Strategy 5:

Implement a Major and Comprehensive Effort to Increase Gas Supplies, Including Coal-to-Gas in Kentucky

GOAL **Kentucky will produce the equivalent of 100 percent of our annual natural gas requirements by 2025 by augmenting in-state natural gas production with synthetic natural gas (SNG) from coal-to-gas (CTG) processing.**

INTRODUCTION

The Kentucky natural gas industry produces about 44 percent of the total gas requirements of the commonwealth. As in many other states, Local Distribution Companies (LDCs) in Kentucky obtain most of their gas requirements from external sources rather than from local production. Most of the gas produced in Kentucky is dedicated to the interstate market.

Being largely dependent on external sources of gas, consumers in Kentucky pay added transportation costs for most of the gas that they use. The average pipeline demand cost for delivery of gas to the five major LDCs in Kentucky is about $0.90 per thousand cubic feet. More importantly, consumers in Kentucky, as in other states, become vulnerable to possible supply uncertainties and price increases and spikes as these may occur in the U.S. natural gas system and market.

Virtually all of the gas needs of Kentucky can be met by natural gas production augmented by synthetic natural gas produced by gasifying coal. To the extent that locally produced SNG becomes available, consumers in Kentucky will not pay interstate transportation costs and will be less likely to encounter supply uncertainties. Also, if Kentucky SNG can be obtained on long-term contract, consumers will less likely be affected by price increases and spikes that may occur in the U.S. natural gas market. Synthetic natural gas production in Kentucky can also create a large new market for Kentucky coal.

Synthetic natural gas produced by gasifying coal would complement a strong conventional natural gas industry in Kentucky.

Kentucky Natural Gas Situation

Resources and Production

The Kentucky Geological Survey (KGS) estimates that Kentucky natural gas resources exceed 12 trillion cubic feet, or enough for 120 years of production at the current rate of just over 95 billion cubic feet per year (KGS, 2008c). Although Kentucky has substantial natural gas resources, and natural gas consumption in Kentucky is moderate compared to other states, annual marketed gas production in the commonwealth is substantially less than total gas demand in the commonwealth. In 2006, 216 billion cubic feet of natural gas were consumed in Kentucky (Table 7) while production was just over 95 billion cubic feet (Table 6), which corresponds to 44 percent of consumption.

Although natural gas production in Kentucky has never reached even half of current consumption in Kentucky, there are indications that production could increase substantially due to the push of increasing gas prices, increased use of unconventional gas production technology, and exploration underway. Already, higher natural gas prices have resulted in increased drilling and production.

However, the traditionally low flow rate of wells in Kentucky indicates that production may continue to be substantially below the level of gas consumption in Kentucky unless larger new resources are found and developed or unless improved production can be obtained by use of unconventional gas production technology and techniques.

The KGS reports that while known natural gas resources in Kentucky total 12 trillion cubic feet, speculative resources may total another 114 trillion cubic feet, with the greatest part of those speculative resources being in the Devonian shale formations which account for virtually all of the known resources and production. Another major unconventional resource is coal bed methane which the KGS estimates at 0.848 trillion cubic feet (KGS, 2008b).

Production in Kentucky has traditionally been characterized by numerous wells but relatively low flow from those wells. In 2006, Kentucky accounted for 3.5 percent of producing gas wells in the United States, but these wells produced only 0.5 percent of U.S. natural gas (EIA, 2008h). In 2006, 77.5 percent of production in Kentucky came from gas wells in the lowest production bracket of 10 barrels per day oil equivalent (10 BOE per day). More than 94 percent of gas wells in Kentucky were reported to be in this production rate bracket. In contrast, gas wells in this lowest category in the United States as a whole accounted for only 7.9 percent of total U.S. production. About 65 percent of wells in the United States were reported to be in this production rate bracket (EIA, 2006b).

Table 6: Wellhead Price, Marketed Protection, and Producing Natural Gas Wells in Kentucky, 2001-2006

	2001	2002	2003	2004	2005	2006
Wellhead Price (Dollars per Thousand Cubic Ft.)	4.78	3.01	4.54	5.26	6.84	8.83
Marketed Production (Million Cubic Ft.)	81,723	88,259	87,608	94,259	92,795	95,320
Producing Wells	14,370	14,367	12,900	13,920	14,175	15,892

Source: USEIA. Natural Gas Data. http://tonto.eia.doe.gov/dnav/ng/ng_prod_whv_dcu_SKY_a.htm; http://tonto.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm.

Table 7: Natural Gas Delivered to Customers in Kentucky, 2002-2007 (million cubic feet)

	2002	2003	2004	2005	2006	2007
Volumes Delivered to Consumers	211,950	206,023	212,556	222,222	200,350	215,727
Residential	59,104	61,886	56,443	56,142	47,379	51,956
Commercial	35,942	38,212	36,989	36,894	32,590	34,606
Industrial	103,112	102,272	114,292	112,004	108,094	109,679
Vehicle Fuel	80	98	110	27	30	NA
Electric Power	13,712	3,667	4,833	17,181	12,287	19,486

Source: (USEIA. Natural Gas Data. http://tonto.eia.doe.gov/dnav/ng/ng_cons_sum_dcu_SKY_a.htm).

