

Synthetic Natural Gas (SNG): Technology, Environmental Implications, and Economics

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Abstract

Increasing demand for natural gas and high natural gas prices in the recent past has led many to pursue unconventional methods of natural gas production. Natural gas that can be produced from coal or biomass is known as “synthetic natural gas” or “substitute natural gas” (SNG). This paper examines the different technologies for SNG generation, the cost, and the environmental impacts of SNG. The paper identifies the conditions under which SNG production could be economically viable. The different pollutants can be better controlled in the process. The sulfur is emitted as hydrogen sulfide (H₂S) and can be removed in the acid gas removal (AGR) system. CO₂ is a byproduct of the coal to SNG process. In a low-carbon economy, the development of the carbon capture and storage would be one of the critical factors in the future development of SNG. In the absence of carbon capture and storage and with carbon allowance price in future, the SNG could be expensive and may not be economically viable. Higher natural gas price and selling of CO₂ to enhanced oil recovery could make the SNG economically viable.

1. Introduction

Energy demand is increasing across the globe. Fossil fuels, primarily coal and natural gas, are the major sources of energy worldwide. The United States has abundant coal resources: it contains 25% of the world’s coal reserves, and the energy content of those reserves exceeds the energy content of the world’s known recoverable oil (DOE 2008). Still, increasing consumption—and the resultant increasing price—of natural gas are a concern. According to DOE (2008), 90% of new U.S. power plants will be natural gas-fired plants. The ever increasing demand and high price of natural gas in recent past has led researchers to consider alternate methods of natural gas generation. Converting coal to natural gas could satisfy the demand for natural gas while utilizing the United States’ abundant coal resources. “Synthetic natural gas” or “substitute natural gas” (SNG) is an artificially produced version of natural gas. SNG can be produced from coal, biomass, petroleum coke, or solid waste. The carbon-containing mass can be gasified; the resulting syngas can then be converted to methane, the major component of natural gas.

There are several advantages associated with producing SNG from coal. SNG could be a major driver for energy security. SNG production could diversify energy options and reduce natural gas imports, thus helping to stabilize fuel prices. SNG can be transported and distributed using existing natural gas infrastructure and utilized in existing natural gas-fired power plants. And as coal is abundant and evenly distributed globally as compared to oil and natural gas, SNG could stabilize the global energy market.

The biomass can also be used along with coal to produce SNG. The use of biomass would reduce the greenhouse gas emissions, as biomass is a carbon-neutral fuel. In addition, the development of SNG technology would also boost the other gasification-based technologies such as hydrogen generation, integrated gasification combined cycle (IGCC), or coal-to-liquid technologies as SNG share at least the gasification process with these processes.

There are many different issues associated with the deployment of SNG. Interest in developing SNG dates back to the 1970s, when the energy crisis led researchers and policymakers to consider ways to convert coal into gaseous and liquid fuels. However, the later stabilization of the fuel market and increased availability of low-cost fuels led to the abandonment of most of coal-to-SNG projects. Another problem with producing SNG from coal is the additional CO₂ created by the process. This paper analyzes SNG generation technology and the current state of SNG development and discusses how carbon capture and sequestration (CCS) technology could affect SNG. It examines the technology's economic and environmental implications to determine under what conditions SNG production becomes economically viable.

2. Coal-to-SNG Technology

2.1. Brief Description

Steam-oxygen gasification, hydrogasification, and catalytic steam gasification are the three gasification processes used in coal-to-SNG. The proven and commercialized method of gasification for the coal-to-SNG process, however, is the steam-oxygen gasification process.

2.1.1. Steam-oxygen gasification

In the steam-oxygen process of converting coal to SNG, coal is gasified with steam and oxygen. The gasification process produces carbon monoxide (CO), hydrogen (H₂), carbon dioxide (CO₂), methane (CH₄), and higher hydrocarbons such as ethane and propane. The gas composition depends upon the gasifier conditions, i.e., temperature and pressure. At higher temperatures and pressures, the major products are CO and H₂. Three moles of H₂ are required to react with each mole of CO to produce one mole of CH₄. The concentration of H₂ in syngas is increased by a step called the water-gas shift reaction, which is followed by a gas cleaning. The cleaned gas, consisting primarily of CO and H₂, reacts in the methanation reactor in the presence of a catalyst to produce CH₄ and H₂O. The resulting gas, after H₂O condensation and polishing, if required, is synthetic natural gas (SNG). Figure 1 shows the flow diagram of steam-oxygen gasification. The essential components of the process are the air separation unit, the gasifier, the water-gas shift reactor, syngas cleanup, and the methanation reactor. Each component is described below.

Air Separation Unit

Oxygen required in the gasifier is either supplied by vendors or generated on-site using an air separation unit (ASU). Cryogenic air separation is the technology generally used in the ASU.

Gasifier

The most important and basic component of the coal-to-SNG process is the gasifier. The gasifier converts coal into syngas (primarily CO and H₂) using steam and oxygen (O₂), generally at a high temperature and under high pressure.

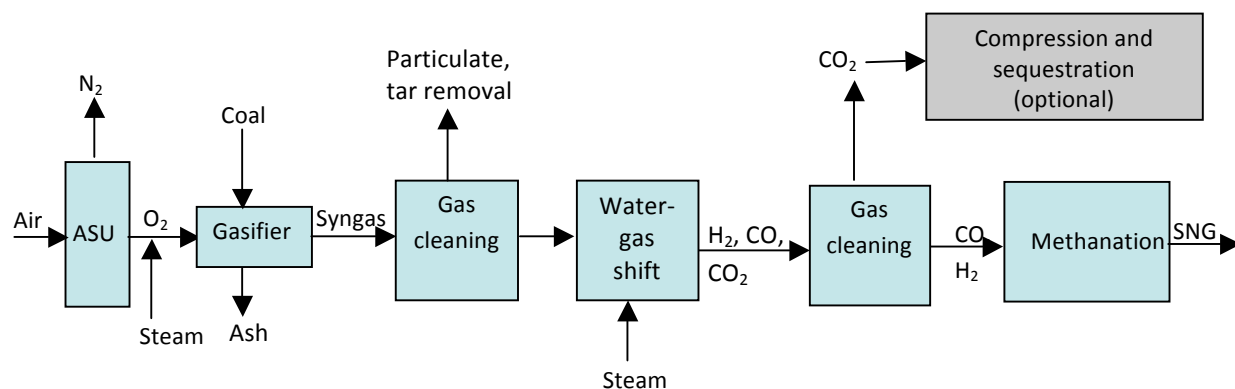


Figure 1. Steam-oxygen gasification process diagram

As an example, the GE/Texaco gasifier temperature operates at 42 bars and 2,500° F. The different types of gasifiers are: entrained flow, fluidized bed, moving bed, and transport reactor (Stiegel 2007). Commercial gasifier vendors include ConocoPhillips, GE Energy (Chevron-Texaco), Shell-SCGP, Siemens (GSP/Noell), KBR Transport, and Lurgi.

