Design for a Coal IGCC Plant for the Co-Production of Electricity and H_2 in Pittsburgh, PA

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Executive Summary

At the turn of the century, climate change became a hot topic in the mainstream media, and as a result, a worldwide concern arose about the possibility of human activity causing recent global temperatures to increase. This concern, coupled with fossil fuel resources becoming increasingly scarce has caused a push for alternative energy technologies with low CO_2 emissions. A need to develop more efficient and clean fossil fuel technologies arises in order to feasibly transition into a clean, renewable energy future because fossil fuels are finite resources, and the majority of current US energy infrastructure is based on fossil fuels. This report's focus is on optimizing coal gasification plant design, and will review literature about integrated gasification combined cycle (IGCC) as well as liquefaction plants to find which plant could be impacted the most with a modified design. Along with a plant design, this report analyzes the plant's performance, environmental management, and cost in order to provide a comparative basis to existing coal power plants.

After an analysis of the coal gasification literature, it was decided that currently implemented IGCC gasification facilities had obvious room for improvement compared to existing liquefaction plants, of which related literature did not provide any significant ideas for improving existing liquefaction plant design.

A 1200 MW coal IGCC plant has been designed for the co-production of electricity and hydrogen to serve the Pittsburgh, PA community. This design included carbon capture technologies which will most likely be necessary for future environmental legislation (carbon tax, or cap and trade). Analysis for the IGCC co-producing plant yielded a respectable overall LHV efficiency of 48.5%, compared to a 36% efficient supercritical CFPP, both using carbon capture technologies. The IGCC plant proposed is also more environmentally friendly option both for its low emissions, as well as for its low water usage. Capitol cost for the proposed plant will be near $2.9 billion, with annual O&M costs totaling $660 million. Based on the anticipated 30 year plant life, lifetime plant costs total about $22.6 billion. With carbon capture technology soon becoming a requirement in the coal-power industry, electricity production can be competitive with CFPP electricity prices, while improving the environmental soundness of coal power generation.

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1 Introduction

At the turn of the century, climate change became a hot topic in the mainstream media, and as a result, a worldwide concern arose about the possibility of human activity causing recent global temperatures to increase. This concern, coupled with fossil fuel resources becoming increasingly scarce has caused a push for alternative energy technologies with low CO_2 emissions. A need to develop more efficient and clean fossil fuel technologies arises in order to feasibly transition into a clean, renewable energy future because fossil fuels are finite resources, and the majority of current US energy infrastructure is based on fossil fuels. This report's focus will be on optimizing coal gasification plant design, and will review literature about IGCC as well as liquefaction plants to find which plant could be impacted the most with a modified design. Along with a plant design, this report analyzes the environmental improvements associated with the new design, as well as the long term cost savings with the improved design.

2 Pennsylvania's Coal Resources

Knowing Pennsylvania's available coal resources is essential to the technological analysis provided below. Figure 1 shows us that the large majority of Pennsylvania's coal is high-volatile bituminous. The second most abundant coal type is medium-volatile bituminous. The coal utilized in the plant proposed here will be based around the properties of high-volatile bituminous coal. The properties of various ranks of coal are presented in Table 1 to get a feel for how high-volatile bituminous coal compares with other coal ranks. The more important properties of coal that have implications for a gasification plant design are the feedstock's heating value, ash content, as well as sulfur content [2].

Table 1: Ultimate Analysis of Various Coals [1]

	As Received,	Percentage by Mass					
Rank	Btu/Lb	O	H	C	N	S	Ash
Anthracite	12,700	5.0	2.9	80.0	0.9	0.7	10.5
Semianthracite	13,600	5.0	3.9	80.4	1.1	1.1	8.5
Low volatile bituminous	14,350	5.0	4.7	81.7	9.4	1.2	6.0
High-volatile bituminous A	13,800	9.3	5.3	75.9	1.5	1.5	6.5
High-volatile bituminous B	12,500	13.8	5.5	67.8	1.4	3.0	8.5
High-volatile bituminous C	11,000	20.6	5.8	59.6	1.1	3.5	9.4
Sub-bituminous	9,000	29.5	6.2	52.5	1.0	1.0	9.8
Lignite	6,900	44.0	6.9	40.1	0.7	1.0	7.3

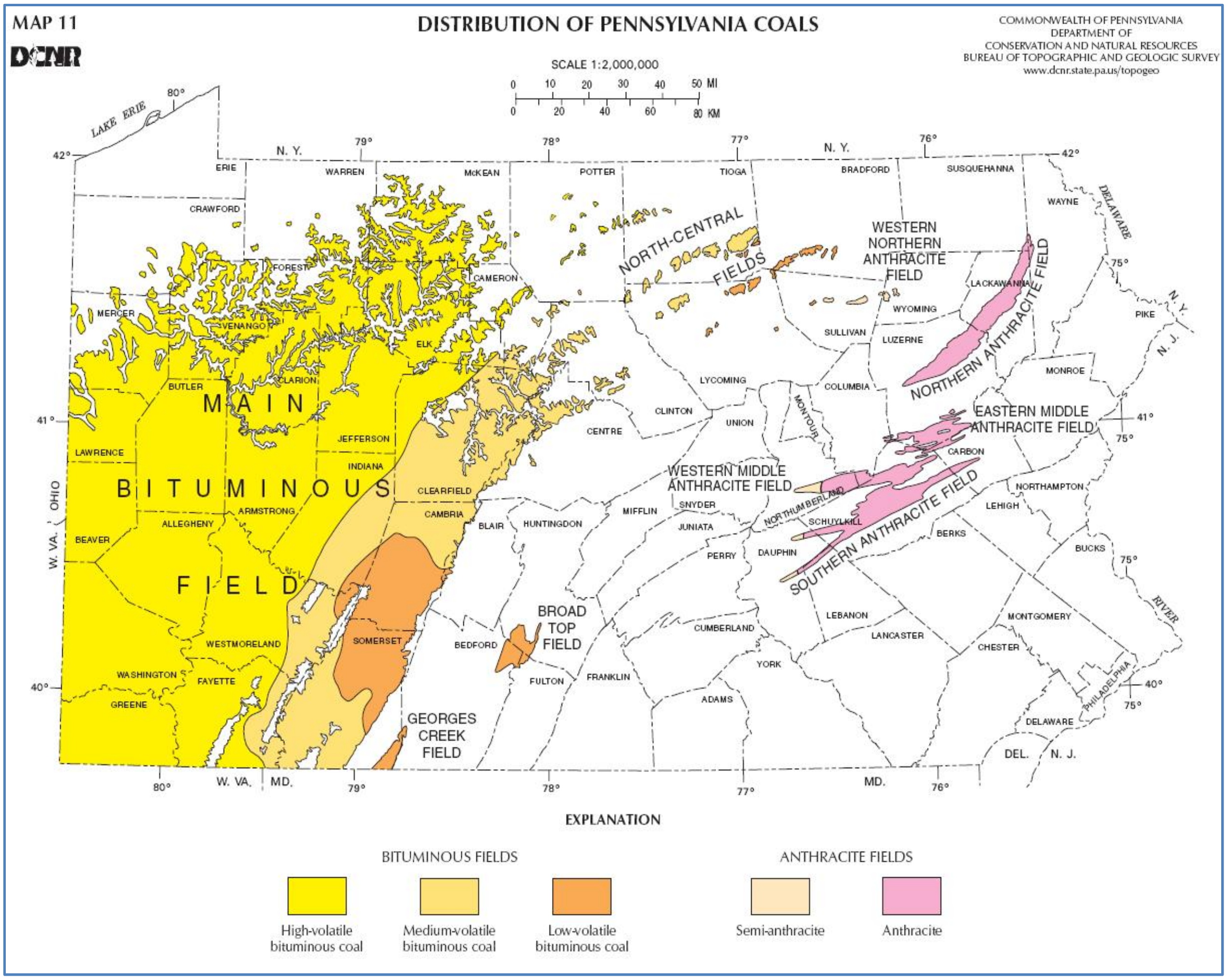

Figure 1: Pennsylvania's Coal Resources [3]

3 Literature Review of Coal Gasification Plants

Gasification is defined as the thermal breakdown of hydrocarbons in a controlled oxygen environment. Coal gasification typically executes with oxygen contents 20 to 30% of that required for theoretically complete combustion. The products produced from this process are primarily synthesis gas (H_2 and CO), or syngas. Once cleaned, syngas can either be combusted for electricity production (IGCC), or used to synthesize virtually any larger organic compound from chemicals to liquid transportation fuels (Liquefaction).

3.1 Coal IGCC Plants

Coal IGCC is being considered the most promising low-CO_2 emission coal technology because the majority of the environmentally-troubling gaseous products can be removed before the combustion process (gas turbine). Also, the latest models for latent heating value (LHV) efficiencies of gasification plants that include CO_2 separation technology are significantly higher than today's dirty coal-fired combustion plants (35-55% compared to 30-35%, respectively) [4]. Figure 2 shows the schematic of a typical existing IGCC facility.

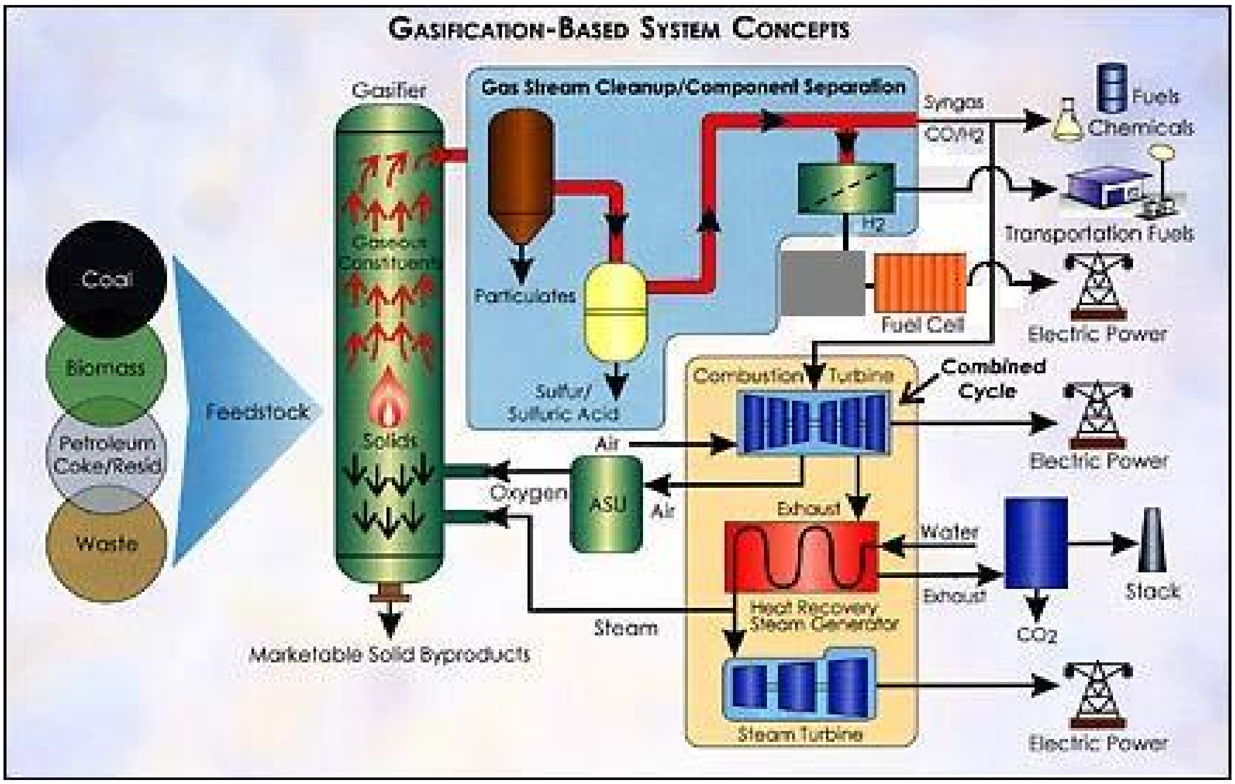

Figure 2: IGCC Plant Configuration Options

3.1.1 Existing Facilities

Syngas production started taking place over two hundred years ago, and was originally produced from coal to light homes. Post World War II, discoveries of large low cost natural gas reserves caused the gasification industry to fade out [1]. In the 1970's, fossil fuel shortages renewed interest in gasification technologies because of the need for finding alternative sources of fuel. At the turn of this century, the subject of climate change mainstreamed very quickly, necessitating clean alternative energy technologies. With coal's relative abundance as a fossil fuel, and a lack of clean, large scale [4] energy solutions, coal gasification has become a popular subject of research.

