Substitute Natural Gas Feasibility Study

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Abstract

High natural gas prices and domestic energy security concerns have led to a resurgence in interest in substitute natural gas (SNG). This technology, which dates back several decades, is currently only utilized in one location in the U.S., though perhaps a dozen more are on the drawing board. This study evaluates the economic climate for plants in the U.S. Major factors in SNG viability such as coal and gas prices, and construction costs, are examined to set the stage for the analysis. Current technology and policy is then used to evaluate SNG in the context of recent natural gas prices. Two major viewpoints were considered in this sensitivity analysis – the savings to the end user from locking in the contract price, and the returns to the developer of the plant. In order for an SNG plant to be built, both parties must have a reasonable certainty of economic benefit.

The results indicated a marginal environment for the long-term contracts that are necessary to finance these plants. Consumer savings scenarios changed drastically during a 3-month period of this study. Initial projected savings of over 30% fell to a loss of 9%, far short of the minimum 25% estimated savings required. This was a result of a significant drop in gas prices, and served to illustrate the consumers need for a large discount over spot prices to mitigate their price risk. As far as developers are concerned, an $8 price of gas was determined to be financially marginal, with returns of 8% predicted. Rising plant costs would tend to put upward pressure on this price point, driving even higher minimum selling prices.

In addition, if one adds the consumers need for a 25% discount to the developers minimum price level of $8, it appears that at least $11 gas is required to satisfy both parties. The current climate of $8 gas thus look unfavorable to the development of SNG contracts, with the exception of potential site locations in areas of high gas prices, cheap coal, or more direct access to end users with the increased value capture that entails. While concerns about high gas prices and energy security will not likely go away any time soon, the time is not yet ripe for SNG development.

Table of Contents
I. Introduction……………………………………………………………………………………………………..3
II. Background………………………………………………………………………………………………...4
   A. Coal gasification and methanation process………………………………………………………..6
   B. Coal prices…………………………………………………………………………………………….7
   C. Gas prices…………………………………………………………………………………………….8
   D. Capital costs………………………………………………………………………………………….10
   E. Long term SNG off-take contracts and gas futures……………………………………………….12
III. Methods………………………………………………………………………………………………………..14
IV. Results…………………………………………………………………………………………………………17
   A. Consumer savings sensitivity analysis……………………………………………………………..17

Howard B Henward
Page 2
12/01/2008
I. Introduction

Recent concerns in the U.S. about volatile natural gas prices, declining gas production and domestic energy security have sparked a revival in interest in developing reliable domestic sources that are decoupled from the world oil market. Substitute natural gas (SNG) presents one such opportunity - it can be produced from cheap plentiful U.S. coal supplies, and has costs driven by coal prices and plant construction, rather than international energy markets.

The major cost drivers of SNG have been examined, along with the respective needs of gas consumers and plant developers, to determine if SNG makes economic sense. In short, developers need a minimum required selling price (RSP) to make a decent return, while consumers demand a low level of price risk
on a long term contract and thus require a discount to expected spot price to cover volatility.

The specific questions analyzed in this study are as follows. Firstly, what prices are consumers willing to pay for SNG? Secondly, what price must developers sell at to make money? Thirdly, if these prices do not overlap, then under what circumstances might this situation change?

Current operating conditions are examined only, with a discussion reserved for other scenarios. *This means no biomass, carbon capture, carbon policy or new technologies will be incorporated in the quantitative analysis.* Biomass is unproven and problematic because of the difficulty in gathering it, as well as the feedstock's variability and caustic nature when gasified. It does, however, have great potential as a relatively widely distributed fuel that is carbon-neutral, and research is continuing to optimize gasifiers to run on biomass. Carbon capture and sequestration (CCS) and carbon policy go hand in hand - without a price on carbon through a tax or cap and trade system no plant will willingly absorb the extra cost, and a carbon price is not immediately imminent or estimable. The CCS process is proven and demonstrated, though, and by nature SNG plants are carbon capture ready, because of their concentrated CO2 waste stream (Dakota Gasification 2008). Lastly, new technologies are promising, but have yet to be commercially demonstrated. These include cost-reducing breakthrough technologies which are not yet proven on a commercial scale, one of which is discussed later in this paper (figure 14).

The purpose of this study is to determine if SNG plants are currently economically feasible in this country. To that end, we examine the major driving forces, including capital cost, investor return, natural gas price trends, coal prices trends, expected consumer savings under long term contracts, the gas value chain, and the repercussions of carbon policy e.g. carbon emissions and sequestration. Through qualitative analysis of the current energy market and quantitative analysis of consumer savings and investor returns, we demonstrate
that SNG will not play a major role in U.S. natural gas supply in the foreseeable future.

