NCEP Technical Appendix

Chapter 4: Expanding Energy Supplies

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ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Natural Gas Issues for the U.S. Industrial and Power Generation Sectors

Executive Summary

Submitted to:
National Commission on Energy Policy

May 2004

Submitted By:

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Natural Gas Issues for the U.S. Power Generation and Industrial Sectors

Natural gas is a primary fuel for the residential, commercial and industrial sectors and increasingly for power generation. In the last four years, natural gas prices have increased significantly and seem to have reached a new stable level almost twice as high as in recent prior years. The last few years have also seen increasing volatility in gas prices. The increase in prices and resulting concerns over supply have raised a variety of questions about natural gas and its role in and effect on the economy.

The industrial sector is the largest consumer of natural gas and the power generation industry is the fastest growing consumer of gas. Between them, they accounted for over 60 percent of U.S. natural gas consumption in 2002[1]. Gas consumption for power generation increased by over 70 percent from 3,342 TBtu in 1990 to 5,721 TBtu in 2002. From 1999 to 2003, more than 150 GW of new power plants were constructed, almost all of them gas-fired and representing the largest per annum increment of new power generating capacity in U.S. history. There is concern that this growth in gas generation and plant construction will continue and greatly increase the demand for natural gas beyond the ability of North America to meet the demand.

In the last few years, U.S. industry suffered a downturn in output and a large loss of manufacturing jobs. Industrial gas demand dropped by 15 percent from 1997 to 2002. Some industries see gas prices as the primary reason for this downturn. They predict that a continuation of higher gas prices will result in permanent loss of U.S. manufacturing capacity and jobs. The loss of gas demand due to the negative impacts of gas prices on the industrial sector is sometimes referred to as "demand destruction". The recent drop in industrial gas demand, characterized as demand destruction, is perceived by some as an indication that high gas prices are having a significant and permanent negative effect on the industrial sector.

EEA has recently completed two reports for the National Commission on Energy Policy examining recent trends in natural gas markets for the industrial and power generation sectors. It addresses issues including:

- What impact have high gas prices had on industrial production, jobs and the broader economy?
- What is the extent and impact of "demand destruction"?
- What has caused increased gas use in power generation?
- What is the impact of new gas-fired power plants – recent and future?
- What is future role of gas in power generation?
- What is the role of fuel switching in the industrial and power generation sectors? How much is available and how will it affect gas markets?

[1] All energy data are from U.S. Energy Information Administration unless otherwise noted.

Industrial Sector

Industrial Sector Background

- The industrial sector is the largest U.S. consumer of natural gas accounting for 37 percent of total gas consumption.
- Overall energy consumption and gas use are concentrated in a few industries. The chemicals and refining industries alone account for more than 50 percent of industrial gas consumption.
- The energy intensive industries are the basic industries, which convert raw materials into intermediate products such as steel, bulk chemicals, plastics, etc. They directly account for a small share of industrial production and employment. The chemicals and refining industry account for only 8 percent of industrial production and 4 percent of industrial employment.
- GDP and employment are concentrated in the less energy intensive industries that produce higher value finished products. The construction, metal durables and "other manufacturing" industries account for 64 percent of industrial GDP and 67 percent of industrial sector employment but only 14 percent of industrial sector gas use. Most of the job losses in the last 5 years have been in the non-gas-intensive light manufacturing industries.
- On average, energy represents only a few percent of the cost of production for industry. For the high value, high employment industries the gas share of production cost is less than 1 percent. For these industries, even large changes in gas prices have a relatively small impact on production cost, though for industries that are already suffering competitive challenges, even small changes can have an effect.
- There are a few industries for which gas represents more than 10 percent of production cost. These tend to be industries such as fertilizer, in which gas is the raw material as well as the fuel. The most vulnerable industries are typically those that are also strongly affected by international competition. However, changes in international markets can have positive or negative effects that are as big as recent gas price trends.

History of Industrial Gas Consumption and Recent Trends

- Industrial gas use peaked in 1973 and then declined for several years due to a variety of factors including rising gas prices and increased energy efficiency.
- Industrial gas use started to increase during the mid 1980s due to lower gas prices and new applications of gas. This trend continued through 1997.
- Industrial gas consumption peaked in 1997 and then started to decline prior to the gas price increases in 2000-01 due to reduced industrial production in the energy intensive industries. This decline in consumption intensified after the increase in gas prices in 2000-01 and 2003.

Gas Use in the Chemical Industry

- The chemical industry is the largest user of natural gas and has some of the most vulnerable segments to high gas prices. The ammonia/fertilizer industry is especially vulnerable because it relies on gas as a feedstock as well as a fuel and because it must compete with ammonia imports from countries with much lower gas prices.
- Although some less efficient ammonia plants have shut down in recent years, U.S. ammonia manufacturing capacity was higher at the end of 2002 than it was in 1992 and is still adequate to meet U.S. demand.
- Reduced ammonia production in recent years seems of a variety of market factors including demand issues related to agricultural cycles. Gas price is one of the factors but not clearly the most important.
- Imports of ammonia and ethylene have been increasing for many years and have continued to increase in the last few years. Over time, imports from countries with lower production costs are likely to increase under currently likely U.S. gas price scenarios.

Overall Industrial Sector Conclusions

- Industrial gas demand was about 14 percent lower in 2002 than at its recent peak in 1997. This reduction was a combination of reduced demand due to an economic downturn, effects of international trade and the effect of high gas prices on some gas-intensive industries. It is difficult to separate these effects but the economic downturn seems to have played a larger role than gas prices. As of early 2004, industrial output is starting to increase, despite continued high gas prices.
- The gas-intensive basic industries in the U.S. are mature and some are vulnerable to competition from other countries with lower energy, labor and raw material costs. These industries may continue to decline in the future under currently likely gas price scenarios, depending on changes in world markets. Gas-intensive industries that do not have foreign competition will try to pass higher gas prices on to their customers. Their success will depend on many factors, though gas price is a small share of production cost for even most gas-intensive industries.
- These continued changes may cause industrial gas demand to decline from historic levels but gas prices at the current levels will be only one of several contributing factors.
- This assessment reflects the general influence of natural gas prices on U.S. industrial sector competitiveness. While the analysis does distinguish between the various categories of activity in the industrial sector and offers insights into the areas most affected by high prices and the potential impacts of sustained high prices, specific companies or industries could experience more significant impacts than described here. An exhaustive review of corporate profit margins and industrial competitiveness compared against the economics of commodity imports is beyond the scope this work.

Power Generation

- Gas consumption for power generation increased from 3,342 TBtu in 1990 to 5,721 TBtu in 2002. Even with this growth, gas generation was a smaller share of the U.S. total in 2002 than in 1970 (18 percent in 2002 vs 24 percent in 1970).
- This growth in gas consumption was the result of a variety of factors. In large part it was a response to growing demand for electricity and a lack of new generating facilities during the 1990s. In many regions, other types of generating facilities have reached maximum utilization, leaving gas-fired plants as the only resources available to meeting growing demand. Regional factors also contributed, such as low hydroelectric generation in the west at the end of the 1990s.
- 152 GW of new gas-fired generating capacity was installed in the U.S. between 1999 and 2002 with another 40 GW under construction. This is the largest increment of new capacity ever to be installed in the U.S. in such a period of time.
- This new gas capacity has not yet had a large effect on gas consumption. About one third of the new capacity is simple cycle peaking turbines that run very little and do not consume a lot of gas. Many of the new baseload combined cycle units are not running at full load due to start-up or competitive issues.
- In areas with substantial existing gas capacity and open electric markets, such as Texas, new gas generators are displacing older, less efficient gas plants. Although absolute gas use in these areas has increased, it has increased less than it would have if the new plants had not been built.
- Half of the gas used for power generation is consumed in California and Texas and these two states accounted for most of the growth in gas consumption for power generation during the 1990s.
  - In Texas, newer, very efficient plants provided much of the generation, displacing older, less efficient gas plants. Gas consumption went up but less than it would have without the new plants.
  - In California, the growth was largely consumption in older plants trying to meet growing demand during a time of low hydroelectric generation. More recently, new plants are starting to replace generation from the older plants, as in Texas.
- As electric demand continues to grow, new gas generators in areas that historically relied on other fuels may start to create incremental gas demand growth. At current gas prices however, new coal plants may start to enter the market as alternatives to the gas plants. The U.S. DOE reports that 62 GW of new coal generating capacity currently proposed or under development. This mix will also be affected the status of electric restructuring, growth in the economy and other broader factors.
- The recent rapid increase in gas consumption for power generation was the result of a mix of institutional, economic, technological and weather-related factors. Continued

changes in these factors could result in slower gas demand growth for power generation in coming years.

Fuel Switching

- Many gas-fueled industrial and power generation facilities have historically had the capacity to switch from gas to oil for short periods of time. This capability allows the facilities to switch to lower priced oil when gas prices are high and to maintain operations when gas supplies are limited due to supply or delivery constraints.
- Fuel-switching can have a high value for customers during periods of high price or constrained supply. It can also help reduce gas prices during periods of peak demand.
- Fuel switching is usually a response to weather conditions and local supply constraints. Its occurrence and effect on gas markets is therefore most significant on a local or regional basis.
- Most fuel switching capacity is designed and permitted for short-term use - a few days to a few months per year at the most. Some of this capacity could be converted to long-term switchable capacity at some capital cost to increase fuel storage capacity, emission controls and other required equipment.
- EEA estimates that total switchable capacity could be as much as 16 billion cubic feet per day (Bcfd), compared to average daily demand of 63 Bcfd. However, it is unlikely that all of this capacity would be switched on any one day because of regional and operational diversity.
- Fuel switching of about 8 to 10 Bcfd has been observed during recent periods of high gas prices. Of this, about one third is industrial switching and the remainder power generation.
- Fuel switching data for the industrial sector are limited and dated. The available data indicate about 4 Bcfd of switchable capacity in boilers and process heaters.
- There is a significant amount of short-term switching capability in conventional gas steam power plants but very little in new combined cycle plants. As new combined cycle plants replace older gas steam plants, fuel switching capability will be decreased.
  - About 36 percent of the 104 GW of gas boilers used for power generation are identified as having capability to switch to residual oil. About 32 percent report actually using residual oil between January 2000 and January 2002. This is about 8.5 Bcfd of capacity.
  - Only about 6 percent of the 116 GW of new gas combined cycle capacity reports having alternative fuel capability (distillate oil), accounting for about 1.1 Bcfd. About 19 percent of the new peaking turbines report switching capability (2.6 Bcfd) but these units run very few hours per year.

- Some operational capacity to switch fuels on very short notice has probably been lost over the last decade when it was used very little. Changes in equipment and new environmental regulations have also caused reductions in fuel-switching capacity.
- In the long term, fuel switching capacity can be regained or expanded if fuel prices make it economic. However, this would require a sustained period of gas prices significantly higher than current levels.

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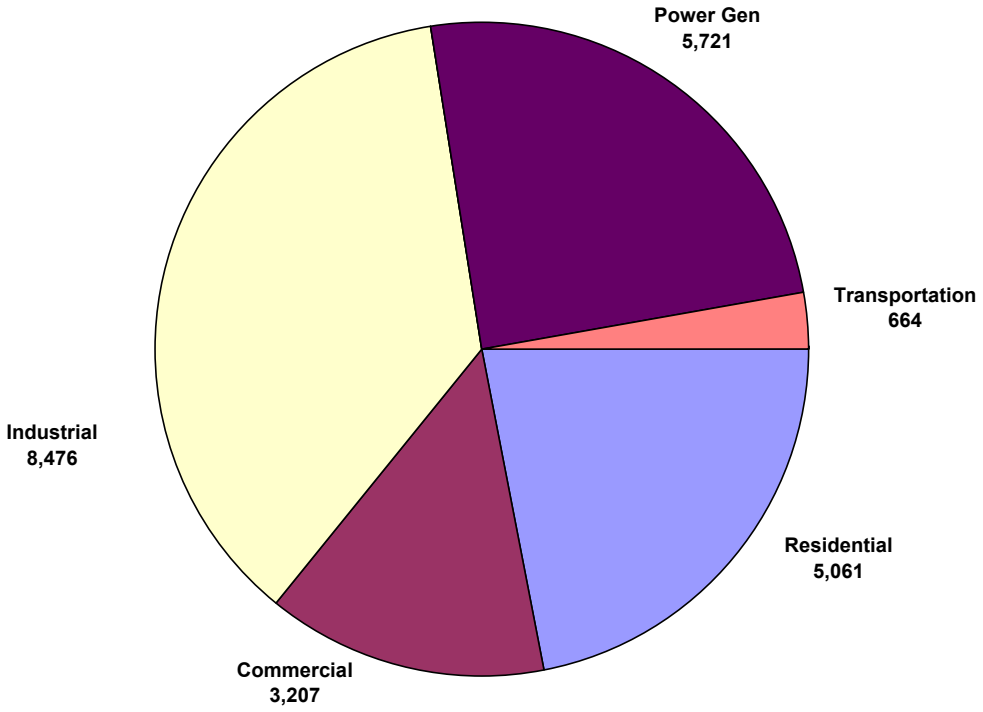
Executive Summary

Power generation is the second largest component of U.S. natural gas consumption, consuming 5,721 trillion Btu (TBtu) or 25 percent of U.S. total gas consumption in 2002 (Figure 1). However, power generation is the fastest growing gas-consuming sector, with consumption increasing by more than 70 percent from 1990 to 2002 (Figure 2). Most forecasts project this trend to continue, with gas consumption for power generation constituting the fastest growing component of gas demand, reaching more than 10 Quads by 2020 (Figure 3). This increase is widely attributed to the recent wave of construction of new gas-fired power plants and stringent environmental requirements on power plants. Over 150 GW of new gas-fired capacity have been constructed since 1999 with more still under construction. Almost all new power plants recently constructed and, until recently, most of the planned additions, are gas-fired. This rapid recent growth and the prospect for continued growth have made power generation the focus of much of the concern over the current imbalance between gas supply and demand. This paper examines the background of these issues and the likely implications.

Figure 1
U.S. Natural Gas Consumption by Sector – 2002[1]
(TBtu)



[1] All energy consumption and power generation data are from the U.S. EIA unless otherwise noted.

Figure 2
U.S. Gas Consumption for Power Generation 1990-2002- (TBtu)

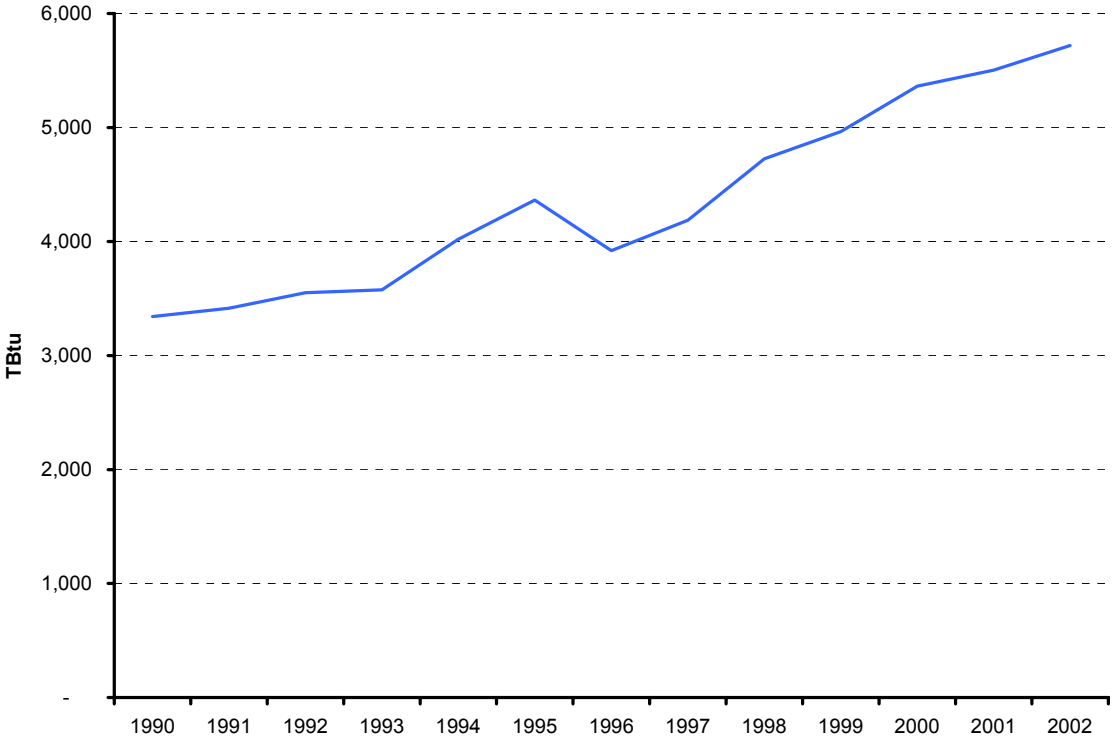
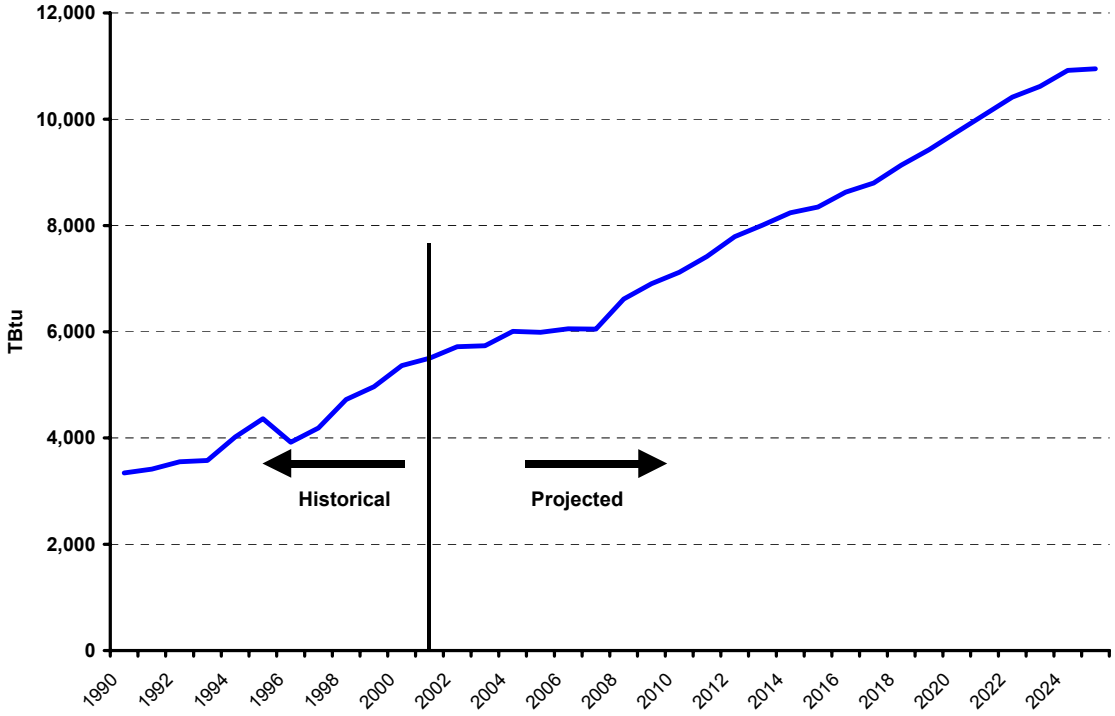


Figure 3
Historical and Projected Gas Consumption for Power Generation - (TBtu)



Data Source: EIA

The conclusions of this analysis can be summarized as follows.

- Gas consumption for power generation increased from 3,342 TBtu in 1990 to 5,721 TBtu in 2002. Even with this growth, gas generation was a smaller share of the U.S. total in 2002 than in 1970 (18 percent in 2002 vs. 24 percent in 1970).
- This growth in gas consumption was the result of a variety of factors. In large part it was a response to growing demand for electricity and a lack of new generating facilities. In many regions, other types of generating facilities have reached maximum utilization, leaving gas-fired plants as the only resources available to meeting growing demand. Regional factors also contributed, such as low hydroelectric generation in the west at the end of the 1990s.
- 152 GW of new gas-fired generating capacity was installed in the U.S. between 1999 and 2002 with another 40 GW under construction. This is the largest increment of new capacity ever to be installed in the U.S. in such a period of time.
- This new gas capacity has not yet had a large effect on gas consumption. About one third of the new capacity is simple cycle peaking turbines that run very little and do not consume a lot of gas. Many of the new baseload combined cycle units are not running at full load due to start-up or competitive issues.
- In areas with substantial existing gas capacity and open electric markets, such as Texas, new gas generators are displacing older, less efficient gas plants. Although absolute gas use in these areas has increased, it has increased less than it would have if the new plants had not been built.
- Half of the gas used for power generation is consumed in California and Texas and these two states accounted for most of the growth in gas consumption for power generation during the 1990s.
  - In Texas, newer, very efficient plants provided much of the generation, displacing older, less efficient gas plants. Gas consumption went up but less than it would have without the new plants.
  - In California, the growth was largely consumption in older plants trying to meet growing demand during a time of low hydroelectric generation. More recently, new plants are starting to replace generation from the older plants, as in Texas.
- As electric demand continues to grow, new gas generators in areas that historically relied on other fuels may start to create incremental gas demand growth. At current gas prices however, new coal plants may start to enter the market as alternatives to the gas plants. The U.S. DOE reports that 62 GW of new coal generating capacity is currently proposed or under development. This mix will also be affected by the status of electric restructuring, growth in the economy and other broader factors.

- There is a significant amount of short-term fuel switching capability in conventional gas steam power plants but very little in new combined cycle plants. As new combined cycle plants replace older gas steam plants, fuel switching capability will be decreased.
  - About 36 percent of the 104 GW of gas boilers used for power generation are identified as having capability to switch to residual oil. About 32 percent report actually using residual oil between January 2000 and January 2002. This is about 8.5 billion cubic feet per day (Bcfd) of capacity. Most of this is short-term switching capability, limited either by regulatory restrictions or operational factors.
  - Only about 6 percent of the 116 GW of new gas combined cycle capacity reports having alternative fuel capability (distillate oil), accounting for about 1.1 Bcfd. About 19 percent of the new peaking turbines report switching capability (2.6 Bcfd) but these units run very few hours per year.
- During recent periods of high gas prices, approximately 5 to 7 Bcfd of switching has been observed in the power generation sector.
- Some operational capacity to switch fuels on very short notice has probably been lost over the last decade when it was used very little. Changes in equipment and new environmental regulations have also caused reductions in fuel-switching capacity.

This paper begins with an historical overview of the power generation sector and its fuel use. It then analyzes recent trends in the power generation sector. It examines the issue of fuel switching and finishes with a summary of conclusions.

1 - Background

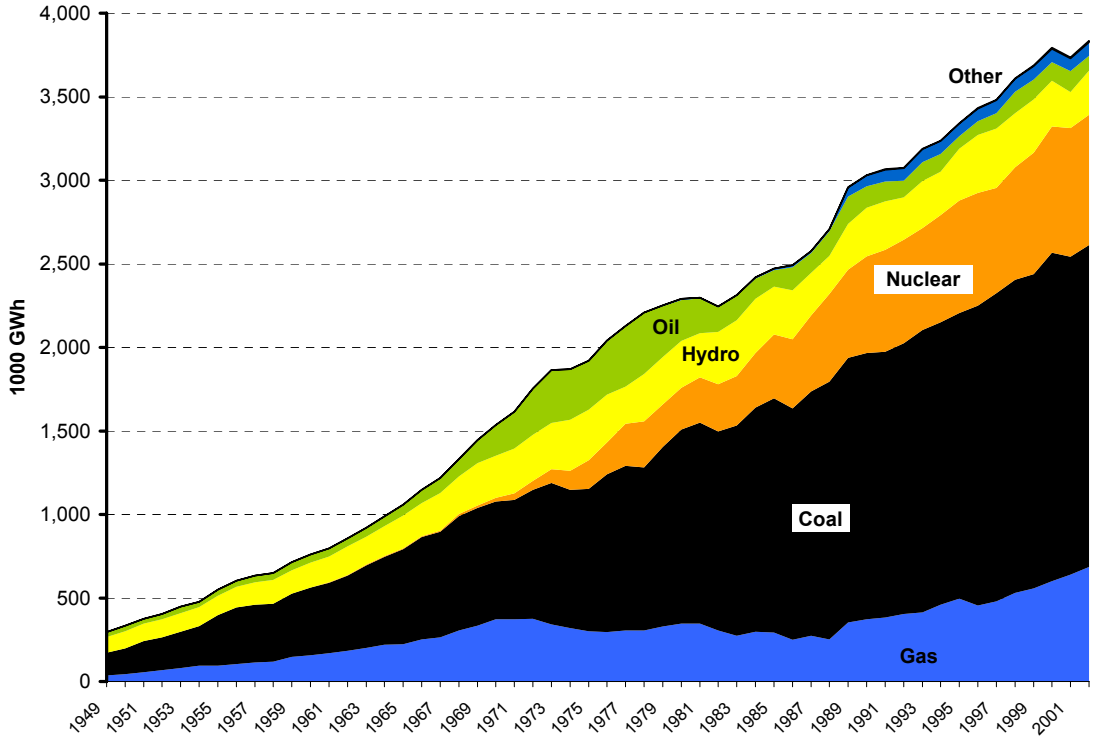
Electricity is a key part of the U.S. economy and continues to grow in importance. Figure 4 shows that electricity consumption in the U.S. has grown steadily for the last 50 years with only minor slow periods. While it has slowed over time, growth in electricity demand has been over 2 percent per year for the last 20 years. Coal has been and remains the primary fuel for electricity generation, despite recent increases in gas-based generation. Coal generation accounted for 51 percent of electricity generation in 2002 and is projected to maintain the largest market share in the future.

Figure 4 shows the growth of U.S. electric generation by fuel since 1949. While coal-based generation has grown steadily, the other fuels have seen ups and downs over this time. Nuclear generation has grown steadily and continues to increase, even though no new plants have come on line in more than 10 years. Nuclear power currently accounts for about 20 percent of generation. No major new hydroelectric generation facilities have come on line in many years and hydroelectric generation has been fairly constant since the 1970s. The variation is due mainly to river flow conditions and hydroelectric generation was lower in the late 1990s, partly accounting for increased generation by other fuels. Oil-fired generation peaked in the mid 1970s when gas prices were high and has declined to less than 5 percent of generation for most of the last 20 years. Most of the oil used is heavy residual oil, burned in large boilers.

Gas-based generation has grown significantly in recent years and gas accounted for about 18 percent of generation in 2002. Gas-based generation grew steadily from 1949 until the early 1970s, during a period of very low gas prices. In the early 1970s, gas prices increased substantially due to regulatory issues in the gas markets (Figure 5). These market issues raised concerns that resulted in the Fuel Use Act, which restricted the use of gas for power generation. These regulations and the high prices resulted in a downturn in gas use for power generation that continued until the late 1980s. By this time, the gas market issues had been addressed and restrictions on gas use for power generation had been lifted. In addition, the Public Utilities Regulatory Policy Act (PURPA) at that time was encouraging the application of cogeneration and many new gas-based cogeneration facilities were starting to come on line. Gas generation reached its low point at 249,000 GWh in 1986 and then started steadily upward, more than doubling to 686,000 GWh by 2002. Nevertheless, at 18 percent of generation in 2002, the gas share of generation was still lower in 2002 than in 1970 when it accounted for 24 percent of generation.

The choice of generating fuel is strongly affected by the available mix of generating plants. This mix has changed over time and also varies by region. Evaluating the changes in this mix over time requires an understanding of the generating technologies. Other than hydroelectric and wind generation, electricity has historically been generated by heating water to make steam and using the steam to turn a turbine-generator system. Coal, oil, gas, biomass and nuclear energy

Figure 4
U.S. Electricity Generation by Fuel



U.S. Electricity Generation by Fuel

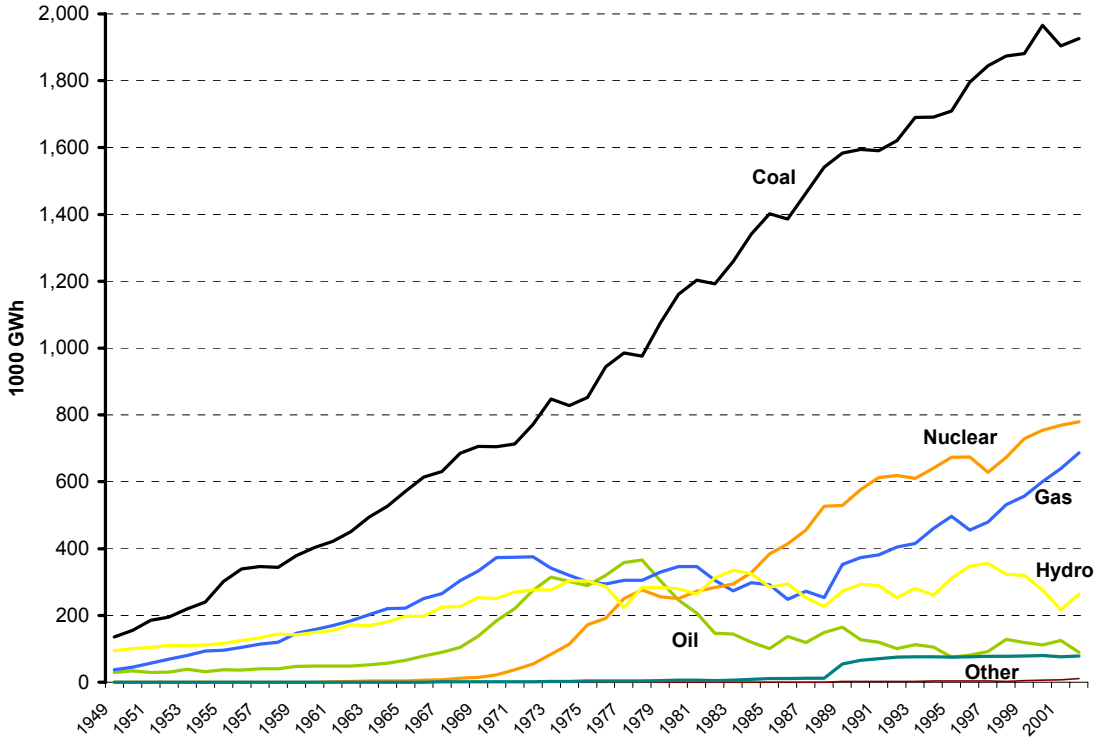
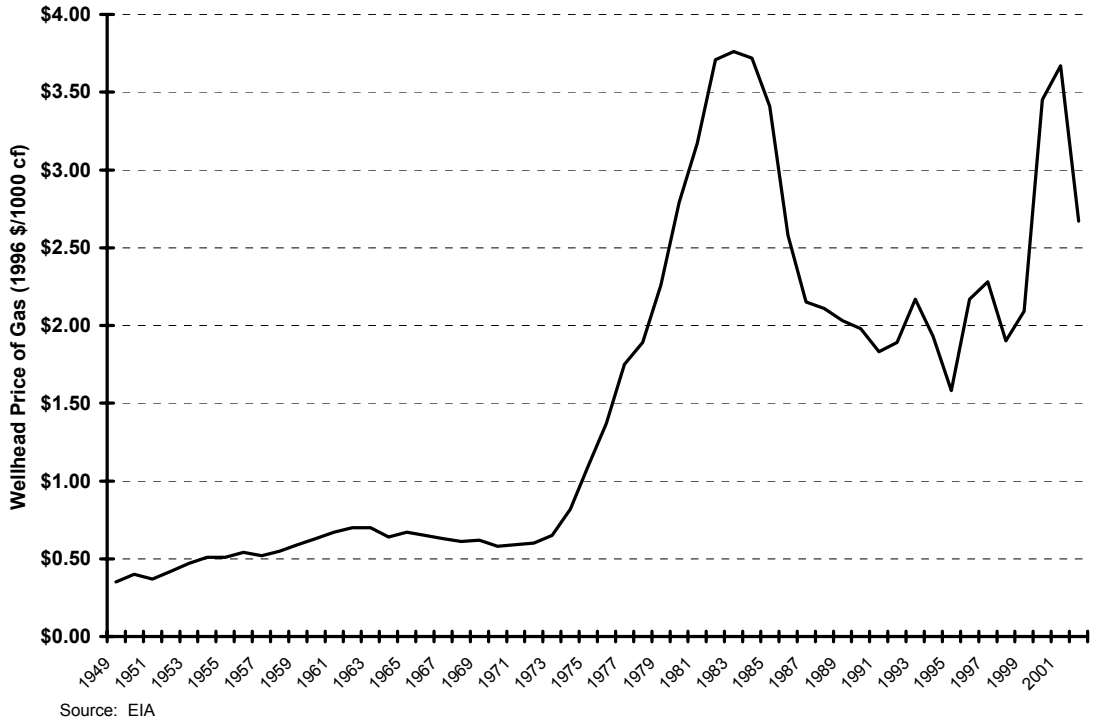


Figure 5
Historical Annual Average Wellhead Gas Prices



are all used in different types of plants to make the steam that drives the generator, but the non-combustion components of these plants are all very similar and the plants have similar efficiencies of 30 to 35 percent.

Natural gas is also used in two additional kinds of power plants. Gas combustion turbines are similar in operation to a jet engine except that the energy from the hot exhaust gases is used to turn a turbine and drive a generator. Combustion turbines (CT) are not as efficient as conventional steam plants but are more compact and can be built in smaller sizes. Most important, they can be started very quickly (in minutes) to respond to peak load demand. Combustion turbines are therefore most commonly used by power generators as peaking units that may run only a few hundred hours per year or less. These combustion turbines consume very little fuel and generate very little electricity due to their low utilization. Some combustion turbines burn distillate oil, but little is consumed or generated in this way[1].

[1] Some combustion turbines are used in industrial cogeneration applications in which heat from the exhaust gases is used to make steam for industrial process use. These combustion turbines typically are baseloaded and can generate a significant amount of electricity.

Gas is also used in combined cycle (CC) generators. A combined cycle uses a combustion turbine to generate electricity while energy from the exhaust gases is used to generate steam, which is then used to drive another generator. Because of this heat recovery, the combined cycle is significantly more efficient than a conventional steam plant or simple combustion turbine, around 50 percent efficient. These combined cycle plants are intended to be used as baseload or intermediate load plants.

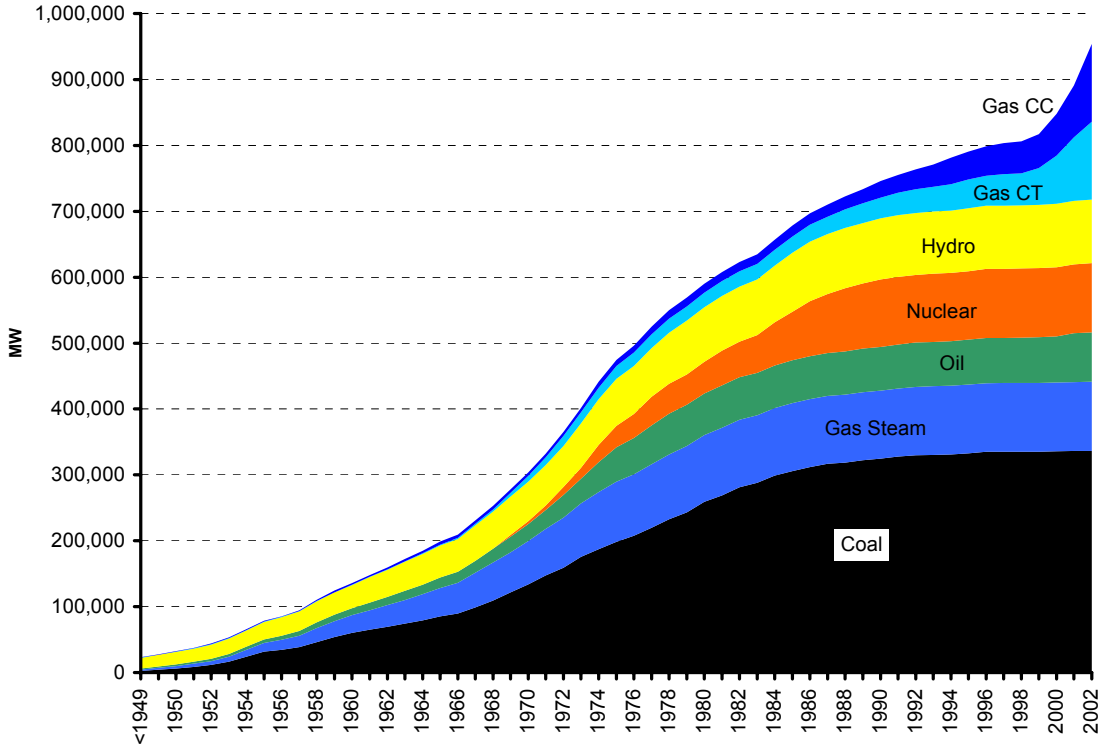
Figure 6 presents a view of the historical mix of U.S. generating plants since 1949. These figures are based on the on-line dates of plants that are currently in operation and therefore do not include plants that have been retired. However, they give a reasonable depiction of the development of U.S. generating capacity. Until the 1970s, almost all generating capacity was hydroelectric or conventional steam plants fueled by coal, gas or oil. Oil capacity increased during the 1970s due to high gas prices and Fuel Use Act restrictions on gas use but very little oil capacity has been built since then.

Most of today's generating capacity was built during the late 1960s and 1970s into the early 1980s. Nuclear plants started to come on line during the 1970s and the last part of the nuclear construction period extended into the 1980s. The majority of existing coal capacity was built during the 1970s and 1980s, with very little built after 1990. Generating capacity grew rapidly during the 1970s but the growth slowed considerably by the 1990s.

Part of the reason for this slowdown during the 1990s is shown in Figure 7, which compares the growth of U.S. electric generation and capacity. Generation and capacity grew at roughly the same rates from 1949 until the energy price shocks of the early 1970s. At that time, consumption stayed flat for a few years while capacity growth continued. Power plant construction is a multiyear process that must start well before the capacity is actually needed and typically will not be stopped due to short term reductions in demand once construction has begun. Thus new plant construction continued during the 1970s and by the second consumption slow-down in the early 1980s, generating capacity had pulled ahead of generation. New construction started to decline at that point, just as demand started to pick up. New capacity growth was quite slow during the 1990s until a large increment of gas combined cycle and combustion turbine construction began in 1999. Figure 6 shows that the increment of new generating capacity in 2002 was almost twice as high as the next highest one year increment in 1974. Moreover, while the increment of new generation in 1974 was a mix of coal, gas, oil, nuclear and hydro, the increment in 2002 was essentially all gas-fired. About one third of the 1999-2002 construction boom was combustion turbine and the remainder combined cycles. This period of rapid growth is discussed more fully below.

Different types of power generating facilities are used different depending on their operating characteristics and cost of generation. Since electricity cannot practically be stored in any significant amount, it must be generated when it is needed. As the demand varies over time, different generating assets are brought on-line to meet demand.

Figure 6
Cumulative U.S. Electric Generating Capacity by On-Line Year



Annual Additions to U.S. Electric Generating Capacity by On-Line Year

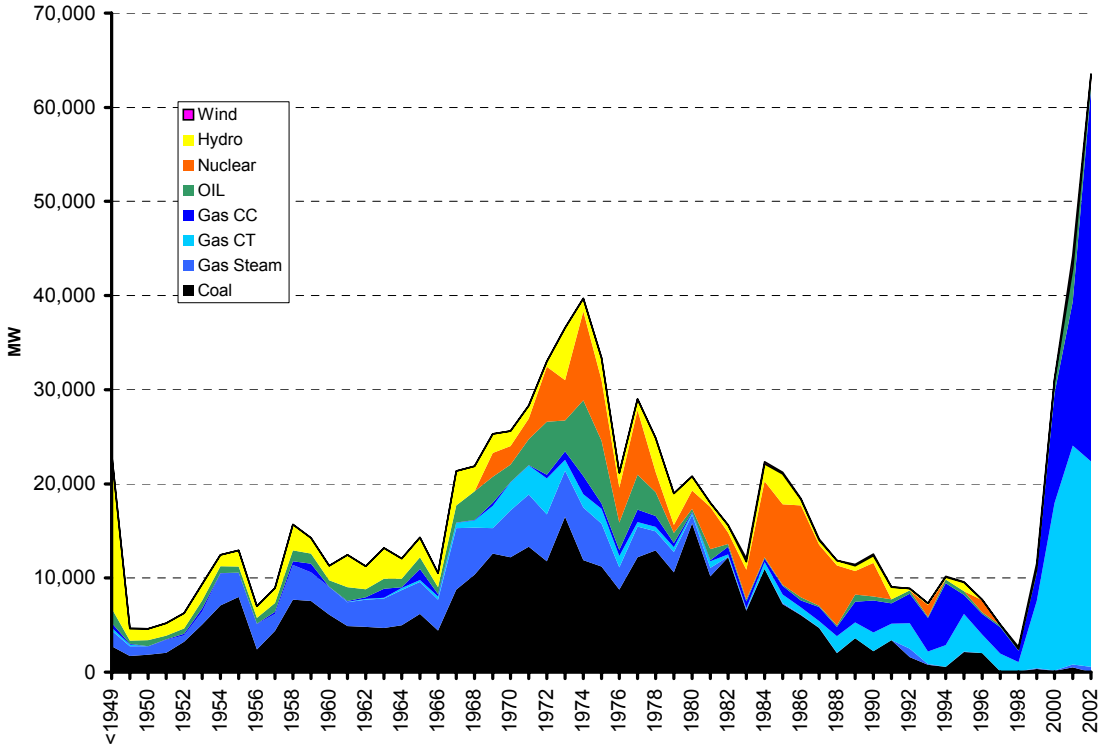
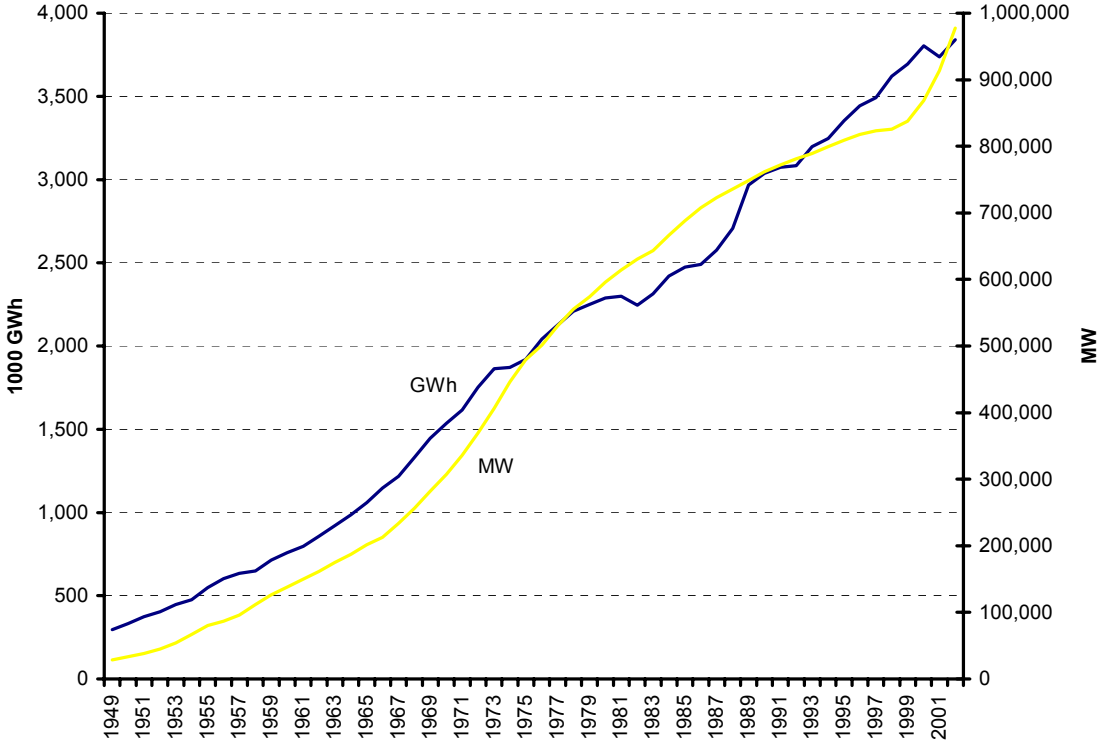


Figure 7
Growth of U.S. Electricity Generation and Capacity

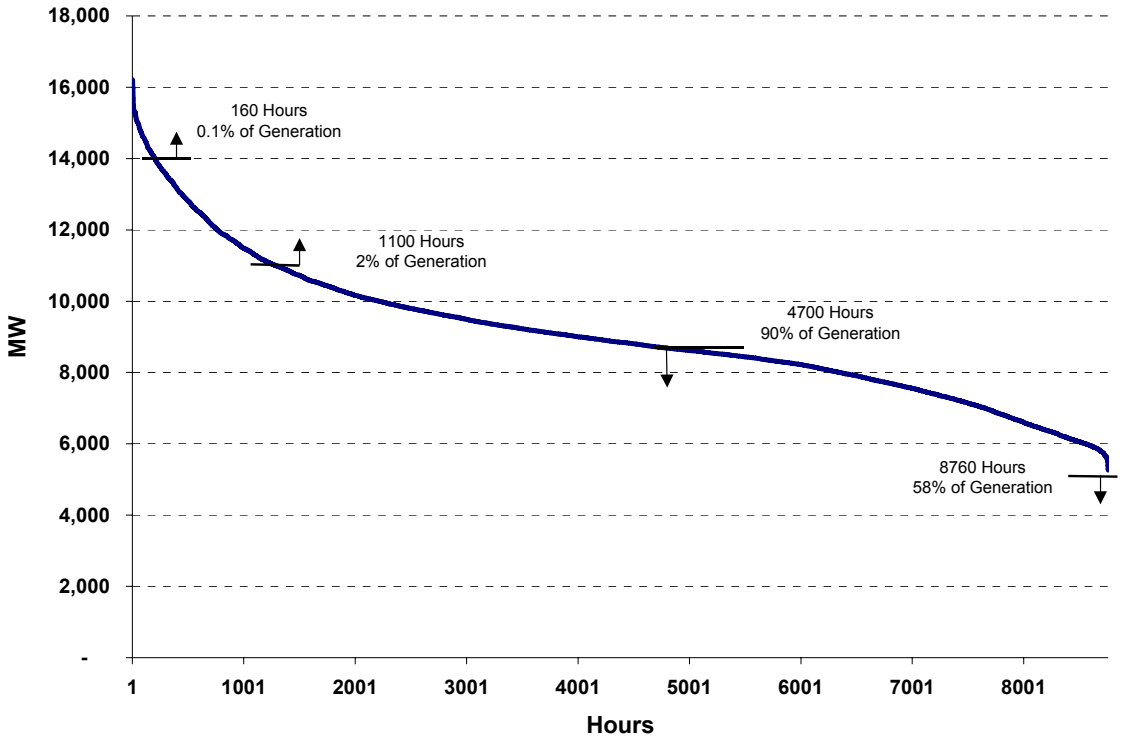


A common way of looking at this varying demand is with a load duration curve. The load duration curve shows the electric demand in MW for a region for each of the 8,760 hours in the year. The hourly demand values are sorted from highest to lowest. As an example, Figure 8 shows the load duration curve for an eastern electric utility. The vertical axis shows the demand in MW and the horizontal axis shows the hours of the year.