Water-Gas Shift Reactor

The concentration of H₂ is increased by the water-gas shift reaction. In the water-gas shift reaction, CO and H₂O are converted to CO₂ and H₂ in a fixed-bed catalytic converter. The reaction is exothermic and can be completed either before or after the acid gas removal. The catalyst composition varies for both types of shift reactions (NETL 2007).

Syngas Cleanup

The syngas cleanup is done in two steps. First, the syngas from the gasifier is quenched and cooled, and the dust and tar carried by the gas are removed. After passing through the water-gas shift reactor, the syngas is cleaned a second time to remove the acid gases H₂S and CO₂. The acid gas cleanup system can use either the Selexol or Rectisol process. Both processes are based on physical absorption, which makes them more economical than the amine process used for CO₂ separation in power plants, which is based on chemical absorption. The processes can be used in a selective manner to produce separate streams of H₂S and CO₂. The H₂S can be further utilized in a Claus plant to generate sulfur.

In the Selexol process, a mixture of dimethyl ethers of polyethylene glycol is used as an absorbent. The Selexol solvent absorbs the acid gases from the syngas at relatively high pressure, usually 20 to 138 bars. The acid gases are released using a pressure swing or steam stripping. The Selexol process is more than 35 years old and there are at least 55 commercial units in service (UOP 2008). In the Rectisol process, cold methanol is used as an absorbent which absorbs the acid gas at a pressure of 27.6 to 68.9 bars and at a temperature of 100° F. The Great Plains Synfuels Plant uses the Rectisol process.

Methanation

In the methanation reactor, CO and H₂ are converted to CH₄ and H₂O in a fixed-bed catalytic reactor. Since methanation is a highly exothermic reaction, the increase in temperature is controlled by recycling

the product gas or by using a series of reactors. Steam is added to the reaction to avoid coke formation in the reactor. After the steam is removed from the product gases by condensation, SNG is ready for commercial applications.

2.1.2. Hydrogasification

As the name implies, the hydrogasification process uses H_2 to gasify coal. H_2 reacts with coal to produce CH_4 . The hydrogasification process is exothermic in nature. H_2 required for the gasification is either provided by an external source or by using a methane steam reformer. A portion of the CH_4 generated in the hydrogasification reactor is converted into CO and H_2 in the methane steam reformer (Figure 2).

The hydrogasification process is in the research stage and is not yet commercialized, although a few studies on the process were conducted from the 1970s to the 1990s. Ruby et al. (2008) have proposed a hydrogasification process which consists of a hydrogasification reactor, desulfurization and carbonizer reactors for CO_2 removal, and a methanation reactor. The advantages of hydrogasification will be discussed in the following section on catalytic steam gasification.

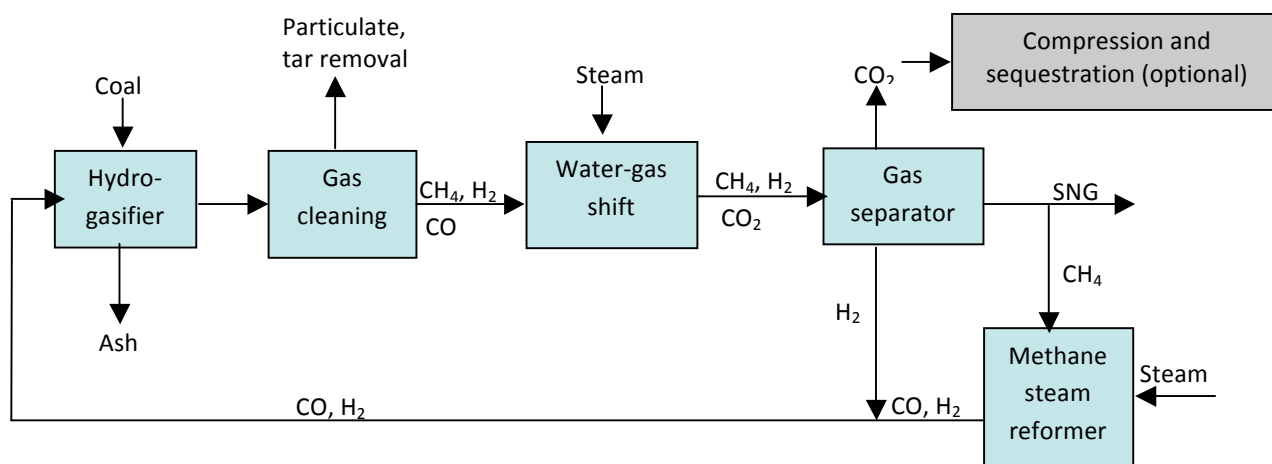


Figure 2. Hydrogasification process diagram

2.1.3. Catalytic steam gasification

Catalytic steam gasification is considered to be more energy-efficient than steam-oxygen gasification. However, the process is still under development. In this process, gasification and methanation occur in the same reactor in the presence of a catalyst (Figure 3). The energy required for the gasification reaction is supplied by the exothermic methanation reaction. CH_4 is separated from CO_2 and syngas (CO and H_2); the syngas is then recycled to the gasifier. The catalytic reaction can take place at a lower temperature (typically 650° – 750° C). The process was initially developed by Exxon in the 1970s using potassium carbonate (K_2CO_3) as a catalyst, but the process was not commercialized.

The advantages of hydrogasification and catalytic steam gasification are that they do not require air separation unit; hence there is less energy penalty for the process. Furthermore, the costs are lower, as

the gasification and methanation occur at a lower temperature. The disadvantages of catalytic steam gasification are the separation of catalyst from ash/slag and the loss of reactivity of the catalyst.