II. Background

Substitute natural gas is functionally identical to natural gas and is derived from the coal gasification process (GTC 2008). The SNG is nearly pure methane (CH4) and is used in the same applications as natural gas - heating, industrial use, power generation, fertilizer production, etc. However, unlike natural gas, SNG can be produced at a plant and distributed via pipeline at nearly any location, contingent upon the availability of affordable feedstock (usually coal, though pet coke and biomass can be used) and a nearby market. Natural gas, on the other hand, is produced where it naturally occurs and often transported hundreds or thousands of miles to market. The spot market price of SNG is the same as regular natural gas, though the drivers behind SNG costs are comprised of the capital costs for plant construction and the cost of coal, whereas the natural gas market is linked to the international oil price and regional availability (Southwest Economy 2008).

A great deal of interest arose in coal-to-gas technology in the 1970s as a result of the oil crises and a perceived peak in gas production. The U.S. government teamed up with industry to investigate the viability of domestically produced gas from the nation’s abundant coal supplies. The intention at the time was to encourage the development of a natural gas supply that was not linked to unreliable and volatile international markets, which might alleviate the rising domestic gas price. The effort culminated in the construction of the Great Plains Gasification Plant in North Dakota, completed in 1984. By the time of the plant’s opening, gas prices had plummeted because of government deregulation and an oil glut, and construction costs had soared beyond the initial estimate (KY Study 2007). Much of the technical studies and engineering data related to SNG were generated during the 1970s to early 1980s, at which point cheap natural gas and withdrawal of government support dampened any further investment (Ibid).
The last five years have witnessed a resurgent interest in SNG. This is primarily due to increased concerns about oil and gas costs, energy security, and the advancement of carbon capture and sequestration technology. There have been several major proposals for SNG plants in recent years, with various studies published by government and industry organizations, as well as several universities (Indiana SNG 2006, Power Holdings 2006, Reuters 2008, Syngas Refiner 2008, KY Study 2007, GL Group 2007). However, the Great Plains plant remains the only plant in operation in this country, despite the presumed attractiveness of a domestic source of energy that is decoupled from the world oil markets. The numerous proposals and studies have not led to a construction start on a significant new plant to our knowledge. Recent events have not had a positive effect on SNG feasibility - witness the skyrocketing construction and commodity costs of recent years, as well as the volatile and apparently dysfunctional capital markets of the past few months (figure 4). Rising costs and lack of financing have had a decidedly negative effect on the current outlook for SNG. This study will attempt to address the feasibility of SNG plant construction in this country by examining the major market forces and stakeholders involved in the coal-to-gas arena.

To that end, this section reviews the major components of the coal-to-gas arena. First, a brief description of the coal gasification process is provided. Second, historical coal prices and trends are discussed, to establish what impact this feedstock may foreseeably have on SNG costs. Third, natural gas prices are examined, as they determine the competitiveness (or lack thereof) of SNG, and are a basis for subsequent analysis. Fourth, recent trends in commodity, construction and financing costs are mentioned, as these have a real and immediate impact on whether SNG plants can get built in the first place. Finally, futures contracts and long-term contracts are explained, to set the stage for the consumer savings model and familiarize the reader with the time horizons and risks associated with SNG. By understanding the major forces at work, the reader will then be well poised to dive into the methodology of this report.
Coal gasification and methanation process

Coal gasification is a "pre-combustion" process, in that the coal is not burned, instead it is partially oxidized (GTC 2008). The process varies from "dry feed" to slurry-fed, though the latter type is more common. In the slurry process, the coal is ground up into fine particles, and then mixed in a particular ratio with water. The resultant slurry is then fed under pressure into a gasification chamber, in which the slurry reacts with pure oxygen and high pressure super-heated steam. The resultant synthetic gas, or syngas, is comprised mainly of hydrogen and carbon monoxide. The gas then is exposed to water in a gas quench system, which sprays water on the gas to remove particulate matter and other impurities. The gas then passes through a "shift" process in which water is combined with carbon monoxide to increase hydrogen and produce carbon dioxide \(\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2\). The gas is then scrubbed of sulfur and passed through a methanation reaction, which reacts with the remaining carbon monoxide and hydrogen to produce methane and water \(\text{CO} + 3\text{H}_2 \rightarrow \text{CH}_4 + \text{H}_2\text{O}\). The methane is then dried and compressed, and is ready for use (Ibid). There are many additional steps to this process, but this serves as a general overview.

Coal Prices

The U.S. has the largest coal reserves on earth - the DOE estimates at least 225 years' worth at today's consumption levels, and the term "Saudi Arabia of coal" has been used often (Energy Information Administration (EIA) 2007). As far as prices go, they have been remarkably steady over the last 50 years, with noticeable peaks during the oil crises of the 1970s and the general commodity surge of the last 5 years (figure 1). Traditionally, U.S. coal producers have simply increased production to meet higher demand, and price spikes have been associated with the imbalance of supply and demand during the time necessary to ramp up output. In general, coal prices have held steady or declined in real terms over time, with the exception of the price spike during the oil crisis of 1975-1983 (see figure 1). Thus, the U.S., with its vast reserves and world class coal mining
companies such as Peabody, is unlikely to face prolonged periods of high coal prices any time in the near future, especially in comparison to coal’s historically volatile cousins, oil and gas (Peabody 2008). This means that feedstock prices for SNG should be manageable in the foreseeable future.