The chart shows that the highest hourly electric demand was 16,216 MW, in this case at 4 PM on July 6. The demand for the next highest hour of demand was 16,191 MW at 5 PM on the same day. The lowest demand was 5,257 MW, in this case at 3:00 in the morning on a mild day in September. Every hour of the year had at least this much demand. The next highest hour had a demand of 5,290 MW. The demand was at least this much for all except one hour of the year.

The area under the curve is the generation needed for load (excluding line losses), about 79.7 million MWh. The total generation (energy) required for the 5,257 MW base demand that exists during all 8,670 hours of the year is 58 percent of the total generation. The units that operate for 4,700 hours per year account for 90 percent of the total generation. In contrast, the peak 2,000 MW of capacity operates for 160 hours or less per year and accounts for only 0.1 percent of generation. The peak 5,000 MW operates about 1,100 hours per year and accounts for only 2 percent of generation. The shape of this curve is typical of electric load duration curves.

Figure 8
Load Duration Curve



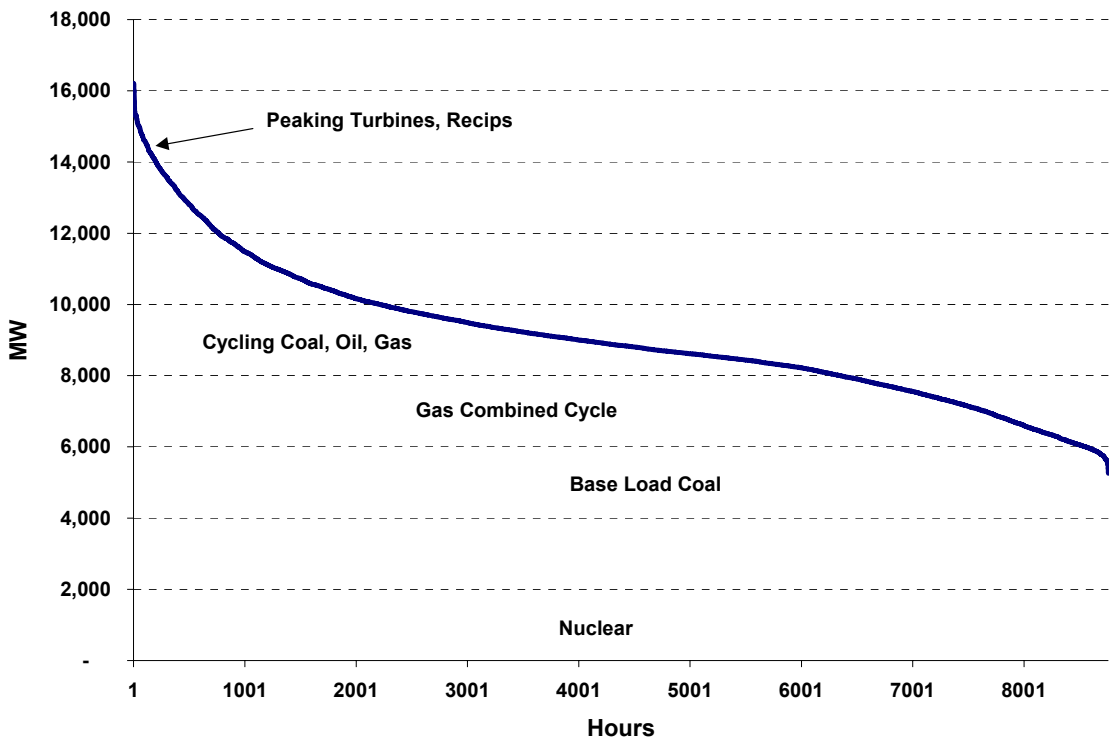
This varying electric load is met with a large number of different types and sizes of generating units. Figure 9 shows a typical mix of generating technologies. The operation of the power plants is increasingly being directed by an independent, central body called a Regional Transmission Operator (RTO). The U.S. Federal Energy Regulatory Commission has ruled that RTO's should be established throughout the U.S. to dispatch electric generators. In this kind of competitive electric market, the generating units are dispatched based on the unit owner's bid, which typically is at or near the unit's variable cost – the cost of fuel, consumable items, and operation and maintenance costs directly related to production[1]. The base load units run as many hours per year as possible. They need to have low variable costs, which means some combination of low fuel cost and high efficiency. Because they will have high utilization, they can support a higher capital investment in efficiency. In this case, the base load is primarily met by large nuclear and coal power plants.

The peaking units may run only tens to hundreds of hours per year, so a high capital cost is hard to support. On the other hand, high efficiency is not critical, since these plants only run when there is no other source of capacity and electricity prices are very high. Simple cycle gas turbines are the classic peaking generator, though reciprocating engines and conventional oil and

[1] The plant owner bids at the variable cost but is paid the market clearing price. The market price must be sufficiently above the bid price for enough hours in the year for the plant to make a profit.

gas steam plants are also used for peaking. Between the peak and the base load is the intermediate or cycling load, which is met with a variety of generating assets. These can be cycling coal, oil and gas steam units. Many of them are small utility generators or independent power generators, many at industrial facilities.

Figure 9
Typical Dispatch Mix



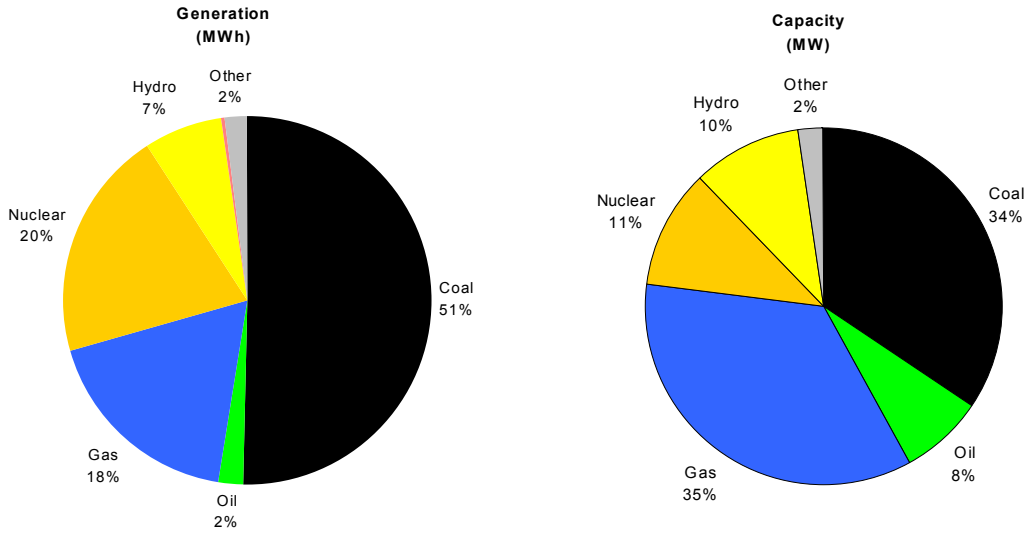
Developers of new natural gas combined cycle plants would like them to run 5,000 hours or more, in the base load to high intermediate load ranges. Depending on the cost of natural gas and other factors, they may run in the middle intermediate range. As these new power plants are added to the generating mix, they will compete with the existing plants to find a place in the generating "stack." If the new plants are very efficient and natural gas prices are low, they will take a position lower down, closer to the base load, running more hours.

These different applications for different technologies make the distribution of generation quite different from that of capacity. In 2002 there was over 970 GW of total electric generating capacity in the U.S. Figure 10 shows that about 300 GW or one third of the total was coal capacity. There was about 100 GW of nuclear and 80 GW of hydro capacity. There was also about 300 GW of gas-fired capacity evenly split between combined cycles, combustion turbines and conventional gas steam plants. There was about 70 GW of oil capacity, roughly split

between combustion turbine and conventional steam plants. There was about 4 GW of wind, about 0.5 percent of the total.

In 2002 coal accounted for 34 percent of capacity but over 50 percent of generation and nuclear accounted for 20 percent of generation, twice its share of capacity. This indicates very high utilization of nuclear and coal plants relative to other facilities. On the other hand, generation from gas combined cycles was about equal to their share of capacity. Generation from gas steam plants and hydro facilities was slightly lower than their share of capacity. Combustion turbines had a much lower share of generation due to their use for peaking. Overall gas accounted for 35 percent of capacity but only 18 percent of generation. Oil-fired and wind generation had only a tiny share of generation, much lower than their share of capacity. These data show that capacity is only one indicator of fuel use. Plant utilization is equally important and depends on many factors, including electric demand, local capacity mix and fuel price differential. Thus construction trends are only a part of the picture in determining future fuel consumption.

Figure 10
Distribution of U.S. Electricity Generation and Capacity - 2002



2 - Recent Trends

From 1990 to 2002, U.S. electric generation grew by 23 percent, from 3,038,00 GWh to 3,835,000 GWh. Gas-fired generation grew by almost 70 percent during this period. Gas consumption for generation grew from 3,342 to 5,721 TBtu. The 2002 gas consumption was more than 70 percent higher than in 1990. This rapid growth of gas generation is one primary source of concern over the role of gas-fired power generation. The end of this time period was also a period of increased, rapid construction of new gas-fired generation that seemed to presage even greater gas consumption.

As noted above, the 1990s was a period during which electricity demand had returned to historic growth levels after a lull during the 1980s (Figure 7) but construction had slowed after the over-capacity period during the 1980s. Construction was also slowed by the onset of electric industry deregulation. Until this time, electric generation had been a regulated monopoly. Power companies built power plants based on their ability to show regulators that the capacity would be required to meet future demand. Recovery of the capital investment was guaranteed by the regulators and fuel costs were passed through to consumers. Long construction lead times were acceptable. The norm during this period was high capital cost conventional power plants with an emphasis on stability and little emphasis on efficiency.

However, as state and federal regulators considered opening power markets to private companies, regulated utilities delayed new construction plans in order to see how they would be affected by restructuring. This further slowed power plant construction during the 1990s. Of the little new capacity that was built during this period, much was actually gas-fired cogeneration plants built by non-utility entities.

By the end of the 1990s, generation/electric demand was starting to get ahead of capacity and new construction was required. The slow construction caused capacity to be tight in some regions. This was reflected in very high prices for peak generation during some summer periods. With completion of the initial phase of electric industry restructuring at the federal level, power plant construction at the end of the 1990s was dominated by non-utility, independent power producers (IPPs). Unlike regulated utilities, the IPPs did not need to get approval from state regulators and were not constrained to build only where there was a clear need for new capacity. They looked for markets that might be constrained or where they could successfully compete in the electricity market with older, less efficient plants either for baseload or peaking.

The market atmosphere of the late 1990s was largely a race to see who could get new plants built and on-line first to capture these potential markets. The IPPs had to depend on project financing and were attracted to low capital cost plants that could be built very quickly. Gas combustion turbine and combined cycle plants cost half as much to build as new coal plants and could be built in a fraction of the time. They were also cleaner and therefore easier to permit, though there was significant opposition to new gas plants in many areas. At the gas prices then prevailing, gas generation was an unbeatable package for independent developers.

From 1999 through 2002, over 150 GW of new gas-fired capacity was installed, with over 60 GW coming on line in 2002. Another 40 GW was still under construction. Of this total, 51 GW or 26 percent was peaking combustion turbines, 116 GW or 60 percent was combined cycle plants for baseload and 22 GW or 11 percent was for cogeneration. As shown in Figure 6, this has been the largest increment of new generation in U.S. history.

This strong growth of gas-fired generation during a period of increased gas consumption has caused some to link the two phenomena. However, this conclusion is not supported by the data. The increase in gas generation started in 1989, while the major influx of new gas generation did not really occur until ten years later, as shown in Figure 11. The figure shows that new capacity development was fairly weak during most of the 1990s and did not start to grow rapidly until 1999. Much of the new capacity prior to 1999 was for industrial cogeneration facilities. About 85 percent of the 240 GW of new gas capacity that came on line during this period was from 1999 through 2003. Moreover, approximately one third of the new gas capacity was peaking combustion turbines, which consume very little fuel. In addition, even combined cycle plants often run very little during their first year of operation due to start-up and competitive issues. Thus the growth in gas demand for power generation largely pre-dates the peak construction period.

2.1 Effect of New Gas Power Plants

If this growth in gas-based generation was not a result of new construction, what was the driver? There are several contributing factors. First, with little new construction during the late 1980s and early 1990s, growth in electric demand needed to be provided from existing plants. Figure 12 shows the mix of generation from 1990 to 2002. While it is clear that gas-fired generation was growing steadily during this period, so did generation from nuclear plants and coal. However, as noted earlier, nuclear and coal facilities were already operating at very high load factors. Coal generation grew slightly slower than the total while oil generation declined sharply in the first part of the decade and recovered to almost no net growth in 2001. Hydroelectric generation was strong in 1996 but was down by over 25 percent in 2001 compared to 1990 due to low rainfall. Gas generation increased, in part to make up for the reduction in hydroelectric generation in certain regions.

Figures 4 and 12 show that 2001 was an unusual year for the overall electric sector. It is one of the few years in recent history in which total generation actually declined. Coal generation declined in 2001 from a high year in 2000 and hydroelectric generation accelerated a pre-existing decline. Gas generation increased despite the overall decline in generation. In some markets, such as in the West, the low hydroelectric generation required an increase in gas generation despite the weaker overall market. In markets with less local hydroelectric reliance, there was no such similar decline in other fuels and no unusual increase in gas generation. The very high apparent gas growth in 2001 is in part due to an anomalous low total combined with low hydroelectric generation in key gas generating markets.

Figure 11
Gas Consumption and Capacity Growth – 1990-2003

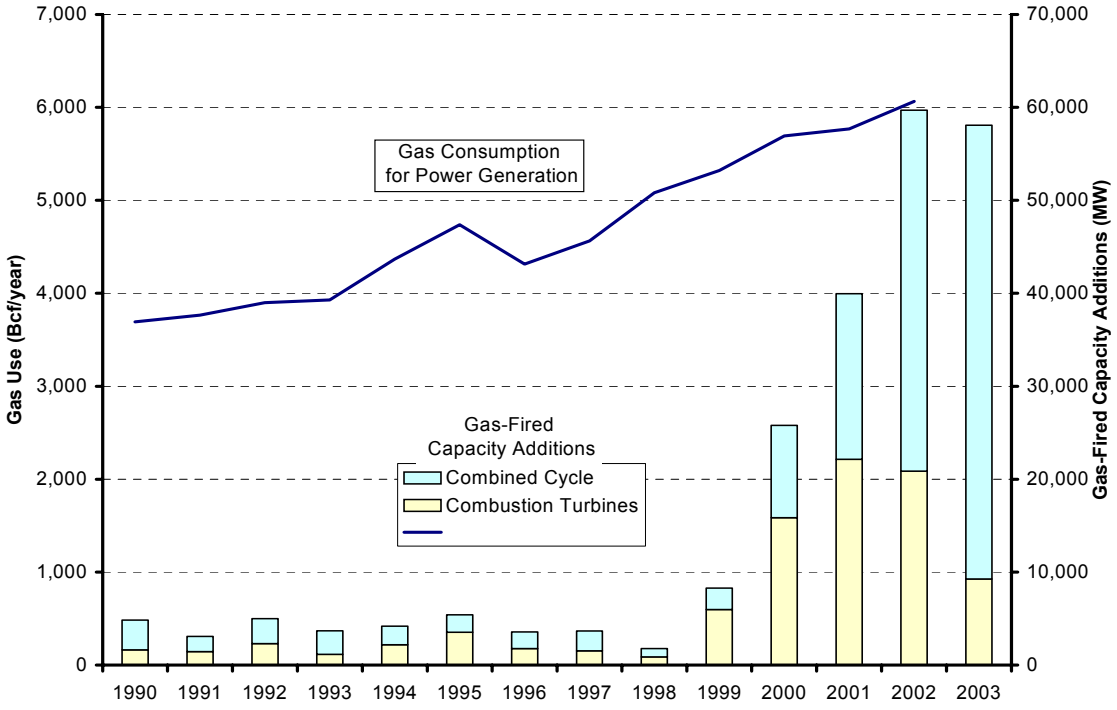
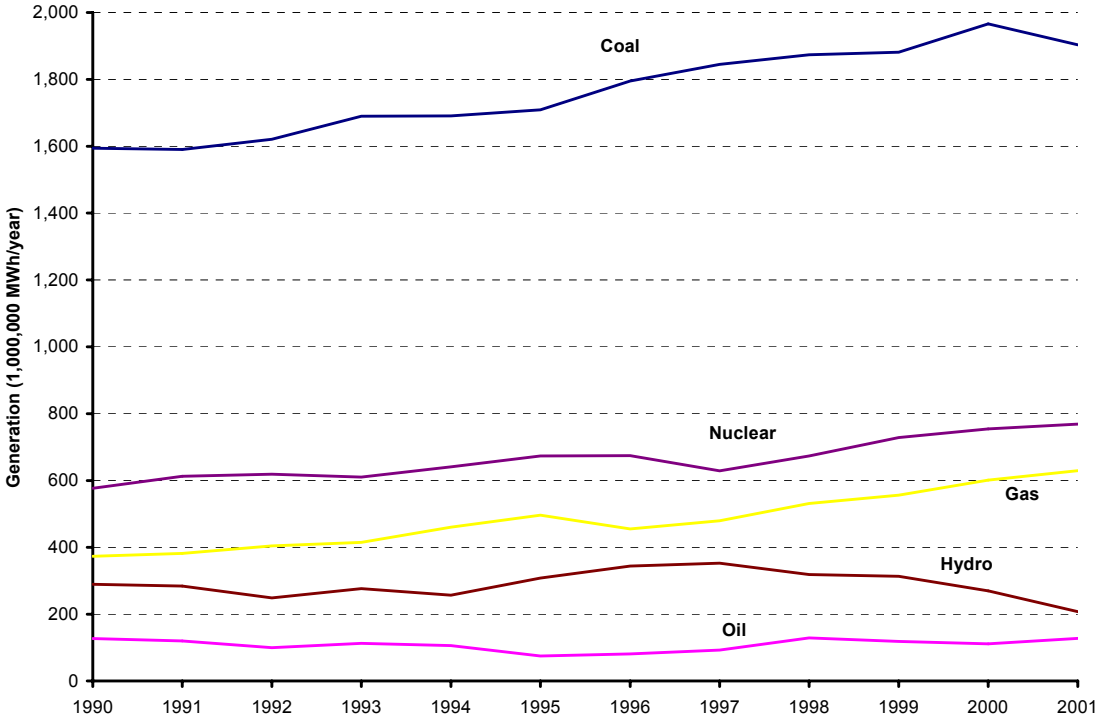


Figure 12
Electricity Generation by Fuel – 1990-2002

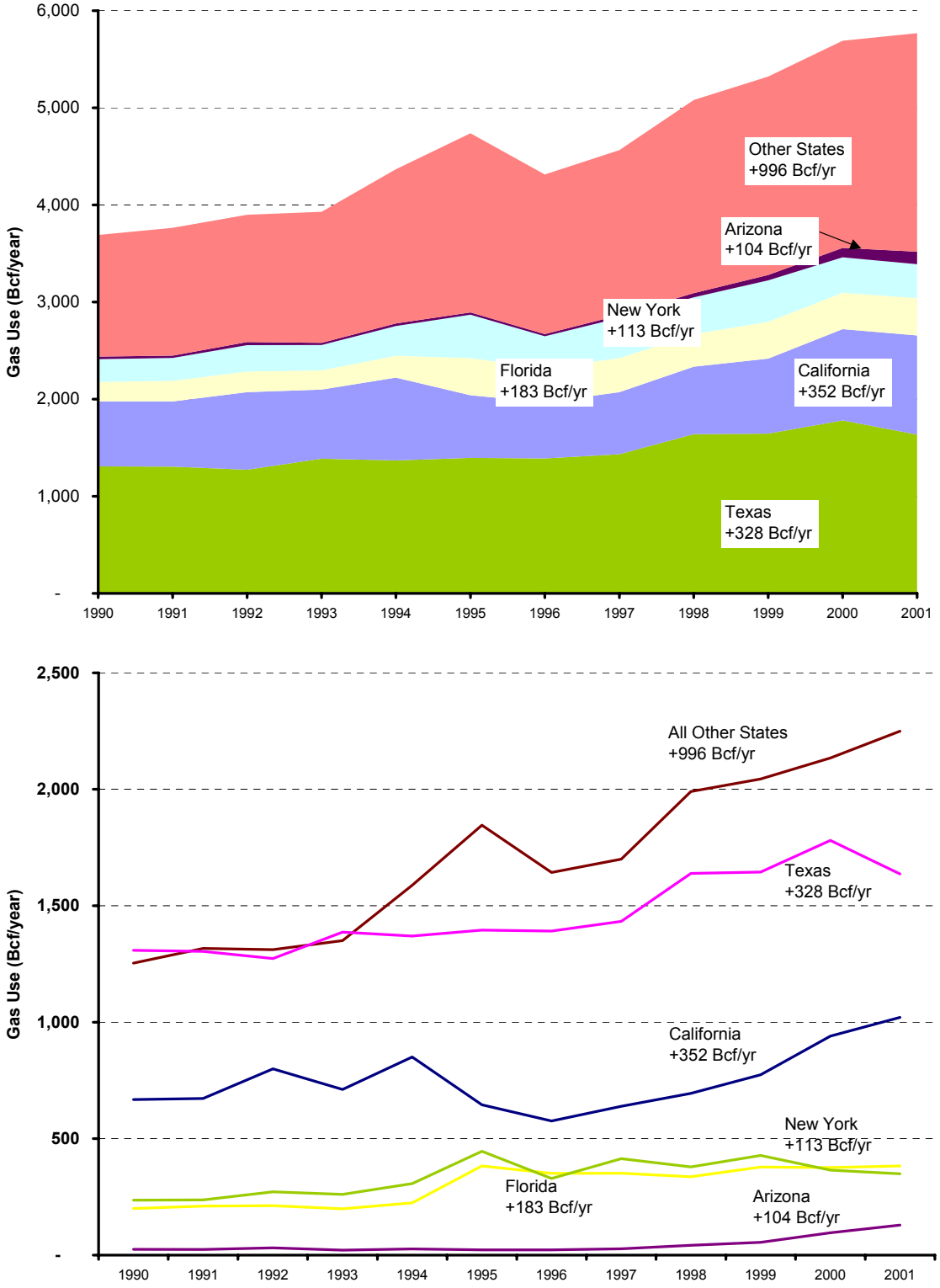


Understanding the trend of gas use for power generation in the 1990s requires a closer look at the behavior by state. Figure 13 shows gas consumption for power generation by state from 1990 through 2002. Total gas consumption in 1990 was about 3,700 Bcf. California and Texas alone consumed 1,975 Bcf or over half of this gas. Gas consumption grew to 5,770 Bcf in 2001, by about 56 percent. California and Texas had the largest absolute growth, accounting for about 680 Bcf of the 2,070 Bcf growth. Florida, New York, and Arizona had the next highest absolute growth and these 5 states together accounted for about half of the growth in gas consumption during the period. Ten additional states accounted for 706 Bcf of the remaining 996 Bcf of increased gas consumption during the period, including:

- Alabama
- Maine
- Colorado
- Massachusetts
- Rhode Island
- Mississippi
- Nevada
- New Jersey
- Oregon
- Washington

Although Texas and California accounted for the greatest growth in gas consumption for power generation during this period, the reasons were quite different and are instructive to consider.

Figure 13
Gas Consumption for Power Generation by State – 1990-2002



2.2 Texas

Figure 14 shows the growth and mix of power generation in Texas from 1990 to 2001. The 1990s were a period of strong economic growth in Texas and electric generation was growing at 2.8 percent per year. Gas has historically been the primary fuel source for electricity generation in Texas. During this period of strong electricity growth in the 1990s, nuclear and coal generators were already running at very high levels, leaving gas as the main potential source of increased generation.

At the same time, there was a lot of new gas-fired capacity in Texas in the 1990s for several reasons:

- The state was early to restructure its electric markets
- There is easy access to gas
- There was a lot of older gas-fired generation against which new combined cycle plants could effectively compete

Because of these factors, a lot of new power plants were built in Texas on a competitive speculative basis, rather than due to a need for more capacity. This has resulted in an overcapacity situation. However, as the developers hoped, the new gas plants have competed effectively with the old gas plants. The new combined cycle plants are typically nearly 50 percent efficient compared to about 30 percent efficiency for older conventional gas plants. Since the plants are burning the same fuel, this difference turns into a significant competitive advantage for the newer plants in a strong gas generation market. Several older natural gas plants have been shut down or mothballed in Texas because they were not competitive with the new plants.

This effect is shown in Figure 15 which shows the amount of gas consumed by the new plants in Texas. This consumption has displaced some of the consumption from older, conventional gas plants. Since the new plants are more efficient, their use actually *reduces* the amount of gas used in Texas to generate electricity. Although gas consumption has gone up during the introduction of these new plants, it has gone up less than it would have if the load had been met by the older, less efficient plants. Thus, in Texas, the introduction of new plants has reduced gas consumption during a time when the region was becoming more dependent on gas to meet growing demand for electricity.

Figure 14
Texas Generation Mix - 1990-2001

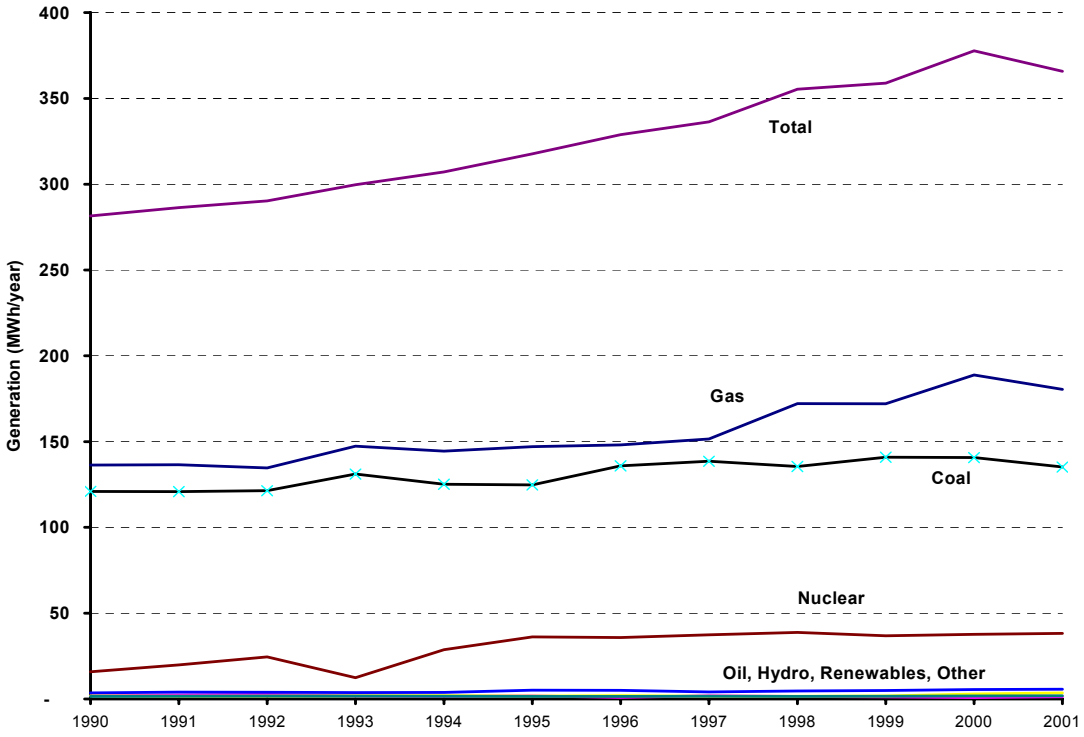
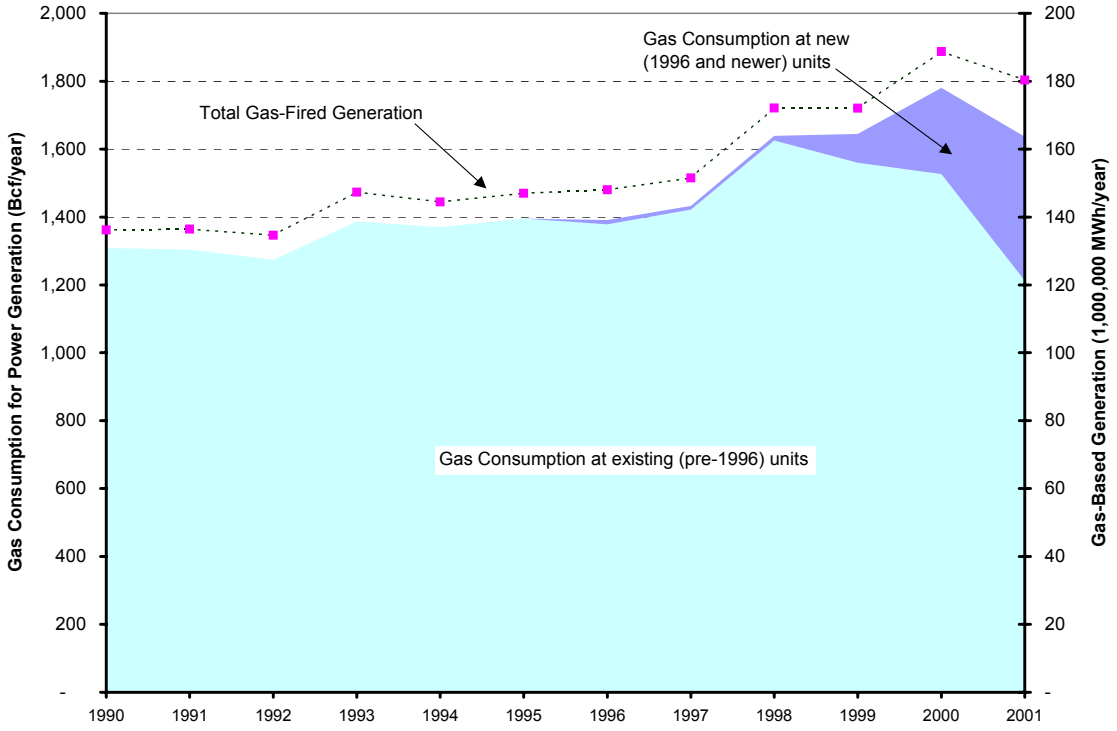


Figure 15
Texas Capacity Displacement by New Plants



2.3 California

The situation in California in the 1990s was quite different from that in Texas. Figure 16 shows the overall generation growth and mix in California from 1990 to 2002. The growth in generation in California was 2.5 percent per year, slightly lower than in Texas. As in Texas, gas generation was already the primary source of electricity. Unlike Texas, California also receives a substantial amount of power from out of state. However, the non-gas, in-state generation was limited to nuclear and renewable sources that were already operating at full capacity, and hydroelectric generation. When hydroelectric generation declined towards the end of the period, gas was the only in-state resource that could respond.

There was less new capacity coming on-line in California than in Texas and it arrived later. Thus the growth in gas generation in California was primarily increased use of existing plants to meet demand growth and make up for a lack of hydro generation. Figure 17 shows very little impact of new plants through 2001.

As new combined cycle capacity has come on-line more recently however, it has started to displace conventional gas generation. Some of the new capacity is direct repowering of old conventional plants. In addition, as in Texas, some old gas plants are being used less, being mothballed or are shutting down because they cannot compete with new, more efficient plants.

While the increases in gas demand for power generation in the 1990s were primarily a response to increased demand and limited hydroelectric capacity, the longer run response will be similar to Texas: new gas plants will help reduce the rate of increase in gas demand.

2.4 Other Markets

Where new gas combined cycle plants are primarily competing with older gas plants and there is excess capacity in the markets, the new plants will replace the less efficient older units. Although gas use may continue to increase, it will not go up as fast as if the new plants had not been built. This assumes that the markets are open to competition. In some areas today, incumbent utilities continue to dispatch their older, less efficient gas plants while excluding the new plants from the mix. In this case, there is no efficiency benefit, but the new plants are also not running, so any growth in demand is simply due to increased use of the old plants.

Overall, the driver for increased gas use has been the fact that there was a lull in power plant construction in the early 1990s and almost all of the new capacity since 1990 has been gas-fired. The non-gas generating resources in many parts of the country are reaching their operating limits, so incremental growth will be gas-based. In areas with older gas-based generation, new plants can displace less efficient equipment and reduce the pace of gas demand growth somewhat. This is clearly the case in California and Texas and will be true in other parts of the country as well.

Figure 16
California Generation Mix – 1990-2001

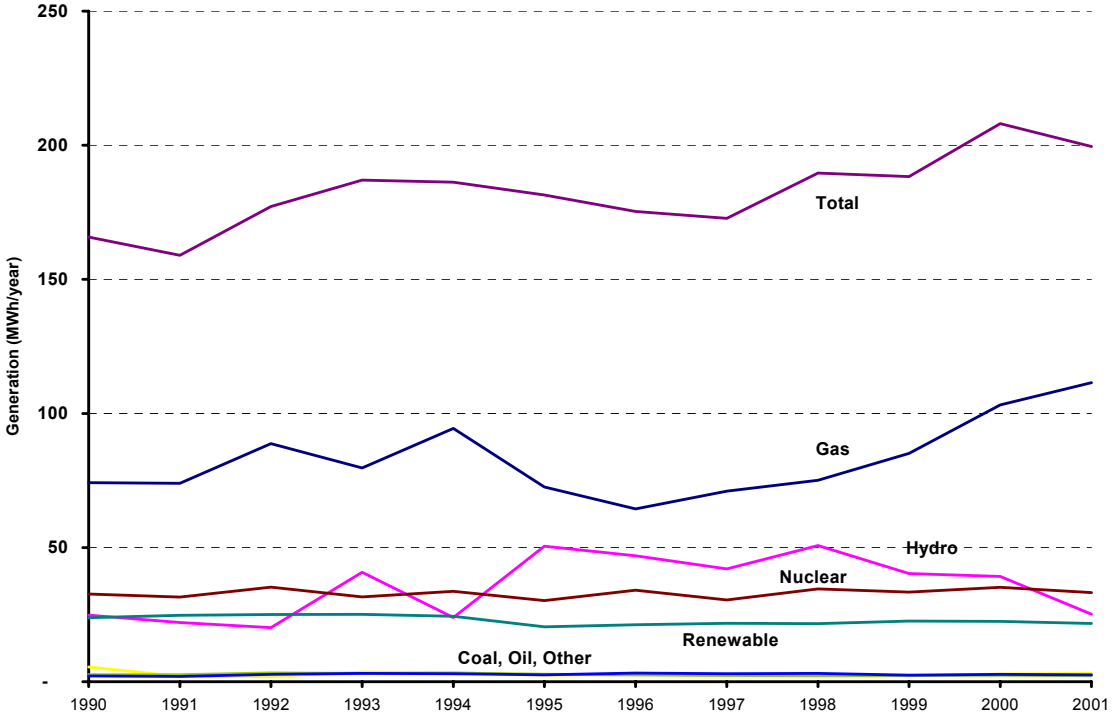
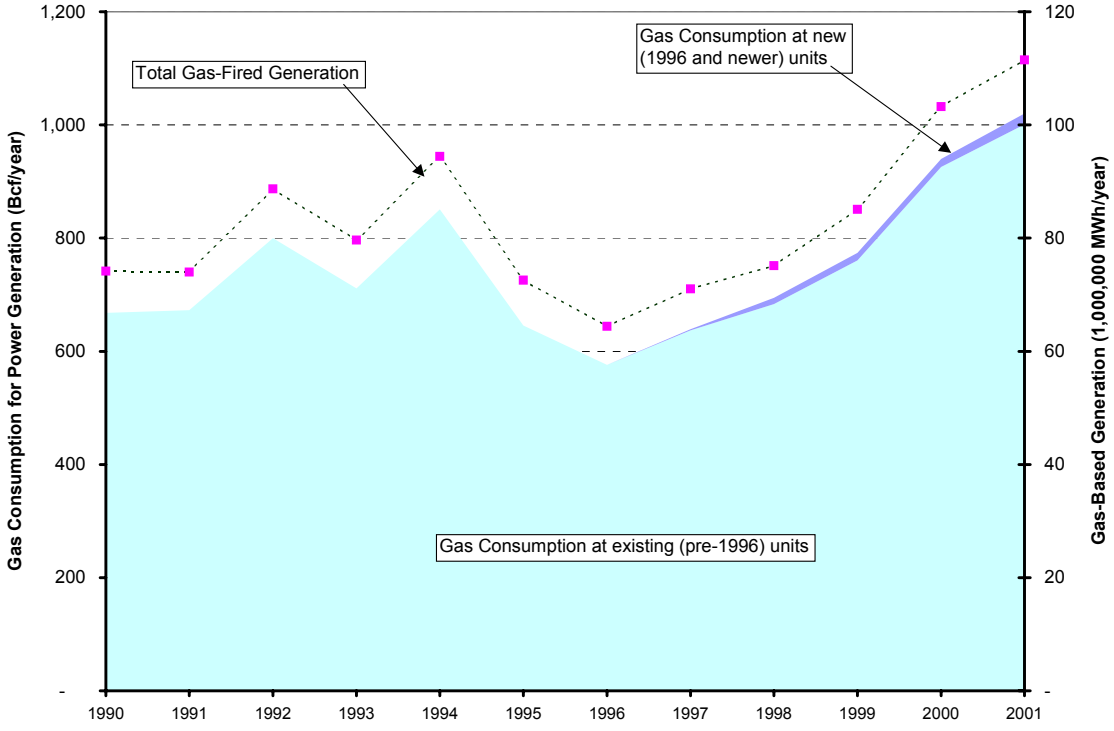
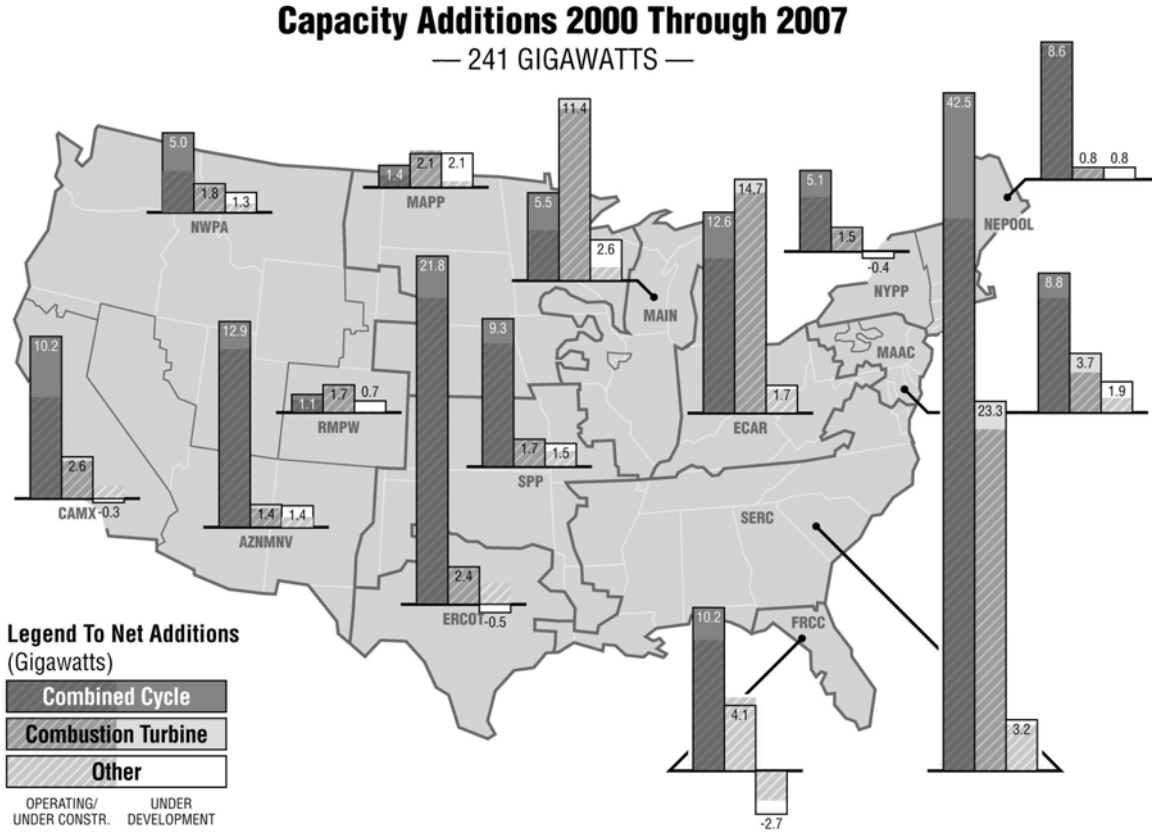


Figure 17
California Capacity Displacement by New Plants



However, Figure 18 shows that the construction boom for gas power plants has affected most parts of the U.S. This boom could create an increase in gas consumption in areas in which the new plants are providing purely incremental gas capacity rather than displacing existing gas generation. In the eastern U.S. regions of historically coal and oil-based electric generation there is a substantial amount of new combined cycle capacity that is still under construction or operating at very low load. If and when these plants reach full utilization, they could actually start to increase the share of gas-based generation.

Figure 18



That said, there are a variety of factors that are resulting in low utilization of many of the new gas power plants and a rapid decline in new construction. These factors include:

- High gas prices – the current high gas prices make new gas generation uncompetitive with coal-based generation in areas in which they compete.
- The slow economy – the current economic decline has reduced electric demand in many parts of the company and reduced the opportunity for new, higher cost plants to get into the market. It has also reduced the need and opportunity for peaking plants.

- Limited transmission capacity – in some areas, new plants do not have adequate transmission access to get their power to the market. While the circumstances can vary, the bottom line is that these plants are unable to operate at capacity, if at all.
- Lack of open access – in some areas, incumbent utilities control access to the markets and can dispatch their own plants rather than new plants, regardless of cost.
- Delays in restructuring - concerns about problems with restructuring in California have slowed the pace of restructuring in many other states, limiting opportunities for non-utility generators.

As a result, some uncompleted power projects are being canceled and some completed projects are going bankrupt and being sold. The combination of high gas prices and return to a regulated utility model could cause a resurgence in construction of coal plants that would further limit the utilization and future construction of new gas plants. The U.S. DOE is currently tracking 62 GW of new coal capacity under development or construction in the U.S. The EIA forecast of gas-fired generation (Figure 3) foresees a lag in the increased consumption of gas until about 2010. Depending on gas prices, the health of the economy, the continued progress of electric restructuring and other factors, this could be enough time for the generating market to swing away from gas in the longer term.

3 - Fuel Switching

Fuel switching is a key factor in gas demand and pricing issues. Some gas-fired industrial and power generation equipment has historically been designed and permitted to use an alternative fuel in addition to gas. This allows the user to switch to the alternative fuel at times when gas prices are high. Gas users also may use fuel switching capacity to take advantage of "interruptible" gas contracts, which offer lower year-round gas prices in return for allowing the gas supplier to use the gas for other customers during periods of high demand. At some times in the past, in parts of the U.S., power generators could be subject to "curtailment", meaning that local gas utilities were required to interrupt large gas users in favor of residential and other small users during times of tight supply. This type of curtailment is not common today. Interruptibility is more an issue of how much the consumer is willing to pay for an uninterrupted supply.

For independent, merchant generators of electricity, the volatility and differentiation between fuel and electricity prices create an opportunity for arbitrage. If gas prices are very high, it may be advantageous to stop generating electricity and sell their gas supply instead. This is not uncommon for IPPs. On the other hand, if they have a secondary fuel, they can sell the gas and still generate electricity. So having a secondary fuel can offer generators a very high value for risk limitation and "optionality".

While the ability to switch fuels can be an important tool for gas consumers to avoid price spikes, it is also an important dampener of price volatility in gas markets, as it helps relieve demand during peak periods. Fuel switching in the industrial and power generation sectors has historically played a key role in this respect. Fuel switching is usually a response to weather conditions and local supply constraints. Its occurrence and effect on gas markets are therefore most significant on a local or regional basis.