Prospects for Increased Production in Kentucky

Table 8 indicates that drilling and production in Kentucky have responded to price increases in recent years. Between 2001 and 2006, the average wellhead price increased from $4.78 per thousand cubic feet to $8.83 per thousand cubic feet, or an 85 percent increase. The number of producing wells in Kentucky increased during that time by over 1,500 (or 10.6 percent), and marketed natural gas production increased by 13.6 billion cubic feet or 16.6 percent. It appears that under the current production conditions, in which the great majority of wells in Kentucky are in the lowest production rate bracket, a very large number of wells would have to be added to increase Kentucky natural gas production to near current consumption levels. Alternatively, production levels would have to be increased by adoption of new technologies or production techniques.

EIA has recently reported that, after nine years of no growth, natural gas production in the Lower 48 States started an upward trend with three percent growth between the first quarter of 2006 and the first quarter of 2007. This was followed by an exceptionally large nine percent increase between first quarter 2007 and first quarter 2008. DOE attributes this increase largely to the use of unconventional production such as horizontal drilling, and notes that horizontal drilling is becoming the primary method used to produce gas from geologic formations like shale (EIA, 2008c).

Gas experts in Kentucky report that recent tests of horizontal drilling in shales like those in Eastern and Western Kentucky have yielded very large flow rates. The KGS reports that Equitable Resources, one of the largest gas producers in Kentucky, has proposed and is on track to drill 200 horizontal wells in Eastern Kentucky. The company reports extremely successful tests of horizontal and related lateral drilling that have yielded very large gas flows (Collings, 2008). There is tremendous potential for shale gas production in both Eastern and Western Kentucky that is limited primarily by the availability of rigs, steel, skilled labor, and infrastructure including pipelines (Nuttall, 2008).

A second large company operating in Kentucky, Chesapeake Energy, reports extensive involvement in unconventional gas production in several areas of the United States. Although Kentucky is not mentioned, it may be assumed that the techniques might be applied in Kentucky before long (Chesapeake Energy, 2008). A third large company operating in Kentucky, NGAS, is also expanding horizontal drilling (Wallen, 2008).

Potential New Resources

The KGS is conducting research on potentially large resources, especially in deeper formations that may contain large natural gas pockets. The Rough Creek Graben Project in the Grayson County area, appears to have especially strong potential for large and deep gas pockets (KGS, Rough Creek Graben, 2008f). Other similar resource characterization is being conducted in the Rome Trough formation in Eastern Kentucky and the East Continent Rift Basin in Western Kentucky (KGS, 2008e).

In recent years, interest has grown concerning potential production of methane from coal beds. In 2004, the Kentucky General Assembly enacted legislation concerning development of coal bed methane, addressing numerous issues including ownership of the gas and safety. A few potential developers conducted assessments of production potential a few years ago. Since that time, there has been little development activity. According to the KGS, issues that may affect future development activities include, in addition to ownership and safety, the lower methane content of much of Kentucky's coal and infrastructure. Developers will not only have to drill for the methane, they will also have to construct pipeline facilities to move the gas to market (Nuttall, 2008).

Infrastructure Obstacles

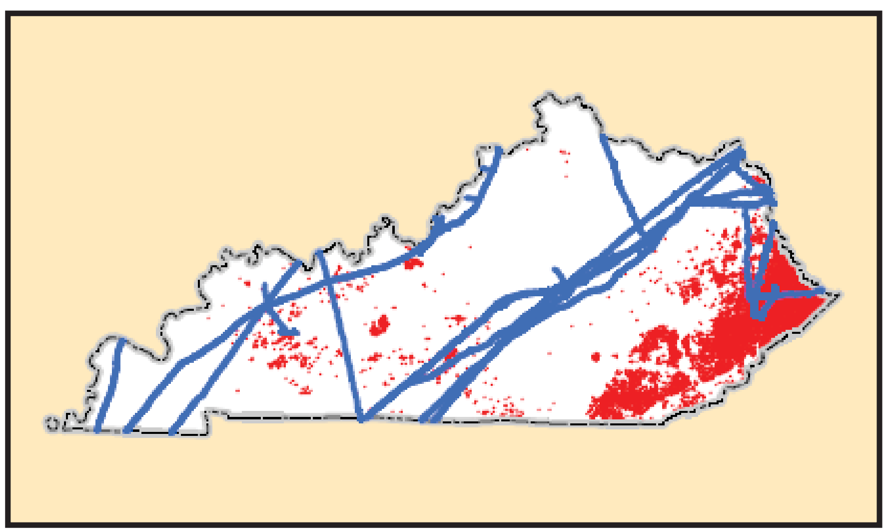
In recent years, infrastructure has presented obstacles to increased natural gas production in Kentucky. The obstacles have been most pronounced in Eastern Kentucky where inability to obtain pipeline capacity for moving gas to interstate pipelines for delivery to Northeastern markets has resulted in decreased production in Eastern Kentucky (Baird, 2005).

Several actions have been taken to address actual or potential problems of inadequate pipeline infrastructure. In 2005, the Kentucky General Assembly created the Kentucky Gas Pipeline Authority to facilitate the construction, reconstruction, improvement or repair of any gas transmission pipeline and appurtenant facilities in the commonwealth (KRS 353.750-776). And in 2006, the Federal Energy Regulatory Commission approved construction and operation of a new 68-mile pipeline from Floyd County to an interconnection in Carter County with an interstate pipeline. The pipeline, built by Equitable Resources subsidiary Equitrans, can transport up to 1,300 thousand cubic feet per day or enough to heat about 400,000 homes per year (Equitable Resources, 2006).