Figure 1: Coal Prices - generally declining over time

![Blended Historical Coal Prices](image)

Gas Prices

SNG prices are identical to natural gas prices, and thus SNG feasibility depends on sustained robust gas prices. Gas is used for power generation, heating and industrial/chemical applications. Prices normally increase in winter as heating demand rises, but may also increase in summer as power demand is strained by cooling systems. Natural gas prices have been historically volatile, perhaps more so than oil, because of the lack of a global market - the vast majority of U.S. natural gas has come from domestic production and from Canada (EIA 2008). Natural gas has risen in sympathy with oil prices, as they are to some degree
substitutable (oil for heating, gas for transport), though mainly rising oil prices tend to provide some cover for gas price hikes. In addition, domestic supply disruptions (such as hurricanes - see 2005 spike in figure 2) and local demand fluctuations (such as a cold New England winter) have created regional price spikes. Prices have been on a general upward trend since 2000, with the past year representing an exceptionally volatile period (see price spike in June, Figure 3). Prices are generally expected to return to their 5 year rough average of $6-$8 (see Figure 2).

Figure 2: Long Term Gas Prices - expected to transition to $6-$8

Figure 3: Short Term Gas Prices - highly volatile
Liquefied natural gas (LNG) has not played an important role in the U. S. market nor is it expected to do so in the next decade. LNG producers receive far higher prices in Europe and Japan, and often choose to send LNG ships to the U.S. as a market of last resort after all other demand has been sated (Cambridge Energy Research Associates (CERA) 2008). This situation is not expected to change until domestic gas prices rise to international levels, which would likely imply some form of production decline in the U.S., which is not likely in the near future because of the surge of "unconventional" sources.

Fortunately, while conventional U.S. and Canadian sources of natural gas have been declining for some time, so-called "unconventional sources" are on the rise. The three main unconventional sources are tight sands, gas shales, and coal bed methane. The term "unconventional natural gas" implies an untried technology that may be developed some time in the future. In fact, "unconventional" gas sources currently account for roughly 40% of U.S. natural gas production and their share is rising fast as conventional fields rapidly deplete and LNG fails to take off in this country (Natural Gas.org 2004). They have largely been termed unconventional because they are not as easy to extract and/or they are more expensive. These definitions may change as technology develops in the near future. In order for the U.S. just to maintain its current natural gas consumption, the share of unconventional sources must necessarily rise to over 50% in the next few years (Ibid). The major players in the industry, such as Chevron, Exxon and the specialty gas firms like Chesapeake, all have major plays in unconventional (Chesapeake 2008, Chevron 2008, Financial Post 2008).

The definition of unconventional will likely shift as conventional sources become depleted and mainstream production increasingly relies on the three sources detailed earlier. At that point, the new unconventional sources will likely include geo-pressurized zones, which are very deep high pressure clay formations, and methane hydrates, which are methane molecules trapped in frozen water located in permafrost or on the sea floor (Natural Gas.org 2004). These two resources alone potentially dwarf the current unconventional sources.
by up to two orders of magnitude, and undermine any arguments of peak gas production (Ibid).

**Capital Costs**

Recent commodity, construction and financing cost trends have all been unfavorable to SNG recently. The prices of basic commodities such as steel, copper and aluminum have shot skywards in the last 5 years, largely owing to an unexpected surge in demand from developing countries, such as China (figure 4). This, in turn, has pushed up construction costs on major infrastructure investments, such as power plants and refineries (see figure 5 for CERA's downstream capital cost index which is used for refineries and is the closest proxy to an SNG plant). Projects that had been slated to begin during this period had to be reassessed and sometime cancelled or postponed due to uneconomic capital costs (none of the proposed plants in this study have been built to the author's knowledge). This study would argue that costs have risen even further in reality because of material scarcity issues and delays from skilled labor shortages, and these higher estimates are used in the SNG plant cost (table 4). Supply shortages and a skilled labor scarcity have exacerbated the rise in capital expenditure estimates, as further delays mean ever-increasing costs (Clean Air Task Force 2008).

Project finance costs have increased since 2005 as a result of interest rate changes and the recent uncertainty in the capital markets. Loan guarantees from the DOE are now essential for viable plant financing (US DOE 2008). Whereas the borrowing spread (over Treasuries) with a DOE guarantee is 75-100 basis points, the spread without a DOE guarantee is up to 700 basis points (Indiana Coal 2006). In today's climate of seized-up capital markets, in which banks themselves cannot attain loans, and the VIX (volatility index) is near all-time highs, attaining finance or equity investors would be a Herculean challenge. In the long term, borrowing costs are high because of technology risk, enormous capital requirements, and project time and cost uncertainty.
Figure 4: Commodity Price Trends - everything on the rise recently

Figure 5: Construction Cost Trends - massive recent cost escalation
A description of long term SNG off-take contracts and gas futures

What are futures and off takes?

