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June 7, 2005

RECEIVED
JUN 0 8 2005
PUBLIC SERVICE
COMMISSION

Via Federal Express

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: An Assessment of Kentucky's Electric Generation, Transmission and Distribution Needs – Administrative Case Number 2005-00090

Dear Sir or Madam:

Please find enclosed 11 copies of the Comments of Kentucky Pioneer Energy LLC in the above-referenced proceeding. Any questions or comments should be directed to the undersigned.

Very truly yours,

W. Ashley Hess

W. Ashley Hess

WAH/kao
Enclosures

624767_3

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served by United States First Class Mail, postage prepaid, on this 7th day of June, 2005, upon:

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COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED
JUN 0 8 2005
PUBLIC SERVICE COMMISSION

In the Matter of:

AN ASSESSMENT OF	)	
KENTUCKY'S ELECTRIC	)	ADM. CASE NO. 2005-00090
GENERATION, TRANSMISSION	)	
AND DISTRIBUTION NEEDS	)	

COMMENTS OF KENTUCKY PIONEER ENERGY LLC

FILED: JUNE 8, 2005

Pursuant to Governor Fletcher's Executive Order 2005 – 121 to develop a Strategic Blueprint to promote future investment in electric infrastructure for the Commonwealth of Kentucky, Kentucky Pioneer Energy LLC (KPE) will address each of the three questions posed in the order by (1) providing recent studies addressing deployment of gasification technology that can be utilized by the Commission as additional information in developing the Strategic Blueprint; (2) discussing natural gas price volatility in comparison to coal and environmental considerations as the top issues facing the electric power industry in Kentucky over the next 20 years; and (3) describing two specific sections of the Electric Generation and Transmission Siting law that are barriers to meeting future investment needs in electric power infrastructure in the Commonwealth.

The difference between coal combustion and coal gasification is significant, and the distinction is sometimes overlooked or ignored. During the gasification process, the combustible matter undergoes a chemical conversion process in a pressurized, closed system. The feedstock is injected into the gasifier with oxygen. The feedstock reacts in the gasifier with steam and oxygen at high temperature and high pressure creating a synthetic gas that is made up primarily of carbon monoxide and hydrogen. The inorganic material in the feedstock is melted to form vitrified frit, an inert, non-leaching material that resembles coarse sand. Trace elements or other impurities are removed from the synthetic gas and are either recirculated back into the gasifier or recovered. Sulfur is recovered in its elemental form or as sulfuric acid, both of which can be sold commercially. In an Integrated Gasification Combined Cycle (IGCC) unit, a high efficiency gas turbine burns the clean synthetic gas to produce electricity. Exhaust heat from the gas turbine is recovered to produce steam to power a steam turbine (hence the designation as *combined* cycle). IGCC technology is more efficient than conventional coal combustion and therefore produces significantly less carbon dioxide.

I. Additional Information Recommended to the Commission

Additional information to be considered in developing the Strategic Blueprint can be found in several recently issued reports and studies. A study commissioned by USDOE's National Energy Technology Laboratory engaged Booz Allen Hamilton to assess the market penetration potential of coal-based IGCC through 2025 within the U.S. electricity sector. Booz Allen employed a scenario analysis approach to assess the technology's potential, and IGCC performed well under all scenarios. The study, "Coal-Based Integrated Gasification Combined Cycle: Market Penetration Strategies and Recommendations" (see public presentation of results in Appendix A), was released in 2004[1]. Although the study utilized the Energy Information Administration's National Energy Modeling System (NEMS), it also addressed many non-Return on Investment (ROI) factors including Public Service

[1] The full report can be found at www.netl.doe.gov/coal/gasification/pubs/pdf/Coal%20Gasification%20Report%20Chapters.pdf and the appendices can be found at www.netl.doe.gov/coal/gasification/pubs/pdf/Coal%20Gasification%20Report%20Appendices.pdf

Commission decisions and other regulatory issues. A review of this study would be beneficial in developing the Strategic Blueprint.

A second study, "National Gasification Strategy: Gasification of Coal & Biomass as a Domestic Gas Supply Option" (Appendix B), was composed under the auspices of the John F. Kennedy School of Government at Harvard University. The study was released in January 2005 as a joint project of the Science, Technology and Public Policy Program and the Environment and Natural Resources Program in the Belfer Center for Science and International Affairs. The study recommends that loan guarantees and other incentives to stimulate investment in gasification plants can significantly enhance gas supplies in the United States by manufacturing gas from coal, biomass and petroleum coke. The study suggests an aggressive but viable target for the Strategy is to produce the equivalent of 1.5 trillion cubic feet of natural gas per year within 10 years.

The same authors at Harvard University also produced a study entitled "Financing IGCC – 3 Party Covenant" (Appendix C), which describes a financing and regulatory proposal aimed at reducing financing costs and providing a risk-tolerant investment structure to stimulate deployment of IGCC coal generation power plants. The 3 Party Covenant described in the study is an arrangement among the federal government, state Public Service Commissions, and equity investors that serves to lower IGCC cost of capital by reducing the cost of debt, raising the debt/equity ratio, and minimizing construction financing costs. The study recommends that states interested in participating in the program adopt utility regulatory provisions for implementation by their respective Public Service Commissions concerning review, approval, and recovery of IGCC project costs. Specifically, a state PSC, acting under state enabling authority, would agree to assure dedicated revenues to IGCC projects sufficient to cover return of capital, cost of capital, and operating costs. The state PSC would provide this revenue certainty through utility rates in states with traditional regulation of retail electricity sales (such as in Kentucky) by certifying that the plant qualifies for cost recovery and establishing rate mechanisms to provide cost recovery, including cost of capital. The certification by the state PSC would occur up-front when the decision to proceed with the project was being made and state PSC prudence reviews would occur at appropriate stages as project development and construction progressed so as to reduce the construction risks borne by the developer of the project, avoid accrual of construction financing expenses, and protect ratepayers.

As part of the study the authors briefly reviewed utility statutes in several states including Kentucky. In a final section addressing the legislative changes necessary to implement the provisions of the 3 Party Covenant, the authors provided the following suggestions:

> More legislative changes may be necessary in order to adopt the model state mechanism in Kentucky. As discussed above [a review of Indiana's utility laws], Kentucky has in place less elaborate procedures than Indiana, but provides for ongoing review, approval, and recovery of capital investment, associated cost of capital, and operating costs for 'complying' with environmental requirements. While the operative term, 'complying' with environmental requirements, may reasonably be interpreted to cover an entire IGCC plant, it may be desirable for the state legislature to adopt expressly that interpretation. In addition, it may

be desirable for more detailed provisions to be adopted concerning: up-front 'due diligence' review of, and issuance of a certificate of public convenience and necessity; ongoing prudence review of project preconstruction and construction costs and operating costs; and, in particular, assurance of pass-through of approved depreciation and amortization of capital investments and associated cost of capital (including cases of uncompleted plant) and of approved operating costs. These types of legislative changes seem to be consistent with Kentucky's express policy to 'foster and encourage use of Kentucky coal by electric utilities.' [KRS 278.020(1)][2]

A fourth study, "An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC Technology in the U.S. Electric Industry" (Appendix D) was prepared for the U.S. Department of Energy and the National Association of Regulatory Utility Commissioners (NARUC) in 2004. The report provides recommended policy, regulatory, executive and legislative initiatives to meet the institutional challenges to the commercialization and deployment of IGCC in the nation's power industry.

Among the recommendations contained in the report is the initiation of an expedited process to develop a single set of standards specifically for siting and permitting IGCC power plants including co-production processes.

II. Top Issues Facing Electrical Power Industry in Kentucky

A. Natural Gas (NG) Price Volatility versus Coal Opportunity

[2] William G. Rosenberg, Dwight C. Alpern and Michael R. Walker, "Financing IGCC – 3 Party Covenant" (Working Paper 2004-01, Energy Technology Innovation Project, Belfer Center for Science and International Affairs), 124-25.

1. The current volatile Natural Gas (NG) market forward curve suggests continued adverse impacts on conventional combustion turbine based generation. As Chairman Greenspan of the Federal Reserve has said in Congressional Testimony, (paraphrasing) "the cost of natural gas is above $4.50 per mmBtu – going up – and not coming back"!

2. Coal, the Commonwealth's great resource, is being afforded an opportunity to "replace" natural gas in the next generation of energy production. Coal prices, though elevated, remain relatively flat and non-volatile in comparison to gas. Congress is creating legislation that encourages technology that enables coal to provide the energy for gas turbines. IGCC, with Federal and Commonwealth of Kentucky encouragement, can minimize fuel volatility and therefore "cost of generation" volatility.

B. More importantly, IGCC also addresses the environmental concerns that impair <u>all other</u> coal based power generation technologies – both today and in the coming decades. Besides superior current performance in all currently regulated emissions, gasification is the ONLY technology that cost effectively and efficiently captures and removes mercury (at a small fraction of capital and operating costs associated with combustion boilers). Further, it is the ONLY technology that can cost effectively capture and sequester carbon dioxide <u>today</u> – should that be desired (either competitively, economically or by regulation). It is the "carbon capture" opportunity that recently caused American Electric Power (AEP) to commit to IGCC today and argue that IGCC is the "low cost option" over the long run.

1. Gasification and IGCC as a Competitor:

Changes to laws and regulations governing energy must include a component that looks to the future. "The next generation of fuel" in the United States, and certainly in Kentucky, must include gasification technology because it is one of the most efficient, environmentally effective means of producing electricity from various feedstock including coal and renewable resources. The gasification process can convert any carbon-containing material into a synthesis gas composed of primarily carbon monoxide and hydrogen, which can be used as a fuel to generate electricity or steam, or used as a basic chemical building block for a large number of products such as synthetic natural gas (SNG) and transportation fuels.

Air emissions from an Integrated Gasification Combined Cycle (IGCC) power plant are far below current U. S. Clean Air Act standards. Sulfur removal efficiencies of more than 99 percent are achievable. Reductions of emissions of SO_2, NO_X, CO_2 and particulates from an IGCC plant are significantly better than those achieved by scrubber-equipped plants, including Circulating Fluidized Bed Combustion (CFBC) plants, on a fuel-by-fuel basis.

One of the top issues facing the electric power industry in Kentucky over the next twenty years is the issue of ever increasing environmental constraints and regulations governing power plant emissions. As air emissions standards become stricter, the superior environmental performance of IGCC will take on added economic benefits because the technology can achieve greater emissions reductions at lower cost than less advanced technologies. Decisions made today will be in force for the life of a power plant, typically 20 to 40 years, so future environmental constraints need to be taken into consideration when selecting a technology. Specifically, while conventional coal generating facilities (e.g. CFB or Supercritical) may be competitive with IGCC on capital cost and certain environmental performance measures, neither can compete with IGCC when the long term "life-cycle costs" of carbon and mercury capture are considered.

An example of what is contemplated for the future can be found in U.S. Department of Energy's (USDOE) FutureGen project. FutureGen is an "Energy Plant of the Future" consisting of a coal-fueled gasification process that produces electricity and hydrogen, emits virtually no air pollutants, and captures and sequesters carbon dioxide. The ability to capture carbon dioxide for sequestration and the ability to provide mercury removal in a more efficient and cost effective manner than conventional coal-fired plants are two compelling reasons why IGCC technology should be a part of the Commonwealth's energy plans for the future.

