

Technology Working Group

Advanced Coal Task Force Western Governors' Association

At the request of the Advanced Coal Task Force, these reports were submitted for the consideration by the task force in crafting their recommendations. The reports do not represent the adopted position of, or an endorsement by, the task force. Contributors to the reports are listed below. Participation as a contributor does not imply any endorsement of the specific elements of the report, or endorsement of the report as a whole.

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Summary and Key Findings

Introduction:

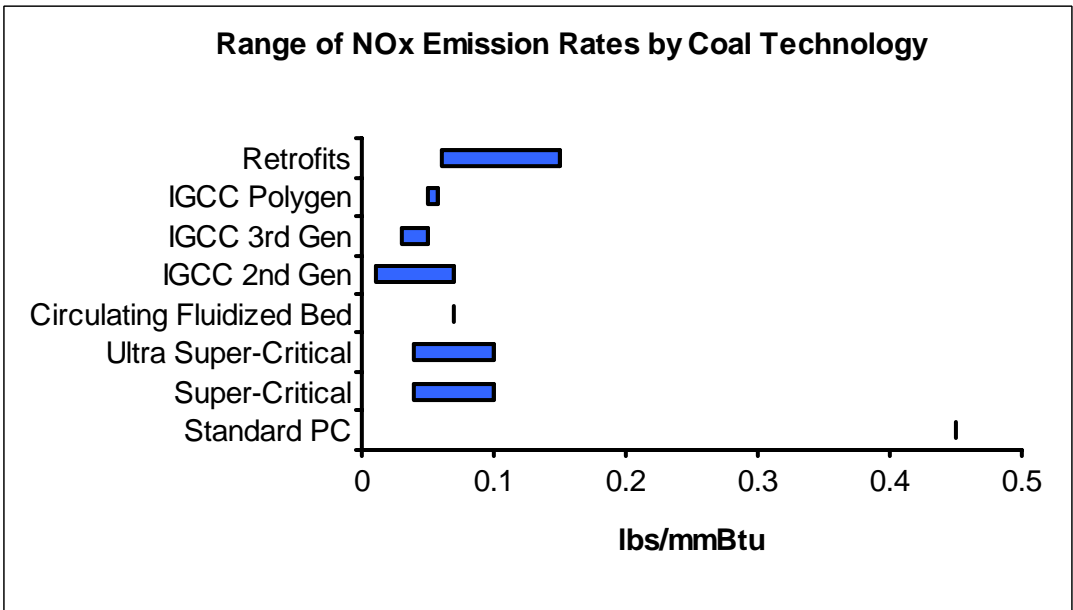
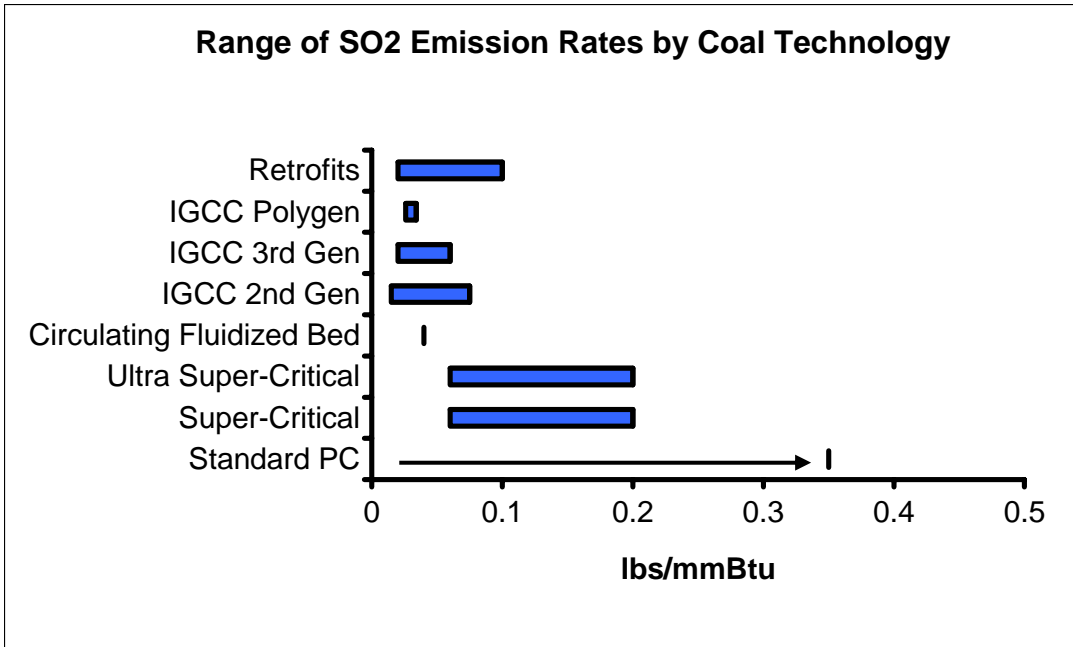
The choice of technology options for new coal power plants studied in this report include commercially available and emerging technology options that include both advanced combustion and gasification options. Advanced combustion includes technologies such as supercritical and ultra supercritical pulverized and circulating fluidized bed combustion technologies. Gasification options include integrated gasification combined cycle technologies (IGCC) and polygeneration technologies for the co production of electricity, fuels and chemicals. These new and emerging advanced clean coal technologies typically demonstrate higher performance levels and lower emissions of criteria pollutants while producing electricity at a cost that is nearing competitive levels with conventional coal-fired electricity production.

In this report, IGCC technologies are further divided into three sub-categories based on the status of the technology. The First Generation IGCC designs, on which the second and third generations are based, were those built, operated, and mostly funded by the Federal Synfuels Corp. in the 1970-80 time period such as Cool Water, Dow Plaquimine, Shell Houston, and Dakota Gasification to produce power, synthetic natural gas and chemicals. Much of that operation was on low rank coals. Data on Second Generation IGCC is from Shell, Texaco, and Destec Projects built and started up in the 1980-90 time periods. Shell, GE, and Conoco/Phillips have had these commercial scale demonstrations in operation for more than five years and are bidding them commercially for 2005-2015 start-ups. These new post 2000 projects are listed as Second Generation IGCC. Third Generation IGCC, which is expected to be available for commercial operation in the latter part of the 2005 to 2015 timeframe, reflects significant technology advancement such as incorporation of Class G/H turbines and/or improved gasifier designs.

Present to 2015

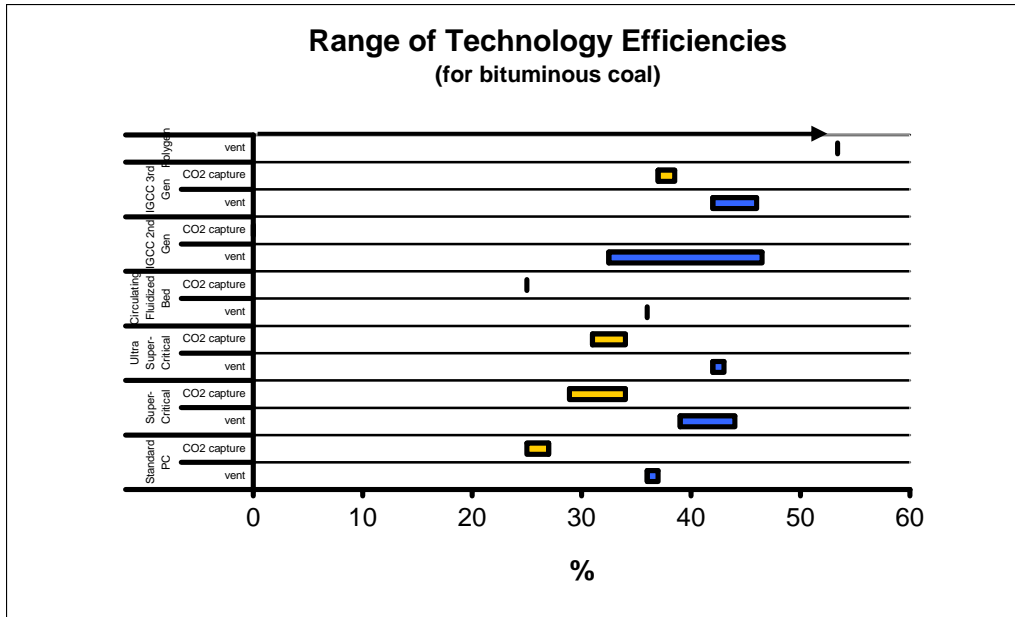
Sulfur Dioxide, Nitrogen Oxide Emissions

- Proposed IGCC emits less sulfur dioxide and nitrogen oxide than proposed advanced coal combustion plants. Both technologies are expected to reduce emissions even further over time.



Carbon Dioxide and Carbon Capture

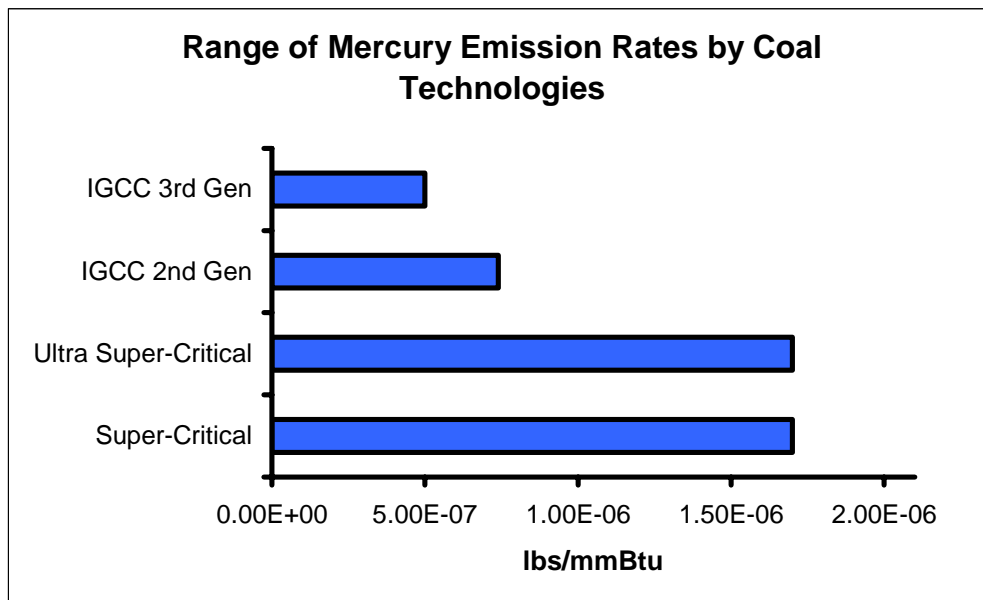
- Carbon dioxide emissions from electric generating plants are a function of efficiency as measured by the heat rate (Btu/kWh).
- Advanced coal plants are more efficient than existing plants. Of new coal plants proposed, IGCC is slightly more efficient than other advanced coal.



- Carbon separation defined here as separating carbon dioxide from flue gas has been commercially demonstrated at an industrial scale but is not economic or commercially available for utility-scale.
- Carbon separation, defined here as separating carbon dioxide from syngas, is economic and commercially available today for coal gasification plants that produce higher-value fuels and/or chemicals. It is practiced, for example, in producing ammonia or hydrogen from coal. Carbon separation is technically achievable for IGCC plants and is offered as a commercial option by at least two of the three leading gasification technology consortiums, but would only be economically viable where CO₂ has value (such as EOR applications). These plants, however, would not capture 90% of the feedstock carbon. The turbines necessary for this application are commercially available but delivery would be delayed up to 3 years for design and testing.
- Three coal to electricity plants in the United States today capture carbon dioxide. These plants capture up to 95 million cubic feet per day out of a potential 240 million cubic feet per day of CO₂ for sale and transport in the use of enhanced oil field recovery.
- For advanced coal combustion plants to separate carbon dioxide, commercially available technology would have to be demonstrated at a commercial scale. If commercially demonstrated, this technology could potentially be retrofit to existing coal combustion power plants. Another technology, such as oxycombustion technology may also be successful and provide a combustion path resulting in a concentrated CO₂ stream that would could be handled similar to an IGCC plant (note, oxycombustion is not expected to be available until after 2015).