During the years of the "gas bubble", this kind of price or constraint-induced fuel switching was minimal due to generally adequate supply and delivery capacity. Power generation gas users were only rarely called upon to use their fuel-switching capability and as a result some plants may not have maintained the operational capability to switch. As gas prices have increased, questions have been raised about the continuing ability to switch fuels to relieve peak demand and limit volatility.

From the beginning, most fuel switching capacity has been designed and permitted for short-term use - a few days to a few months per year at the most. Fuel switching in the power sector has historically meant switching between gas and residual fuel oil in conventional boilers. Residual fuel oil is a very heavy fuel that must be heated in order to flow at low temperatures. It often contains significant amounts of sulfur as well as heavy metals and constituents that can foul or corrode combustion and power equipment. It usually must be delivered by barge or rail and stored on-site. The volume of oil required to keep a power plant of any significant size running is quite large, so oil-fired power plants require tank farms. The delivery and handling requirements

for residual oil are more similar to coal than gas. These kinds of operational limitations tend to limit the duration of switching capabilities.

Environmental regulations also play a key role in fuel switching. Oil combustion typically has higher emissions than gas combustion, so many dual-fuel processes are limited by environmental regulation in the amount of time and/or the time of year when they can burn their alternative fuel. Often they are limited to 30 days or less of alternative fuel consumption, often only in the winter. In some cases, new, more stringent emissions regulations may have further limited the ability to switch.

According to annual surveys of power plant operators by the U.S. Energy Information Administration (EIA), approximately 36 percent of the 105 GW of gas boiler capacity reports residual oil as a secondary fuel. While there is some question as to the accuracy of these reports, the plant operators reported to EIA that 32 percent of the capacity *actually used* residual oil sometime between January 2000 and December 2002. The data on actual fuel use suggest that the EIA fuel switching data are fairly accurate in this case. This capacity corresponds to about 8.5 billion cubic feet per day (Bcfd) of gas switching capacity compared to average gas consumption of 15 Bcfd for power generation.

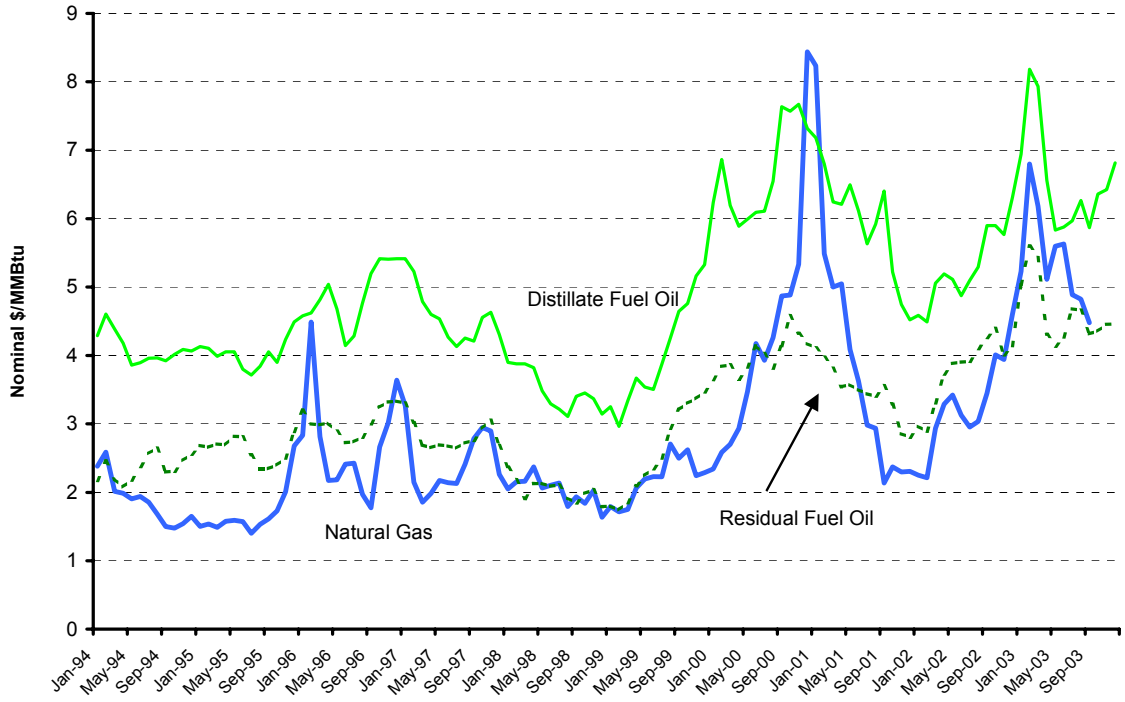
Table 1 lists the states with the largest reported gas boiler capacity that used residual oil during this period. Texas, Louisiana, New York, Florida, Illinois, Mississippi and California accounted for 80 percent of this capacity. These data suggest that there is still significant capacity to switch fuels at gas boilers.

Table 1
Fuel Switching for Gas Power Generation Boilers

State	Gas Boiler Capacity	Residual Oil is Nominal 2nd Fuel		Residual Oil Used Between Jan 2000 to Dec 2002	
	(MW)	(MW)	(%)	(MW)	(%)
Total U.S.	104,665	37,585	36%	33,016	32%
TX	37,459	5,987	16%	7,358	20%
LA	12,357	5,396	44%	4,458	36%
NY	5,201	3,844	74%	4,101	79%
FL	3,862	3,480	90%	3,468	90%
IL	2,902	2,650	91%	2,650	91%
MS	3,469	2,961	85%	2,511	72%
CA	17,203	4,785	28%	1,485	9%
KS	1,920	1,254	65%	1,197	62%
OK	6,081	1,346	22%	1,173	19%
NJ	1,013	545	54%	998	98%
MI	1,772	790	45%	780	44%

Combustion turbines in the U.S. today are not designed to burn residual oil. Some can burn lighter distillate oil. Distillate has been used as a primary or secondary fuel for some simple cycle peaking turbines for many years. Using distillate as a secondary fuel for new combined cycle turbines raises several issues, however. First, the new turbines are subject to very stringent environmental limits. While these limits can be met with distillate in many cases, it requires additional expense and additional negotiation with environmental regulators that many developers are not willing to bear. Secondly, a large combined cycle facility would require a tank farm to store adequate liquid fuel for extended operation. Since the relatively small footprint of a combined cycle plant is one of its main advantages, adding the fuel storage facility can be a serious problem. This is especially true because of the issues it raises with local communities. Finally, distillate oil is significantly more expensive than residual oil so it is less likely to be an economically viable alternative to gas. Figure 19 shows that gas prices have historically exceeded residual oil prices at regular intervals but they are rarely higher than distillate prices.

Figure 19
Historical Oil and Gas Prices



Distillate is the same grade of petroleum used to make home heating oil and diesel and jet fuel. Distillate prices are more likely to be high during peak heating periods when gas prices tend to be highest. A large increase in power generation demand for distillate could also strain supplies of heating oil during these periods. During the summer, increased use of distillate could conflict with increased demands for transportation fuels (diesel and jet fuel).

So while the ability to switch fuels has great option and risk avoidance value to developers of new gas generating facilities, most have chosen not to include it. Of the 116 GW of new combined cycle capacity built or under construction in the last 5 years, only about 7 GW or 6 percent identifies the use of a secondary fuel. This is equivalent to about 1.1 Bcfd of switchable gas demand. It's possible that even some of these are not actually exercising the option to purchase fuel and maintain their fuel switching capability. The 6 percent is probably an upper limit. There also may be regulatory limitations on when and for how long they can use their secondary fuel.

In contrast, almost 20 percent of the 51 GW of new peaking capacity has oil as a secondary fuel, equivalent to about 2.6 Bcfd. There are probably several reasons for this:

- The peakers are small and run for shorter periods of time so they can get by with much less storage.
- They are usually subject to less stringent environmental limits.
- They expect to make all of their money during a very few, brief periods of operation at peak load. They absolutely must be available to run at those times. If they miss that opportunity due to a fuel limitation, they may not make any money at all in that year.

Due to regional and operational diversity, not all of the switching capacity in the power sector is likely to be applied at the same time. During recent periods of high gas prices, EEA has observed approximately 5 to 7 Bcfd of fuel switching from gas in the power generation sector.

To the extent that the new plants with less switching capability replace older conventional plants that do have fuel-switching capability, the national fuel-switching capacity is declining. This effect varies regionally. The new plants have displaced older gas plants in Texas and the Northeast, but much of this displacement is simply a change in dispatch. A few older plants have been mothballed but few if any have been decommissioned. Several older plants have been mothballed and a few repowered in California, affecting fuel-switching capacity there. If the new gas plants continue to be economically successful, it is likely that more conventional plants will be removed from operation and available fuel-switching capacity will decline.

4 - Conclusions

Gas consumption for power generation increased by more than 70 percent from 1990 to 2002, increasing from 3,342 TBtu in 1990 to 5,721 TBtu in 2002. Even with this growth, gas generation was 18 percent of the U.S. total in 2002 compared to 24 percent in 1970. This growth in gas consumption was the result of a variety of factors. In large part it was a response to growing demand for electricity and a lack of construction of new generating facilities during the 1990s. In many regions, other types of generating facilities have reached maximum utilization, leaving gas-fired plants as the only resources available to meeting growing demand. Regional factors also contributed, such as low hydroelectric generation in the west at the end of the 1990s.

152 GW of new gas-fired generating capacity was installed in the U.S. between 1999 and 2002 with another 40 GW under construction. This is the largest increment of new capacity ever to be installed in the U.S. in such a period of time. This new gas capacity has not yet had a large effect on gas consumption. About one third of the new capacity is simple cycle peaking turbines that run very little and do not consume a lot of gas. Many of the new baseload combined cycle units are not running at full load due to start-up or competitive issues.

In areas with substantial existing gas capacity and open electric markets, such as Texas, new gas generators are displacing older, less efficient gas plants. Although absolute gas use in these areas has increased, it has increased less than it would have if the new plants had not been built.

Half of the gas used for power generation is consumed in California and Texas and these two states accounted for most of the growth in gas consumption for power generation during the 1990s. In Texas, newer, very efficient plants provided much of the generation, displacing older, less efficient gas plants. Gas consumption went up but less than it would have without the new plants. In California, the growth was largely consumption in older plants trying to meet growing demand during a time of low hydroelectric generation. More recently, the new plants are starting to replace generation from the older plants, as in Texas.

As electric demand continues to grow, new gas generators in areas that historically relied on other fuels may start to create incremental gas demand growth. At current gas prices however, new coal plants may start to enter the market as alternatives to the gas plants. The U.S. DOE is currently tracking 62 GW of new coal capacity. This mix will also be affected by the status of electric restructuring, growth in the economy and other broader factors.

There is a significant amount of short-term switching capability in conventional gas steam power plants but very little in new combined cycle plants. About 36 percent of the 104 GW of gas boilers used for power generation are identified as having capability to switch to residual oil. About 32 percent report actually using residual oil between January 2000 and January 2002. This is about 8.5 Bcfd of capacity. Most of this is short-term switching capability, limited either by regulatory restrictions or operational factors.

Only about 6 percent of the 116 GW of new gas combined cycle capacity reports having alternative fuel capability (distillate oil), accounting for about 1.1 Bcfd. About 19 percent of the new peaking turbines report switching capability (2.6 Bcfd), but these units run very few hours per year.

Fuel switching is typically triggered by extreme weather or local delivery constraints. Therefore, the effects are typically local or regional and short-term in nature. The total national switchable capacity is unlikely to be applied at one time due to regional and operational diversity. During recent periods of high gas prices, approximately 5 to 7 Bcfd of switching has been observed in the power generation sector. As new combined cycle plants replace older gas steam plants, fuel switching capability will be decreased.

The recent rapid increase in gas consumption for power generation was the result of a mix of institutional, economic, technological and weather-related factors including:

- Electric utility restructuring
- Availability of new combustion turbine technologies
- Low hydroelectric generation
- Low gas prices

Continued changes in these factors may slow the growth of gas demand for power generation in the coming years.

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Natural Gas Price Impacts and Implications for U.S. Industry

Submitted to:
National Commission on Energy Policy

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Submitted By:

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Executive Summary

As natural gas prices have increased in recent years, there has been increasing concern over their effect on industrial sector competitiveness, jobs and the economy in general. Gas price increases in 2000-01 and in 2003 were followed by periods of economic decline and increasing unemployment. Some attribute these economic declines to the gas prices. At the same time, there is concern that high gas prices could result in permanent shutdown of gas-intensive industries, reducing gas demand. Such "demand destruction" in the industrial sector could result in lower demand for gas which could subsequently temper gas price levels and minimize volatility, though at the cost of U.S. productive output and jobs.

This white paper examines industrial gas markets and the effects and implications of recent gas price increases. The report examines the general influence of natural gas prices on U.S. industrial sector competitiveness. While the analysis does distinguish between the various categories of activity in the industrial sector and offers insights into the areas most affected by high prices and the potential impacts of sustained high prices, specific companies or industries could experience more significant impacts than described here. An exhaustive review of corporate profit margins and industrial competitiveness compared against the economics of commodity imports is beyond the scope of this work.

The major conclusions of this analysis include:

Industrial Energy Consumption Background

- The industrial sector is the largest U.S. consumer of natural gas.
- Gas is a key fuel and an important feedstock for the industrial sector.
- Energy and gas use are concentrated in a few industries. The chemicals and refining industries alone account for more than 50 percent of industrial gas consumption.
- The energy-intensive industries are the basic industries, which convert raw materials into intermediate products such as steel, bulk chemicals, plastics, etc. They directly account for a small share of industrial GDP and employment though they contribute feedstocks and intermediate inputs to other industries. The chemicals and refining industry account for 8 percent of industrial GDP and 4 percent of industrial employment.
- GDP and employment are concentrated in the less energy-intensive industries that produce higher value finished products. The construction, metal durables and “other manufacturing” industries account for 64 percent of industrial GDP and 67 percent of industrial sector employment. They account for 14 percent of industrial sector gas use.
- On average, energy represents only a few percent of the cost of production for industry. For the high value, high employment industries the gas share of production cost is less than 1 percent. For these industries, even large changes in gas prices have a relatively

small impact on production cost, though for industries that are already suffering competitive challenges, even small changes can have an effect.

- There are a few industries for which gas represents more than 10 percent of production cost. These tend to be industries such as fertilizer, in which gas is the raw material as well as the fuel. The most vulnerable industries are typically those that are also strongly affected by international competition. However, changes in international markets can have positive or negative effects that are as big as recent gas price trends.

History of Industrial Gas Consumption and Recent Trends

- Industrial gas use peaked in 1973 and then declined for several years due to a variety of factors including rising gas prices and increased energy efficiency.
- Industrial gas use started to increase during the mid 1980s due to lower gas prices and new applications of gas. This trend continued through 1997.
- Industrial gas consumption started to decline in 1997 due to reduced industrial production in the energy-intensive industries prior to the recent gas price increases. This decline in consumption intensified after the increase in gas prices in 2000-01 and 2003.

Fuel Switching

- The limited data available indicate that there is significant fuel switching capability in the industrial sector, though much of it is usable only for short periods of time and may be limited to certain times of year.
- The data indicate about 4 Bcfd of switchable capacity in boilers and process heaters. Due to regional and operational diversity, not all of this capacity would be expected to switch at one time. During recent periods of high gas prices, EEA has observed about 2 to 3 Bcfd of industrial sector fuel-switching.
- Some operational capacity to switch fuels on very short notice has probably been lost over the last decade when it was used very little. However, this could be regained with investment in new or updated equipment.
- Changes in equipment and new environmental regulations have also caused reductions in fuel-switching capacity, but not in a major way.
- In the long term, fuel switching capacity can be regained or expanded if fuel prices make it economic.

Gas Use in the Chemical Industry

- The chemical industry is the largest user of natural gas and has some of the most vulnerable segments to high gas prices.
- The ammonia/fertilizer industry is vulnerable because it relies on gas as a feedstock as well as a fuel and because it must compete with ammonia imports from countries with much lower gas prices. At this time, international ammonia prices are higher than would be indicated by U.S. production costs, so international prices are actually increasing U.S. ammonia costs.

- Reduced ammonia production in recent years seems to be the result of a variety of factors, including gas prices. However it's not clear that gas prices were the most significant.
- Although some less efficient ammonia plants have shut down, U.S. capacity was higher at the end of 2002 than it was in 1992 and is still adequate to meet U.S. demand.
- Imports of ammonia and ethylene have been increasing for many years and have increased in last few years. Over time, imports from countries with lower production costs are likely to increase under currently likely U.S. gas price scenarios.

Overall Conclusions

- Industrial gas demand was about 14 percent lower in 2002 than at its recent peak in 1997.
- This reduction was a combination of reduced demand due to an economic downturn, effects of international trade and the effect of high gas prices on some gas-intensive industries.
- It is difficult to separate these effects but the economic downturn and international trade issues seem to have played a larger role than gas prices. As of early 2004, industrial production seems to be increasing despite gas prices continuing to be higher than recent historical levels. Changes in international markets are also supporting recovery of some gas-intensive industries.
- The gas-intensive basic industries in the U.S. are mature and some are vulnerable to competition from other countries with lower energy, labor and raw material costs. These industries may continue to decline in the future under currently likely gas price scenarios, depending on the changes in world markets. Gas-intensive industries that do not have foreign competition will try to pass higher gas prices on to their customers. Their success will depend on many factors, though gas price is a small share of production cost for even most gas-intensive industries.
- These continued changes may cause industrial gas demand to decline from historic levels but gas prices at the current levels will be only one of several contributing factors.

These topics are discussed in more detail in the report, which is organized as follows:

- Chapter 1 provides background on the U.S. industrial sector, its use of energy and the relationships between economic output, employment and energy consumption.
- Chapter 2 reviews the long-term and recent trends in industrial production, gas consumption and gas prices.
- Section 3 analyzes fuel switching
- Chapter 4 analyzes the use of gas in the chemical industry.
- Chapter 5 summarizes the discussion and draws some conclusions.

1 -Overview of the Industrial Sector

The U.S. industrial sector consists of all agricultural farms, mining, construction and manufacturing establishments (SIC categories 1 through 39). Table 1 lists the industries included in the industrial sector. Agriculture, construction and mining are categorized as the non-manufacturing industries while the remaining industries are the manufacturing industries.

Table 1 - The U.S. Industrial Sector

Non-Manufacturing Industries

Agriculture-Crops (SIC 01)
Agriculture- Livestock, etc (SIC 02, 07, 08, 09)
Mining-Energy (SIC 12, 13)
Mining-Non-Energy (SIC 10, 14)
Construction (SIC 15)

Manufacturing Industries

Food and Kindred Products (SIC 20)
Tobacco Products (SIC 21)
Textile Mill Products (SIC 22)
Apparel and Other Textile Products (SIC 23)
Lumber and Wood Products (SIC 24)
Furniture and Fixtures (SIC 25)
Paper and Allied Products (SIC 26)
Printing and Publishing (SIC 27)
Chemicals and Allied Products (SIC 28)
Petroleum and Coal Products (SIC 29)
Rubber and Miscellaneous Plastic Products (SIC 30)
Leather and Leather Products (SIC 31)
Stone, Clay, and Glass Products (SIC 32)
Primary Metals (SIC 33)
Fabricated Metal Products (SIC 34)
Industrial Machinery and Equipment (SIC 35)
Electronic & Other Electric Equipment (SIC 36)
Transportation Equipment (SIC 37)
Instruments and Related Products (SIC 38)
Miscellaneous Manufacturing (SIC 39)

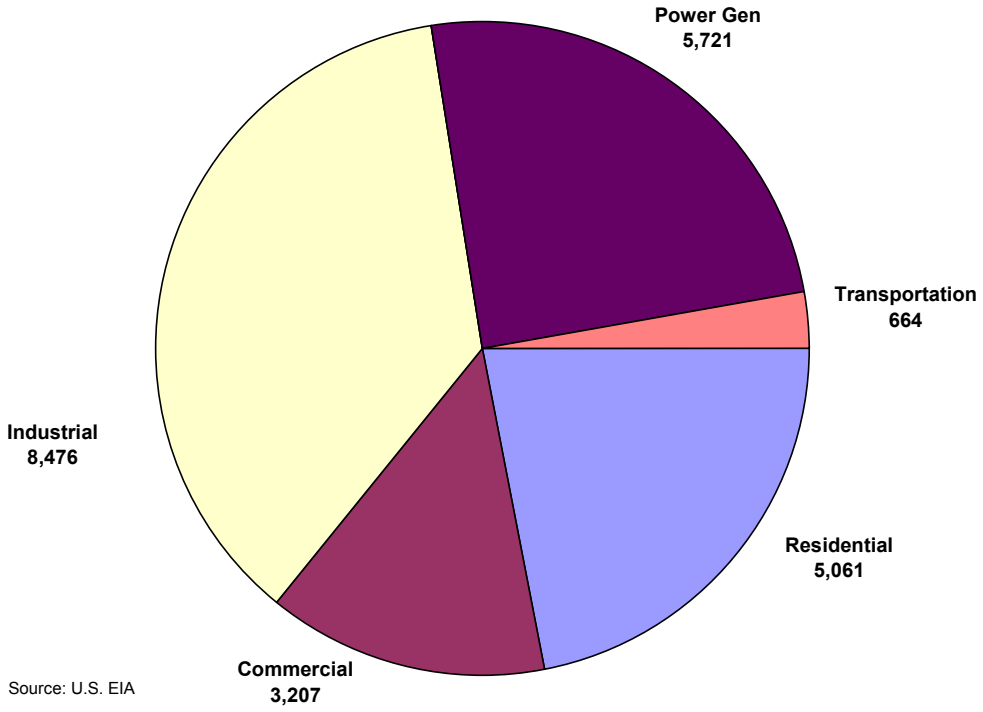
The industrial sector is the largest user of natural gas in the U.S. Including natural gas lease and plant consumption[1], the sector accounts for 8,476 TBtu or almost 40 percent of total natural gas use in the U.S (Figure 1). The electric power and residential sectors consume over 20 percent of gas consumption each. The commercial and transportation sectors account for the rest.

Because different industries use different technologies and processes, their use of energy and choice of energy sources vary considerably. Figure 2 shows the consumption of natural gas, fuel oil, electricity, coal, and other fuel (by-product and waste fuel) by industry group. The largest users of energy and the most energy-intensive industries are the food, paper, chemicals, petroleum refining, stone, clay and glass, and primary metals industries. These industries are considered basic industries since they are involved in processing basic raw materials into more useful intermediate products, requiring substantial amounts of processing and energy use. (In the

[1] Natural gas lease and plant fuel is the natural gas used in drilling and field operations and in natural gas processing plants. This consumption is about 1.2 TBtu per year and is categorized in the mining industry for overall tracking purposes but is often listed separately in gas industry accounting.

food industry, most of the energy is consumed in "basic processing" segments such as corn, sugar, and meat processing.)

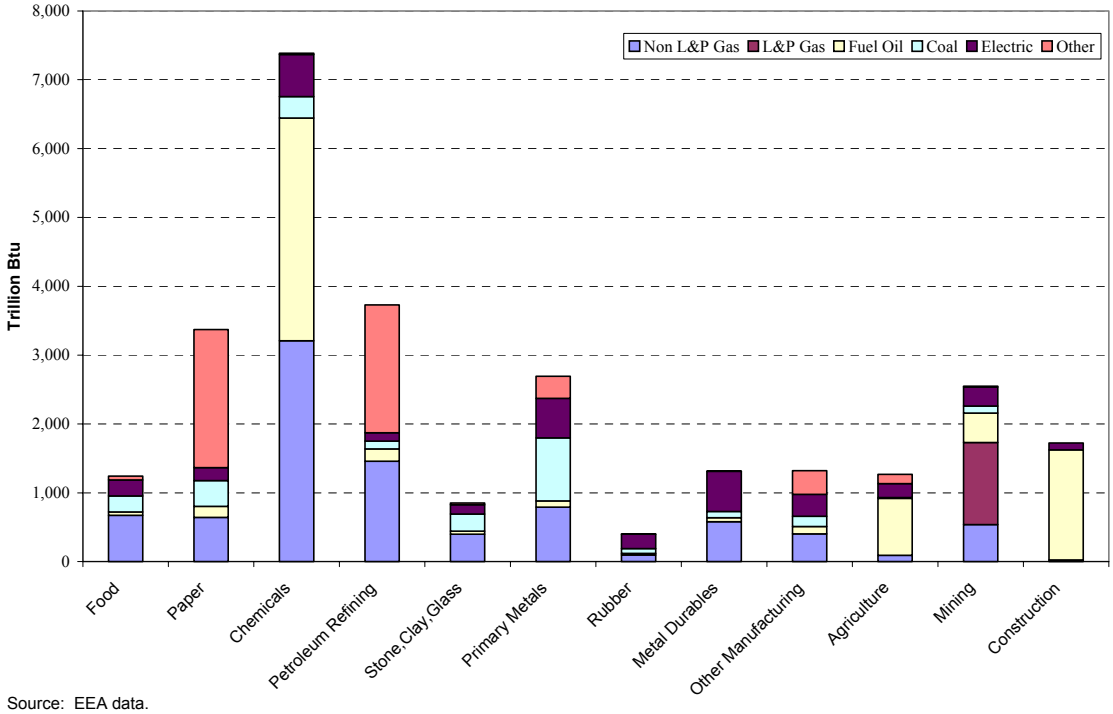
Figure 1 -U.S. Natural Gas Consumption – 2002 (TBtu)



These six energy-intensive industries account for 70 percent of total industrial energy consumption and 71 percent of total industrial natural gas consumption. The six industries account for 81 percent of industrial natural gas consumption, excluding lease and plant gas. The chemical and petroleum refining industries alone consume over half of total non-lease and plant gas. The metal durables sector includes many of the industries commonly thought of as manufacturing – automobiles, appliances, electronic equipment, etc. These industries and all of the "other manufacturing" industries account for only about 12 percent of industrial gas consumption.

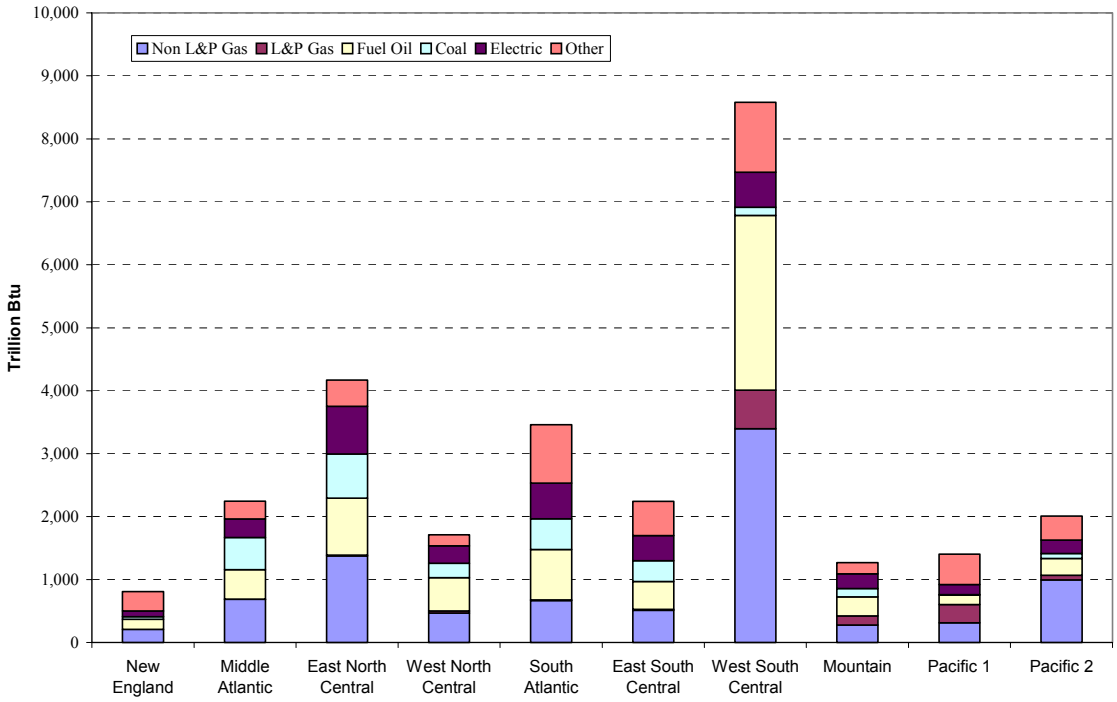
Because certain industries are concentrated in certain parts of the U.S., the concentration of energy use by industry also translates to regional concentration. Figure 3 shows the regional breakdown of industrial energy and natural gas consumption in the U.S. Two regions account for over half of the natural gas consumption in the U.S. The West South Central region, consisting of Texas, Oklahoma, Louisiana, and Arkansas, reports the largest natural gas consumption, comprising 38 percent of total industrial natural gas consumption. The chemical and petroleum refining industries account for over 80 percent of total industrial natural gas

Figure 2 –Industrial Energy Consumption by Industry - 1998



Source: EEA data.

Figure 3 – Industrial Energy Consumption by Region and Energy Source, 1998



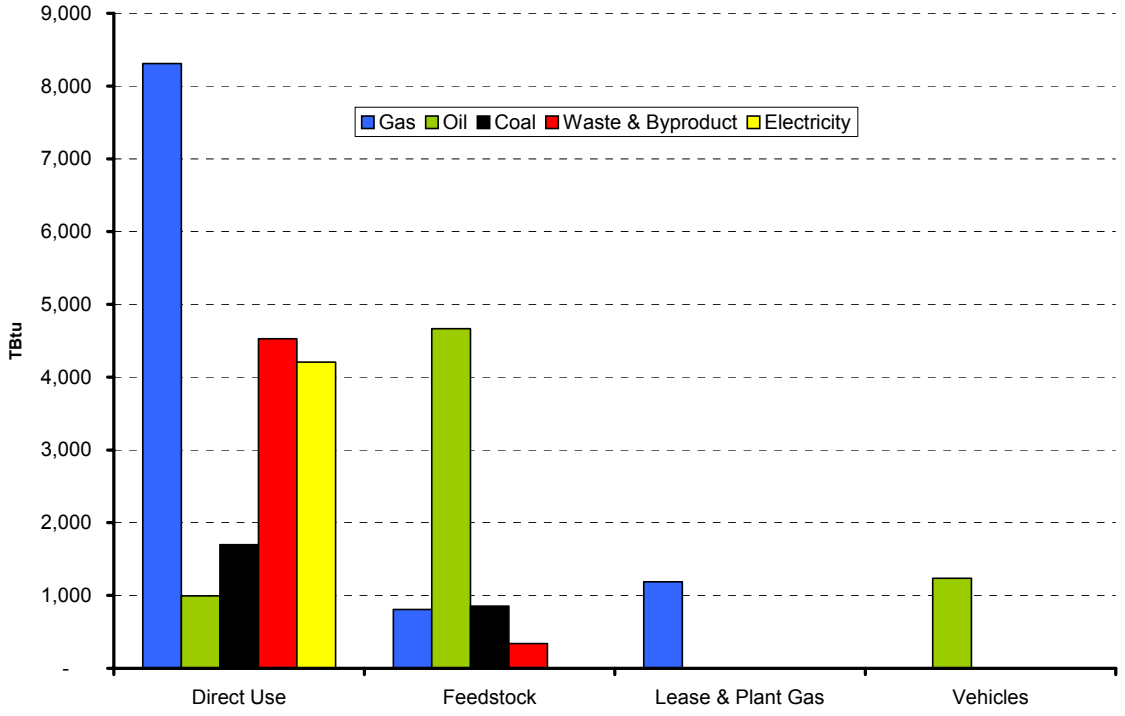
Source: EEA data.

consumption in this region. These industries rely on natural gas both as fuel and feedstock and originally located in this region in part due to its proximity to gas supplies.

The East North Central region, consisting of Illinois, Indiana, Michigan, Ohio, and Wisconsin, is a distant second in gas consumption, at 15 percent of the total. This region includes a high concentration of food, petroleum refining, chemicals, and metals industries, which prefer natural gas not only for its historically competitive prices but also due to the industries' preference for gas in specific applications such as cooking, baking, ammonia production, and metal processing. The clean-burning, excellent combustion characteristics of natural gas have made it the fuel of choice for many industrial processes.

The uses of energy are significant factors in the choice of fuel. Figure 4 breaks down industrial energy consumption by fuel and end use. Natural gas, including lease and plant gas, comprises approximately 36 percent of the 28,300 trillion Btu (TBtu) of total energy used in the industrial sector in 2000. Lease and plant gas is 12 percent of the gas use and about 8 percent of the gas is used for chemical feedstocks for products such as ammonia and methanol. The remaining 80 percent of natural gas is used directly for combustion in boilers, process heaters or power generation equipment.

Figure 4 - Industrial Energy Consumption by End Use - 2000



Oil accounts for 24 percent of industrial energy consumption but most of the oil is used for petrochemical feedstocks and more than half of the remainder is used as vehicle fuel, mostly in

the agriculture, construction and mining sectors. Only about 14 percent of the oil consumption is used for direct combustion. Coal accounts for only about 9 percent of industrial energy consumption and about one third is used as feedstock, primarily to make coke for iron production. Most of the direct use of coal is in boilers and cement kilns. Electricity accounts for 15 percent of industrial energy consumption. Most of this is used for lighting and motors. Most of the process use of electricity is in electric arc furnaces for steelmaking.

Waste and byproduct fuels account for 17 percent of industrial energy consumption. These fuels include biomass byproducts from papermaking, petroleum byproduct gases from refineries, coke oven and blast furnace gases from iron and steelmaking and a wide variety of other fuels. These waste and byproduct fuels are essentially free, so there is a great incentive to use them before using purchased fuels. These fuels make up almost 25 percent of the direct energy use (excluding feedstock, lease and plant and vehicles) in the industrial sector.

Putting all of this together, gas accounts for 76 percent of purchased fossil fuel for direct use in the industrial sector. Thus, the industrial sector today is highly dependent and heavily concentrated in its use of natural gas. This concentration extends to industry, region and application.

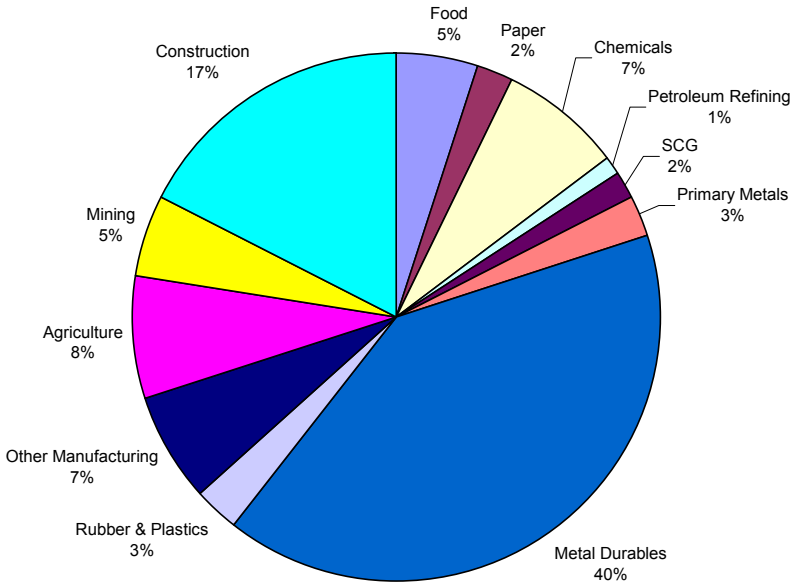
While energy and natural gas consumption are concentrated in a relatively few industries, this concentration does not extend to other economic factors, such as GDP or employment. As noted above, energy consumption is largely concentrated in the basic commodity industries, which use large amounts of energy to convert raw materials into intermediate materials and may also consume energy feedstocks. However, the direct unit value of these intermediate products, such as steel, bulk chemicals, plastics, etc, is relatively low compared to finished products such as consumer goods, electronic products, etc.

GDP values are a measure of economic activity generally used to compare the relative contributions of various sectors of the economy. In 2001, the industrial sector accounted for 23 percent of total U.S. GDP. Within the industrial sector, the largest GDP value was represented by the metal durables industry, accounting for 40 percent of total industrial sector GDP (Figure 5). This sector includes manufacturers of consumer goods such as automobiles, appliances, computers, etc. However, the metal durables sector accounts for only 7 percent of industrial natural gas consumption. The second largest component of industrial GDP, at 20 percent, is the construction industry, which consumes less than 1 percent of industrial natural gas. The third largest GDP component is agriculture, also a small gas consumer at about 1 percent, though it is a large user of gas-derived ammonia.

The energy-intensive industries account for only 20 percent of total industrial GDP. The chemicals and refining industries, which account for over half of industrial gas consumption, account for only 8 percent of industrial GDP. At that, it is the less energy-intensive segments of the chemical industry such as pharmaceuticals that account for most of the GDP component. While, the energy-intensive and gas-intensive segments of the economy are not the greatest

direct contributors to GDP, they do supply many of the raw materials for the manufacturing and construction industries that constitute the bulk of GDP.

Figure 5 – Industrial Sector Gross Domestic Product, 2001
2,132 Billions of Chained (1996) Dollars



Source: Bureau of Economic Analysis.

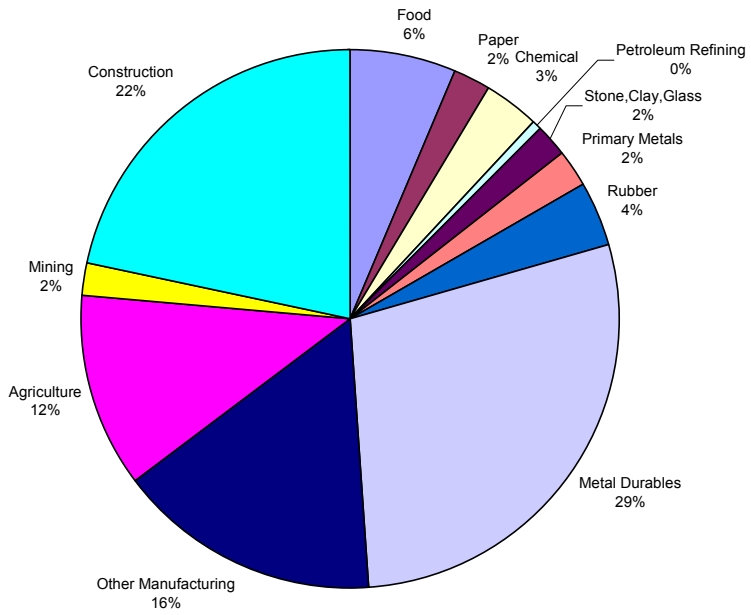
U.S. industrial employment is also concentrated in the non-energy-intensive industries. Figure 6 shows the distribution of U.S. industrial sector employment by industry group. The figure shows that employment in the non-manufacturing, metal durables, rubber and plastics, and "other manufacturing" industries accounts for over 83 percent of total industrial sector employment. These industries account for only 20 percent of gas consumption.

Among the energy-intensive industries (which account for less than 17 percent of industrial employment), the food industry has the largest employment level. The chemical and petroleum refining industries, which account for over half of natural gas consumption, account for less than 4 percent of total industrial employment.

One way to measure the impact of gas prices on industry is as the cost of gas consumed over total production costs by industry. While all costs are important to industries that are facing competitive challenges, the share of production cost is a reasonable first order indicator of the impact of energy prices. On average, natural gas and energy costs represent only about 2 percent of total production cost in industry. This means that natural gas and energy costs are small compared to other production costs, such as labor and raw materials. Therefore, high energy and

gas prices should not drastically damage a majority of industries. However, a number of industries have very high natural gas expenditures over total production cost, so that a scenario of high gas prices, such as those that have recently occurred, can be significant.

Figure 6 – Industrial Sector Employment, 1998
26.2 Million Employees



Source: Bureau of Census.

Table 2 shows the industry segments with the highest shares of natural gas expenditures over total production costs based on EIA and Census data.[2] (Only the manufacturing industries are analyzed). The gas consumption, employment and value added are also presented in the table.

The industries shown in the table represent almost 60 percent of total industrial gas consumption but only 4 percent of total industrial employment, and 9 percent of total industrial GDP. The nitrogen fertilizer industry, which manufactures ammonia, tops the list, with natural gas expenditures accounting for almost 40 percent of total production costs. This is primarily because natural gas is a raw material for the fertilizer industry as well as a fuel. The chlor-alkali industry ranks second, with natural gas cost representing almost 9 percent of total production cost. This industry manufactures chlorine and its co-product caustic soda. It is both electricity and steam-intensive. The industrial gas industry, which manufactures oxygen, hydrogen, acetylene and other gases, ranks third. In this industry, natural gas is used as a raw material in the production of hydrogen and acetylene. Other industries with significant gas cost shares

[2] Natural gas expenditures were taken from the EIA Manufacturing Energy Consumption Survey. Labor, capital, material, and other energy costs used to calculate total production cost were taken from Census data.

include paper, paperboard and pulp mills (for cogeneration), and other basic organic chemicals industries.

Table 2 - Industries with the Highest Shares of Natural Gas Expenditures Over Total Production Costs, 1998

Major Industry Group	Industry	Gas Cost Share	Gas Consumption (TBtu)	Employment	Value Added ($1000)
Chemicals	Nitrogenous Fertilizers	39.6 %	572	5,016	1,034,892
Chemicals	Alkalies and Chlorine	8.7 %	54	4,693	1,063,736
Chemicals	Industrial Gases	6.4 %	105	11,097	3,097,214
Chemicals	Petrochemicals	5.0 %	308	8,756	2,588,422
Paper	Paper Mills, except Newsprint	4.6 %	231	104,964	22,676,592
Chemicals	Other Basic Organic Chemicals	4.5 %	782	81,910	16,098,307
Paper	Pulp Mills	3.9 %	24	7,218	1,413,321
Paper	Paperboard Mills	3.8 %	227	48,773	11,029,318
Chemicals	Phosphatic Fertilizers	3.5 %	14	7,195	1,105,022
Food	Wet Corn Milling	3.4 %	77	8,635	2,869,704
Chemicals	Synthetic Rubber	3.3 %	55	10,340	2,437,624
Primary Metals	Iron and Steel Mills	3.3 %	494	127,359	14,375,029
Stone, Clay and Glass	Glass and Glass Products	3.1 %	159	122,504	13,679,586
Chemicals	Cyclic Crudes and Intermediates	2.9 %	50	6,771	1,349,637
Chemicals	Other Basic Inorganic Chemicals	2.7 %	102	47,584	9,224,221
Primary Metals	Foundries	2.3 %	137	199,343	16,203,518
Primary Metals	Alumina and Aluminum	2.0 %	189	76,354	8,600,132
Petroleum Refining	Petroleum Refineries	2.0 %	948	63,258	40,335,212
Chemicals	Plastics Materials and Resins	1.9 %	259	58,613	15,153,244
Stone, Clay and Glass	Cement Manufacturing	1.7 %	27	17,220	4,790,951

Source: EIA MECS and Census Bureau Annual Survey of Manufactures for 1998.
Note: Employment and Value Added values are for 2001.

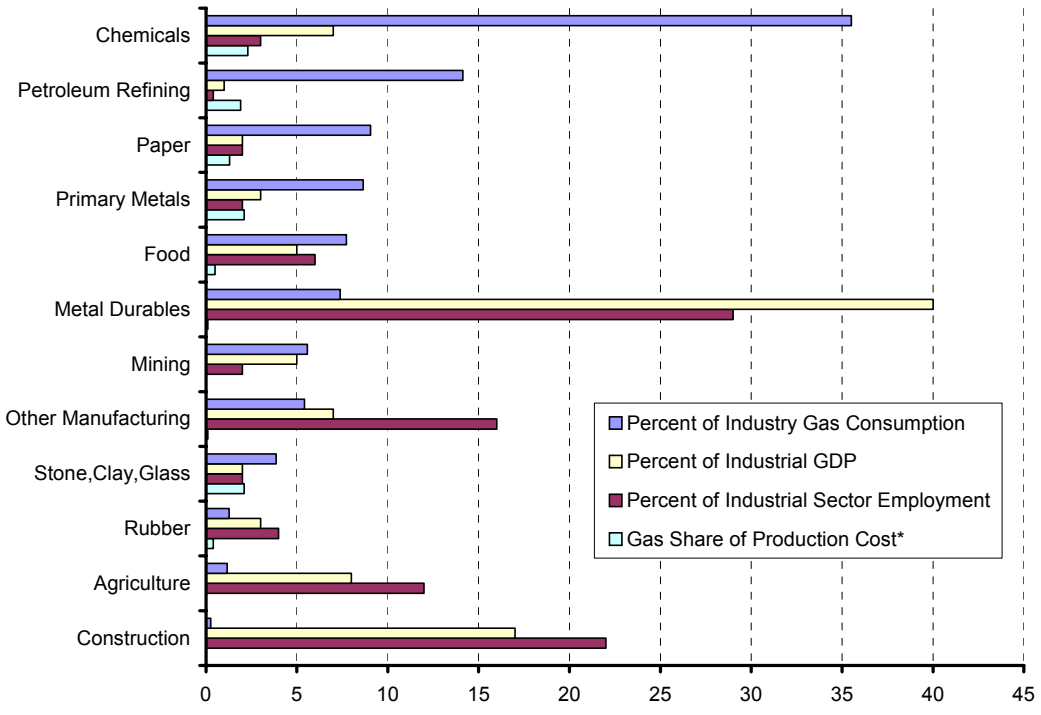
The petrochemicals industry, which manufactures a variety of products, including ethylene, propylene, and other derivatives, ranks fourth. This industry is of particular interest because the ethylene industry relies heavily on natural gas liquids as a raw material. Although natural gas liquids (which include ethane, propane, and other liquids) are not considered natural gas (methane), they are extracted from gas at the wellhead before it enters the pipeline and the price of ethane correlates strongly with the price of natural gas.