In early 2003, the US government launched a $1 billion coal gasification demonstration project called FutureGen. The aim of the prototype plant was to prove both Integrated Gasification Combined-Cycle (IGCC) and H_2 generation technology combined with carbon capture technology [2]. IGCC is a type of gasification power generation that utilizes a gas turbine that compresses syngas and combusts it at high temperature, a heat recovery steam generator that recovers heat from the combustion stage of the gas turbine through water, and a steam turbine that is typical in coal-fired power plants. Unfortunately, this project's funding was cut due to the US's unstable economy.

The companies described below are the current industry leaders that have their own gasification technologies demonstrated on a commercial scale. Although they haven't implemented IGCC technology coupled with carbon capture yet, newly proposed gasification plants are starting to capture CO_2 [1].

Texaco's gasification technology is the most widespread commercial gasification technology, and in 1994 General Electric (GE) bought the rights to Texaco's gasification business. There are currently about 65 GE (Texaco) gasification facilities worldwide, only two of which are used to produce electricity from coal. The other 63 plants gasify either coal, oil derivatives or natural gas in order to synthesize a wide range of chemicals (methanol, ammonia, methane, etc.) [2]. Synthesizing chemicals in this manner is also known as coal liquefaction, which is described in greater detail later in this report.

Shell currently owns five gasification facilities worldwide, one of these being a coal fed IGCC power plant. The other plants gasify petroleum wastes for the production of chemicals and/or H_2. The existing Shell IGCC plant will provide the basis for future Shell IGCC power/H_2 plant endeavors [2].

Because of GE's obvious dominance in the commercial-scale gasification industry, this study will focus specifically on GE gasifier technology.

3.1.2 Maturity of Integrated Gasification Combined Cycle (IGCC) Plants

Compared to gasification plants that produce chemicals, IGCC power plants are not widely demonstrated considering there are only a handful of current IGCC power plants out of the 100 total gasification facilities. However, each gasification facility shares the same fundamental elements. Figure 3 shows a schematic of a proposed gasification plant co-producing power and H_2. The fundamentals of the gasification plant that are shared regardless of what is produced from the plant are: the gasifier, particulate separation unit, and acid gas separation. Plants looking to reduce NOx emissions implement an air separation unit (ASU), which allows a purified oxygen feed into both the gasifier as well as the gas turbine. The integration of these components, therefore, is well proven at commercial scale. Although combined cycle gas turbines' (CCGT) integration into gasification systems is not currently the most popular gasification configuration, anticipated carbon legislation will help implement more of these power facilities.

3.1.3 IGCC Configuration Options

The literature provided many different plant output recommendations. Some researchers looked at producing power using only IGCC technology [5-8], while others proposed to use a coal gasification plant for H_2 production [9]. With the hydrogen economy being anticipated to take off in a couple decades, there isn't a great immediate need for dedicated H_2 production plants. For the transition into the anticipated hydrogen economy, gasification plants that co-produce power and H_2 would make the most sense in both a practical and economical sense. These proposed co-production gasification facilities have been modeled for overall plant efficiency in several research simulations [10-14]. Typically gasification product gas is primarily syngas, but fairly pure H_2 production is achieved through a water gas shift reactor placed immediately after the gasifier, to convert virtually all CO gas to CO_2 via the reaction below. The CO_2 can then be separated from the H_2 and transported to storage in geologic formations.

$$CO + H_2O \rightarrow H_2 + CO_2$$

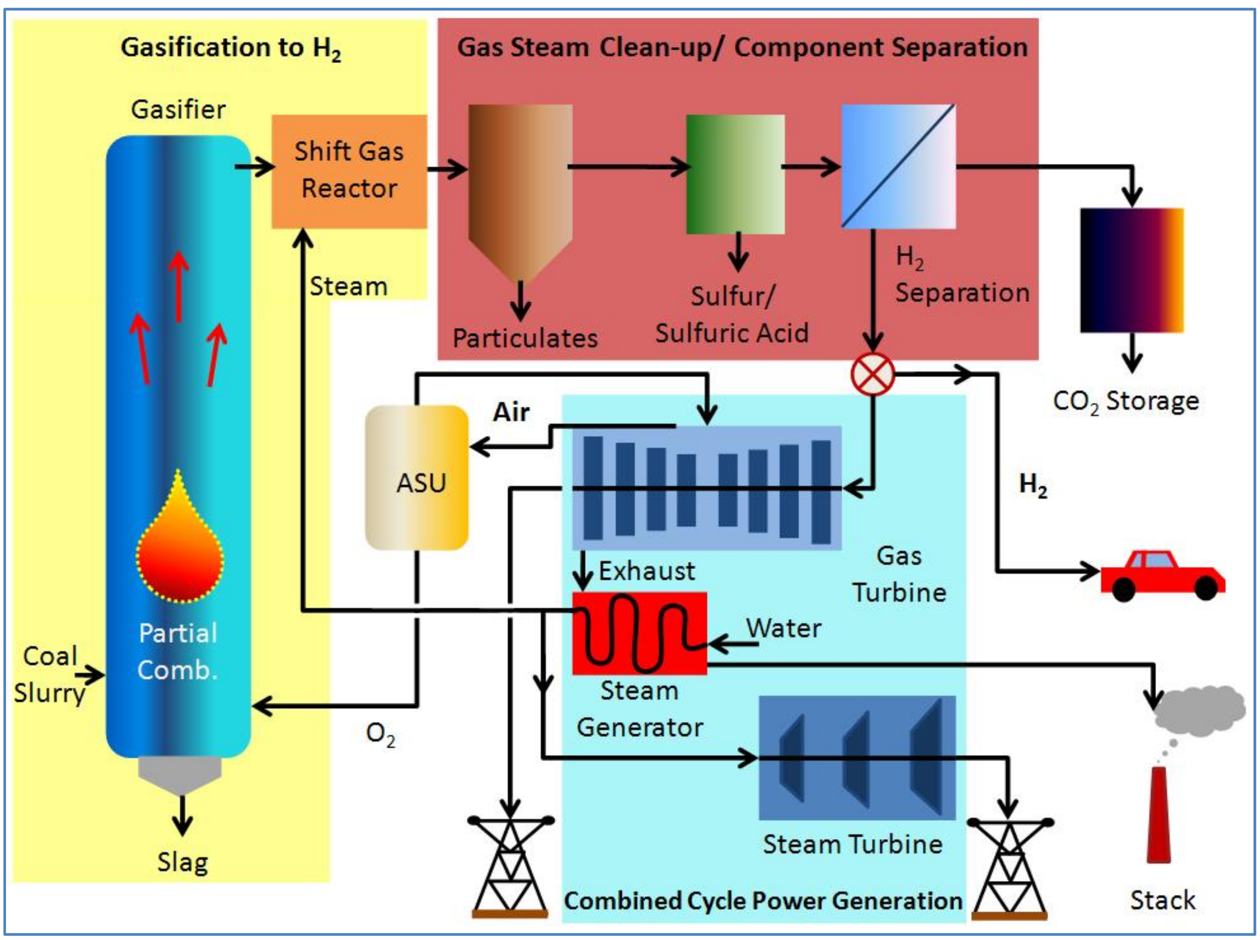

Figure 3: Schematic of an IGCC plant that co-produces power and H_2 while capturing CO_2

Co-production plants provide great flexibility to adjust to daily electricity demand fluctuations. In periods of highest demand, the CCGT alone will be producing power at full capacity, and in periods of medium demand, a small percentage of the produced hydrogen can be piped to the community for fuel cell applications such as vehicles, generators and portable electronics. For periods of lowest demand, such as late-night hours, plants can produce solely H_2, providing a significant quantity of transportation fuel for the next day [13]. Some forward looking research studies suggested using a solid oxide fuel cell in place of the CCGT for power production [15, 16]. Solid oxide fuel cells have not yet been proven at utility-scale [1], so this technology will be considered an unfeasible option for utility-scale power production at this time.

The cases for the co-production of power and H_2 seem the most flexible and energy efficient. Existing IGCC facilities have not yet implemented a WGS reactor immediately after the gasifier for pre-combustion CO_2 separation. See Figure 3 for the exact plant's schematic. Again, the WGS reactor allows for 90% of the carbon to be captured before the hydrogen-rich gas is combusted in a CCGT or transported to a transportation fueling station.

3.2 Coal Liquefaction Plants

Coal is a solid with high carbon content but with a hydrogen content of less than 5%. Coal may be used to produce liquid fuels suitable for transportation fuels by removal of carbon or addition of hydrogen, either directly or indirectly. Liquefying coal involves increasing the ratio of hydrogen to carbon atoms (H/C) from 0.8 to 1.5-2.0. Germany developed the liquefaction of coal in the twentieth century, which transforms coal to liquid fuels (CTL). There are two radically different technologies of CTL. In 1913, Friedrich Bergius patented a direct coal liquefaction that produces a high boiling fuel by dissolving a coal in a solvent at high temperature and pressure. As an alternative to direct coal liquefaction, Hans Fischer and Franz Tropsch introduced indirect coal liquefaction in 1922 by producing synthesis gas (mixture of H_2 and CO), or syngas, then reacting syngas with an iron-based catalyst. However, South Africa was the only country with the means to invest time and money to improve CTL since the cost of liquid fuels was much higher than petroleum-based fuels. Recently, many countries such as the United States and China have an interest in CTL in order to find out an alternative energy source to replace high priced conventional oil and secure their energy independence. Pennsylvania is estimated to have over 34 billion tons of coal and waste coal in ground reserve which is sixth largest amount in US.

3.2.1 Comparison of DCL and ICL

The thermal efficiency is between 60 and 70% for DCL and 55% for ICL. Low grade coal can be used in DCL, but ICL shows low efficiency for low quality coals. There is also a greater cost for upgrading process in DCL. With regard to environmental aspects, DCL is more problematic than ICL. As for the quality of the products produced, DCL yields high-octane gasoline and low-cetane diesel. ICL does the reverse (low-octane gasoline and high-cetane diesel). Since both high-octane gasoline and high-cetane diesel are desired for most vehicular applications, neither one is more favorable based on the quality of products produced. The remaining literature review will be on ICL because of its environmental edge on DCL.

Table 2: Comparison of DCL and ICL End-Products [21]

		DCL	ICL
Product	Diesel	65%	65-80%
	Naphtha	35%	20-35%
Diesel	Cetane	42-47	70-75
	Sulfur	< 5 ppm	< 1 ppm
	Aromatics	4.8 wt%	< 4 wt%
Naphtha	Octane	>100	45-75
	Sulfur	< 0.5 ppm	Nil
	Aromatics	5 wt%	2 wt%
Thermal efficiency		60-70%	55%
Pros and cons		High-octane gasoline Low-cetane diesel Using low grade coal	Low-octane gasoline High-cetane diesel High quality products

3.2.2 Indirect coal liquefaction (ICL)

Indirect coal liquefaction is applicable not only to conventional bituminous and sub-bituminous coals but also to low quality coals and even biomass. Indirect method consists of three important steps:

1. Gasification of coals
2. Adjustment of gas composition (H_2 is increased; H_2S and CO_2 are removed)
3. Producing the liquids from the synthesis gas over a catalyst

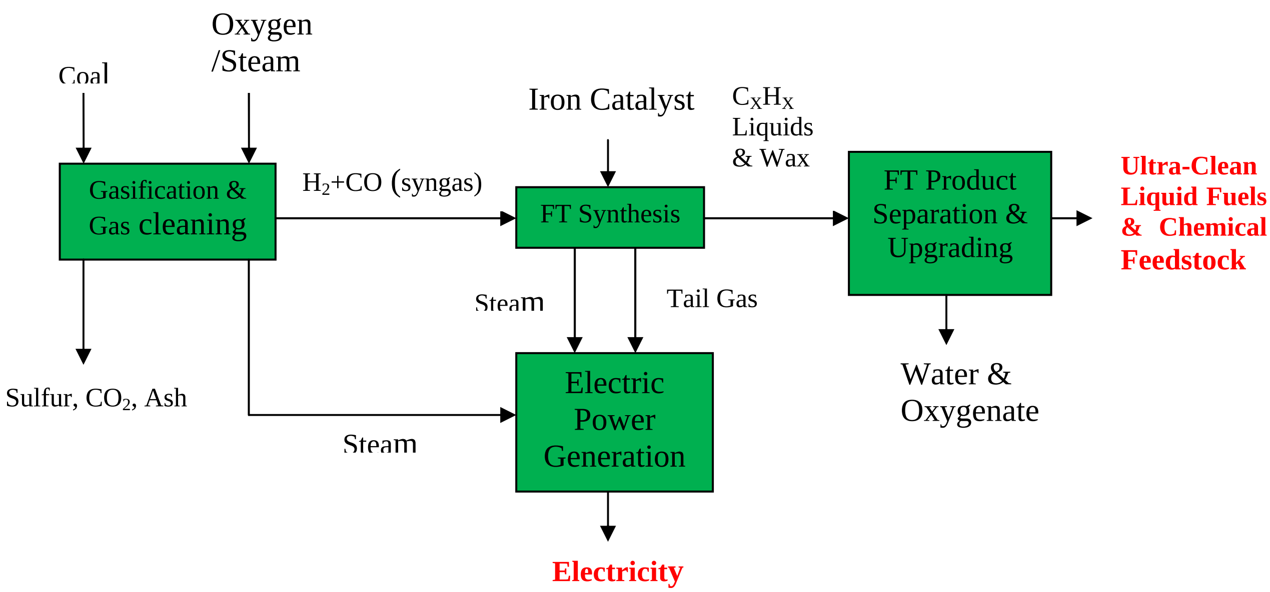

Figure 4: Indirect Coal Liquefaction Schematic

Indirect coal liquefaction starts with the complete breakdown of the coal structure by gasification with steam. The H_2/CO ratio for the gasifier's raw gas (0.5 to 0.8) is adjusted to the value required for the Fischer-Tropsch reactor, and then all its impurities are removed. Syngas is reacted over a catalyst at relatively low pressure and temperature. The product obtained in the Fischer-Tropsch synthesis is sent to an upgrading step to bring the properties of the final product into conformity with the specifications in effect. Generally, we can obtain selectivity of about 30% paraffinic naphtha, 70% diesel with a very high cetane number and no impurities, depending on the catalyst selected and the reaction conditions used.