Mercury

- Mercury capture in existing conventional coal plants varies widely, between 5 to 10% to as high as 95%. Generally, mercury capture in conventional coal plants is more challenging on subbituminous coals than bituminous ones.
- New technologies for conventional coal plants, including activated carbon injection and its variants, are expected to erase the mercury control gap between subbituminous and bituminous coals over time. By 2015, new conventional coal plants should be capable of 95% or greater mercury removal by 2015, regardless of fuel type.
- Carbon beds are a commercially available and inexpensive option to capture mercury from gasified coal. One coal to chemicals plant in Tennessee has been capturing virtually all the mercury in the syngas for nearly 20 years. Approximately 94% of this capture is from a carbon bed.
- No existing IGCC plant in the United States employs a carbon bed. Proposed IGCC plants do.
- By 2015, carbon bed technology for IGCC and coal gasification plants should be capable of 99% or greater mercury removal.



Water and Solids

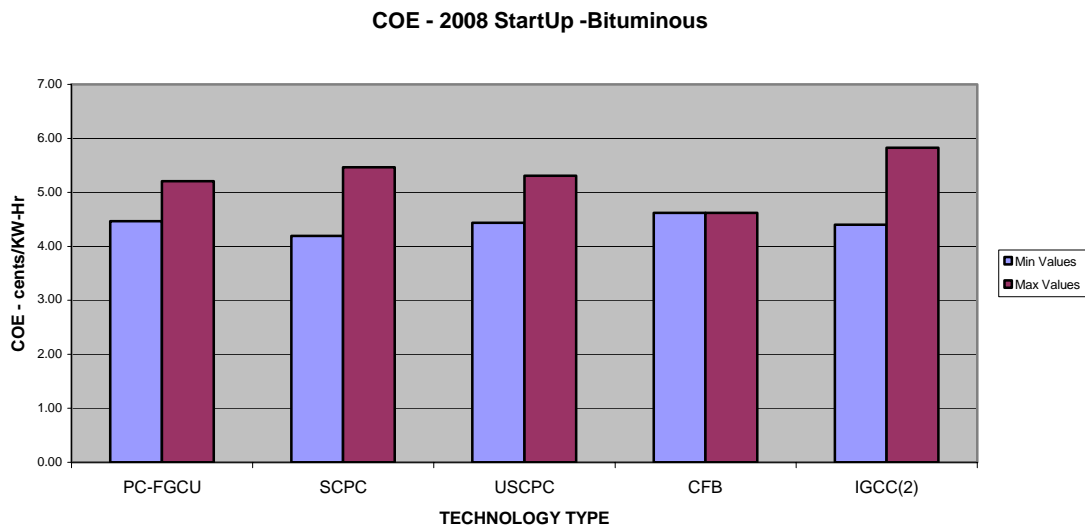
- IGCC plants use less water and produce fewer solid wastes than conventional coal plants.

Altitude Effects on IGCC

- Altitude and Ambient Temperature effects on IGCC units are real, but are manageable at reasonable cost and efficiency impacts using state-of-the-art methods that have been demonstrated at commercial scale.

Costs without Carbon Capture

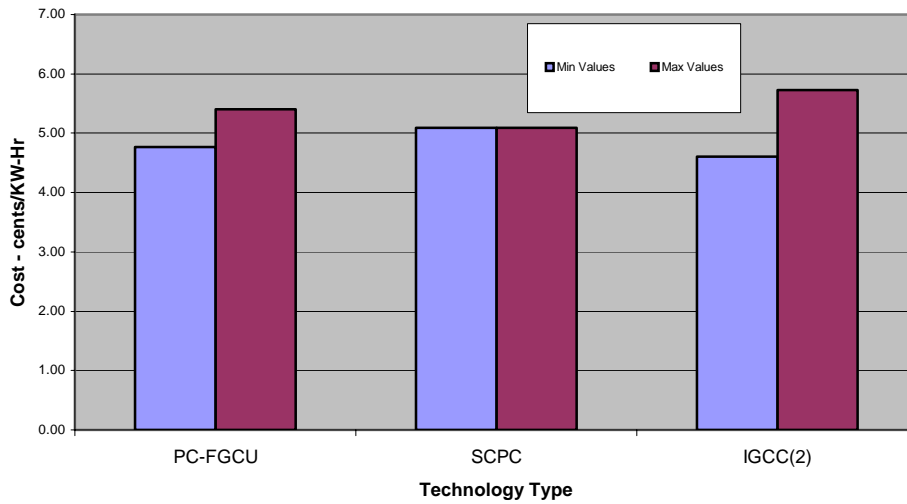
- Electricity produced from advanced coal combustion plants costs less than electricity produced from IGCC plants. It is expected over time that this cost gap will narrow.



* Note, these charts are under review and may change in the final report.

- This cost difference is more pronounced with subbituminous and lignite coals than bituminous coals.

COE - 2008 Start Up SubBituminous



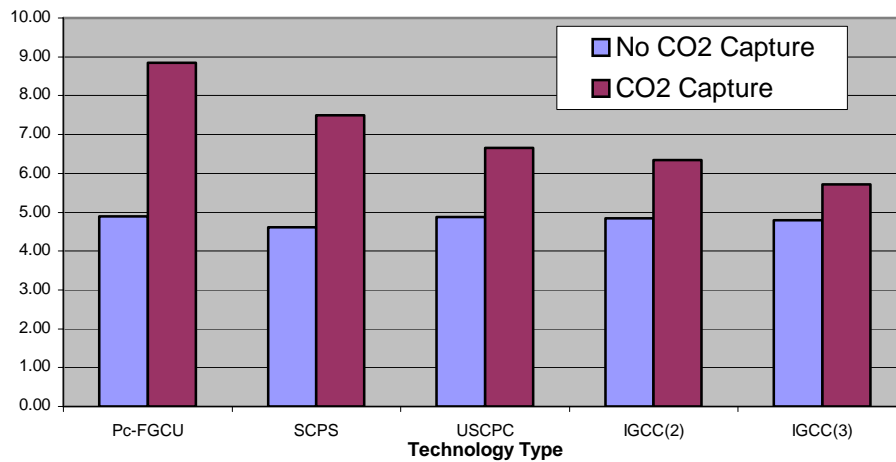
* Note, these charts are under review and may change in the final report.

- The exact magnitude of this cost gap is hard to establish absent actual construction of both new advanced coal combustion plants and new IGCC plants. Some estimates place the gap at a relatively large 20% and some place the gap as low as 5% on certain projects, such as bituminous coal in non-attainment areas.

Costs with Carbon Capture

- The cost of electricity (COE) is increased substantially when CO₂ capture and pressurization is added to either advanced coal combustion (up to 75%) or IGCC (up to 50%).
- Based on current technology costs IGCC is expected to produce a lower COE (~15% less) over advanced coal combustion technologies when projected CO₂ sequestration costs are considered.

COE -2013 Start Up Bituminous



* Note, these charts are under review and may change in the final report

- Coal quality also affects carbon capture costs. Advances in separation technologies may lower the cost differential between advanced coal combustion technologies and IGCC.

Polygeneration through Coal Gasification

- Co-production of electricity with liquids (F-T diesel, methanol, ammonia) is economic at today's oil prices but not at historical levels. (Most studies show that FT production is economic in the \$35-40/BBL range).
- Polygeneration often requires CO2 separation in order to produce chemicals.
- Polygeneration may allow for faster entry of IGCC into today's market than IGCC alone.

Learning Curve

- Advanced coal combustion and gasification technologies will benefit from technological advances that are expected to lower future capital, operating costs, and emission levels. A few examples might include near-zero emissions from combustion technologies, advances in oxygen separation as well as advances in gasifier designs for IGCC. It is deemed beyond the capability of this group to quantify the cost and efficiency improvements that may be realized in future advanced coal combustion and gasification designs. It is, however, expected that these advances will narrow the cost gap between IGCC and electricity produced from other advanced coal combustion plants.

Technologies Beyond 2015

- The Subcommittee evaluated the following post 2015 technologies:
 - Hydro-gasification
 - Oxygen Combustion
 - Steam Reforming FB Gasification
 - IGCC – Hydraulic Air Pressurization
 - Hydrogen Fueled IGCC

Advanced Clean Coal Technology Descriptions

Introduction and Summary

Coal-fired electric generating plants supply more than 50% of the electricity in the United States and are projected to continue to do so through 2025 and beyond. The majority of these power plants utilize conventional pulverized coal technology with subcritical steam conditions of 2400 psi and 1000°F and energy conversion efficiencies of less than 37%. The choice of technology options for new coal-fired power plants will benefit from commercial available and emerging advanced clean coal technologies such as supercritical and ultra supercritical pulverized and circulating fluidized bed combustion technologies, integrated gasification combined cycle technologies and polygeneration technologies for the coproduction of electricity, fuels and chemicals. These new and emerging advanced clean coal technologies typically demonstrate higher performance levels and lower emissions of criteria pollutants while producing electricity at a cost that is nearing competitive levels with conventional coal-fired electricity production.¹

In addition most of these new and emerging technologies can be designed with CO₂ capture systems that are capable of removing 90% or more of the CO₂ emissions. Current CO₂ capture technology is both energy intensive, consuming between 14% and 28% of the units capacity and expensive, increasing the cost of electricity between 47% and 87%.² Further, none of these CO₂ capture technologies have been demonstrated on a major combustion or gasification based electric generating facility. However, the US Department of Energy with the participation of States, Universities and private researchers has undertaken a major research, development and demonstration effort with the goal of reducing the power consumption and cost to capture CO₂ from both combustion and gasification technologies which is expected to result in commercial designs ready for full scale demonstrations beginning in 2012 that increase the cost of electricity by no more than 10%.

The suite of Advanced Clean Coal Technologies presented in the following discussion includes:

- Supercritical pulverized coal (PC) combustion where coal is finely ground is injected into a boiler where it is combusted to produce supercritical steam that has higher pressure (3500psi vs 2400psi) and temperature 1050°F vs 1000°F) than most conventional PC power plants in service today. These higher steam conditions result in a greater efficiency of power production (energy output as a percentage of energy input) and with the addition of high performance

¹ The pre-treatment of low-rank high moisture, low Btu coal, such as sub-bituminous and lignite, can be effective in removing moisture and boosting Btu value, thereby making such low-rank coals more efficient. These pre-treated coals may result in lower costs, increased efficiency, and reduced emissions when combusted in advanced clean coal technologies as well as existing technologies.

² Carbon Capture and Storage From Fossil Fuel Use, Howard Herzog and Dan Colomb, Massachusetts Institute of Technology, Contribution to Encyclopedia of Energy, to be published 2004.

emission controls produces lower emissions of criteria pollutants (SO₂, NO_x, particulate, mercury, etc.) and carbon dioxide per unit of electricity output. SCPC technology is commercially available.

- Ultra supercritical pulverized coal combustion is the same as supercritical except that with the introduction of boiler parts made from advanced materials, steam conditions can be raised even higher (4500psi and 1100^oF). With the development of advanced materials for production of critical boiler and turbine parts it is expected that USCPC technology will be commercial demonstrated and available before 2015.
- Supercritical circulating fluidized bed (CFB) combustion differs from PC combustion because pea-sized coal and limestone particles are injected into the boiler which is filled with spent bed material (primarily ash, free limestone and calcium sulfate). Air is injected at the bottom of the boiler, which causes the coal and spent bed material to rise and mix rapidly making it appear to be fluidized. Combustion gases and a portion of the spent bed material are carried out the top of boiler and enter a cyclone(s) where the combustion gases and the majority of the spent bed materials are separated. The combustion gases are subjected to further clean up and enough of the spent bed material is returned to the boiler to maintain the amount required for fluidization. Because of the complete and rapid mixing caused by fluidization, a much broader range of solid fuels can be used and the boiler temperature is lower (1500^oF vs 3000^oF for PC combustion) which allows the limestone to capture and retain sulfur dioxide and lower amounts of NO_x to form. By designing the CFB combustion boiler to achieve supercritical steam conditions the efficiency of the technology can also be increased, resulting in lower criteria pollutant and carbon dioxide emissions per unit of electricity generated. Subcritical CFB combustion technology is commercial available in unit sizes up to 400MWe, but no supercritical CFB combustion units have been demonstrated on a commercial scale.
- Integrated gasification combined cycle (IGCC) technology combines both a gas turbine cycle and a steam turbine cycle to produce electricity. Coal is converted to a fuel gas (syngas) consisting of hydrogen, carbon monoxide and other contaminants in gasifier. Gasification is done through partial combustion of the coal in the presence of either air or oxygen. The fuel gas must be treated to high levels of removal of the contaminants (sulfur, nitrogen and mercury compounds) before it is combusted in the gas turbine. The waste heat in the exhaust of the gas turbine is used to produce steam to power the steam turbine. CO₂ emission from a IGCC unit can be controlled by shifting the CO in the syngas to hydrogen and CO₂ and scrubbing out the CO₂ before combusting the hydrogen in the gas turbine. IGCC is an emerging technology that has been demonstrated on a commercial scale. IGCC with CO₂ capture has not been demonstrated on a commercial basis, but the technology for

shifting and capturing the CO₂ are being used commercially in refineries and industrial applications.