Industry representatives report that access to pipeline capacity continues to be a major and increasing problem in Kentucky. Recent increases in production, largely due to increased use of horizontal drilling techniques, are causing pipelines serving the producing areas to be fully subscribed and unable to accept additional gas for movement to markets via interstate pipelines. Producers are concerned that they will have to shut-in current producing wells and severely reduce their plans for expanding production. The commonwealth would, consequently, lose the economic benefits of employment and severance tax revenues as well as indirect and continuing economic activity that would result from natural gas production (Gabbard, 2008).

Kentucky Natural Gas Market

Because of the location of the major gas fields in Kentucky, most gas produced in Kentucky enters the interstate market via major pipelines that traverse the commonwealth. Most gas production in Kentucky occurs in far eastern counties (Figure 19). In 2006, Eastern Kentucky accounted for almost 99 percent of Kentucky's total natural gas production of over 95 billion cubic feet. Pike County, the easternmost county, produced over 32 billion cubic feet, one-third of total Kentucky



Source: Kentucky Public Service Commission

Figure 19: Natural Gas Producing Areas and Transmission Pipelines in Kentucky

gas production in 2006 (computed from KGS, Oil and Gas Production Data, 1980 – 2007). The counties in the Big Sandy area contain a dense network of transmission lines that move gas to the major interstate pipelines which traverse Kentucky from southwest to northeast, carrying over 21 percent of all the natural gas consumed annually in the Eastern United States (calculated from EIA Gas Data, various tables).

As noted, Western Kentucky may have large deep resources capable of both providing a greater part of Kentucky gas requirements from indigenous production and of marketing the gas throughout the commonwealth via the existing pipeline network The KGS is exploring the potential for such large deep reserves in the Grayson County area of Western Kentucky. At this time, it is not known if such resources exist or can be economically developed (KGS, 2008f).

Economic Benefits of Production

The economic impact of natural gas production in Kentucky is significant. In 2007, over 2,300 persons worked in natural gas production in Kentucky, earning nearly $112 million in wages and salaries (Kentucky Department of Workforce Investment). The production of natural gas in Kentucky generated severance tax revenues of $32.6 million in fiscal year 2007 (Kentucky Department of Revenue).

Consumption

Natural gas is important to Kentucky's continued economic growth, especially industrial growth. Both total natural gas consumption and gas consumed by residences in Kentucky are about average among the states, ranking 27th and 25th respectively. However, consumption by industrial plants is in the top one-third of the states, ranking 16th. In expenditures for natural gas by industry, Kentucky ranks 13th among the states (EIA, 2005). Use of natural gas in electricity generation in Kentucky is small; however, Kentucky, like the rest of the United States, may see greatly increased use of gas in generation in coming years. A recent report by the U.S. Department of Energy National Energy Technology Laboratory showed that the United States will likely experience a substantial increase in natural gas consumption for several years following enactment of federal climate change legislation since about 18 gigawatts of coal-fired electricity generation capacity is forecast to be replaced by generation from natural gas units (NETL, 2008). Although it is not clear how much gas-fired electricity generation will replace coal-fired in Kentucky, it may be expected to be significant.

Kentucky Reliance on External Sources

Because of the nature of Kentucky's resources, production and transportation systems, natural gas consumed in the commonwealth comes predominantly from producing areas to the southwest. It is important to understand that this is not unusual. Few states produce sufficient gas to meet all of their needs. Also, it is a common practice for the gas industry in a state to displace gas that is shipped to out-of-state markets with gas brought into the state rather than constructing and operating pipelines sufficient to deliver in-state gas to all in-state markets.

Supply Uncertainties

States, including Kentucky, for which substantial parts of their gas requirements are transported by pipeline from external producing areas have in recent years encountered supply uncertainties.

Hurricanes have significantly curtailed or threatened to curtail production in the Gulf region (Stanley, 2006). The vulnerability of the transportation network to terrorism has become of increased concern. The possibility of supply-threatening accidents is always present. In 1976 – 1977, a combination of a production shortfall caused largely by federal price control policy along with greatly increased demand due to severe winter weather caused curtailment of gas supply in Kentucky (U.S. DOE *U.S. Energy Policy, 1980 – 1988*). This was an extreme situation, and Kentucky experienced a moratorium on new natural gas service and numerous schools and businesses closed for a time.

Price Impacts

In recent years, the U.S average wellhead price of natural gas has more than tripled, increasing from about $2.00 per thousand cubic feet in 2000 to over $6.00 in 2007 (Figure 20). Figure 20, which shows prompt month (delivery the next month) natural gas futures prices, indicates that consumers have been subject to severe price spikes in recent years. The spikes that occurred in 2000 and 2002 were due to a combination of weather, lagging production, and shortfalls in storage. A major spike also occurred when hurricanes in the late summer of 2005 took over 80 percent of Gulf offshore gas production off-line, causing a cumulative loss by the end of November 2005 of almost 14 percent of total annual production in the area (Stanley, 2006).