The Fischer-Tropsch Synthesis is a catalyzed chemical reaction in which synthesis gas is converted into various forms of liquid hydrocarbons. This synthesis is represented by following reaction [18-20]:

$$nCO + 2nH_2 \rightarrow \text{--}CH_2\text{--} + nH_2O$$

These reactions produce large amount of thermal energy, and to avoid an increase in temperature, which results in lighter hydrocarbons, it is important to have sufficient cooling, to secure stable reaction conditions. The reaction is dependent of a catalyst, mostly an iron or cobalt catalyst where the reaction takes place. There is either a low or high temperature process (LTFT, HTFT), with temperatures ranging between 200 and 240 °C for LTFT and 300 to 350 °C for HTFT. The HTFT uses an iron catalyst, and the LTFT either an iron or cobalt catalyst. The FT Synthesis yields different olefins and paraffins of different length. The process is basically a chain building process, where the chain either gains length by absorbing a CO group, or terminates and leaves the catalyst as either an olefin or paraffin [19].

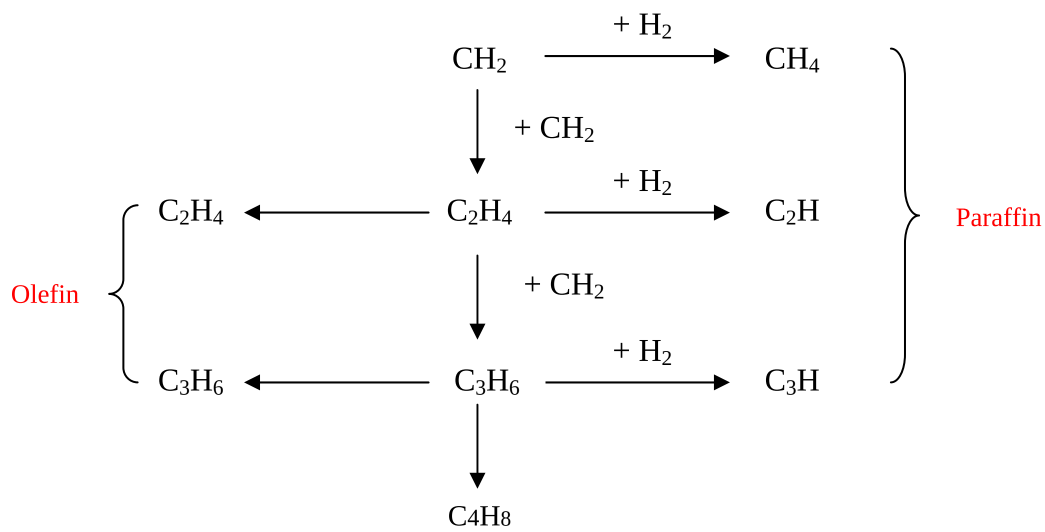

Figure 5: Manipulation of Chemical Structures

3.2.3 Existing Facilities

3.2.3.1 Shenhua in China

China is the world's largest hard coal producer and possesses huge reserves (trillions of tons) of all types of coal. Although China has a lot of natural resources, their population is rapidly increasing, to well over one billion people. Consequently, the cost-effective use of coal for transportation fuels in an environment-friendly way is necessary for China.

The Shenhua liquefaction plant uses coal from the Shenhua coalfield in Northern Shaanxi Province and Inner Mongolia near Baotou City. The Shenhua coalfield is the largest developing coalfield in China and the eighth largest deposit of coal in the world, with coal mines owned and operated by Shenhua Group. The technology used in this project was developed under sponsorship of the US Department of Energy.

The process used at the Shenhua facility will be the world's first commercially proven DCL process. The facility consists of two back mixed reactor stages utilizing a proprietary dispersed superfine, iron catalyst plus a fixed-bed in-line hydrotreater. Unconverted residuum is recycled or used for hydrogen production. Low/high reactor temperature staging that promotes hydrogenation and improves solvent quality is practiced. This process operates at a pressure of 17 MPa and reactor temperatures in the range of 400 to 460 °C. Slurry of pulverized coal in recycled, coal-derived heavy oil is premixed and pumped through a pre-heater along with hydrogen and catalyst into the first stage reactor. The effluent from the first stage undergoes separation in an interstage separator to remove gases and light ends, and the slurry stream is sent to the higher temperature second stage reactor. Effluent from the second stage is flashed in a hot separator and atmospheric flash vessel consecutively. The overhead vapor stream from the hot separator, combined with that from the interstage separator, flows to the fixed-bed, in-line hydrotreater for enhanced upgrading to very clean fuels. The overhead stream from the atmospheric flash is condensed and also pumped to the hydrotreater. The effluent from the hydrotreater is the major liquefaction product, comprising mostly naphtha and diesel fuel fraction. The atmospheric bottoms stream, containing solids, is used as recycle with a portion going to a vacuum still and then to solids separation. The resulting solids are sent to partial oxidation for H_2 production, and the overhead is recycled [22, 23].

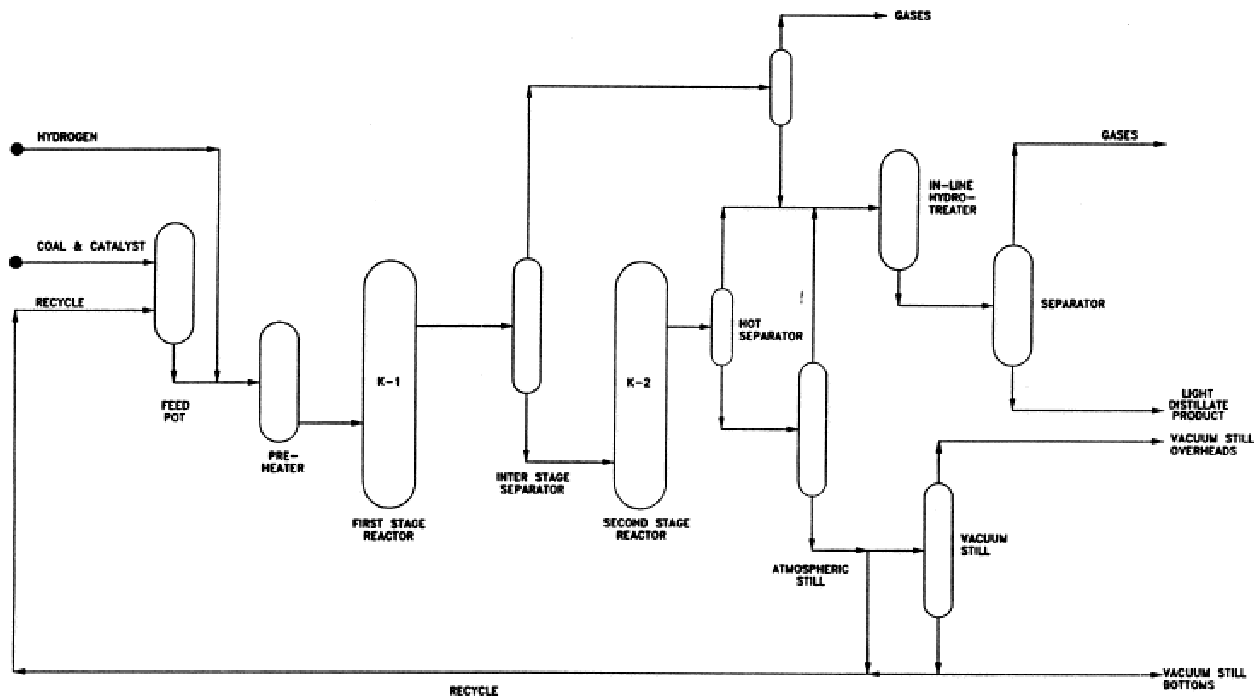

Figure 6: Shenhua Facility Schematic [23]

Shenhua's proposal of building a direct coal liquefaction plant in Inner Mongolia was granted state approval in 2002. The first trial operation of this facility was launched at the end of 2008. Shenhua's DCL plant has a capacity to produce 1 million tons of liquid fuels per year. If the second trial operation to be launched this summer turns out to be a success, production will begin to expand this project to three times its current size.

3.2.3.2 Sasol in South Africa

This process is compatible not only with conventional bituminous and sub-bituminous coals, but also less mature coals such as lignite or even biomass. The Sasol process is based on the Fischer-Tropsch synthesis. Syngas is converted into a myriad of products ranging from methane to long-chain hydrocarbons. Commercially, Sasol produces chemicals, fuels and monomers using iron-based catalysts in their Sasolburg and Secunda facilities. Sasol uses low-temperature Fischer-Tropsch (LTFT) and high-temperature Fischer-Tropsch (HTFT) synthesis. The developments by

Sasol have resulted in several changes to currently implemented processes. A slurry phase reactor (SPR) and a fixed fluidized bed reactor (SAS reactor) placed Sasol in a unique position in the petrochemical industry.

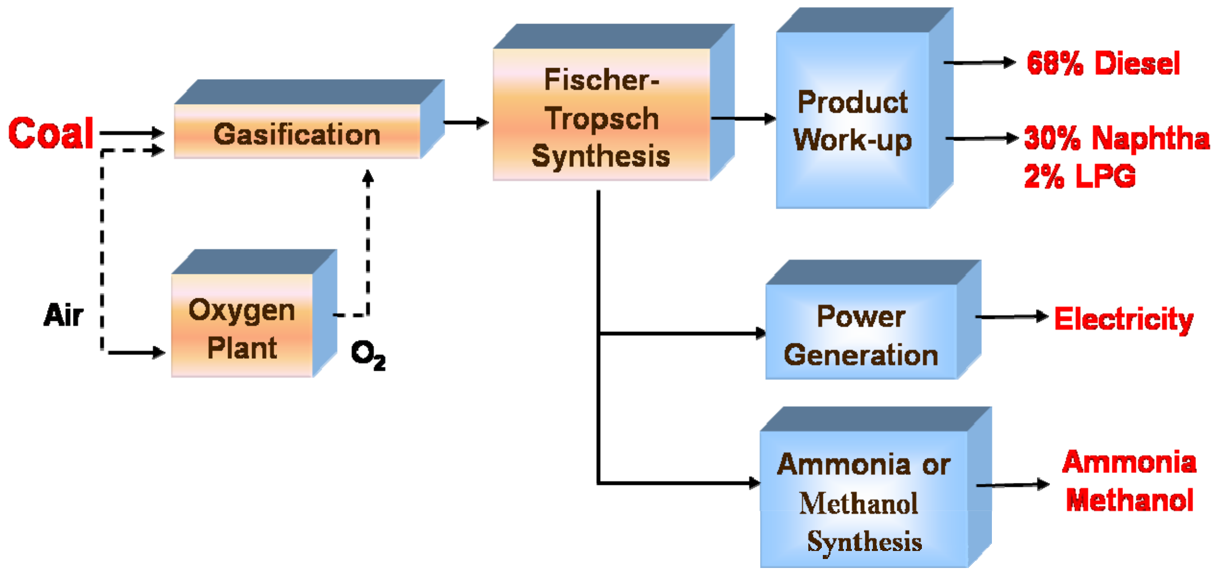

Figure 7: Sasol's Plant Schematic

The high temperature Fischer-Tropsch (HTFT) technology recently applied by Sasol is the conventional fluidized bed reactor technology (the Sasol Advanced Synthol process, SAS) which replaced the circulating fluidized bed reactor. HTFT is mainly used to yield gasoline. The SAS reactor consumes about half the catalyst quantity per reactor compared to circulating fluidized bed reactor. In addition, operating the SAS reactor at higher pressures decreases the carbon formation rate which further decreases the required catalyst consumption. The SAS reactor operation is much easier. It is essentially amounts to loading the right quantity of catalyst and ensuring that the number of cooling coils in service matches the heat generated at the prevailing feed-gas rate. Regular catalyst removals are required to control the bed level and catalyst addition is required to maintain conversion levels. With simple method of shutdown, the reactor can be shut down and restarted without any problems. There is considerable opportunity for producing chemical products in addition to the hydrocarbon fuels. Cost estimates indicate a capital cost reduction of 50% for this reactor [24-25, 28].