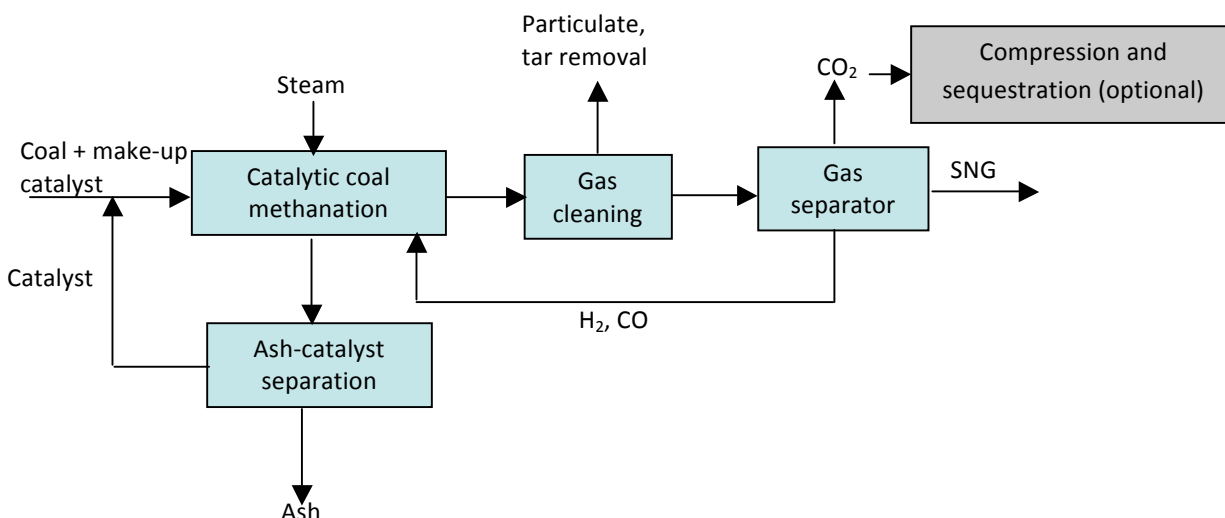


Figure 3. Catalytic steam gasification process diagram

2.2. Thermal Efficiency of SNG Plants

The thermal efficiency of an SNG plant employing the steam-oxygen gasification process varies in the range of 59% to 61%. A DOE study reported plant efficiencies of 60.4% for Illinois #6 (bituminous) coal and 59.4 % for Powder River Basin (PRB) (sub-bituminous) coal (NETL 2007). A University of Kentucky study calculated the efficiency of an SNG plant using bituminous Kentucky coal to be 60.1% without CO₂ capture and 58.9% with CO₂ capture (Gray et al. 2007).

The hydrogasification and catalytic gasification processes are thought to be more efficient than the steam-oxygen gasification process. The theoretical efficiency of these processes is estimated to be as high as 79.6% for hydrogasification and 72.7% for catalytic gasification (Steinberg 2005). Ruby et al. (2008) have estimated a thermal efficiency of 64.7 % for the hydrogasification process using low-ranked western (sub-bituminous) coal. The thermal efficiency of GreatPoint Energy’s catalytic gasification–based plant is reported to be 65% (Great Point energy 2008a).

2.3. Great Plains Synfuels Plant: An Existing SNG Plant

The Great Plains Synfuels Plant in Beulah, North Dakota, is the only commercial plant in the United States producing SNG from coal. The plant, which is owned and operated by the Dakota Gasification Company, a subsidiary of Basin Electric Power Cooperative, has been in operation since 1984. The key figures of the plant are listed in Table 1. The plant produces more than 54 billion standard cubic feet of natural gas annually using 6 million tons of lignite coal. The annual plant capacity factor is 90%–92%. The

plant also demonstrates CO₂ capture and sequestration. Since 2000, as much as 95 million standard cubic feet per day of CO₂ has been transported from the plant via a 205-mile pipeline to the Weyburn Oil Field in southwestern Saskatchewan, Canada, for enhanced oil recovery (EOR) (Perry and Eliason 2004). The CO₂ production capacity is more than 200 million standard cubic feet per day (Dakota Gasification Company 2008). In addition, the plant also produces fertilizers, solvents, phenols, and other chemicals.

The Dakota gasification plant uses 14 Lurgi Mark IV Gasifiers operating at 1,204° C. Each gasifier has a height of 12.2 meters and an internal diameter of 4.0 meters. The Rectisol process is used to remove H₂S and CO₂, and a nickel-based catalyst is used in the methanation process. The final gas is further cooled, cleaned, dried, compressed, and supplied to consumers through a pipeline.

Table 1. Key figures of North Dakota Gasification Plant

Great Plains Synfuels Plant-Key Figures	
Coal type	Lignite coal
In operation since	1984
Annual coal consumption (million tons)	6
Annual SNG production (billion standard cubic feet)	54
CO ₂ emissions from the SNG plant (tons/day)	6,080
Annual plant capacity factor (%)	90–92

2.4. Recent Developments in SNG

2.4.1. Research and development in SNG

Recently, the energy industry has shown considerable interest in the coal-to-SNG concept. General Electric Energy is working with the University of Wyoming to build a \$100 million advanced coal gasification research and technology center in Wyoming which will focus on the different aspects of converting Powder River Basin (PRB) coal to SNG. The proposed research center would build a scaled-down commercial power plant, which could be operational by 2010 (Farquhar 2008). The Arizona Public Service Company (APS) along with the Department of Energy and other partners are developing a hydrogasification process to co-produce SNG and electricity from western coals. The objective of the \$12.9 million project is to develop and demonstrate an engineering-scale hydrogasification process which can produce SNG at a cost of less than \$5/MMBtu and can utilize low-ranked western coal (NETL 2008). The Western Research Institute (WRI) is working on the development of a gasification process which uses counter-current cyclonic methods in a unique sequence that causes activated carbon char to react with synthesis gas, both derived from coal. The method does not require pure oxygen to produce the synthesis gas (WRI 2008).