- IGCC with coproduction of fuels and chemicals utilizes the same technology that is used in IGCC applications that produce electricity except that a portion of the syngas, after clean up, is converted to high-value transportation fuels and chemical feedstocks. Coproduction allows the gasifier to run at a very high capacity factor and produce a greater portion of fuels and chemicals when electricity is not needed or when economics favor their production over electricity. Production of fuels and chemicals from syngas is commercial technology. The economics of coproduction of electricity, fuels and chemicals remains a concern for commercially viable in the US.

Post 2015 Advanced Clean Coal Technologies

- Oxygen combustion (Oxycombustion) uses conventional PC technology but rather than air providing the oxygen for combustion, a cryogenic Air Separation Unit (ASU) supplies oxygen to the PC fired boiler and a portion of the flue gas is recirculated to provide the required amount of combustion gas for the desired amount of heat transfer in the boiler. Since most of the nitrogen from air is eliminated in the ASU, the flue gas leaving the boiler essentially contains CO₂ and water vapor. Water is condensed out of the flue gas stream and a concentrated CO₂ stream is obtained. The CO₂-rich stream is compressed to for sequestration. The flue gas recycle flow, oxygen flow and coal flow are adjusted to achieve the same temperatures for flue gas leaving the boiler to generate the same amount of steam from the boiler as a PC boiler firing air. Overall, the power generated from steam turbines is the same as the air-fired PC boiler. However, a significant portion of the power is supplied to the ASU and the CO₂ compressor. Oxycombustion is an emerging technology that may be ready for commercial demonstration before 2015 and commercially available after 2015.
- Hydrogasification is a process for producing substitute natural gas (SNG) which can be used in natural gas pipelines and equipment. The process produces a large amount of methane in the hydrogasifier, the first step of the process. Hydrogasification (the production of methane from hydrogen and carbon) requires lower reaction temperatures (about 1000° F or lower) and about twice the pressure of other coal gasification processes. The lower reactor temperature offers the advantage of eliminating ash slag problems in the reactor. Hydrogasification can be incorporated into an IGCC configuration, or used with existing commercial combined cycle technology, as well as any other current uses of natural gas. Hydrogasification has been tested and evaluated with biomass fuels. Hydrogasification is an emerging technology that may be ready for commercial demonstration before 2015 and commercially available after 2015.

- Hydraulic Air Compression Cycle (HAC) uses low pressure air entrained in a large volume of water with the resulting mixture pressurized using a deep well or reservoir. The high pressure air produced can be used to replace the high pressure air normally supplied by the gas turbine compressor in a combined cycle power system. Conceptually, the gas turbine in an IGCC configuration is modified by removing the compressor while retaining the combustor and expander sections. Additionally, the proposed HAC power cycles employ the expander exhaust in a recuperator to preheat the high pressure air sent to the combustor. HAC is an emerging technology that may be ready for commercial demonstration after 2015
- Hydrogen Turbine Cycle is an alternate approach for achieving CO₂ capture is a power cycle based on the gas turbine being fueled with hydrogen. High pressure air supplied by the compressor section is still used in the combustor. The hydrogen stream is produced using an IGCC process that uses coal. The major plant sections: high pressure E-Gas Gasifier, ASU, HGPU, Acid plant, HSD, H₂ stream HRSG, CO₂ stream HRSG, CO₂ compression, steam turbines are retained for the standard IGCC configuration. The hydrogen turbine cycle is an emerging technology that may be ready for commercial demonstration after 2015

Subcritical Pulverized Coal Combustion (PC)

Description: This power plant is a conventional PC plant using wet flue gas desulfurization (FGD) for sulfur capture, selective catalytic reduction for NO_x removal, and electrostatic precipitator for particulate control,. The design configuration is typical of the PC power plants that provide the vast majority of electric power in the US today. This design unlike any commercial power plant in the US includes a monoethanolamine (MEA) unit for CO₂ capture from the flue gas. As a result, this design is considered the reference plant design and included for comparative purposes with the advanced clean coal technologies (Adv CCT) described in the following discussion. Table ___ illustrates the reference plant design basis and configuration.

Table ___

Pulverized Coal Combustion Plant Design Basis

Plant Capacity Nominal	400 to 1300 MWe
Plant Configuration	Conventional Subcritical PC with CO ₂ capture
Steam Conditions	Single reheat; 2400 psig/1000°F/ 1000°
Particulate Removal	Electrostatic precipitator (ESP)
Sulfur Removal	Limestone wet FGD
NO _x Control	Selective catalytic reduction (SCR)
CO ₂ Removal	Monoethanolamine (MEA) absorption

The major subsystems of the PC power plant as shown in Figure __ are:

Coal Handling

The equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Coal Combustion System

The primary components of the pulverized-coal combustion system are:

- Air Handling and Preheat – Air from the FD fans is heated in two vertical Ljungstrum regenerative type air preheaters, recovering heat energy from the exhaust gases on their way to the stack. This air is distributed to the burner windbox as secondary air. A portion of the combustion air is supplied by the primary air fans, and is heated in the Ljungstrum type air preheaters for use as combustion air to the pulverizers.
- Coal Burners – Boiler will employ approximately 30 coal nozzles arranged in six elevations, divided between the front and rear walls of the furnace. Each burner is designed as a low-NO_x configuration, with staging of the coal combustion to minimize NO_x formation.
- Steam Generation and Reheat – Steam generator in this supercritical PC-fired plant is a once-through, wall-fired, balanced draft type unit. The power plant is designed for operation as a base-loaded unit for the majority of its life, with some weekly cycling the last few years.
- NO_x Control – Two measures are taken to reduce the NO_x. The first is a combination of low-NO_x burners and the introduction of staged overfire air in the boiler. The second measure is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NO_x to N₂ and H₂O.
- Soot and Ash Removal – The soot-blowing system utilizes steam in an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Particulate removal is achieved with an ESP.
- Ash Handling System – The ash handling system scope is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). Fly ash collected in the ESP and the air heaters is conveyed to the fly ash storage silo with pneumatic transport. Bottom ash from the boiler is fed into a clinker grinder prior discharge via a hydro-ejector to the ash pond.

Flue Gas Desulfurization

The flue gas desulfurization system comprises three subgroups:

- Limestone Handling and Reagent Preparation System – Function of the limestone handling and reagent preparation system is to receive, store, convey, and grind the limestone delivered to the plant. Limestone will be delivered to the plant by 25-ton trucks. Limestone is unloaded onto a storage pile located above vibrating feeders, fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.

- Flue Gas Desulfurization System – Function of the FGD system is to scrub the boiler exhaust gases to remove the SO₂ content prior to release to the environment. The scope of the FGD system is from the outlet of the ID fans to the stack inlet.

- Byproduct Dewatering – Function of the byproduct dewatering system is to dewater the bleed slurry from the FGD absorber modules. The dewatering process selected for this plant is a gypsum stacking system. The scope of the system is from the bleed pump discharge connections to the gypsum stack.

Steam Turbine Generator

The turbine consists of a high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 2400 psig/1000°F.. Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system.

Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

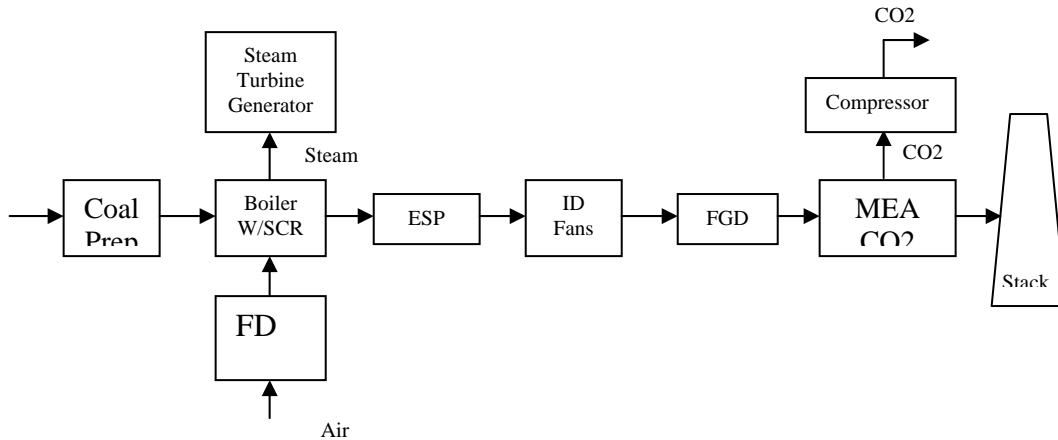
CO₂ Removal and Compression

It is technically possible to limit CO₂ emissions from a PC power plant using a design based on removing 90 percent of the CO₂ in the flue gas exiting the FGD system. An inhibited aqueous solution of monoethanolamine (MEA) is used to remove the CO₂. CO₂ is compressed to a pipeline pressure of 1200 psi by a multi-stage CO₂ compressor and dried.

Commercial Readiness: PC power plants make up the majority of coal-fired power plants in service today throughout the world. Although there are several plants through out the world that capture CO₂ from gas and coal-fired industrial boilers, there are no commercial-sized utility coal-fired units that are capturing and sequestering CO₂.

Source: Evaluation of Fossil Power Plants with CO₂ Recovery, J. L. Haslbeck, et. al., Parsons Infrastructure & Technology Group inc., February 2002.

Figure ___ Subcritical Pulverized Coal (PC) Combustion w/ CO₂ Capture



Supercritical Pulverized Coal Combustion (SCPC)

Description: This Adv CCT is a supercritical PC electric power plant that uses wet flue gas desulfurization (FGD) for sulfur capture, selective catalytic reduction (SCR) for NO_x control, an electrostatic precipitator for particulate control, and MEA unit for CO₂ capture from the flue gas. This plant configuration differs from the reference plant because it incorporates a steam generator and steam turbine that produces and utilizes higher pressure (3500psi versus 2400 psi) and higher temperature (1050°F versus 1000°F) steam resulting in increased operating efficiency. Table ___ illustrates the design basis for and configuration.

The major subsystems of the power plant as shown in Figure ___ are:

Coal Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Table ___

SCPC Plant Design Basis

Plant Capacity Nominal	400 to 1300 MWe
Plant Configuration Conventional	Supercritical PC with CO ₂ capture
Steam Conditions	Double reheat; 3500 psig/1050°F/ 1050°F/1050°F
Particulate Removal	Electrostatic precipitator (ESP)
Sulfur Removal	Limestone wet FGD
NO _x Control	Selective catalytic reduction (SCR)
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- NO_x Control – Two measures are taken to reduce the NO_x. The first is a combination of low-NO_x burners and the introduction of staged overfire air in the boiler. The second measure is the installation of an SCR system prior to the air heater. SCR uses ammonia and a catalyst to reduce NO_x to N₂ and H₂O.
- Soot and Ash Removal – The soot-blowing system utilizes steam in an array of retractable nozzles and lances that travel forward to the blowing position, rotate through one revolution while blowing, and are then withdrawn. Particulate removal is achieved with an ESP.
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bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.

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Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, high-pressure (HP) section, intermediate-pressure (IP) section, and two double-flow low-pressure (LP) sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system.

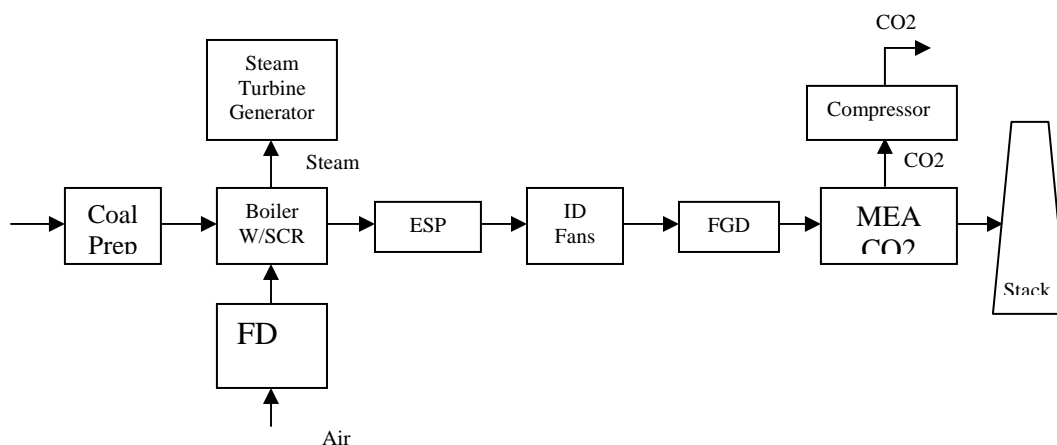
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CO₂ Removal and Compression

It is technically possible to limit CO₂ emissions from a SCPC power plant using a design based on removing 90 percent of the CO₂ in the flue gas exiting the FGD system. An inhibited aqueous solution of monoethanolamine (MEA) is used to remove the CO₂. CO₂ from the stripper is compressed to a pipeline pressure of 1200 psi by a multi-stage CO₂ compressor and dried.