Table 1: Futures and Off take Agreements - uses and features

<table>
<thead>
<tr>
<th>Contract type</th>
<th>Description</th>
<th>Use</th>
</tr>
</thead>
<tbody>
<tr>
<td>Futures contract</td>
<td>Method of hedging or speculating</td>
<td>Hedge exposure to gas price collapse/rise</td>
</tr>
<tr>
<td></td>
<td>Account balance updated as spot market price shifts</td>
<td>Hedge exposure to coal price rise</td>
</tr>
<tr>
<td></td>
<td><strong>No physical delivery</strong></td>
<td>Inflation hedge</td>
</tr>
<tr>
<td></td>
<td><strong>Up to 12 year span</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td><strong>Used by varied companies and investors</strong></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Highly liquid in near term</td>
<td></td>
</tr>
<tr>
<td>Off take agreement</td>
<td>Guaranteed contract price</td>
<td>Secure cash flow for debt repayment</td>
</tr>
<tr>
<td></td>
<td><strong>Physical delivery of product</strong></td>
<td>Secure low interest debt</td>
</tr>
<tr>
<td></td>
<td><strong>Two party agreement, usually utilities and generators</strong></td>
<td>Lock in returns</td>
</tr>
<tr>
<td></td>
<td><strong>Up to 30 year span</strong></td>
<td>Establish client relationships</td>
</tr>
<tr>
<td></td>
<td>Illiquid</td>
<td>Garner political and community backing</td>
</tr>
<tr>
<td></td>
<td>May vary greatly from spot market</td>
<td></td>
</tr>
</tbody>
</table>

SNG off-take contracts are essential to building an SNG plant. These contracts basically provide for a fixed amount of SNG production (often 100% of the plant’s expected output) to be sold to a pipeline company or utility for a fixed price for 30 years, indexed to inflation and sometimes coal extraction costs (Indiana SNG 2006, Power Holdings 2006). This guaranteed cash flow is essential to receiving lender financing on these risky, capital intensive plants. Without financing, the larger upfront cash outlay and the lower unlevered returns may serve to deter a potential SNG developer. The DOE requires these contracts as a precondition to the extension of its low cost clean coal subsidized loans (DOE 2008).

Futures contracts, on the other hand, are market based and are utilized to hedge or speculate on future movements in the gas market. A utility might buy futures to protect against upward price swings for its natural gas fired power facilities, while a gas speculator might want to attempt to profit from a potentially
unexpectedly cold winter. Futures are the best comparable to long term off-takes, in that they are the only other method by which one can lock in gas prices years down the road, and also serve to put a number on the market’s bet on where gas prices are trending (see table 1). Futures prices tend to project today's prices forwards in a seasonally adjusted manner, with the assumption that futures price trends are already incorporated in the current spot price (see figure 6). However, the futures prices are often quite different from the actual settled spot prices, and this reflects the extreme difficulty of predicting the various factors, including natural events like severe weather, that influence price (see Katrina-related 2005 price spike, figure 7). That said, futures are the most viable alternative by which one may lock in long term gas prices, and this analysis will use them as a comparison for the consumer looking forward from a point in time towards the future.

Figure 6: Short Term Futures Pricing - moderate price movement expected
Figure 7: Difference between Futures and Spot - significant discrepancy

Futures Prices vs. Spot Prices

III. Methods

Given the current state of demand, capital costs, policy, technology etc., a model of consumer savings under long term contracts has been generated, using gas futures markets to determine a baseline scenario under which consumers may stand to gain or lose under different negotiated long term contracts. This serves to illustrate the end user's need for a significant discount to spot market prices, in order to protect against long term price volatility.

Investor returns are also examined using a pro-forma developed for SNG plants. The gas prices acceptable to the end user are compared on the price/return graph to examine investors' internal rate of return (IRR) levels under the contract terms determined previously. This serves to illustrate the poor returns that can be expected for investors at today's prices.
The analysis starts by developing a 30-year price baseline, generated by statistical forecasting from 12 years of current gas futures data. The upper and lower confidence intervals function as the upper and lower gas price scenarios. These scenarios, including the baseline forecast, are displayed in terms of the total 30-year savings expected for the end user under different gas contract prices, escalated for inflation over that period. In effect, the futures market is modeled to determine price scenarios, which are then compared with a locked-in contract price over the same period. The cumulative differences between the expected spot price (represented by the futures market forecast) and the contract price over 30 years are listed in the output tables 2 and 3. This savings model is run using futures data from June and late September. The drastic drop in prices during this time affords an opportunity to analyze SNG at a historically anomalous price as well as a high, though more reasonable price. Should SNG be determined unfeasible at a price above 95% of the 14-year historical range of gas (see figure 8), it is unlikely to be feasible in the near term.