Product	(%)
Paraffins	14
Olefins	65
Aromatics	10
Oxygenates	11

Table 3: Typical functional groups produced from HTFT

The low temperature Fischer-Tropsch synthesis is used for the production of longer chain hydrocarbon (predominantly waxy products) which in turn can be hydro-cracked to produce diesel. The slurry phase reactor (SPR) is much simpler than a tubular fixed bed reactor (TFBR) and is easier to fabricate. The slurry phase of coal is well mixed and tends towards isothermal operation. This gives much greater temperature control. Temperature can be much higher than in a TFBR without the danger of catalyst deactivation, carbon formation and break-up of catalyst. A much better control of product selectivity becomes possible at higher average conversion. On-line catalyst removal and additions can be done without difficulty. Catalyst consumption per unit product is reduced by as much as 70% compared to TFBR. The capital cost reduction for a large scale SPR is expected 40% of that needed for an equivalent TFBR.

Figure 6 illustrates modification of reactors of each high temperature F-T synthesis and low temperature F-T synthesis [26-28].

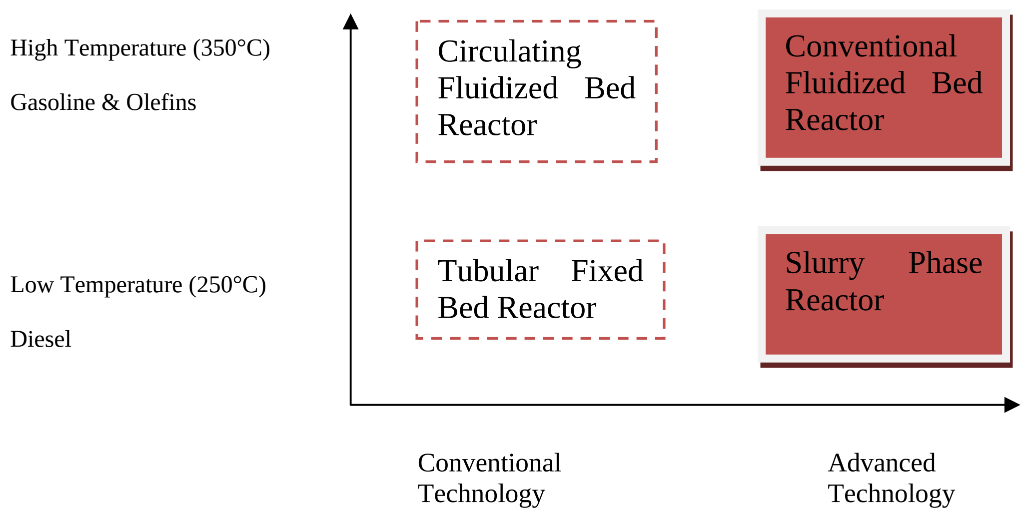

Figure 8: Advanced Fischer-Tropsch reactor of Sasol

3.2.3.3 Early Entrance Co-production Plant (EECP) in Pennsylvania

This project encompasses multi-product facilities which co-produce transportation fuels, chemicals, electric power, process heat, etc from various waste coal and anthracite feed-stocks. The technology is based on the gasification of waste coal residue, followed by a liquefaction process to produce sulfur-free low particle diesel. After coal has been mined and sorted, there is a combination of waste coal particles and silt left over. There are over 250,000 acres of abandoned wasteland that were previously coalmines. This is therefore an environmental clean-up and energy production win-win situation.

The slurry of hydrocarbons and water will be heated in a gasifier to over 2,500°F and mixed with oxygen via oxygen blown gasifiers. This gasification of the feedstock produces synthesis gas (syngas) and water. The syngas is put through cyclones which get rid of some fine particles. Yellow sulfur is removed at this stage, which can be sold to pharmaceutical companies. The remaining clean syngas will then be added to a slurry phase vessel and mixed with catalysts to produce steam and paraffin, which can then be processed to produce transportation fuel having a high-cetane, zero-percent sulfur and nitrogen, low aromatic and low particulate. The excess tail gas will be pumped through the adjacent co-generation plant to produce electricity. The F-T naphtha can be upgraded to clean-burning reformulated gasoline. F-T naphtha is also an excellent feedstock for olefin production, or as onboard reforming feed for fuel-cell powered vehicles [29].

EECP project started construction from 2005 and its plan had the capacity to convert 4,700 tons/day of coal waste materials into 41 megawatt of electric power and over 5,000 barrels per day of transportation fuels. This project processed about 1.0 million tons per year of coal waste materials from the Gilberton area. However, this co-production plant in Gilberton was stopped in 2008 without a further plan because of skyrocketing operation costs and a lack of governmental support.

3.2.4 Maturity of Coal Liquefaction Plants

Based on the various considerations discussed above, it is appropriate to choose indirect coal liquefaction technology as the basis for a liquefaction facility in Pennsylvania.

Sasol's indirect coal liquefaction is the most mature technology since Sasol has spent more than fifty years to keep modifying its ICL technology, such as its reactors, catalysts and co-products. On the other hand, Shenhua's DCL plant only completed their first trial operation last December and they will finish a second trial test this coming summer. There has been no commercially proven DCL technology so far.

DCL yields a diesel with naphthenic characteristics, a high specific gravity and a low cetane number which could be unacceptable to be utilized due to environmental concerns. Also, the DCL process involves more environmental contamination such as large water requirements, as well as increased air pollution.

However, ICL produces more environmentally favorable diesels which have a high cetane number, low sulfur and low aromatics.

Since there are two different processes in Sasol ICL, high temperature F-T synthesis (HTFT) and low temperature F-T synthesis (LTFT), it is possible to control the amount of products by choosing either of these two processes, HTFT for producing gasoline and olefin as well or LTFT for producing mainly diesel according to market demand. On the other hand, Sasol's process allows the use of various types of coal, coal wastes, petroleum coke and even biomass, alone or as blends, as feedstock. In other word, ICL would provide the extended flexibility of end products and feedstock as well.

Even though there are several challenges in liquefaction plants such as wastewater treatment and disposal, viability of CO2 capture/storage, high production cost and high capital cost, the coal to liquid technology provides environmental benefits as it reclaims the land by eliminating the potential pollution problems of acid mine drainage into groundwater and streams that could be caused by the coal waste. And other positive impacts of using coal based liquid fuels include long-term environmental advantages of possible ways to reduce hazardous emissions in coal combustion. In addition, there are high possibilities to use stored CO_2 in a profitable way such as enhancing coalbed methane, oil recovery or storing in an aquifer, in an abandoned coal mine. Therefore, liquid fuels from coal could be called clean alternative energy source for Pennsylvania in the near future.

4 Pennsylvania's Energy Market

Before proposing a power/H_2 production plant in Pennsylvania, it is important to know if there is demand for such commodities. Quantifying future demand of these energy forms also provides a sense of scale for how much infrastructure can currently be replaced with potentially greener alternatives.

4.1 Hydrogen Market

Pennsylvania has the 5th largest petroleum refinery capacity in US and currently hydrogen demand in petroleum refining sector takes up about 67% in overall hydrogen consumption. Hydrogen demand for petroleum refining sector in PA has increased 12 billion SCF in 2001 to 19.3 billion SCF in 2006(see the chart).

Table 4: PA Hydrogen Demand History

Year	2001	2002	2006
H_2 demand in PA(billion SCF)	12	13	19.3

According to DOE' study, fuel cell vehicles (FCVs) will start commercialization in 2015 and replace half of conventional light duty vehicles by 2035. In the mean time, hydrogen internal combustion Engines (HICEs) are expected to be a short term bridge between gasoline vehicles and FCVs with the assets of relatively low modification cost and favorable energy efficiency.

Another hydrogen demand from fuel cell technology will be stationary power systems which produce electricity, water, space or process heating with various types of applications, from industrial sites, large commercial buildings to home. All things considered, hydrogen demand of

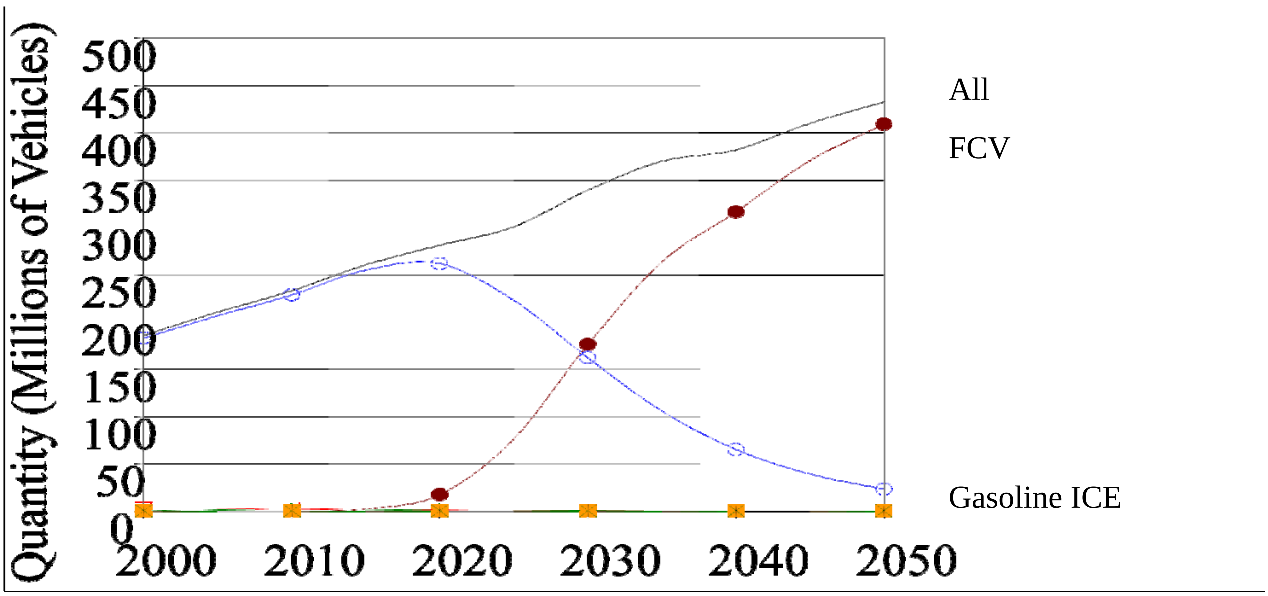

Figure 9: Anticipated US Vehicle Diversity

2050 is estimated to reach 4.74 billion gallon per year in the middle Atlantic region (Pennsylvania, New Jersey and New York). In addition, future feedstock used to produce hydrogen should be coal since PA is the 6th largest coal reserve state in the US and natural gas as a feedstock is expected to be phased out by 2035.

4.2 Electricity Market

Analysts at the U.S. Department of Energy (DOE) predict overall US electricity consumption will grow at a rate of 0.8% per year through 2030. This means electric power consumptions will be 43% greater in 2030 than they are today [29].