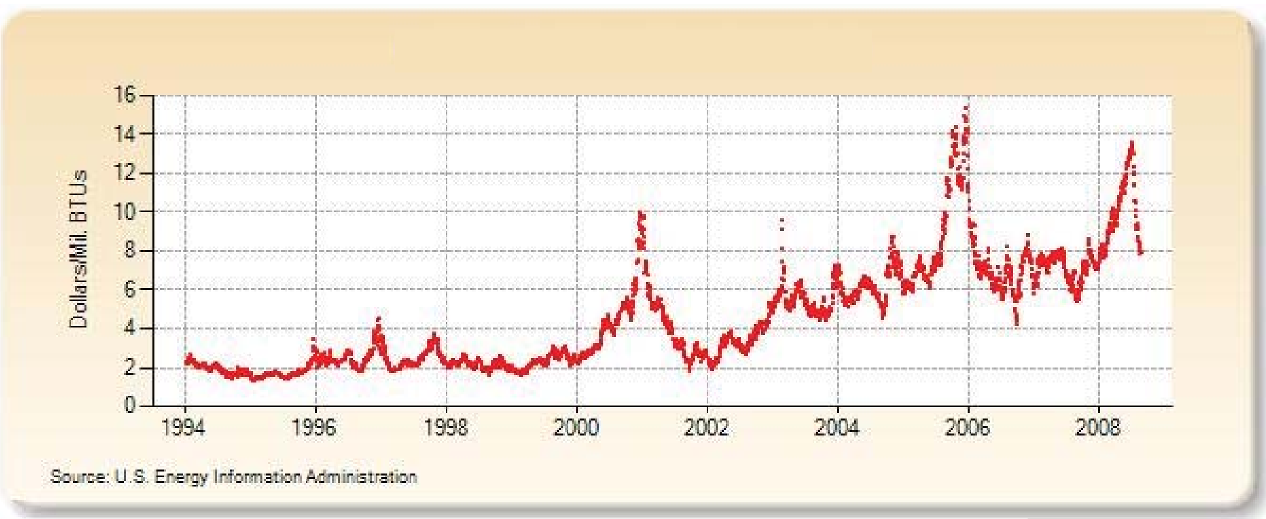


Figure 20: Daily Natural Gas Futures Contract, January 1, 1994 – August 12, 2008

http://tonto.eia.doe.gov/dnav/ng/hist/rngc1d.htm.

It is very difficult to predict just where natural gas prices will be in coming years. The tripling of price in recent years has been largely due to decreasing production capacity coupled with increasing demand, largely for electricity generation. U.S. production capacity peaked at 55 billion cubic feet per day in 1994 (Yergin, 2004). Similar to production in Kentucky, increasing numbers of producing wells in the United States have been producing less total volume. Table 8 shows that the number of producing gas and condensate wells in the United States increased by 61,079, or 15.8 percent from 2002 through 2006 while marketed production actually decreased by 602.9 billion cubic feet, or three percent. The severe spikes in price of recent years have been due largely to weather and perceived potential shortfalls in storage, as noted above.

There are indications, that, over the long-term, the U.S. natural gas supply situation could improve and put downward pressure on prices, although gas prices steadily increased from the beginning of 2008 through July. Since July, prices have decreased precipitously. EIA attributes this decrease to increased onshore gas production, lower oil prices, mild weather, and substantial increases in storage. EIA predicts that, unless weather becomes severely hot, prices will not rise until winter and then only moderately because of increased production and lower oil prices (EIA, 2008g). It can be expected that weather, storage, and oil prices will continue to strongly influence short-term gas prices. It is unclear how recent increases in production, the first such increases in several years, will impact gas prices in the future. How long production increases will continue remains to be seen. However, it appears quite certain that proposed federal climate change legislation will dramatically increase demand and put upward pressure on the price of natural gas in the long-term.

Table 8: Marketed Production of U.S. Natural Gas and Producing Wells in the U.S., 2002 - 2006

	2002	2003	2004	2005	2006
Production (million cubic ft)	19,984,780	19,974,360	19,517,491	18,927,095	19,381,895
Producing wells	387,772	393,327	406,147	425,887	448,841

Source: (USEIA. Natural Gas Data. http://tonto.eia.doe.gov/dnav/ng/ng_prod_whv_dcu_nus_a.htm; http://tonto.eia.doe.gov/dnav/ng/ng_prod_wells_s1_a.htm))

Climate Change Legislation Impacts on U.S. Natural Gas Demand and Price

Although production is up and is influencing gas prices, climate change legislation is expected to cause dramatically increased demand and prices for U.S. natural gas. Recent analyses of the potential impacts of major policy changes, most notably S. 2191, the Lieberman-Warner Climate Security Act of 2007, indicate that demand for natural gas will increase strongly in the first several years after climate change legislation is enacted because gas will be the only alternative in the short-term to coal-fired electricity generation. The studies also find that in the long-term, to about 2030, the price of gas will further increase because of the carbon content in natural gas. Expected price increases for 2030 over the $5.80 per thousand cubic feet base case (not including input from Lieberman-Warner) range from 22 percent (American Council for Capital Formation), to 57 percent (Environmental Protection Agency), to up to 81 percent (EIA – residential delivered price), to as much as 146 percent (National Association of Manufacturers). Thus, there is substantial uncertainty in natural gas price increases due to potential carbon management legislation.

The major variables affecting the future demand for and price of natural gas in these studies are the speed of deployment of new nuclear units, increased use of renewables, the timely development and demonstration of carbon capture and sequestration, and policies concerning offsets. In its analysis of the impacts of S. 2191, EIA stated that the analysis shows "the importance of development and deployment of key low-carbon generating technologies like nuclear, renewables, and fossil with CCS in a timeframe consistent with the emission reduction requirements of legislation similar to Lieberman-Warner. Without them, allowance prices would be higher and greater demands would be placed on natural gas markets" (EIA, 2008d).