Figure #8 is a historical cumulative frequency table of gas prices for the past 14 years. The price of $13 in June is above over 95% of past prices, while the September price is above approximately 90% of past prices, despite the sizable drop to $8. This figure serves to put the two price scenarios modeled in this study in context. The September price, though lower than recent highs, is still quite high historically, and it is telling that it is the minimum RSP quoted in studies, including the Kentucky Study. This means that a high gas price of $8 (by historical standards) is the base price needed for SNG feasibility (KY Study 2007). This is intended as a hypothetical sensitivity analysis, and is not a prediction of future gas prices - a risky occupation at best.

The volatility during this period (see figure 3) will also convincingly illustrate the risk associated with long term contracts. The inspiration for this model came from the proposal for the Indiana SNG plant, which claimed to offer an average estimated savings of $3.7BN to the consumer over 30 years at an annual output.
of 40 BCF, based on a Carnegie Mellon study (Indiana Coal 2006). In this case, the results dramatically display the fluctuations in estimated savings that a few months can bring in the volatile natural gas market, and thus the consequent need for a large consumer discount to expected spot prices in order to manage their price risk.

Figure 8: Historical Gas Price Probabilities - recent prices anomalous

The analysis then moves on to examine the interplay between the gas contract price and the returns to the plant developer. A pro-forma of SNG plant IRR versus natural gas prices is utilized for this purpose. The pro-forma uses many of the assumptions of the Kentucky study, of which the major ones are listed here.

1. 85% plant availability
2. 100% Equity
3. 20 BCF annual production
The spreadsheet attempts to encapsulate the average plant scenario in the study, and then develop a sensitivity analysis of varying plant costs and gas prices, to display their impact on investor return. The received price of gas is equated with the contract price, as the majority of recent plant proposals have involved sales of 100% of output through fixed 30-year contracts. The capital costs relevant to the model are estimated based on a meta-analysis of current and projected plants, updated to the present using a 35% annual common cost inflator (table 4). Thus, while the plant size and operating features are modeled from the study, the plant costs are not. The expected result for developer returns in the contract price range that is feasible in today’s market is an IRR that is unacceptably low to an equity investor.

IV. Results

Consumer Savings Sensitivity Analysis

The graph below (figure 9) shows the actual futures prices for 12 years forward as of June 24th in blue, with red indicating the projections for another 18 years along a base, high and low price scenario out to 2038. The purpose of the projection was to develop a comparable to a 30 year off take agreement. The solid black lines represent a fixed contract price indexed for inflation and extending outwards to 2038. The difference in prices between the contract prices and the futures gas price scenarios were tallied up and inserted into table 2 to display how consumers might have fared (saving versus loss) over the 30-year term of the contract. There is a large difference in consumer savings (though all are positive in the June scenario) between differently priced contracts, both of which may have seemed reasonable at the time, and also within the price scenarios (see table 2). A consumer utilizing this model in June would have been wrong to assume a savings based on any likely price trend, as the subsequent graph (figure 10) of September prices will show. Again, these scenarios are from the perspective of a gas consumer standing at a point in time and looking to lock in prices, while examining where prices may head beyond the term of the 12-year futures.
Table 2: Consumer Savings as of June 24th

<table>
<thead>
<tr>
<th>Market Prices</th>
<th>$8 Contract Price</th>
<th>$10 Contract Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Forecast</td>
<td>30.2% savings $3.0 BN</td>
<td>12.7% savings $1.6BN</td>
</tr>
<tr>
<td>Low Price Scenario</td>
<td>25.3% savings $2.5BN</td>
<td>6.5% savings $800MM</td>
</tr>
<tr>
<td>High Price Scenario</td>
<td>33.4% savings $3.3BN</td>
<td>17.4% savings $2.2BN</td>
</tr>
</tbody>
</table>

The situation in September is markedly different - even at the lower $8 price contract, the consumer stands to make a considerable loss on a long term agreement (figure 10). An $8 contract in June would have been estimated to save $3BN, but would now be expected to cost the consumer $861MM over the life of the contract (table 3). The corresponding percentage savings difference is a 30% gain to the consumer in June versus an almost 9% loss to the consumer in September. Clearly a consumer would not enter upon a fixed 30 year contract for $8 at this time, and would insist on a lower price to cover their risk, a price at which SNG is not feasible. Thus, all else constant, no deal would be made and no plant constructed in this recent scenario.
Figure 10: Consumer "Savings" Model as of September 26th

<table>
<thead>
<tr>
<th>Market Prices</th>
<th>$8 Contract Price</th>
<th>$10 Contract Price</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base Forecast ($8)</td>
<td>8.7% loss <strong>$861MM</strong></td>
<td>Not feasible</td>
</tr>
<tr>
<td>Low Price Scenario</td>
<td>14.1% loss <strong>$1.4BN</strong></td>
<td>Not feasible</td>
</tr>
<tr>
<td>High Price Scenario</td>
<td>4.1% loss <strong>$400MM</strong></td>
<td>Not feasible</td>
</tr>
</tbody>
</table>