Figure ___ Supercritical Pulverized Coal (SCPC) Combustion w/ CO₂ Capture



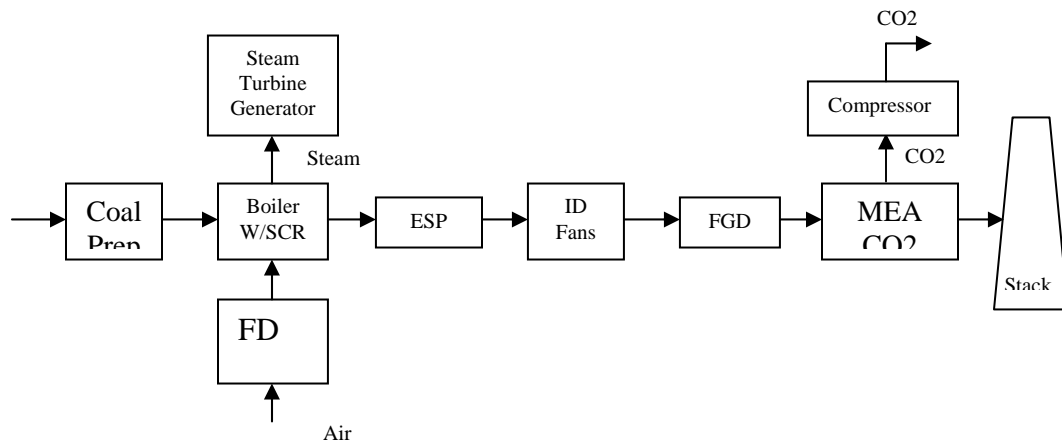
Commercial Readiness: This technology is commercially mature and many of these units are in operation around the world today. However none of these units are capturing CO₂.

Source: Evaluation of Fossil Power Plants with CO₂ Recovery, J. L. Haslbeck, et. al., Parsons Infrastructure & Technology Group Inc., February 2002.

Ultra Supercritical Pulverized Coal Combustion (USCPC)

Description: All system are the same as the Supercritical Pulverized Coal Combustion with CO₂ Capture design except that the main steam conditions are 4500 psia/1100°F/1100°F/1100°F.

Figure ___ Ultra Supercritical Pulverized Coal (USCPC) Combustion w/ CO₂ Capture



Commercial Readiness: With the development of advanced materials for production of critical boiler and turbine parts it is expected that USCPC boilers will be commercial demonstrated and available before 2015.

Source: Evaluation of Fossil Power Plants with CO₂ Recovery, J. L. Haslbeck, et. al., Parsons Infrastructure & Technology Group Inc., February 2002.

Supercritical Circulating Atmospheric Fluidized-Bed Combustion (SCCFB) Power Plant

Description:

This Adv CCT is a supercritical circulating atmospheric fluidized bed combustion (SCCFB) power plant, including limestone injection for sulfur capture selective catalytic reduction for NOx control, a fabric filter (baghouse) for particulate control, and an monoethanolamine (MEA) unit for CO2 capture in the flue gas. The SCCFB power plants is designed to operate at supercritical conditions of steam pressure at 3500 psi and steam temperatures of 1050°F. Table ___ illustrates the basis for the size and configuration.

Table ___

AFBC Plant Design Basis

Plant Capacity Nominal	Up to 400 MWe
Plant Configuration	Single train AFBC
Steam Conditions	Double reheat; 3500 psia/1050°F/ 1050°F/1050°F
Particulate Removal	Baghouse filter
Sulfur Removal	Limestone injection with coal/caustic polisher
NOx Control	Selective catalytic reduction (SCR)
CO2 Removal	MEA absorption

The major subsystems of the power plant are:

Coal Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Limestone Sorbent Handling

To provide the equipment required for unloading, conveying, preparing, and storing the limestone delivered to the plant. The scope of the system is from the trestle bottom dumper and limestone receiving hoppers up to the pulverizer fuel inlet.

Limestone Handling and Preparation System

Function of the limestone handling and preparation system is to receive, store, convey, and grind the limestone delivered to the plant. Limestone will be delivered to the plant by 25-ton trucks. Limestone is unloaded onto a storage pile located above vibrating feeders, fed onto belt conveyors via vibrating feeders and then to a day bin equipped with vent filters. The day bin supplies a 100 percent capacity size ball mill via a weigh feeder.

Ash Handling System

The ash handling system scope is from the bag house hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck

filling stations (for fly ash). Fly ash collected in the bag house and the air heaters is conveyed to the fly ash storage silo with pneumatic transport.

CO2 Removal and Compression

Part of the criteria of this power plant design is the limitation of CO2 emissions, based on removing 90 percent of the CO2 in the flue gas exiting the baghouse. An inhibited aqueous solution of MEA is used to remove the CO2. CO2 from the stripper is compressed to a pipeline pressure of 1200 psig by a multi-stage CO2 compressor and dried.

Steam Turbine Generator

The turbine consists of a very-high-pressure (VHP) section, HP section, IP section, and two double-flow LP sections, all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 3500 psig/1050°F. Turbine bearings are lubricated by a closed-loop, water-cooled pressurized oil system.

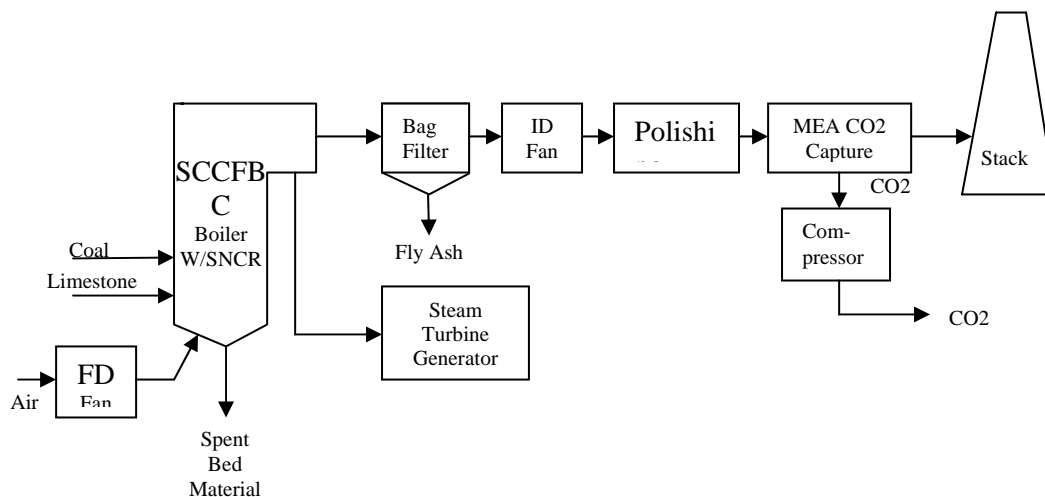
Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator, through the gland steam condenser, and the LP feedwater heaters. Each system consists of one main condenser; two 50 percent capacity, motor-driven vertical condensate pumps; one gland steam condenser; four LP heaters; and one deaerator with a storage tank.

Commercial Readiness: There are a significant number of subcritical CFB boilers in service around the world, but none that are designed for super-critical steam conditions. There are no CFB designs that are capturing CO2 in service.

Source: Evaluation of Fossil Power Plants with CO2 Recovery, J. L. Haslbeck, et. al., Parsons Infrastructure & Technology Group Inc., February 2002.

Figure___ Supercritical Circulating Atmospheric Fluidized-Bed Combustion (SCCFB) Power Plant w/ CO2 Capture



Integrated Gasification Combined Cycle (IGCC)

Description:

This Adv CCT is an IGCC power plant that use a gasifier to partially combust the coal producing a fuel gas that is cleaned of conventional combustion contaminants and combusted in a gas turbine to produce electricity. The hot exhaust gas from the gas turbine is channeled through a heat recovery boiler where steam is produced that is utilized in a steam turbine to produce a second source of electricity. Integrating the fuel gas produced electricity with the steam produced electricity results in a higher levels of efficiency than for a PC or CFB Adv CCT. In this design the fuel gas is subjected to CO₂ recovery by shifting the carbon monoxide in the fuel gas to hydrogen and using a Selexol unit for CO₂ capture and H₂S removal. Table __ illustrates the basis for the size and configuration.

Design Basis

This greenfield power plant is a coal-fired Integrated Combine Cycle (IGCC) power plant with H₂S and CO₂ removal. The major subsystems of the power plant are:

Coal Receiving and Handling

To provide the equipment required for unloading, conveying, preparing, and storing the coal delivered to the plant. The scope of the system is from the trestle bottom dumper and coal receiving hoppers up to the pulverizer fuel inlet.

Coal-Water Slurry Preparation and Feeding

The slurry preparation and feeding system mills crushed coal and generates a slurry for the gasifier. Three trains at 50 percent are required. The slurry storage tank is sized to hold 8 hours of slurry product.

Table __

IGCC Plant Design Basis

Plant Capacity	Nominal 400 to 800 MWe
Fuel Gas Processing	Oxygen-blown quench entrained-bed gasifier Conventional pressure air separation unit (ASU) with high pressure feed Sour gas two-stage shift with COS hydrolysis Two-stage Selexol for H ₂ S and then CO ₂ capture
Sulfur Recovery	Claus plant plus tail gas treating unit (TGTU)
Power Generation	Syngas expander GE 7FA combined cycle with steam injection for NO _x control
Steam Conditions	Double reheat; 1800 psig/1000°F/1000°F
CO ₂ Stream	Compressed to 1200 psia

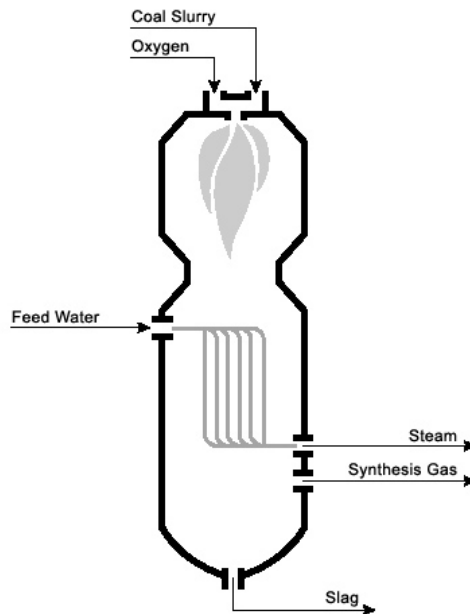
Coal Gasification

Gasifiers convert carbonaceous feedstock into gaseous products at high temperature and elevated pressure in the presence of oxygen and steam. Partial oxidation of the feedstock provides the heat. At operating conditions, chemical reactions occur that produce synthesis gas or "syngas," a mixture of predominantly CO and H₂. Gasification systems can incorporate any one of a number of type of gasifiers. Four gasifier designs are predominantly used in commercial applications and one additional design is under development by DOE

General Electric Entrained Flow (Downflow) Gasifier

General Electric (formerlyTexaco) coal gasification technology uses a single-stage, downward-firing, entrained-flow coal gasifier in which a coal/water slurry (60-70% coal) and 95% pure oxygen are fed to a hot gasifier. At a temperature of about 2700°F, the coal reacts with oxygen to produce raw fuel gas (syngas) and molten ash.

The hot gas flows downward into a radiant syngas cooler where high pressure steam is produced. The syngas passes over the surface of a pool of water at the bottom of the radiant syngas cooler and exits the vessel. The slag drops into the water pool and is fed from the radiant syngas cooler sump to a lock hopper. The black water flowing out with the slag is separated and recycled after processing in a dewatering system.