Although there are industry segments for which gas comprises a very high share of production cost, that share is relatively low for the major industry groupings even among the energy-intensive industries. The gas share of production cost for the food, paper, chemicals, refining, primary and stone, clay and glass industries ranges from 1 to 3 percent. The industries with the highest GDP component and the highest employment such as metal durables, construction and agriculture have gas cost shares of less than 1 percent. The computer and electronic product industries, which have been the fastest growing sectors in terms of output during the 1990s and

experienced a stark downturn in recent years, have the lowest share of natural gas costs over total production cost, at 0.1 percent.[3]

Figure 7 compares gas consumption, GDP, employment and gas cost shares for the industrial sector. It reinforces the point that the gas-intensive industries are the lower GDP, lower employment industries and vice versa. It also shows that natural gas is a small part of production costs, even for the gas-intensive industries. Higher natural gas costs certainly will affect industry profitability and competitiveness, but that effect needs to be kept in perspective with other costs and other determinants of industry health and the overall economy.

Figure 7 – Industrial Gas Consumption and Economic Factors



*Gas cost share not available for agriculture, construction and mining.

Beyond the direct cost to a particular industry, the effect of gas prices depends on the competitive position of the industry. The most vulnerable industries are those with high cost dependency on gas and strong international competition. Many of these, such as the primary metals industries, have had periods of decline at various times due to a variety of domestic and international factors. Higher gas prices can be one factor that contributes to that decline, as they may have in 2001-02. On the other hand, the steel industry is currently very strong, despite high gas prices, due to strength in the international steel markets.

[3] The overall energy costs share over production cost in the computer and electronic product industry is less than 1 percent. Electricity cost share is 0.8 percent and natural gas cost share is 0.1 percent.

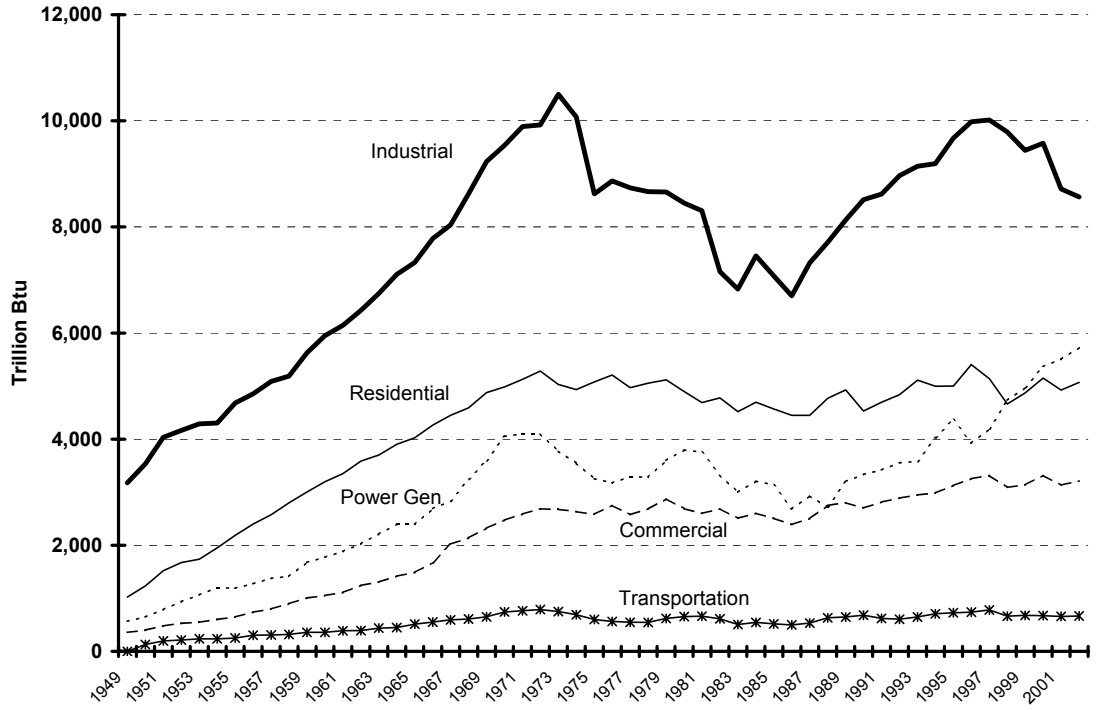
At this time, the world competitive situation seems to be more important than gas prices for the steel industry. If world steel prices fall, then the U.S. industry could again be at risk. The issue of whether it is better for U.S. industry and consumers to pay more for U.S. steel or buy lower cost foreign steel but risk losing U.S. steel jobs and manufacturing capacity is dependent on many other factors besides gas prices and is beyond the scope of this analysis. However, similar questions can be raised for other U.S. basic industries that are gas-intensive, such as the fertilizer industry.

For industries with less direct foreign competition, the issue is whether the gas price increases can be passed on to consumers and what effect those costs have on the overall economy. Where gas constitutes only a few percent of production costs or where there is little foreign competition, this would seem feasible, however there will certainly be exceptions and the macroeconomic implications are also beyond the scope of this study.

2 - History of Industrial Gas Consumption and Recent Trends

This section reviews historical trends in natural gas prices, industrial activity and gas consumption. Figure 8 shows the history of U.S. natural gas consumption by sector. Industrial natural gas demand started to grow rapidly after World War II as pipelines started to deliver gas to a broad range of customers. Gas demand grew continuously and rapidly for almost 25 years, from 1949 through the early 1970s. This steady rise was primarily driven by the expansion of U.S. industries after World War II and their adoption of natural gas as a primary fuel. Industrial demand for natural gas peaked in 1973, just before the Arab oil embargo.

Figure 8 - Natural Gas Consumption by Sector, 1949-2002



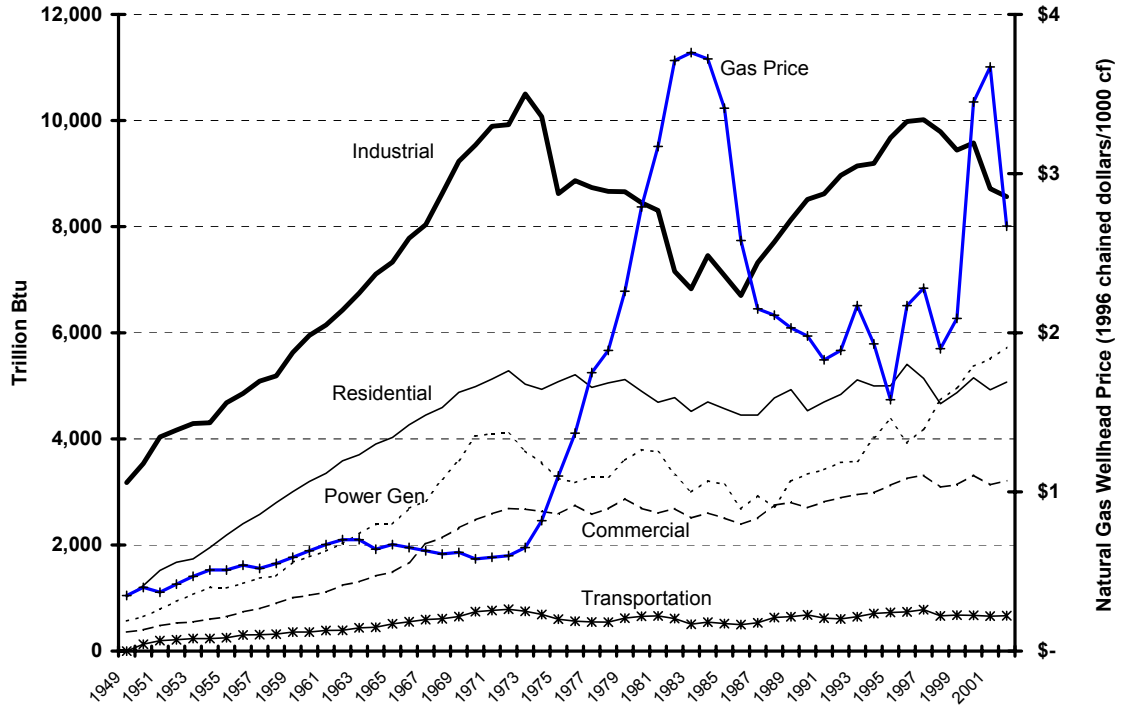
Source: EIA. Industrial gas demand includes lease and plant.

The U.S. economy staggered after the oil embargo. While GDP grew by almost 5 percent per year from 1970 to 1973, it declined by 0.5 percent per year from 1973 to 1975. As a result, industrial energy consumption dropped significantly. Industrial oil consumption fell by 10 percent during this period and natural gas consumption declined by 20 percent. However, when the economy recovered after the 1975 recession, natural gas demand by industries remained low through 1986. The low demand reflects several factors.

The energy price shock of the early 1970s pushed industry to become more energy efficient. Industry began greater recovery and utilization of waste fuels[4], displacing some of the fossil fuels used in the past. Electrotechnologies also started penetrating industrial markets during this period. The successful penetration of electrotechnologies was driven by changes in processes, which include electric arc furnaces in steel manufacturing and electric-based technologies in the metal fabrication, glass, and chemical industries. Overall, from 1973 to 1986, industrial natural gas demand declined by 36 percent or 3.4 percent per year.

Figure 9 shows that high gas prices also played an important role in continued reduced industrial gas consumption. Wellhead natural gas prices were extremely low, less than $1/MMBtu, from the 1950s through 1970. Much of the investment in gas-dependent industries began during this very low-price period. Natural gas prices spiked during the 1970s, primarily due to supply shortages resulting from controls on natural gas wellhead price, which resulted in low natural gas exploration activities. This enormous increase in gas prices was an important factor in limiting the rebound in industrial gas consumption.

Figure 9 - Natural Gas Price and Consumption by Sector, 1949-2002



Source: EIA. Industrial gas demand includes lease and plant.

After the passage of the Natural Gas Policy Act of 1978, which removed the controls on natural gas wellhead prices, natural gas supply increased, causing a "gas bubble" in the 1980s. That

[4] Waste fuels are byproducts of manufacturing processes that could be used as fuel. Examples include spent liquor, black liquor and wood waste in the pulp, paper and paperboard industry, and refinery gas and petroleum coke in the petroleum refining industry.

began the steep decline in natural gas prices, which was sustained until the late 1990s. After 1986, natural gas consumption by industry started to revive. From 1987 through 1997, industrial gas demand grew by 4 percent per year, a rate similar to the years prior to 1970.

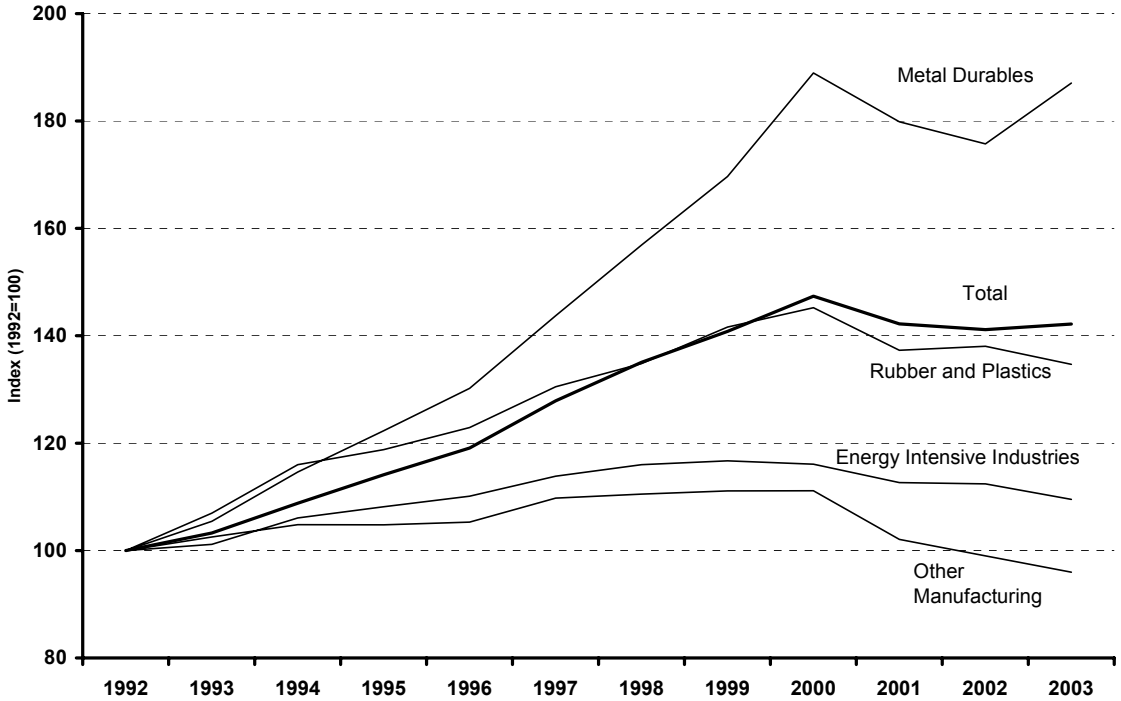
Gas consumption during this period was also driven by the rapid expansion of gas-fired cogeneration encouraged by the Public Utility Regulatory Policy Act of 1978 (PURPA). PURPA removed regulatory barriers to the development of industrial cogeneration by exempting cogenerators from the Public Utilities Holding Company Act (PUHCA), and by requiring electric utilities to interconnect cogenerators and provide backup power at reasonable rates. PURPA also required electric utilities to purchase any electricity produced by cogeneration facilities at the same rate the utilities would have had to pay to generate it themselves (their avoided cost). Industrial cogeneration capacity approximately tripled from the mid-1980s to the mid-1990s.

The resurgence in industrial gas consumption continued until 1998, when industrial gas consumption slowed down and actually declined through 2002 (latest available data). The beginning of this decline predates the increase in gas prices in 2000-01 and was primarily due to a slowdown in industrial activity of the large natural gas users in industry as well as the overall slowdown of the economy. The 1998 downturn in industrial gas consumption was triggered by declines in consumption in the primary metals, food and paper industries and slower growth in the stone, clay and glass industry. This initial drop was exacerbated by the high gas prices starting at the end of 2000. By 2002, after gas prices increased, industrial natural gas consumption was 14 percent lower than its peak in 1997.

As Chapter 1 shows, energy consumption in the industrial sector is highly concentrated in a few industries, end uses and regions. It is these energy-intensive components that drive the overall energy consumption patterns of the U.S. industrial sector. While the energy-intensive industries are the driver for energy and natural gas consumption in the U.S. industrial sector, the less energy-intensive ones have been the primary source of production growth in recent years. Over the last decade, the less energy-intensive industries have shown tremendous growth while energy-intensive industries have shown slow to moderate production growth. Thus, because most of the energy consumed in the sector is in the energy and gas-intensive industries, one would expect that total industrial energy and natural gas consumption would not have followed the overall industrial production trend, but would be lower.

Since the early 1990s, the U.S. industrial sector has grown robustly, peaking in 2000, as shown in Figure 10. However, much of this growth was driven by less energy-intensive sectors such as the metal durables sector, which includes the semiconductor and computer industries. The metal durables sector was responsible for much of the economic growth during the 1990s, nevertheless, some signs of slowing down were already seen starting in 1997 and 1998, especially in the basic industries. Figure 10 shows production leveling off in the energy-intensive industries starting in 1997-98 and declining in 1999-2000, prior to the increase in gas prices. This early decline was driven primarily by the primary metals, food and paper industries. A broader slowdown was felt in almost all industries by 2001, and by 2002 a slight recovery (from 2001) was evident.

Figure 10 – Industrial Production by Industry Group, 1992-2003

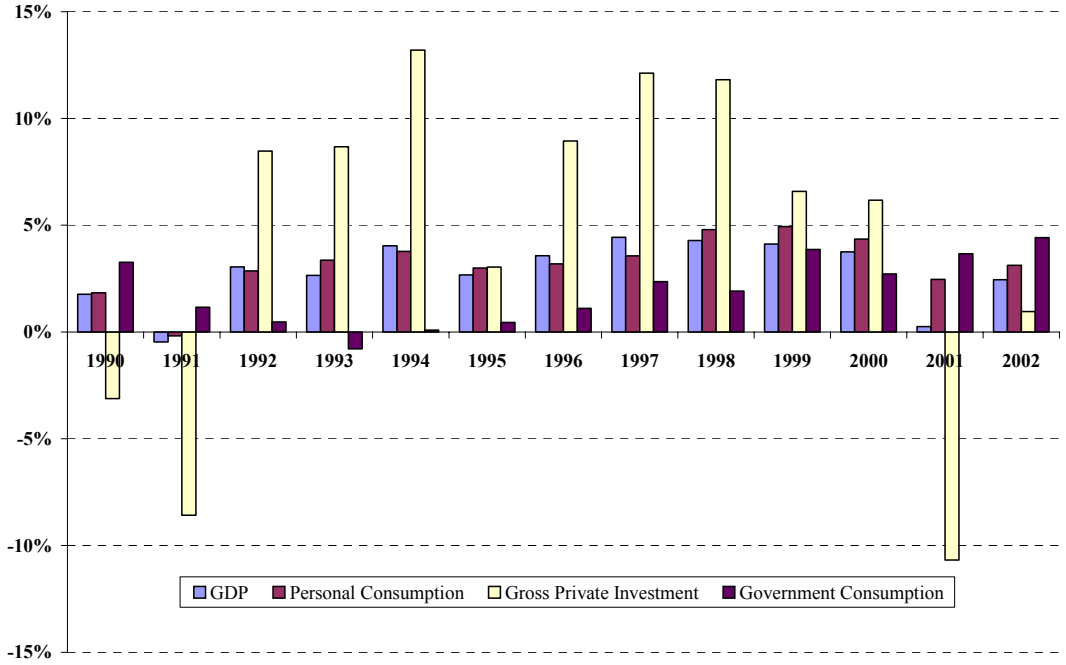


Source: FRB

These industrial production trends generally follow GDP trends. The nation's GDP grew robustly from 1991 to 2000, slowed down in 2001 and grew slightly in 2002. The largest component of GDP is personal consumption, followed by government consumption, private investment, and net exports, respectively. Figure 11 shows the annual percent change in GDP and its components (the chart does not show data for net exports because they are a very small part of GDP). The figure shows that the annual growth in GDP has been slowing since 1997. All of the GDP components report slowing growth rates since that year. In fact, private investments shrank in 2001. Government expenditures were the only component that has shown an increasing annual rate of change.

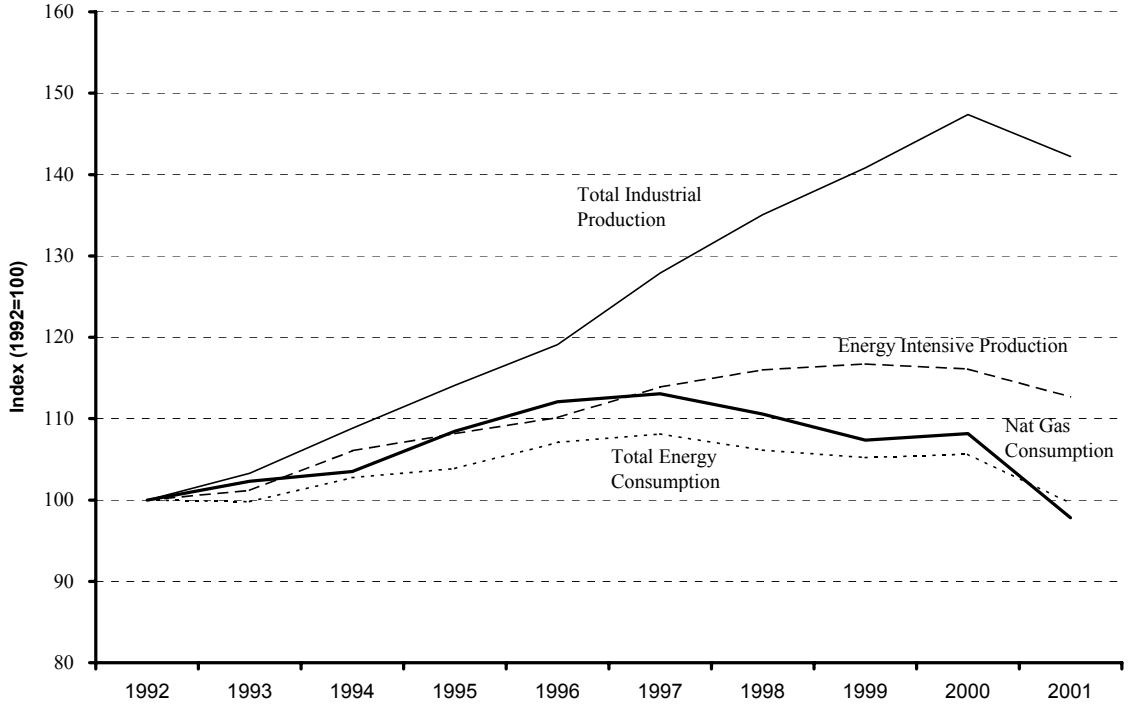
Figure 12 provides an indication of this effect in a more detailed view of the recent trends of industrial production, industrial natural gas demand, and natural gas prices. Despite the rapid growth in industrial production from 1994 to 2000 and low natural gas prices from 1994 through 1999, industrial gas demand was flat or declining over this time period. Industrial gas demand increased only slightly from 1994 to 1997 and started declining in 1998, before gas prices peaked. While total industrial production grew rapidly during the 1990s, production in the energy-intensive industries grew much more slowly and reached its peak around 1998-99. Within the energy-intensive sector, some segments including the organic chemicals and food sector actually declined in 1996-7, initiating the downward trend in gas consumption. The primary metals sector declined in 1998, also contributing to this trend.

Figure 11 – Annual Percent Change of GDP and Components, 1990-2002



Source: Bureau of Economic Analysis.

Figure 12 – Industrial Production and Energy Consumption, 1992-2001

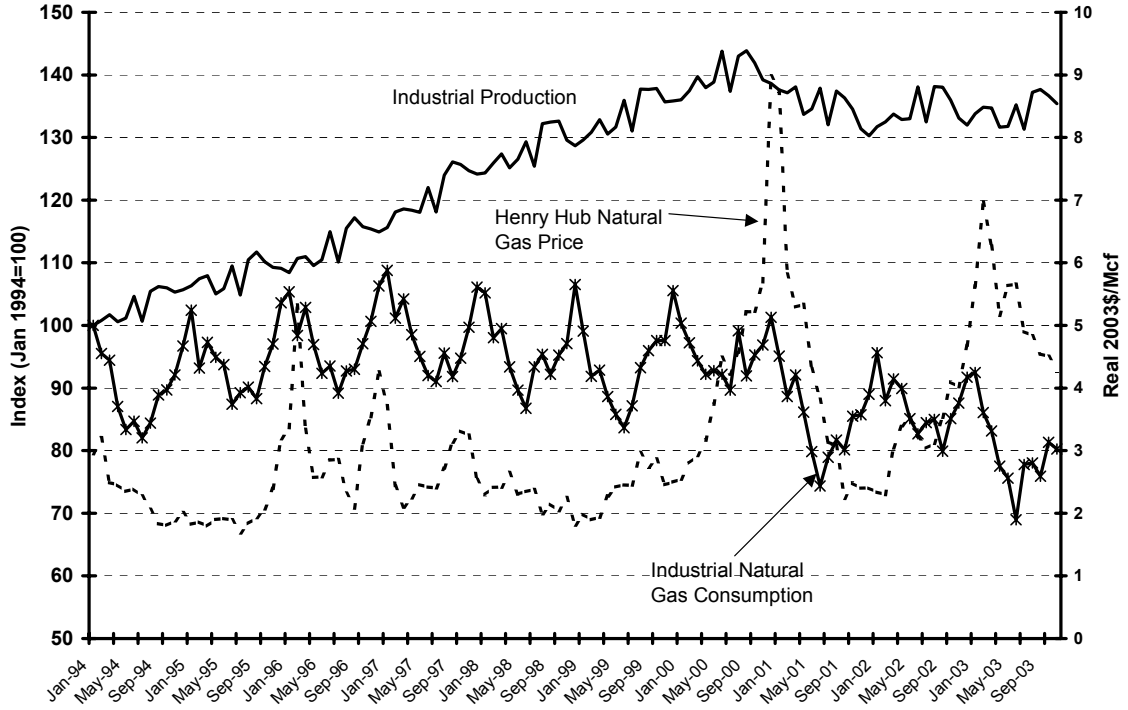


Source: Industrial Production - FRB; Energy and natural gas consumption- EIA.

Overall, both the total energy and gas consumption trends follow the production trend of the energy-intensive basic industries rather than that of overall industrial production, which is driven by the less-energy-intensive industries. This illustrates that total industrial production growth is not necessarily a good indicator of industrial energy consumption or vice versa. It also shows that slowing growth in the energy-intensive industries was the first factor in slowing industrial gas demand growth rather than high gas prices causing a slowdown in industrial growth.

Figure 13 shows a monthly perspective of the same period. It shows the monthly Henry Hub natural gas price, overall industrial production levels, and industrial natural gas consumption from 1994 to 2003 (up to April 2003). The monthly natural gas prices shown in Figure 13 show that natural gas prices peak during winter, as demand for gas for space heating increases.

Figure 13 – Monthly Industrial Production, Natural Gas Consumption and Natural Gas Prices, January 1994 to November 2003



Source: Industrial production - FRB; Natural Gas Price - EEA data; Natural gas consumption - EIA.

The figure shows that natural gas prices were relatively stable and low from 1994 to 1999, but started inching up by January 2000, accelerating by the middle of 2000 and peaking by December 2000. The price by December 2000 (in real terms) was $9.21/Mcf. Natural gas prices then fell as fast as they rose, dropping to the $2/Mcf range by September 2001. They started going up again in the early part of 2002, reaching their next peak by February 2003. They have

declined since, but only to the $4.50 to $5.50/Mcf range. Thus, by the beginning of 2000, a new period of higher volatility and price levels of natural gas price had begun.

Figure 13 also shows industrial natural gas consumption monthly trends. Industrial natural gas consumption increased slightly from 1994 to 1997 and started trending downward from 1997 through the middle of 1999, with the usual seasonal winter peaks and summer troughs. It rebounded slightly in 2000, and then dramatically declined from early 2001, reaching its bottom in June 2001. Although it has recovered slightly, overall, natural gas consumption in industry is still trending down from historic levels.

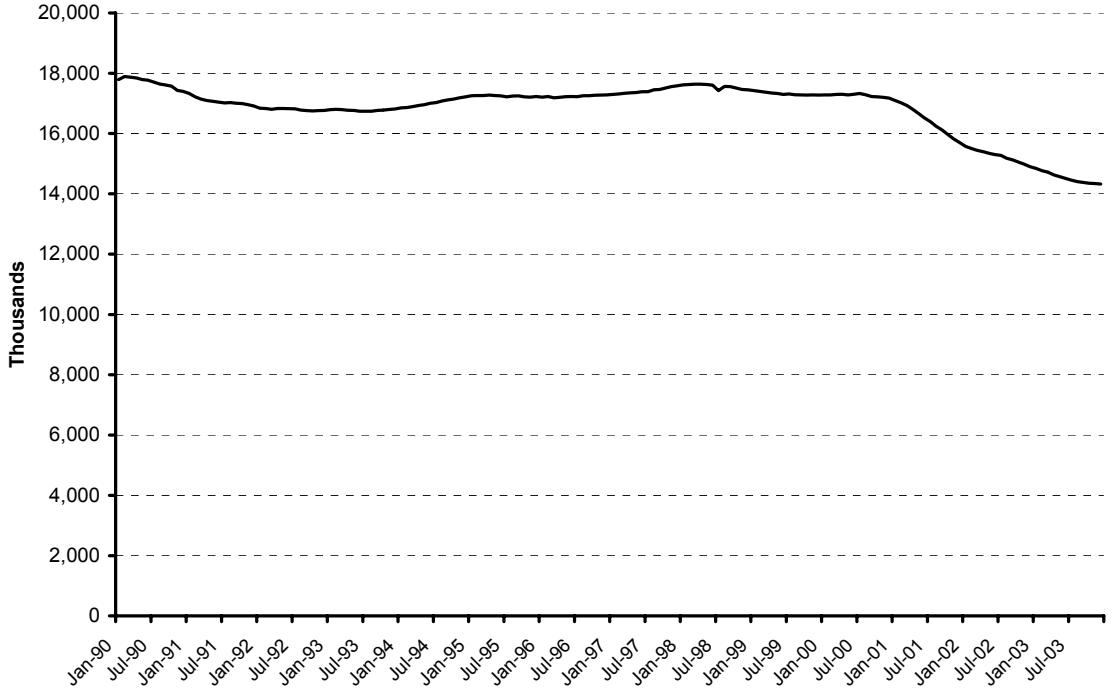
Figure 13 also shows overall monthly industrial production trends. Overall industrial production had been expanding from 1994 to its peak in September 2000. It then started declining, reaching its lowest point on December 2001. It then recovered somewhat, although by July 2003, industrial production was still about 10 percent lower than its peak in September 2000.

The declining trend in overall industrial natural gas consumption is the combined result of the slowdown in production of the energy-intensive industries and the rest of the economy and the advent of high natural gas prices. The slowdown in production by gas-intensive industries started in 1997-98, prior to the advent of high natural gas prices. Therefore, industrial natural gas consumption was already declining before the period of high gas prices. With the appearance of high gas prices, further reductions in natural gas consumption occurred. These further reductions were a result of the temporary or permanent shutdowns of some industrial plants (especially fertilizer and petrochemicals) and switching to alternative fuels as industry tried to manage the impacts of high gas prices. The continued slowdown in the economy resulted in reduced gas consumption from the non-energy-intensive industries as well, even though they play a much smaller role.

Of these multiple factors, the major link between high gas prices and reduced production/gas demand seems to be primarily the most gas-intensive industry segments, such as ammonia fertilizer. Other gas-intensive industries, such as primary metals were already in decline prior to the high gas prices and have since recovered somewhat. The response of the non-energy-intensive industries seems to be more affected by other factors than gas prices and the behavior of these industries has a relatively small effect on overall gas consumption.

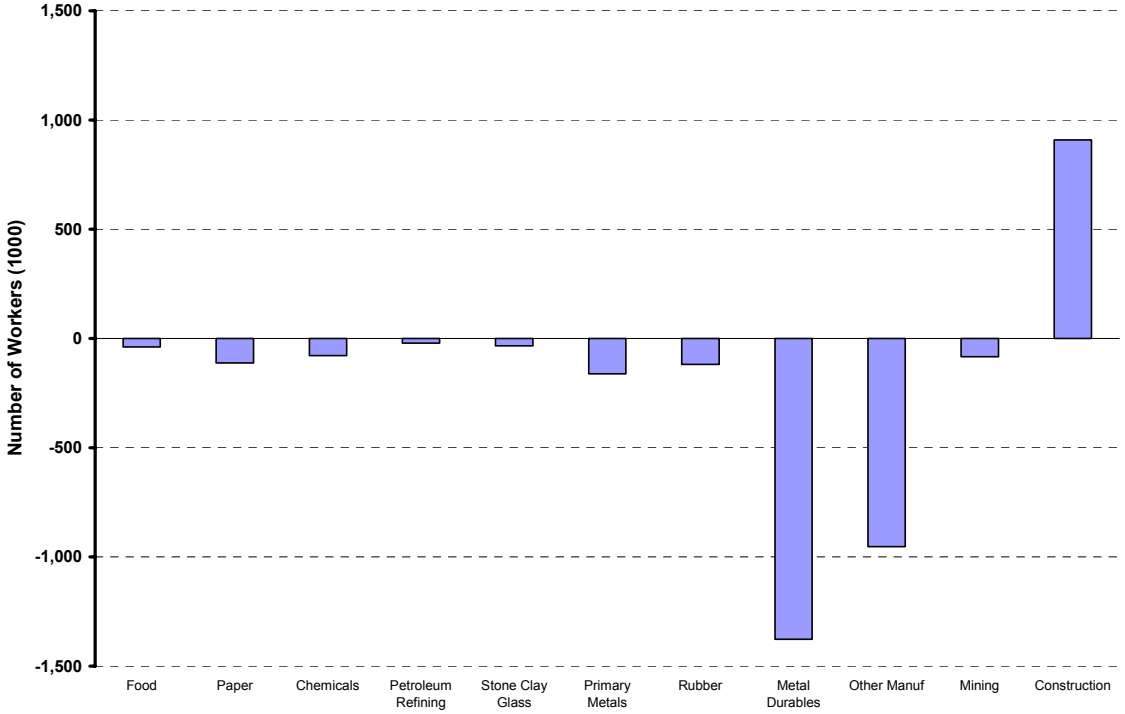
Figure 14 presents monthly manufacturing employment from 1990 to 2002. The figure shows that manufacturing employment had been fairly flat through the early 1990s but started declining in early 1998. A large drop in employment occurred in 2001 and continued through 2002. Figure 15 shows the loss of jobs from 1997 to 2002 by industry. The drop in employment was driven by the drop in employment in the labor-intensive industries, such as the metal durables industry and "other manufacturing" industry. Job losses in the energy-intensive industries are much lower in absolute terms. The largest losses from the energy-intensive industry were in the primary metals industry, which was undergoing great turmoil during this period. The only industry experiencing a gain in number of workers was the construction industry.

Figure 14 – Monthly Manufacturing Employment, January 1990-December 2003



Source: Bureau of Labor Statistics.

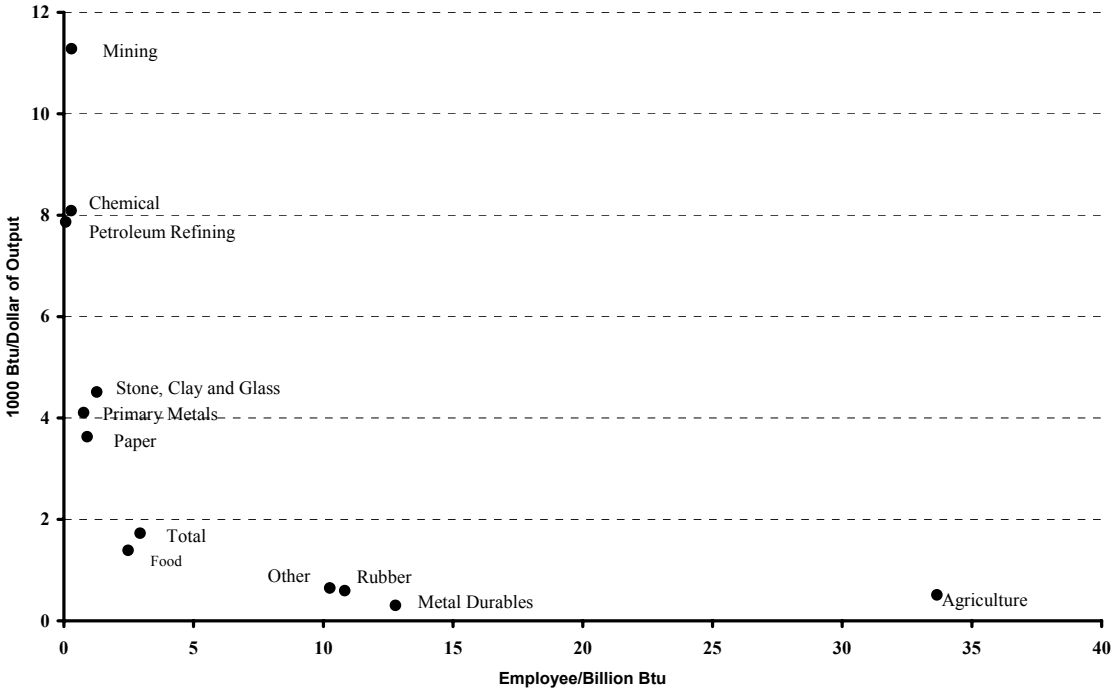
Figure 15 – Change in Employment by Industry Group, 1997-2003



Source: Bureau of Labor Statistics. No data for agriculture is available.

Figure 16 plots employment over gas consumption (number of employees/billion Btu of gas consumption) versus natural gas demand intensity (1000 Btu of gas consumption/ dollar of industry output) by industry. The industries with high employment to gas consumption ratios (e.g., agriculture, metal durables, rubber and other manufacturing industries) have very low natural gas demand intensity (in terms of production). Thus, a large loss of gas load (due to high gas price or demand destruction) would not necessarily induce a similarly large loss in employment because the gas-intensive industries have low employment and vice versa. This is consistent with recent data.

Figure 16 –Employment/Gas Consumption and Gas Consumption/Output by Industry Group, 1998



Source: EEA estimates.

3 - FUEL SWITCHING

Fuel switching is a key factor in industrial gas demand and pricing issues. Some gas-fired industrial combustion equipment has historically been designed and permitted to use an alternative fuel in addition to gas. This allows the user to switch to the alternative fuel at times when gas prices are high. The most common alternative fuels for gas equipment are residual oil, distillate oil or LPG. Gas users also may use fuel switching capacity to take advantage of "interruptible" gas contracts, which offer lower year-round gas prices in return for allowing the gas supplier to use the gas for other customers during periods of high demand. At some times in the past, in parts of the U.S., industrial customers could be subject to "curtailment", meaning that local gas utilities were required to interrupt large gas users in favor of residential and other small users during times of tight supply. This type of curtailment is not normal today. Interruptibility is more an issue of how much the consumer is willing to pay for an uninterrupted supply.

While the ability to switch fuels can be an important tool for gas consumers to avoid price spikes, it is also an important dampener of price volatility in gas markets, as it helps relieve demand during peak periods. Fuel switching in the industrial and power generation sectors has historically played a key role in this respect. During the years of the "gas bubble", this kind of price or constraint-induced fuel switching was minimal due to generally adequate supply and delivery capacity. Industrial gas users were only rarely called upon to use their fuel-switching capability and as a result some plants may not have maintained the operational capability to switch. As gas prices have increased, questions have been raised about the continuing ability to switch fuels to relieve peak demand and limit volatility.

Environmental regulations also play a key role in fuel switching. Oil combustion typically has higher emissions than gas combustion, so many dual-fuel processes are limited by environmental regulation in the amount of time and/or the time of year when they can burn their alternative fuel. Often they are limited to 30 days or less of alternative fuel consumption, often only in the winter. In addition, new, more stringent emissions regulations may not be achievable with the alternative fuel, further limiting the ability to switch. While short periods of fuel-switching can have a significant effect on price spikes, longer-term backing out of industrial gas consumption could be limited by these types of regulatory constraints.

This section assesses fuel switching capabilities in the U.S. industrial sector using two primary data sources, the U.S. EIA Manufacturing Energy Consumption Survey (MECS) and a private data base of industrial energy characteristics, the Major Industrial Plant Data Base (MIPD).

3.1 MECS 1994

MECS is a statistical survey of energy use characteristics in the U.S. manufacturing sector. Although the MECS survey is carried out every three years, the fuel switching section has been dropped in recent years and the most recent MECS fuel switching data are for 1994. Although this source is somewhat out-of-date, it is one of the few available.

The MECS fuel switching data report the amount of fuel consumed that is switchable and identify the alternative fuels. This reflects actual consumption that is switchable rather than total switchable capacity, which is a more common expression of fuel switching capability. The MECS fuel switching data cover energy consumption for heat and power applications. They include non-boiler uses but no feedstock consumption. The survey reflects short-term fuel switching, particularly an establishment's capability to switch within 30 days.

Table 3 summarizes the MECS data on switching from natural gas to an alternative energy source in 1994. The results show that 28 percent of gas use in the manufacturing sector was switchable to another fuel. In terms of consumption, the chemical industry had the largest switchable load, at 287 Bcf, followed by the paper, food and petroleum refining industries. In terms of the share of switchable over total gas use, the table shows that the paper, stone, clay and glass and rubber industries had the largest share of natural gas switchable consumption. The industries with the lowest share of switchable consumption were chemicals, primary metals and metal durables. Thus, some of the largest gas-consuming industries had the least switching capability.

Table 3 – MECS Data: Capability to Switch from Natural Gas to Alternative Energy Sources by Industry Group (Billion Cubic Feet)

	Gas Consumption	Switchable	Non-Switchable	Percent Switchable
Food	611	236	375	39%
Paper	558	238	320	43%
Chemicals	1840	287	1553	16%
Petroleum Refining	734	216	518	29%
Stone, Clay, Glass	419	182	237	43%
Primary Metals	778	180	598	23%
Metal Durables	554	144	410	26%
Rubber	107	45	62	42%
Other Manufacturing	361	128	233	35%
Total Manufacturing	5962	1656	4306	28%

Table 4 shows the swtchability by region. The East North Central, South Atlantic and West South Central regions had the largest switchable gas consumption. In terms of the share of switchable over total gas use, the table shows that the South Atlantic and West North Central regions had the largest switchable consumption, while the West South Central, Mountain and East North Central regions had the lowest share of switchable consumption. The West South Central had a noticeably lower switching consumption share than the other regions. This may be because of the historically low-cost, highly reliable gas supply in this gas-producing region. The low share in the West South Central region is probably linked to the low switching share in the chemical industry, which is concentrated in that region.

Table 5 shows the switchable consumption by alternate energy source for each industry group. Fuel oil is the primary alternative fuel to natural gas. Distillate fuel oil and liquid propane gas

(LPG) are suitable substitutes for natural gas in process heaters. Distillate fuel oil can also be a substitute for natural gas in turbine-based cogeneration systems. Natural gas can be replaced by residual fuel oil in larger dual-fuel boilers. The table shows that among the alternative energy sources, distillate fuel oil is the most common, followed by residual fuel oil and LPG. The food industry has the highest switchable consumption from natural gas to distillate fuel oil in terms of share. The most common switching is in process heaters (cooking and baking). The paper industry on the other hand has the highest switchable consumption share from natural gas to residual fuel oil (in large boilers). The paper industry is the largest consumer of residual fuel oil among all industries. The refining industry has the highest switchable consumption share from natural gas to LPG. LPG and refinery gas are the common alternative fuels in process heaters in the refining industry.

Table 4 – MECS Data: Capability to Switch from Natural Gas to Alternative Energy Sources by Region (Billion Cubic Feet)

	Gas Consumption	Switchable	Non-Switchable	Percent Switchable
New England	69	26	43	38%
Middle Atlantic	433	160	273	37%
East North Central	1220	360	860	30%
West North Central	368	160	208	43%
South Atlantic	586	297	289	51%
East South Central	455	165	290	36%
West South Central	2135	256	1879	12%
Mountain	164	47	117	29%
Pacific	534	186	348	35%
U.S.	5962	1656	4306	28%

MECS also reports the number of establishments that actually switched from natural gas to residual fuel oil in 1994. No data is given in terms of gas consumption. Nevertheless, according to MECS, of the 5,779 establishments able to switch, 1,279 establishments actually switched. This represents 22 percent of the total number of establishments capable of switching from natural gas to residual fuel oil. Of those who actually switched from natural gas to residual fuel oil, MECS reports the main reasons for switching. A majority of those who switched (70 percent) cited supply shortage or curtailment of fuel as their main reason. This could also mean interruptions under an interruptible rate tariff. About 43 percent cited lower residual fuel oil price as their main reason. Other reasons cited include maintenance schedule (9 percent) and environmental restrictions (4 percent).

Table 5 – MECS Data: Capability to Switch from Natural Gas to Alternative Energy Sources by Alternative Energy Source (Percent of Gas Consumption Switchable to Alternative Energy Source)

	Distillate Fuel Oil	Residual Fuel Oil	LPG	Other
Food	49%	34%	26%	12%
Paper	34%	59%	9%	29%
Chemicals	40%	34%	31%	15%
Petroleum Refining	22%	35%	75%	7%
Stone, Clay, Glass	43%	14%	47%	20%
Primary Metals	22%	29%	28%	39%
Metal Durables	40%	24%	42%	8%
Rubber	42%	49%	16%	13%
Other Manufacturing	45%	38%	35%	4%
Total Manufacturing	37%	35%	35%	19%

MECS also surveyed manufacturers on the price difference that would cause them to switch from natural gas to residual fuel oil. Because of the operational cost and disruption associated with fuel switching, there is usually a price differential required to induce a fuel switch. Table 6 shows the percent of establishments that would switch by the different levels of price difference between natural gas and less expensive residual fuel oil. Although the MECS results are presented by industry, only the overall manufacturing results are presented in Table 6. The table shows that about 32 percent of the establishments able to switch said they would switch when the price of natural gas is higher than residual oil by less than 50 percent and an additional 2.1 percent said they would switch when natural gas price is higher than residual oil by 50 percent or more. A large percentage of those with switching capability stated that they would not switch due to price and almost 2 percent of the establishments would consider switching to a more expensive substitute. This seems like a very price insensitive response, however this survey was taken during a period when gas prices were rarely higher than the alternative fuel prices.

Table 6 – Percent of Establishments that Would Cause Fuel Switching from Natural Gas to Less Expensive Residual Fuel Oil by Levels of Price Difference

Level of Price Difference	Percent of Establishments
1-5 percent	6.3%
6-10 percent	6.6%
11-15 percent	7.1%
16-20 percent	4.6%
21-30 percent	4.4%
31-40 percent	2.8%
41-50 percent	0.6%
Over 50 percent	2.1%
Would not switch due to price	25.7%
Estimate cannot be provided	38.1%
Would switch to more expensive substitute	1.7%

3.2 MIPD

The MIPD is a privately maintained, proprietary data base of energy consuming characteristics of U.S. industrial facilities. It includes information for over 19,000 facilities that account for the majority of U.S. industrial energy consumption. The data are collected by phone and by written survey on a continuous updating basis.

