turbine that will be used. The use of several large gas turbines allows us to generate steam, via a heat exchanger, from the combustion products of syngas. By utilizing several large gas turbines on a multi shaft design we can use a larger steam turbine that runs at higher pressure and efficiencies. If we decided to use a single shaft system we will have to use a steam turbine that doesn’t run at such high pressures or temperatures.

\(^1\) (Siemens)  
\(^2\) (GE Energy)
5 Conclusion
Society has more of a focus on being environmentally friendly, and IGCC variety power plants are on a rise in America. The main goal of our project is to investigate the cost effectiveness of a clean coal power plant as compared to a conventional coal power plant. We have determined that this analysis will be feasible, and will continue on in our research.

Over the course of the semester, we have performed preliminary research into the important aspects necessary for the design of our power plants. Important variables for optimization have been identified and compared. These variables include safety, emissions, and costs. Some variables have been constrained for the sake of comparison, such as location, coal type, and power output. The energy flow has been modeled using EES software, and we are currently reaching a final decision on the energy flow of the process. We have identified the key components necessary to process the rankine cycle and prepare the coal for the boiler or gasifier, and will continue to improve our model of them.

Moving forward into the next semester, we will begin detailed design of the conventional power plant. This includes system-wide performance and cost optimization, as well as an in-depth design of individual components. The components to be designed will be the coal pulverizer, cooling tower, boiler, and condenser. The remaining components, due to scope constraints and limits of education, will be specified using information taken from other companies and industries.

In conjunction with groups 14 and 15, we will make a choice as to compare the conventional plant to either the oxygen-fed plant, IGCC plant, or both options. Depending on which plant option is chosen, we will compare them on the basis of cost and emissions. For our final deliverable, we will present the cost and implications of being environmentally friendly with coal power generation.


6 Appendices
Appendix A: EES Code for Rankine Cycle Calculations
Appendix B: Work Breakdown Schedule
Appendix A – EES Code for Rankine Cycle Calculations

"Simple Rankine Cycle"
"State Point 1 - Condenser Outlet, Pump inlet"
T[1] = Temperature(Water, P=P[1], x=x[1])
P[1] = 101.325 [kPa]
h[1] = enthalpy(Water, T=T[1], P=P[1])
s[1] = entropy(Water, T=T[1], P=P[1])

\[ \eta_{pump} = 0.86 \]

\[ \eta_{pump} = \frac{(h_{2_s} - h[1])}{(h[2] - h[1])} \]

h_{2_s} = enthalpy(Water, P=P[2], s=s[1])

\[ W_{pump,1} = m_w *(h[2] - h[1]) * \text{convert}(\text{kW}, \text{MW}) \]

"Isentropic Efficiency of Compressor"

"State Point 2 - Pump outlet, Boiler inlet"
T[2] = temperature(Water, P=P[2], h=h[2])
s[2] = entropy(Water, P=P[2], h=h[2])

"State Point 3 - Boiler Outlet, Turbine inlet"
T[3] = temperature(Water, P=P[3], h=h[3])
P[3] = 15000 [kPa]
s[3] = entropy(Water, T=T[3], P=P[3])

\[ \eta_{turb,HP} = 0.86 \]

\[ \eta_{turb,HP} = \frac{(h[3] - h[4])}{(h[3] - h_{4_s})} \]

h_{4_s} = enthalpy(Water, T=T[4], s=s[3])

\[ W_{turb,1} = m_w *(h[3] - h[4]) * \text{convert}(\text{kW}, \text{MW}) \]

"Isentropic Efficiency of Turbine"

"State Point 4 - Turbine outlet, Condenser inlet"
h[4] = enthalpy(Water, T=T[4], P=P[4])
s[4] = entropy(Water, T=T[4], P=P[4])

"Energy Calculations for Makeup water"
HHV_{coal} = 27[MJ/kg]

\[ W_{\text{out}} = P_{elec} / \eta_{gen} \]

\[ W_{\text{out}} = W_{turb,1} - W_{pump,1} \]

Q_{boiler} = m_w *(h[3] - h[2]) * convert(kW, MW)