The catalytic steam gasification process developed by Great Point Energy Inc. is considered to be a great advancement in SNG technology. The process involves a single reactor using a proprietary, recyclable catalyst developed in-house and made from abundant low-cost metals. The catalyst was developed with

the help of Southern Illinois University, the University of Toronto, and the University of Tennessee (Fairley 2007). The heat released in the syngas-to-methane step is sufficient to sustain the gasification, eliminating the need to fire up the reactions with purified oxygen. The process was demonstrated with a week-long pilot run in November 2007. The pilot plant for the process is a 60-foot-high gasifier with an internal diameter of 14 inches. A proposed large pre-commercial plant is expected to be operational by 2009. The price of pipeline-quality gas by GreatPoint Energy’s process could be less than \$3 per MMBtu (Fairley 2007). GreatPoint Energy Inc. and Peabody are working together to commercialize the technology with the goal of developing a coal-to-SNG plant at or near Wyoming’s Powder River Basin area (GreatPoint Energy 2008b).

2.4.2. Commercial SNG plants planned in the U.S.

Table 2 shows that there are at least 15 coal-to-SNG plants proposed in U.S., all in different stages of development. Some of these plants are also considering carbon capture and storage. For example, the joint ConocoPhillips/Peabody Energy project in the Midwest is considering CO₂ capture and storage for its mine-mouth facility (ConocoPhillips 2007). An Indiana Gasification LLC plant in southwest Indiana would demonstrate geologic CO₂ sequestration (Indiana Coal to SNG 2008). Secure Energy Inc.’s plant in Illinois would use 10% biomass for SNG generation.

Table 2. Proposed commercial-scale coal-to-SNG projects in the U.S.

Project Name/Owner	Location	Status	Capacity (BCF/yr)	Capital Cost	Year of completion	Remarks
Secure Energy Inc.	Illinois	Front-End Engineering and Design (FEED)	20	\$250 million	2009	The gasifier is 10% biomass-ready
Peabody Energy and Arclight Capital	Illinois	Proposed	35			
Power Holdings of Illinois LLC	Illinois	Pre-FEED	50	\$1 billion	2009	
Taylorville Energy Center (IGCC/SNG)	Illinois	Feasibility Study		\$2 billion		50% of CO ₂ to be captured
Global Energy	Indiana	Proposed				
GreatPoint Energy’s Pilot Project	Massachusetts	Pre-FEED				

Oswego SNG Project – TransGas	New York	Planned		\$2 billion	2010	
South Heart Coal Gasification Project (Great Northern Power Development, L.P. and Allied Syngas Corporation)	North Dakota	Feasibility study	36.5	\$1.4 billion	2012	¹ CO ₂ would be captured and used for Enhanced Oil Recovery (EOR) applications in future
SES/Consol Coal-to-SNG Project	West Virginia	Planned				
Peabody/ GreatPoint SNG Project	Location undecided	Planned				
ConocoPhillips/ Peabody Energy	Midwest	Feasibility Study	50–70			
Lockwood Project	Texas	Conceptual Design	65.7		2011	CO ₂ will be captured and utilized for EOR – fuel will be pet coke and biomass
Tondu’s Nueces Syngas Plant	Texas	Planned				
Peabody Energy	Wyoming	Proposed				

2.5. Use of Biomass for SNG

The use of biomass to generate SNG could be the most interesting scenario. SNG production from biomass—also referred to as “bio-SNG”—has advantages because biomass is carbon-neutral, and above all, CO₂ capture would generate negative carbon emissions. The challenges of using biomass instead of coal arise due to the chemical composition of biomass, the lower calorific value per unit of biomass compared with coal, and the higher moisture content of biomass. One of the issues associated with biomass gasification is tar formation. The seasonal variation in the biomass supply and moisture content could require large storage and drying capacities for commercial-scale biomass gasification units. Another possible way of utilizing biomass would be in a coal-biomass co-gasification process. Co-gasification could make it possible to install large-scale gasification capacity, which could be more commercially viable.

¹ Industrial Commission of North Dakota, 2007. Great Northern Power Development and Industrial Commission Announce Coal Gasification Project at South Heart. <http://www.gasification.org/Docs/News/2007/South%20Heart%20statewide.pdf>.

The concept of biomass-to-SNG is relatively new. The process components for coal and biomass should be similar, although there may be slight differences in the gasification and tar removal processes. The fluidized-bed gasifier may be better suited for biomass gasification as it can handle variations in size, density, moisture, and tar formation.

The Energy Research Centre of the Netherlands (ECN) has demonstrated SNG generation from biomass (Mozaffarian et al. 2003, 2004). In this process, indirect gasification is used, and both gasification and methanation are carried out at atmospheric pressure. The biomass is gasified in the riser of a circulating fluidized bed (CFB) and the remaining char is circulated to the combustor (downcomer of CFB). In this process, the heat required for gasification is supplied by char combustion in the combustor. Steam is used for gasification and air is used for char combustion. The lab-scale gasifier, developed in 2004, has a biomass capacity of 5 kg/h and operates at temperatures of 750° to 900° C (Zwart et al. 2006). Direct gasification was also tested, which uses oxygen and steam for gasification (bubbling fluidized bed) and operates at 850° C. The gas treatment in the integrated bio-SNG system consists of tar removal with organic scrubbing liquid technology, and sulfur and HCl removal with adsorbents.

Based on the experiments, an SNG system was optimized which consists of an indirect gasifier, a tar removal system which recycles tar to the gasifier, a gas cleaning reactor and shift, and a methanation combined reactor. The indirect gasifier working at 850° C produces nearly nitrogen-free syngas and a high amount of methane. The tars are recycled to the gasifier in order to increase efficiency, whereas the tar free syngas is cleaned from other contaminants (e.g., sulfur and chlorine). The clean syngas is fed to a combined shift and methanation process, converting the syngas into SNG. After methanation, further upgrading (e.g., CO₂ and H₂O removal) is required in order to comply with the desired SNG specifications. The overall net thermal efficiency is reported as 70% Low Heat Value (LHV) (approximately 64% High Heat Value [HHV]). Forty percent of the carbon of the biomass becomes part of the SNG and an equal amount of carbon is captured as CO₂. The remaining 20% of the carbon in biomass becomes as flue gas from the process (Zwart, 2008). The cost of the bio-SNG production proposed by the ECN and its sensitivity to biomass price are analyzed in sections 3.2.4. and 3.2.5.

3. Environmental Implications and Economics of SNG

As described earlier, steam-oxygen gasification is the only commercialized and operational technology. Henceforth, the environmental impacts and costs of SNG refer to steam-oxygen gasification. However, it should be noted that the higher a plant's thermal efficiency, the lower its CO₂ emissions will be. Therefore, CO₂ emissions from the hydrogasification and steam catalytic gasification processes should be lower than those of the steam-oxygen gasification process.