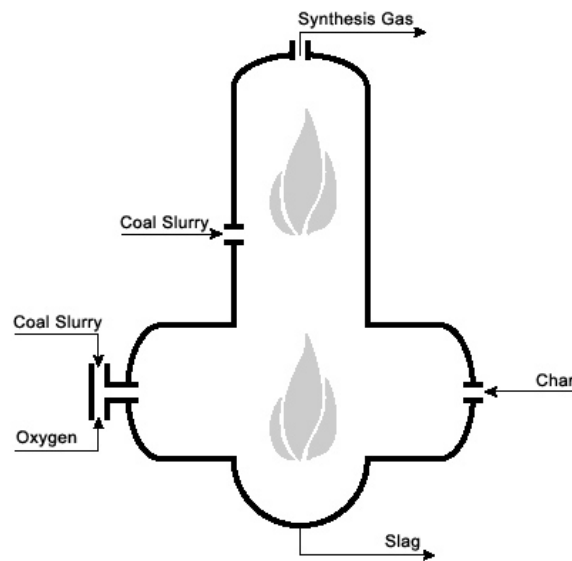
Connoco/Phillips Entrained-Flow (Upward) Gasifier

The Connoco/Phillips E-GAS (formerly Destec) coal gasifier is a slurry-feed, pressurized, upflow, entrained slagging gasifier whose two-stage operation makes it unique. Wet crushers produce slurries with the raw feed coal. Dry coal slurry

concentrations range from 50 to 70 wt%, depending on the inherent moisture and quality of the feed coal. About 80% of the total slurry feed is fed to the first (or bottom) stage of the gasifier. All the oxygen is used to gasify this portion of the slurry. This stage is best described as a horizontal cylinder with two horizontally opposed burners. The highly exothermic gasification/oxidation reactions take place rapidly at temperatures of 2400 to 2600°F. The coal ash is converted to molten slag, which flows down through a tap hole. The molten slag is quenched in water and removed in a novel continuous-pressure letdown/dewatering system.

The hot raw gas from the first stage enters the second (top) stage, which is a vertical cylinder perpendicular to the first stage. The remaining 25% of the coal slurry is injected into the hot raw gas. The endothermic gasification/devolatilization reactions in this stage reduce the final gas temperature to about 1900°F and add some hydrocarbons to the product gas.

Char is produced in the second stage. However, the yield of this char is relatively small because only about 25% of the coal is fed to the second stage. Char yield is dependent on the reactivity of the feed coal and decreases with increasing reactivity. The char is recycled to the hotter first stage, where it is readily gasified. The gasifier is refractory-lined and not cooled. The hotter first stage section of the gasifier is lined with a special slag-resistant refractory. The 1900°F hot gas leaving the gasifier is cooled in a fire-tube product gas cooler to 1100°F, generating saturated steam which is sent to the steam turbine.



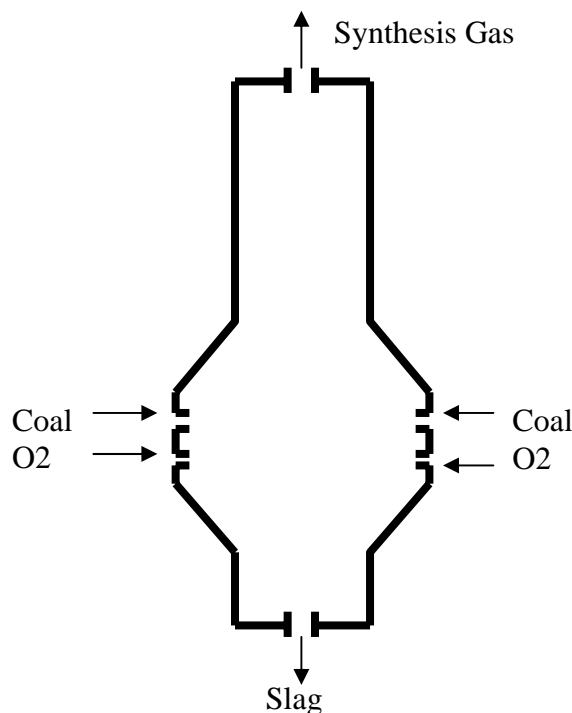
Shell Entrained-Flow (Upward) Gasifier

The Shell Gasification Process is a highly reliable and flexible process that can operate on a wide variety of feedstocks. It consists of three principal stages:

(1) Gasification (Partial Oxidation), in which the feedstock is converted to syngas in the presence of oxygen and a moderating agent (steam) in a refractory-lined gasification reactor, (2) Syngas Effluent Cooler (SEC), in which high pressure steam is generated from the hot syngas leaving the reactor, and (3) Carbon Removal, in which residual carbon and ash are removed from the syngas in a two-stage water scrubbing unit

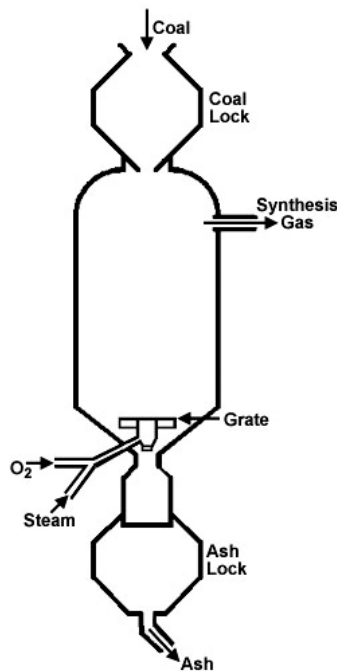
The Shell gasifier is a dry-feed, pressurized, entrained slagging gasifier. Feed coal is pulverized and dried with the same type of equipment used for conventional pulverized coal boilers. The coal is then pressurized in lock hoppers and fed into the gasifier with a transport gas by dense-phase conveying. The transport gas is usually nitrogen; however, product gas can be used for synthesis gas chemical applications, where nitrogen in the product gas is undesirable. The oxidant is preheated to minimize oxygen consumption and mixed with steam as moderator prior to feeding to the burner. The coal reacts with oxygen at temperatures in excess of 2500°F to produce principally hydrogen and carbon monoxide with little carbon dioxide. Operation at elevated temperatures eliminates the production of hydrocarbon gases and liquids in the product gas.

The high-temperature gasification process converts the ash into molten slag, which runs down the refractory-lined water wall of the gasifier into a water bath, where it solidifies and is removed through a lock hopper as a slurry in water. Some of the molten slag collects on the cooled walls of the gasifier to form a solidified protective coating. The crude raw gas leaving the gasifier at 2500-3000°F contains a small quantity of unburned carbon and about half of the molten ash. To make the ash non-sticky, the hot gas leaving the reactor is partially cooled by quenching with cooled recycle product gas. Further cooling takes place in the waste heat recovery (syngas cooler) unit, which consists of radiant, superheating, convection, and economizing sections, where high-pressure superheated steam is generated before particle removal.



Lurgi Dry Ash Gasifier

The Lurgi dry ash gasifier is a pressurized, dry ash, moving-bed gasifier. Sized-coal enters the top of the gasifier through a lock hopper and moves down through the bed. Steam and oxygen enter at the bottom and react with the coal as the gases move up the bed. Ash is removed at the bottom of the gasifier by a rotating grate and lock hopper. The countercurrent operation results in a temperature drop in the reactor. Temperatures in the combustion zone near the bottom of the gasifier are in the range of 2000°F, whereas gas temperatures in the drying and devolatilization zone near the top are approximately 500-1000°F. The raw gas is quenched with recycle water to condense tar. A water jacket cools the gasifier vessel and generates part of the steam to the gasifier. Sufficient steam is injected to the bottom of the gasifier to keep the temperature below the melting temperature of ash.

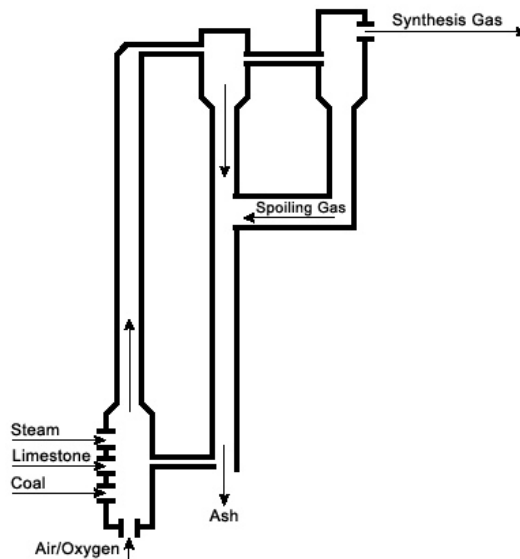


Kellogg/Brown & Root Transport Reactor

The Kellogg Brown & Root Transport Gasifier is a circulating-bed reactor concept that uses finely pulverized coal and limestone. The gasifier is currently in development, which may lead to a commercial design. It is expected that the small particle size of the coal and limestone will result in a high level of sulfur capture. Additionally, the small particle size will increase the throughput compared to a KRW gasifier, thereby potentially reducing the required number of gasifier trains (or the gasifier size) and the cost.

The Transport Gasifier is conceptually envisioned as consisting of a mixing zone, a riser, cyclones, a standpipe, and a non-mechanical valve. Oxidant and steam are introduced at the bottom of the gasifier in the mixing zone. Coal and limestone are introduced in the upper section of the mixing zone. The top section of the gasifier discharges into the disengager or primary cyclone. The cyclone is connected to the standpipe, which discharges the solids at the bottom through a non-mechanical valve into the transport gasifier mixing zone at the bottom of the riser. The gasifier system operates by circulating the entrained solids up through the gasifier riser, through the cyclone, and down through the standpipe. The solids reenter the gasifier mixing zone through the non-mechanical valve.

The steam and oxidant jets provide the motive force to maintain the bed in circulation and oxidize the char as it enters the gasifier mixing zone. The hot gases react with coal/char in the mixing zone and riser to produce gasification products. The gas and entrained solids leaving the primary cyclone pass through the secondary cyclone to provide final de-entrainment of the solids from the gas. The solids separated in the secondary cyclone fall through the dipleg into the standpipe. A solids purge stream is withdrawn from the standpipe for solids inventory maintenance. The gas leaving the secondary cyclone passes through a gas cooler, which reduces the gas temperature from about 1900°F to 1100°F.



The gasification technology presented here is an oxygen-blown slurry-feed entrained flow quench configuration licensed by general Electric. For a typical 400 MWe size, two commercial-scale gasifiers with each having a maximum coal throughput of 2,500 tpd dry would be required.

Air Separation Unit

One train at 100 percent will be used to produce nominally 3000 tpd of 95 percent oxygen product. Plant consists of a multi-staged air compressor, an air separation cold

box, and an oxygen compression system. A liquid oxygen storage tank will be maintained in order to ensure reliability. A slipstream of vent nitrogen will be compressed and available for miscellaneous plant requirements.

Raw Gas Cooling

Hot raw gas from the quench gasifier exits the gasifier at about 1100 psia and 486°F. This gas stream is scrubbed and cooled to 400°F.

Water Gas Shift / Syngas Humidification

A set of high-temperature shift reactors is used to shift the bulk of the CO in the fuel gas to CO₂. A two-staged shift is utilized in order to maximize CO conversion while maintaining reasonable reactor volumes. The fuel gas stream is cooled in a series of low temperature economizers and then routed to the Selexol unit. Fuel gas condensate is recovered and routed to a sour drum.

Sulfur Removal and Recovery / Carbon Dioxide Removal and Compression

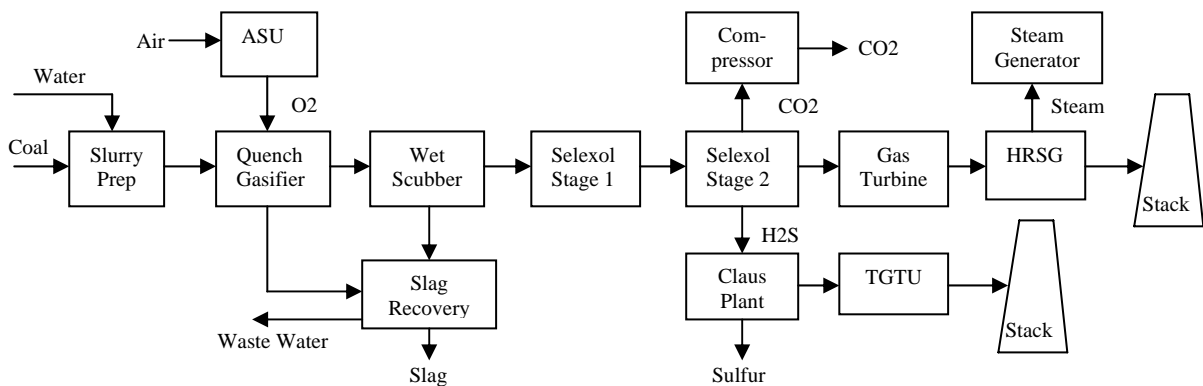
A unique feature of this power plant configuration is that H₂S and CO₂ are removed within the same process system, the Selexol process.