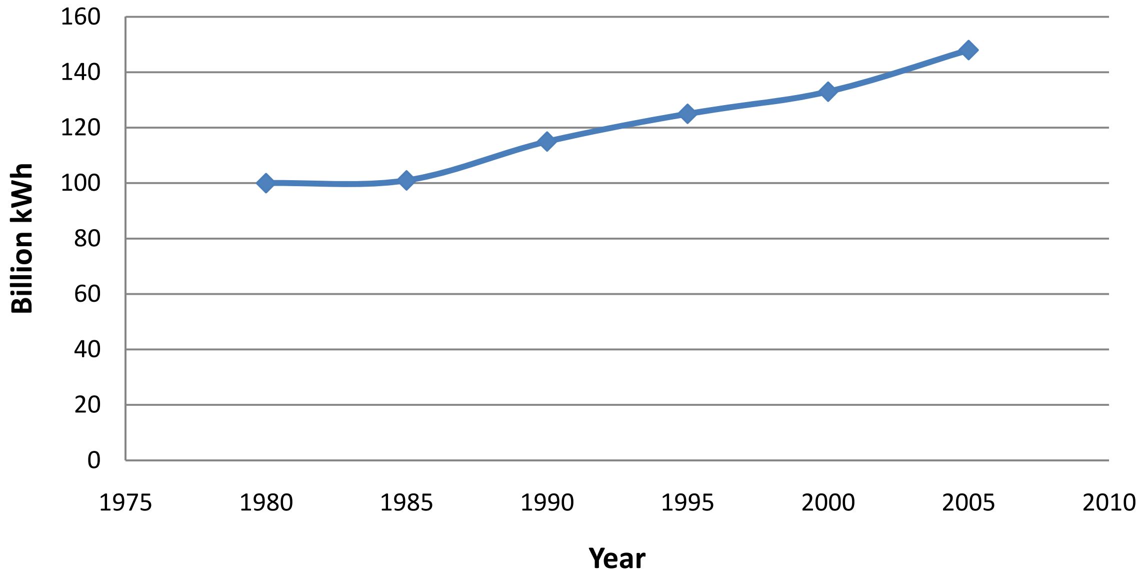

Figure 10: Total Electricity Consumption in PA (Billion kWh vs. Year) [30]

With the demand of electricity in Pennsylvania rising, and the number of retiring power plants rising, it is appropriate to invest in large capacity, clean power plants to replace these retiring units.

5 Coal IGCC Plant Design

When this study of coal gasification began, it was unclear where improvements could be made in either coal IGCC plants, or coal liquefaction facilities, so a thorough literature investigation of both types of plants were necessary for identifying where plant modifications and improvements could take place. Because of coal liquefaction's maturity, liquefaction plants have been well refined through the years, so only minor improvements could be proposed. It was realized however, that the addition of a water gas shift reactor coupled with carbon capture in a conventional IGCC plant would allow for the clean co-production of H_2 and electricity. These additions would make a huge impact on both the overall plant efficiency, as well as on the plant's CO_2 emissions [31]. See Figure 3 for details on the plant's configuration.

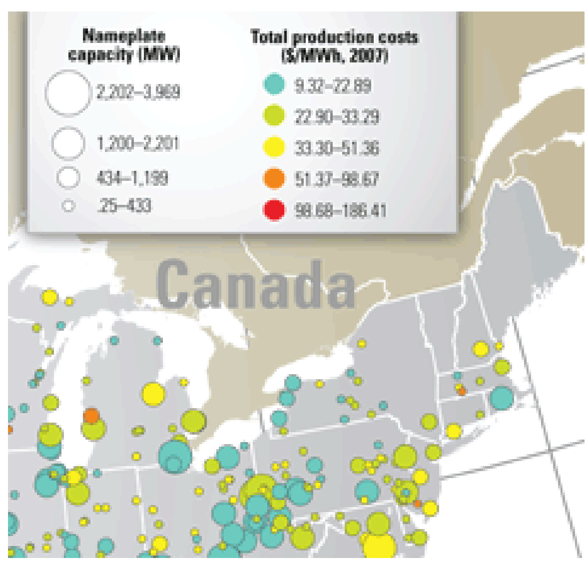

Figure 11: Coal Power Plant Capacity in Northeastern US [32]

When considering a power plant design, the most fundamental design parameter is the energy market of the proposed plant's region to know the required scale of the plant. The capacity for the IGCC power plant in Pittsburgh, PA was determined by observing available coal-fired power plants that are currently servicing the Pittsburgh area. Figure 11 shows us that the typical coal-fired power plant in Pittsburgh operates between 1,200 and 1,500 MW. Based on this data, it was decided that a plant consisting of three 420 MW combined cycle gas turbines giving a plant capacity of 1,200 MW would be ideal for the Pittsburgh area. This large-capacity facility will eliminate the need for one aging coal-fired power plant in the area. Another fundamental design parameter is the type and properties of the feedstock to be gasified, as gasifier selection relies heavily on the feedstock's heating value, ash content, as well as sulfur content [31, 32]. The majority of Pennsylvania's coal is high-volatile bituminous (see Table 1 for properties of various ranks of coal), therefore, the plant will need a gasifier suitable for it. Once these parameters have been well-defined, the plant's components will be easier to choose. The order of plant design decision making was in the order as presented below.

5.1 Plant Location

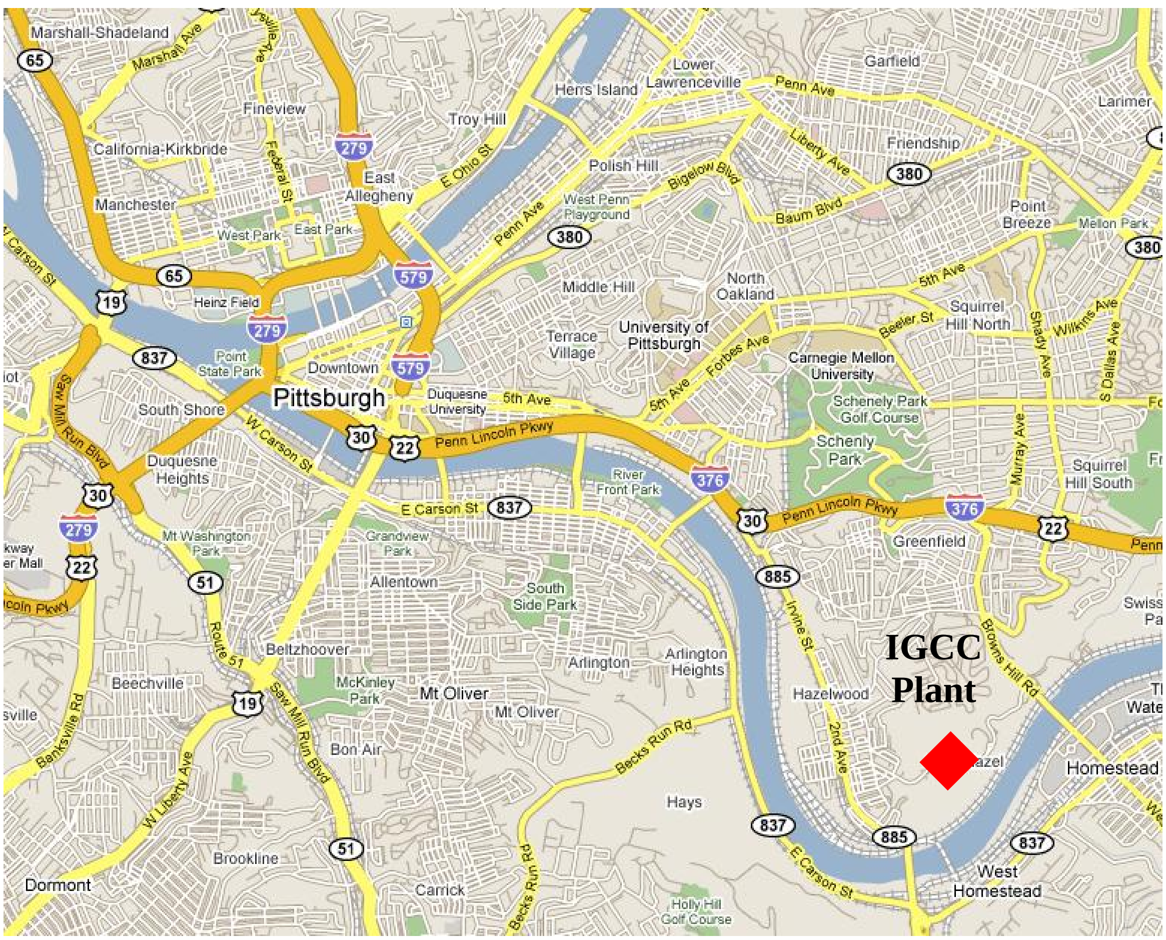

Figure 12: IGCC plant location in Pittsburgh, PA [Google Map]

Pennsylvania's population density and energy demand varies drastically from region to region. An IGCC plant would be most efficiently placed near high electricity as well as (eventually) high H_2 demand, to minimize transmission and transportation energy penalties. Pittsburgh, PA was picked as the ideal location for the plant site because there is huge electricity demand currently for industry as well as for residents. For the most efficient feedstock transportation, the plant will be located on the Monongahela River in Glen Hazel, as shown in Figure 12. This location was chosen to minimize the distance between the electricity source and its use.

5.2 Plant Components

5.2.1 GE Gasifier Technology

GE slurry-fed entrained flow gasifiers have been chosen among other options due to GE's substantial dominance in the gasification industry, with an unparalleled number of gasification facilities currently up and running. This section will be used to describe the specifications of the chosen GE Gasifier.

Figure 13 gives an idea of how the GE (Texaco) gasifier operates. This gasifier operates at temperatures between 1250 and 1450 °C at 8 MPa. These conditions have been found to maximize the syn-gas content of the raw gas. The gasifier has an expensive refractory lining that typically needs replacement every couple of years due to molten mineral matter penetration, which causes cracks that worsen with use. This refractory deterioration is a subject of great importance to the overall cost of gasification facilities and is currently under a vigorous investigation. Before the raw gas enters the gas shift reactor, it is cleaned and cooled via water quenching. There is heat losses associated with this method, because the steam created isn't high enough quality to curriculum. The raw gas flows with the generated steam to the water gas shift reactor for converting most of the produced CO to CO_2. Molten slag is also water quenched to cool it back to solid state and is transported through a lock hopper [31].

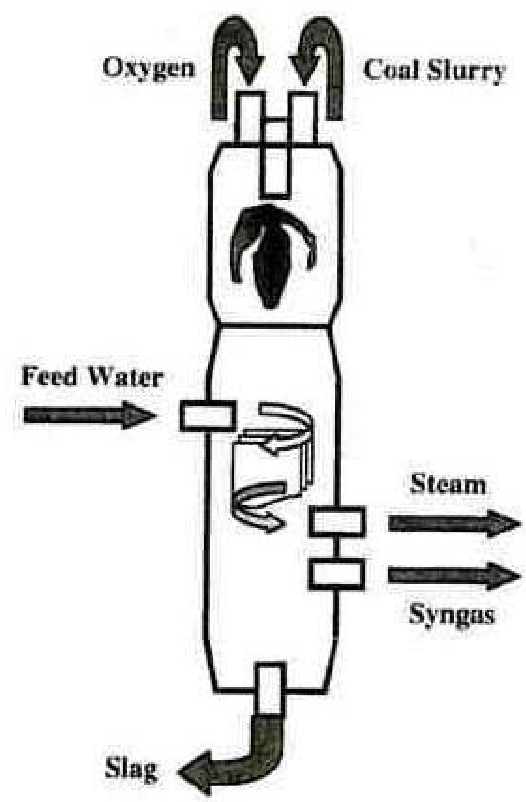

Figure 13: Texaco Gasifier [31]

Polk Power IGCC Station, located out of Tampa, Florida, utilizes GE's coal slurry-fed entrained flow gasifier and has been in operation for 12 years. The plants first three years of operation were to test various coal types to find the cheapest functional feedstock. The plant's recommendation for feedstock requirements for this gasifier are that ash content should not exceed 12 wt% (dry basis). The minimum heating value for coal feedstock is 12,900 BTU/lb. Sulfur content should not exceed 3.5 wt% (dry basis) due to downstream equipment fouling issues. If you refer to Table 1, you can see that most of these parameters are met by the high-volatile bituminous coal found in Pennsylvania except for the heating value of some high-volatile bituminous coals [31].

The coal feedstock's heating value should be known before plant design, because if the feedstock' heating value is less than this recommended value, the plant will need to increase the oxygen supply size, as well as the slurry delivery system's capacity. High volatile bituminous coal from PA has a relatively high heating value (about 12,500 Btu/dry lb), so modifications from demonstrated plants will not need to be made for this plant's design.

5.2.2 Water Gas Shift (WGS) Reactor

The WGS reactor is the defining difference between existing gasification plants and this proposed plant's design. In this reactor, virtually all of the CO gas exiting the gasifier reacts with steam (generated in the gasifier) to produce a gas of mainly CO_2 and H_2. The justification for this step in the design is that 90% of the carbon emitted from the gasifier will be separated in a single step, using selexol as a solvent, and stored as CO_2 prior to combustion. After CO_2 capture, H_2 is the only significant constituent in the gas to be combusted, so the emissions from the gas turbine will mainly be water and heat (steam). This exhaust steam could potentially be returned to the WSG reactor.