Q_{boiler} = HHV_{coal} * m_{coal}

Q_{cond} = m_w *(h[4] - h[1]) * convert(kW, MW)

"Net Work Output"
"Electricity Delivered to Grid"
"Heat from boiler"
"Waste heat from condenser"

"Power Calcs"
P_{elec} = 1000[MW]

\[ \eta_{gen} = 0.98 \]

\[ \eta_{th} = W_{\text{out}} / Q_{\text{boiler}} \]

"Generator Efficiency"
"Overall Thermal Efficiency"

"Solutions"
eta_th=0.3044
m_.c=124.2 [kg/s]
P_{elec}=1000 [MW]
Q_.cond=2332 [MW]

Thermal Efficiency of Cycle
Rate of Coal Consumption
Electricity Generation
Waste Heat through Condenser
"Super Critical"
"State Point 1 - Condenser Outlet, Pump inlet"
\[ T[1] = \text{Temperature(Water, P=P[1], x=x[1])} \]
\[ P[1] = 101.325 \text{ [kPa]} \]
\[ h[1] = \text{enthalpy(Water, T=T[1], P=P[1])} \]
\[ s[1] = \text{entropy(Water, T=T[1], P=P[1])} \]
\[ x[1] = 0.0 \]
\[ \eta_{\text{pump}} = 0.86 \]
\[ \eta_{\text{pump}} = \frac{h_2 - s[2] - h[1]}{h[2] - h[1]} \]
\[ h_2 = \text{enthalpy(Water, P=P[2], s=s[1])} \]
\[ W_{\text{pump,1}} = \dot{m}_w * (h[2] - h[1]) \text{ convert(kW,MW)} \]

"State Point 2 - Pump outlet, Boiler inlet"
\[ T[2] = \text{temperature(Water, P=P[2], h=h[2])} \]
\[ s[2] = \text{entropy(Water, P=P[2], h=h[2])} \]

"State Point 3 - Boiler Outlet, Turbine inlet"
\[ T[3] = \text{temperature(Water, P=P[3], h=h[3])} \]
\[ P[3] = 300 \text{ [bar]} \text{ convert(bar,kPa)} \]
\[ s[3] = \text{entropy(Water, T=T[3], P=P[3])} \]
\[ \eta_{\text{turb,HP}} = 0.86 \]
\[ \eta_{\text{turb,HP}} = \frac{h[3] - h[4]}{h[3] - h_4} \]
\[ h_4 = \text{enthalpy(Water, T=T[4], s=s[3])} \]
\[ W_{\text{turb,1}} = \dot{m}_w * (h[3] - h[4]) \text{ convert(kW,MW)} \]

"State Point 4 - Turbine outlet, Condenser inlet"
\[ T[4] = \text{T\_sat(Water, P=P[4]) + 10[K]} \]
\[ h[4] = \text{enthalpy(Water, T=T[4], P=P[4])} \]
\[ s[4] = \text{entropy(Water, T=T[4], P=P[4])} \]

"Energy Calculations for Makeup water"
\[ \text{HHV}_{\text{coal}} = 27 \text{ [MJ/kg]} \]
\[ W_{\text{out}} = P_{\text{elec}} / \eta_{\text{gen}} \]
\[ W_{\text{out}} = W_{\text{turb,1}} - W_{\text{pump,1}} \]
\[ Q_{\text{boiler}} = \dot{m}_w * (h[3] - h[2]) \text{ convert(kW,MW)} \]
\[ Q_{\text{boiler}} = \text{HHV}_{\text{coal}} * \dot{m}_\text{coal} \]
\[ Q_{\text{cond}} = \dot{m}_w * (h[4] - h[1]) \text{ convert(kW,MW)} \]

"Power Calcs"
\[ P_{\text{elec}} = 1000 \text{ [MW]} \]
\[ W_{\text{pump, total}} = W_{\text{pump,1}} \]
\[ \eta_{\text{gen}} = 0.98 \]
\[ \eta_{\text{th}} = W_{\text{out}} / Q_{\text{boiler}} \]