- Selexol Process – The purpose of the Selexol process is to preferentially remove H₂S as a product stream and then to preferentially remove CO₂ as a separate product stream. This is achieved in the double-stage Selexol process.

Commercial Readiness: There are 4 commercial IGCC plants operating around the world. Two of these units are operating in the US. The US units were built using up to 50% cofunding from the Department of Energy Clean Coal Technology Fund. A third US unit was constructed under the DOE CCT Program but it failed to reach commercial operation. IGCC is being offered commercially in the US by four technology license providers. At least two of these providers are offering complete engineering, procurement and construction options with commercial performance guarantees. To date no units have begun construction under this scheme. There are no IGCC units operating that capture CO₂, although there is one gasification plant that is capturing CO₂ and sending it via pipeline to an enhanced oil recovery operation in Canada.

Source: Evaluation of Fossil Power Plants with CO₂ Recovery, J. L. Haslbeck, et. al., Parsons Infrastructure & Technology Group inc., February 2002.

Figure __ Integrated Gasification Combined Cycle w/ CO₂ Capture



Integrated Gasification Combined Cycle with Coproduction of Fuels and Chemicals (Coproduction)

Description: Coproduction involves the integration of three major building blocks: (1) Gasification of coal or other hydrocarbon fuels to produce synthesis gas (syngas), (2) Conversion of a portion of the syngas to high-value products such as liquid fuels and chemicals, and (3) Combustion of syngas to produce electric power. In coproduction, the relative amounts of syngas used for power generation or converted to fuels and chemicals depend on market demands. The goal of coproduction is to fully utilize the feedstock and maximize revenue streams. By permitting operation of the gasifier at full capacity to make syngas for either power generation or fuels and chemicals production, coproduction makes more efficient use of capital than when producing power alone. Coproduction options include conversion of syngas to methanol, higher alcohols, Fischer-Tropsch (F-T) liquids, waxes, and other high-value products.

Fischer-Tropsch Process

F-T technology was initially developed, beginning in 1923, by two German scientists, Franz Fischer and Hans Tropsch, based on earlier observations by Sabatier and Senderens. The F-T process converts syngas into a mixture of mainly straight chain paraffin and olefin hydrocarbons. F-T synthesis takes place over a cobalt- or iron-based catalyst that promotes the reaction of CO and H₂ to form hydrocarbons and water. The hydrocarbon product includes material of varying properties from light gases (C₂-C₄) through waxes such as C₅₀₊ molecules. The process operates at relatively moderate temperatures (400–550 °F) and pressures (150–560 psia).

Production of Methanol

The Liquid Phase Methanol (LPMEOH™) process (described in Topical Report No. 11) integrates coal gasification with chemicals production. It was demonstrated on a commercial scale as part of the CCT Pro-gram. Application of this technology can enhance the economics and efficiency of power generation by producing a clean-burning, storable liquid (methanol) from syngas during periods of low power demand. The methanol can be used to fuel combustion turbines during peak demand. The main uses for methanol are in the production of chemicals, such as formaldehyde, acetic acid, and other derivatives, and as a fuel. It can be dehydrated to produce olefins, a large and growing market

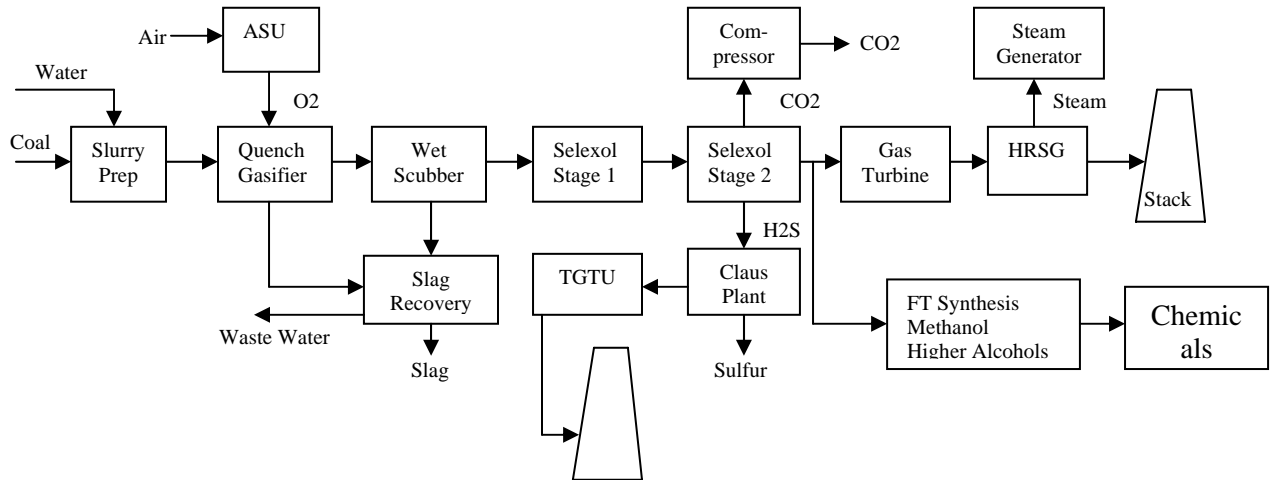
Production of Higher Alcohols

In addition to methanol, alcohols having higher molecular weights, such as C₂-C₆ alcohols, can be produced from syngas. Research is underway to develop processes suitable for commercial application. Higher alcohols are candidates for inclusion in gasoline as oxygenates to reduce exhaust emissions that contribute to smog formation.

Commercial Readiness: Coproduction through gasification of coal is a commercial technology.

Source: Coproduction of Power, Fuels and Chemicals, Topical Report Number 21, US DOE, September 2001.

Figure __ Coproduction of Power, Fuels & Chemicals w/ CO₂ Capture



Stack

The following advanced clean coal technologies are examples of those types of technologies that are currently in the development stage and are not expected to be commercially available until after 2015.

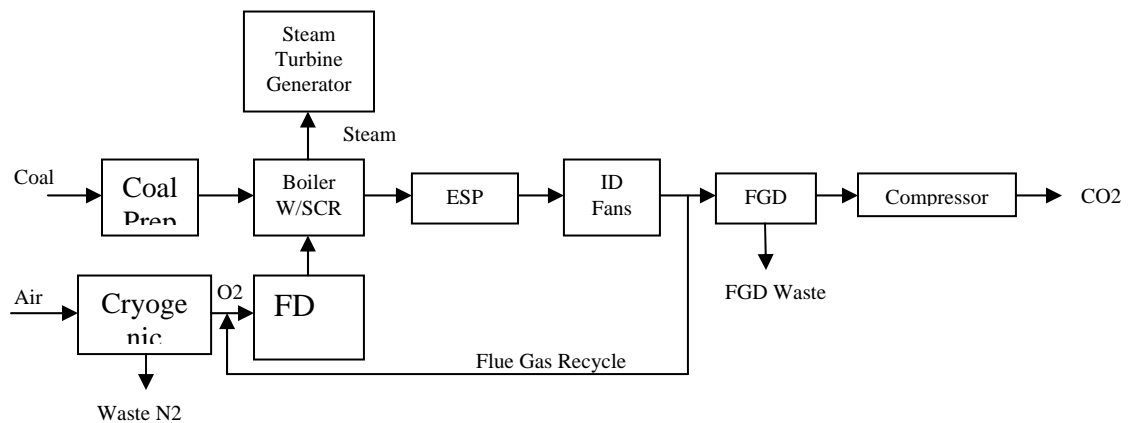
Oxygen Combustion (Oxycombustion)

Description: This Adv CCT uses a conventional PC plant with wet FGD for sulfur capture and rather than air providing the oxygen for combustion a cryogenic Air Separation Unit (ASU) supplies oxygen to the PC fired boiler and a portion of the flue gas is recirculated to provide the required amount of combustion gas for the desired amount of heat transfer in the boiler.. Oxygen with 95% purity is used, because the cost of oxygen is significantly lower than that for high-purity oxygen (>99.5% purity). The recycled flue gas is mixed with oxygen from the cryogenic ASU. The resulting oxidant stream (mixture of O₂, CO₂ and H₂O and small amounts of Ar and N₂) is preheated in the inlet heater and fed to the boiler along with pulverized coal. Since most of the nitrogen from air is eliminated in the ASU, the flue gas leaving the boiler essentially contains CO₂ and water vapor. After the flue gas preheats the oxidant stream, it passes through a precipitator and the portion that is not recycled enters the SO₂ scrubber. Water is condensed out of the flue gas stream exiting the scrubber and a concentrated CO₂ stream is obtained. The CO₂-rich stream is compressed to for sequestration. The flue gas recycle flow, oxygen flow and coal flow are adjusted to achieve the same temperatures for flue gas leaving the boiler to generate the same amount of steam from the boiler as a PC boiler firing air.. Overall, the power generated from steam turbines is the same as the air-fired PC boiler. However, a significant portion of the power is supplied to the ASU and the CO₂ compressor. A simplified flow diagram is shown in Figure__:

Commercial Readiness: There are no oxygen fired PC boilers in commercial operation and nor has the concept been demonstrated at the pilot plant or commercial scale.

Source: Advanced Fossil Power Systems Comparison Study by E. L. Parsons, NETL, W. W. Shelton, J. L. Lyons, EG&G Technical Services, Inc., December 2002.

Figure ___ Oxygen-Fired Subcritical Pulverized Coal (PC) Combustion w/ CO₂ Capture



Hydrogasification

The following descriptions summarize concepts for hydrogasification to generate electric power and to produce SNG. Both concepts are relatively easily adapted to carbon management requirements where the CO₂ is captured and treated for pipeline transport. While hydrogasification has been studied and tested in the past, the new concepts discussed here are not fully defined. The estimated performance and cost information is derived by factors and engineering judgments based on past work with related, but different designs. More detailed energy and material balances are needed in parallel with process integration and trade-off studies. Based on the more refined engineering, equipment lists and specifications need to be prepared to support cost estimates of plants to produce power and SNG.

Hydrogasification Power Generation

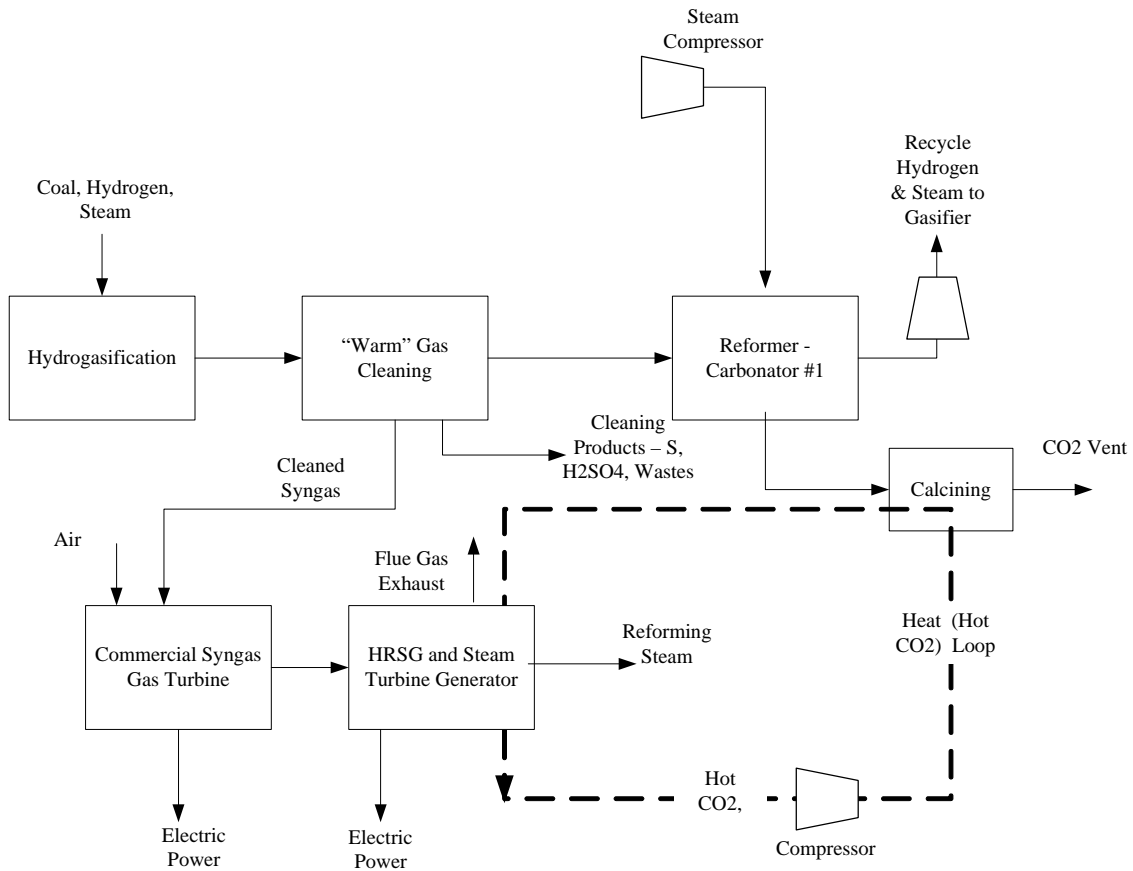
In this concept hydrogasification is used to generate synthesis gas for combustion in a commercial turbine combined with a heat recovery steam generation (HRSG) and a steam turbine. "Warm" acid gas cleaning is used to remove contaminants before the medium Btu syngas is sent to the gas turbine. Future work would also examine using a fluidized bed of limestone to clean the raw gas. A portion of the cleaned gas is sent to a reformer-carbonator reactor where methane is reformed to hydrogen and separated from the other gases (CO₂). The hydrogen is recycled to the gasifier to react with the coal and steam inputs. In the present concept the limestone used for reforming and carbonation is reclaimed by calcining with indirect heat exchange from a stream of hot CO₂.