Fuel switching data in the MIPD are limited to boilers. The data include boiler capacity, primary fuel and secondary fuel for each plant included in the database. To identify switchable capability, it was assumed that all industrial boilers identified with a secondary fuel are switchable. Out of the 25,156 boilers included in the database, about 19,000 or 76 percent of them are fired primarily with natural gas. In terms of capacity, total boiler capacity in the database is 457 million lbs/hr of which 224 million lbs/hr or 49 percent is fired primarily with natural gas. Out of the population of natural gas boilers (19,000 boilers), MIPD identifies 7,500 boilers or 39 percent as dual-fuel fired. In terms of capacity, about 44 percent of total natural gas boiler capacity (98.6 million lbs/hr) is identified as switchable.

Table 7 shows natural gas boiler capacity and switchable capacity (in physical units and percent of total capacity) by industry group. The results show that 44 percent of natural gas boiler capacity is reported as switchable to another fuel. The results also show that the chemicals, paper, food, and metal durable industries report the largest installed capacity of natural gas boilers and also the largest installed switchable capacity. In terms of the share of switchable capacity, other manufacturing has the highest share, followed by stone, clay and glass and petroleum refining. The industries with the smallest switchable share are metal durables, and chemical industries. These results are consistent with the MECS data.

Table 7 – MIPD: Natural Gas Boiler Capacity by Industry Group (1000 lbs/hr)

	Total Capacity	Switchable Capacity	Percent Switchable
Food	41,385	19,676	48%
Paper	41,718	20,420	49%
Chemicals	58,307	22,357	38%
Petroleum Refining	16,912	8,984	53%
Stone, Clay, Glass	2,229	1,201	54%
Primary Metals	7,144	2,981	42%
Rubber	6,704	3,145	47%
Metal Durables	32,551	10,129	31%
Other Manufacturing	16,636	9,682	58%
Total Manufacturing	223,586	98,575	44%

Table 8 shows natural gas boiler capacity and switchable capacity by region. The table shows that the West South Central, East North Central and South Atlantic regions have the largest natural gas boiler capacity and switchable capacity as well. In terms of the share of switchable capacity over total capacity, the regions with the highest shares are South Atlantic, West North Central, East South Central and Middle Atlantic regions. The regions with the lowest shares are

West South Central and Mountain regions. The share of switchable boiler capacity in the West South Central region shown in MIPD is much higher here than the total switchable consumption in MECS. This suggests that most of the non-boiler, gas-fired process heating equipment in this region is not switchable, which is quite plausible.

Table 9 presents natural gas switchable capacity by alternative fuel. Given that the MIPD fuel switching is limited to boilers, it is not surprising that residual fuel oil is the most common alternative fuel source. The table shows that residual fuel oil is the secondary fuel for 58 percent of the switchable boiler capacity. Distillate fuel oil and other fuels are the next most common alternative fuels.

Table 8 – MIPD: Natural Gas Boiler Capacity by Region (1000 lbs/hr)

	Total Capacity	Switchable Capacity	Percent Switchable
New England	4,773	2,281	48%
Middle Atlantic	20,430	10,219	50%
East North Central	46,713	17,961	38%
West North Central	18,597	10,383	56%
South Atlantic	30,321	18,588	61%
East South Central	17,990	9,400	52%
West South Central	54,703	17,619	32%
Mountain	8,712	2,565	29%
Pacific	21,348	9,558	45%
U.S.	223,586	98,575	44%

Table 9 – MIPD: Natural Gas Switchable Capacity by Alternative Energy Source (Percent of Total Natural Gas Switchable Capacity)

	Distillate Fuel Oil	Residual Fuel Oil	LPG	Coal	Other
Food	19%	67%	5%	5%	4%
Paper	16%	55%	1%	6%	23%
Chemicals	18%	60%	2%	2%	18%
Petroleum Refining	8%	52%	0%	1%	39%
Stone, Clay, Glass	18%	73%	9%	0%	0%
Primary Metals	28%	39%	2%	1%	30%
Rubber	17%	76%	0%	3%	4%
Metal Durables	35%	44%	8%	7%	5%
Other Manufacturing	26%	58%	4%	3%	10%
Total Manufacturing	19%	58%	3%	4%	16%

3.3 COMPARISON OF MECS AND MIPD RESULTS

When comparing the MECS and MIPD results, it must be noted that the coverage of the data is different. While the MIPD data cover only boilers, the MECS data cover all heat and power energy use, including process heaters and power generation equipment. Also, the MECS data

report switchable consumption while MIPD reports switchable capacity. The MECS data are also less current.

Except for the metal durables industry, the MECS switchable consumption percentage is lower than the MIPD results (Table 10). This is to be expected since the MIPD focuses only on boilers, which are more switchable than other end-uses, such as process heat and power generation. In both the MECS and MIPD, the chemical industry has one of the lowest switching capabilities. This seems odd at first since the chemical industry is the largest steam generator in the sector, and would therefore be expected to have substantial switchable capacity. However, a significant portion of the chemical industry is located in the West South Central region, which has historically had an abundant and cheap supply of natural gas. As such, there would be relatively small incentive for manufacturers in the region to install switchable capacity. In addition, the chemical industry is a large user of turbine-based cogeneration facilities, which are likely to have limited switching capability.

Table 10 – MIPD and MECS Comparison:
Natural Gas Switching Capability by Industry Group

	MECS	MIPD
Food	39%	48%
Paper	43%	49%
Chemicals	16%	38%
Petroleum Refining	29%	53%
Stone, Clay, Glass	43%	54%
Primary Metals	23%	42%
Rubber	26%	47%
Metal Durables	42%	31%
Other Manufacturing	35%	58%
Total Manufacturing	28%	44%

Comparing the results by region (Table 11), it is apparent that the switching capability results from MECS are consistently lower than the MIPD results. This is expected because of the differences in the data coverage. The regions with the largest switching capability are the same for both databases: South Atlantic and West North Central regions. The region with the lowest switching capability in MECS is the West South Central while in the MIPD, it is the Mountain region. Nevertheless, even in the MIPD, the West South Central region reports the second lowest switching capability.

Table 11 – MIPD and MECS Comparison: Natural Gas Switching Capability by Region

	MECS	MIPD
New England	38%	48%
Middle Atlantic	37%	50%
East North Central	30%	38%
West North Central	43%	56%
South Atlantic	51%	61%
East South Central	36%	52%
West South Central	12%	32%
Mountain	29%	29%
Pacific	35%	45%
U.S.	28%	44%

While the 1994 MECS data may not be a good indicator of current fuel switching capacity, the more contemporaneous MIPD data show similar levels of switcability. Both data sources indicate a significant amount of physical capacity to fuel switch. The MECS data, however, suggest that such switching is not very price sensitive.

3.4 FUEL PRICE TRENDS

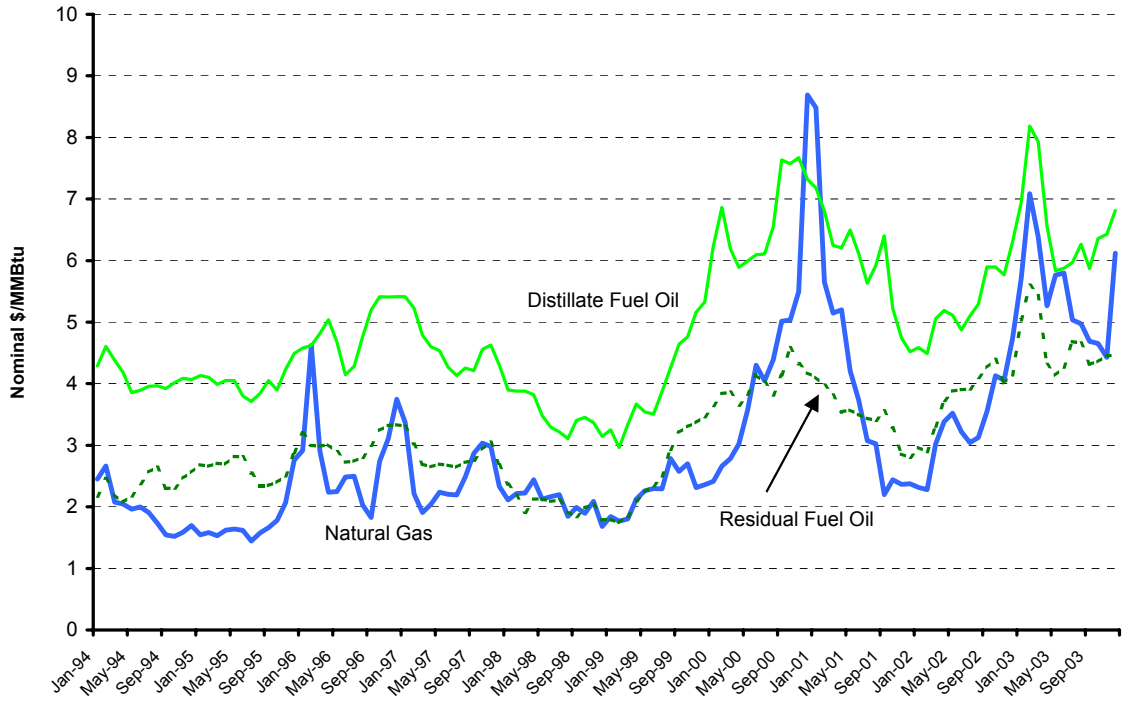
Another way to assess fuel switching is to evaluate fuel consumption during the period of high gas prices starting in 2000. While gas is essentially a North American product, petroleum prices are dependent on world oil prices and are affected by global market and political situations. This can be the source of variation in gas vs oil prices that can drive fuel switching.

Figure 17 shows natural gas, residual fuel oil and distillate fuel oil monthly price trends from 1994 to 2002.

The figure shows the following:

- During this time period, distillate fuel oil has been consistently more expensive than natural gas, except for a short period in 1996 (February 1996) and during the natural gas spike from December 2000 to January 2001. From December 2000 to January 2001, natural gas prices were 30 percent higher than distillate fuel oil (in nominal terms).
- From 1994 to 1997, residual fuel oil was consistently more expensive than gas, except for the normal peaking period of gas prices (during the winter season). The price difference between natural gas and residual fuel oil during the times when residual fuel oil was less expensive was relatively small. After 1996, there is a long period, from early 1998 to spring 1999 when natural gas was less expensive than residual fuel oil. Starting June 2000, residual fuel oil was less expensive than natural gas and this continues through April 2001. At the peak period of natural gas prices (December 2000 to January 2001), residual fuel oil price was half the price of natural gas. From May 2001 through April 2002, residual fuel oil was once again more expensive than natural gas. Since then, natural gas prices have been consistently higher.

Figure 17 – Monthly Natural Gas and Petroleum Prices



In summary, natural gas prices have generally been lower than distillate fuel oil, with brief periods of relatively higher natural gas prices. It would be expected therefore that if there were fuel switching between natural gas and distillate fuel oil due to relative price changes from 2000 to 2001, there would have been only a small amount of switching of natural gas to distillate fuel oil. This is because the period during which distillate fuel oil prices were lower than natural gas was very brief. This is not true for residual fuel oil prices. Residual fuel oil prices since 2000 have been less expensive than natural gas for longer periods than in the past. Also, the price differences are more substantial than in the past.

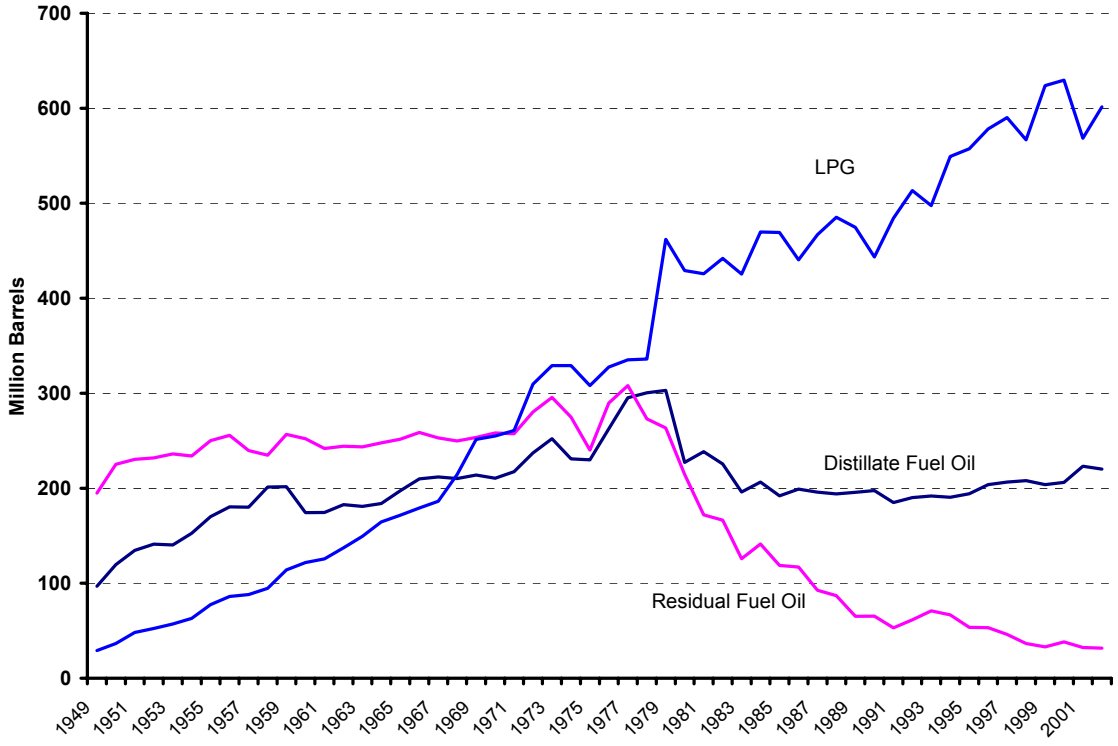
Unfortunately, monthly EIA data on industrial fuel consumption are not available to reflect this type of switching. However, Figure 18 shows annual industrial sector petroleum consumption trends. The figure shows that LPG has experienced tremendous growth throughout the period shown (1949 to 2002). Although LPG can be used as an alternative fuel for natural gas, it is primarily used by industry as a chemical feedstock to produce ethylene and its derivatives. The growth of the plastics industry has driven growth in ethylene demand and subsequently, LPG.

Distillate fuel oil consumption has been fairly flat in the industrial sector since the early 1980s. Distillate fuel oil is primarily used as off-road transportation fuel in farms, mining and construction sites. Increased efficiency and moderate growth and activity in these sectors have resulted in flat demand for distillate fuel oil.

Since the late 1970s, residual fuel oil consumption has been declining. Residual fuel oil is primarily used in boilers. Residual oil consumption was highest in the late 1970s when gas prices were very high. It declined during the post-NGPA era as gas use increased. The decline in demand for residual fuel oil reflects the dominance of natural gas for steam generation during the 1990s.

During the period of the recent high natural gas prices (2000 to 2001), distillate fuel oil consumption increased slightly, residual fuel oil consumption decreased, and LPG consumption also decreased. The decline in LPG is a reasonable result given that the ethylene industry suffered during this period, and used less LPG. The decline in residual fuel oil consumption runs counter to what we might have expected: that manufacturers switched from natural gas prices to residual fuel oil. Nevertheless, the results do not mean that manufacturers did not switch. During this period, industrial production was also suffering, hence, the decline in residual fuel oil consumption could be more of a reflection of the impact of lower industrial production.

Figure 18 – Industrial Petroleum Consumption



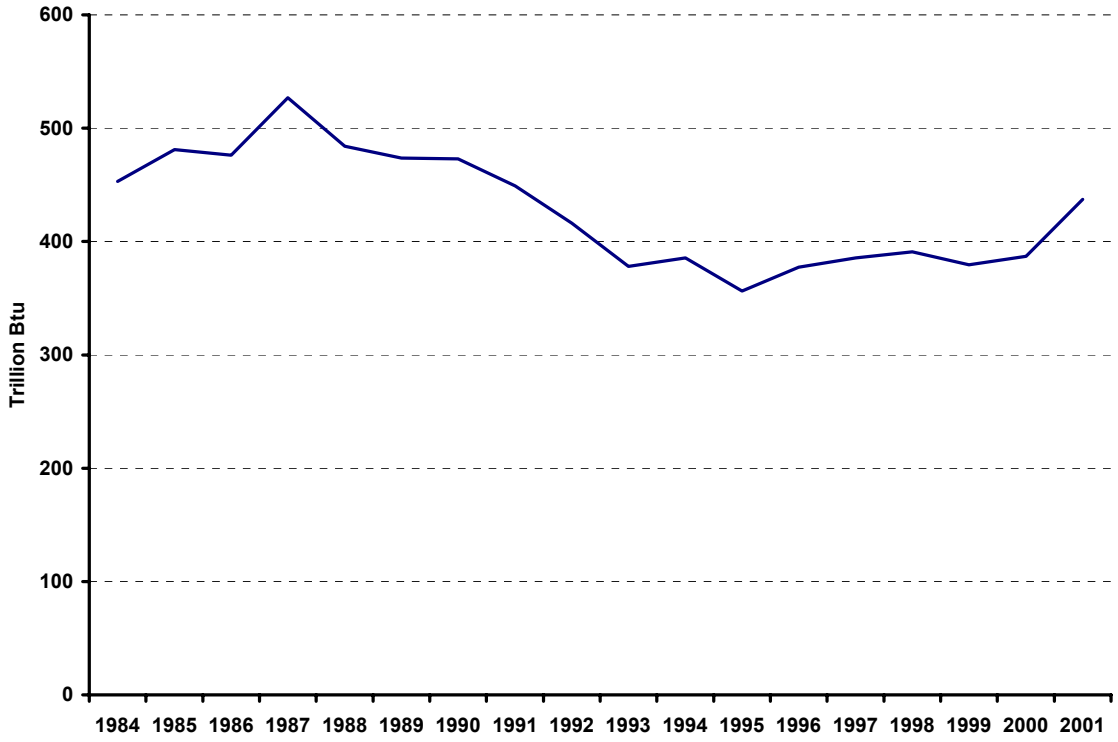
It is difficult to assess the distillate fuel oil results since they do not distinguish between off-road transportation use and process heater/boiler use. However, Figure 19 shows EIA data for distillate fuel oil demand for industrial non-farm use, excluding most of the industrial distillate fuel oil consumption for off-road transportation. The figure shows that from 1999 to 2001,

industrial distillate fuel oil consumption increased by 15 percent. This trend may be a reflection of fuel switching from natural gas to distillate fuel oil in industry.

Finally, one can estimate the extent of fuel switching from an independent analysis of the response of gas markets to high prices. EEA has estimated a 1 to 2 billion cubic feet per day (Bcfd) reduction in industrial gas consumption during recent periods of high gas prices. This equates to about 5 to 10 percent of average industrial gas demand. While this is lower than the MECS estimate of 28 percent overall switchability, we would expect actual switching to be lower than the potential switching capacity for several reasons:

- The MECS survey data indicate that even some facilities that can switch will not switch purely on price.
- High prices affect different parts of the country at different times and to different degrees, so we may not see the full switching capability take effect at once.

Figure 19 – Industrial Consumption of Distillate Fuel Oil for Non-Farm Use



3.5 OTHER FACTORS

One factor often cited in the possible diminution of fuel-switching capacity is the effect of more stringent environmental regulations. Industrial facilities in some parts of the country have become subject to more stringent emission regulations, particularly for emissions of nitrogen oxides (NO_x). The concern is that some industrial facilities will not be able to achieve the more

stringent standards while burning their alternative fuel, and will therefore lose their fuel-switching capability.

There is probably some basis for this concern, though it is probably not a major factor in fuel switching trends. More stringent NO_x limits have been set for large industrial boilers and some industrial process heaters over the last ten years in some parts of the country. The most significant such regulations have been established in the Northeast U.S. These regulations focus on operations during the summer months. Thus, fuel switching during winter high price periods would not be constrained. Some of the rules also may explicitly allow for short-term fuel-switching.

Extremely stringent limits also have been established in the gas-intensive eastern part of Texas. These limits are in effect year-round and are likely to affect switching capability. However, it has already been pointed out that this part of the U.S. has the lowest fuel-switching share, so the effect of these stringent regulations is not as large as it would have been elsewhere in the country.

The other factor that may have changed fuel-switching capability is the increased use of cogeneration or combined heat and power for steam generation. Cogeneration generates electricity and steam at the same time at a higher efficiency than possible through conventional separate generation of electricity and steam. Many of the industrial cogeneration facilities use combustion turbines to generate electricity and then recover heat from the exhaust gases to make steam. The amount of industrial cogeneration approximately tripled during the 1990s, much of it based on combustion turbines.

The combustion turbines may be switchable from gas to distillate but not to residual oil. If these cogeneration facilities replace boilers that were switchable to residual oil, they will result in a move from switchability to residual oil to distillate. Given the price trends discussed above, this could reduce the amount of cost-effective switchability in recent years.

3.6 FUEL SWITCHING SUMMARY

The available data sources indicate that the U.S. manufacturing sector has a significant physical capacity to switch from natural gas to an alternate fuel. MECS data from 1994 show 28 percent switchable consumption for all heat and power uses, and current MIPD data show a 44 percent switchable capacity for boilers. Both databases identify the food, paper, stone, clay and glass, and other manufacturing industries as having relatively high switchability. Both databases also indicate that the chemical industry, which is the largest consumer of natural gas and steam, has the lowest switchable capacity in terms of percentage over total natural gas use. Both data bases also indicate that the South Atlantic and West North Central regions have the highest percentage of switchable capacity and that the West South Central region, the region with the largest industrial consumption of natural gas, has the lowest percentage of switchable capacity. According to MECS, distillate fuel oil is the most common alternate fuel to natural gas. MIPD on the other hand identifies residual fuel oil as the most common alternate fuel for boilers only.

Nevertheless, the combination of macro and micro level data suggests that there is switchable gas equipment that is not switching even at fairly high price differentials. MECS indicates that in 1994, the most common reason for a manufacturing establishment to switch from natural gas to residual fuel oil was supply shortage or curtailment/interruption. Lower residual fuel oil price was cited by a smaller number of establishments. The MECS survey also states that only 34 percent of the establishments with the capability to switch would switch if the price of residual fuel oil were cheaper. This in combination with the high response to the MECS survey of facilities stating that they will not switch on price raises questions about the potential for realizing the full amount of claimed switchable capacity. In any case, much of this switchable capacity is likely to be switchable only for short periods of time due to environmental regulations.

EEA's analysis indicates that about 4 Bcfd of switchable capacity exists in industrial boiler and process heat applications. During recent periods of high gas prices, EEA has estimated about 2 to 3 Bcfd of actual switching. It is possible that some of the switching capability identified in the other data sources has been lost or limited due to lack of upkeep. Environmental regulations may have caused some erosion in switching capability in recent years and the increased use of combustion turbine-based cogeneration may also have reduced the amount of more cost-effective switchability to residual oil. However, it is possible that a higher degree of switchability is physically feasible under sufficiently high prices. It is also possible to add or restore switching capability if fuel prices make this measure cost-effective.

4 - Impact of High Natural Gas Prices on the Chemical Industry

The chemical industry is perhaps the industry most affected by high gas prices. The chemical industry is one of the most gas-intensive industries and is also the most diverse industry in the industrial sector in terms of product mix and processes. The ammonia fertilizer segment of the chemical industry is perhaps the most vulnerable to high gas prices because it is gas-intensive and competes in a world market with ammonia from countries with much lower gas prices. This section analyzes some of the gas-related issues for the chemical industry.

4.1 BACKGROUND

The chemical industry consumes the largest amount of energy and natural gas in the industrial sector. In 1998, the industry consumed 7.4 quadrillion Btu (quads) or 27 percent of total industrial energy consumption. Natural gas represented 43 percent of its total energy consumption, and as such, the chemical industry is the largest natural gas user among all U.S. industries, accounting for 36 percent of total industrial natural gas consumption.

The chemical industry is a highly complex industry involved in the production of many diverse products. The industry manufactures numerous products falling into 5 major groups:

- Inorganic chemicals: industrial gases, chlor-alkali and sulfuric acid
- Organic chemicals: petrochemicals such as, ethylene, propylene, methanol, MTBE, etc.
- Plastic material and resin: polyvinyl chloride, polyethyelene, etc.
- Agricultural chemicals: ammonia, phosphoric acid, fertilizers, pesticides
- Other chemical products: drugs and medicines, soaps and detergents, paints and varnishes, and other miscellaneous chemicals

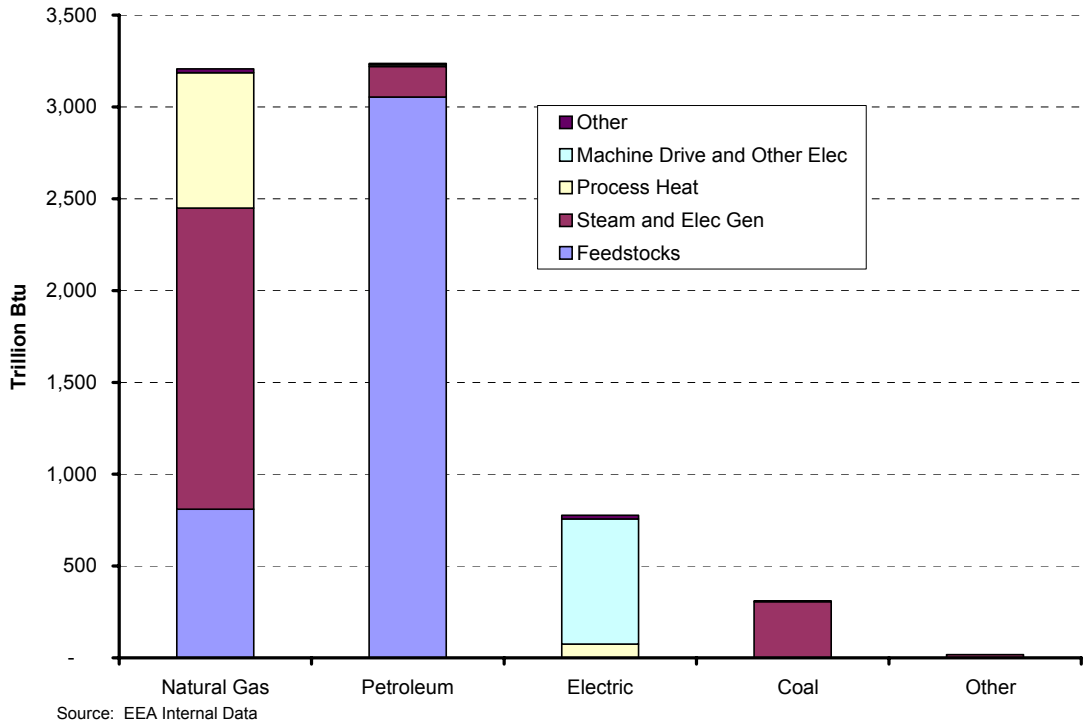
The inorganic chemicals, organic chemicals, plastic materials and resins, and agricultural chemicals are considered basic chemicals. The basic chemical industry is a mature industry and is expected to grow at only a slow to moderate pace, as has been the case over the last decade. This industry is highly capital and energy-intensive (for fuel and feedstocks). The "other chemicals" segment of the chemical industry consists of specialty chemicals (paints, adhesives, electronic chemicals, etc.), pharmaceuticals, and consumer products (soaps and detergents, household chemicals, personal care products). These industries in general produce higher value products, consume a lot less gas and energy, spend more on R&D, advertising, labor, and other general, sales and administration. This segment of the chemical industry is expected to expand at a faster rate than the basic chemicals, thus accounting for most of the production growth in the entire chemical industry.

Figure 20 shows the energy consumption pattern of the U.S. chemical industry. Petroleum and natural gas are the primary fuels consumed in the industry, accounting for 43 and 42 percent of total energy consumption, respectively. Most of the petroleum is used as chemical feedstock (raw materials) for many of the industry's products, from plastics to pharmaceuticals to pesticides and more. Only a small amount of petroleum is used directly for steam generation or process heating. Included in the petroleum category is liquefied petroleum gas or LPG.

Although categorized as petroleum, LPG contains natural gas liquids (NGLs) such as ethane, butane, propane as well as naphthas and gasoils. NGLs are extracted from raw natural gas at the wellhead, before it is put into the pipeline. LPG is used to manufacture the main olefin products such as ethylene, propylene and butadiene that are used to manufacture plastics and other products.

Natural gas on the other hand is used for a variety of purposes including steam generation, feedstock use, and process heating. Over half of natural gas in the chemical industry is for steam generation (through boilers and cogeneration equipment) making it the largest end-use for natural gas in the industry. Most of this steam is consumed in the petrochemicals and other organic chemical industries. Natural gas as a feedstock is the second largest end-use, primarily for the manufacture of ammonia, methanol and hydrogen. The third largest end-use of natural gas in the industry is for direct process heating. This process energy is used across all the basic chemicals.

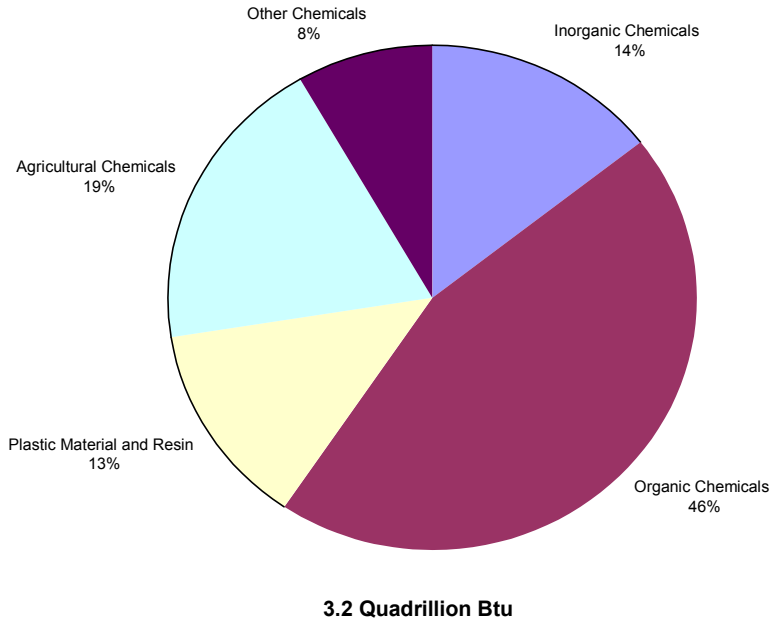
Figure 20 – Chemical Industry Energy Consumption Pattern



As Figure 21 shows, the largest users as well as most gas-intensive segments of the chemical industry are the organic chemicals, inorganic chemicals, plastic materials and resin, and agricultural chemicals segments. Among these segments, the organic chemicals industry consumes the largest amount of natural gas, accounting for 45 percent of total chemical industry natural gas consumption. It is followed respectively by the agricultural chemicals group (19

percent), inorganic chemicals (14 percent), and plastic materials and resin (13 percent). Thus, these segments are the main drivers of natural gas consumption in the chemical industry.

Figure 21 – Chemical Industry Natural Gas Consumption by Segment

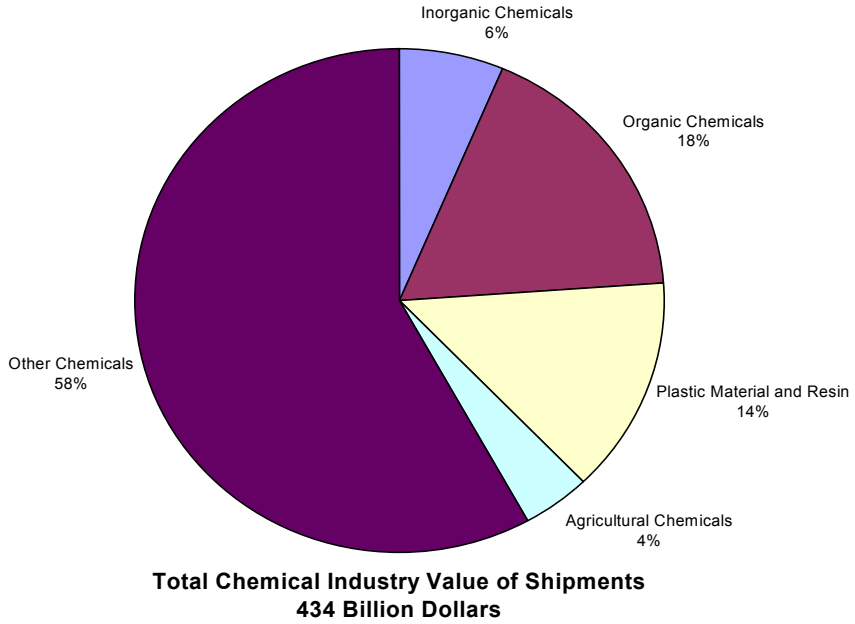


Source: EEA estimates

Although "other chemicals" account for the smallest share of gas use, Figure 22 shows that this product segment accounts for almost 60 percent of the chemical industry's value of shipments. This is because these products tend4 to be higher value consumer products vs lower value basic commodity chemicals produced in the other industry segments. The organic chemical segment accounts for the second largest share of value of shipments at 18 percent. The plastic materials and resins group represents the third largest share of value of shipments at 14 percent. The other chemical product segment is not a heavy user of natural gas, but is a critical driver of the economic output trends of the entire chemical industry.

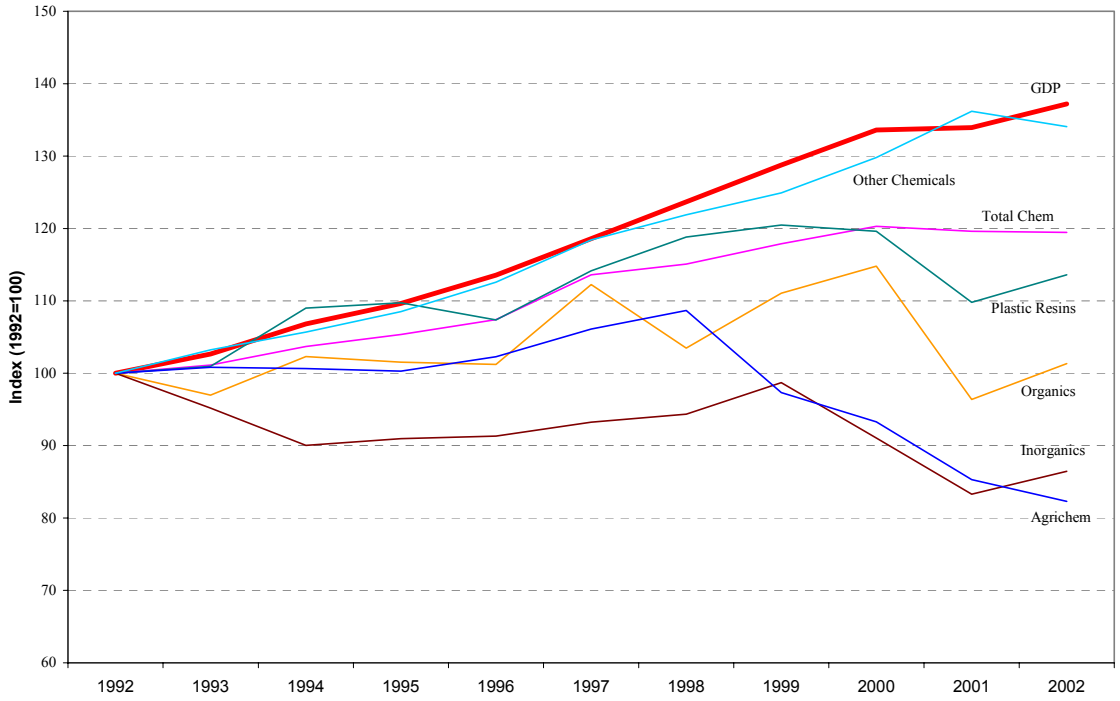
Figure 23 presents the production trends of the various chemical groups as well as total U.S. GDP from 1992 to 2002. The figure shows that overall chemical industry production grew rapidly from 1992 to 1997, slowed down by 1998, increased again through 2000, and has been flat since then. Nevertheless, the growth of the overall chemical industry was still much slower than total GDP. The "other chemical" segment of the industry has shown the fastest and most consistent expansion from 1992 to 2001, although it shows a decline in 2002. It is the only segment of the chemical industry that has consistently grown in line with total GDP.

Figure 22 – Chemical Industry Value of Shipments by Sector



Source: Bureau of Census.

Figure 23 – U.S. GDP and Chemical Industry Production Trends

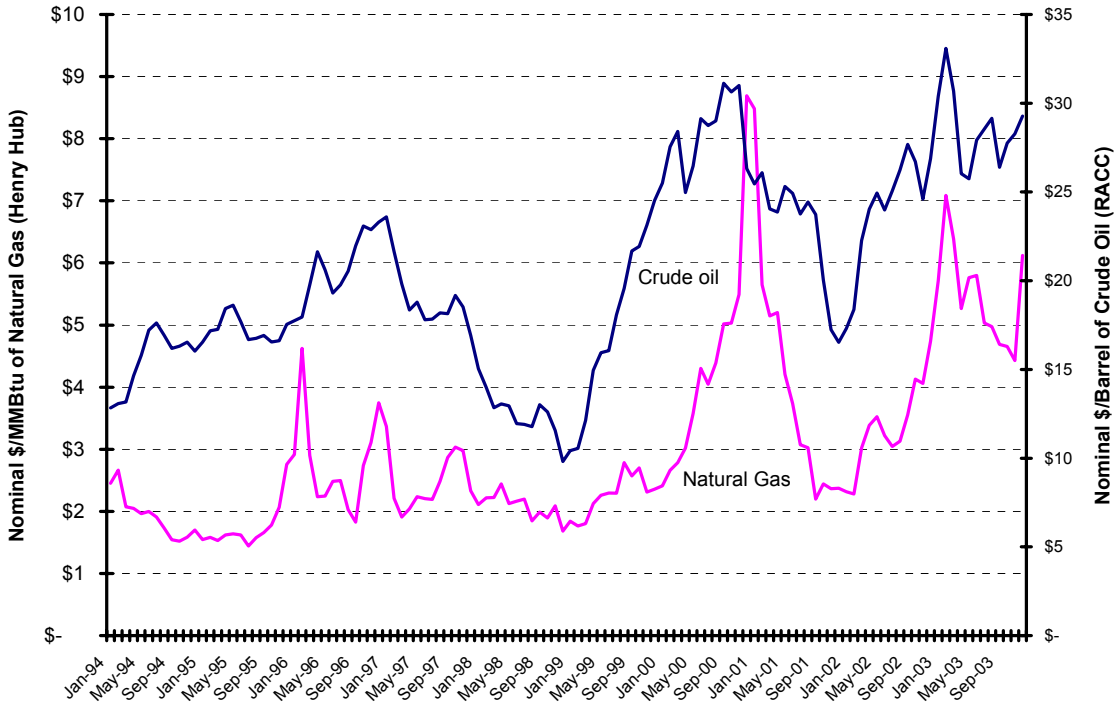


Source: FRB.

Among the energy-intensive chemical industry segments, only plastic materials and resin and organic chemicals exhibit a positive growth over the 10 year period shown. The growth of the plastic materials and resin industry from 1992 to 2000 was driven by the explosive growth of the computer and telecommunications as well as the overall growth of the U.S. economy, which stimulated demand for plastic. The organic chemicals industry provides the raw materials to the plastic material and resin industry and other chemical processing industries, and as such, participated in the growth, though not as consistently. During the same period (1992 to 2000), the inorganic chemicals and agricultural chemicals segments declined overall, with that decline most significant in 1998 or 1999, prior to the gas price increases.

From 2000 to 2001, all of the chemical industry subgroups suffered declines, except for other chemicals. The declines were driven by low demand (due to poor economic conditions) and high petroleum and natural gas prices. Petroleum and natural gas are primary raw materials of the chemical industry, and thus the prices of these materials are critical for the industry, particularly, the petrochemical, industrial gases, and nitrogen fertilizer segments. Figure 24 shows recent monthly natural gas and crude oil price trends. The figure shows that natural gas prices and crude oil prices increased from 1999 through early 2001. To make matters worse, the economy was also slowing down so overall demand for chemical products were also slowing down. From early 2001 through 2002, natural gas and crude oil prices declined somewhat, and this has supported the slight recovery for the basic chemical industries through 2002, though prices of both have since increased.

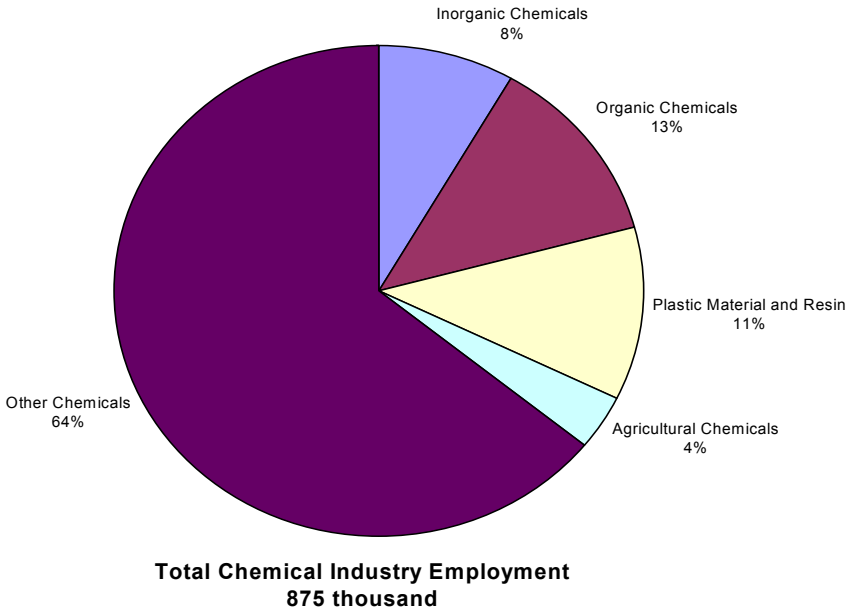
Figure 24 – Monthly Natural Gas and Crude Oil Prices



Source: EIA and EEA.

Figure 25 shows the distribution of employment in the chemical industry by chemical group. The figure shows that the other chemical product segment accounts for almost 64 percent of the chemical industry's total employment. Since the segment of the industry with the largest employment is not the most gas-intensive, periods of high natural gas prices should not cause massive loss of employment in the chemical industry as a whole. The organic chemical segment accounts for the second largest share of employment at 13 percent. The plastic materials and resins group represents the third largest share of employment at 11 percent. The agricultural chemical segment accounts for only 4 percent of chemical industry employment. Thus, while high gas prices will have a serious negative effect on this segment, the overall employment impacts will be limited.

Figure 25 – Chemical Industry Employment by Sector



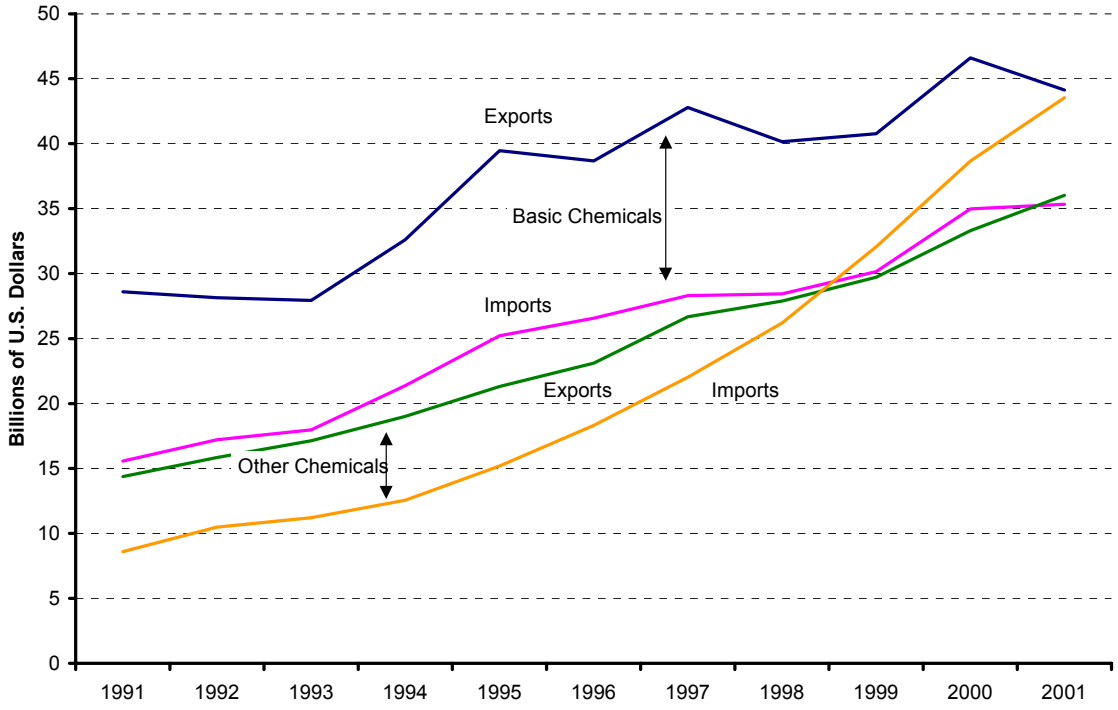
Source: Bureau of Census.

The chemical industry is a global industry. According to the American Chemistry Council (ACC), the U.S. is the largest chemical producer in the world followed by (in order) Japan, Germany, China, France, Italy, South Korea, United Kingdom, Brazil and Belgium/Luxembourg. These 10 countries account for 70 percent of total world chemical output. The U.S. is also the largest chemical exporter and largest importer in the world. Thus, the U.S. chemical industry does not rely entirely on its domestic markets, but also on global market situations. As in any international traded commodity, the price and demand for chemical products depend on various international market factors including global and regional economic health, currency exchange, and competitiveness of domestic producers with producers from other countries.