Plant Cost Figures

In Table 4, the costs of the one existing plant and various proposed plants were adjusted to the present day and used to determine a price per unit of output. We used a 2% annual inflation rate to get 2008 dollars on the Dakota project. For the more recent plants, a 35% year on year cost increase estimate was based on an interpretation of the IHS downstream capital cost index and “Syngas Refiner” 3/1/08 report (Syngas Refiner 2008). The Peabody plant proposal is given a ½ year adjustment of 17.5%. Power Holdings may have used more out of date plant cost estimates, and more conservative IRR requirements or capital structure, and its costs are considered an outlier. The pro-forma model of investor return uses...
the Kentucky study production level of 20bcf, and this model is used in the next analysis (figure 11). Therefore, the cost per bcf is as follows: 20bcf, thus 20 X $60MM/bcf = $1.2BN. Cost vs. size depends on financing costs (which increase costs with size) versus economies of scale (which lower costs with size) and are assumed to be on a straight line basis in this study, for want of clear evidence either way. In all cases, the plant costs originally given are substantially out of date because of the massive run up in construction costs in recent years. While the average plant size proposed is 40-50bcf, the pro-forma is based on 20bcf, and thus the expected cost is adjusted accordingly, per the calculation above.

Table 4: Updated SNG Plant Costs

<table>
<thead>
<tr>
<th>Plant name</th>
<th>Actual plant costs ($BN)</th>
<th>Current plant cost ($BN)</th>
<th>Output (bcf)</th>
<th>Unit cost MM/bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dakota Gasification</td>
<td>$2.1 (1984)</td>
<td>$3.4 (current $)</td>
<td>54</td>
<td>$63</td>
</tr>
<tr>
<td>Indiana Gasification</td>
<td>$1.7 *** (in 2007)</td>
<td>$2.3 adjusted</td>
<td>40</td>
<td>$58</td>
</tr>
<tr>
<td>Power Holdings (Ill)</td>
<td>$1.0 *** (in 2006)</td>
<td>$1.8 adjusted</td>
<td>50</td>
<td>$36</td>
</tr>
<tr>
<td>U. Kentucky Study*</td>
<td>$1.0 * (in 2007)</td>
<td>$1.4 adjusted</td>
<td>24</td>
<td>$56</td>
</tr>
<tr>
<td>Peabody (KY)</td>
<td>$3.0 *** (last fall)</td>
<td>$3.5 adjusted</td>
<td>~60</td>
<td>$59</td>
</tr>
</tbody>
</table>

Average range of cost = $56-$63MM/bcf
Average plant size = 40-50bcf

Average of three cases, cost accelerated in line with prior 2 plants ** Capital costs written off ***
35% year on year cost inflator
Investor Return vs. Consumer Savings

The graph in figure 11 is based on the assumptions of the University of Kentucky study and is an output of a pro-forma developed to model plant cost vs. return. Using the plant cost estimates developed in the prior section (table 4), the relevant cost for the University of Kentucky plant is determined, and the corresponding internal rates of return, per the contract costs of $8 and $10 modeled in this study, are circled in yellow. The graph indicates that, for a given output, higher costs equal lower returns, while higher received gas prices equal higher investor returns. The rates of return for investors and projected savings for consumer are then combined in table 5 below, to indicate respective returns and savings at different price levels. The last part of the table adds the expected consumer discount to the minimum required selling price for the investor to come up with a possible minimum natural gas Henry Hub market price for the feasible production of SNG.

Figure 11: Investor Return vs. Plant Costs
V. Discussion

SNG is often discussed in terms of the price of natural gas necessary for a SNG plant to be viable. This has recently been quoted in the $6-$9 range, and is usually associated with the acronym RSP, for required selling price (KY Study 2007, NETL 2004). This term is misleading, however, as the price that a SNG producer actually receives will be negotiated with the utility or municipality that agrees to purchase the production of the plant. In recent plant proposals, such as Indiana SNG, a savings of over 25% of the expected spot price was built into the 30 year off-take agreement between the plant and the three utilities that were going to purchase its production (Indiana Coal 2006). In the consumer savings scenarios modeled in this analysis, a 25% discount to expected spot, in the $8 contract scenario, still comes out slightly in the red in the September model after the major price decline. While this extreme volatility may not be the norm, it does make a case for a 25% discount as the minimum needed to reduce risk sufficiently to secure a 30 year contract. A gas consumer simply needs to be compensated (through expected discount to spot prices) for the added risk of taking on a 30 year contract - a compensation that apparently outweighs the reduced price volatility that they receive, the pricing of which is beyond the scope of this analysis. Unfortunately, because of the perceived risk and novelty of these projects, most major recent plant proposals (table 4) have included these