The power generation operation is typical of other IGCC processes except that thermal energy is required for methane reforming and possibly the calcining operation. These energy demands have been approximated, and need to be better defined as part of the full energy and material balance calculations.

Exhibit 1 illustrates the power generation concept.

If the concept requires CO₂ separation and capture, the process would be altered to produce hydrogen instead of the synthesis gas by expanding the reforming process to include the entire clean gas product. From previous work, about half of the hydrogen produced is recycled to the gasifier. The gas turbine fuel would be hydrogen diluted by CO₂. Others, including turbine manufacturers, have studied this gas turbine arrangement and implementation seems practical with small modifications. This approach would provide a plant with basically zero emissions to the atmosphere, assuming the compressed CO₂ is sequestered.

Figure __, Hydrogasification for Power Generation



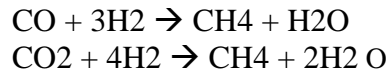
Hydrogasification for Synthetic Natural Gas Production

Hydrogasification was initially investigated for the purpose of producing SNG. The concept described here is significantly different than the design and pilot work in the 1970s and 80s, but much of the basic science is the same. The SNG production concept is shown in Exhibit 2.

In this concept the raw gas is cleaned in a limestone bed before going to the reformer/carbonizer to make hydrogen for recycle. The rest of the clean gas is sent to a methanation process to complete the production of methane. The SNG is next dried and compressed. CO2 is also separated during the SNG production process.

Methanation

The methanation process is commercial. Some hydrogen plants use the simple and convenient methanation reaction to remove traces of carbon oxides from the process gas. This involves the conversion of carbon oxides to methane and water by the use of a nickel catalyst with the reactions:

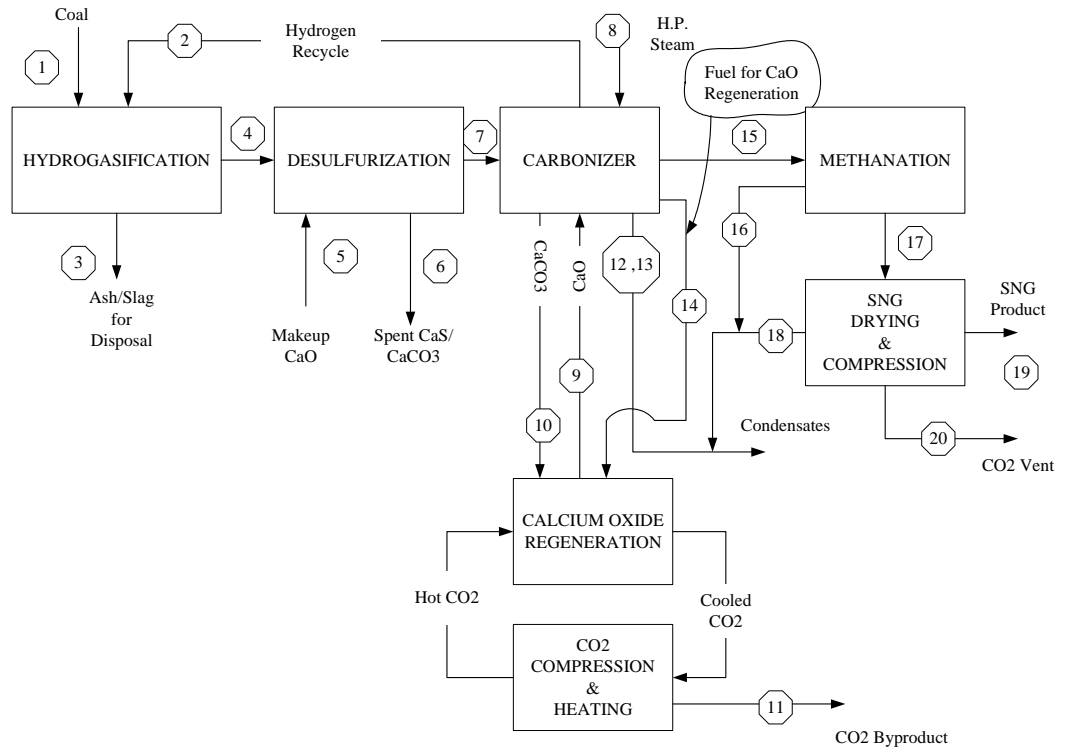


The methanation reaction has been well known for more than 70 years and applied to a variety of industrial processes. In the 1950s, hydrocarbon steam reforming was being introduced and methanation was used more extensively in processes for manufacturing ammonia and hydrogen. In current hydrogen plant flowsheets low temperature carbon monoxide conversion followed by removal of carbon dioxide and methanation is a commonly used process gas purification procedure.

Although the major use of methanation catalysts is in ammonia synthesis and hydrogen plant purification, several other important applications have been developed. Examples include the production of substitute natural gas from a variety of feedstocks (The Dakota Gasification SNG plant is a coal-based example.) and removal of carbon oxides from hydrogen-rich off gas streams in olefin crackers and oil refineries.

CO₂ sources are the calcining step to regenerate the limestone and the methanation operation. If the design is to target zero emissions, additional compression of the streams to meet pipeline specifications is all that is required.

Figure __, Hydrogasification for Synthetic Natural Gas Production



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Commercial Readiness: A hydrogasification process developed by the Institute of Gas Technology (IGT), IGT investigated hydrogasification in the 1970 's as one of the candidate technologies for generation of methane as a synthetic pipeline gas. A 72 ton-per-day pilot plant was operated. There are no commercial plants operating the hydrogasification process today.

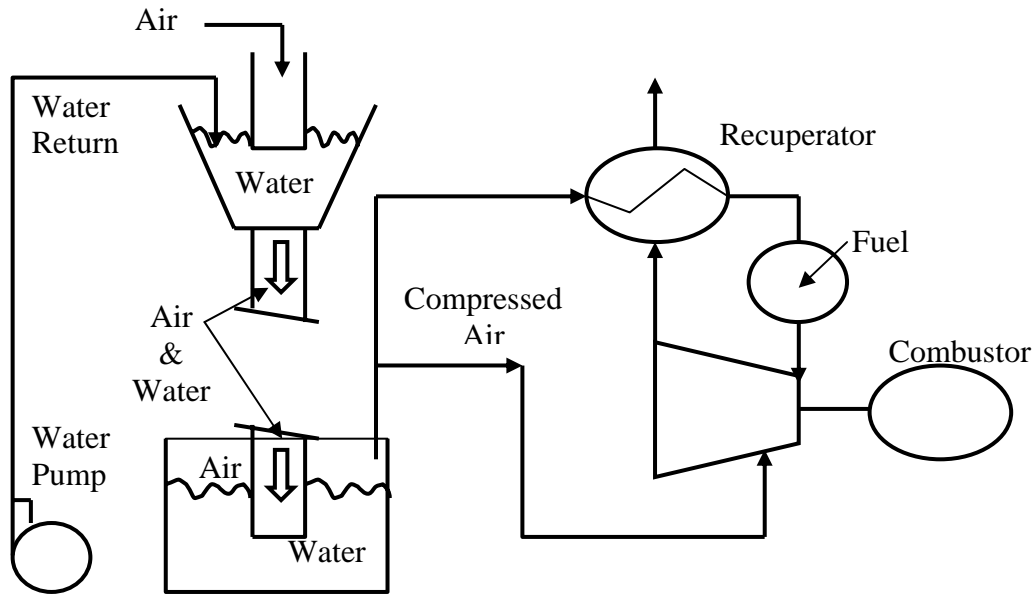
Source: Personnel communication from Ray Hobbs, Arizona Public Service, July 2005.

Hydraulic Air Compression Cycle (HAC)

The use of hydraulic air compression (HAC) has been proposed as a means for increasing the efficiency of high-efficiency power cycles. In this approach, low pressure air is entrained in a large volume of water with the resulting mixture pressurized using a deep well or reservoir. The high pressure air produced can be used to replace the high pressure air normally supplied by the gas turbine compressor in a combined cycle power system. Conceptually, the gas turbine in an IGCC configuration is modified by removing the compressor while retaining the combustor and expander sections. Additionally, the proposed HAC power cycles employ the expander exhaust in a recuperator to preheat the high pressure air sent to the combustor. This either eliminates the need for a steam cycle

or greatly reduces its size and cost. A simplified diagram illustrating the HAC is shown in Figure ___.

Figure ___. Hydraulic Air Compression (HAC) Power Block



Commercial Readiness: There are HAC plants in commercial operation and nor has the concept been demonstrated at the pilot plant or commercial scale.

Source: Advanced Fossil Power Systems Comparison Study by E. L. Parsons, NETL, W. W. Shelton, J. L. Lyons, EG&G Technical Services, Inc., December 2002.

Hydraulic Air Compression Cycle (HAC) – Coal – without CO₂ Capture

This approach assumes the modification of a standard IGCC case based on the E-Gas gasification process that uses CGCU for sulfur recovery. The modifications include:

- The HAC is used to replace the gas turbine's air compressor. High pressure air is supplied to both the gas turbine combustor and the air separation unit (ASU). As in the natural gas cases, the air flowrate required for the combustor and ASU is fed to the HAC module. Nitrogen available from the ASU was used to replace chargeable cooling air for cooling in the turbine expander. The water flow rate is set at 1115 times the air flowrate. (mass basis).
- A recuperator is added that uses the turbine exhaust to preheat air sent to the combustor. The turbine exhaust leaves the recuperator at 265 °F and is sent to a stack.
- The standard IGCC steam cycle (HRSG/steam turbines) that generates steam at three pressure levels is replaced with a smaller system based on generating steam at a single high pressure. The steam generation is mainly now due to the syngas cooler since the heat available in the turbine exhaust was used in the recuperator section for preheating air.

Hydraulic Air Compression Cycle (HAC) – Coal – with CO₂ Capture

For HAC with CO₂ capture, the standard E-Gas IGCC cases was modified to benefit from the higher efficiency obtained by using HGCU as the starting point for HAC with CO₂ capture case since a significant energy penalty is expected for sequestering the CO₂. An additional reason was that having a cleaned coal syngas at high temperature would allow the use of a Hydrogen Separation Device (HSD). The HSD is a membrane catalytic reactor being designed to both shift the coal syngas and separate out a high purity hydrogen stream. The modifications made to the standard E-Gas IGCC case include the following:

- Gasifier pressure was increased to enable the downstream HSD device to have an inlet pressure of approximately 1000 psia. This also increases the power requirements for the oxygen boost compressor that supplies the gasifier. Steam at 1000 psia was added for accomplishing the shifting of the coal syngas stream. The HSD produces two streams, a high pressure CO₂ rich-stream and a low pressure high purity H₂ rich-stream.
- The CO₂-rich stream (with residual fuel gas) is sent to a power turbine and proceeds to an oxygen fired combustor to burn any residual fuel before entering a HRSG for steam generation. This stream is further cooled before entering a multi-stage compression section that raises the pressure to 2100 psia. Subsequent cooling to 100 °F produces a liquefied product stream.
- The hydrogen-rich stream is sent to a separate HRSG for steam generation before entering a compression section. The hydrogen is now available for use as a fuel in the HAC module.
- The steam cycle developed recovers energy from the gasifier syngas cooler, the acid plant section, and the two HRSG sections that follow the HSD device. The inclusion of the HAC system again results in a power plant having a significant energy penalty of 8.6 percentage points.