3.1. Environmental Implications of SNG

The coal-to-SNG process is capable of achieving very low sulfur emissions. The sulfur is emitted as hydrogen sulfide (H₂S) and can be removed by the acid gas removal (AGR) system. The acid gas (CO₂ and H₂S) can be separated in the Selexol or Rectisol process in a SNG plant. The H₂S can be utilized in a Claus

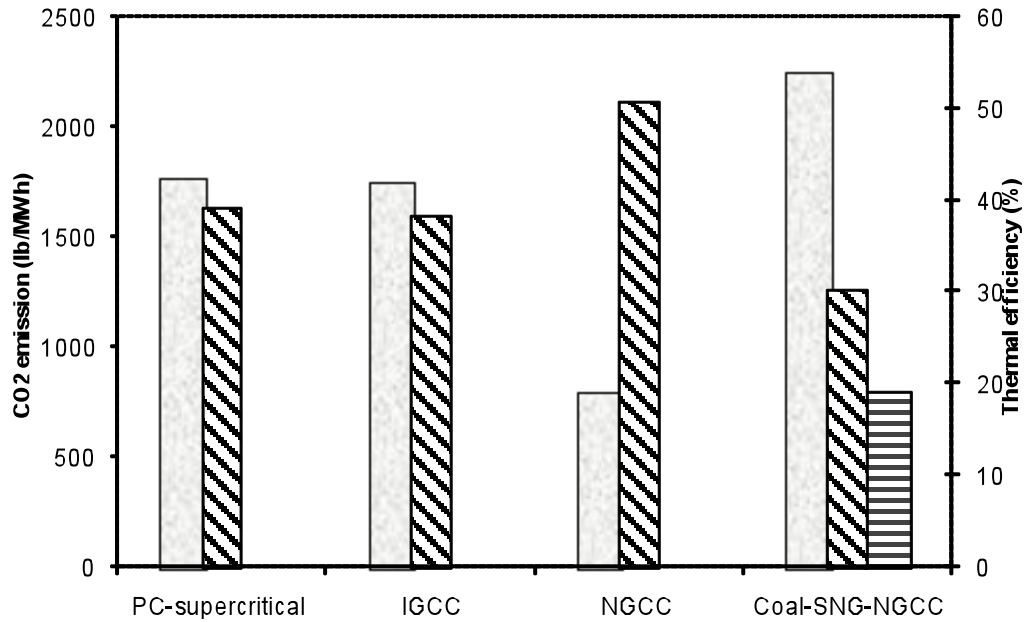
plant to generate elemental sulfur. Mercury can be removed in the water quench during the syngas cleaning. The removal level should be sufficient to meet the permitted emissions level. However, if required, a carbon bed could be used for additional mercury removal. NO_x emissions from the process would be very low; the only NO_x emissions would be from the boiler used to generate steam and power for the process. Considering that the sulfur is removed by Claus plant, the coal-to-SNG should be considered a clean coal technology.

CO₂ Emissions

CO₂ and H₂S are emitted from the acid gas removal plant. Separate streams of CO₂ and H₂S can be obtained from the AGR process. CO₂ is either captured or released into the atmosphere. Approximately two-thirds of the carbon content of the coal is converted into CO₂ in the SNG process and the remaining carbon becomes a component of SNG. CO₂ emissions would depend upon the type of the coal and the process used. CO₂ emissions calculated from a DOE study are approximately 175 lbs./MMBtu for bituminous Illinois coal #6 and 210 lbs./MMBtu for sub-bituminous Powder River Basin coal.

When comparing the CO₂ emissions caused by converting coal into SNG with the emissions caused by utilizing coal directly for power generation, it is assumed that the SNG is utilized in a natural gas combined cycle (NGCC) power plant for power generation. Figure 4 compares the CO₂ emissions per MWh of a supercritical PC boiler, an IGCC plant, and a coal-SNG-NGCC system using Illinois #6 coal. It is assumed that the net thermal efficiency of the NGCC power plant is 50.8%. The figure shows that CO₂ emissions are highest from the coal-SNG-NGCC power system. However, it is interesting to consider that CO₂ from the SNG plant is a byproduct of the process and that there is no additional cost associated with CO₂ separation. Moreover, the CO₂ from this process is obtained at high pressure. If the CO₂ emitted from the SNG plant is sequestered, CO₂ emissions from the coal-SNG-power cycle can be brought to the level of the NGCC plant. In that case, CO₂ emissions would be approximately 45% of the emissions of the IGCC or supercritical PC plants. Nonetheless, the thermal efficiency of the coal-SNG-NGCC system is lower than that of coal-based power plants (PC and IGCC).

Figure 4. CO₂ emissions from different power plant options using Illinois #6 coal (CO₂ emissions for supercritical PC boiler, IGCC, and NGCC are from NETL 2007b)



3.2. Economics of SNG

The DOE and the University of Kentucky report the costs of the individual components and the operation and maintenance (O&M) of an SNG plant. Figure 5 shows the percentage distribution of the equipment capital cost for the components of an SNG plant (Gray et al. 2007). The costliest part of the SNG system is the gasifier, which corresponds to about 21% of the total equipment cost, followed by the syngas cleanup system, which accounts for 15.8%. The air separation and compression components cost 11.3%, and the methanation reactor costs 11%. SNG could be generated in co-production with electricity, IGCC, or hydrogen. However, for the present economic analysis, it is assumed that the plant only produces SNG.