<table>
<thead>
<tr>
<th>Gas price contract</th>
<th>Developer IRR (Unlevered)</th>
<th>End user savings</th>
</tr>
</thead>
<tbody>
<tr>
<td>$8</td>
<td>~8%</td>
<td>25.3-33.4% (6/24)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>4.1-14.1% Loss (9/26)</td>
</tr>
<tr>
<td>$10</td>
<td>~11%</td>
<td>6.5-17.4% (6/24)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>(9/26 not feasible)</td>
</tr>
</tbody>
</table>

 Irr requirement ($8) plus consumer discount (25%) = $11
contracts, as a means to secure lender financing, though actual contract prices could only be found for the Indiana SNG plant. Thus, when evaluating a required spot price for viable SNG, we need to add at least 25% to the minimum required selling price. The argument that long-term contracts reduce volatility to consumers has little effect on the value of the contract, as a consumer could easily view themselves as taking on risk by guaranteeing to pay a set price for a commodity that may drop.

The returns to investors, as examined in the results section, are minimal at a price roughly equivalent to today’s spot prices. Investor IRR is in the 8-11% range, which is below the unregulated utility standard of 15%, and certainly below an equivalent project in terms of technology and commodity price risk (EPRI 1999). If the capital cost assumption made in the pro-forma were adjusted, e.g. if plant construction costs fell, then the plant cost curve would shift upwards and a higher IRR received. This does not currently look likely, with construction and commodity costs at all-time highs, though an improvement in technology could affects costs, and several new developments will be discussed in a subsequent section. It is important to note that the pro-forma in this analysis assumes no debt financing per the assumptions in the University of Kentucky study. While this has no effect on IRR, it should be noted that lower returns are needed to satisfy investors in a more heavily levered project. However, to secure financing for these plants is a tricky endeavor at the time this paper is being written - even before the onset of the malfunctioning capital markets, these plants required government loan guarantees, which lowered the prospective cost of debt financing quite considerably (see page 11). The limited amount of funds available at the DOE for these multi-billion dollar plant investments, as well as the additional need to line up buyers in the form of 30 year off-takes, make debt financing a necessary but currently extremely difficult component of SNG plants.

The prices used in this analysis are Henry Hub spot prices, and need to be adjusted for regional variation and positioning along the gas value chain. For example, regional prices in the East are significantly higher than the Midwest,
which are in turn higher than the inter-mountain region. The gas value chain is a term for the whole process of gas extraction, processing, transportation, marketing and use. Each segment of the value chain adds a cost to the gas, and thus if a SNG plant can locate close to an end-user in a high price market, and thus capture more of the value of the end-user price, a plant might be potentially viable in certain niche markets in the U.S. while being generally impracticable for the country as a whole. Figure 13 is a process flow diagram of the gas value chain which indicates where SNG might play and provides a rough idea of value added along the process of extraction to use - note that Henry Hub (HH) prices are *well below* the prices received by gas retailers. As the gas moves along the value chain, each party adds value (and thus cost) to the gas before it reaches the end user.

The gas distribution network in this country is extensive and provides SNG plants an opportunity to locate along a pipeline or a large consumer, wherever the economics are favorable (figure 12). Thus, developer evaluating a plant would want to adjust their viability estimates to reflect the de facto price they will receive for their product, rather than automatically using the industry benchmark Henry Hub price.

Figure 12: Gas Pipelines - from source to market
There are certain factors that may provide for a more ideal situation for SNG plants than those which exist at a national level. The sites most favorable for an SNG plant would provide ready affordable access to coal, a nearby large gas market with premium prices and local political support. In addition, they possess ideal geologic structures, such as deep saline formations, for the sequestration of carbon, which is necessary for plant siting approval, as well as public acceptance, and will be discussed later. These areas are precisely where most of the SNG plant proposals have occurred, and include SW Indiana, Illinois and Kentucky (Indiana Coal 2006, Power Holdings LLC, KY Study 2007). These areas will likely be the first to develop SNG should the economic climate ever prove sufficiently favorable, especially as they are located in pro-coal, pro-growth areas in need of industrial jobs. For example, the legislatures of both Indiana and Illinois have passed legislation favorable to SNG plants, including "no look back" policies, which prevent the renegotiation of long term off take agreements, enabling plant investors to plan on secure cash flows (Indiana Coal 2006). Likewise, until we see a plant developed in this region, we should not expect to see any SNG plants being proposed in the rest of the U.S., where access to feedstock, adverse political and social attitudes towards coal, unfavorable geology or a low price regional gas market may serve as further constraints.
The process to convert coal into SNG is carbon intensive, as carbon is released both in the manufacture of the gas and during its eventual end use. The environmental and political concerns about carbon emissions have been addressed in recent plant proposals through the possibility of carbon capture and sequestration (CCS). Carbon capture is fairly easy with a coal gasification plant, as the carbon dioxide is separated in an almost pure form to make the SNG, and then emitted in a narrow, concentrated waste stream. The additional cost would lie in the compression of the CO2 (estimated at 2% efficiency penalty and 4% cost of product penalty) and the cost of transportation and storage (KY Study 2007). Transport costs would depend on the length of transit and would be calculable from gas transit charges, but the cost of storage would depend on the geology being used and the use of enhanced oil recovery (EOR). The general figure used for carbon storage costs at GE and at the Climate Change Policy Partnership is $5/ton CO2 for storage with transport expected to be minimal (C.C.P.P. 2008.
To put these figures in perspective, this extra cost would move a plant with a break-even SNG price of $8.42 MM/Btu to a new break-even of $9.15 - an 8.7% increase (Ibid, p.19). The geological formation could affect costs either way, and EOR would help defray costs through payment for CO2 and lack of plant responsibility for storage. This contrasts with a coal combustion power plant, in which the coal is burned with a large amount of air, rather than concentrated oxygen, and the flue gas is an order of magnitude larger.