2. Synthetic Fuels

The Commonwealth of Kentucky positioned itself to be the nation's leader in synthetic fuels production in the 1980s. Specific, bold initiatives were undertaken by the General Assembly to take advantage of Kentucky's vast coal resources in proposed gasification and liquefaction facilities. The opportunity did not come to fruition due to a changing oil market and lukewarm support for synthetic fuels in Washington. The current situation has come full circle. Elected officials in Washington are supportive of IGCC as a way to lessen the nation's dependence on foreign oil and LNG. IGCC technology has been enhanced, tested and proven. Kentucky cannot afford to let another opportunity to become the nation's leader in synthetic fuels technology slip away. Consideration for gasification technology must be addressed in the Strategic Blueprint.

III. Barriers to Investment in Kentucky

A. Need to Conform Regulatory Implementation to Existing Law:

In addition to the information contained in the four studies referenced above, a more specific barrier to future investment needs, in electric power infrastructure, exists in Kentucky. The Electric Generation and Transmission Siting Law (KRS 278.700 to 278.716) passed in 2002 contains several areas that have created conflicts between the law as it is written and the implementation of the law through the various regulations and procedures adopted to implement it. Specifically, there are two areas of the law, which needs to be addressed through more consistent application.

First, the law states that a preference should be given to coal-fired merchant plants. KRS 278.710 (2) reads, "When considering an application for a construction certificate for a merchant electric generating facility, the board may consider the policy of the General Assembly to encourage the use of coal as a principal fuel for electricity generation. . ." Although this is a stated preference in the law, no mechanism exists to actually encourage the siting and construction of these types of plants versus other types.

Second, the law also states a clear preference to site merchant power plants on existing utility sites, but the implementation and interpretation of the law does not conform to this provision. As an example, existing utility sites for regulated utilities are exempt from local planning and zoning laws. In KRS 278.706 (2) (g) a summary of the efforts made by the siting applicant to locate the proposed facility on a site where existing electric generating facilities are located is required in the application for a siting certificate. Also, the granting or denial of a construction certificate in KRS 278.710 (1) (d) is based upon whether the facility is proposed for a site upon which existing generating facilities are currently located. *Yet a recent Siting Board has ruled that a merchant plant does not have the same planning and zoning exemption as a regulated utility and in fact must petition local planning and zoning boards for rezoning if the proposed site is not zoned for such a plant.* The dichotomy forces a merchant plant to try and rezone property (or a portion of the property) that is already being utilized for a power plant operation. This is a situation that Kentucky Pioneer Energy has faced, and it is certain to be repeated as other proposed plants endeavor to locate on existing utility sites. The Siting Board is, for all intents and purposes, turning the jurisdiction of the matter over to local planning and zoning boards. If this is the intent of the siting law, then one could argue that the siting law is not needed for existing utility sites, and the question of siting for these proposed merchant plants should then be referred directly to local planning and zoning authorities. The preference in the law is not being followed and is, in fact, being ignored. This is clearly a barrier to future investment.

B. A more level playing field for non-jurisdicational projects would be helpful to maximizing deployment of new technologies. While rate recovery may necessarily apply only to regulated entities, the non-regulated 'merchant' entities do not benefit from such certainty. Some form of loan guarantee "safety net," for example, is suggested as a low risk (to the Commonwealth) mechanism for providing a relevant and effective alternative form of comfort to lenders.

Gasification and IGCC have matured and are ready for competitive deployment. Large regulated utilities have begun major projects. Yet, even AEP is asking the State of Ohio for rate recovery of their "development costs" (the first of three project phases). While this initiative is consistent with the "Harvard Study" discussed above, it creates an unlevel playing field for 'merchant' projects in the Commonwealth.

IV. Trends

A. USEPA has recently proposed positive incentives in the New Source Performance Standards, for IGCC versus conventional coal combustion based units.

B. The Energy Bill currently in moving through Congress has significant incentives for deploying the IGCC technology.

C. Some states, such as Indiana, are legislating strong support mechanisms for further deployment of IGCC. In Ohio, the Public Utility Commission has included language in recent Orders that is intended to facilitate progressive rate recovery during project development of IGCC generation.

In closing, Kentucky Pioneer Energy believes gasification and IGCC are "here and now" and will prove immensely beneficial in coming years to those states which support it and foster its deployment.

Coal-Based Integrated Gasification Combined Cycle:
Market Penetration Strategies and Recommendations

Presented To:

Gasification Technologies 2004

October 4, 2004
Washington, DC

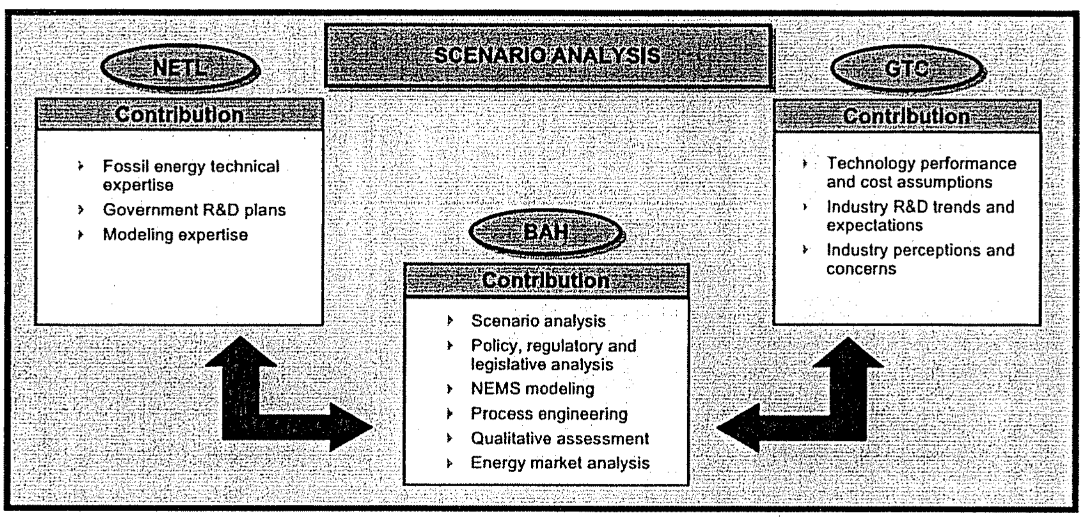
Booz | Allen | Hamilton

Major Conclusions:
On paper, IGCC can be a robust technology under all future scenarios…

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible] Additions
Base Natural Gas Prices	Moderate / *Advanced* Technology Progression	Current Regulatory Framework	2010 *2010*	34 *89*	12% *30%*
		Multi-Pollutant Regulation	2010 *2010*	74 *98*	25% *32%*
		Multi-Pollutant Plus Carbon Regulation	2010 *2010*	41 *80*	14% *29%*
High Natural Gas Prices	Moderate / *Advanced* Technology Progression	Current Regulatory Framework	2010 *2010*	67 *131*	22% *38%*
		Multi-Pollutant Regulation	2009 *2009*	109 *164*	35% 50%
		Multi-Pollutant Plus Carbon Regulation	2010 *2009*	86 *146*	30% *50%*

… however, qualitative factors can have a significant influence over the investment decision.

We led a year-long study to assess the IGCC market potential and to provide technology, policy, and business risk mitigation recommendations.



We benefited from solid technical and modeling insights from GTC members and NETL staff and derived our data assumptions from:

- ***Workshops***
- ***Literature review***
- ***Personal interviews***
- ***Monthly teleconferences***

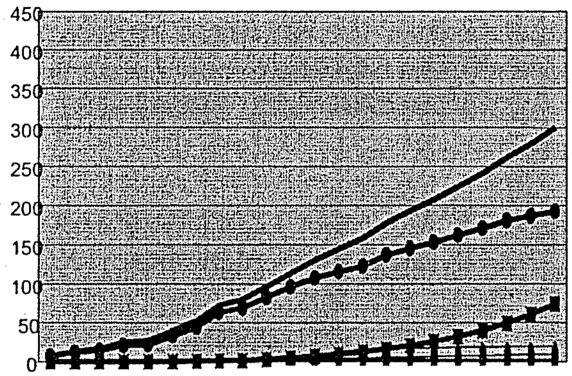
Its favorable environmental characteristics result in IGCC capturing a significant market share under all environmental scenarios

Three scenarios with increasingly restrictive environmental constraints were modeled.

- **Current regulatory framework**
  - Essentially similar to today's federal framework.
- **Multi-pollutant scenario**
  - Reduced NO_x and SO_2 emission levels similar to Clear Skies
  - New Mercury emission cap similar to former EPA MACT proposal
- **Multi-pollutant plus carbon scenario**
  - NO_x, SO_2 and Mercury same as previous scenario
  - Carbon constraint similar to that in the McCain-Lieberman bill

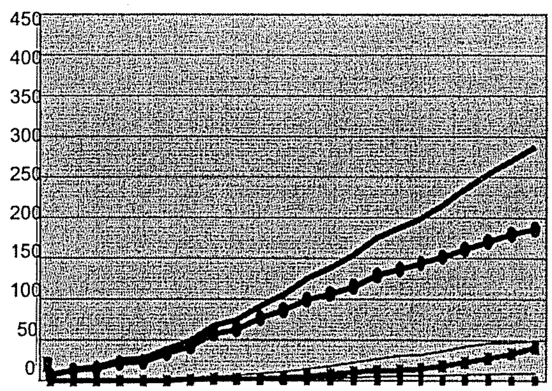
In designing these scenarios, we attempted to capture the policy debates on these issues, but in no way should the analysis be interpreted as either supporting or opposing any of the issues assessed.

Of the three environmental scenarios, IGCC performs best in the Multi-Pollutant regulation scenario.



IGCC accounts for about 25% of capacity additions through 2025.

- ***Primarily a result of capital cost advantages in meeting mercury requirement.***



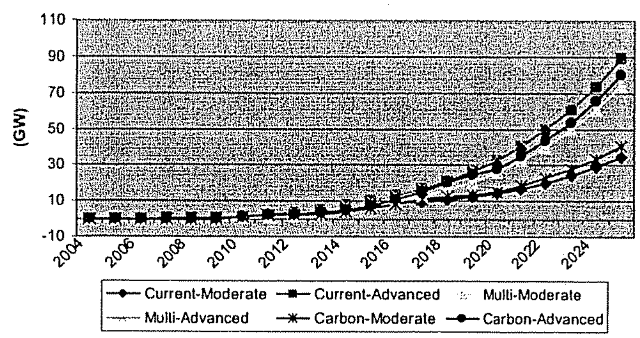
It does less well with a carbon constraint added, but still accounts for about 14%.

- ***It benefits from relatively lower cost of carbon capture.***
- ***Non-carbon emitting technologies become competitors.***

Even under the current regulatory framework, IGCC accounts for 12% of new capacity.

As an emerging technology, IGCC benefits from increasing the pace of technology advancement.

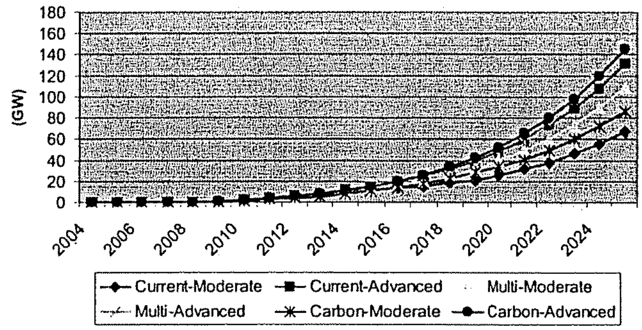
- **Two scenarios were developed to assess this issue.**
- **Moderate progression**
  - Natural evolution of all power generation technologies,
  - Based on cost and efficiency improvements that are gradual and consistent with historical trends and current industry advancements.
- **Advanced progression**
  - More aggressive pace of development
  - Based upon successful accomplishment of Federal power generation R&D goals for the study period.



Under advanced technology assumptions, IGCC performs better in all scenarios, with marked improvements in the more environmentally constrained scenarios.