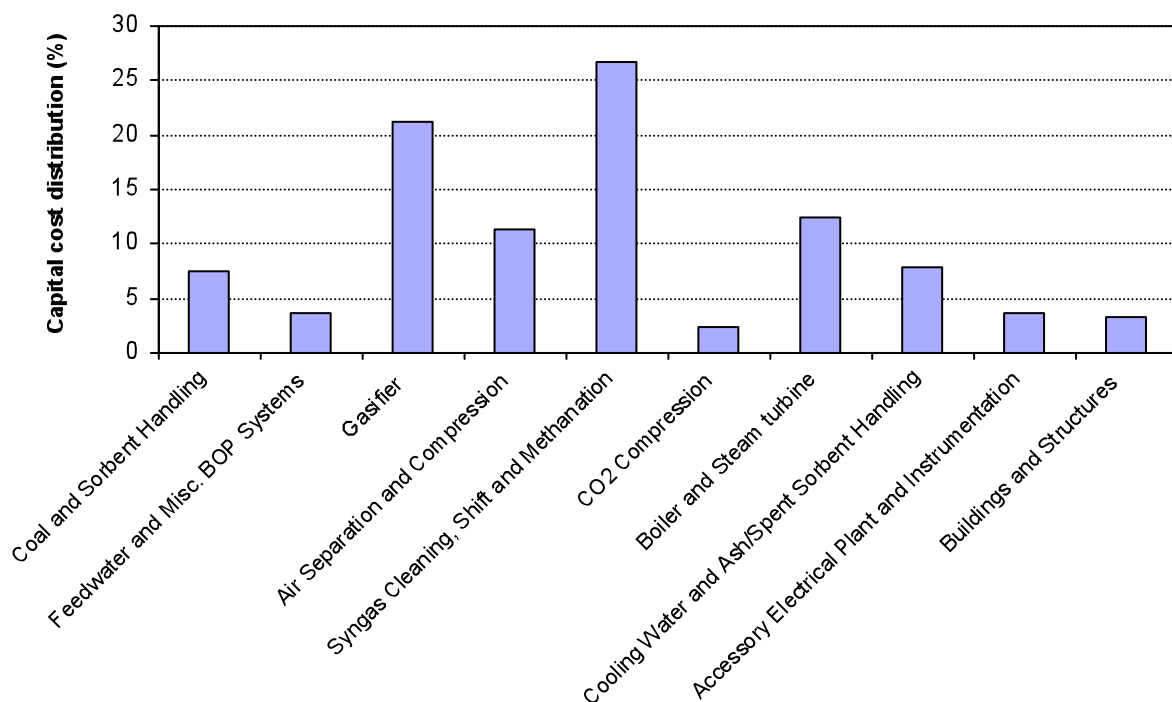


Figure 5. Distribution of the capital equipment costs of the individual components of an SNG plant

3.2.1. Cost of SNG

We calculated the levelized cost of SNG on the basis of the capital and O&M costs reported by DOE (NETL, 2007). A cash flow model is used to calculate the cost of SNG. The different assumptions in the model are provided in Table 3. The capital cost is updated to 2008 using the chemical engineering plant cost index. According to the index, the cost has increased by a factor of 1.173 since 2005 (CEPCI 2008). The levelized cost is for an industrial-scale SNG plant using Illinois #6 and PRB coal.

Table 3. Assumptions for the cost evaluation of SNG

Parameter	Value
Interest rate (%)	8.0
Expected return to equity investor (%)	12
Debt fraction (%)	60
Tax rate (%)	40
Debt term (years)	10
Plant life (years)	30
Construction period (years)	3
Depreciation schedule (years, accelerated)	15
Debt repayment rate (%)	15
Capacity factor (%)	90

3.2.2. Effect of coal type and coal price

Assuming that CO₂ is not captured in the process, the levelized cost of SNG is \$8.42/MMBtu using Illinois #6 coal and \$9.53/MMBtu using PRB coal. The coal prices are \$1.34/MMBtu for Illinois #6 coal and \$0.95/MMBtu for PRB coal. Note that although PRB coal is less expensive than Illinois #6 coal, the cost of SNG using PRB coal is higher. This is because Illinois #6 is a bituminous coal, while PRB is a sub-bituminous coal which generates more slag in the SNG process and therefore requires more costly slag-handling equipment. Another factor may be the lower efficiency at which the gasifier operates with lower ranked sub-bituminous coal.

Figure 6 shows the effect of the increase in coal price on the levelized cost of SNG. For example, an increase in the coal price by 100% increases the cost of SNG (without CO₂ capture) by 18.8% and 12.5% using Illinois coal and PRB coal, respectively.

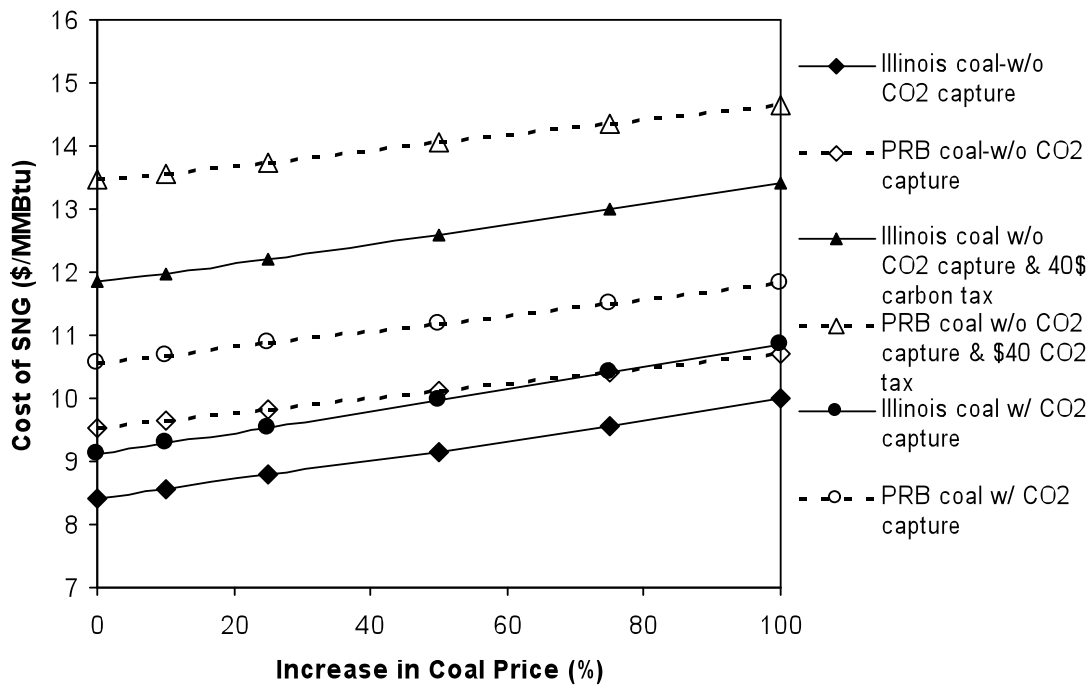


Figure 6. Effect of coal price on SNG cost

3.2.3. Effect of carbon price allowances and CO₂ sequestration on SNG cost

If the future climate policy in the United States restricts the CO₂ emissions from the industries, there would be carbon allowances for the CO₂ emissions. The carbon price allowance would increase the levelized cost of SNG. Figure 7 shows the levelized cost of SNG with different carbon allowance price. Higher the carbon allowance price, less economically viable SNG is. Since, CO₂ is a byproduct of the SNG process, it would be economic for the SNG producers to sequester CO₂ rather than paying the carbon allowance price. Additional cost in sequestering CO₂ in comparison to venting CO₂ would be in compressing CO₂ to the high pressure and loss of a small portion of the energy due to the process

modification. It should be noted that the energy penalty for compressing CO₂ is not as high as in the case of post-combustion CO₂ capture in power plants because CO₂ released from the process is already at a high pressure.