Imports of Liquefied Natural Gas (LNG)

The combination of declining U.S. natural gas production, normal increase in natural gas demand, and the likelihood of greatly increased demand for natural gas for the first decade or so following potential federal climate change legislation will result in increased need for imports of natural gas. Whereas the United States has for some years imported about 15 percent of its natural gas requirements from Canada, the imports will almost entirely cease by 2030. EIA forecasts that net imports of natural gas from Canada will decrease from 2.9 trillion cubic feet in 2006 to 0.3 trillion cubic feet in 2030 (EIA, 2008a). Imports from Canada are being decreased by Canadian government policy in order for the gas to be available for use in the production of heavy oil from the vast tar sands formations in Alberta. The loss of imports from Canada will be made up by LNG imports which will increase from 0.5 trillion cubic feet in 2006 to 2.8 trillion cubic feet in 2030 (EIA, 2008a).

Relying on LNG imports is problematic. Development of an LNG terminal can take several years, and there is indication that LNG terminals may have difficulty in gaining necessary state and federal approvals in coastal areas. Also, LNG is subject to the same international commodity market vagaries that have made imports of petroleum increasingly unreliable and costly. Early expectations that development of LNG systems would cause world gas prices to clear at about $3.50 per thousand cubic feet have been replaced by competitive bidding behavior among gas-short countries that has diverted shipments away from the U.S. even when gas prices in the U.S. are above $10 per thousand cubic feet. Thus, given increasing world demand, LNG is likely to be very expensive (NETL, 2008). It can also be expected that gas surplus countries that sell on the LNG market may exhibit the same cartel behavior as OPEC.

The reliability problems of LNG are currently being experienced, as noted in the following statement in the June 26, 2008 EIA Natural Gas Weekly Update:

> "The pace of deliveries of liquefied natural gas (LNG) imports remains considerably below last year's volumes and now appears to have been less than 200 billion cubic feet for the first half of the year, which is less than half of the approximately 460 billion cubic feet received last year during the same time period. LNG imports in June have averaged about 0.9 billion cubic feet per day (based on sendout data from LNG import terminals), which is significantly less than the average of 2.8 billion cubic feet per day in June 2007. Most flexible LNG cargoes are heading to Europe and Asia, where buyers continue to purchase LNG at prices higher than those that have prevailed in U.S. markets" (EIA, 2008f).

Great Plains Synfuels Plant

Created in response to the energy crises of the 1970s and 1980s, the Great Plains Synfuels Plant since 1984 has produced 54 billion cubic feet of pipeline quality synthetic natural gas (SNG) each year by gasifying about six million tons per year of lignite, a relatively low grade of coal. The Great Plains Synfuels Plant is the only coal to SNG plant operating in the United States.

SNG leaves the plant via a two-foot diameter pipeline, traveling 34 miles south. The pipeline joins the Northern Border Pipeline, which transports the gas to four pipeline companies. These companies supply thousands of homes and businesses in the eastern United States.

Of major importance to the future of meeting America's energy needs by gasifying coal, the plant sells captured carbon dioxide to oil producers for enhanced oil recovery in a mature oil field in Canada.

Coal-to-Gas (CTG) Technology

Production of synthetic natural gas (SNG) by gasification of coal is an established and proven technology. The process is similar to production of diesel and jet fuel by gasification of coal, but the SNG process is simpler and less costly. Both processes use catalysts to convert synthesis gas produced by gasification of coal and made up primarily of H_2 and CO into liquid and gaseous fuels.

In a 2007 study, the UK Center for Applied Energy Research reported:

> "The production of synthetic natural gas … is a way of converting coal into the equivalent of pipeline quality natural gas. The technology involved in SNG production is much less cumbersome than for CTL. The main reaction is to convert the syngas produced from coal gasification to methane in a methanation reactor, and the product gas is then adjusted to meet natural gas pipeline specifications. The reaction is typically catalyzed by nickel catalysts and it is best performed at high temperatures … where additional heat is liberated that can be used in the gasification process. Commercial catalysts and technology are available.
>
> SNG from coal is particularly attractive in situations where relatively cheap coal is available while there is demand for natural gas (methane) which can be logistically transformed or when natural gas prices are high enough to sustain the economics" (CAER, 2007).

CTG Economics

Estimated prices of SNG compare very favorably with the $14.00 per thousand cubic feet wellhead price of natural gas in July, 2008. The prices compare even more favorably with the city gate price of natural gas which includes the cost of transporting the gas from production areas in the Gulf region.

In a study conducted for the CAER, Mitretek Corporation modeled costs and efficiencies of generic non-site specific small CTG plants utilizing about 5,000 tons per day of coal. The analysis showed that such a plant can produce about 74 million cubic feet of SNG per day at a capital cost of about $900 million. The cost of the SNG would be $9.10 per thousand cubic feet for a plant using East Kentucky coal priced at $35 per ton and not capturing carbon. The cost would be $9.47 per thousand cubic feet for a plant using East Kentucky coal priced at $35 per ton and capturing carbon (but not sequestering or marketing it). The cost would be $9.39 per thousand cubic feet for a plant using West Kentucky coal priced at $30 per ton and not capturing carbon. Mitretek did not analyze the cost of a West Kentucky plant that captured carbon. The CAER also found that larger plants can achieve economies of scale which can reduce the cost of production to between $7.50 to $8.00 per thousand cubic feet (CAER, 2007).