"Solutions"
\[ \eta_{\text{th}} = 0.3425 \]
\[ Q_{\text{cond}} = 1959 \text{ [MW]} \]
\[ P_{\text{elec}} = 1000 \text{ [MW]} \]
\[ m_c = 110.3 \text{ [kg/s]} \]

thermal efficiency of cycle
waste heat through condenser
electricity generation
rate of coal consumption
"Reheat-Regenerative"
"State Point 1 - Condenser Outlet, Pump 1 inlet"
\[ T[1] = \text{temperature(Water, } P=P[1], \ x=x[1]) \]
\[ P[1] = 10 \ [kPa] \]
\[ h[1] = \text{enthalpy(Water, } P=P[1], \ x=x[1]) \]
\[ s[1] = \text{entropy(Water, } P=P[1], \ x=x[1]) \]
\[ x[1] = 0 \]

\[ \eta_{\text{pump\_1}} = 0.86 \]
\[ \eta_{\text{pump\_1}} = \left( h_{2\_s} - h[1] \right) / (h[2] - h[1]) \]
\[ h_{2\_s} = \text{enthalpy(Water, } P=P[2], \ s=s[1]) \]

"Assumed Base Pressure"

"State Point 2 - Pump 1 outlet, Open FWH inlet"
\[ T[2] = \text{temperature(Water, } P=P[2], \ h=h[2]) \]
\[ P[2] = 500 \ [kPa] \]
\[ s[2] = \text{entropy(Water, } P=P[2], \ h=h[2]) \]

"State Point 3 - Open FWH outlet, Pump 2 inlet"
\[ T[3] = \text{temperature(Water, } P=P[3], \ x=x[3]) \]
\[ h[3] = \text{enthalpy(Water, } P=P[3], \ x=x[3]) \]
\[ s[3] = \text{entropy(Water, } P=P[3], \ x=x[3]) \]
\[ x[3] = 0 \]

\[ \eta_{\text{pump\_2}} = 0.86 \]
\[ \eta_{\text{pump\_2}} = \left( h_{4\_s} - h[3] \right) / (h[4] - h[3]) \]
\[ h_{4\_s} = \text{enthalpy(Water, } P=P[4], \ s=s[3]) \]

"Isentropic Efficiency of Pump 1"

"Isentropic Efficiency of Pump 2"

"State Point 4 - Pump 2 outlet, Closed FWH inlet"
\[ T[4] = \text{temperature(Water, } P=P[4], \ h=h[4]) \]
\[ P[4] = 15000 \ [kPa] \]
\[ s[4] = \text{entropy(Water, } P=P[4], \ h=h[4]) \]

"State Point 5- Closed FWH outlet, Mixing Chamber inlet"
\[ T[5] = \text{temperature(Water, } P=P[5], \ h=h[5]) \]
\[ s[5] = \text{entropy(Water, } P=P[5], \ h=h[5]) \]

"State Point 6 - Closed FWH outlet, Pump 3 inlet"
\[ T[6] = \text{temperature(Water, } P=P[6], \ x=x[6]) \]
\[ h[6] = \text{enthalpy(Water, } P=P[6], \ x=x[6]) \]
\[ s[6] = \text{entropy(Water, } P=P[6], \ x=x[6]) \]
\[ x[6] = 0 \]

\[ \eta_{\text{pump\_3}} = 0.86 \]
\[ \eta_{\text{pump\_3}} = \left( h_{7\_s} - h[6] \right) / (h[7] - h[6]) \]
\[ h_{7\_s} = \text{enthalpy(Water, } P=P[7], \ s=s[6]) \]

"Isentropic Efficiency of Pump 3"

"State Point 7 - Pump 3 outlet, Mixing chamber inlet"
\[ T[7] = \text{temperature(Water, } P=P[7], \ h=h[7]) \]
\[ s[7] = \text{entropy(Water, } P=P[7], \ h=h[7]) \]

"State Point 8 - Mixing chamber outlet, Boiler inlet"
T[8] = temperature(Water, P=P[8], h=h[8])
s[8] = entropy(Water, P=P[8], h=h[8])

"State Point 9 - Saturated Liquid, Boiler"
T[9] = temperature(Water, P=P[9], x=x[9])
h[9] = enthalpy(Water, P=P[9], x=x[9])
s[9] = entropy(Water, P=P[9], x=x[9])
x[9] = 0