Removing CO₂ is based on treating the coal syngas by a membrane reactor system (an advanced technology presently in the research stage of development) that produces a H₂ rich fuel stream and a CO₂ rich stream.

Hydrogen Turbine Cycle

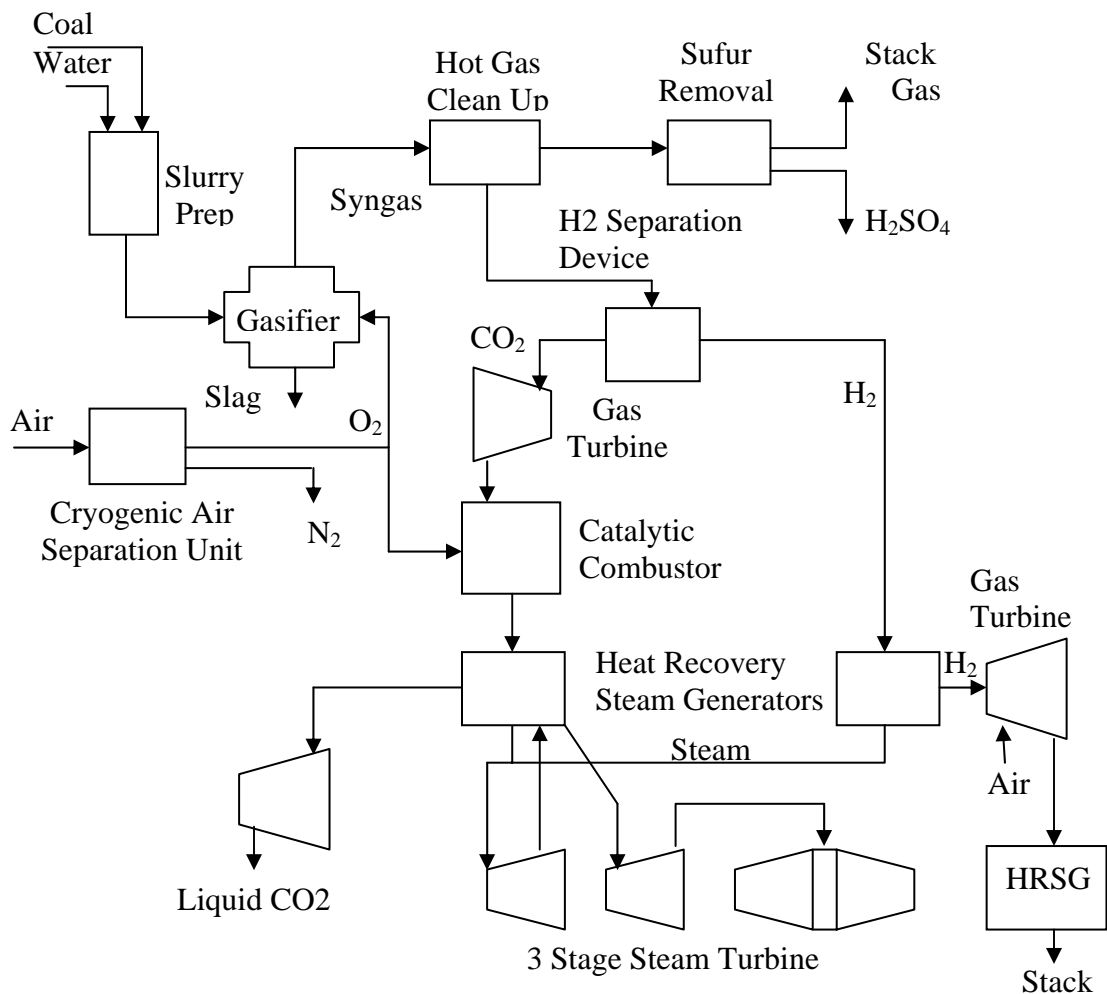
As an alternate approach for achieving CO₂ capture is a power cycle based on the gas turbine being fueled with hydrogen. High pressure air supplied by the compressor section is still used in the combustor. The hydrogen stream is produced using an IGCC process that uses coal. The major plant sections: high pressure Destec Gasifier, ASU, HGCU, Acid plant, HSD, H₂ stream HRSG, CO₂ stream HRSG, CO₂ compression, steam turbines are retained for the standard IGCC configuration. One change from the standard IGCC configuration is the insertion of a hydrogen powered “G” gas turbine. The hydrogen turbine cycle relies on hydrogen combustion with oxygen. Steam is also injected in the combustors. The coal syngas generated by gasification is shifted and sulfur compounds and CO₂ removed using the RECTISOL absorption process and sulfur recovered in a CLAUS/SCOT section. The hydrogen produced is split between a high pressure combustor and a reheat combustor between two turbine expander sections. A heat recovery steam generator is used to generate steam before the flue gas (essentially

steam) is expanded in a low pressure turbine section. The process projects efficiencies of approximately 50% (HHV), which includes CO₂ compression to 80 bar (1160 psia).

Commercial Readiness: There are no hydrogen turbine cycles in commercial operation and nor has the concept been demonstrated at the pilot plant or commercial scale.

Source: Advanced Fossil Power Systems Comparison Study by E. L. Parsons, NETL, W. W. Shelton, J. L. Lyons, EG&G Technical Services, Inc., December 2002.

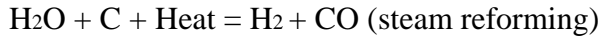
Figure __. Hydrogen Turbine Cycles



Steam Reforming Gasification

Steam reforming gasification utilizes a fluidized bed gasifier. Fluidized-bed gasifiers are typically air or oxygen blown, bubbling or circulating bed, and operate with crushed (0.5 - 5 millimeter) fuels. Fuel is introduced into an upward flow of gas that fluidizes the bed of fuel and provides reactants for gasifying the fuel. The bed is usually formed from sand, char, sorbent, and ash. The residence time of the fuel is typically in the order of 10 to 100 seconds. Fluidized bed gasifiers operate at lower temperatures than entrained-flow gasifiers do, and well below the ash fusion temperatures to avoid ash melting. They generally operate at 1,400 °F – 2,000 °F and 15 psi – 450 psi. Some atmospheric fluidized bed gasifiers, known as steam reformers (MTCI and FERCO processes), are indirectly heated and thus steam is used as the primary fluidizing gas. These gasifiers produce a hydrogen rich, medium heating value gas without requiring an oxygen unit.

Superheated steam reacts endothermically with the carbonaceous components to produce hydrogen and carbon monoxide fuel gases:

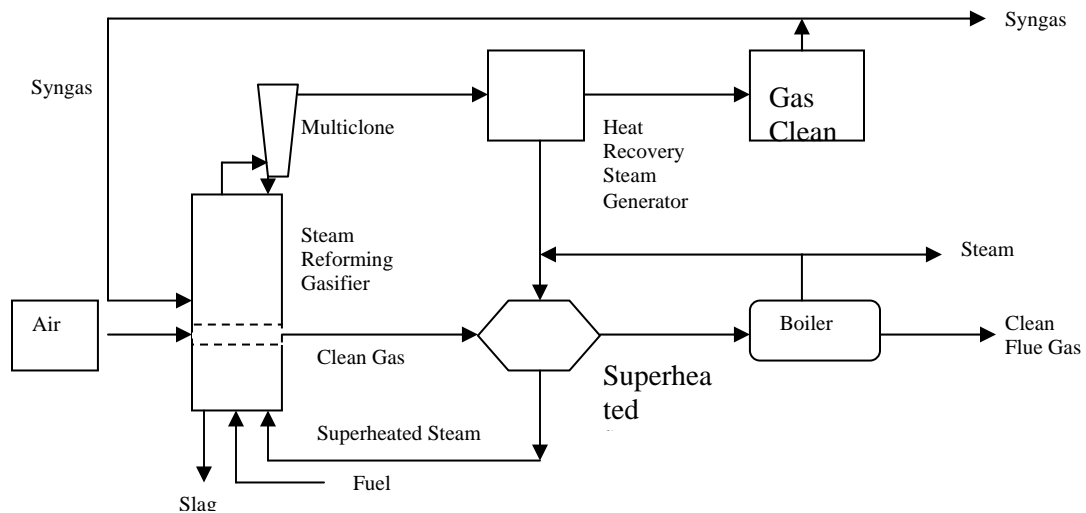


Water-gas shift reactions also occur simultaneously with the steam reforming reactions to yield additional hydrogen and carbon dioxide:



Sulfur present in the feed is reduced to hydrogen sulfide gas (H₂S) and joins the product gas exiting the reformer. A simple schematic of steam reforming gasification is shown in Figure ___ below:

Figure ___ Steam Reforming Gasification



Commercial Readiness: Steam reforming gasification has been demonstrated on biomass at the commercial scale.

Source: BIOMASS GASIFICATION FOR HYDROGEN PRODUCTION – PROCESS DESCRIPTION AND RESEARCH NEEDS, Suresh P. Babu, Ph.D., IEA Thermal Gasification Task Lead, Gas Technology Institute, 1700 South Mount Prospect Road Des Plaines, IL 60018-1804, U.S.A. ASSESSMENT OF THE COMMERCIAL POTENTIAL FOR SMALL GASIFICATION COMBINED CYCLE AND FUEL CELL SYSTEMS PHASE II FINAL DRAFT REPORT, HM Associates Inc., Princeton Energy Resources International, LLC And TFB Consulting, March 2003

SITE ALTITUDE & AMBIENT TEMPERATURE EFFECTS ON IGCC

- The Gas Turbine Compressor Section is a “Constant Volumetric Flow” machine, while the output of the Turbine Section depends on the mass flow of air, fuel, and other diluents (nitrogen, steam, Water, etc), added to the gas stream between the compressor discharge and turbine entrance.
- The density of the airflow and, hence, the turbine mass flow varies inversely with ambient temperature and site altitude..
- The turbine output per unit of mass flow is typically twice that of the compressor work required to compress the air, because of the higher temperature of the gas. The difference between turbine output and compressor work is net output to the electric generator.
- The turbine is normally output and environmental performance rated for ISO condition – a 59°F ambient temperature at a sea level site. However, its shaft torque capacity is usually based on 0°F sea level conditions, 13-15% higher than ISO-rated output, with significant extra safety margin for generator ground fault dynamic loads.
- The turbine is normally designed for natural gas or oil fuels, where the fuel mass flow is on the order of 2% of the compressor air mass flow. In synfuel operation, the flow of fuel is 4-5 times that of natural gas and the nitrogen or steam diluent required to meet NO_x environmental limits equals or exceeds the fuel flow, for a total of 16-20% of compressor air flow.
- The extra mass flow through the Heat Recovery Steam Generator also increase steam turbine output by a similar percentage. Hence the IGCC system at the same site altitude and ambient temperature will have a potential electrical output that is 27-35% greater than that for a NGCC, even considering the firing temperature reductions required by the high gas stream moisture content and its effect on heat transfer.
- At 5000 feet site elevation the air density is down by 13%, which reduces the IGCC generator output by approximately 13% -- still 6-14% greater than an ISO rated NGCC.. There is a second order effect on parasitic power for the Air Separation Unit; meaning the IGCC would be down another 0.5-1% in net electrical output.
- The unit can be “flat-rated” at Turbine Shaft Torque limits over the 0-100°F ambient temperature range by (1.) injecting more nitrogen, steam, or water between the compressor discharge and turbine inlet (2.) cooling and possibly turbo-charging the compressor inlet air, or (3) duct burning in the inlet to the HRSG to increase steam turbine output.
- All of the output enhancements, which would be used on high elevation IGCC units at temperatures above 30-50°F, have lower incremental costs than the base plant or even peaking natural gas capacity, have small impacts on cycle efficiency, and provide

valuable hot day generation capacity. **Altitude and Ambient Temperature effects on IGCC units are real, but are manageable at reasonable cost and efficiency impact using state-of-the art methods that have been demonstrated at commercial scale**