A study done in 2008 by URS Corporation estimated that a larger generic, non-site specific SNG plant in West Kentucky capable of converting about 12,000 tons per day of coal into SNG would have a capital cost of approximately $1.7 billion, including the cost of capturing but not sequestering carbon dioxide. Such a plant could produce about 175 million cubic feet of SNG per day at an estimated cost of production of SNG of $7.96 per thousand cubic feet, assuming a coal price of $30 per ton. The URS report stated that the price of SNG would increase about 34 cents for each $5 increase in the cost of coal (URS Corporation Pipeline Group, 2008). A lower-quality West Kentucky coal would currently sell for about $50 per ton (perhaps substantially less on long-term contract). According to the URS assumptions, the increase in the price of coal from the assumed $30 per ton to the more current $50 per ton would increase the cost of SNG by $1.36 per thousand cubic feet raising the price to $9.32 per thousand cubic feet.

Meeting Kentucky's Natural Gas Requirements with SNG

The business-as-usual case in EIA's forecast of U.S. natural gas consumption shows an increase of almost 10 percent between 2006 and 2016. Between 2017 and 2030, U.S. natural gas consumption is forecast by EIA to decrease by almost five percent (EIA, 2008). Assuming that the same growth rates would apply in Kentucky, the commonwealth's 2006 natural gas consumption of 215 billion cubic feet in 2006 would increase to 237 billion cubic feet in 2016 and would decrease to 225 billion cubic feet in 2030.

A small CTG plant such as the plant analyzed by the CAER that produced 74 million cubic feet of SNG per day would produce about 27 billion cubic feet of SNG per year. Thus, to meet 100 percent of Kentucky's natural gas requirements at the high point of consumption between 2006 and 2025 (i.e., 237 billion cubic feet in 2016) would require about five CTG plants capable of producing 27 billion cubic feet per year each, assuming that the current natural gas production rate is maintained.

It should be noted that there are numerous possible plant sizes and configurations. The CAER chose the 5,000 ton-per-day size from which extrapolations could be made about larger plants. The CAER does not estimate how large an optimally economically viable plant would be.

The generic plant analyzed by URS Corporation may be a more optimal size. That plant would cost about $1.7 billion. It would convert about 12,000 tons per day of coal (about 4.4 million tons per year) into 175 million cubic feet per day, or 64 billion cubic feet of SNG per year. It would require between two such plants to meet the high point (237 billion cubic feet in 2016) of Kentucky's projected gas requirements between now and 2030 assuming natural gas production grows slightly.

The only commercially operating CTG plant in the United States is the Dakota Gasification Plant in North Dakota. That plant utilizes about six million tons per year of lignite, a very low grade (low Btu, high moisture) coal, to produce 54 billion cubic feet per year of SNG (Dakota Gasification Co., 2008). Given differences in coal quality and scale, the generic plants analyzed by the CAER, Mitretek and URS Corporation appear to compare well with the Dakota Gasification Plant.

CTG Economic Benefits

The CAER estimated that the small CTG plant that it analyzed would cost about $900 million, including carbon capture (but not storage). The plant would require about 5,000 tons per day of coal or about 1.8 million tons per year. They estimated that about 240 miners would be employed in producing the coal and 650 – 1,100 people would be required to construct the plant and 190 employees would be required for plant operation (CAER, 2007). The CAER did not estimate how long construction would take, but the construction time most often cited in the many projects that have been proposed in recent years is four years (CAER, 2007).

The economic benefits of the construction and operation of five such plants to complement existing natural gas from wells would be significant. Total construction costs of the five plants would be over $4 billion. Up to 5,500 construction jobs would be created. Each plant would consume 1.8 million tons of coal, resulting in new annual coal demand when all five plants are in operation of about nine million tons per year. A total of 950 new jobs in plant operation would be created.

Kentucky LDC Long-term Contracting Policy

Perhaps the major benefit of SNG production is, as discussed above, ending Kentucky's dependence on natural gas from external sources and vulnerability to supply interruptions and to price increases and spikes that may occur in the United States natural gas market. Kentucky has already taken legislative action to ensure that natural gas local distribution companies can take advantage of the predictable prices that SNG can provide.

KRS 278.5085 (SB 131, enacted 2007) provides for approval by the Kentucky Public Service Commission of the purchase by an LDC of up to 25 percent of gas needs from SNG producer(s). The price of the SNG is to be set at the average of 60 months futures price for natural gas at the Henry Hub. The price may vary by no more than $1.50 per thousand cubic feet over the life of the contract.

Figure 21 illustrates how the statute would set the price of gas in a contract initiated on July 1, 2008 between an LDC and a producer of SNG. The average of the next 60 months Henry Hub futures prices shown on Figure 21 is $11.609 per thousand cubic feet. The allowable price adjustment of $1.50 would create a range between $11.61 per thousand cubic feet and $13.10 per thousand cubic feet. This set price which would be in effect for 25 years smoothes out the severe spikes of recent years. It also seems very likely to be less than the price increases predicted by many. As noted earlier in this report, analyses of the impacts of the Lieberman-Warner bill predict price increases over the EIA forecast price for 2030 of 22 – 146 percent.