5.2.3 Gas Scrubber

There are several identical gas scrubbers required immediately after the WGS reactor for environmental reasons. Each of these scrubbing units' purpose is to remove both particulate matters as well as sulfur constituents that make up the raw gas. In these units, lime slurry, which consists of $Ca(OH)_2$ and water, is introduced as a spray to the inflow of raw gas. The spraying of the slurry creates a larger surface area for sulfur to react with lime to create a waste stream of CaS. The scrubbing units will remove 99% of the particulate matter and 92% of the sulfur in the raw gas [33]. The particulate matter or flyash that is removed from the scrubbers can be a feedstock for concrete, grouting, and roofing shingles.

Some coal-fired power plants implement a CaS processing stage that oxidizes CaS into $CaSO_4$, which can then be supplied to gypsum (used in dry-wall) manufacturers. This process is a good option for sustainable handling of the CaS waste stream, but for simplification purposes has not been included in this IGCC plant design.

5.2.3.1 Carbon Capture

The mechanism behind the proposed carbon separation method is not required for qualitative IGCC plant design, however, the materials and processes necessary for carbon separation are necessary. Selexol is the solvent that has been proven to put CO_2 in solution under high pressure, and when the pressure is released, CO_2 will be released, separated and compressed for storage. It is obvious that this process will require an electricity supply for the condensers and compressors, but the overall efficiency loss for the carbon capture technology is 5.7%, which includes the compression of the CO_2. Research has suggested that 90% carbon capture efficiency is the most economical capture efficiency because past this point, energy and cost requirements increase drastically [34].

5.2.4 IGCC Turbine

Not only has GE significantly dominated the gasifier industry, but GE has remained a market leader in the gas turbine industry as well. In 2003, GE unveiled its revolutionary H-series of CCGT at the Baglan Bay power facility in Wales. GE's laboratory tests proved their H-series turbines to break the 60% barrier for fuel efficiency, an industry first. Unfortunately, this new series of turbine's design is based around using highly durable and quality components to allow higher combusting temperature of methane, so a syngas friendly turbine has to be selected for the proposed plant. Although not quite as efficient, GE's MS-9001FA is the next best flexible fuel CCGT that achieves a net efficiency of 56.7%, and a capacity power output of 400 MW, meaning that three of these turbines will be needed to achieve our 1200 MW overall plant capacity [34].

5.2.5 Air Separation Unit (ASU)

In order to minimize NO_x emissions in both the gasifier as well as in the gas turbine, their feed gases should contain little to no nitrogen and this is where the ASU comes in. Air is inputted into the ASU, where N_2 is released back into the atmosphere, leaving a purified O_2 feed gas for the gasifier and gas turbine to minimize NO_x formation. Compressed air is cooled and cleaned prior to cryogenic heat exchange and subsequent distillation into the oxygen into nitrogen streams. The ASU is expected to account for 2.0% of the total plant energy losses from this separation.

5.3 Anticipated Plant Performance

A calculation was carried out to derive the conversion efficiency of the coal feedstock to hydrogen-rich gas, and is shown in Table 5. The calculation considers the amount of carbon in the initial coal feedstock, which was the basis for finding out how much CO and CO_2 are expected to exit the gasifier. Carbon dioxide should account for 25% of the coal's carbon content, as gasifiers typically operate with 25% the amount of oxygen then that required for stoichiometric combustion, leaving 75% of the carbon as CO. After the WGS reactor, equal moles of H_2 are produced from each mole of CO. It was found that the energy content in the H_2 rich gas was 68.2% of the coal feedstock's energy content.

Other overall plant efficiency losses were derived from Chiesa *et. al* [35]. A breakdown in the overall IGCC plant efficiency losses is shown in Table 6. The greatest loss is occurs during the conversion of coal to H_2 (31.8%), followed by losses in the CCGT (13.8%), and the third greatest efficiency loss is from carbon capture (5.7%). For the case of the H_2 producing gasification plant, the losses associated with the CCGT are eliminated, and therefore improving the plant by 13.8 efficiency percentage points.

Table 5: Coal to Gas Conversion Analysis

Gas	Gasifier Exit Gas (mol./100 MBtu Coal)	WGS Exit Gas (mol./100 MBtu Coal)	WGS Exit Gas (kg/100 MBtu Coal)	Gas Turbine (MBTU gas/ 100 Mbtu Coal)
H_2	99,790	253,558	507.12	68.198
CO	153,768	-	-	-
CO_2	51,256	205,024	9,021.05	-

Table 6: Efficiency Loss Breakdown of IGCC Plant

Process	% of Input Coal Energy
Initial Coal Energy	100.0
Coal to H_2 Conversion Losses	(31.8)
Carbon Capture Losses (Comp. Inc.)	(5.7)
CCGT Conversion Losses	(13.8)
ASU Losses	(2.0)
Compression Losses	(4.0)
Aux. Power Requirement	(0.9)
Heat Losses	(0.3)
Overall Plant Efficiency (LHV)	41.6

In order to compare coal gasification technology operations with existing CFPP, it is important to compare their overall operating efficiencies both with and without carbon capture implementation. Table 7 is a summary of the overall plant efficiencies for CFPPs, the proposed plant only generating electricity (IGCC), the proposed gasification facility solely producing hydrogen, as well as the proposed gasification facility co-producing power and hydrogen (power during the day and hydrogen at night). It is evident that gasification plants have a huge efficiency edge on typical CFPP's. Of the gasification facilities, the hydrogen generating facility operates at an efficiency of 55.4%, including carbon capture. This provides great incentive for a co-producing power plant to produce as much hydrogen as the market allows for. Around the year 2030, when the hydrogen economy is expected to be significant, the co-producing plant will operate at an efficiency of 48.5%. This figure is assuming half electricity output, and half hydrogen output.

The main reason why CFPPs have greater efficiency losses associate with carbon capture compared to gasification plants is because the carbon capture occurs post-combustion in CFPPs, as opposed to gasification plant's pre-combustion carbon capture. CO_2 separation requires the raw gas to be at a moderate temperature, so lower inlet gas temperatures equate to less heat loss. For this reason, CO_2 separation is better implemented pre-combustion rather than post-combustion. Gas coming out of the gasifier would have to make less of a temperature drop for CO_2 separation compared to post-combustion. Pre-combustion CO_2 separation is made possible through the water-gas shift WGS reactor, which reacts virtually all the CO of a syngas with steam, to create solely CO_2 and H_2. After this step, the CO_2 can be removed before combustion, where there is negligible carbon to convert into CO_2.

Table 7: Plant Efficiency Comparison With and Without Carbon Capture (CC)

(%)	η_{plant} w/o CC	η_{plant} w/ CC
Coal-Fired Power Plant	35.0	26.0
100% Power Gasification Plant	47.3	41.6
100% H_2 Gasification Plant	61.1	55.4
50% IGCC and 50% H_2 Gasification Plant	54.2	48.5

6 Environmental Analysis

IGCC is chosen because of its environmental performance and its ability to accommodate future carbon dioxide capture technology. It has the best solution to reduce greenhouse gas emissions, acid rain and smog. It also has good potentials to generate saleable by-products such as hydrogen and slug. If carbon tax or cap-and-trade system is imposed in the near future, this IGCC plant will generate an annual saving of $ 150-375 million.

6.1 Environmental Performance

IGCC is able to generate energy with the least environmental impact [36]. It produces the least amount of pollutants compare to other type of coal power plants. IGCC plant that will be built in this project emits less sulfur dioxide and nitrogen dioxide than even the best coal power plants with advanced pollution controls [37]. Furthermore, IGCC plants are compatible with carbon capture and storage method that are predicted to be used widely in America [36].

In order to prove that IGCC has the best overall environmental assessment, comparison is done with three other coal-fired power plants. This comparison is shown in Table 1 [36].The first coal power plant is a conventional coal-fired power plant with advanced pollution controls. The second power plant is an atmospheric circulating fluidized bed power plant (AFBC) and the third is a pressurized fluidized bed plant (PFBC).The comparisons of the pollutants emitted from all of these four power plants showed that IGCC has the best environmental performance among all of them. IGCC emits 60-80% less sulfur dioxide compare to other type of coal-fired power plants. It also emits 40-55% less nitrous oxide [36]. By reducing sulfur dioxide and nitrous oxide, acid rain and smog can be prevented especially in urban areas [38].

Table 8 shows the comparison of environmental performance between IGCC and other coal-fueled technologies [36]

Table 8: comparison of environmental performance between IGCC and other coal-fueled technologies [35]

Criteria Pollutants, Ionic Species, CO2 and byproducts	PC-Fired Plant (With Advanced Pollution Controls)	AFBC (With SNCR)	PFBC (Without SNCR)	IGCC Plant
SO_2, Ib/10^6 Btu (Ib/MWh)	0.2 (2.0)	0.4 (3.9)	0.2 (1.8)	0.08 (0.7)
NO_X, Ib/10^6 Btu (Ib/MWh)	< 0.15 (< 1.6)	0.09 (1.0)	0.2-0.3 (1.7-2.6)	0.09 (0.8)
PM10, Ib/10^6 Btu (Ib/MWh)	< 0.03 (< 0.3)	0.011 (0.12)	0.2-0.3 (1.7-2.6)	< 0.015 (<0.14)

CO_2 (Ib/kWh)	2.0	1.92	1.76	1.76
HCl as Chloride (Ib/MWh)	0.01	0.71	0.65	0.007
HF as Fluoride (Ib/MWh)	0.003	0.05	0.05	0.0004
HCN as Cyanide (Ib/MWh)	0.0003	0.005	0.005	0.00005
Ammonia(Ib/MWh)	0	0.001	0.001	0.004
Water Usage, (gallons/MWh)	1 750	1 700	1 555	750-1 100
Total Solids Generated (Ib/MWh)	367 (Ash and Gypsum)	494 (Ash and Spent Sorbent)	450 (Ash and Spent Sorbent)	175 (Slag and Sulfur)

6.1.1 Water Usage

IGCC plant used half of the water compare to the conventional coal power plant that we have now. In this IGCC plant, 800 gallons of water will be used for each MWh [36]. Its impact on the groundwater is also very minimal [36]. Data obtained from different gasifiers has shown that its by-product – the gasifier slag is highly non-leachable [36]. IGCC water use can also be reduced by using dry or hybrid (wet/dry) cooling technology for the steam turbine. Hybrid cooling can reduce water use by 35% compared to conventional cooling towers [38].

IGCC has water effluents that are similar to those in other type of coal-fired power plants except that it recycles and purifies raw process streams before discharging into a blow downstream [36]. These effluents contain minerals and even salts from the raw feed water [40]. The other effluent contains dissolved solids and gases and ionic species such as sulfide, chloride and cyanide. These effluents are recycled and sent to a wastewater treatment system. This technology is already available commercially and has been tested in IGCC power plant near the Wabash River [39]. This technology has proven that water usage in IGCC abides the strict environmental permit [40]. And, most importantly, by recycling and using hybrid cooling, IGCC will save 50% of water than conventional coal-fired power plants [36].

6.1.2 Carbon Tax

Carbon tax is a tax imposed on carbon emitted by the combustion of fossil fuels [40]. Coal produced the most amount of carbon among the fossil fuels- followed by oil and natural gas. Studies have shown that the carbon from the combustion of coal leads to global warming. Carbon dioxide from the combustion of carbon accounts for 42% of greenhouse gasses and its production is predicted to grow rapidly in the coming years [38].

The United State of America emits 20% of global carbon dioxide [41]. It is therefore imperative to create a system that will allow the reduction of carbon dioxide emitted. Carbon tax is seen by many states such as California as a solution not just for global warming but also as a way to balance its huge budget deficit [42]. So far, several proposals have been brought up to the Congress. H.R. 4805 was brought by Congressman Pete Stark in 1990s and he called for a carbon tax of $15 per ton of carbon dioxide [43]. It is important to note that there is a difference between weights of carbon versus carbon dioxide, since carbon comprises only 27.29% of the mass of carbon dioxide. There is only 27 tons of carbon in 100 tons of carbon dioxide.

Many economists believe carbon tax as the best solution to fight global warming. Many politicians and social scientists are also backing carbon tax. Gregory Mankiw, the former chairman of the Bush administration's Council on Economic Advisors and Al Gore, the former Vice President are also supporters of carbon tax [43]. Even Alan Greenspan the former Federal Reserve Chairman and Carl Pope, the head of Sierra Club are also behind this idea. With such diverse supports, carbon tax is seen as the best way to tackle greenhouse gases [38]. But so far, these supports have not translated into law. There is just one bill in the House, from Rep. Pete Stark (D-Fremont), to impose a carbon tax, and it's not expected to go far [42].

Stern Review, a study on the economics of climate change done by the British Government, found that carbon dioxide would have to be priced at about $30 per ton to significantly reduce the climate change risk [38]. Sweden levied $62 tax per ton of carbon dioxide compare to $6.50 in Finland and $1.50 in the Netherland. These taxes have been levied since 1990. The implementation of carbon tax led to taxes on energy to be cut in half [44].