Moreover, while an SNG plant is usually billed as "carbon capture ready", and the process actually occurs along with enhanced oil recovery at the Dakota Gasification plant which sells a significant portion of it's CO2 to the mature Weyburn oil field in Saskatchewan, the carbon will not be captured and sequestered unless there is a price on carbon set forth in legislation. It remains to be seen what the effect of carbon legislation will have on SNG plants - while it would clearly improve the economics of an Integrated Gasification Combined Cycle (IGCC) plant because they compete with coal plants, the SNG plant would be at a disadvantage when compared with a natural gas fired plant, but at an
advantage when compared with a Super Critical Pulverized Coal (SCPC) power plant. In practice, the carbon allowance process would be key, in terms of the initial allocation and how it was determined by legislators. However, when the additional costs of carbon compression, transportation, storage and monitoring are taken into account, a currently uneconomic process looks even worse under a carbon policy. Unless, of course, the carbon price is high enough to drive up the price of low-carbon natural gas to the point that SNG with sequestration is viable. That said, the technology is in place, as evinced by the EOR contract in the Dakotas and the recent partnership of GE and Schlumberger in which a GE-designed plant pays Schlumberger to take delivery, store and monitor carbon emissions on a per ton basis (Reuters 2008). This leverages both firms' areas of expertise and is a promising step forward for clean coal technology in general. In sum, it is not yet clear how carbon policy will affect SNG, though it will likely have a negative impact (as plants must either pay a tax or pay for CCS), and the technology is ready, proven and being commercialized in anticipation of future IGCC plant construction.

The financial assumptions in this study are based on cost estimates derived from currently available technology and plant costs. Improvements in SNG technology that reduce the cost per unit of production could significantly improve the odds of SNG development in this country. While diverse firms such as GE, Siemens, Lurgi, ConocoPhillips and Shell all license and produce gasification equipment, the real potential for cost savings lies in the simplification of the Syngas-to-SNG reaction (Process Energy 2008). There is one firm out in the lead in this regard, and that is GreatPoint Energy, whose patented "Blue Gas" gasification technology promises to greatly reduce SNG production costs through the use of a unique catalyst inside the gasifier that serves to convert coal directly to methane (GreatPoint 2008). This eliminates several intermediate processing steps, and purportedly eliminates the need for the air separation unit (ASU), thus increasing throughput and reducing capital costs (figure 14). Similar to the refining industry's transition from high energy use thermal "cracking" to the less energy intensive use of catalysts, coal has the potential to be processed at lower
temperatures, using the exothermic process heat generated naturally in the methanation process. If this process lives up to its promises (commercial application is unproven), then there is the potential for a major shift in the minimum natural gas price point required for SNG feasibility (GreatPoint 2008). It remains to be seen whether this simplified SNG process technology can live up to its promises at scale.

Figure 14: GreatPoint Process Flow Diagram - simplified SNG process

Hydromethanation Process

VI. Conclusion

SNG is not currently practical in this country, except perhaps in some regionally advantaged locations. If the technology improves to the point where costs are significantly reduced, if gas prices experience a permanent price shift upwards to $11 or more, or if carbon is priced at sufficiently high levels and CCS is available, SNG will be poised for significant expansion, particularly in the favorable areas listed previously. Another critical factor will be the availability of government subsidized debt to facilitate lending and carry the technology risk of these
projects until they are amply demonstrated to Wall Street. For now, the price level at which consumers receive an acceptable discount from market prices is too low a price to generate acceptable returns for a plant investor. U.S. demand for natural gas and concerns over energy security are not likely to diminish over the long term, however, and it is probably a question of when, not if, SNG plants re-emerge as potential candidates in our energy portfolio.

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Much of the relevant data on SNG is in the form of recent studies and proposals, which may not be available in bound form, as the industry has only recently returned to some degree of prominence after a 20-year hiatus.