Projecting Impacts of Higher Natural Gas Price Curves
Natural gas prices are a major determinant in IGCC penetration, but the future is uncertain.

- **Natural gas prices in the base scenarios closely resemble EIA's latest projections.**
  - Similar to the AEO2004 projections.
  - Higher gas prices than previous EIA forecasts.
- **We tested the effect of higher natural gas prices on IGCC additions. To model this price curve, we:**
  - Used the mid-December futures' curve which goes out to 2009; and.
  - Used the National Petroleum Council's (NPC) high-end natural gas price estimate for 2025 for the end point of the projections.
  - The result is significantly higher natural gas prices on a real cost basis, and thus a more even mix of new capacity across technologies.



Higher natural gas prices significantly increase IGCC market penetration in all scenario, with a doubling in the more environmentally constrained cases.

Uncertainties and non-ROI factors can affect these outcomes!

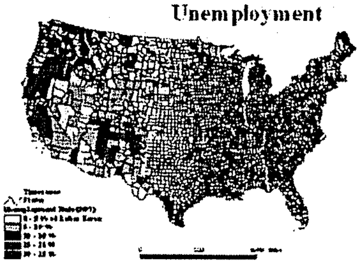
Energy investors make their decision while facing a number of key uncertainties.

- **Capital cost**
  - Environmental future
  - Potential for cost overruns
  - Time to operation
  - Capital availability
- **Variable cost**
  - Natural gas prices
  - Capture & sequestration costs
  - Transportation & transmission costs
- **Fixed cost**
  - Staff retraining or hiring costs
  - Reliability and availability
- **Price and unit sales**
  - Local demand
  - Local generation capacity

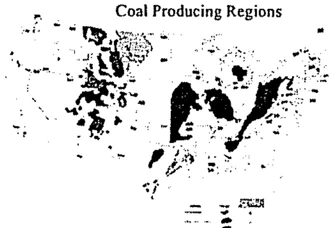
Most of these uncertainties can be related back to the relative scarcity of in-use cost and performance data.

In addition, other factors that cannot be captured by conventional ROI-type analyses enter into the investment decision

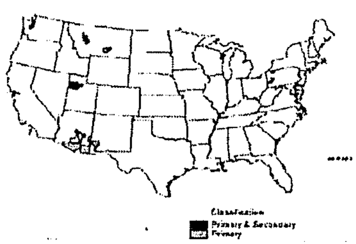
Unemployment



Coal Producing Regions



Counties Designated Nonattainment for SO2



PUBLIC:

- **National**
  - Energy Security
  - Fuel diversity
  - Environmental performance
- **Local**
  - Cost of electricity
  - Availability & reliability
  - Jobs
  - Use of local resources
  - Local fuel diversity
  - Transmission capacity
  - Air and water impacts
  - Land use/ NIMBY
  - Landfill impacts
  - Noise
  - Negative perception of coal

Conclusion: IGCC market potential looks promising...

- **IGCC performs well in all scenarios modeled.**
  - It performs best in a future characterized by
    - High natural gas prices,
    - Increased environmental constraints, and
    - Aggressive technology development.
  - It also performs well under current conditions.
- **The adoption of IGCC however, will depend on strategies employed for overcoming:**
  - Investment uncertainty and
  - Siting and other non-ROI risk factors.

...however, the ability to realize that potential will require sound government and corporate strategies.

Copies of the final report will be available on the DOE/NETL website

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National Gasification Strategy

Gasification of Coal & Biomass as a Domestic Gas Supply Option

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DISCLAIMER

EXECUTIVE SUMMARY

Natural gas provides 24 percent of the energy used by U.S. homes and businesses and is a vital feedstock for chemical, fertilizer, and other industries. Since 1999, natural gas prices in the U.S. have more than doubled,[1] adding about $70 billion annually to U.S. natural gas customers[2] and causing widespread adverse economic impacts, including high home heating bills, escalating commercial energy costs (affecting hospitals, schools, office buildings, and shopping centers), substantial job losses in chemicals, fertilizer, and manufacturing industries, and financial distress in the electric power sector.[3]

The root of the natural gas problem is that production in North America has hit a plateau and can no longer keep up with growing demand in the U.S. and Canada. As a result, the U.S. is facing a future with higher natural gas prices and a growing dependence on overseas imports of liquefied natural gas (LNG) for incremental supply. In December 2004, the Senate Energy and Natural Resources Committee, Chaired by Senator Domenici, requested "fresh ideas" to address the growing natural gas crisis in the U.S.

An option to supplement natural gas supply and reduce demand is for Congress to adopt the National Gasification Strategy to promote commercial investment in gasification technologies that manufacture gas from domestic coal, biomass, or petroleum coke. By providing federal loan guarantees and other incentives for industrial and electricity sector investments in gasification technology, the National Gasification Strategy could produce gas supplies equivalent to those expected from the Alaska Gas Pipeline (1.5 trillion cubic feet (TCF)), but in a more immediate time frame.

Loan guarantees (like the ones provided for the Alaska Gas Pipeline) are a preferred incentive approach because they can minimize federal budget costs. A $30 billion loan guarantee program for gasification would cost the federal budget approximately $3 billion spread over five years,[4] and could stimulate manufactured gas production equivalent to 1.5 TCF of natural gas. The manufactured gas could be produced for $4.5 per million Btu (mmBtu) and coal gasification power for 4.2 cents per kilowatt-hour (cents/kWh), well below current natural gas prices of $6 -7.00/mmBtu and natural gas power that costs over 6 cents/kWh.

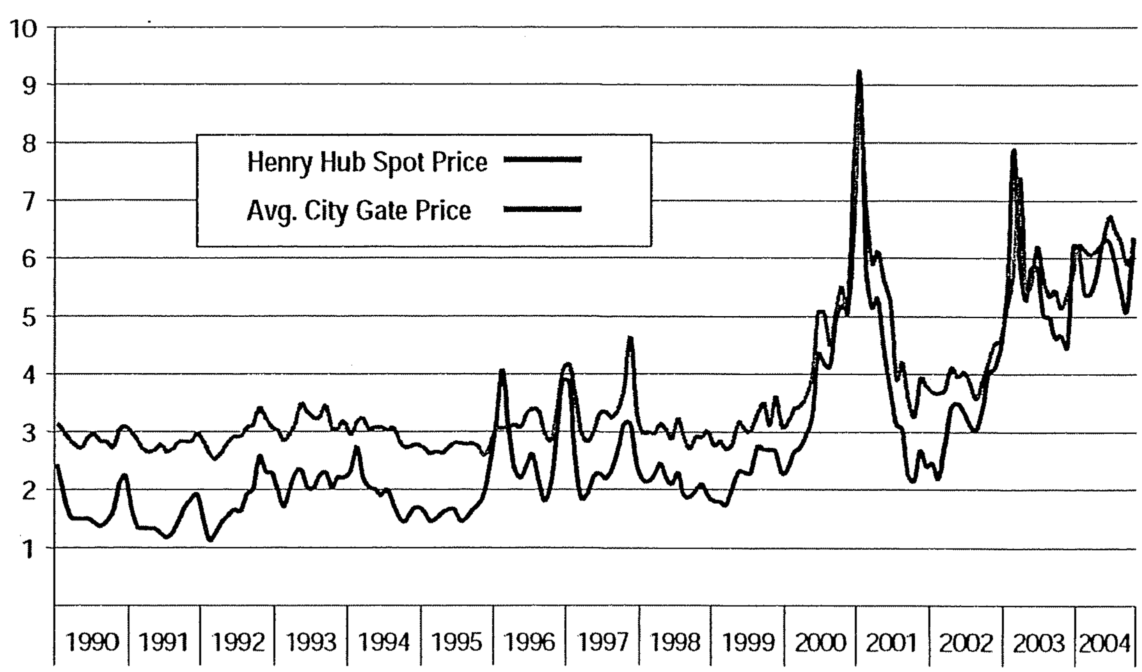
The National Gasification Strategy should also include funding for research, development, demonstration, and deployment of carbon capture and sequestration technologies that could leverage gasification investments under the program. Considering that every $0.50/mmBtu increase in natural gas prices adds about $10 billion in costs annually to U.S. businesses and consumers, investment in the National Gasification Strategy is justified to promote a more secure, predictable, and affordable national energy future.

U.S. NATURAL GAS CRISIS

For two decades (1980-1999), annual average wellhead natural gas prices in the U.S. remained between $1.5/mmBtu to $2.6/mmBtu.[5] However, in late 2000, gas prices began a steep rise, with December city gate prices reaching $6.60/mmBtu and a spot market peak near $10/mmBtu (Figure 1).[6] A combination of intense drilling activity and demand reductions (resulting from the high prices) brought prices partially back down by late 2001, leading many to assume that the 2000-2001 price increases were a short-term phenomenon. However, prices began to rise again in 2002 and continued to rise in 2003 and 2004. These sustained price increases led to a rethinking of past supply and price projections and a new understanding that supply constraints are likely to keep prices high for the foreseeable future. The National Petroleum Council noted in its September 2003 report:

> Current higher gas prices are the result of a fundamental shift in the supply and demand balance. North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas needs; production from traditional U.S. and Canadian basins has plateaued. Government policy encourages the use of natural gas but does not address the corresponding need for additional natural gas supplies. A status quo approach to these conflicting policies will result in undesirable impacts to consumers and the economy, if not addressed.[7]

Figure 1. Henry Hub & Average City Gate Natural Gas Prices 1990-2004.



Sources: Henry Hub Spot Price: Reuters, Wall Street Journal and Oil & Gas Journal;
City Gate Price: EIA at: http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm

This fundamental shift in the supply/demand balance and the sustained rise in prices were not foreseen by industry or government forecasts prior to 2003. As late as 2002, most analysts agreed that expanding domestic natural gas production and Canadian imports would keep pace with growing demand and maintain wellhead prices below $3.60/mmBtu through 2020.[8] For example, the average wellhead price projected for 2005 in the Annual Energy Outlook 2002 was $2.60/mmBtu. However, wellhead prices in October 2004 were $5.3/mmBtu[9] and are now expected to remain at that level through 2005, a level 106 percent higher than predicted in 2002,[10] and current estimates of 2005 production are 2.2 TCF below Energy Information Administration (EIA) estimates published between 1996 and 2002.[11]

Forecasters have now revised their natural gas price projections based on a new understanding that domestic production is unlikely to significantly increase to meet growing demand. The 2005 Annual Energy Outlook Reference Case projects the average delivered price of natural gas to remain above $5.5/mmBtu through 2025[12] and that 96 percent of the incremental supply needed to meet growing U.S. demand must come from overseas imports of liquefied natural gas (LNG) (72 percent) and Alaska (24 percent).[13] The continuation of historically high natural gas prices and the potential for U.S. dependence on imports from countries such as Algeria, Malaysia, and Qatar for needed supply are cause for serious concern.