Consumer Expenditure Survey and its analysis of carbon tax have suggested $100 per ton of carbon. This translates into an average burden of 5% for the low-income household and 2% for the top two income deciles. The disparities are found to be smaller if expenditures of the households are used instead of their incomes. The survey has also suggested that in order to reduce the burden on low income households, tax credit should be provided in the income tax [44].

Though there has been no consensus on what should be the right rate for carbon tax, the rate set by the Stern Review and Sweden can be used as the reference point. The $50 per ton of carbon dioxide might be used by many congressmen and environmental groups in the near future as the initial carbon tax. This amount might decrease or increase based on the supports from the public, lobbying groups, congress and companies. With such complex factors and voices vying to set the right rate, it is suffice to say, any price set should at least be above $ 30 according to the suggestion by the Stern Review [38].

By opting for this IGCC plant and by basing on carbon tax of $50 per ton of carbon dioxide, between $155-370 million of carbon tax can be avoided annually by this IGCC plant. This calculation is made based on the data available in Table 2. This IGCC power plant will capture 90% of its carbon dioxide which equal to 8,100,000 tons of carbon dioxide while emitting 900,000 tons of carbon dioxide and costing around $ 45,000,000 annually.

Table 9: The amount of CO2 produced, captured and emitted annually.

CO_2	Tons of CO_2
Produced annually	9,000,000
Captured annually	8,100,000 (90%)
Emitted annually	900,000 (10%)

6.1.3 Cap and Trade

The cap-and-trade policy has been implemented in many countries in Europe [45]. The policy works by setting a limit for the amount of carbon dioxide that each company can emit. If the company managed to emit less carbon dioxide than the limit, that company can sell this extra cap it has to companies that didn't meet the cap. This will allow for healthy investments to reduce the emission of carbon dioxide because going below the limit will allow you to make profit [46].

So far, many utility companies already have to follow the cap-and-trade policy for the emission of sulfur dioxide and nitrous oxide [46]. This policy is fully handled by the Environmental Policy Agency (EPA) to reduce acid rain. Since this policy is handled by EPA, they have been little debate about how the policy should be implemented [46]. The federal government launched a cap-and-trade program for sulfur dioxide in 1995 to reduce acid rain. The goal was to reduce emissions to half their 1980 levels by 2010, and the program is expected to reach it or fall just short. It also has led to Kyoto Protocol, an international cap-and-trade system for greenhouse gases. This carbon-trading concept has widespread political and business support — from BP America to General Motors. Many states too have started to set limit for their carbon emission, propelling for the implementation of the cap-and-trade policy in their own state [47].

The problem with this system is how the cap will be decided. Many companies especially those from the utility industry will like to have bigger share in this cap-and-trade system. They also argued that U.S. companies will have hard time competing with companies from China and India because companies from those two countries are not forced to control their carbon emissions [48]. Lobbying groups are also lobbying on behalf of nuclear and gas energy to tie the cap-and-trade system with carbon per megawatt. Such a move will put old coal-fired plants at a disadvantage position [47].

Given how disadvantage coal-fired plants are in term of this cap-and-trade policy, they are running a formidable lobbying group to lobby on their behalf. So far, until April of 2009, no law has been passed by the Congress to support this system. Some are fearful that if this system is being pushed, utilities that rely heavily on dirty, old coal plants will pass the extra cost to their customers [46]. Of all possible approaches, it would have the worst effect on the state economy. But some other businesses such as cement manufacturers feel that cap-and-trade system is more conducive to their business than the carbon tax.

Energy specialist predict the cap-and-trade policy will be passed in the congress soon because it has the backup and strong support from the EPA. Congress too wants the carbon emission to be reduced by 83% in 2050 [46].

As shown in table 2, this IGCC plant will capture 90% of its carbon dioxide before sending it to a carbon capture and sequester a plant. This reduction is below the 83% that Congress has wanted in 2005[48].

EPA backing on cap-and-trade system might propel it to the forefront. The Bush administration has suggested that the cap-and-trade system will generate $ 646 million for 8 years while the Obama administration has said it will generate $2 trillion for 8 years [45].

6.1.4 Summary

IGCC has the best environmental performance among all other coal-fired power plants. It can provide affordable energy with minimum impacts on the environment. Even its byproducts such as slag can be used in the cement industry. Analyses performed showed that carbon dioxide release and prevention of fossil fuel depletion as its most significant lifecycle impacts. Based on these analyses, IGCC is the best technology to generate electricity in the future. In 30 years to come, IGCC will be the technology to generate electricity.

7 Cost Analysis

Total plant cost for the IGCC plant includes all equipment, materials, labor, engineering and construction management, and contingencies (process and project).

Plant size, fuel type, fuel cost, construction time, total plant cost (TPC) basis year, plant capacity factor, plant heat rate, plant life, and plant in-service date were used as inputs to develop capital cost, production cost, and operating and maintenance cost. Costs for the plant were based on adjusted vendor-furnished and actual cost data from GE Energy's recent design/build projects [49]. Values for financial assumptions and a cost summary are shown in Table 10.

Table 10: Major Financial Assumptions for the IGCC plant

Major Assumptions		1,200 MWe net IGCC with CCS	
Plant Size:	1,200 (MWe, net)	Heat Rate:	10,505 (Btu/kWh)
Fuel Type:	Pittsburgh #8 Coal	Ave. Fuel Cost:	86 ($/ton)
Construction Duration:	3 (years)	Plant Life:	30 (years)
Total Plant Cost Year:	2010 (January)	Plant in Service:	2013 (January)
Capacity Factor:	80 (%)	Capital Charge Factor:	17.5 (%)

7.1 Capital Cost

In general, the capital costs for IGCC plants with CCS are 15-20% lower than that of traditional coal plants with CCS [50]. Table 11 summarizes the capital cost for the proposed gasification plant. Total cost for this IGCC plant is estimated at about $2,390/kW_e$ [53, 54]. For the proposed plant capacity of 1,200 MW_e, the capitol cost will be near $2.87 billion.

Table 11: Estimates of capital cost for the IGCC plant

Item		%	$/kWe	x 1,200 MWe
Base Plant	Slurry Prep & Feed	5	120	$ 144,000,000
	Gasifiers	15	359	$ 430,800,000
	WGS Reactor	8	191	$ 229,200,000
	Turbine Generators	10	239	$ 286,800,000
	Construction & Others	27.5	707	$ 848,400,000
	Total	65.5	1,566	$ 1,879,200,000
Gas Cleanup/CO2 Capture		20.1	482	$ 578,400,000
Air Separation Unit		14.3	342	$ 410,400,000
Total		100	2,390	$ 2,868,000,000

7.1.1 Total Plant Cost (TPC)

Capital cost covers the entire cost of building and financing the construction of the power plant and includes:

- Slurry Preparation and Feed – systems are operating at approximately 800 psia as compared to 600 psia for the other IGCC cases.
- Gasifiers and Coolers – 15 percent on all IGCC cases – next-generation commercial offering and integration with the power island.
- Combustion Turbine Generators – 5 percent on all IGCC non-capture cases – syngas firing and ASU integration; 10 percent on all IGCC capture cases – high hydrogen firing.
- Instrumentation and Controls – 5 percent on all IGCC accounts and 5 percent on the PC and NGCC capture cases – integration issues.
- Construction Costs and Others

The normalized total plant cost (TPC) for the plant is shown in Table 11.

7.1.2 Cost of CO_2 Capture / Air Separation Unit

The cost of CO2 capture was calculated in two ways, the cost of CO2 removed and the cost of CO2 avoided, as illustrated in equations ES-1 and ES-2:

$$Removal\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{CO_2\ removed\}\ tons/MWh} \qquad \text{(ES-1)}$$

$$Avoided\ Cost = \frac{\{LCOE_{with\ removal} - LCOE_{w/o\ removal}\}\ \$/MWh}{\{Emissions_{w/o\ removal} - Emissions_{with\ removal}\}\ tons/MWh} \qquad \text{(ES-2)}$$

In case of air separation unit, the cost is derived from the Greenfield GE IGCC plant's operation [52]. The resulting CO2 capture & air separation unit costs are also shown in Table 11.

7.2 Operating and Maintenance Cost

Operating and maintenance (O&M) costs are usually divided into fixed O&M cost and variable O&M cost. We set $7.2/MWh as the fixed cost and $9.4/MW as the variable cost (Table 12) [52]. Values for these were largely derived from GE Energy's IGCC project that is in progress at a Greenfield site in the Midwestern in U.S. [52]. The $/MWh hour allowed for the calculation of the plant's annual O&M costs, as shown in Table 12 [53, 54]. The resulting overall annual cost of O&M will be about **$658 million**.

Table 12: Estimates of annual O&M cost for the IGCC plant

Item	%	$/MWh	Annual cost
Fixed O&M cost	15.6	7.2	$ 75,686,000
Variable O&M cost	20.4	9.4	$ 98,813,000
Coal Cost	73.5	46.0	$ 483,552,000
Total	100	62.6	$ 658,051,000

7.2.1 Fixed Operating and Maintenance

Fixed O&M is comprised of those costs that occur regardless of how much the plant operates. What is included in this category is not always consistent from one assessment to another, but they will always include labor costs and the associated overhead.

- Annual Operating Labor Cost
- Maintenance Labor Cost
- Administrative & Support Labor

Costs that are not consistently included are equipment, regulatory filings and miscellaneous direct costs. The numbers in Table 12 for fixed O&M costs are derived from the Greenfield GE IGCC plant's operation [52].

7.2.2 Variable Operating and Maintenance

Variable O&M represents variable maintenance and depend upon the system of the plant. In case of our IGCC plant, the variable O&M includes:

- Maintenance Material Cost
- Water Supply Costs
- Chemicals – Carbon, Selexol Solution, and WGS Catalyst
- Waste Disposal – Mercury, Fly Ash, and Bottom Ash
- By-products & Emissions - Sulfur

The annual maintenance and overhaul costs are the largest expenditures. Again, the numbers in Table 12 for variable O&M costs are derived from the Greenfield GE IGCC plant's operation [52].

7.2.3 Coal Cost

The coal prices represent the baseline cost and a range of ±25 percent around the baseline [52]. The average delivered coal price to the electric power sector is estimated to have annually increased \$2.23/ton (\$0.113/MMBtu) for the last decade (Figure 14) [55]. With this fairly linear price increase, an estimate can be obtained for the price of coal during the middle of the plant's life (2028), in order to give a rough average price of coal per operating year. The average price of coal assumed for our annual coal cost calculation is \$86.5 per ton of coal or \$4.38 per MMBtu of coal. Coal cost was calculated by multiplying the plant's heat rate with the expected lifetime average coal price.