The globalization of the chemical industry caused U.S. companies to build production capacity worldwide. U.S. companies, especially the large ones, have the capability of taking advantage of cheap input costs across the globe, so that when one region experiences high input costs (e.g., feedstocks) or currency changes, they can shift production to another establishment in another region. Although this strategy helps the financial health of the company as a whole, it will be a negative for the plant/region being displaced.

Figure 26 shows the export and import trends in the chemical industry from 1991 to 2001. The figure shows that both imports and exports were substantial and grew steadily during this time period. More than half of the chemicals exported from the U.S. are basic chemicals, accounting for 28 percent of total shipments of basic chemicals. Furthermore, about half of the basic chemicals exported from the U.S. are bulk petrochemicals and their intermediates. During the high gas price period of 2000-01, exports of basic chemicals declined, but still remained higher than imports, which did not increase. This suggests that high gas prices made exports uneconomic but a slow-down in demand (world-wide as well as U.S.) obviated the need for increased imports.

Figure 26 – U.S. Chemical Industry Trade



Source: American Chemistry Council

Interestingly, Figure 26 shows that the major growth in imports has been in the "other chemicals" category, starting in 1999. Since this category is less gas-intensive and the growth rate increased prior to the gas price increases, it seems likely that this increase is linked to factors other than gas prices.

Table 12 shows the shares of expenditures for natural gas, liquefied petroleum gas (LPG) and natural gas liquids (NGL) over total value added for various segments of the basic chemical industry. Most of the NGL extracted from natural gas is ethane. Ethane has several uses including as fuel, as raw material to manufacture ethylene and halogenated ethanes, and as a refrigerant. In the U.S., the most important use of ethane is as a feedstock for ethylene production. Ethylene production accounts for about 97 percent of all ethane used in the U.S. Because ethane supply comes mostly from natural gas, ethane prices are determined by natural gas prices. Thus, if natural gas prices are high, ethane prices also increase.

Table 12 – Share of Energy Expenditures over Value Added

Industry Group	Natural Gas	Natural Gas & LPG/NGLs
Chemicals	2.5%	5.7%
Petrochemicals	13.0%	50.2%
Industrial Gases	5.7%	5.7%
Alkalies and Chlorine	9.1%	9.1%
Other Basic Inorganic Chemicals	1.7%	1.7%
Cyclic Crudes and Intermediates	4.9%	4.9%
Other Basic Organic Chemicals	7.9%	19.7%
Plastics Materials and Resins	3.3%	16.9%
Synthetic Rubber	4.8%	29.0%
Noncellulosic Organic Fibers	1.8%	1.8%
Nitrogenous Fertilizers	68.5%	68.5%
Phosphatic Fertilizers	6.0%	6.0%

Source: MECS 1998

Table 12 shows that after nitrogenous fertilizers, the industry with the second largest share of natural gas expenditures over value added is the petrochemical industry at 13 percent. If LPG and NGLs (only combined data exist) are included, the share for the petrochemical industry goes up to 50 percent. Other industries that exhibit the same pattern are other basic organic chemicals, plastic materials and resins, and synthetic rubber. These industries are all related to ethylene, the basic chemical used to create a host of chemical products, and is the focus of the next section.

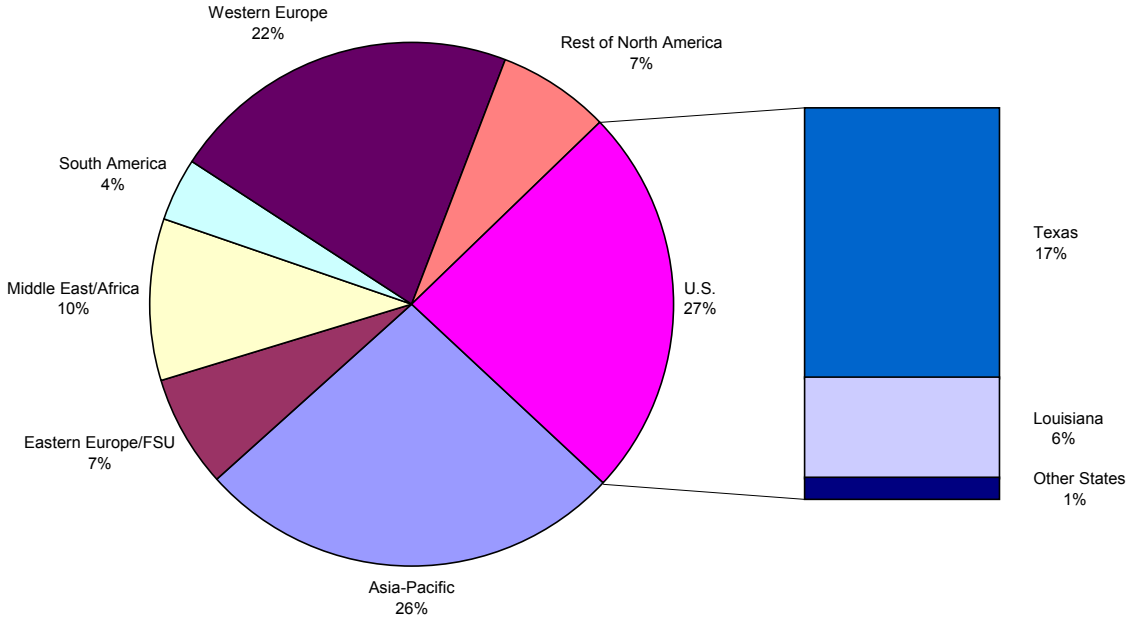
4.2 ETHYLENE INDUSTRY

Ethylene is a light, sweet gas that belongs to the olefins group of petrochemicals. Ethylene and its intermediate products are important chemicals in the production of plastics and polymers. Polyethylene, ethylene's major intermediate product, accounts for over half of ethylene use in the U.S. Other major intermediate products made from ethylene include ethylene oxide and ethylene dichloride. Ethylene is produced either by the pyrolysis of NGLs (ethane, propane or butane), or the thermal cracking of naphthas or gas oils. Among all the feedstocks, ethane has the advantage in ethylene production because of its higher ethylene yield combined with minimal

coproducts. Naphtha crackers generate more coproducts and thus require more capital to process.

The U.S. dominates the global production of ethylene. The dominance of the U.S. in world ethylene production has been supported by its large demand for ethylene and its intermediate products, its abundance of cheap natural gas resources, and an efficient infrastructure to store and transport the products. The U.S. has 27 percent of total world capacity (Figure 27). Six of the ten largest ethylene plants in the world are in the U.S. Gulf Coast region. In this region (which represents 95 percent of the U.S. ethylene capacity), 42 percent of total ethylene capacity relies on ethane as a feedstock, while propane, naphthas, gas oil, and other feedstocks account for 19 percent, 30 percent, 3 percent, and 6 percent, respectively. Much of the ethylene capacity in Europe is based on naphtha and gas oil feedstock (derived from petroleum).

Figure 27–Worldwide Ethylene Capacity - 2004



Source: Oil and Gas Journal.

Currently, the world ethylene industry is suffering from overcapacity. World ethylene production capacity is at 109.4 million tons per year. About 50 million tons of new capacity have been added since the 1990s. New plants are still being built in the Middle East region and in Asia. These plants are largely an attempt to make use of cheap NGLs associated with increasing production of gas in these regions. Since the gas price in these areas is already very low and there is no other use for the NGLs, the cost of this feedstock is very low. In addition, the new plants may be more efficient than older plants in the U.S. and elsewhere. Thus, any

movement towards an increase in domestic production costs (such as that caused by high natural gas prices) could negatively impact U.S. ethylene producers in the global market.

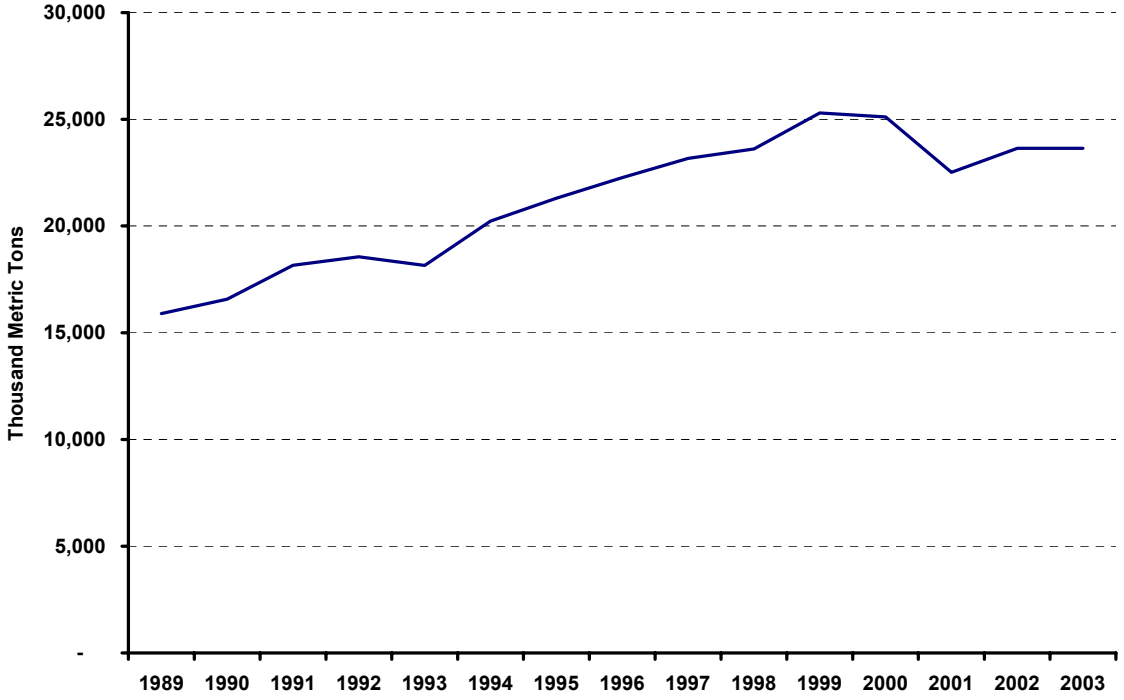
Because ethane is the primary feedstock in U.S. ethylene production, ethane prices are critical to the overall economic condition of the U.S. ethylene industry as well as the intermediate products segment. The level of ethane prices is influenced by crude oil and natural gas prices. Crude oil price drives the price of oil-based ethylene feedstocks (naphthas and gas oils). If crude oil price is high relative to natural gas price then oil-based ethylene feedstock price is also relatively higher, and thus ethane becomes a more profitable feedstock choice resulting in high levels of demand for ethane.

The price of natural gas is also critical in ethane pricing and industry profitability. Before natural gas is delivered through the pipelines, raw natural gas is processed to remove the NGL constituents. However, NGLs can be left in the gas stream to sell as fuel. Because the fuel value of NGLs is higher than that of methane, there is an incentive to leave more of the NGLs in the gas when natural gas prices are high. In this situation, NGL feedstock users (especially ethylene producers) have to pay a higher price to the NGL producer to justify removing the NGL from the gas stream. This then puts the NGL-based ethylene producer at a less competitive situation relative to non-NGL users.

Figure 28 shows U.S. ethylene production from 1989 to 2002. The figure shows that domestic ethylene production grew moderately from 1989 to 1999, flattened in 2000, declined in 2001, recovered slightly in 2002, and held steady in 2003. The U.S. economic expansion and the high demand for plastic products drove the growth from 1989 to 1999. The slowdown in 2000 parallels the slowdown in the U.S. economy as well as a decline in the demand for polyethylene. In 2001, with the continuing economic slowdown and high gas and crude oil prices, about 10 percent of U.S. ethylene capacity shut down. By 2002, as energy prices and the economy recovered, ethylene production increased slightly.

As a global industry, the business of ethylene and its derivatives involves not only domestic markets but also export and import markets. Relative to the size of the U.S. ethylene market, exports make up a very small share. Exports of ethylene account for only 0.1 percent of total U.S. ethylene production. Imports account for a much larger share of apparent consumption (production plus imports minus exports), currently 18 percent. Figure 29 shows U.S. ethylene import reliance (ratio of imports over apparent consumption). The figure shows that the country's reliance on imported ethylene has accelerated since 1995. From 1995 to 2000, import reliance increased from less than 1 percent to 12 percent, as demand for plastic products increased. In 2001, when gas prices were high but demand was slow, ethylene imports actually fell and import reliance decreased to 11 percent. By 2002-03, imports resumed their prior rapid growth, following the slight recovery in the economy.

Figure 28 - U.S. Ethylene Production



Source: Chemical and Engineering News.

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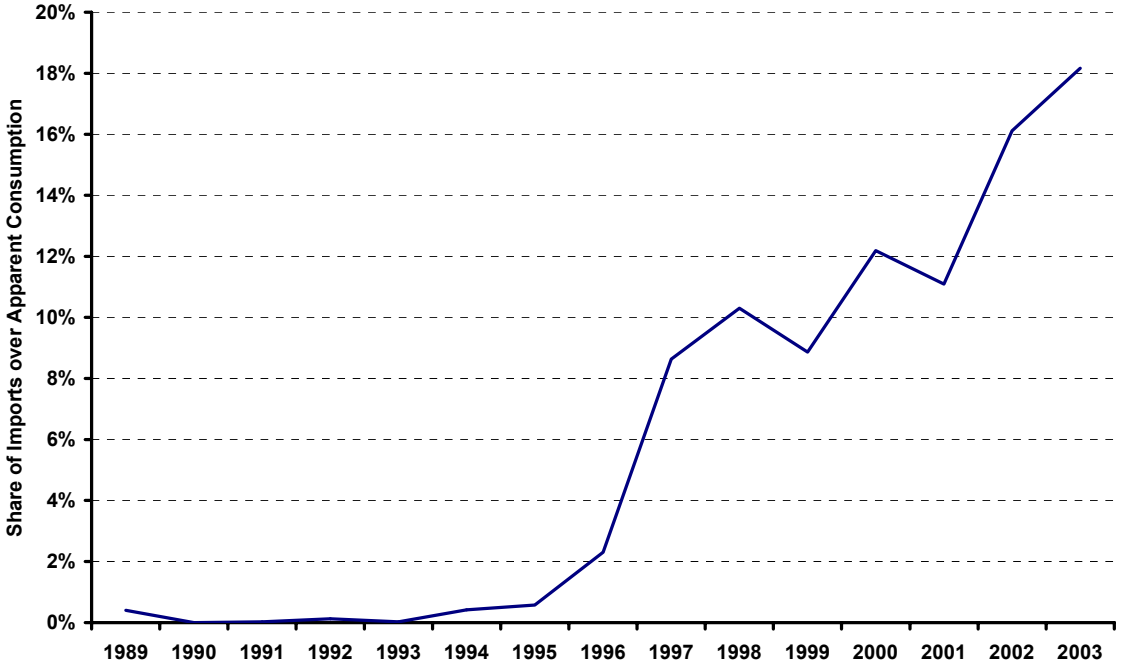
Figure 29 – U.S. Ethylene Import Reliance

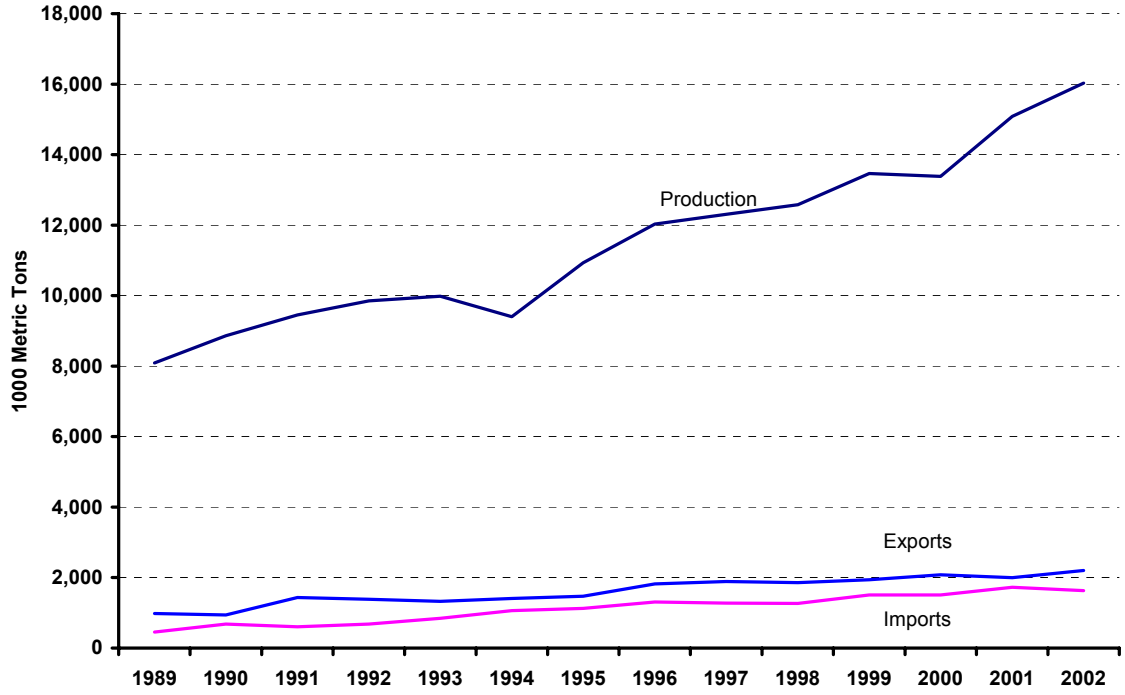


Sources: Production - U.S. Chemical and Engineering News. Trade data - U.S. International Trade Commission.
Apparent Consumption=Production + Imports - Exports

All of these trends seem to indicate that the import level and reliance are driven both by domestic demand for ethylene and global competition. They also point out that the future growth in demand for ethylene will most likely be increasingly supplied by imports, even if natural gas prices stabilize. Saudi Arabia, Algeria, Venezuela and Mexico are the largest exporters to the U.S., accounting for over half of all imported ethylene in2002. These countries have much lower ethylene production costs than the U.S. due to their large natural gas resources.

It is also important to assess the markets for ethylene derivatives, specifically, the polyethylene market, since it is the largest market for ethylene in the U.S. Some industry participants have expressed concern with loss of domestic derivative market to imports (for finished products such as plastic bags). Figure 30 shows U.S. polyethylene production, imports and exports from 1989 to 2002. The figure shows that U.S. polyethylene production has been increasing rapidly throughout this period, growing annually by 5 percent. From 1989 to 1999, domestic polyethylene production increased substantially as the economy demanded more plastic products. It then declined from 1999 to 2000, as the domestic demand for polyethylene slowed down. It recovered in 2001, despite increased gas prices and economic slowdown, and continued through 2002. Note that the increase in polyethylene demand in 2001 did not result in an increase in ethylene production and demand. Production of other derivatives of ethylene was down in 2001 resulting in lower overall demand for ethylene.

Figure 30 – U.S. Polyethylene Production, Exports and Imports



Source: Production: Chemical and Engineering News; Trade Data: U.S. International Trade Commission

Polyethylene exports account for 14 percent of total production. The share of exports over total production of polyethylene has not really changed significantly over the course of this period, hovering between 10 and 15 percent. Imported polyethylene has been increasing since 1989, although the country's import reliance has not really changed since 1994, as it has been hovering around 11 percent. Even when natural gas prices were high in 2001, import reliance did not really change, although import levels rose slightly.

In summary imports of ethylene from low cost foreign producers have been increasing since the mid 1990s due to the development of new ethylene production capacity in countries with much lower gas prices. U.S. production declined in recent years during periods of high gas prices and reduced demand. The fact that imports during this period did not increase faster than in prior years suggests that reduced demand was a greater factor than feedstock prices. Nevertheless, continuing high gas prices in the U.S. may exacerbate the trend towards greater imports. Imports of polyethylene products have yet to increase over recent historical levels.

4.3 FERTILIZER INDUSTRY

Because the nitrogen fertilizer industry (includes ammonia production) has the largest natural gas cost over total production cost, it is not surprising that this industry has been among the most concerned with high natural gas prices. Natural gas is used as a feedstock and as fuel for heat and power in the manufacture of ammonia, a major fertilizer and a major ingredient to other fertilizer materials.[5] The nitrogen fertilizer industry produces several major products: ammonia, nitric acid, ammonium nitrate, urea ammonium nitrogen (UAN) solution, and solid urea. Natural gas demand for ammonia production peaked at about 382 TBtu in 1998. In 2001, it was only about 260 TBtu.

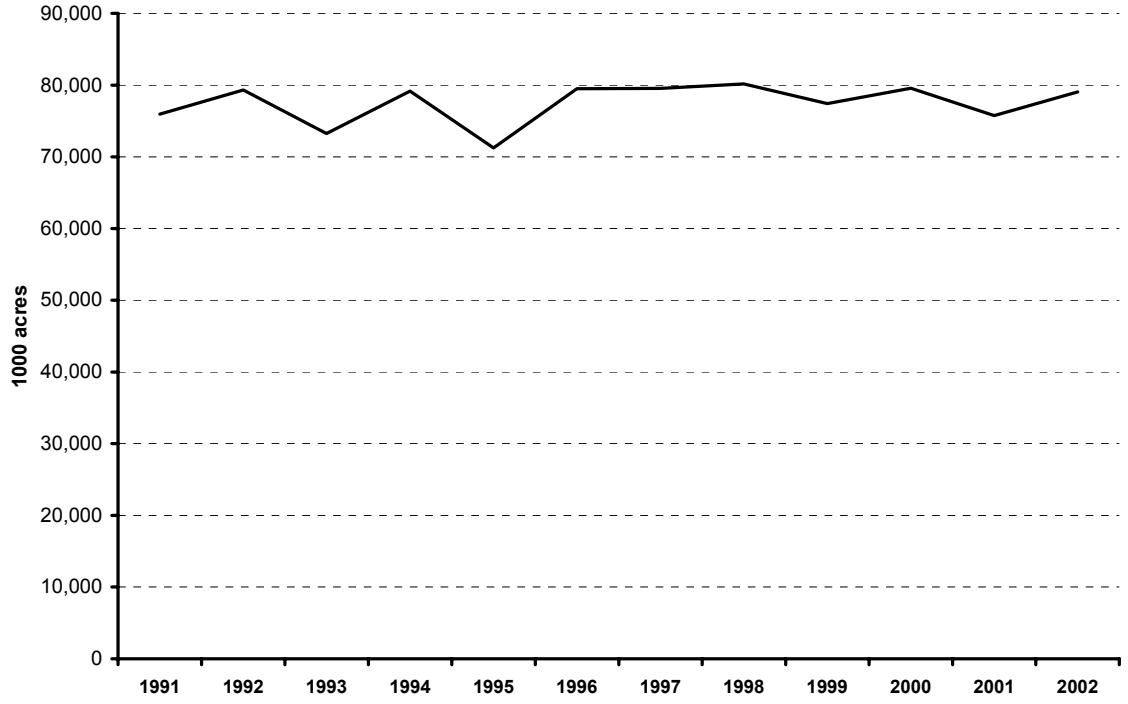
Ammonia is the basic material for all nitrogen-based fertilizer and fertilizer accounts for about 90 percent of U.S. ammonia consumption. Ammonia can be used directly as a fertilizer or used to make other nitrogen-based fertilizer such as ammonium nitrate, UAN solution and urea. The level of crop production and the rate of fertilizer application, especially for corn and wheat, are the primary drivers for nitrogen fertilizer demand. For example, in 1998, corn cultivation accounted for 57 percent of total nitrogenous fertilizer consumption, and wheat (spring and winter) accounted for another 25 percent. The application rate of fertilizer generally does not change substantially. Thus, the amount of corn planted as driven by demand for corn products, is critical to present and future demand for ammonia and other nitrogenous fertilizers.

Figure 31 shows the planted acreage for corn in the U.S. from 1991 to 2002. The figure shows that planted acreage for corn has been fairly constant, between 70 million to 80 million acres. Seventy-five percent of corn harvested in the U.S. is for feed for livestock, while most of the rest is for sweeteners and ethanol production. The future growth in the demand for corn is seen in increased use of ethanol for reformulated gasoline and continued increase in using corn-based sweeteners. In 2001, when natural gas prices spiked, the planted acreage for corn declined by

[5] Ammonia is used for fertilizer and non-fertilizer purposes. About 90 percent of ammonia is used for fertilizer and the rest is for industrial (non-fertilizer) use.

almost 5 percent due to a combination of lower crop demand (due to recession) and other factors. Fertilizer price is one factor, but not the most significant since fertilizer prices were lower in 2000 than in the early 1990s when demand for fertilizer was much higher.

Figure 31 – U.S. Planted Corn Acreage, 1991-2002



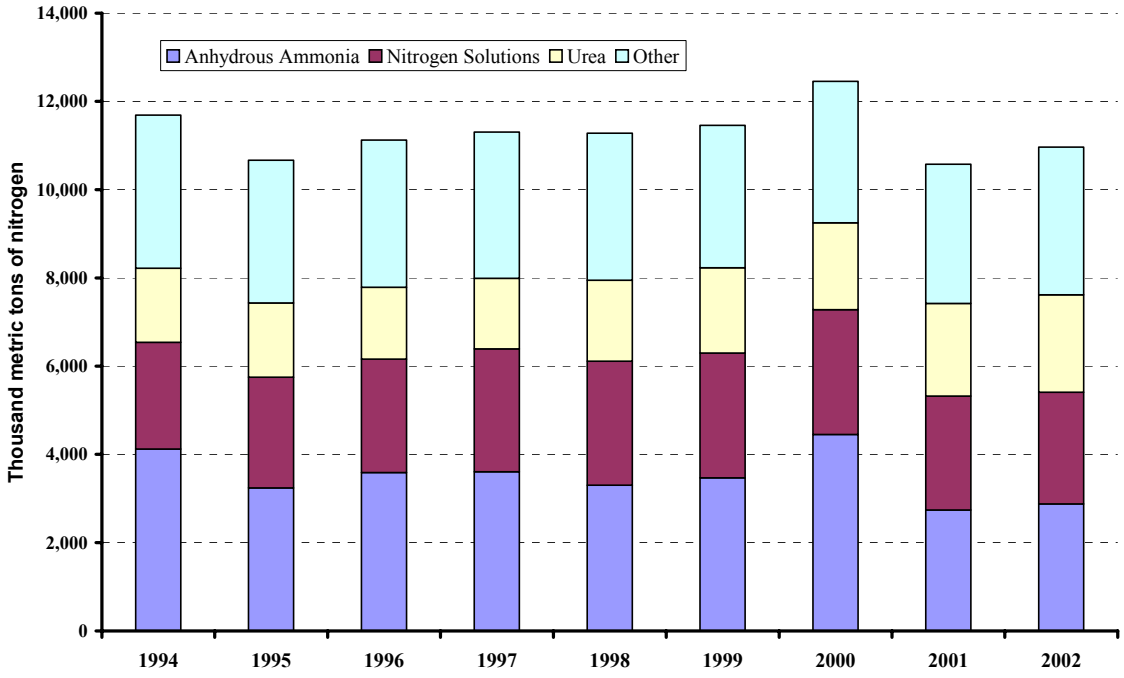
Source: USDA

Figure 32 shows the U.S. consumption of nitrogen-based fertilizer by major fertilizer type in recent years. The figure shows that the demand for nitrogen fertilizer has been fairly constant between 10 and 12 thousand metric tons per year since 1995, with a jump in 2000, decline in 2001 and slight recovery in 2002.[6] The decline in the 2001 nitrogen fertilizer demand was due to a decrease in corn planted acreage, wet spring weather in the Midwest, and the decline in offshore diammonium phosphate (DAP) demand.

Figure 33 shows U.S. ammonia production, imports and exports from the early 1940s to the present. The chart shows that domestic ammonia production/consumption grew steadily starting in the 1940s until reaching its peak by 1980. A dramatic downturn occurred in the early 1980s and since then domestic ammonia production has been fairly flat, hovering between 12 thousand to 14 thousand metric tons. Production peaked in 1998 and then started falling off in 1999 and 2000, prior to the gas price increases. Production fell significantly in 2001, to its lowest level since 1970. A slight recovery occurred in 2002 followed by a drop in 2003.

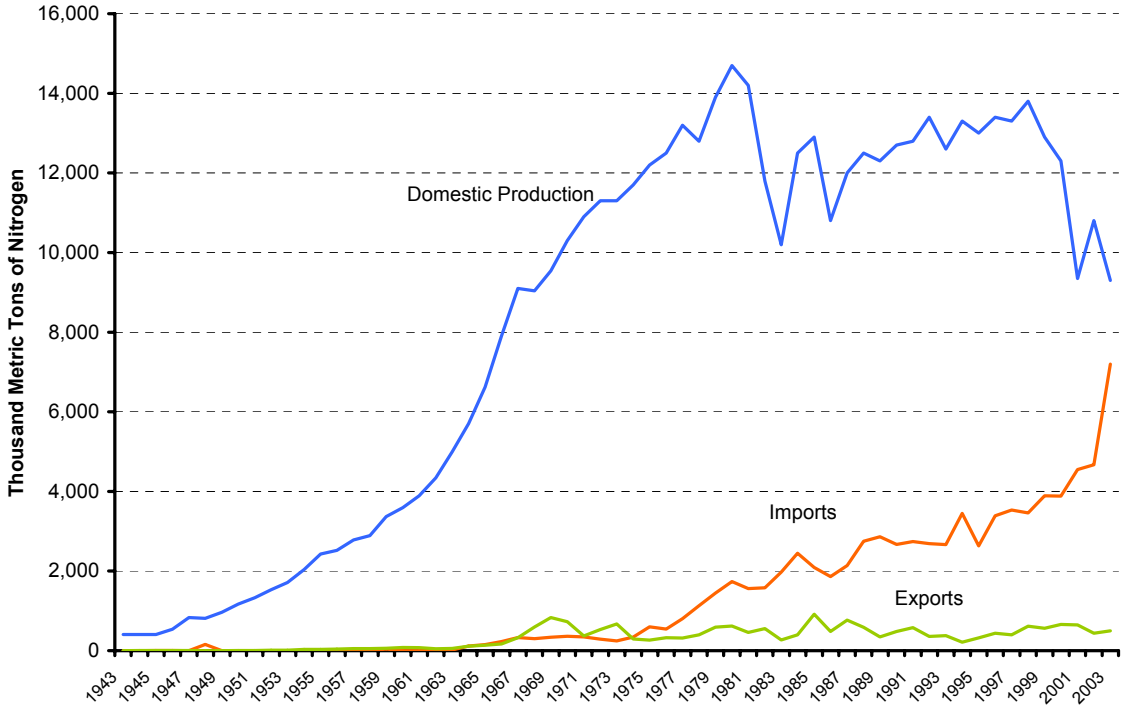
[6] The jump in ammonia consumption in 2000 was in response to increased corn planted acreage. Note that the spikes in natural gas and fertilizer prices did not start to happen until December 2000.

Figure 32 – U.S. Nitrogenous Fertilizer Consumption by Type, 1994-2002



Source: U.S. Geological Survey.

Figure 33 – U.S. Ammonia Production, Imports and Exports, 1943-2003

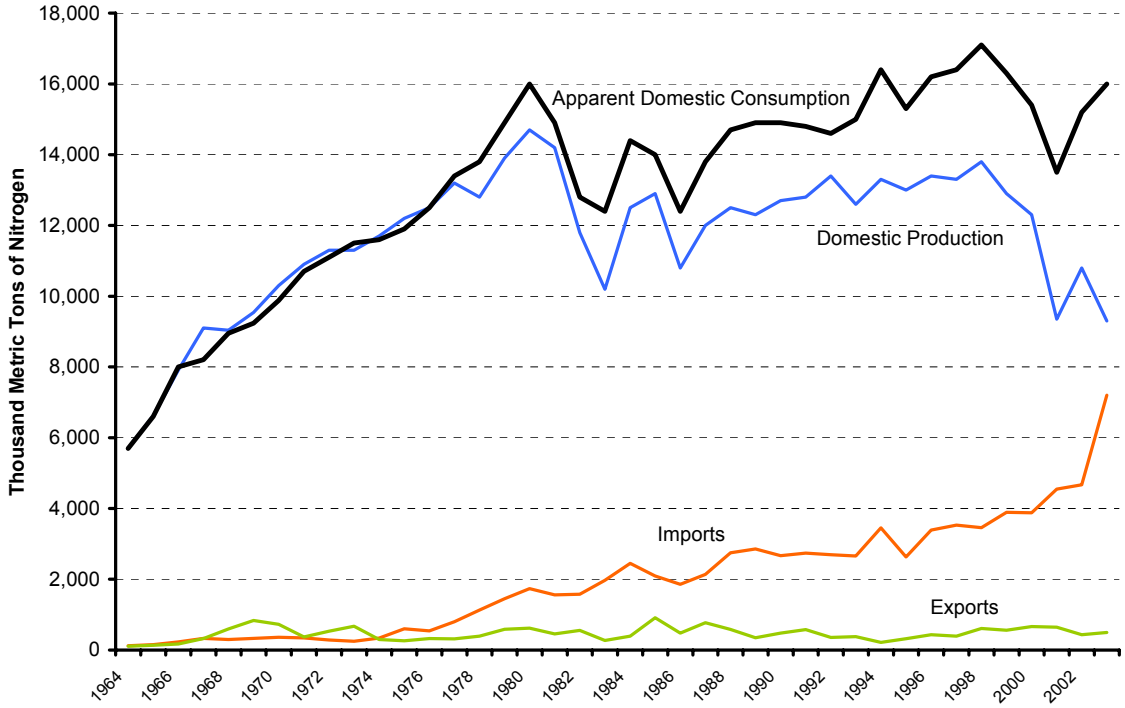


Source: U.S. Geological Survey.

Ammonia imports and exports started to become significant in the mid 1960s and the U.S. became a net ammonia importer starting in the mid 1970s. U.S. ammonia imports have been steadily increasing since the mid-1970s. Historically imports were mostly from Canada but more recently have been coming from Trinidad, Tobago and Ukraine. Ammonia exports have been fairly low and flat since the 1970s. About 80 percent of total U.S. exports are from the Agrium plant in Alaska, which are primarily destined for Korea and relatively independent of other U.S. markets.

Figure 34 shows the U.S. apparent consumption of ammonia for the last 40 years along with the production, imports and exports. Apparent consumption is domestic production minus exports plus imports plus stock changes. The figure shows that the consumption of ammonia in the U.S. grew steadily from the mid 1980s through 1998 and started to decline in 1999, prior to the gas price increases. In 2001, ammonia consumption reached its lowest point since the mid-1980s, and came back up in 2002 and 2003.

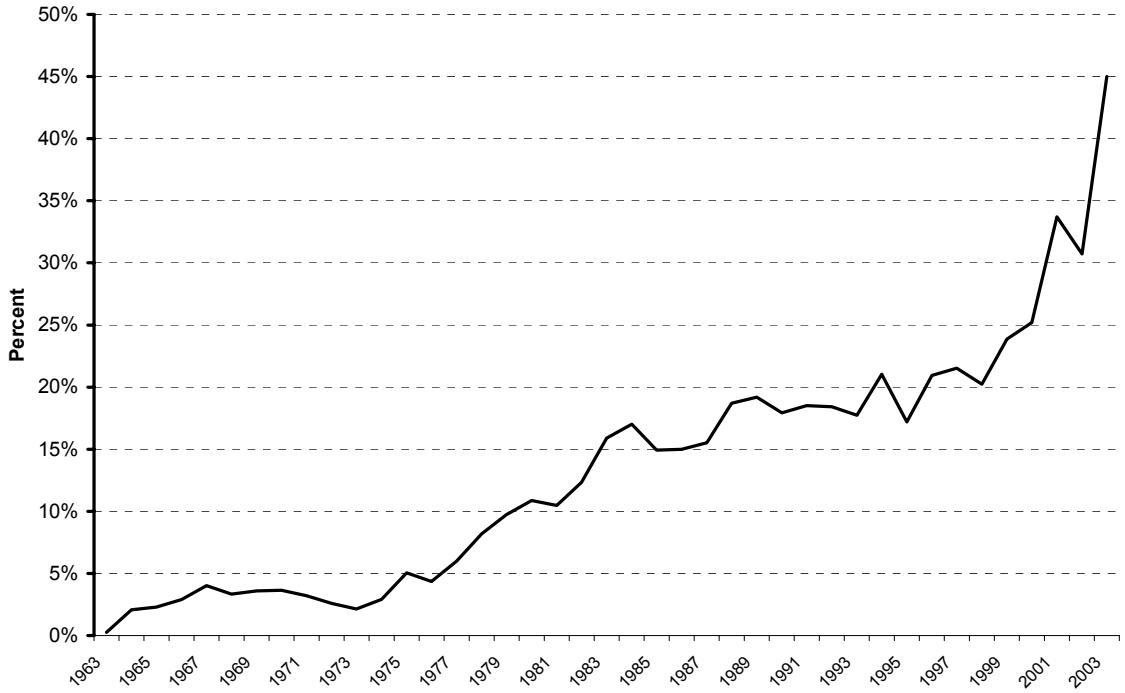
Figure 34 – U.S. Apparent Ammonia Consumption and Sources, 1984-2003



Source: U.S. Geological Survey.

Imports and exports have continued their long-term trends – exports relatively flat and imports continuing to steadily increase. The U.S. has been relying on increasing imports since the 1970s. Increasing consumption in the last few years with relatively flat production resulted in a large increase in the import share of consumption, which reached its highest level in 2003 at 45 percent, as shown in Figure 35.

Figure 35 – U.S. Import Reliance: Import Share over Total Ammonia Consumption 1963-2003

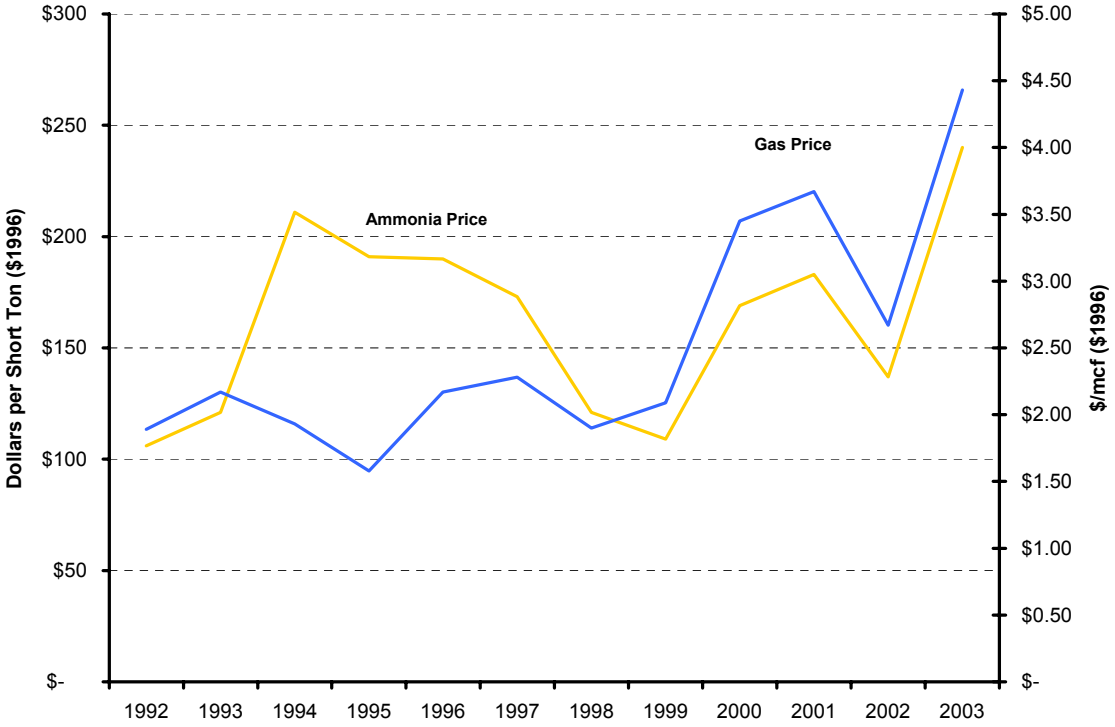


Source: U.S. Geological Survey.

Figure 36 shows f.o.b. ammonia prices at the U.S. Gulf Coast and U.S. wellhead gas prices. While ammonia prices have fluctuated, they were flat or declining in the early 1990s when consumption started to decline. Even in 2001, ammonia prices were lower than they had been in 1994, when consumption was still increasing and gas prices were lower. This is largely an indicator of the international nature of the ammonia market, which influences ammonia prices independent of U.S. gas prices. However, it also indicates that while ammonia prices were certainly a factor in declining consumption in 2001, other factors including lower crop demand also had a significant effect.

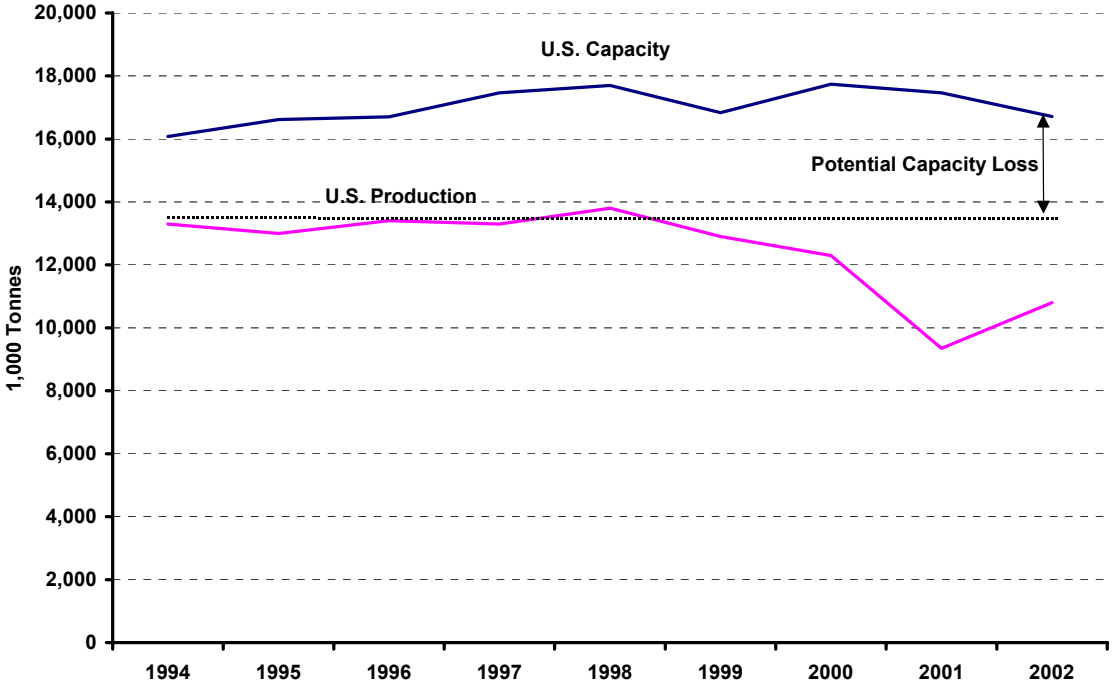
When natural gas prices reached very high levels from the end of 2000 to early 2001, ammonia producers shut down several plants or reduced their operating rates. From 2000 to 2002, 5 ammonia plants shut down completely for some period of time. In early 2001, approximately 40 percent of total U.S. ammonia capacity had closed at least temporarily with some shut down permanently. Ammonia producers operated at only 56 percent of design capacity during this period. By the middle of 2001, as natural gas prices dropped to the $2-$3 per Mcf range, most of the ammonia capacity that had been shut down was restarted. Nevertheless, some of the capacity was permanently closed. Figure 37 shows U.S. ammonia capacity and production from 1994 to 2002. The chart shows that 6 percent of ammonia capacity had closed by 2002 since its peak in 2000. However, the capacity at all times was well above domestic production levels.

Figure 36 – Average Gas and Ammonia Prices (f.o.b. Gulf Coast), 1992-2003



Source: U.S.G.S.

Figure 37 – U.S. Ammonia Annual Capacity and Production



Data Source: U.S.G.S.

The shutdown and capacity adjustments in the ammonia industry in part reflect consolidation and evolution in that industry. During periods of high natural gas prices, the plants with relatively higher-cost margins are the most vulnerable to temporary or permanent closure. Some of the U.S. plants were built during a period of much lower gas prices and are not efficient enough to compete at current prices. Since U.S. ammonia capacity is well above recent production, some of these plants can close down without affecting the ability to meet U.S. demand. In addition, ammonia can be stored both by producers and consumers. Therefore, temporary shutdowns of producing plants can often be made up by increased production later on.