Impact of High Natural Gas Prices

High natural gas prices are seriously undermining the economic competitiveness of many U.S. industries. For example, the chemical industry, which is the largest industrial consumer of natural gas in the U.S., estimates it has lost $50 billion in business to foreign competition and more than 90,000 jobs since 2000 due to high natural gas prices.[14] Similarly, the fertilizer industry, where 70 to 90 percent of the cost of producing ammonia for fertilizer is the cost of natural gas, reported in 2003 that 11 ammonia plants representing 21 percent of U.S. capacity had already been closed, that only 50 percent of the remaining U.S. capacity was operating, and that two major U.S. fertilizer producers had already filed for bankruptcy.[15] A chief executive officer of a leading fertilizer company stated in remarks to the Secretary of Energy in November 2003:

> If we are to prevent further decimation of the U.S. industry, we must enact policies that stabilize the supply/demand balance for natural gas. I can't overemphasize to you the urgency of the need to act decisively and immediately on this issue. U.S. natural gas markets are in a full-blown state of emergency.[16]

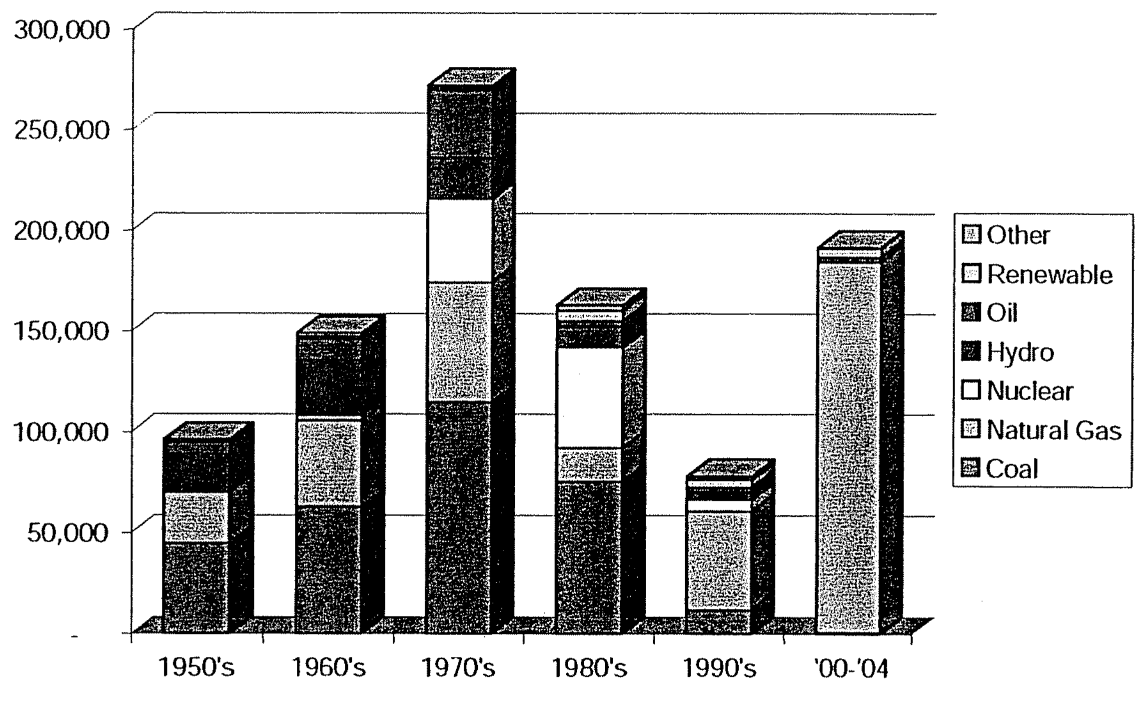
Despite this plea, natural gas prices continued to rise in 2004.

Another impact of the high prices has been to increase significantly the cost of generating electricity with natural gas. Low natural gas price assumptions in the late 1990's (based on industry and government projections indicating prices would remain at historic levels) led to an unprecedented surge in the construction of natural gas-fired power plants. Since

1995, over 230,000 mega-watts (MW) of new natural gas generating capacity came on line, including 184,000 MW since 2000, which is more natural gas capacity in four years than the total capacity (all fuels) added in any decade except the 1970's (Figure 2).

At current prices, operating this new fleet of natural gas generation is uneconomic most of the time. Consequently, natural gas power plants, specifically natural gas combined cycle (NGCC) facilities built to sell power into deregulated electricity markets, are operating at very low capacity utilizations and are in widespread financial distress. Some of these facilities financed with non-recourse debt have already been turned over to banks, and other facilities have been sold for less than 20 percent of their original cost.[17] NGCC facilities built by utilities in regulated electricity markets and approved by state utility commissions are still operating at higher capacity factors and passing high generating costs through to electric customers.[18] Thus, in some areas, high natural gas prices are forcing residential and business consumers to take a one-two punch from high natural gas and electricity prices.

Figure 2. U.S. Capacity Additions by On-line Date (MW)



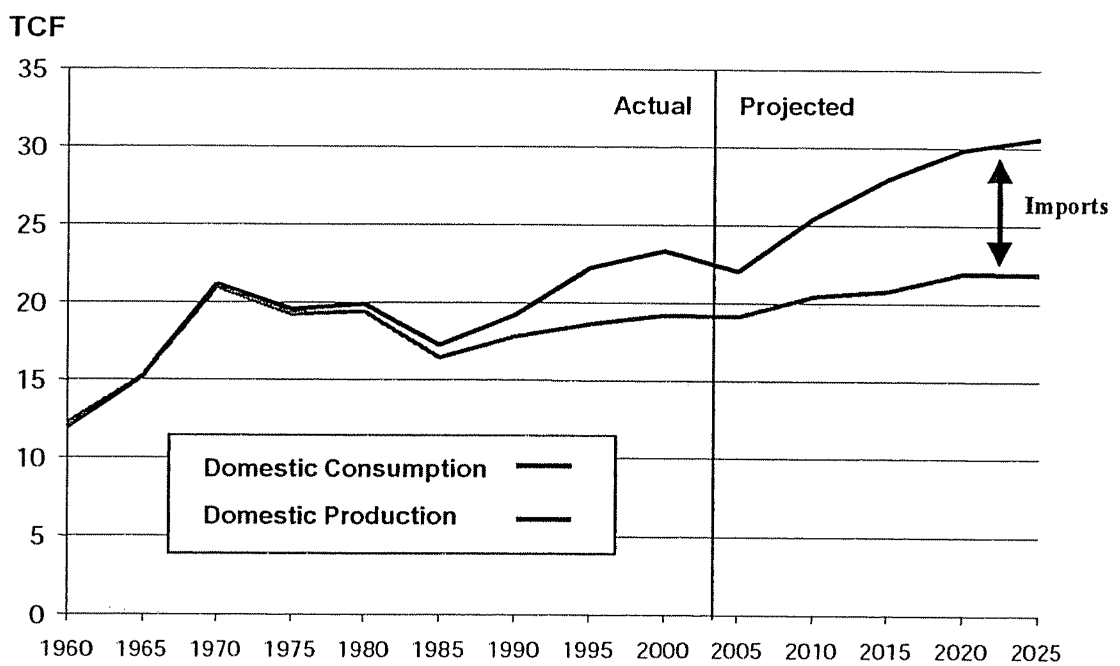
Sources: EIA, Form 860 for 2003; EIA, Electric Power Monthly, Nov. 2004, Table ES-3.

Natural Gas Supply Outlook

Historically, natural gas supplied to U.S. markets has come almost entirely from domestic production in the lower 48 states (both on and offshore) and, beginning in about 1985, from imports from Canada and Mexico. However, over the next 20 years, U.S. natural gas production from on and offshore wells in the lower 48 states is expected to grow by only 5 percent and net imports from Canada and Mexico are expected to decline slightly as those countries consume more for their own use.[19] At the same time, the share of U.S. imports is expected to increase significantly as domestic production lags further and further behind domestic consumption (Figure 4).

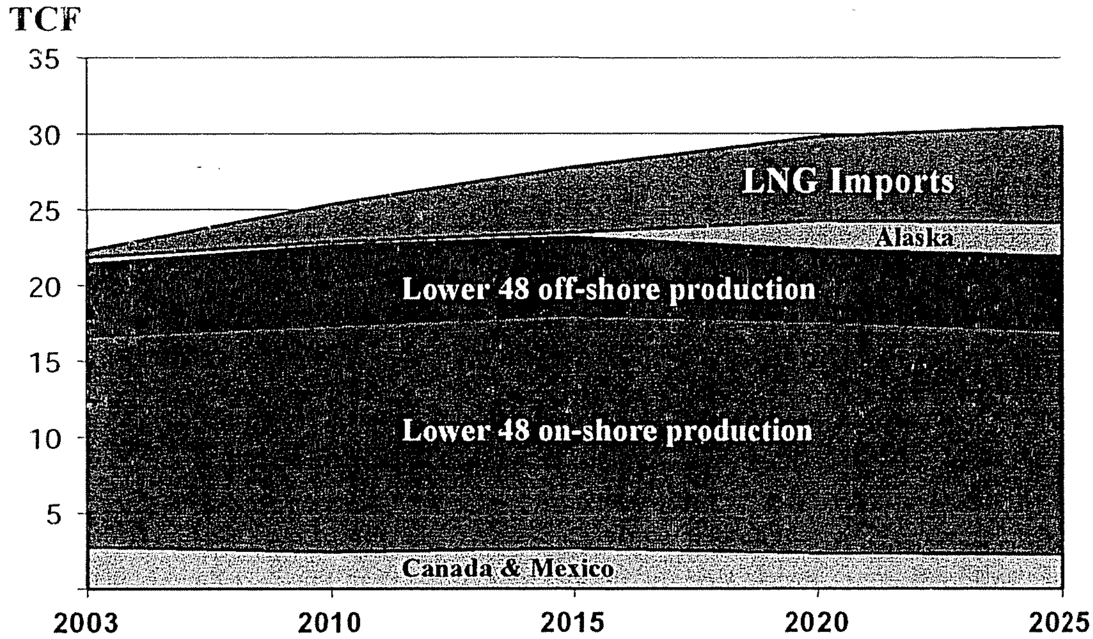
Natural gas production in the U.S. faces a constant battle to replenish (and expand) supplies by drilling new wells, which is evidenced by the fact that 28 percent of natural gas wellhead capacity in the U.S. is from wells that are less than a year old and 53 percent is from wells less than 3 years old.[20] Only the constant drilling of new producing wells allows domestic natural gas production to remain stable. Most analysts believe that domestic production has either already peaked, or will peak in the next decade before beginning a gradual decline.[21] The difficulty of expanding domestic production is illustrated by recent trends, with the number of wells drilled increasing significantly in response to higher prices but overall natural gas production remaining flat.[22]

Figure 3. Domestic Natural Gas Production is not Keeping Pace with Demand.



Sources: Historic data: EIA, Annual Energy Review 2003, Table 6-1; Projections: EIA, Annual Energy Outlook 2005, Table A-14.

Figure 4. Projected U.S. Natural Gas Supply



Source EIA, Annual Energy Outlook 2005

Due to the stagnation of domestic production, incremental supplies needed to meet growing demand are expected to come from additional production and pipeline capacity to deliver natural gas from Alaska (24%) and from the development of significantly expanded LNG terminal capacity to import gas (72%) from overseas (Figure 5).

Alaska Natural Gas Pipeline

In 2004, legislation was enacted to support construction of the Alaskan Gas Pipeline. The Alaska Gas Pipeline is expected to cover 3,500 miles and be completed around 2015.[23] When completed, it is expected to deliver 1.5 TCF per year of natural gas from Alaska, which one study estimated would reduce natural gas costs by about $0.50/mmBtu.[24] Pipeline construction is expected to cost about $20 billion.