"State Point 10 - Saturated Steam, Boiler"
T[10] = temperature(Water, P=P[10], x=x[10])
h[10] = enthalpy(Water, P=P[10], x=x[10])
s[10] = entropy(Water, P=P[10], x=x[10])
x[10] = 1

"State Point 11 - Boiler Outlet, Turbine 1 inlet"

$\eta_{turb\_1} = 0.86$


$h_{\_12\_s} = enthalpy(Water, P=P[12], s=s[11])$

"Isentropic Efficiency of Turbine 1"

"State Point 12 - Turbine 1 outlet, Split inlet"
T[12] = temperature(Water, P=P[12], h=h[12])
P[12] = 4000 [kPa]
s[12] = entropy(Water, P=P[12], h=h[12])

"State Point 13 - Split outlet 1, Reheater inlet"
h[13] = h[12]
s[13] = s[12]

"State Point 14 - Reheater outlet, Turbine 2 inlet"
T[14] = converttemp(C,K,600)
P[14] = P[12]
h[14] = enthalpy(Water, P=P[14], T=T[14])
s[14] = entropy(Water, P=P[14], T=T[14])

$\eta_{turb\_2} = 0.86$

$\eta_{turb\_2} = (h[14] - h[15]) / (h[14] - h_{\_15\_s})$

$h_{\_15\_s} = enthalpy(Water, P=P[15], s=s[14])$

"Isentropic Efficiency of Turbine 2"

"State Point 15 - Turbine 2 outlet 1, Open FWH inlet"
T[15] = temperature(Water, P=P[15], h=h[15])

"State Point 16 - Saturated Steam, Open FWH"
T[16] = temperature(Water, P=P[16], x=x[16])
\[ \begin{align*}
\text{P}[16] &= \text{P}[2] \\
\text{h}[16] &= \text{enthalpy}(\text{Water}, P=\text{P}[16], x=\text{x}[16]) \\
\text{s}[16] &= \text{entropy}(\text{Water}, P=\text{P}[16], x=\text{x}[16]) \\
\text{x}[16] &= 1 \\
\eta_{\text{turb}_2} &= (\text{h}[15] - \text{h}[17]) / (\text{h}[15] - \text{h}_{17}\_s) \\
\text{h}_{17}\_s &= \text{enthalpy}(\text{Water}, P=\text{P}[17], s=\text{s}[15]) \\
\end{align*} \]

"State Point 17 - Turbine 2 outlet 2, Condenser inlet"
\[ \begin{align*}
\text{T}[17] &= \text{T}[1] + 5 [K] \\
\text{P}[17] &= \text{P}[1] \\
\text{h}[17] &= \text{enthalpy}(\text{Water}, T=\text{T}[17], P=\text{P}[17]) \\
\text{s}[17] &= \text{entropy}(\text{Water}, T=\text{T}[17], P=\text{P}[17]) \\
\end{align*} \]

"State Point 18 - Split outlet 2, Closed FWH inlet"
\[ \begin{align*}
\text{T}[18] &= \text{T}[12] \\
\text{P}[18] &= \text{P}[12] \\
\text{h}[18] &= \text{h}[12] \\
\text{s}[18] &= \text{s}[12] \\
\end{align*} \]

"State Point 19 - Saturated Steam, Closed FWH"
\[ \begin{align*}
\text{T}[19] &= \text{temperature}(\text{Water}, P=\text{P}[19], x=\text{x}[19]) \\
\text{P}[19] &= \text{P}[12] \\
\text{h}[19] &= \text{enthalpy}(\text{Water}, P=\text{P}[19], x=\text{x}[19]) \\
\text{s}[19] &= \text{entropy}(\text{Water}, P=\text{P}[19], x=\text{x}[19]) \\
\text{x}[19] &= 1 \\
\end{align*} \]

"Mass Balances"
\[ \begin{align*}
\text{m\_w\_1} &= \text{m\_w\_2} + \text{m\_w\_3} \\
\text{m\_w\_2} &= \text{m\_w\_4} + \text{m\_w\_5} \\
\end{align*} \]