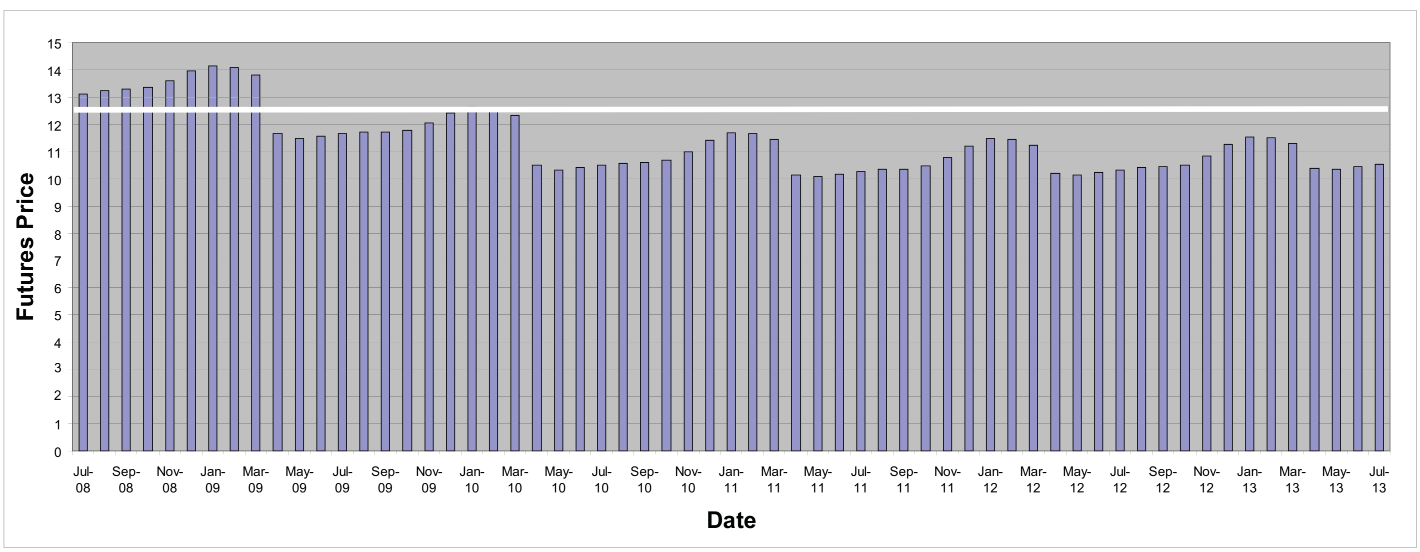


Figure 21: NYMEX Natural Gas Futures

Source: Chart created from data provided by Natural Gas Intelligence. http://intelligencepress.com/data/futures/nymex_report.emb?trade_date=2008-06-26&commodity=NG.

In addition, creation of an assured supply of gas at predictable prices by development of an SNG industry in Kentucky can lay the groundwork for developing industry in Kentucky that utilizes natural gas as feedstock or for heat in industrial processes. The National Energy Technology Laboratory has reported that "(I)n trade-exposed sectors of industry, especially aluminum, fertilizer, and chemicals, the rise in natural gas prices, which in the first part of the decade was U.S.-centric, caused production to be shut in or moved offshore." Also, Middle Eastern production of chemicals especially, threatens the competitive position of U.S. industry because of cheap natural gas reserves in the Persian Gulf area (NETL, 2008). Both factors reinforce the importance of a CTG industry in Kentucky.

ACHIEVING THE GOAL

Kentucky will produce the equivalent of 100 percent of our annual natural gas requirements by 2025 by augmenting in-state natural gas production with synthetic natural gas (SNG) from coal-to-gas (CTG) processing.

Near-Term Actions (1-3 years)

Kentucky has already taken major actions that enable the production and utilization of SNG in the commonwealth. These include:

1. Establishment of incentives for attracting CTG plants to Kentucky.

    - Kentucky Incentives for Energy Independence Act, 2007 (KRS 154.27-020). Tax incentives for up to 25 years, up to a maximum of 50 percent of the capital investment, include:
        - Sales and Use Tax refunds up to 100 percent of tax paid on tangible personal property made to construct, retrofit or upgrade a facility.
        - Severance Tax incentives up to 80 percent of taxes paid on the purchase or severance of coal.
        - Tax Credits up to 100 percent of tax paid on corporate income or Limited Liability Entity Tax arising from the project.
        - Wage Assessment incentives up to four percent of gross wages of each employee.
    - Commercialization Grants Program
        - Grants for economic and technical feasibility studies. Several assessments are underway; two are for potential CTG plants.
2. Statutory authorization KRS 278.5085 for the Kentucky Public Service Commission to approve purchase by Kentucky Local Distribution Companies (LDC's) of gas from SNG producers.
3. Preparation of a bank of potential sites for plants utilizing coal gasification.

    - About 29 potential sites have been nominated by local governments, industry, and others. These have been characterized by size, configuration, access to coal, access to pipelines, market for products, carbon sequestration potential, etc. Specific follow-on tasks are proposed.
        - Pre-permit the most promising sites.
        - Conduct preliminary carbon sequestration assessment on the most promising sites.
        - Drill wells at the most promising sites to assess host strata, cap strata, potential volume that can be sequestered.