Legislation enacted as part of the 2004 military spending bill established an 80% (not to exceed $18 billion) loan guarantee program to support and help finance the pipeline development. The legislation also includes provisions for expedited Federal Energy Regulatory Commission (FERC) permitting approvals (including putting FERC in charge of the Environmental Impact Statement required by the National Environmental Policy Act) and enhanced federal coordination.[25] In addition, separate legislation passed as part of the American Jobs Creation Act of 2004 allows for certain Alaska pipeline property to be treated as seven-year property and provides a tax credit for the cost of a needed gas conditioning plant on the North Slope of Alaska to process gas before it goes into the pipeline.[26]

LNG Terminal Expansion

LNG imports are projected to account for 72 percent of the incremental natural gas supplied to the U.S. between 2003 and 2025, raising the LNG share of total supply from less than 3 percent to 21 percent by 2025.[27]

There are currently four LNG import terminals in the U.S.[28] All four terminals were operational in 2003 for the first time since 1981 and supplied a record 507 Bcf of natural gas to U.S. markets.[29] The vast majority of the LNG was supplied from Trinidad and Tobago, which accounted for 75 percent of LNG exports to the U.S. The other suppliers were Algeria, Nigeria, Oman, Malaysia, and Qatar.[30]

Three of the existing LNG terminals have announced expansion projects that would approximately double LNG import capacity to about 1.7 TCF per year by 2008. In addition, the Energy Information Administration has tracked at least 35 LNG terminal proposals to supply North American markets. Several proposals are currently being considered by regulators, and at least three projects have been approved by FERC (one on-shore project) and the Maritime Administration (two off-shore facilities). Most LNG proposals face substantial public opposition that can hinder permitting and development.

LNG terminals cost between $400 and $600 million to construct and require multi-billion dollar upstream liquefaction investments to prepare the LNG for shipment to the U.S. A number of companies have announced intent to make these investments overseas.[31]

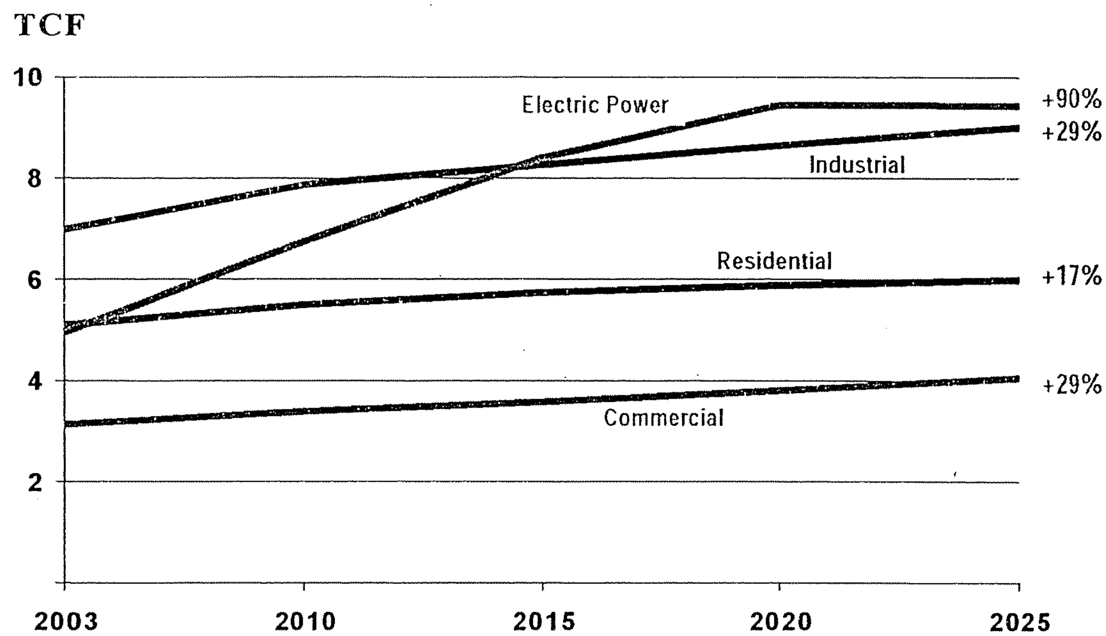
The growth of LNG imports is expected to play a major role in expanding natural gas supplies to meet growing demand in the U.S. However, the ability for LNG to fill this role remains uncertain and will be highly dependent on permitting and public acceptance, as well as the successful construction and safe operation of new domestic import terminals and overseas liquefaction facilities.

Electric Sector Natural Gas Demand Growth

In 2004, the U.S. consumed 22 TCF of natural gas. By 2025 demand is projected to grow 41 percent to 31 TCF. Demand growth is expected in all sectors, but demand from electric generators is expected to grow the fastest, increasing 90 percent by 2025 (Figure 3).

Beginning around 1997, electric generator natural gas demand growth began to accelerate as new natural gas-fired power plants came on-line. Between 1997 and 2004, demand from electric generators grew 1.1 TCF, or 27 percent, while natural gas demand from all other sectors decreased 1.8 TCF, or 10 percent (with industrial demand declining 16 percent).[32]

Figure 5. EIA Projected Natural Gas Consumption by Sector



Source EIA, Annual Energy Outlook 2005

Demand from the electric power sector is currently about 5.3 TCF (25 percent of total demand), but the existing fleet of natural gas power plants, particularly NGCC plants in deregulated markets, are operating well below their design capacities. The underutilization of these plants creates a demand overhang estimated to be 3.3 TCF and creates the potential for significant increases in natural gas use from the electric power sector without any additional capital investment.[33] This also indicates that any short to mid-term increase in natural gas supply (until the 3.3 TCF overhang demand is eliminated) will likely be absorbed by the electric power industry at prices exceeding those which other U.S. industries can afford to pay, resulting in additional job losses as those industries continue to move overseas where energy prices are lower. To help U.S. industry in the short to mid-term, natural gas demand must also be reduced by a combination of energy conservation and substitution of natural gas with gas produced from domestic feedstocks such as coal, petroleum coke, or biomass via gasification.

It has now become clear that under business as usual, North American natural gas production will not be able to keep up with projected demand growth (especially from power generation), which will keep pressure on prices and require significant LNG import expansions for incremental supply. Federal intervention to stimulate additional supply and ease demand pressure by expanding commercial gasification is a prudent national response to help domestic industry and improve natural gas affordability and security.

NATIONAL GASIFICATION STRATEGY

Gas supplies in the U.S. can be significantly enhanced by manufacturing gas from coal, biomass, and petroleum coke using commercially available gasification technologies. Federal incentives to stimulate investment in these technologies are critical if they are to come on line in substantial enough quantity to have a significant near-term impact on the natural gas supply/demand balance in the U.S. An aggressive but viable target for the National Gasification Strategy is to produce the equivalent of 1.5 TCF of natural gas per year within 10 years. This is an amount equivalent to the supply expected from the Alaska Gas Pipeline beginning around 2015. The supply from gasification could begin to come on-line in 5-7 years, providing a mid-term supply bridge to Alaska Gas Pipeline completion. Achieving 1.5 TCF of domestic gas production from gasification would require approximately $37 billion of capital investment in on-site gasification plants across the country (See Appendix A calculation).

The discussion below briefly describes gasification technology and its potential use in the industrial and electric power sectors, explains the federal budget and financing benefits of federal loan guarantees for stimulating investment, and recommends the National Gasification Strategy, which provides:

- Loan guarantees and other incentives to stimulate investment in gasification plants that produce synthesis gas for industrial and electrical use equivalent to 1.5 TCF of natural gas; and
- Funding for research, development, demonstration, and deployment of technology to capture and store carbon dioxide (CO_2) from gasification plants.

Gasification Technology

Gasification is the partial oxidation of a solid or liquid fuel feedstock to manufacture a gaseous product (synthesis gas or "syngas") made up of predominantly hydrogen (H_2) and carbon monoxide (CO).[34] Impurities, such as particulates, sulfur, nitrogen, and volatile mercury are easily removed from the syngas using commercially proven systems to produce synthesis gas that is almost as clean as natural gas. Synthesis gas has a lower heating value than natural gas,[35] but can be readily substituted in many industrial processes and in the generation of electricity with modern gas turbines. Synthesis gas can also be converted to synthetic natural gas (methane) using commercially-available methanation catalysts.[36]

According to a recent survey by the Gasification Technologies Council (GTC), there are 385 gasifiers in operation at 117 projects worldwide.[37] These gasifiers are used to produce liquid fuels in South Africa (Sasol facility), chemicals in the U.S. (Kingsport facility), electricity in the U.S., Europe and Japan (Polk, Wabash River, Puertollano, Buggenum, and Negishi facilities),[38] methane in the U.S. (Great Plains facility) and ammonia fertilizer in China and India. There are several different commercial gasifier designs available, including systems from GE Energy,[39] ConocoPhillips,[40] Shell,[41] Lurgi, and Noell. Each of these systems has been proven in commercial use around the world.

When a gasification plant is combined with a combined cycle power block to produce electricity, the process is called integrated gasification combined cycle (IGCC). The existing fleet of natural gas combined cycle (NGCC) power plants (over 100 GW) offers the potential for deploying gasification technology to refuel those plants to generate electricity at reduced cost. About 40 to 45 percent of the cost of an IGCC facility is the combined cycle power block, so using existing, underutilized NGCC infrastructure for the development of IGCC facilities could provide for significant cost savings. The conversion of NGCC facilities to utilize coal or other gasified fuels would also directly reduce natural gas demand.

Gasification also can be used to produce process fuel feedstocks, heat, steam, and electricity for a variety of industrial processes that currently use natural gas. For example, Eastman Chemical has successfully operated a GE Energy gasifer at its Kingsport, Tennessee facility since 1983 as the only source of gas for its chemical processes to produce film and other acetyl-based products. Similarly, Sasol operates one of the oldest and largest gasification operations in the world in South Africa, where high-ash coal is gasified with Lurgi gasifiers to produce a variety of liquid fuels and chemical products. Several players in the chemical industry are looking at new production technology to utilize syngas for the production of large volume commodity chemicals that are currently based on natural gas liquids. In addition, China is currently constructing nine gasification systems for ammonia fertilizer production based on the Shell technology.

Gasification technology is also important because it offers substantial environmental benefits in the use of coal. Direct combustion of coal (in pulverized coal power plants, for example) creates significant air emissions of pollutants regulated by the U.S. Environmental Protection Agency, including nitrogen oxides (NOx), sulfur dioxide (SO_2), particulates, and mercury (Hg). Unlike combustion processes that rely on combustion or post-combustion controls to reduce emissions, gasification cleans up the gas prior to combustion when there is a greater concentration of pollutants, lower mass flow rate, and higher pressure than is present in flue gas after combustion. Therefore, emissions control through syngas cleanup in gasification processes is generally more cost effective than post combustion treatments to achieve the same or greater emissions reductions.[42] Gasification facilities also use significantly less water and produce less solid waste than pulverized coal power plants.

Perhaps the most significant environmental benefit of gasification is that it provides a technical pathway for addressing carbon dioxide (CO_2) emissions. The National Commission on Energy Policy underscored the importance of gasification and IGCC technology for addressing CO_2 stating:

> Coal-based integrated gasification combined cycle (IGCC) technology, which—besides having lower pollutant emissions of all kinds—can open the door to

> economic carbon capture and storage, holds great promise for advancing national as well as global economic, environmental, and energy security goals. The future of coal and the success of greenhouse gas mitigation policies may well hinge to a large extent on whether this technology can be successfully commercialized and deployed over the next 20 years.[43]

By adding water-gas shift reactors and physical absorption processes to the syngas treatment system (processes that are commercially proven in industrial applications), CO_2 can be removed from syngas (and pure hydrogen produced) prior to combustion. Several studies have shown this to be a more cost-effective approach to CO_2 capture with proven technology than post-combustion CO_2 capture on conventional coal combustion technologies.[44]

Carbon-neutral biomass gasification technology is close to being ready for deployment. Much of the major benefit will come from gasification technology using spent pulping liquors, which are by-products of pulp and paper manufacturing operations. The syngas produced from the organic lignin in the spent pulping liquor is similar in composition to that produced coal or petroleum coke, and would come from a renewable source of energy that is carbon-neutral with regard to greenhouse gas emissions. An independently-reviewed study in 2003 estimated that spent pulping liquor and wood residuals gasification could potentially produce 25 Gigawatts of electric power by the year 2020.[45]

Incentives to stimulate gasification investment will create gasification infrastructure that can serve as a foundation to research, develop, demonstrate, and deploy carbon capture and storage technologies. For example, a commercial coal gasification plant could sell a percentage of syngas manufactured to a federally financed research project, which could then test a variety of technologies to separate CO_2, operate turbines and fuel cells on hydrogen-rich fuel, and store CO_2 in geologic formations. The research projects should be funded separately from the commercial gasification investments and user costs. This concurrent approach—incentives for gasification technology deployment and separate funding for carbon capture and storage demonstration and deployment—is consistent with recommendations from the National Commission on Energy Policy, which proposes a $4 billion program over ten years to stimulate IGCC deployment and $3 billion over ten years for commercial-scale demonstration of geologic carbon storage.[46] While analyzing the costs of capturing and storing incremental CO_2 emissions from converted units was beyond the scope of this paper, this option is worth evaluating, considering the benefits it would provide in reducing gas demand, providing practical experience with carbon capture and storage, and enabling the program to be carried out without an increase in CO_2 emissions.