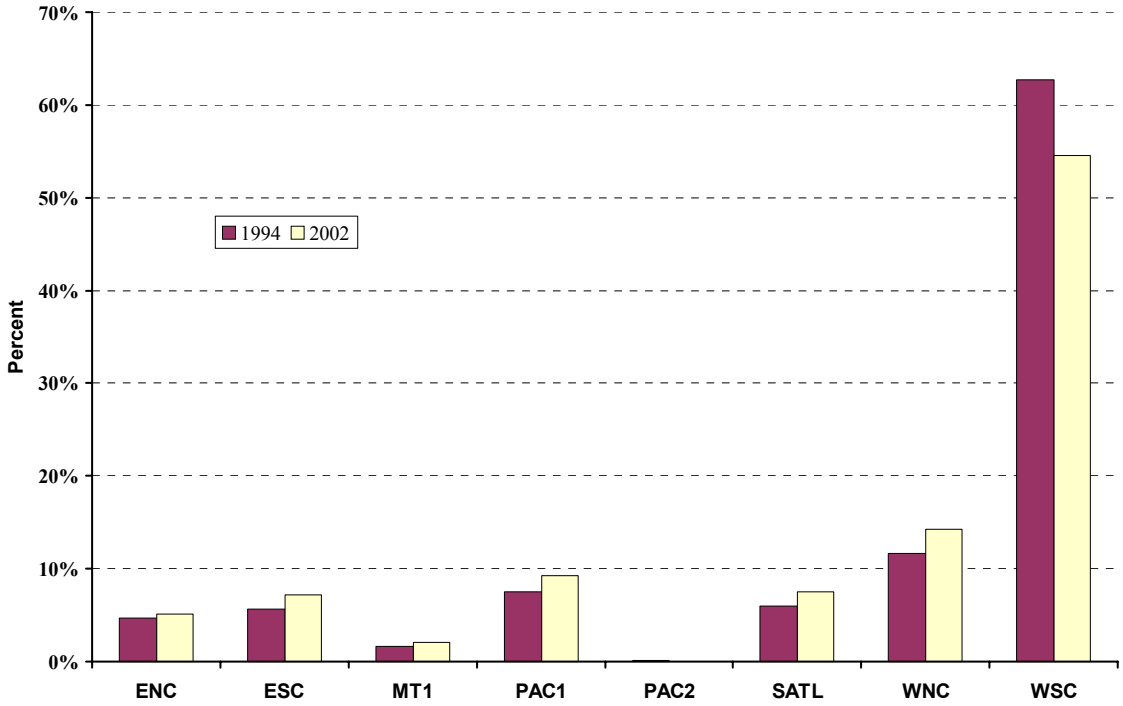
Despite the recent plant closures, U.S. ammonia production capacity was higher at the end of 2002 than it was in 1992. Industry analysts projected in 2002 that 12 additional ammonia plants were at risk of permanent closure if high natural gas prices continued through 2003. Shutdown of these plants would mean a loss of about 26 percent of total U.S. 2000 capacity. This would leave U.S. capacity slightly below the recent peak production levels, though not by much, as shown Figure 37. Furthermore, this would mean 1,300 workers out of a job (out of a total of 5,000 employees in the nitrogenous fertilizer industry), most of them in Louisiana and some in Texas. However, as of early 2004, these shutdowns had not occurred

Geography as well as plant performance and gas price affect the vulnerability of ammonia plants. In the U.S., ammonia producers are located either where the fuel/feedstock supply is inexpensive (near the Gulf) or where the main markets are (in the Midwest). Figure 38 shows the regional distribution of ammonia capacity in the U.S. The figure shows that the majority of ammonia capacity is located in the West South Central region, which includes Louisiana, Arkansas, Oklahoma and Texas. The region with the second highest capacity is the West North Central region, which includes North Dakota, South Dakota, Nebraska, Kansas, Minnesota, Iowa and Missouri.

In the past, the Gulf coast ammonia industry has had the advantage of proximity to low cost domestic gas supplies. However, these plants are also close to the seaports through which ammonia from other countries with lower gas prices can arrive. They are therefore more vulnerable to foreign competition when U.S. gas prices are higher. Midwestern ammonia plants are less vulnerable because the imported ammonia must be shipped from seaports, reducing its cost advantage. This difference is reflected in Figure 38, which shows that most of the lost ammonia capacity has been in the West South Central region, most vulnerable to foreign competition, whereas production capacity has increased in the areas closer to markets and further from shipping ports.

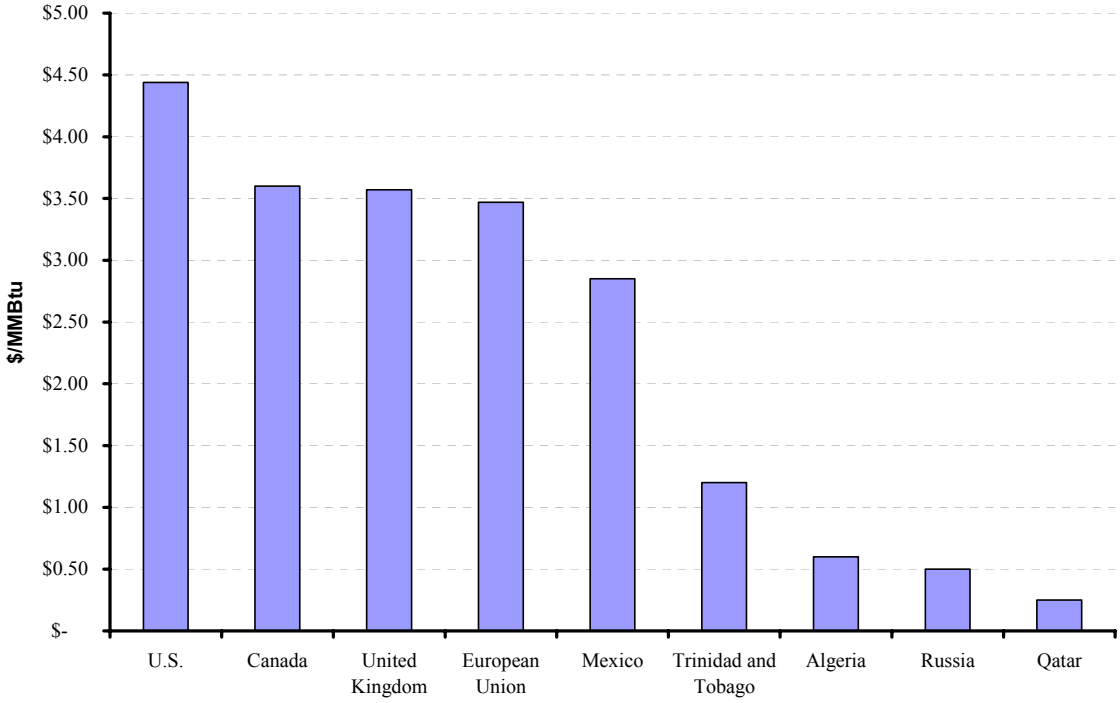
Since the end of 2000, the competitive gas price has been lost. Figure 39 compares natural gas prices for 2003 for different countries. U.S. natural gas prices are among the highest, especially compared to the gas/ammonia exporting countries in the mid-east, Caribbean and former Soviet Union. With high natural gas prices, the cost of U.S. ammonia production will be high as well. But high natural gas prices, do not mean an immediate collapse of the U.S. ammonia industry. The domestic industry still has the advantage of proximity to the market.

Figure 38 – U.S. Ammonia Capacity Share by Region, 1994 and 2002



Source: U.S. Geological Survey.

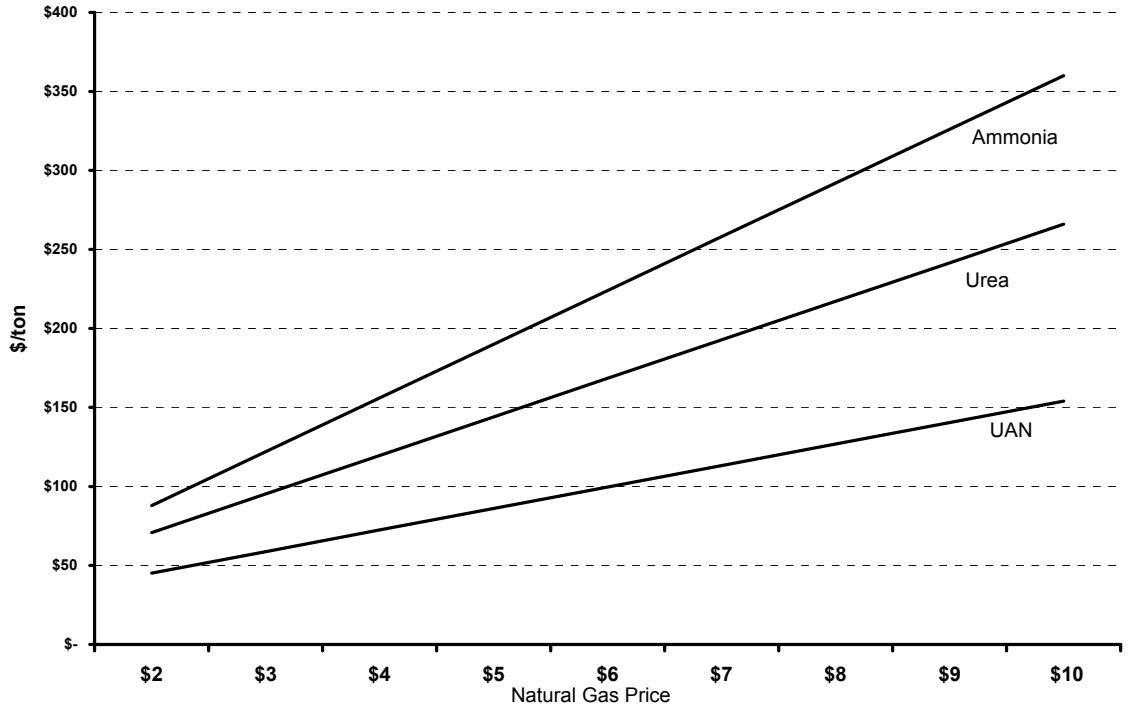
Figure 39 – Natural Gas Price Comparison



Sources: Various Sources: International Energy Agency, World Bank, Energy Information Administration, and private companies.

Figure 40 shows the cost of producing the three major fertilizers: ammonia, urea, and UAN as a function of gas price. At current natural gas prices of about $5.50 to $6, domestic ammonia can be produced for about $200 per ton. However, recent ammonia prices have been about $300/ton due to tightness in the international ammonia market. As long as the international market is strong, domestic ammonia producers will remain competitive, even at current gas prices. On the other hand, if the international market weakens, U.S. producers may have difficulty competing with ammonia from countries with very low gas prices even at historic U.S. gas prices. Even in 1999, some domestic ammonia producers with relatively high-cost margins were negatively impacted by low international prices and shut down permanently. This is evident in the annual capacity data (see Figure 37).

Figure 40 – Effect of Gas Price on Fertilizer Production Costs



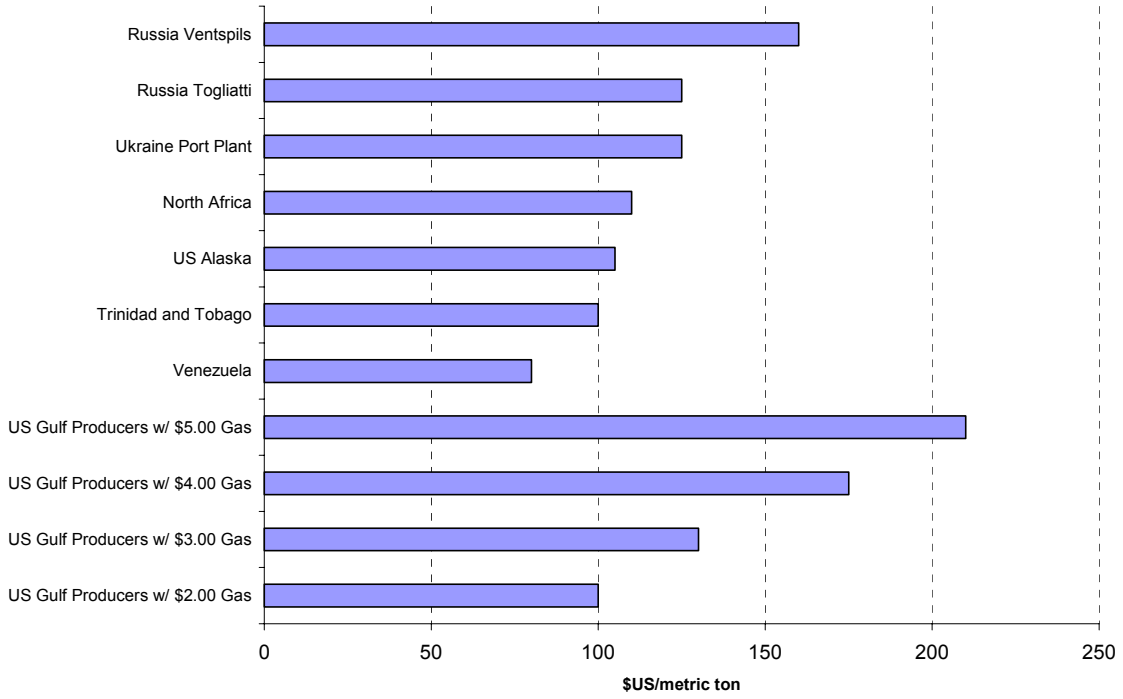
Source: Oklahoma State University, Division of Agricultural Sciences and Natural

Figure 41 compares the ammonia costs from different sources, delivered to the U.S. Gulf coast. The figure shows that, barring any infrastructure limitations to imports, U.S. ammonia producers are directly competitive only at natural gas prices below $2, as Venezuela and Trinidad Tobago would be able to produce and transport ammonia to the U.S. at cheaper prices. At natural gas prices of $4, almost all the current import sources would be able to challenge domestic producers at the Gulf Coast.

Current worldwide capacity of ammonia production is concentrated in Asia (includes Middle East), where natural gas is cheap and ammonia demand is high. The U.S. accounts for only 12

percent of world ammonia capacity. Over the next few years, the U.S. is expected to continue to lose ammonia capacity, while Latin America and Asia add substantial amounts of new capacity. This creates an unfavorable long-term outlook for the domestic ammonia industry.

Figure 41 – Ammonia Costs to U.S. Gulf
(includes gas, other cash and freight costs)



Source: Potash Corp. Annual Report.

Over the short-term, even aside from the current high international price situation, domestic ammonia producers still have some advantage, since the current distribution, storage and infrastructure of fertilizer supply in the U.S. is still founded on domestic supply. There is still a limited infrastructure to accommodate large amounts of imports. Also, at present, generally there is a two-month time requirement to make arrangements for imported ammonia to be transported to the U.S. Nevertheless, over the long-term, the infrastructure to handle imports could be developed, and thus, the viability of the domestic ammonia industry could be at risk.

Several strategies are already being pursued by domestic ammonia producers to counter the effects of high natural gas prices. These include closing plants that are relatively less efficient and have higher cost margins, passing production cost increases to customers, hedging risks by purchasing long-term gas contracts, and building new capacity with alternative feedstock that has a more stable price and supply (e.g., coal).

In 2001, for example, Farmland Industries and Synfuel Technologies announced their joint agreement to build a coal gasification plant next to Farmland Industries' ammonia plant in

Oklahoma. The plant will use over 9 thousand metric tons per day of coal from Wyoming's Powder River Basin. Farmland Industries is already manufacturing ammonia using petroleum coke in one of its plants in Kansas. Also, the coal gasification plant used to produce ammonia in North Dakota has expanded from 22 thousand metric tons in 1994 to 363 thousand metric tons (almost 17 times) in 2000. Nevertheless, the switching to alternative feedstock is not projected to be the solution for the industry. Ammonia production from coal gasification for example, costs twice as much as production from natural gas.

4.4 CONCLUSIONS

Although parts of the chemical industry are highly dependent on natural gas, the fastest growing and highest value components are the less gas-intensive segments. Some gas-intensive segments of the chemical industry have grown slowly or not at all in the last decade while imports have been steadily increasing. Some of these changes in demand are well correlated to prices of the chemicals and seem more linked to changes in demand caused by other factors. The prices themselves seem, in some cases, to be driven more by international markets than by U.S. gas prices. Although recent years have seen temporary and permanent shutdowns of some high-cost ammonia plants, ammonia production capacity today is still adequate to meet historical production levels. The recent high gas price levels seem to be only one of several factors driving the long-term trends in the industry.

5 - Summary and Conclusions

The industrial sector is the largest U.S. consumer of natural gas. Moreover, gas is a key fuel and an important feedstock for the industrial sector. However, industrial energy in general and gas use in particular are concentrated in only a few industries. For example, the chemicals and refining industries alone account for more than 50 percent of industrial gas consumption.

The energy-intensive industries are the basic industries, which convert raw materials into intermediate products such as steel, bulk chemicals, plastics, etc. While they are the largest energy consumers, they directly account for a small share of industrial GDP and employment. The chemicals and refining industry account for only 8 percent of industrial GDP and 4 percent of industrial employment.

GDP and employment are concentrated in the less energy-intensive industries that produce higher value finished products. The construction, metal durables and "other manufacturing" industries account for 64 percent of industrial GDP and 67 percent of industrial sector employment but only 14 percent of industrial sector gas use.

On average, energy represents only a few percent of the cost of production for industry. While this does not reflect all aspects of industrial profitability, it is a good indicator of the effect of energy cost on industry. For the high value, high employment industries the gas share of production cost is less than 1 percent. For these industries, even large changes in gas prices have a relatively small impact on production cost. There are a few industries for which gas represents more than 10 percent of production cost. These tend to be industries such as fertilizer, in which gas is the raw material as well as the fuel. Many of these industries, such as the fertilizer and steel industries, are strongly affected by international competitive markets which can affect their viability as much or more than gas prices.

This assessment reflects the general influence of natural gas prices on U.S. industrial sector competitiveness. While the analysis does distinguish between the various categories of activity in the industrial sector and offers insights into the areas most affected by high prices and the potential impacts of sustained high prices, specific companies or industries could experience more significant impacts than described here. An exhaustive review of corporate profit margins and industrial competitiveness compared against the economics of commodity imports is beyond the scope this work.

5.1 GAS CONSUMPTION TRENDS

Industrial gas use peaked in 1973 and then declined for several years due to a variety of factors including rising gas prices and increased energy efficiency. Industrial gas use started to increase during the mid 1980s when gas prices started to decline and new applications of gas such as cogeneration entered the market. This trend continued through 1997. Industrial gas consumption started to decline again in 1997 prior to the recent gas price increases due to reduced industrial production in the energy-intensive industries. This decline in consumption

intensified with an economic downturn in 2001 and the increase in gas prices in 2000-01 and 2003.

5.2 FUEL SWITCHING

The limited data available indicate that there is significant physical fuel switching capability in the industrial sector, perhaps 20 to 25 percent of industrial gas capacity for heat and power applications or about 4 Bcfd. This capability has probably declined over the last decade when it was used very little due to relatively low gas prices. Conversion from boilers to turbine-based cogeneration systems has also reduced switchability and also changed the primary alternative fuel from residual oil to distillate. More stringent environmental regulations have also probably reduced the capacity for switching, but only in certain parts of the country and in some cases for certain parts of the year.

Macro analysis of industrial sector response to gas prices shows short-term fuel switching of 5 to 10 percent of demand or about 2 to 3 Bcfd. There is probably greater physical capability to switch in the short term but less capability to switch for longer periods of time due to equipment, infrastructure and environmental constraints. However, these constraints could be overcome if a sufficient economic driver were present. Fuel switching capacity could be expanded if there were a sufficient gas/oil price differential for an extended period of time. One would then have to separately consider the effects of greater industrial consumption on oil markets, especially distillate oil.

5.3 EFFECTS ON SPECIFIC INDUSTRIES

The chemical industry is the largest user of natural gas and has some of the most vulnerable segments to high gas prices. The ammonia/fertilizer industry is vulnerable because it relies on gas as a feedstock as well as a fuel and because it must compete with ammonia imports from countries with much lower gas prices. Although some less efficient ammonia plants have shut down, U.S. capacity is higher than it was in 1992 and is still adequate to meet U.S. demand.

Imports of ammonia and ethylene have been increasing for many years and ammonia imports have increased significantly in recent years. Today however, ammonia can be produced in the U.S. significantly below the current world price. This indicates that recent reduced production is the result of a variety of market factors, including gas prices, rather than foreign competition or gas prices alone. The continued development of new chemical manufacturing capacity in countries where gas prices are significantly lower than in the U.S. will exacerbate this situation over the longer term.

5.4 OVERALL CONCLUSIONS

Industrial gas demand was about 14 percent lower in 2003 than at its recent peak in 1997. This reduction is a combination of reduced demand due to an economic downturn, world markets for certain U.S. products and the effect of high gas prices on some gas-intensive industries. It is difficult to separate the effects of these factors but the economic downturn and world markets seem to have played a larger role than gas prices. As of early 2004, industrial production seems

to be increasing while gas prices are still higher than historical levels and greater demand in world markets is supporting recovery in some of the gas-intensive industries.

Some gas-intensive basic industries in the U.S. are mature and vulnerable to competition from other countries with lower energy, labor and raw material costs. They can still compete successfully when world markets are tight but may become more vulnerable under currently likely U.S. gas price scenarios as basic industries are developed in countries with much lower costs. Other industries, such as the basic food processing or cement industries, will continue as domestic industries but will have to pass on higher energy costs to their customers. Higher gas prices will also affect the cost and competitiveness of less energy-intensive industries but to a much lesser extent. Gas prices will be only one of several factors that determine the future U.S. industrial mix.

NATIONAL COMMISSION ON ENERGY POLICY

INCREASING U.S. NATURAL GAS SUPPLIES

A Discussion Paper and Recommendations from the National Commission on Energy Policy

October 2003

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The **National Commission on Energy Policy** was founded in 2002 by the William and Flora Hewlett Foundation, and its partners – The Pew Charitable Trusts, the John D. and Catherine T. MacArthur Foundation, the David and Lucile Packard Foundation and the Energy Foundation. The 18-member bipartisan Commission includes leading energy experts representing government, industry, academia, labor, and consumer protection and environmental interests. The Commission is currently developing comprehensive recommendations for long-term national energy policy to be released in December 2004.

The economic modeling analysis for this report was provided by **Energy and Environmental Analysis, Inc.** (EEA). Founded in 1974 to perform economic, engineering and policy analysis in the energy and environmental fields, EEA conducts analyses of environmental regulatory policy, emission trading issues and corporate environmental strategy. In the energy field, EEA is nationally known for its analysis of natural gas supply, transportation and market issues and provides strategic planning and regulatory support to all segments of the natural gas industry. Most recently, EEA provided the economic modeling and analysis for the National Petroleum Council's latest report, *Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy.*

INCREASING U.S. NATURAL GAS SUPPLIES

A Discussion Paper and Recommendations from the National Commission on Energy Policy

U.S. consumption of natural gas increased by 18 percent between 1990 and 2002 and is expected to grow for at least the next two decades, in large part because of substantial additions of gas-fired electric generating capacity. However, the conditions that spurred much of this expansion – an apparent abundance of natural gas and relatively low prices – now appear to be changing quickly. In fact, recent trends indicate that future supply and demand dynamics for natural gas may be far different from the experience in the 1990s, leading many analysts to conclude that the North American natural gas market has moved to a permanently higher price level. Underlying these trends is the reality that growth in domestic natural gas production has been unable to keep pace with increased demand. Even with increased imports from Canada – which have historically helped to meet U.S. demand – natural gas prices have continued to rise rapidly.

In this context, U.S. policymakers are now considering a variety of long-term supply and demand strategies to address concerns about potentially high prices and increased price volatility in future natural gas markets. Prominent among the supply-side options under discussion are: (a) the construction of a major new pipeline to bring natural gas from developed fields in the North Slope of Alaska to the lower 48 states and (b) the expansion of available infrastructure for importing liquefied natural gas (LNG) from foreign sources. With respect to the Alaska pipeline, in particular, recent discussions have focused on the appropriateness and desirability of providing some form of federal tax incentive or subsidy to support pipeline construction.

The primary purpose of this paper is to help inform the current national debate by presenting the results of a cost-benefit analysis of the Alaska pipeline sponsored by the National Commission on Energy Policy and conducted by Energy and Environmental Analysis, Inc., a consulting firm with expertise in the economics of the natural gas industry. The analysis was designed to examine two major questions. First, what is the potential impact of the Alaska pipeline on future U.S. gas supply, demand and prices? Second, what are the likely costs, to the U.S. Treasury, of tax credits at the levels now being proposed in support of the pipeline?

The results of this analysis, which are summarized below and explained in more detail in a technical attachment to this discussion paper, suggest that completion of the pipeline could provide substantial consumer benefits in the form of reduced future natural gas prices. Moreover, the net benefits appear likely to far outweigh the costs to the U.S. Treasury of current tax credit proposals aimed at helping pipeline developers manage the financial risks associated with the project.

Two important points must be emphasized in connection with the above finding and with the recommendations put forward elsewhere in this paper. First, this paper does not attempt to develop a detailed framework or broadly applicable set of criteria for assessing whether or at what level government subsidies – be they in the form of tax credits or direct subsidies – are justified. However, it is the Commission's strong belief that such interventions generally are justified *only* where identified market imperfections and regulatory barriers provide a principled public interest rationale for government action. Second, this paper does not attempt to provide a

comprehensive discussion of natural gas policy options – which would necessarily address available demand side policies, as well as other important issues related to natural gas transportation, production and supply security. In the last section of this paper we do summarize a number of ongoing Commission activities and research projects in other areas of natural gas policy. However, we have chosen at this time and in this paper to focus more narrowly on the pipeline question – and to a lesser extent on some LNG-related opportunities – to inform the important policy discussions that are now taking place regarding natural gas supply.

Background

U.S. natural gas production has grown, on average, less than 1 percent per year since 1990 as U.S. basins have matured and premium reservoirs have been depleted. At the same time, U.S. consumption growth has averaged about 1.4 percent per year. Depletion rates for new wells (the rate at which production declines over time from a particular well, reservoir or field) have also been increasing in recent years. In part, faster depletion rates reflect improvements in production technology that allow resources to be extracted more quickly resulting in higher initial production from new wells. However, faster depletion rates also signal a decline in the recoverable volumes in new wells. While better technology has allowed producers to increase initial production from newer wells, it does not appear to have been able to fully offset the impacts of declining well quality. This has resulted in a treadmill effect, where more and more wells must be drilled simply to maintain production levels. Meanwhile, natural gas imports from Canada have increased significantly over the past decade in response to the growing gap between U.S. demand and production. Growth in Canadian production, however, now appears to be slowing as well and prices for Canadian gas have increased substantially.

Construction of a pipeline linking the significant natural gas resources of already developed fields in Alaska's North Slope with North American markets and expansion of the domestic infrastructure needed to support LNG imports currently represent promising opportunities for expanding U.S. supply options in the near to medium-term timeframe. The process of constructing the Alaska pipeline, if begun now, could be completed in 2013-2014. Meaningful expansion of LNG import capacity could be accomplished somewhat more quickly, in the next 5 to 7 years, or even faster through expansion of existing facilities. Both options are described in greater detail below. The market, regulatory and other challenges that apply to each – together with the Commission's recommendations for addressing those challenges – are discussed in a separate section, following a presentation of the results of our cost benefit analysis for the Alaska pipeline.

Alaska Natural Gas Pipeline

Proposals to build a natural gas transmission pipeline from the North Slope of Alaska to the lower 48 states have been discussed for more than 20 years. In the mid-1980s, the Alaska Natural Gas Transportation System project applied for and received various elements of the regulatory approval needed to construct the pipeline. As a result of low natural gas prices through the late 1980s and 1990s however, the pipeline project was put on hold.

Significant increases in natural gas prices over the past three years have led to renewed interest in the Alaskan pipeline. The Alaskan North Slope holds significant natural gas resources: approximately 35 trillion cubic feet have been discovered to date, equivalent to roughly 20

percent of U.S. proved reserves.[1] A substantial volume of this gas is currently being produced and re-injected to support oil production because there is no infrastructure to deliver it to natural gas markets in the United States.

Constructing such a pipeline would be an extremely large project even by major world energy project standards and is estimated to require nearly $20 billion in incremental investment and approximately 8 to 10 years to complete. Stretching from the Alaskan North Slope to Alberta, Canada, the first pipeline segment would be roughly 2,100 miles long and would be capable of transporting 4.5 billion cubic feet per day (Bcf/d).[2] The pipeline segment from Alberta to Chicago would be 1,470 miles long, bringing the total length of the pipeline to 3,270 miles. The additional natural gas that could be supplied by the pipeline annually is equivalent to nearly 7 percent of current U.S. natural gas consumption.

Liquefied Natural Gas (LNG) Infrastructure

The U.S. holds only a small proportion of the world's proved natural gas reserves.[3] Because it allows for marine transport over long distances, LNG provides a means of accessing global natural gas supplies, particularly as recent substantial cost declines in liquefaction and shipping have made it economic to develop LNG projects that target the U.S. market. Currently LNG plays a small role in the U.S., contributing less than 1 percent (200 billion cubic feet annually) to national consumption. However, existing facilities can expand their import capacity and new facilities could be constructed to meaningfully increase LNG's contribution to domestic gas markets within the next 5 years. Indeed, current forecasts estimate that LNG imports will triple by 2005. If LNG imports become the marginal supplier of natural gas to U.S. markets, the U.S. will in effect be entering a larger regional, if not global, marketplace for gas. Over time, this could assist in reducing volatility in U.S. natural gas markets, because LNG pricing is typically tied to global oil prices, which have been less volatile than U.S. natural gas prices.

Although only four U.S. LNG terminals exist today, plans are underway to develop additional terminals and possibly expand existing facilities. LNG importation facilities require enough land for re-gasification and storage infrastructure along with harbors with sufficient depth, anchorage, and turning space to accommodate LNG tankers, which can measure 900 feet in length, 140 feet in width, and 36 feet in draft below the waterline. The size and draft of LNG tankers clearly limit potential sites for new onshore LNG marine terminals.

[1] Estimates of undiscovered natural gas resources in the North Slope reach as high as 150 trillion cubic feet.
[2] Based on the proposed "southern route."
[3] The world's proved reserves alone provide a 61-year supply of gas at present global production levels.

Results of a Cost-Benefit Analysis of the Alaska Pipeline and Associated Tax Credit Proposal

As indicated in the Introduction, the Commission has analyzed the economic impacts of a pipeline connecting the natural gas resources of Alaska's North Slope to the Alberta hub in Canada via the "southern route".[4] The analysis was designed to examine two major questions related to the Alaska pipeline. First, what is the potential impact of the Alaska pipeline on U.S. natural gas supply, demand, and prices? Second, how likely is it that the tax credits currently being proposed in support of the pipeline would be triggered by low natural gas prices, and how much would those credits cost? It should be emphasized that our examination of benefits in this analysis is limited to the impact of using Alaskan gas to replace more expensive domestic sources and the effect of this increased supply on future natural gas prices. Meanwhile our examination of costs is limited to the immediate impacts on the U.S. Treasury of a tax credit designed to provide some insurance against low-probability, low-price contingencies (see further discussion below).[5] As such, the analysis does not attempt a comprehensive quantification of costs and benefits, though some of the larger public interest benefits of the project are discussed qualitatively elsewhere in this paper.

To conduct the analysis, the Commission worked with Energy and Environmental Analysis, Inc. (EEA) to construct and model several natural gas market scenarios. The first set of scenarios simply forecasts natural gas supply, demand, and prices both with and without the Alaskan pipeline. The second set of scenarios examines five important variables to assess their impact on future natural gas prices. These factors include (1) modified economic activity, as measured by the growth rate in GDP, (2) level of LNG imports, (3) natural gas production levels in the lower 48 states, (4) end-use efficiency and fuel-switching capabilities, and (5) crude oil prices. Importantly, this analysis was designed to quantify and characterize the aggregate, economy-wide impacts of the Alaskan pipeline and therefore does not account for regional differences which could certainly be substantial under the various scenarios analyzed.

Impact of the Pipeline

The first part of the analysis examined two scenarios: one in which pipeline construction is completed with gas flowing into Alberta starting in 2013; the second in which pipeline construction is delayed or abandoned entirely and no Alaskan natural gas is available in the lower 48 states throughout the forecast period (i.e., through 2025).

The results indicate that the increase in natural gas supplies is likely to have a significant impact on North American natural gas prices. Model-predicted price impacts are highest in the first two years after the pipeline is completed, with Henry Hub prices falling by approximately $2.00 per million Btu.[6] As producers in Canada and the lower 48 states adjust their production in response

[4] While the analysis is based on cost estimates for the "southern route", construction costs for the "northern route" are likely to be comparable.

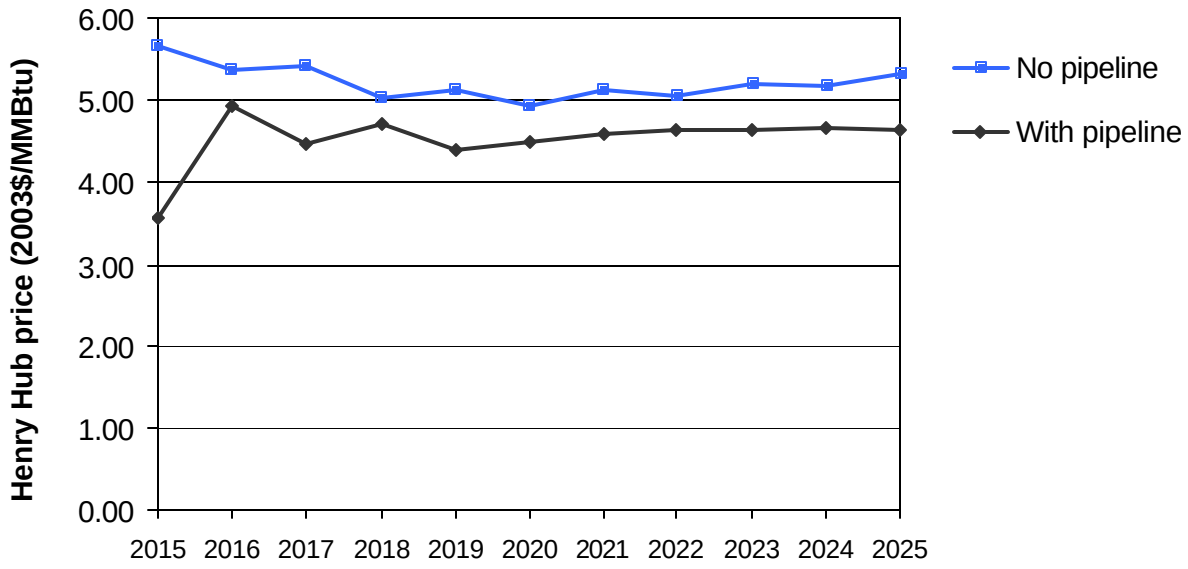
[5] Some Commission members believe that if a tax credit of this type is adopted some sharing of the associated costs with the State of Alaska should be considered.

[6] The analysis assumes the pipeline begins operation in the 3rd quarter 2013. Production is ramped up gradually, with the full 4.0 Bcf/d delivery beginning in 2015. For simplicity, all results are calculated for the 2015 through 2025 period. Note that because of substantial uncertainties about how quickly producers and markets will respond to the new availability of Alaskan gas, we do not include the initial, model-predicted $2.10 per million Btu price drop in our primary calculation of consumer gains and producer gains and losses.

to the lower prices resulting from additional supplies from Alaska, the price differential between the two cases narrows. On average, the analysis suggests that Henry Hub natural gas prices would be reduced by roughly $0.45 per million Btu through 2025 as a result of the pipeline.

Figure 1: Henry Hub Natural Gas Prices

With and Without the Alaska Natural Gas Pipeline



Resulting savings to consumers and net benefits as a whole would be substantial. Consumers are expected to save, on average, $18.9 billion per year for the 2016-2025 forecast period based on an estimated price decline of $0.56 per million Btu.[7] These savings, however, come partially at the expense of producers — primarily Canadian and lower 48 producers — who would face lower prices. On the one hand, producer costs fall by $3.9 billion as cheaper Alaskan gas replaces more expensive sources elsewhere. On the other hand, producer revenues fall by $18.4 billion as the equilibrium gas price falls from $5.18 to $4.62 on average over 2016-2025, leading to net producer losses of about $14.5 billion per year.[8] Thus, the net gain to society[9] from access to Alaskan natural gas is estimated at $4.4 billion per year.[10]

[7] As described in the preceding footnote, this average gain excludes 2015 (as well as 2013-2014). If prices decline by $2.10 per million Btu in 2015 as indicated in Figure 1, the net welfare gain in 2015 would be $3.9 billion with consumers reaping $67.6 billion in savings and producers losing $63.7 billion in that year. If prices decline more modestly in 2015, along the lines forecast in future years, the effects in 2015 would be similar to the average computed over 2016-2025 and reported in Table 1.

[8] These losses accrue to producers in Alaska, Canada, the lower 48, as well as LNG suppliers. If we exclude LNG suppliers in our estimates, producer losses would be about $2 billion less with a consequent increase in net benefits.

[9] That is, the (partial equilibrium) sum of changes in consumers' and producers' surplus. This probably underestimates somewhat the aggregate (general equilibrium) net benefits to the U.S. economy.

[10] As noted previously, this estimate reflects only the direct impact of changes in expenditures for natural gas and does not include any benefits associated with maintaining U.S. manufacturing jobs or other indirect economic benefits.

Table 1: Annual Changes in Natural Gas Expenditures and Revenues (Billions 2003$)

Consumer Savings	**$18.9**
Producer Gains (from lower-cost Alaskan gas)	**$3.9**
Producer Losses (from lower prices)	**– $18.4**
Net Benefit	**$4.4**

Impact of Current Tax Credit Proposals

The analysis above shows that the net social benefits of the pipeline exceed the costs of building and operating it.[11] However, as discussed in more detail below, there are a number of potential market imperfections and regulatory barriers that may make what appears to be a socially desirable investment unprofitable to private investors. A number of policy proposals have been put forward recently to encourage construction of the Alaskan pipeline, at least partially motivated by concerns that private investment incentives and net societal benefits are not fully aligned. These include efficient permitting provisions that would ensure permits and environmental reviews are completed within a prescribed period, appointment of a Federal coordinator to oversee activities of all Federal agencies involved in the permitting process, and clarification of existing permits and authorities stemming from the Alaska Natural Gas Transportation Act of 1976. While these policies have generally garnered wide support from policymakers and stakeholders, proposals that the Federal government provide financial incentives for construction of the pipeline have been much more controversial.

Proposed financial incentives include accelerated depreciation for the pipeline; authorization for loan guarantees up to 80 percent of the cost of the pipeline; and tax credits linked to natural gas spot prices. Under one tax credit proposal, producers would receive a tax credit if the monthly average spot price of natural gas at the Alberta Hub falls below $3.25 per million Btu[12], with the tax credit equal to the difference between the trigger price of $3.25 and the actual spot price. Any tax credits previously received by producers would then be refunded to the government if the Alberta spot price rose above $4.88 per million Btu. This mechanism effectively provides producers of Alaskan gas with insurance against prices falling below $3.25 per million Btu. At the same time, it provides that any payments under this insurance policy are partially or fully repaid if prices rise above $4.88 per million Btu.

This tax credit proposal is unlike existing production tax credits for energy, such as the federal wind energy tax credit. Rather than providing a set subsidy for every unit of production, the tax credit would function as a risk management mechanism that would encourage private developers to go forward by providing some de facto insurance against low-probability, low-price

[11] The analysis assumes there are no incremental production costs associated with Alaskan gas, as it is currently a byproduct of oil extraction.

[12] Both the $3.25 and $4.88 trigger prices are nominal prices for the year that gas first starts flowing from Alaska (2013 in this analysis). In 2003$, the values correspond to $2.48 per million Btu and $3.72 per million Btu, respectively.

contingencies. Advocates of this approach contend that producers are likely to pursue less risky investment projects elsewhere until a period of sustained high prices provide them with greater certainty that the Alaska pipeline will yield adequate risk-adjusted returns. Opponents have argued that the tax credits would interfere with the market by creating a price floor. The tax credit mechanism discussed below, however, would not set market prices or distort the process by which price is determined. Market prices would still be determined through balance of supply and demand.

If pipeline construction is accompanied by the proposed tax credit at $3.25 per million Btu, the obvious cost to consider is the payout from the U.S. Treasury when prices are low. Even though the expected annual gas price is predicted to remain well above the $3.25 "trigger price," during the life of the project, monthly fluctuations do lead to a small payout by the federal government in our reference case. The projected monthly Alberta Hub (AECO) price was compared to the $3.25 trigger price and the $4.88 payback price. In the months that the AECO price falls below the support price, the federal government makes up the difference. In the months AECO prices are above the payback price, producers reimburse the government up to the amount of the tax credit they had received during previous low-price periods. Our reference case analysis indicates that the tax credit is triggered only in 2015 when Alaskan gas delivered to the lower 48 reaches the full 4.5 Bcf/d, with a total payout of $215 million. As prices adjust to increased supplies, the tax credits are quickly paid back by producers the following year, and the net cost to the U.S. Treasury is zero.

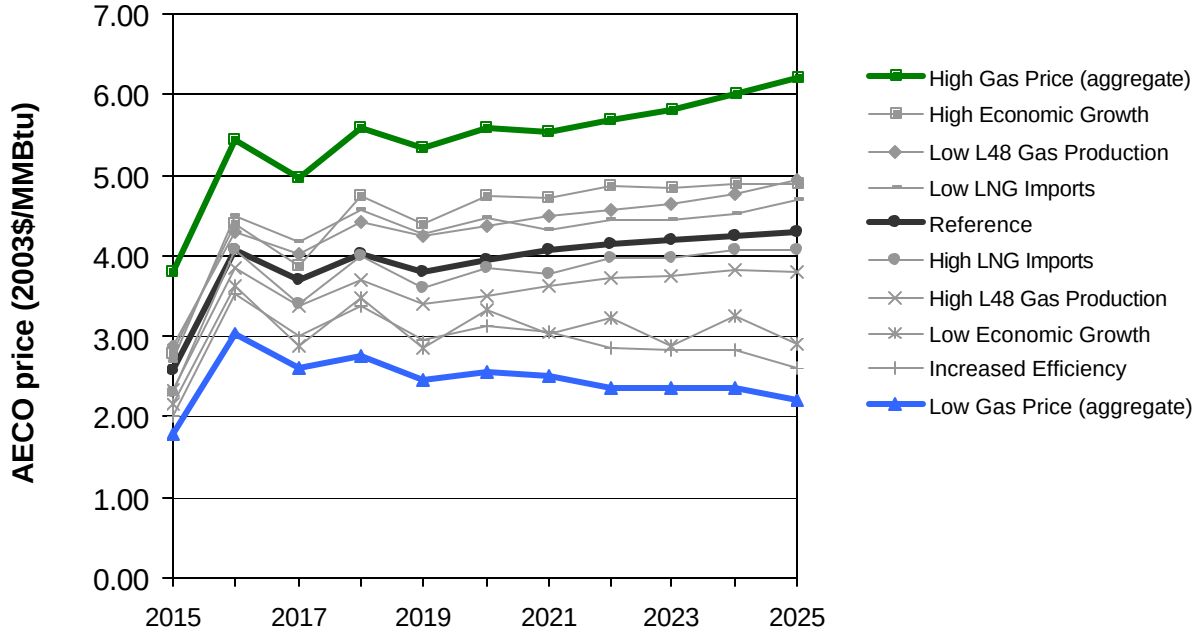
Because of significant uncertainties surrounding future gas prices,[13] however, we constructed and examined a number of alternative scenarios to the reference case in an attempt to bound the potential costs to taxpayers of this particular tax credit proposal. The scenarios, which are developed and explained further in an accompanying technical memorandum, use different assumptions for oil prices, economic growth, gas production in areas other than Alaska, and LNG imports. Figure 2 below illustrates the impact of the various scenarios on annual gas prices at the Alberta Hub (AECO).

We find that in 7 out of the 10 cases analyzed, the net payout from taxpayers is zero. In each of these cases, there is an initial payout in 2015, but the tax credits are fully paid back the next year as the market adjusts to the additional Alaskan supplies (the exception being the "High Gas Price" case, in which the tax credit is never triggered).

Only in 3 out of the 10 cases is there a net payout from taxpayers to producers — the "Low Economic Growth" case, the "Increased Efficiency" case, and the "Low Gas Price" case. The net tax credits paid to producers under these three cases average $39 million, $72 million, and $350 million per year, respectively. In our view, however, the "Low Gas Price" scenario is highly unlikely. This scenario combines all of the assumptions likely to lower natural gas prices, including reduced economic growth, significantly increased end-use efficiency, increased gas production in the lower 48 States and increased LNG imports. These assumptions are somewhat inconsistent, as it is unlikely that firms would invest in new LNG facilities if natural gas demand fell. We have included the results here for the sake of completeness, but consider $72 million per year to be a more plausible upper bound estimate of the net Treasury payout.

[13] Future natural gas prices will depend critically on the cost and availability of additional supplies from North America and imports of LNG from other areas of the world, as well as on continued improvement in end-use efficiency in homes, businesses and electricity generation and other factors.

Figure 2: Alberta Hub Natural Gas Prices for the 10 Scenarios



Rationales for Policy Intervention and Commission Recommendations

Both the construction of an Alaska pipeline and the expansion of LNG import infrastructure pose challenges for private investors. The challenges for LNG are generally more manageable and are primarily related to safety concerns and to the fact that – because no new facilities have been constructed in this country for over 20 years – there is considerable uncertainty surrounding the regulatory process and the actual siting challenges involved in bringing a new facility on line. Concerns over the safety of LNG – which is not explosive in its liquid state, but can become so under certain conditions once re-gasified – are understandably a major issue in light of the terrorist attacks of September 11, 2001.[14] However, these risks are not different in kind or degree from those associated with other fuels and types of energy infrastructure and there is no reason to expect that they cannot successfully be managed using existing market and regulatory arrangements.

With respect to siting issues for new LNG facilities, recent regulatory changes by the Federal Energy Regulatory Commission (FERC) have eased open access requirements for such facilities and encouraged applications for new greenfield projects. The Commission applauds these efforts and believes more can be done to reduce the uncertainty to potential investors in this arena without sacrificing safety or environmental protection. The signs are encouraging. FERC

[14] Natural gas is only explosive within a narrow range of concentrations in the air (5 percent to 15 percent). Less air does not contain enough oxygen to sustain a flame, while more air dilutes the gas too much for it to ignite. Since 1952, LNG ships around the world have made more than 33,000 voyages. While there have been accidents during this period, there have been no cargo explosions, fires or shipboard deaths.

recently granted authorization for the construction of the first new LNG terminal in the U.S. in 20 years, which will be located along the Gulf coast in Louisiana. More facilities like this will be needed. The manner in which this project progresses, and the timeliness of its activation, could be important indicators for the future of LNG as a supply option for the U.S. The Commission encourages overseeing authorities to work cooperatively with industry and to handle additional applications with similar efficacy in an effort to develop a set of best practices that accommodates all parties.