In addition to the actions already underway, it is recommended that the following also be done in the short term:

1. Expand catalysis research at CAER to focus on methanation for SNG production.
2. Expand research at CAER to include the life-cycle carbon reduction potential of gasifying biomass with coal in CTG processes.
3. Initiate a PSC administrative case to ensure that Kentucky local distribution companies (LDCs) and customers are not harmed by direct sales of gas from SNG producers to industrial plants. The PSC conducted Administrative Case 297 in 1986, when the natural gas market was deregulated by federal legislation and set policies concerning bypass of LDCs by industry desiring to purchase directly off pipeline.
4. Expand and accelerate assessments of new gas resources in Kentucky.
5. Initiate a comprehensive study of pipeline infrastructure in Kentucky to determine needs in relation to expanded production of natural gas and coal-bed methane.

Mid-term Actions (3-7 years)

1. Continue research on carbon dioxide reduction potential of gasifying biomass along with coal.
2. Review effects on similar or competing energy policies, e.g., exploration for new deep gas reserves.
3. Analyze the need for legislation to allow investment in SNG plants by Kentucky LDCs and electric generators.
4. Assess pipeline infrastructure adequacy for serving Kentucky markets and interstate markets by CTG industry.
5. Assess carbon dioxide pipeline infrastructure needs.

Long-term Actions (>7 years)

1. Continue research, demonstration and deployment of carbon sequestration.

IMPLEMENTATION SCHEDULE

A new SNG plant started today would require about seven years to begin operation, assuming three years to obtain all necessary permits and four years for construction and start-up. For the purpose of estimating coal demand from operation of five SNG plants in Kentucky, it is assumed that a first plant is announced now and requires seven years to begin operation and that one other plant begins the process soon and also is ready for production in seven years, or in 2015. It is assumed that two additional plants come on line in 2020 and that the final plant comes on line by 2030.

As the first two plants come on line in 2015, coal demand will increase by 3.6 million tons per year in 2015. Coal demand will increase an additional 3.6 million tons per year in 2020 as two additional plants come on line. Coal demand will increase by an additional 1.8 million tons per year in 2030 as the final plant comes on line.

Since coal production for coal-fired power plants is likely to decrease substantially due to climate change legislation, the new demand would be replacing some lost production. The National Energy Technology Laboratory estimates that nationally the Lieberman-Warner bill, if enacted, could cause the cancellation of 18 gigawatts of planned coal-fired electricity generation capacity in 2016. (NETL, 2008). A one-gigawatt plant consumes approximately 3.5 million tons per year of coal (Kentucky Utilities, 2008). Eighteen gigawatts of capacity would require 63 million tons per year of coal. In 2006, Kentucky accounted for 10.4 percent of U.S. coal production (Kentucky Coal Facts, 2007-2008). If Kentucky lost its proportionate share of the deferred coal production due to the cancellation of 18 gigawatts of coal-fired generating capacity, Kentucky coal production by 2016 would be reduced by 6.6 million tons per year.

Kentucky coal production can meet the new demand in 2015, 2020, and 2030. First, there is considerable ability to expand production with existing infrastructure. In 1990, Kentucky produced over 170 million tons of coal. In 2006, production had declined to 121 million tons. Expansion to 178 million tons by 2015 is achievable. An example of rapid expansion of production is the new River View mine being opened by Alliance Coal in Union County (Alliance Resource Partners, 2008). Originally planned as a three million ton-per-year mine, the mine when it opens in a year or so, will produce six million tons per year.

ENVIRONMENTAL BENEFITS & LIMITATIONS

SNG plants, as part of their design requirements, separate and can capture virtually all carbon dioxide produced. The CAER estimates that the small 5,000 ton-per-day plant with carbon capture would produce 8,382 tons of carbon dioxide per day, or just over three million tons per year. The plant would capture 8,217 tons per day, or 98 percent (CAER, 2007). According to CAER, the removal of carbon dioxide in the CTG process imposes a small efficiency penalty of about two percent and a cost of production penalty of about four percent. The CAER estimate is for separation, capture, and pressurization of carbon dioxide but does not include the cost of storing, transporting, or sequestering the carbon dioxide.

Five small plants sufficient to meet Kentucky's natural gas requirements would produce a total of 15 million tons of carbon dioxide per year when all are in operation in 2030. At 98 percent capture, if the plants could sequester carbon dioxide, there would be a net increase of 120 thousand tons of annual carbon dioxide emissions in 2015, an additional 120 thousand tons in 2020, and an additional 60,000 thousand tons in 2030. In 2030, total additional carbon dioxide emissions would be 300 thousand tons per year while almost 15 million tons would be captured and sequestered. This is much lower than if the nine million tons of coal per year were used for coal-fired electricity generation.

It may be possible to actually reduce life cycle carbon dioxide emissions by gasifying biomass along with coal to produce the SNG. Research by the Idaho National Laboratory recently showed that liquid transportation fuels produced by the Fischer-Tropsch process in which coal is gasified to produce syngas which is transformed under catalysis into liquid fuels can emit less life-cycle carbon dioxide than conventional transportation fuels when coal and biomass are gasified together in 70/30 proportions, respectively, and the produced carbon dioxide is sequestered (Baard Energy, 2007). It would appear that the same carbon dioxide reductions could be achieved in CTG processes since the first stage, the gasification of coal, is the same in CTG as in CTL. Research is needed to determine if the gasification of biomass along with coal is feasible in CTG processes as it is in CTL processes.

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