Gasification is an established technology worldwide that offers the potential for supplying gas and reconciling coal use and environmental protection. Its application for industrial processes and power production in the U.S. has been modest due to historically low natural gas prices and the expectation that natural gas would be available for the foreseeable future at these low prices. The recent rise in natural gas prices has begun to stimulate commercial interest in gasification, but commercial development and utilization is likely to be a slow process that takes many years as companies, investors, and utility regulators become familiar with the technology. Government incentives to kick-start gasification deployment are required if it is to play a significant role in helping stabilize the natural gas supply/demand imbalance in the next decade.

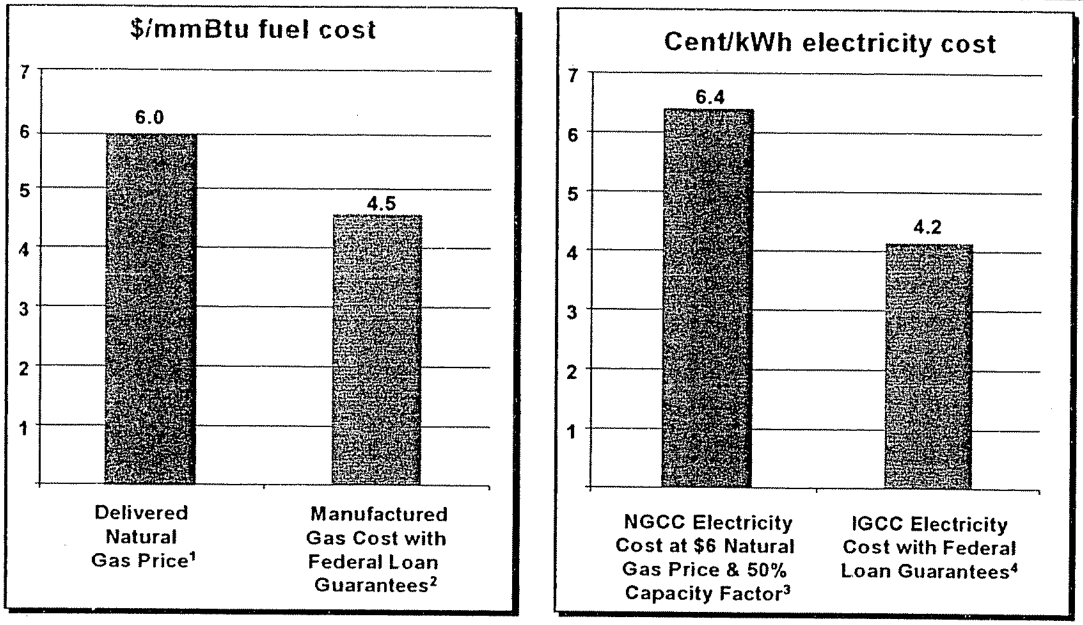
Loan Guarantees for Gasification

The federal government has a number of policy levers that could be incorporated in the National Gasification Strategy to stimulate investment in gasification technologies. The most significant policy options include credit financing support (loans, loan guarantees, performance guarantees, or lines of credit), tax incentives (investment tax credits, production tax credits, or accelerated depreciation treatment), or direct grants. As noted in the recent National Commission on Energy Policy report that recommends federal incentives to stimulate gasification investments, different incentives can be appropriate depending on the type of developer and development circumstances, suggesting that a suite of incentives may provide for the broadest participation.[47] At the same time, however, the federal budget impact of different approaches is a vital consideration given the current deficit and the focus in Washington on less, not more government spending. It is for this reason that loan guarantees provide a particularly attractive policy option for a National Gasification Strategy. Loan guarantees serve to provide access to capital markets, improve project economics, and minimize federal budget impacts.

A July 2004 report by Rosenberg, et al.[48] describes how coal gasification power plants (IGCC) could be made commercially viable if utilities, state public utility commissions, and the federal government join together (an arrangement referred to as the "3Party Covenant") to finance a fleet of plants. Federal loan guarantees allow higher leverage and provide for lower cost debt, thereby reducing the cost of capital by over 30%.[49] These savings can be passed on to industrial and residential customers in return for state public utility commissions (or municipal utilities in the case of public power) guaranteeing revenue to recover costs and prevent default on federally financed loans. Coal gasification power plants financed with federal loan guarantees as part of the 3Party Covenant would yield lower price power than conventionally financed new pulverized coal or natural gas plants operating in today's natural gas markets.[50]

Loan guarantees also enable debt investors to focus primarily on the federal guarantee to secure their investment rather than uncertain project economics and technology risks of an advanced technology deployment. Consequently, raising capital for a project becomes easier and less expensive for most developers, because debt investors protected by the federal guarantee can learn to become comfortable with technology and project risks in the future.

Figure 6. Cost of Manufactured Gas and IGCC Electricity with Loan Guarantees



Notes:
[1]YTD 2004 avg. electric generator natural gas price through August is 5.90 lb/mmBtu, see EIA: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm.
[2] See Appendix A for cost calculation. Assumes $500/MWth total plant investment (including construction financing and 10% reserve), 11.2% capital charge rate with loan guarantees that includes 10% owners cost, 90% gasifier capacity factor, $1.25/mmBtu fuel price, 75% gasifier efficiency, and O&M of 4% of capital cost.
[3] NGCC cost of energy calculated based on $510/kW overnight capital, 16.9% capital charge that includes 10% owner's cost, 50% plant efficiency, $6.00/mmBtu gas, 50% capacity factor, and 0.25 cent/kWh O&M.
[4] See Rosenberg et. el., *Deploying IGCC in this Decade with 3Party Covenant Financing*, pg. 14. Calculated based on $1,400/kW overnight capital, 12% capital charge that includes 10% owner's cost & 10% reserve, 85% IGCC capacity factor, $1.25 fuel cost, 39% IGCC efficiency, 0.80 cent/kWh O&M.

In the case of refueling existing natural gas combined cycle plants,[51] Independent Power Producer owners are generally not in a financial position to invest $500 million to $1 billion to construct gasification plants as a supply option. Federal credit support and upfront utility regulatory approval are necessary to enable a portion of this huge fleet of high natural gas demand plants to convert to gasification. Under the financing and regulatory proposal presented in the report by Rosenberg, et al., it is estimated that manufactured gas could be produced for $4.5/mmBtu and power could be produced for 4.2 cents/kWh, well below current gas prices of $6 -7.00/mmBtu and natural gas power that costs over 6 cents/kWh (Figure 6) (See Appendix A calculations).

Critical to the federal budget cost of any loan guarantee program is how the federal guarantee is secured. The budget cost of federal loan guarantees is governed by the Federal Credit Reform Act of 1990 (FCRA), which makes commitments of federal loan guarantees contingent upon prior budget appropriations ("budget scoring") of enough funds to cover the estimated present value cost of the guarantees. The present value cost is estimated based on the dollar amount guaranteed and the risk of loan default, which is typically evaluated by rating agencies and the Office of Management and Budget (OMB). Without any credit to protect the guarantee, the scoring cost will be based strictly on project risks, making the program more risky and expensive for the federal government. The alternative is to secure strong credit enhancement to substantially mitigate default risks and protect the federal guarantor, which reduces the federal budget scoring and program cost.

The 3Party Covenant mitigates loan default risk by establishing an assured revenue stream to service debt obligations through utility rate determinations. For the electric power sector, this type of revenue stream can be created through a state public utility commission or other ratemaking body (e.g., a municipality or rural electric cooperative) providing up-front and ongoing determinations of prudence and approvals of timely pass-through of project (or power purchase agreement) costs to ratepayers. This is the mechanism recommended under the 3Party Covenant to provide revenue certainty to reduce the risk and budget scoring cost of a federal loan guarantee program. Under this program, the federal risk is only that the state assurances unravel, which is why a low budget scoring of 10 percent or less is expected. With 10 percent budget scoring, if a one billion dollar loan is guaranteed, the cost scored to the federal budget would be $100 million.

In the case of industrial gasification projects, strong credit (and low budget scoring) could also be accomplished with corporate guarantees, off-take agreements with creditworthy entities, insurance, or other credit enhancements. The key factor is ensuring that the federal risk is mitigated sufficiently to reduce the budget scoring to an acceptable level, such as 10 percent or less of the loan principal. At this level, a loan guarantee program will be very cost effective for the federal government and enable a gasification incentive program to have a substantial impact in producing additional gas supply and easing natural gas demand at reasonable federal cost.

It should be noted here that the Alaskan Gas Pipeline legislation specifically determined that the $18 billion of loan guarantees would *not have to provide credit enhancement.*[52] If the Congress decided to accept similar risks under the National Gasification Program, the level of credit enhancement could be specified at lower levels than those recommended here, but budget costs would then increase.

Incentives vs. Regulation

In the 1970's after the Arab Oil Embargo, Congress enacted two regulatory programs to respond to natural gas shortages—the Fuel Use Act and the Coal Conversion Program. The Fuel Use Act prohibited utilization of natural gas in certain power plants and the Coal Conversion Program sought to convert, back to coal, natural gas electric generators that had previously used coal. Both programs had the unintended consequences of favoring coal-based generation without addressing resulting emissions of high polluting coal operations.

The National Gasification Strategy, on the other hand, advances deployment of the most advanced clean coal technologies and funds research, demonstration, and deployment of CO_2 sequestration technologies. The National Gasification Strategy is based on government incentives to stimulate investment rather than regulatory mandates.

Recommended National Gasification Strategy Legislation

It is recommended that Congress enact the National Gasification Strategy to manufacture the equivalent of 1.5 TCF of natural gas per year, using domestic coal, biomass, and petroleum coke. The National Gasification Strategy should be targeted to stimulate gasification investments to substitute for natural gas demand from both industrial and electric power users and needed research, development, demonstration, and deployment of CO_2 sequestration options, and include the following elements:

- $3 billion authorization and appropriations ($600 million per year for five years) for federal budget scoring and authorization of $30 billion of loan guarantees for industrial and electric sector gasification projects;
- Loan guarantee program requirements:
    - Qualification for guarantees contingent on owner establishing strong credit support to minimize federal government risks and ensure federal budget scoring of 10 percent (or less) of loan principal. (the 3Party Covenant with state public utility commission or other rate-making body would qualify);
    - Administered by the Secretary of Energy, who shall promulgate regulations implementing the program within 12 months of the date of program enactment;
    - Loan guarantees available to cover up to 80% of total investment in each project, provided that the project owner(s) contributes at least 20 percent equity to the project;
    - Environmental conditions for power generation projects:
        - 99% removal (including any fuel pretreatment) of sulfur with total sulfur dioxide emissions not to exceed 0.04 lb/mmBtu.
        - 95% removal (including any fuel pretreatment) of mercury
        - Nitrogen oxides emissions not to exceed 0.025 lb/mmBtu.
        - Total particulate emissions not to exceed 0.01 lb/mmBtu.
    - Priority given first to projects that will start up operations by December 31, 2009 and then to projects that will commence construction by December 31, 2009.
- Consideration of investment tax credits, tax provisions for accelerated depreciation treatment, and performance guarantees for gasification investments to ensure broader participation;
- $1 billion in grants or other incentives to support research, development, and demonstration of technologies for the capture and storage of CO_2 from gasification facilities and demonstration of biomass gasification technology;
- $2 billion in tax credits, grants, and loan guarantee scoring to support commercial deployment of carbon capture and storage technologies on gasification facilities.