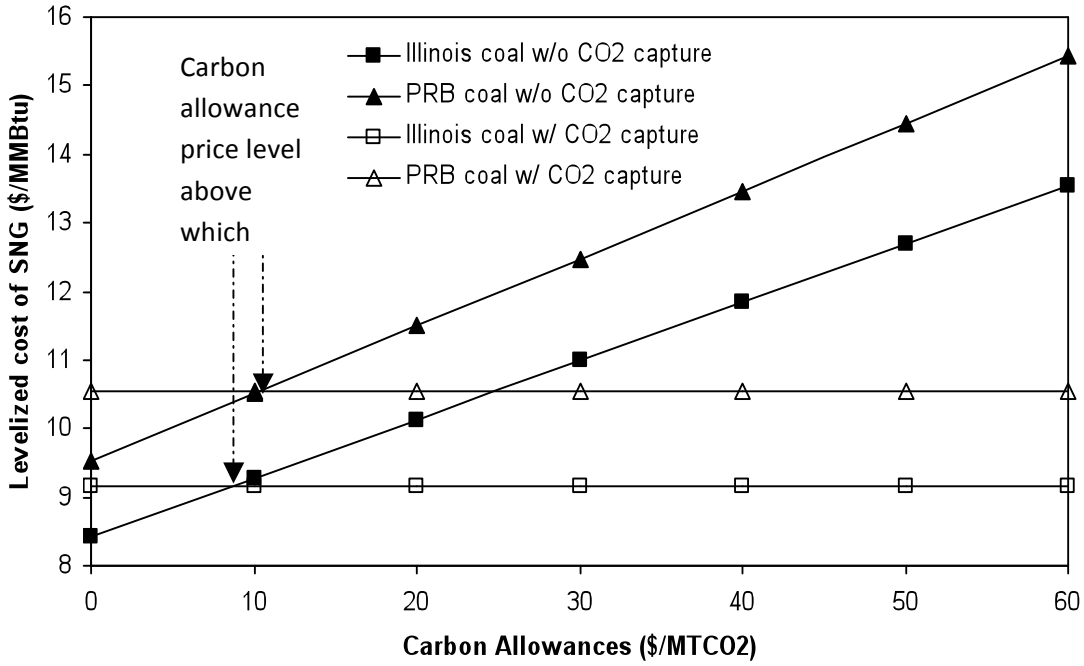


Figure 7. Effect of carbon allowances on the cost of SNG

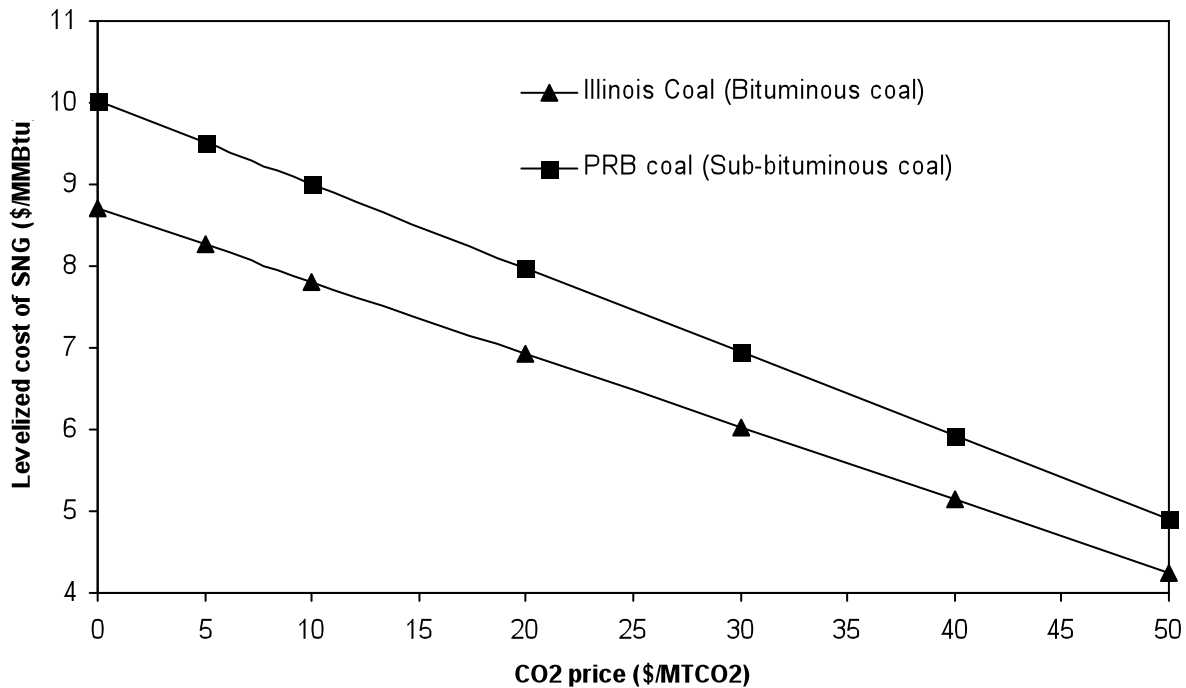


Figure 8. Effect of CO₂ price on SNG costs

SNG costs would become \$9.15/MMBtu for Illinois coal and \$10.55/MMBtu for PRB coal with CO₂ sequestration. The cost of CO₂ transport and sequestration was assumed to be 5\$/Mt. It was assumed that the SNG facility would be near the CO₂ sequestration site. Figure 7 shows that in the case of carbon allowances higher than \$9.5/Mt CO₂ for Illinois coal and \$10.5/Mt CO₂ for PRB coal, CO₂ sequestration is a more economic option than paying carbon allowances.