Coal Cost = 10,505 Btu/kWh × \$4.38/MMBtu **= \$46.01/MWh**

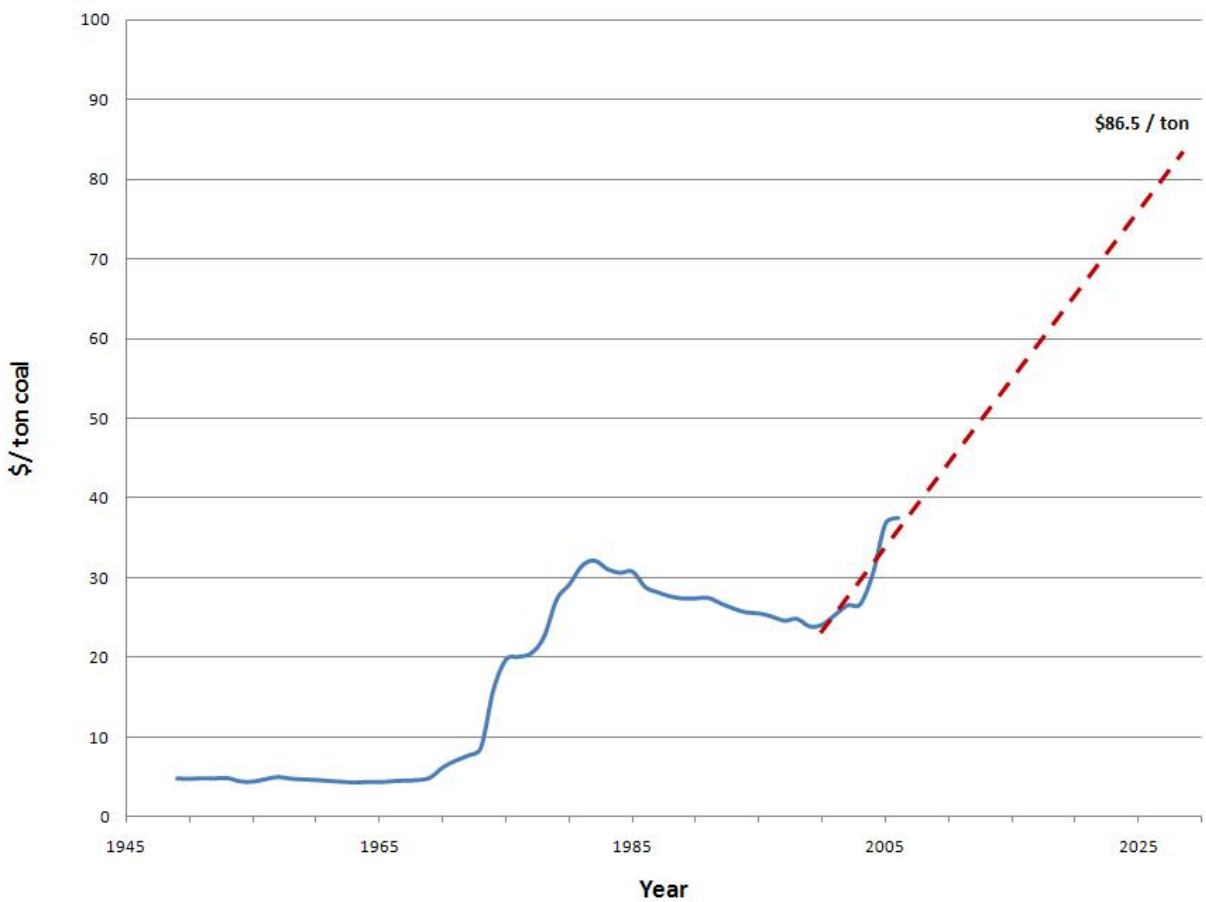

Figure 14: Bituminous coal price fluctuation/ prediction in US for utilities

Now, we have \$46.01/MWh of coal cost for our IGCC plant. Then, we can calculate the O&M cost per megawatt hour by adding coal cost to fixed and variable O&M costs and it should be \$62.6/MWh.

7.3 Plant Lifetime Cost Analysis

Total lifetime cost is the sum of total capital and O&M costs, provided in Table 13. The capitol cost analysis presented in Table 11 totaled \$2.9 billion. Annual O&M costs are applied over the 30 year lifetime of the plant, so just multiplying the annual O&M costs by the number of years gives a lifetime O&M cost of **\$19.74 billion** for the plant. Therefore, the total lifetime cost for the proposed plant should be expected to be about **\$22.6 billion**.

Table 13: Total Lifetime Cost of Plant (provided in 2010 US dollars)

Item	Cost	
Total Capitol Cost	$	2,868,000,000.00
Total O&M Cost (Annual O&M Cost x 30 yrs)	$	19,741,530,000.00
Total Lifetime Cost	$	22,609,530,000.00

7.4 Anticipated Cost of Electricity and H_2 Produced

It is important to take a look at the anticipated price of IGCC electricity production compared to competing coal power generation. Table 14 shows us that without carbon capture technology, CFPP allow for cheaper electricity costs for electricity (COE). The cheapest COE was 6.29 ¢/kWh, provided by supercritical CFPPs, either with or without oxy-fuel technology. However, when carbon capture is implemented in the plants, IGCC will provide cheaper electricity prices than CFPPs. Out of the IGCC gasification plants; GE Energy plants provide the cheapest cost of electricity at 10.29 ¢/kWh, which is the expected COE for the proposed plant here. When calculating the cost of electricity from our plant cost data, a value of 7.16 ¢/kWh was obtained (see below equation). One reason this is low is because it doesn’t account for loan interest for the capitol investment, which would be difficult to establish. It is evident however, that IGCC technology will be a major part of cleaner coal power production in the future because of its environmental edge and price competitiveness.

$$COE = Capitol\ \frac{¢}{kWh} + O\&M\ \frac{¢}{kWh} = 6.26\ \frac{¢}{kWh} + \frac{239{,}000\,\frac{¢}{kW}}{30yrs * 365days * 24hrs} = 7.16\ \frac{¢}{kWh}$$

Table 14: Cost of Electricity (COE) for CFPPs and IGCC with and without Carbon Capture (CC)

	COE (¢/kWh)	w/o CC	w/ CC
CFPP	Subcritical	6.40	11.88
	Supercritical	**6.29**	11.44
	Ultra Supercritical	6.46	11.44
	Supercritical Oxyfuel	**6.29**	11.30
	Ultra Supercritical Oxyfuel	6.46	10.73
IGCC	Shell	8.05	11.04
	E-Gas	7.53	10.57
	GE Energy	7.80	**10.29**

The anticipated production costs of hydrogen from various production methods are summed up in Table 15. The black line in the middle of the plot is the production costs of coal gasification derived hydrogen. Since this line is roughly in the middle of the other plots, it says that coal gasification will be a competitive hydrogen producer, thus validating the proposal to producing hydrogen power eventually when there is a significant need. Again, this significant need is expected to be around the year 2030, so it will be a couple of decades before the demand is there for substantial co-production of hydrogen in the proposed plant.

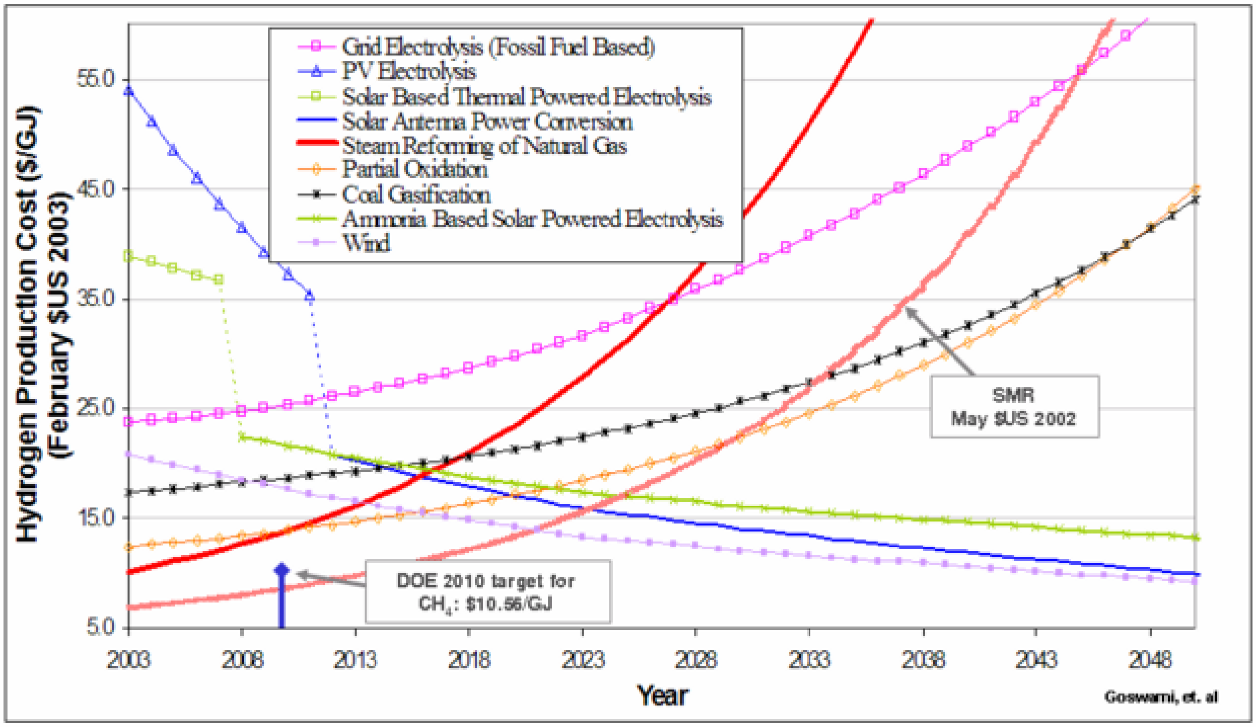

Figure 15: Hydrogen Production Costs for Various Methods [56]

8 Conclusion

In summary, a coal 1260 MW IGCC plant has been designed for the co-production of electricity and hydrogen to serve the Pittsburgh, PA community. This design included carbon capture technologies which will most likely be necessary for future environmental legislation. Analysis for the IGCC co-producing plant yielded a respectable overall LHV efficiency of 48.5%, compared to a 36% efficient supercritical CFPP with carbon capture. The IGCC plant proposed is also the most environmentally friendly both for its low emissions, as well as for its low water usage. Capitol cost for the proposed plant will be near $2.87 billion, with annual O&M costs totaling $660 million. Based on the anticipated 30 year plant life, lifetime plant costs total about $22.6 billion. With carbon capture technology soon becoming a requirement in the coal-power industry, electricity production can be competitive with CFPP electricity prices, while improving the environmental soundness of coal power generation.

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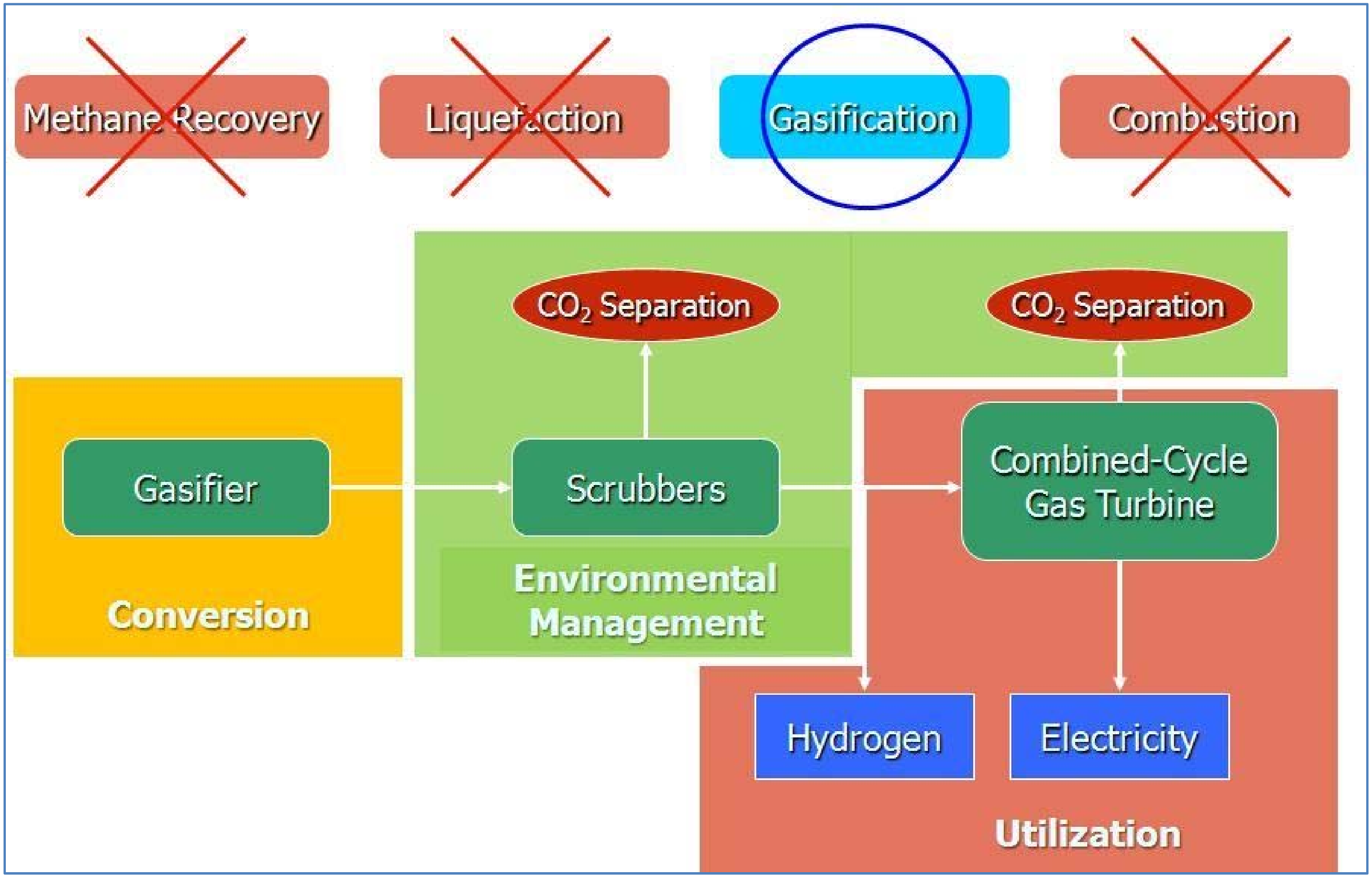
APPENDIX A: Concept Map



APPENDIX B: Road Map