(More details of the program are provided in Appendix B "Legislative Concepts.")

CONCLUSION

Natural gas production in North America has hit a plateau and can no longer keep up with growing demand in the U.S. As a result, the U.S. is facing a future with higher natural gas prices and a growing dependence on LNG imports for incremental supply. The National Gasification Strategy to manufacture synthesis gas from coal, biomass, and petroleum coke can provide additional domestic gas supply and ease natural gas demand to help alleviate price pressure and allow American industry to remain competitive. Federal loan guarantees backed by assured revenue streams, off take contracts, or corporate credit to substantially mitigate loan default risk, provide a cost-effective vehicle for government support for gasification technology investment. As part of a National Gasification Strategy, a $30 billion federal loan guarantee program, coupled with targeted tax incentives, will stimulate early industrial and electric sector investment in gasification projects across the country to manufacture the equivalent of 1.5 TCF per year of domestic gas supply. To address the expanded CO_2 emissions when coal or petroleum coke is the fuel, a concurrent research, development, demonstration, and deployment program focused on CO_2 capture and storage technology should be an integral part of the National Gasification Strategy.

APPENDIX A: SYNGAS COST CALCULATION

Plant Summary		
Gasifier Capacity (MWth)		1,000
IGCC Capacity (MWe)		500
Gasifier Syngas output (mmBtu/hour)		3,413
Gasifier Capacity Factor		90%
Annual syngas output (mmBtu)		26,908,092
IGCC Capital Cost		
Capital Cost ($/kWe)		1,596
Total Capital		798,000,000
Gasifier Capital Cost		
Capital Cost ($/kWth)	$	500
Total Capital	$	500,000,000
Capital Charge Rate		11.2%
Annual Capital Cost	$	56,000,000
Syngas Capital Cost ($/mmBtu)		**2.08**
Fuel Cost		
Gasifier Efficiency		75%
Coal Cost ($/mmBtu)	$	1.25
Annual coal cost	$	44,846,820
Syngas Fuel Cost $/mmBtu		**1.67**
O&M		
Annual O&M	$	20,000,000
O&M ($/mmBtu)		**0.743**
Total Syngas Cost ($/mmBtu)		**4.5**
National Gasification Strategy		
Number of IGCC Plants		28
Cost of IGCC Plants		22,344,000,000
IGCC Loan Guarantee Program		17,875,200,000.0
IGCC Plants Syngas Production (mmBtu)		753,426,576
Number of Industrial Gasifiers		30
Cost of Industrial Gasifiers		15,000,000,000.0
Industrial Gasifier Loan Guarantee Program	$	12,000,000,000
Industrial Gasifier Syngas Production (mmBtu)	$	807,242,760
Total Investment under Program	$	37,344,000,000
Total Loan Guarantee Program	$	29,875,200,000
Program Total Syngas Production (mmBtu)		1,560,669,336
Natural Gas Equivalent (Mcf)		1,515,212,948

APPENDIX B: LEGISLATIVE CONCEPTS FOR NATIONAL GASIFICATION STRATEGY LOAN GUARANTEE PROGRAM

1. PURPOSE AND GOALS.

The purpose of this act is to establish a federal loan guarantee program as part of the National Gasification Strategy to stimulate commercial deployment of integrated gasification combined cycle and industrial gasification technology in order to:

a. Develop gasification as a gas supply option that provides the energy equivalent of 1.5 TCF of natural gas:

b. Promote the use of domestic coal and biomass and other domestic fuel resources;

c. Reconcile coal use and environmental protection;

d. Reduce the demand pressure on domestic natural gas prices and supply by promoting the use of gas derived from domestic coal and biomass and other domestic fuel resources for electric generation and industrial use;

e. Provide affordable and reliable electricity and gas supply;

f. Promote the position of the U.S. as a global leader in advanced gasification technology; and

g. Accomplish the goals in subsections (a) through (f) of this section while restricting the burden on the federal budget.

2. DEFINITIONS.

a. The term "carbon capture ready" shall mean, with regard to a project, having a design that is determined by the Secretary of Energy to be capable of accommodating the equipment likely to be necessary to capture the carbon dioxide that would otherwise to emitted in flue gas from the project.

b. The term "IGCC project" shall mean a project for which coal will account for at least 50% of annual heat input and any other liquid or solid fuel will account for the remainder, and electricity will account for at least 75% of annual useful energy output, during the term of the federal loan guarantee under section 3.

c. The term "industrial coal gasification project" shall mean a project for which coal, biomass, and any other liquid or solid fuel, in any combination, may account for annual fuel heat input, and electricity will account for less than 75% of annual useful energy output, during the term of the federal loan guarantee under section 3.

d. The term "project" shall include an IGCC project or an industrial coal gasification project and shall mean:

1. Any combination of equipment located at a specific site and used to gasify coal, biomass, or other liquid or solid fuel, and remove pollutants from the gas, for industrial purposes (except electric generation); or

2. Any combination of equipment used to gasify coal, biomass, or other liquid or solid fuel, burn the gas in a turbine, and generate electricity (including existing natural gas combined cycle plant refueled using gasification technology).

e. The term "Secretary of Energy" shall mean the Secretary of the United States Department of Energy.

f. The term "total plant investment" shall mean the total amount, for a project, of the engineering, procurement, and construction costs, the owner's costs in developing and starting up the project, the construction financing costs, and the contingency reserves under paragraph (b)(7) of section 5.

3. SCOPE AND DEADLINES.

a. The federal loan guarantee program will provide for a total amount of $30 billion of federal loan guarantees, with authorization of appropriations of $3 billion over 5 years for budget scoring under the Federal Credit Reform Act of 1990, such that:

1. Up to $12 billion of the total amount of federal loan guarantees will be issued for industrial coal gasification projects; and

2. The remaining portion of the total amount of federal loan guarantees will be for IGCC projects.

b. The federal loan guarantee program will be administered by the Secretary of Energy, who shall promulgate regulations implementing the program within 12 months of the date of enactment of this act and shall issue federal loan guarantees, and commitments for such federal loan guarantees, pursuant to such regulations. The Secretary of Energy may, to the extent he or she determines to be appropriate, require by regulation and collect application and other fees to cover administrative costs and insurance fees to reduce the burden on the federal budget.

c. The Secretary of Energy shall issue the federal loan guarantees under subsection (b) of this section for projects selected under section 6, and shall require construction to commence on such projects, within ten years after the deadline under subsection (b) of this section for promulgation of implementing regulations. In issuing such federal loan guarantees, the Secretary of Energy shall give priority first to projects that will commence operation by December 31, 2009 and then to projects that will commence construction by December 31, 2009.

4. PROVISIONS OF FEDERAL LOAN GUARANTEES.

Each federal loan guarantee under section 3 shall:

a. Cover up to 80% of the total plant investment in each project selected under section 6, provided that the project owner must provide equity investment in such project of at least 20% of the total plant investment;

b. Apply to the project's long-term debt obligations, which may, at the discretion of the Secretary of Energy, be non-recourse and shall have a term of up to 30 years; and

c. Be backed by the full faith and credit of the United States.

5. QUALIFYING PROJECTS.

a. The Secretary of Energy shall establish, by regulation, the submission requirements and procedures for an application for a federal loan guarantee under section 3.

b. In order to be considered by the Secretary of Energy for a federal loan guarantee, the owner of a proposed project must demonstrate, in an federal loan guarantee application submitted to the Secretary of Energy, that:

1. For a proposed IGCC project, the project will meet the following requirements:

A. Coal will account for at least 50% of annual fuel heat input, and any other liquid or solid fuel will account for the remainder, during the term of the federal loan guarantee;

B. Electricity will account for at least 75% of annual useful energy output during the term of the federal loan guarantee;

C. To the extent that electricity will be generated at the project, the generation portion of the project will have a design heat rate of 8,900 btu/KWh (HHV) or lower. To the extent that the project gasifies coal, biomass, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the non-generation portion of the project will have a design efficiency of [TO BE ADDED]; and

D. The project will be a new power plant, a repowering of an existing coal power plant, or a refueling of an existing natural gas combined cycle power plant; and

2. For a proposed industrial coal gasification project, the project will meet the following requirements:

A. Coal, biomass, or other liquid or solid fuel, in any combination, will account for annual fuel heat input during the term of the federal loan guarantee; and

B. To the extent that electricity will be generated at the project, the generation portion of the project will have a design heat rate of 8,900 Btu/KWh (HHV) or lower (except in the case of facilities using biomass). To the extent that the project gasifies coal, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the non-generation portion of the project will have a design efficiency of [TO BE ADDED] (except in the case of facilities using biomass).

3. To the extent that electricity will be generated at the project, the project will comply with the following enforceable emission limitation requirements, in addition to any other applicable federal or state emission limitation requirements:

A. 99% removal (including any fuel pretreatment) of sulfur from the coal-derived gas, and any other fuel, burned in the generation of electricity and total sulfur dioxide emissions in flue gas from the electric generation portion of the project not exceeding 0.04 lb/mmBtu;

B. 95% removal (including any fuel pretreatment) of mercury from the coal-derived gas, and any other fuel, burned in the generation of electricity;

C. Total nitrogen oxides emissions in the flue gas from the electric generation portion of the project not exceeding 0.025 lb/mmBtu; and

D. Total particulate emissions in the flue gas from the electric generation portion of the project not exceeding 0.01 lb/mmBtu.

4. To the extent that the project gasifies coal, biomass, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the project will comply with the following enforceable emission limitation requirements, in addition to any other applicable federal or state emission limitation requirements:

A. 99% removal (including any fuel pretreatment) of sulfur from the coal-derived gas, and any other fuel, used in the non-electric generation portion of the project and total sulfur dioxide emissions in the flue gas from the non-electric generation portion of the project not exceeding XX ppm; [TO BE ADDED]

B. [95%] removal (including any fuel pretreatment) of mercury from the coal-derived gas, and any other fuel, used in the non-electric generation portion of the project; [TO BE ADDED]

C. Total nitrogen oxides emissions in the flue gas from the non-electric generation portion of the project not exceeding [5] ppm; and [TO BE ADDED]

D. Total particulate emissions in the flue gas from the non-electric generation portion of the project not exceeding XX ppm. [TO BE ADDED]

5. The project will be carbon capture ready (except for biomass projects which are assumed to be net zero carbon emissions).

6. The project will have an assured revenue stream (acceptable to the Secretary of Energy, consistent with the purpose and goals in section 1) covering the project capital and operating costs (including the costs of servicing all debt obligations covered by the federal loan guarantee) through:

A. Procedures established by the State public utility commission or commissions, or by the other governmental body or bodies, with jurisdiction over the prices charged for the electricity produced by the project and providing:

i. Upfront review, and ongoing periodic review (starting during construction), of the prudence of project capital and operating costs; and

ii. Timely recovery of those project capital and operating costs determined to be prudent; or

B. Insurance, customer guarantees, or other credit enhancements that provide credit and federal budget scoring acceptable to the Secretary, consistent with the purpose and goals in section 1.