If CO₂ is supplied for enhanced oil recovery (EOR), then the SNG producer pays no sequestration costs. Figure 8 shows the effect of CO₂ price on the levelized cost of SNG. Higher is the CO₂ price, more economically viable would be the SNG.

3.2.4. Cost of bio-SNG

There are no commercial bio-SNG plants. ECN has estimated the cost of bio-SNG on the basis of their research facility (Zwart et al. 2006). The size of the plant, operating pressure, and biomass cost would decide the cost of the bio-SNG. The cost of bio-SNG decreases with higher pressure system and larger facilities. The results have shown that the plant operating at 7 bar pressure was cost effective compared to the plant operating at atmospheric pressure. However, in all the cases, the cost of bio-SNG was higher than the market price of natural gas.

3.2.5. Effect of biomass price

It should be noted that the cost of biomass varies greatly with geographical factors. We have evaluated the effect of biomass price on cost of SNG. A 341.21 MMBtu/h plant operating at 7 bar pressure was chosen for the analysis. The capital cost of the plant and the operating and maintenance cost was assumed to be the same as described by ECN (Zwart et al. 2006). The cost was updated for the year 2008 using chemical engineering plant cost index (CEPCI 2008). One Euro was assumed to be equal to 1.42 US\$. The assumptions to evaluate the cost of bio-SNG were the same as those described in Table 3.

Figure 9 shows the cost of bio-SNG at different biomass prices. Since biomass is carbon-neutral, if CO₂ is sequestered, carbon credits could generate addition revenue. The selling of CO₂ to EOR could generate additional revenue. The additional revenue from carbon credits or selling CO₂ for EOR would reduce the price of bio-SNG. An important result of this analysis is that for the bio-SNG price to be less than \$12/MMBtu, the biomass price should not exceed \$2.2/MMBtu. For the same price of coal and biomass the levelized cost of bio-SNG is \$11.2/MMBtu compared to \$8.42/MMBtu using bituminous coal. The difference between the costs will be reduced if we consider the cost of CO₂ credits due to carbon-neutral biomass.

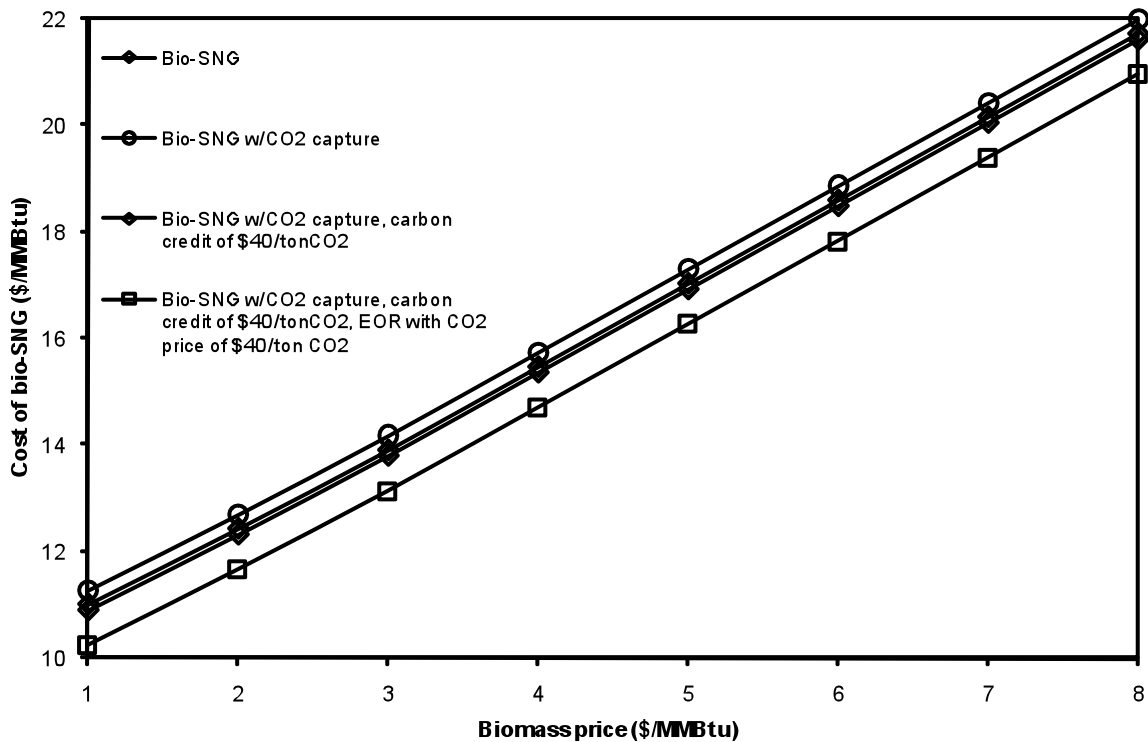


Figure 9. Effect of biomass price on the cost of bio-SNG

4. Conclusions

Steam-oxygen gasification, hydrogasification, and catalytic-steam gasification are the different processes that could be used to convert coal to synthetic natural gas. Steam-oxygen gasification is the only proven technology, while hydrogasification and catalytic steam gasification are thought to be more energy-efficient methods whose development could decrease the cost of SNG. There are at least 15 SNG projects planned in the United States under various stages of the development. Biomass could also be utilized for SNG production.

The process of converting coal to SNG produces CO₂ as a byproduct. Coal-to-SNG power plants would produce more CO₂ than would be produced by directly using the coal in power plants. If CO₂ is captured from the coal-to-SNG process, however, the CO₂ emissions from coal-to-SNG power plants could be equal to those from natural gas power plants.

The levelized cost of SNG is \$8.42/MMBtu for plants using bituminous coal and \$9.53/MMBtu for those using sub-bituminous coal. With CO₂ sequestration, SNG costs would increase to \$9.15/MMBtu for bituminous coal and \$10.55/MMBtu for sub-bituminous coal. It would be more economical, however, to sequester the CO₂ than to pay carbon price allowances in the event of a future carbon-pricing scheme. Selling CO₂ for enhanced oil recovery would make coal-to-SNG more economically viable. Bio-SNG is an interesting example of using carbon-neutral fuel for the generation of SNG. However, for the bio-SNG price to be less than \$12/MMBtu, the biomass price should not exceed \$2.2/MMBtu.

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