"Energy Balances"
"Pumps"
\[ \begin{align*}
\text{W\_pump\_1} &= \text{m\_w\_3}(\text{h}[2] - \text{h}[1])*\text{convert(kW,MW)} \\
\text{W\_pump\_2} &= \text{m\_w\_2}(\text{h}[4] - \text{h}[3])*\text{convert(kW,MW)} \\
\text{W\_pump\_3} &= \text{m\_w\_3}(\text{h}[7] - \text{h}[6])*\text{convert(kW,MW)} \\
\end{align*} \]

"Turbines"
\[ \begin{align*}
\text{W\_turb\_1} &= \text{m\_w\_1}(\text{h}[11] - \text{h}[12])*\text{convert(kW,MW)} \\
\text{W\_turb\_2} &= \text{m\_w\_2}(\text{h}[14] - \text{h}[15])*\text{convert(kW,MW)} \\
\text{W\_turb\_3} &= \text{m\_w\_5}(\text{h}[15] - \text{h}[17])*\text{convert(kW,MW)} \\
\end{align*} \]

"Feed Water Heaters"
\[ \begin{align*}
\text{Q\_closed\_FWH} &= \text{m\_w\_3}(\text{h}[18] - \text{h}[6])*\text{convert(kW,MW)} \\
\text{Q\_closed\_FWH} &= \text{m\_w\_2}(\text{h}[5] - \text{h}[4])*\text{convert(kW,MW)} \\
\text{m\_w\_2}\text{h}[3] &= \text{m\_w\_5}\text{h}[2] + \text{m\_w\_4}\text{h}[15] \\
\end{align*} \]

"Mixing Chamber / Split"
\[ \begin{align*}
\text{m\_w\_1}\text{h}[8] &= \text{m\_w\_3}\text{h}[7] + \text{m\_w\_2}\text{h}[5] \\
\text{m\_w\_1}\text{h}[12] &= \text{m\_w\_2}\text{h}[13] + \text{m\_w\_3}\text{h}[18] \\
\end{align*} \]

"Energy Calculations for Makeup water"
\[ \begin{align*}
\text{HHV\_coal} &= 27[\text{MJ/kg}] \\
\text{HHV} &= 15 \text{MJ/kg} - 27 \text{MJ/kg} \\
\text{W\_out} &= \text{W\_turb\_1} + \text{W\_turb\_2} + \text{W\_turb\_3} - \text{W\_pump\_1} - \text{W\_pump\_2} - \text{W\_pump\_3} \\
\text{W\_out} &= \text{P\_elec} / \eta\_\text{gen} \\
\text{"Total work into Generator"} \\
\end{align*} \]
\[ Q_{\text{boiler}} = ((m_\text{w}_1 \cdot (h[11] - h[8])) + (m_\text{w}_2 \cdot (h[14] - h[13]))) \cdot \text{convert(kW,MW)} \]
\[ Q_{\text{boiler}} = \text{HHV_coal} \cdot m_\text{c} \]
\[ Q_{\text{cond}} = m_\text{w}_5 \cdot (h[17] - h[1]) \cdot \text{convert(kW,MW)} \]

"Power Calcs"
\[
\begin{align*}
P_{\text{elec}} &= 1000\text{[MW]} \\
&= 0.98 \\
\eta_{\text{th}} &= \frac{W_{\text{out}}}{Q_{\text{boiler}}} \\
\eta_{\text{gen}} &= \text{Electricity Generated} \\
\eta_{\text{th}} &= \text{Overall Thermal Efficiency} \\
\end{align*}
\]

"Solutions"
\[
\begin{align*}
\eta_{\text{th}} &= 0.4012 \\
P_{\text{elec}} &= 1000 \text{[MW]} \\
Q_{\text{cond}} &= 1523 \text{[MW]} \\
m_\text{c} &= 94.2 \text{[kg/s]} \\
\end{align*}
\]

- Thermal Efficiency of Cycle
- Electricity Generation
- Waste Heat through Condenser
- Rate of Coal Consumption
Appendix B – Work Breakdown Structure