7. The total plant investment for a project will include a reserve equal to at least 10%, and not exceeding 20%, of the engineering, procurement, and construction cost of the project in order to cover construction modifications or overruns or revenue shortfalls or additional costs due to startup operations, unscheduled maintenance, and other factors.

6. PROJECT SELECTION AND ISSUANCE OF FEDERAL LOAN GUARANTEES.

a. The Secretary of Energy shall establish, by regulation, the review and approval criteria and procedures for selecting a proposed project for a federal loan guarantee under section 3.

b. The review and approval criteria applied to each proposed project shall include the following:

1. A determination that the project meets the application demonstration requirements in subsection (b) of section 5 and the budget scoring requirement in subsection (d) of this section;

2. A determination that the project is technically and economically feasible;

3. An evaluation of the financial strength of the project;

4. An evaluation of the environmental performance of the project;

5. The project priorities in subsection (c) of section 3; and

6. Any other criteria determined by the Secretary of Energy to be consistent with the purpose and goals in section 1.

c. In applying the review and approval criteria to each proposed project, the Secretary of Energy shall ensure that, to the extent practicable, the portfolio of projects issued federal loan guarantees under section 3 will result in gasification of a diversity of coal types and other fuel types and in a geographic diversity of projects.

d. The Secretary of Energy shall issue a federal loan guarantee to a proposed project only if the federal loan guarantee for such project has a budget scoring under the Federal Credit Reform Act of 1990 that does not exceed a percentage level established by the Secretary of Energy, consistent with the purpose and goals specified in section 1.

7. ADDITIONAL REQUIREMENTS AND PROCEDURES.

The Secretary of Energy is authorized to adopt by regulation:

a. Conditions for the disbursement of funds subject to a federal loan guarantee under section 3;

b. Procedures and requirements for monitoring and reporting the status of projects issued federal loan guarantees under section 3; and

c. Procedures for taking actions to restrict the impact on the federal budget in the event of foreclosure of a project issued a federal loan guarantee under section 3.

8. CARBON REDUCTION.

The Secretary of Energy is authorized to provide:

a. \$1 billion in grants or other incentives to support research, development, and demonstration of technologies for the capture and storage of carbon from projects for which federal loan guarantees under section 3 are issued and for research, development, and demonstration of biomass gasification technologies; and

b. \$2 billion in tax credits, grants, and loan guarantee scoring to support commercial deployment of technologies for capture and storage of carbon from projects for which federal loan guarantees under section 3 are issued.

NOTES

[1] Energy Information Administration, *Natural Gas Monthly*, Nov. 2004, Table 4.
[2] Based on $3.30/mmBtu applied to current national consumption of 22 TCF.
[3] The economic consequences of high prices are described broadly in the 2003 House Speaker's Task Force for Affordable Natural Gas report. See House Energy and Commerce, Task Force for Affordable Natural Gas, *Natural Gas: Our Current Situation,* (Sept. 30, 2003).
[4] This cost assumes low federal budget scoring of the loan guarantees based on a program requirement that the guarantees are secured with strong credit backing.
[5] See Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3a.htm
[6] See Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3M.htm; See also National Petroleum Council, Balancing Natural Gas Policy—Fueling Demands of a Growing Economy (Sept. 2003, National Petroleum Council, Washington DC), pg. 22.
[7] National Petroleum Council (Sept. 2003) pg. 5.
[8] See Energy Information Administration, *Annual Energy Outlook 2002*, Table 23, Comparison of Natural Gas Forecasts (showing that the range of projected natural gas wellhead prices in 2020 was between $2.94/Mcf to 3.65/Mcf).
[9] Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm indicating October 2004 wellhead prices were $5.45/Mcf, which equates to $5.3/mmBtu.
[10] See Energy Information Administration, *Short-term Energy Outlook*, December, 2004.
[11] Annual Energy Outlook Reference Case forecasts between 1996 and 2002 projected U.S. dry gas production in 2005 would be between 19.7 and 22.7 TCF, with the average across the projections being 21.3 TCF. The December 2004 Short-Term Energy Outlook now projects 19.1 TCF of production, which is 2.2 TCF below the average of the projections during the seven year period prior to 2002.
[12] Energy Information Administration, *Annual Energy Outlook 2005*, Table A3.
[13] Id. Table A13, A14.
[14] American Chemistry Council, "Energy Costs Destroying Chemical Manufacturing Competitiveness," (Nov. 3, 2004 news release).
[15] The Fertilizer Institute. "Fertilizer Industry Weights in on Energy Crisis at Natural Gas Summit. (June 26, 2003 news release).
[16] Id.
[17] For example, on May 4, 2004, Duke Energy announced the sale of 5,325 MW of eight natural gas-fired power plants in the Southeast U.S. for $475 million, or about $90/MW, which is less than one-fifth of their original cost. In a related matter, Duke Energy announced in January, 2004 that it was taking a $3 billion write off from 2003 earnings, in large part because of the decline in value of its natural gas generation fleet in the Southeast U.S. See http://www.dukeenergy.com/news/releases/2004/jan/2004010701.asp. As of April 2004 as much as 33,000 MW of distressed natural gas capacity was for sale, and many natural gas-fired power plants had already been repossessed by lending institutions, including Citibank (4,150 MW), Societe Generale (5,550 MW) and BnP Paribas (3,400 MW). See NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.
[18] In the regulated Florida market, for example, combined cycle power plants operated at 50% capacity factors in 2003 despite high natural gas prices. See Florida Public Service Commission, *Statistics of the Florida Electric Utility Industry 2003*, Sept. 2004.
[19] See Energy Information Administration, *Annual Energy Outlook 2005*, Table A14.
[20] Based on 2003 data. See Energy Information Administration, Office of Oil and Gas, Reserves and Production Division at:
http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngcap2003/ngcap2003.html
[21] For example, the Annual Energy Outlook 2005 production forecast indicates lower 48 production will peak around 2015. See Energy Information Administration, *Annual Energy Outlook 2005*, Table A14.
[22] See National Commission on Energy Policy (NCEP), *Ending the Energy Stalemate, A Bipartisan Strategy to Meet America's Energy Challenges* (Washington DC, National Commission on Energy Policy, Dec. 2004) Figure 4-4.
[23] Dow Jones Newswire, "Alaska Gas Pipeline Project Aided by Gov't Help," Oct. 27, 2004.

[24] NCEP (Dec. 2004) pg. 46; citing National Commission on Energy Policy, Increasing U.S. Natural Gas Supplies: A Discussion Paper and Recommendations (Washington, DC National Commission on Energy Policy, 2003).

[25] See H.R.4837, *Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act*, 2005.

[26] See H.R. 4520, American Jobs Creation Act of 2004, Sec. 706-707.

[27] Energy Information Administration, *Annual Energy Outlook 2005*, Table A13.

[28] The terminals are located in Cove Point, Maryland; Elba Island, Georgia, Everett, Massachusetts, and Lake Charles, Louisiana.

[29] Energy Information Administration, *U.S. LNG Markets and Uses*, June 2004.

[30] Id.

[31] For example, ExxonMobil announced in December 2004 they had arranged $12 billion of financing to move forward with their joint venture Qatargas II project (See Dallas Business Journal, December 15, 2004) and Shell announced in March 2004 an agreement with Libya to develop LNG resources (See BBC News, March 25, 2004).

[32] Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2a.htm; Energy Information Administration, *Short-term Energy Outlook*, December 2004.

[33] In the last 5 years, 115,000 MW of NGCC power plant capacity was built that was designed to operate about 65 percent of the time. On average, these plants are now reportedly running less than 15 percent of the time. At an average of 15 percent capacity factor, the NGCC plants use about 1 TCF/year of natural gas, if they operated at the expected 65% capacity factor they would use 4.3 TCF/year, resulting in a 64 percent increase in electric generator natural gas demand without additional capital investment.

[34] Syngas also contains some carbon dioxide (CO_2), moisture (H_2O), hydrogen sulfide (H_2S) and carbonyl sulfide (COS) as well as small amounts of methane (CH_4), ammonia (NH_3), hydrogen chloride (HCl) and various trace components from the feedstock. See SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 7.

[35] The heat content of syngas can vary depending on the gasifier type and fuel feedstock. Typical heat content of syngas produced from large gasification systems is around 250 Btu/cf, which is 24 percent of the 1.028 Btu/cf heating value of dry natural gas.

[36] Methanation is a process for removing carbon monoxide from gas streams or for producing methane by the reaction $CO + 3H2 \rightarrow CH4 + H2O$.

[37] Presentation by James Childress, "2004 World Gasification Survey: A Preliminary Evaluation," Gasification Technologies Conference, Washington, DC (Oct. 4-6, 2004).

[38] In addition to the two integrated gasification combined cycle (IGCC) facilities operating in the U.S., American Electric Power and Cinergy Corporation have both announced intentions to develop new IGCC power plants in the U.S. and Excelsior Energy and Southern Company received funding grants in 2004 from the Department of Energy to develop IGCC facilities.

[39] GE Energy Gasification Technologies acquired the ChevronTexaco process July 1, 2004.

[40] ConocoPhillips acquired the patents and intellectual property rights to Global Energy's proprietary E-GAS gasification process in 2003. This technology was originally developed by Dow Chemical Company and later transferred to Destec, a partially held subsidiary of Dow Chemical. In 1997, Destec was purchased by Houston-based NGC Corporation, which became Dynegy, Inc. in 1998. In December 1999, Global Energy Inc. purchased the gasification technology from Dynegy and in 2003 ConocoPhillips purchased the technology from Global Energy (see DOE, Clean Coal Technology Topical Report Number 20, "The Wabash River Repowering Project—an Update," Sept. 2000, p. 4).

[41] The performance and economics of the Shell gasification system are described in a paper presented by Shell at the 2004 Gasification Technology Conference in Washington DC. See H.V. van der Ploeg, T. Chhoa, P.L. Zuideveld, *The Shell Coal Gasification Process for the US Industry* (Oct. 2004).

[42] See NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technology*, Dec. 2002, citing DOE—EPRI Report 1000316, Dec. 2000. See also Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.

[43] NCEP (2004).

[44] See NETL, *Major Environmental Aspects*, Dec. 2002, citing DOE—EPRI Report 1000316, Dec. 2000. See also Jeremy David and Howard Herzog, *The Cost of Carbon Capture*, 2000.

[45] Larson, E. D., S. Consonni, and R. Katofsky, "A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry," Final Report, 8 October 2003 (available at: http://www.princeton.edu/~energy/publications/texts.html#2003).

[46] NCEP (2004), p. 55.

[47] Id.

[48] Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, *Deploying IGCC Technology in this Decade with 3Party Covenant Financing*, Kennedy School of Government, Harvard University, July 2004 (available at: www.ksg.harvard.edu/bcsia/enrp).

[49] Id. Vol. I, pg. 14.

[50] Id. Vol. I, Table 5-7, Table 5-8.

[51] The devaluation and market availability of underutilized natural gas generation assets presents an important opportunity for early and cost-effective coal gasification refueling. The combined cycle power block associated with new NGCC power plants can be converted to use synthesis gas from a coal gasifier for a nominal cost that could be more than made up for by the savings associated with using a distressed, devalued NGCC asset.

[52] The legislation states: "The Secretary shall not require as a condition of issuing a Federal guarantee instrument under this section any contractual commitment or other form of credit support of the sponsors (other than equity contribution commitments and completion guarantees), or any throughput or other guarantee from prospective shippers greater than such guarantees as shall be required by the project owners." See H.R.4837, Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005, Sec. 116(b)(3).