The challenges confronting potential investors with respect to the Alaska pipeline – by contrast – are considerably more complex and will likely be more difficult to overcome. Some of the most important include:

- Substantial financial risk as a result of the magnitude of the project and the length of time needed to complete the pipeline, especially in the face of significant uncertainty over future prices and potential price volatility.
- The difficulty of managing these risks given the decline of long-term contracts in recent years as a result of gas market unbundling and competition, together with the unsettled state of electricity restructuring and competition policies.
- Regulatory uncertainty regarding siting and permitting of the pipeline and uncertainty regarding royalty payments for Alaskan gas production.

The first two of these challenges are exacerbated by the pipeline's inherent geographic commitment to the North American market. In the case of LNG, for example, production infrastructure, LNG tankers and liquefaction facilities can be utilized to deliver natural gas to markets other than the intended U.S. delivery location, should U.S. market prices fall. Only the re-gasification facility is tied exclusively to the U.S. market. The Alaska project's value, on the other hand, is inexorably linked to the value of gas at the Canadian or U.S. terminus of the line.

None of the above challenges faced by potential pipeline investors *necessarily* represent market "failures" that would themselves justify government intervention. However, there are at least two important factors related to the considerations listed above that are more likely than not to create a gap (of uncertain magnitude) between private investor valuations and social benefits. First, dramatic changes in the structure and regulation of gas and electricity markets in the last decade have led to a significant decline in reliance on long-term contracts linking producers and consumers and the associated allocation of market risks between them. One of the goals of these gas and electricity industry reforms was to allow consumers to express their own risk preferences vis-à-vis gas and electricity price uncertainty by choosing the nature and duration of contractual commitments with suppliers, and the associated allocation of market risks, themselves rather than relying on regulators to act on their behalf. A more diverse portfolio of contracts between consumers and producers, with shorter average durations and leading to more market risk being allocated to producers, is a natural outcome of these regulatory and market reforms. Accordingly, it should have been expected that the cost of capital (or hurdle rates) faced by investors in natural gas infrastructure would rise as a consequence of these reforms, while consumers generally benefit from better market incentives for cost control, lower prices overall and from an allocation of market risk that better reflects relative risk-bearing costs. Nevertheless, the transition to well-functioning, competitive gas and – more importantly -- wholesale and retail electricity markets is far from complete and faces significant challenges. These imperfections have likely led to a situation where consumers and their agents presently

face distorted incentives that are leading them to avoid longer-term contractual commitments. This situation is compounded by the credit crisis among energy marketers and investors in merchant generating plants. Accordingly, it is more likely than not that an efficient market for risk management tools to properly allocate market risks between consumers and producers has not yet emerged and is acting as a deterrent to investment in large capital-intensive infrastructure projects whose profitability is tied to variations in gas and electricity spot prices.

A second relevant consideration that may lead to a gap between private investment incentives and the social value of an investment with the Alaska pipeline's attributes is that this type of project can be characterized – from an investment standpoint – as extremely "lumpy." That is, it involves a large, "all or nothing" capital investment in new supply capacity where the average cost of the new capacity being added declines as the capacity increases, other things being equal. Economists have demonstrated that similarly "lumpy" investments – in the case of electricity transmission infrastructure, for example – can lead to a situation where the value of the new capacity being added, from the perspective of potential private investors, *understates* the social surplus it creates by reducing future prices.[15] In these cases, cautious government intervention – subject to several caveats indicated below – may be appropriate. The results of our cost-benefit analysis suggest that the Alaska pipeline very likely does represent such an instance of mismatch between private and societal valuations of a large and risky capital investment.

In addition to these two factors related to the project itself, it may be the case more generally that society values the risk associated with low and high gas price outcomes differently than private investors. We briefly discuss possible reasons for this divergence in the "National Interests" section below.

Accordingly, the Commission's recommendation with respect to the Alaska pipeline is that government policymakers give favorable consideration to options that would support pipeline construction by partially shielding investors from the risks of extreme low-price contingencies, while ensuring that taxpayers will be fully compensated for any outlays should natural gas prices subsequently rise to higher levels.

Importantly, the Commission does not endorse any particular level of tax credit, nor was our analysis designed to provide a basis for choosing a particular number. More broadly, the above recommendation must be understood in the context of the Commission's strong belief that government subsidies or tax credits generally are justified only where true market imperfections or regulatory barriers have been identified that stand in the way of the full exploitation of socially beneficial supply and demand side options. Programs designed to mitigate the impacts of market imperfections and regulatory barriers should be used cautiously — after reasonable efforts have been made to reduce the underlying market imperfections and regulatory barriers – and only when remaining market imperfections and regulatory barriers create a clear public interest in enhancing competitive market incentives and market discipline. Moreover, such programs should be structured so as to complement rather than distort market processes and to minimize any financial burdens on taxpayers. For the reasons described above, it appears likely that certain features of the Alaska pipeline — notably current imperfections in markets for natural gas risk management instruments and the project's "lumpiness" — are creating a gap between private and societal valuations of moving it forward. It is the existence of this gap —

[15] For a fuller theoretical treatment, see Paul Joskow and Jean Tirole, *Merchant Transmission Investment*, May 6, 2003. (http://econ-www.mit.edu/faculty/?prof_id=pjoskow&type=paper)

together with the availability of incentive policies that can, at modest cost and without adversely distorting natural gas markets, at least partially close the gap — that provide a principled rationale for the Commission's recommendation.

In the case of LNG infrastructure — which, for the reasons discussed above, presents lesser challenges to private investors — the Commission offers the more modest recommendation that policymakers codify FERC's recent policy changes regarding open access and reserve capacity for LNG re-gasification facilities. These policy changes will reduce uncertainty and encourage investment in LNG facilities.

At the same time, the Commission acknowledges the legitimate concerns of local communities as they evaluate the implications of accommodating a major new industrial facility. Therefore LNG siting decisions should take full account of states' coastal zone management programs, and avoid marine sanctuaries, marine protected areas, sensitive habitats, and fragile resources like deep corals.

The National Interest in Expanding Natural Gas Supply Options

The cost-benefit analysis of the Alaska pipeline described above attempts to capture only the "partial equilibrium" benefits directly attributable to reduced prices for consumers and users of natural gas. Major groups in this category include the chemical industry, the millions of Americans who use natural gas in their homes for heating and cooking, and natural-gas fired power plants that directly influence the price of electricity. In fact, lower natural gas prices are expected to result in several additional benefits to the U.S. economy by helping to preserve U.S. manufacturing jobs, enhancing energy security, and displacing pollution from energy sources with higher emissions. While our analysis did not include quantitative estimates of these benefits, the Commission believes they are important and should not be overlooked.

Alaskan natural gas is also a relatively secure, stable domestic source of supply that will help to enhance U.S. energy security. LNG imports are expected to rise substantially over the next several years in response to higher U.S. prices. While increasing reliance on natural gas imports does not immediately pose the same energy security issues as oil, it is not entirely clear how global LNG markets will evolve over the next few decades and how this might affect the U.S. In addition, consideration must be given to inherent security risks related to terrorism and sabotage associated with the Alaska pipeline project. These risks appear substantially similar to those presently being managed in the operation and protection of the Trans-Alaska oil pipeline. Ensuring the security of critical energy assets and infrastructure has been identified as a top priority by the Office of Homeland Security and would need to be addressed in planning for the construction and operation of the Alaska pipeline if it moves forward.

Finally, lower natural gas prices are likely to reduce environmental compliance costs for a number of industries, in particular the electric power sector. Natural gas is the cleanest burning fossil fuel. Increasing reliance on natural gas in the electric power sector allows firms to avoid additional environmental compliance costs that would be incurred with new coal or oil plants. In addition, natural gas emits fewer carbon dioxide emissions when burned than either coal or oil. If the U.S. begins to reduce greenhouse gas emissions over the next few decades, natural gas use is likely to increase even further. Additional natural gas supplies and lower prices will help to lower future emission reduction costs.

Other Areas of Commission Research in Natural Gas Policy

The Commission has four additional research projects underway on natural gas related topics. These studies are intended to complement the study recently completed by the National Petroleum Council and provide additional detail on supply and demand issues. They include: (1) Natural Gas Use in the Industrial and Electric Power Sectors; (2) Expanded LNG Imports: Implications for U.S. Energy Markets; (3) Energy Efficiency Opportunities in New Buildings and Equipment; and (4) Retrospective Examination of Energy Demand-Side Policies. The Commission will draw upon these studies and other research in reaching its final recommendations.

Natural Gas Use in the Industrial and Electric Power Sectors

This study will provide detailed description of natural gas usage trends in the industrial and power sectors and evaluate the impacts of high gas prices on specific gas-dependent industries such as the chemical and fertilizer industry. In particular, the study will focus on gaining a better understanding of current fuel-switching capabilities in both the industrial and electric power sectors and its impact on natural gas price volatility. The study will also examine the longer-term potential for demand destruction in major U.S. industries as a result of higher natural gas prices.

Expanded LNG Imports: Implications for U.S. Energy Markets

If LNG imports become the marginal supplier of natural gas to the U.S. markets, the U.S. will in effect be entering a regional, if not global marketplace for gas. Understanding the implications of this fundamental transition from a North American to a global natural gas market is an important energy policy issue. Key questions to be examined in this study include:

- If gas markets globalize will oil and gas prices again become linked as they are in other parts of the world such as Europe?
- Will the U.S. economy become more vulnerable to oil or gas price shocks?
- What is the projected long-term natural gas price as LNG imports become an increasingly important supply source?
- What are the potential consequences of competition for LNG among the U.S., Europe, and Japan?
- What are the national security implications of a steadily increasing reliance on imported natural gas?

In addition to these studies on supply-related natural gas topics, the Commission also has two research projects underway that address demand-side issues.

Energy Efficiency Opportunities in New Buildings & Equipment

This study will provide estimates of the economic potential for energy and cost savings by fuel and sector, and the environmental impacts from improved energy efficiency in new buildings and equipment in the residential, commercial, and industrial sectors. In particular, the study will estimate the additional costs to retrofit buildings rather than incorporating advanced efficiency into the initial building design. The study will also provide an overview of market barriers and failures related to energy efficiency investments, and policies designed to overcome them. The report will provide recommendations for continuing or improving existing policies and/or implementing new policies.

Retrospective Examination of Energy Demand-Side Policies

This study will examine the effectiveness and cost of past demand-side energy programs, including regulatory, voluntary and tax strategies, and identify the lessons they provide for possible new initiatives. Programs to be evaluated include: appliance and equipment standards, demand-side management programs operated by electric utilities, market transformation initiatives, federal energy management program (FEMP), voluntary programs, including EPA and DOE programs, and late 1970s/early 1980s tax breaks for energy efficiency investment. The evaluation will be based on review of published data sources, technical reports, and academic literature.

Conclusion

Over the past few years increased demand for natural gas, especially for electricity generation, combined with flat production in the lower 48 states, has resulted in higher natural gas prices. Moreover, natural gas prices are likely to continue to rise in the future as producers are forced to move to more expensive supplies to keep up with demand. Many analysts argue that the North American natural gas market has moved to a permanently higher price level.

Substantial supplies of natural gas in Alaska and from other nations are currently inaccessible due to lack of domestic infrastructure. Construction of a major 3,000 mile natural gas pipeline would provide the continental U.S. with access to Alaska natural gas, but three major factors make building such a pipeline a particularly risky investment — the large capital costs of the project ($20 billion), the length of time needed to build the pipeline (8 to 10 years), and, by its nature, the pipeline's geographic commitment to the future U.S. and Canadian market.

The Commission examined a tax credit approach in which producers would receive a tax credit if the monthly average spot price of natural gas at the Alberta Hub falls below $3.25 per million Btu, with the production subsidy equal to the difference between the trigger price of $3.25 and the actual spot price. Any production subsidy previously received by producers would then be refunded to the government if the Alberta spot price rose above $4.88 per million Btu.

The Commission found that the Alaskan gas pipeline would be expected to provide a range of benefits to the U.S., including 10 to 20 percent reductions in natural gas prices and net benefits averaging $4 billion annually. In addition to savings in natural gas expenditures, lower natural gas prices would also be expected to help preserve U.S. manufacturing jobs, enhance energy security, and reduce environmental compliance costs.

Given the substantial benefits likely to accrue from construction of the Alaska natural gas pipeline and the likelihood that certain factors – notably current imperfections in markets for natural gas risk management instruments and the project's "lumpiness" – may be creating a gap between societal and private assessments of the value of moving it forward, the Commission believes that cautious government intervention may be justified to promote construction of the pipeline sooner than might otherwise occur in the absence of intervention.

While the Alaska natural gas pipeline will bring additional natural gas supplies to the market in approximately 10 years, LNG imports are likely to be an important near-term source of

additional supply. Recent policy changes by FERC have helped to spur further market interest in building new LNG facilities in the U.S. Codifying these policy changes will provide clarity for market participants and ensure that investments in new facilities continue to move forward.

The 18 members of the National Commission on Energy Policy join in support of the recommendations stated herein:

Dr. Marilyn Brown
Director, Energy Efficiency and Renewable Energy Program, Oak Ridge National Laboratory

Ralph Cavanagh
Senior Attorney & Co-Director, Energy Program, Natural Resources Defense Council

Archie W. Dunham*
Chairman, ConocoPhillips

Rodney Ellis
State Senator, Texas

Leo Gerard
International President, United Steelworkers of America (USWA)

F. Henry Habicht
CEO, Global Environment & Technology Foundation; former Deputy Administrator of the Environmental Protection Agency

Dr. John P. Holdren
Teresa and John Heinz Professor of Environmental Policy, Harvard University

Dr. Paul L. Joskow*
Professor of Economics and Director of MIT Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology

Andrew Lundquist
President, The Lundquist Group; former Executive Director, The White House National Energy Policy Development Group

Dr. Mario J. Molina
Institute Professor, Massachusetts Institute of Technology

Sharon Nelson
Chief, Consumer Protection Division, Washington Attorney General's Office; Chair, Board of Directors, Consumers Union

William K. Reilly
President and CEO, Aqua International Partners; former Administrator of the Environmental Protection Agency

John W. Rowe
Chairman and CEO, Exelon Corporation

Phillip R. Sharp
Senior Advisor, Lexecon, Inc.; Senior Policy Advisor, Van Ness Feldman; former U.S. Representative, IN

Linda Stuntz
Stuntz, Davis & Staffier; former Deputy Secretary of Energy

Susan Tierney
Managing Principal, The Analysis Group; former Assistant Secretary of Energy

R. James Woolsey
Vice President, Booz, Allen, Hamilton; former Director of Central Intelligence

Dr. Martin B. Zimmerman*
Group Vice President, Corporate Affairs, Ford Motor Company

Concurrence from Commissioner Paul L. Joskow

Professor of Economics and Director of MIT Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology

I concur with the analysis and recommendations regarding tax subsidies for an Alaska natural gas pipeline contained in this paper without great enthusiasm. I would have preferred the Commission to wait to release a comprehensive peer reviewed paper on natural gas supply, demand and infrastructure investment issues that reflected a more complete analysis of natural gas markets, market imperfections and regulatory barriers affecting infrastructure investment, and a range of policy options. Nevertheless, I believe that this "interim" paper can provide useful information to inform the current debate about government support for an Alaska natural gas pipeline in particular, and to begin to articulate a public interest framework for properly evaluating proposals for direct and indirect government subsidies more generally. I have voted for releasing the paper primarily for these reasons.

There are several aspects of the analysis and recommendations contained in the paper that I want to emphasize. First, the paper makes clear the Commission's reluctance to rely on direct and indirect government subsidies. The public interest case for subsidies should be based on the presence of significant market imperfections or regulatory barriers that are adversely distorting private investment decisions and that superior policy interventions to mitigate these imperfections and barriers are unavailable. The recommendations in the paper are based on the conclusion that it is more likely than not that certain market imperfections and regulatory barriers associated with the unsettled state of natural gas and electricity markets, whose effects are compounded by the attributes of a project of this size, lead to a gap between private investment incentives and the expected societal value of the Alaska pipeline. Second, while the paper analyzes a particular contingent tax credit proposal, it does not endorse a specific trigger price for the credit. Based on the analysis upon which this paper relies, it appears to me that a lower trigger price may be justified. In addition, I see no reason why the State of Alaska should not share the costs of any subsidies provided to the pipeline since it will benefit from royalty payments produced by sales of Alaskan natural gas. Third, the analysis contained in the paper indicates that the expected costs of the tax credit will be very low, consistent with the net benefit calculations presented and the view that it is basically an insurance policy against a low gas price trajectory that has a low probability. These results, of course, depend on a large number of assumptions about gas supply costs, gas demand, and the cost of the pipeline. If additional analyses indicate that the expected cost of the tax credit is significantly higher than the estimates contained in the paper it would either seriously undermine the case that the pipeline is a wise investment or suggest that the tax credit is providing unreasonably large subsidies to Alaskan gas producers. Finally, despite the fact that the analysis contained in this paper focuses on the "southern" route, I believe that government policies should not favor one pipeline route over another and that any tax breaks should be route-neutral.

Martin B. Zimmerman joins in this concurrence.

Group Vice President, Corporate Affairs, Ford Motor Company

Concurrence from Commissioner Archie W. Dunham
Chairman, ConocoPhillips

I strongly concur with the recommendation of the Commission. My company, ConocoPhillips, would benefit if a low-price tax credit mechanism were incorporated into law; however, the public will benefit even more generously as they will have access to an important new natural gas supply. Without the low-price tax credit provision, the pipeline will not be built.

Appendix A: Description of EEA Modeling Analysis

Appendix A: Description of EEA Modeling Analysis

In order to assess the impacts of an Alaskan natural gas pipeline, the Commission contracted Energy and Environmental Analysis, Inc. (EEA) to construct and model several natural gas market scenarios. The scenarios were completed using EEA's Gas Market Data and Forecasting System, which is discussed in detail in this document. A Reference scenario, including a 4 Bcfd Alaskan gas pipeline beginning operation in late 2013, was developed based on EEA's current base case forecast for the North American gas market. Each of the alternate scenarios presented and discussed either increase or decrease gas supply and/or gas demand using the Reference scenario as a starting point.

The first alternate scenario presented projects natural gas supply, demand, and prices without the Alaska pipeline, that is, the Alaskan gas pipeline is removed from the Reference scenario. The other alternate scenarios examine five important variables to assess their impact on future natural gas prices. The variables include:

1) Economic activity, as measured by growth in GDP and industrial production;
2) Crude oil prices;
3) LNG imports;
4) Natural gas production levels in the Lower 48 and Canada, and;
5) End-use efficiency and fuel switching capability.

Impact of Alaskan Gas

The first part of this analysis examined two scenarios:

1) Reference Scenario – Alaska natural gas is delivered into western Canada and the Lower-48 U.S. beginning in late 2013. The analysis assumes the pipeline begins operation in the 4th quarter of 2013. Production is ramped up gradually, with the full 4.0 Bcf/d delivery beginning in the 4th quarter of 2014.

2) No Alaska Scenario – Construction of an Alaskan natural gas pipeline is delayed or abandoned altogether and Alaskan natural gas remains stranded in Alaska through 2025.

The presence of the pipeline and access to Alaskan natural gas supplies has a significant impact on natural gas prices throughout Canada and the U.S. The price impacts are highest in the first two years after the pipeline is completed, with Henry Hub[16] prices falling by approximately $2.00 per million Btu. As other non-Alaskan natural gas production throughout North American responds to the additional supplies from Alaska and lower natural gas prices, the price differential between the two scenarios narrows.

Alternative Scenarios

The alternate scenarios modeled and studied here can be divided into two major groups, as shown in Table A-1. The first group, shown in yellow, reduces gas prices relative to the Reference scenario by either decreasing natural gas demand and/or by increasing natural gas supply. The second group of scenarios, shown in light blue, increases gas prices relative to the

[16] Henry Hub, located in Southern Louisiana, is a frequently referenced pricing point for natural gas.

Reference scenario by either increasing natural gas demand and/or by decreasing natural gas supply.

Figures A-1 through A-3 show demand and price results of the alternate scenarios, with Figure A-1 showing a comparison of the price and demand results for the years 2015 to 2025, relative to the Reference Scenario. For that period, gas demand in the Reference scenario averages 34,250 Bcf per year and gas prices at Henry Hub average $4.52 per million Btu. Across all of the alternate scenarios, demands range from 30,950 Bcf, or about 3,300 Bcf per year lower than the Reference scenario, to 35,100 Bcf, or about 800 Bcf higher than the Reference scenario. Prices range from $2.60 per million Btu, or almost $2 per million Btu below the Reference scenario, to $6.12 per million Btu, or almost $2 above the Reference scenario. Not surprisingly, the High and Low Gas Price scenarios bound the price results, although the No Alaska scenario yields the highest gas price in the year 2015.

Table A-1: Summary of Scenarios

Scenario	Economic Environment	Gas Production	LNG Imports	R/C/I Efficiency	Income Elasticity of Electricity Sales	Industrial & Power Generation Fuel Switching	Nuclear Capacity	Renewable Capacity and Generation	Oil Price	Alaska Pipeline
Reference										
No Alaska										No Alaska Pipeline
Low Economic Growth / Low Oil Price	Slower Economic Growth			Increased Efficiency		Greater Flexibility			Averaging $16/bbl	
High LNG Imports			Increased Imports							
Increased Efficiency / Fuel Switching					Increasing Efficiency Yields Lower Income Elasticity		Increased Uprates of Existing Units	Double Reference Case Capacity and Generation		
High Gas Production		Base Value Increased by 5%								
Low Gas Price	Slower Economic Growth	Base Value Increased by 5%	Increased Imports	Increased Efficiency	Increasing Efficiency Yields Lower Income Elasticity	Greater Flexibility	Increased Uprates of Existing Units	Double Reference Case Capacity and Generation	Averaging $16/bbl	
Low LNG Imports			Decreased Imports							
Low Gas Production		Base Value Decreased by 5%								
High Economic Growth / High Oil Price	Faster Economic Growth				Increasing Efficiency Yields Lower Income Elasticity				Averaging $24/bbl	
High Gas Price	Faster Economic Growth	Base Value Decreased by 5%	Decreased Imports		Increasing Efficiency Yields Lower Income Elasticity				Averaging $24/bbl	

Results from the alternate scenarios fall into three groups. Changes that affect gas demands shift the results along the supply curve labeled S1 in Figure A-1, while changes that affect gas supply move results along the demand curve labeled D1. The High Gas Price scenario, which combines changes that increase demand with changes that decrease supply, shifts the results to a higher demand curve labeled D2.

Figure A-1: Comparison of Price and Demand Impacts Relative the Reference Scenario

U.S. & Canada 2015-2025

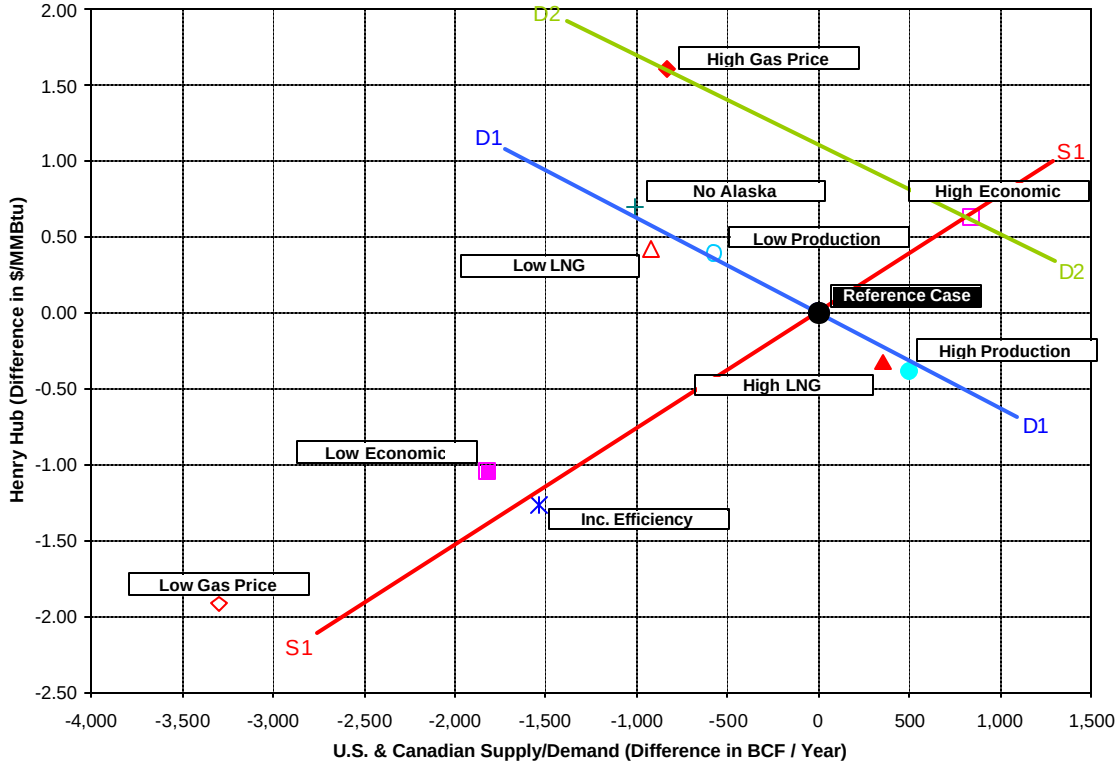
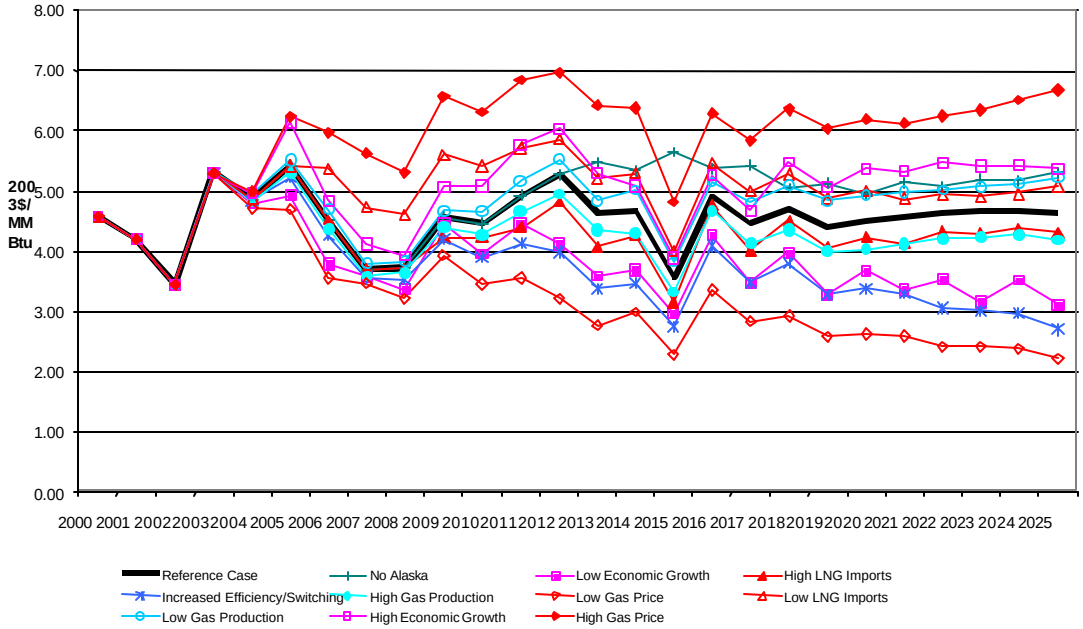
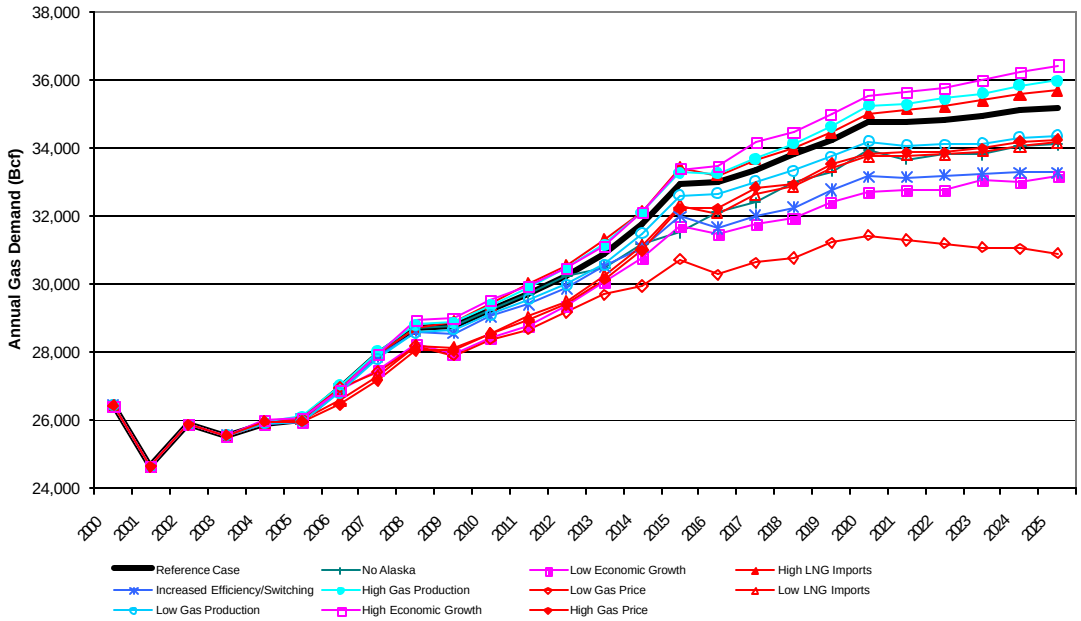


Figure A-2: Henry Hub Gas Prices for Scenarios (2003$ per million Btu)



	2002	2005	2010	2015	2020	2025	2015-2025 Average	Difference from Reference Case
Reference	3.44	5.41	4.45	3.56	4.50	4.64	4.52	NA
No Alaska	3.44	5.41	4.45	5.65	4.93	5.31	5.22	0.70
Low Economic Growth	3.44	4.92	3.95	2.97	3.67	3.11	3.48	-1.04
High LNG Imports	3.44	5.41	4.23	3.15	4.23	4.30	4.19	-0.33
Increased Efficiency/Switching	3.44	5.23	3.91	2.75	3.39	2.70	3.26	-1.26
High Gas Production	3.44	5.31	4.27	3.32	4.03	4.18	4.14	-0.38
Low Gas Price	3.44	4.69	3.45	2.28	2.63	2.22	2.60	-1.92
Low LNG Imports	3.44	5.41	5.41	4.00	5.01	5.07	4.94	0.42
Low Gas Production	3.44	5.50	4.66	3.82	4.92	5.23	4.91	0.39
High Economic Growth	3.44	6.14	5.07	3.88	5.36	5.37	5.15	0.63
High Gas Price	3.44	6.22	6.31	4.81	6.19	6.67	6.12	1.60

Figure A-3: U.S. and Canada Gas Demand for Scenarios (Billion Cubic Feet per Year)



	2002	2005	2010	2015	2020	2025	2015-2025 Average	Difference from Reference Case
Reference	25,868	26,016	29,243	32,937	34,759	35,151	34,247	NA
No Alaska	25,868	26,016	29,243	31,491	33,940	34,094	33,239	-1,008
Low Economic Growth	25,868	25,944	28,387	31,686	32,689	33,179	32,418	-1,829
High LNG Imports	25,868	26,016	29,398	33,394	34,996	35,672	34,596	349
Increased Efficiency/Switching	25,868	26,038	29,032	31,967	33,155	33,252	32,707	-1,540
High Gas Production	25,868	26,095	29,373	33,263	35,227	35,950	34,742	495
Low Gas Price	25,868	26,032	28,374	30,712	31,421	30,902	30,949	-3,298
Low LNG Imports	25,868	26,016	28,536	32,291	33,726	34,134	33,324	-923
Low Gas Production	25,868	25,947	29,101	32,595	34,182	34,334	33,670	-577
High Economic Growth	25,868	26,044	29,520	33,366	35,535	36,413	35,076	829
High Gas Price	25,868	25,967	28,534	32,196	33,793	34,245	33,414	-834

Low Economic Growth/Low Oil Price

This scenario reduces the annual GDP growth rate by 0.5 percentage points, from 2.8 percent to 2.3 percent. Growth rates for industrial production and Canadian economic activity have been reduced proportionately. The forecast value for the refiner's average cost of crude (RACC) was reduced by $4.00 to average $16.00 per barrel over the forecast period in response to the lower economic growth.

These changes decrease demand by over 1,800 Bcf per year versus the Reference scenario. Most of the change occurs in the power sector, which uses 1,300 Bcf less gas per year than in the Reference scenario. Industrial gas demand is also down versus the Reference scenario, but only slightly. The lower gas prices in the scenario tend to yield less demand destruction in the industrial sector.

High LNG Imports

The High LNG Imports scenario adds 2.5 Bcfd of LNG imports to the Reference scenario, mostly on the Gulf Coast. The increase in LNG imports decreases gas prices by an average of $0.40 from 2015 to 2025, versus the Reference scenario. Conversely, demand increases by 400 Bcf per year over the period in response to the lower gas prices. The lower gas prices tend to dampen development of U.S. and Canadian gas supplies slightly, reducing production by about 400 Bcf, or by approximately half of the increase in LNG imports. Most of the increase in gas demand in this scenario versus the Reference scenario occurs in the price-sensitive industrial and power sectors.

Increased Efficiency and Increased Fuel Switching

This scenario assumes a number of changes to represent a lower gas demand growth environment due to increasing efficiency in energy use (both gas and electricity) and greater flexibility in fuel choices in the industrial and power sectors. An increased penetration rate for new equipment and appliances combines with conservation measures to reduce the growth rates of gas and electricity sales in the residential and commercial sectors. In power generation, coal-based capacity additions are increased by 35 gigawatts, and gas-based combined cycle additions are reduced by the same amount, based on an assumption that siting coal capacity is more favorable than in the current environment. Nuclear capacity is increased by 10 gigawatts, assuming an aggressive program to upgrade existing units. Renewable capacity and generation penetrate the market at double the rate assumed in the Reference scenario, assuming more aggressive state implementation plans for non-fossil generation. Fuel switching capacity of the fleet of combined cycle and combustion turbines increases by 12 percent, assuming relaxed permitting of oil burning capability. In the industrial sector, fuel switchability in industrial boilers is increased to ¼ of the boiler stock (versus only 5 percent in the Reference scenario). Last, energy intensity has been reduced, assuming a greater penetration of more efficient manufacturing capacity.

As a result of these changes, demand in the power sector is down by nearly 2,000 Bcf per year versus the Reference scenario. Despite the increased efficiency assumed in the industrial sector, the lower gas prices lead to a net increase in industrial gas demand over the Reference scenario. The residential and commercial sectors reduce their demand only slightly versus the Reference scenario, as a slight rebound in demand due to lower gas prices offsets some of the reductions due to increased efficiency. Overall, gas demand in this scenario is about 1,500 Bcf per year less than demand in the Reference scenario, and gas prices are lower by about $1.25 per million Btu.

High Gas Production

This scenario increases base values for productive capacity of gas wells in the Lower-48 and Canada (excluding frontier areas) by 5 percent. The increase in productive capacity reduces gas prices by $0.40 per million Btu, versus the Reference scenario. The lower gas prices have a negative impact on gas production, so the 5 percent increase in productive capacity yields only a 2.5 percent increase in forecast gas production. Gas demand increases by an average of 500 Bcf per year, versus the Reference scenario.

Low Gas Price

The Low Gas Price scenario combines the features of the Low Economic Growth, High LNG Imports, Increased Efficiency and Increased Fuel Switching, and High Gas Production scenarios.

The lower economic growth rate combined with increased efficiency and increased fuel switching has a significant impact on power sector gas use. Electricity sales, which are a function of economic growth and the efficiency assumptions, are more than 12 percent lower than in the Reference scenario. The lower demand for electricity combined with increased availability of nuclear and renewable generation lead to a 3,300 Bcf per year decrease in the forecast gas demand for power generation, roughly equal to the total decrease in gas use versus the Reference scenario. The low gas prices, which are nearly $2 per million Btu below Reference scenario gas prices, push commercial and industrial gas demand slightly higher than levels observed in the Reference scenario.

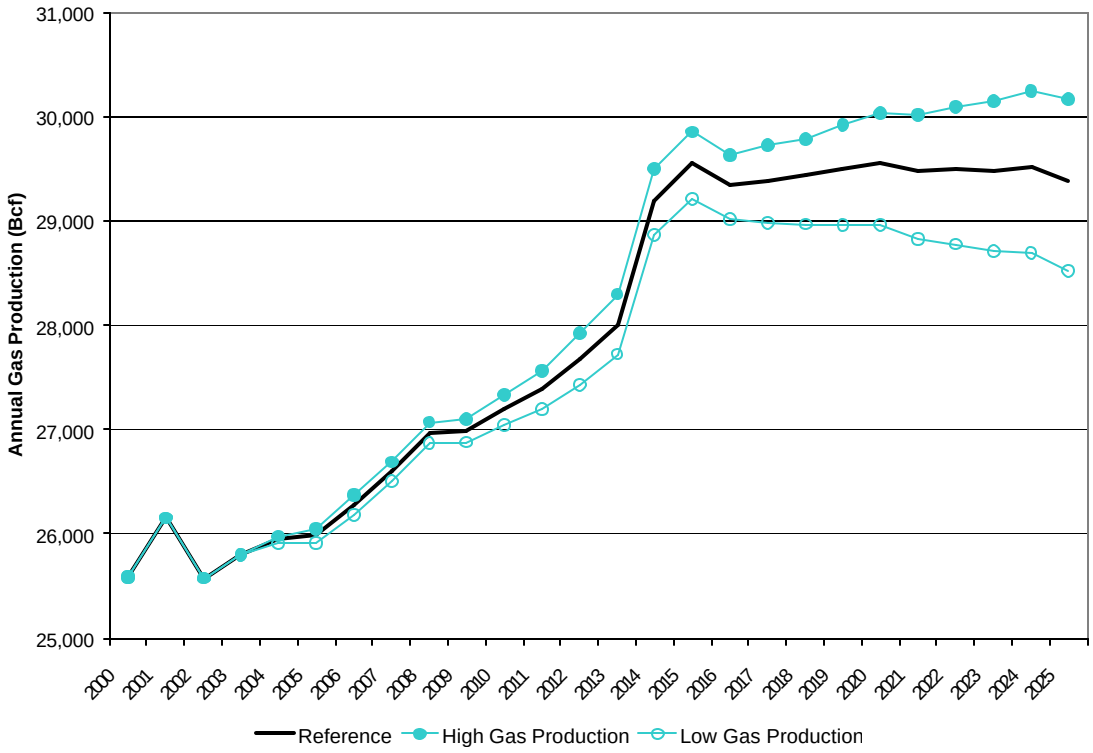
Low LNG Imports

This scenario removes 4 Bcfd of LNG imports by 2025 from the reference scenario, all on the east and west coasts, assuming an unfavorable environment for siting new LNG import facilities. This change increases gas prices by an average of $0.40 per million Btu and reduces gas demand by over 900 Bcf per year versus the Reference scenario.

Low Gas Production

This scenario decreases the base values for productive capacity of gas wells in the Lower-48 and Canada (excluding frontier areas) by 5 percent. The decrease in productive capacity increases gas prices by $0.40 per million Btu versus the Reference scenario. However, since production tends to increase as gas prices move higher, the 5 percent decrease in productive capacity yields only about a 2.6 percent decrease in forecast gas production. Figure A-4 contrasts the gas production results in this scenario with the gas production results in the Reference and High Gas Production scenarios. In response to the lower gas production and higher gas prices, gas demand decreases by an average of 500 Bcf per year versus the Reference scenario, primarily in the industrial and power sectors.

Figure A-4: U.S. and Canadian Gas Production for Different Scenarios



High Economic Growth/High Oil Price

This scenario increases the annual GDP growth rate by 0.5 percentage points, from 2.8 percent to 3.3 percent. Growth rates for industrial production and Canadian economic activity have been increased proportionately. The forecast value for the refiner's average cost of crude (RACC) has been increased by $4.00 to average $24.00 per barrel over the forecast period in response to the higher economic growth. In addition, the efficiency of electricity consumption has been increased to reduce the impact of higher GDP on electricity sales growth; the increase in 2025 electricity sales versus the Reference scenario has been limited to 200 million kWh. Power generation capacity has been increased to meet the additional electricity demand.

The increased economic growth and oil prices increase gas demand by over 800 Bcf per year, versus the Reference scenario. Some of the potential increase in gas demand is offset by greater efficiencies in the power sector, which tend to reduce some of the increase in electricity sales resulting from higher economic growth. Still, the majority of the increase in gas demand is concentrated in the power sector, where gas use exceeds Reference scenario gas use by over 400 Bcf. Gas prices are $0.60 per million Btu higher than in the Reference scenario, which tends to motivate gas to oil switching, offsetting some of the economy-motivated increases in gas demand in this scenario.

High Gas Price

The High Gas Price scenario combines the increased demand and decreased supply features of the Low LNG Imports, Low Gas Production, and High Economic Growth scenarios.

The combined decrease in supply pushes gas prices up by $1.60 per million Btu while gas demand drops by over 800 Bcf per year versus the Reference scenario. Versus the Reference scenario, reduced gas use is concentrated in the industrial and power sectors, where high gas prices motivate switching to oil. As a result, oil consumption in the power sector increases by nearly 900 trillion Btus by 2025, versus the Reference scenario. There is also a significant increase in coal consumption as generation shifts away from gas at higher gas prices.

EEA's Gas Market Data and Forecasting System

EEA's *Gas Market Data and Forecasting System (GMDFS)*, a nationally recognized modeling and market analysis system for the North American gas market was used to obtain the scenario results presented in this report. EEA's GMDFS was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. For example, much of the initial work with the model in 1996-97 focused on measuring the impact of the recently completed Alliance pipeline. The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance? If not, when will demand support Alliance?
- Will supply be adequate to fill Alliance? If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, EEA's model has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of power generation growth, and carbon reduction of the gas market
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

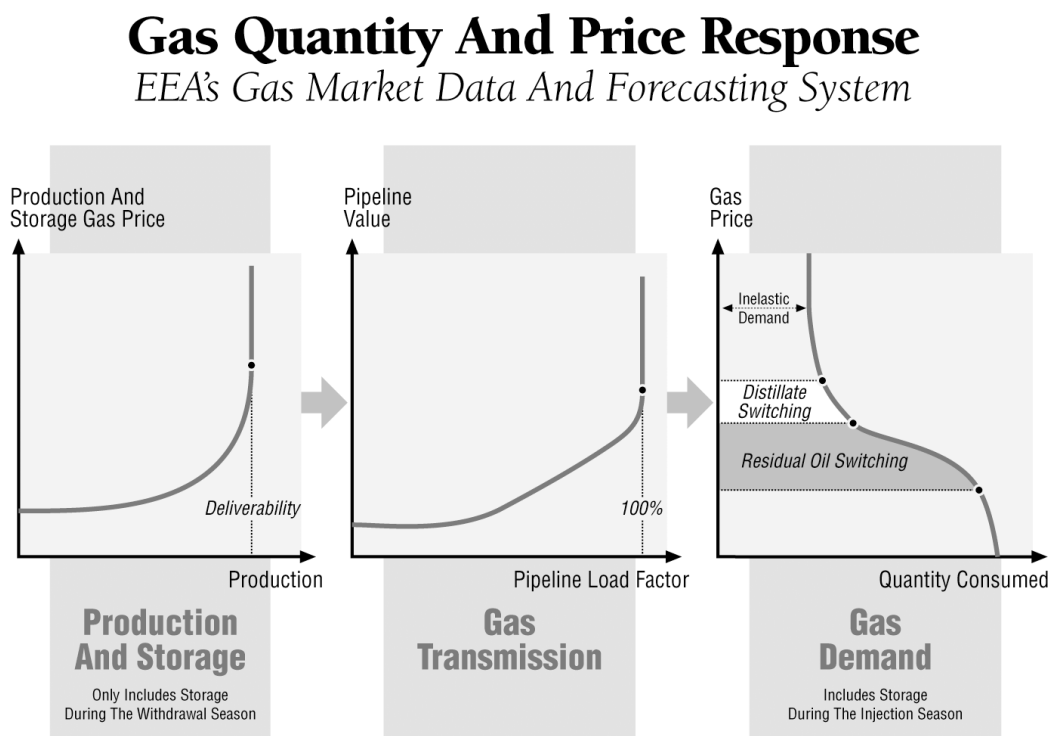
In addition to its use for strategic planning studies, the EEA model has been widely used by a number of institutional clients, including *INGAA*, who relied on the model for the 30 Tcf market analysis completed in 1998. *INGAA* is currently relying on the model for an update to the 30 Tcf market analysis. *GRI* has relied on EEA mode for the *GRI Baseline Projection*. The model was the primary tool used to complete the widely referenced study of the North American Gas

Market for the *National Petroleum Council* in 1999, and the primary tool used to complete the 30 Tcf market analysis for *INGAA* in 1998.

EEA's *Gas Market Data and Forecasting System* is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solve for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure A-5). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, EEA does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

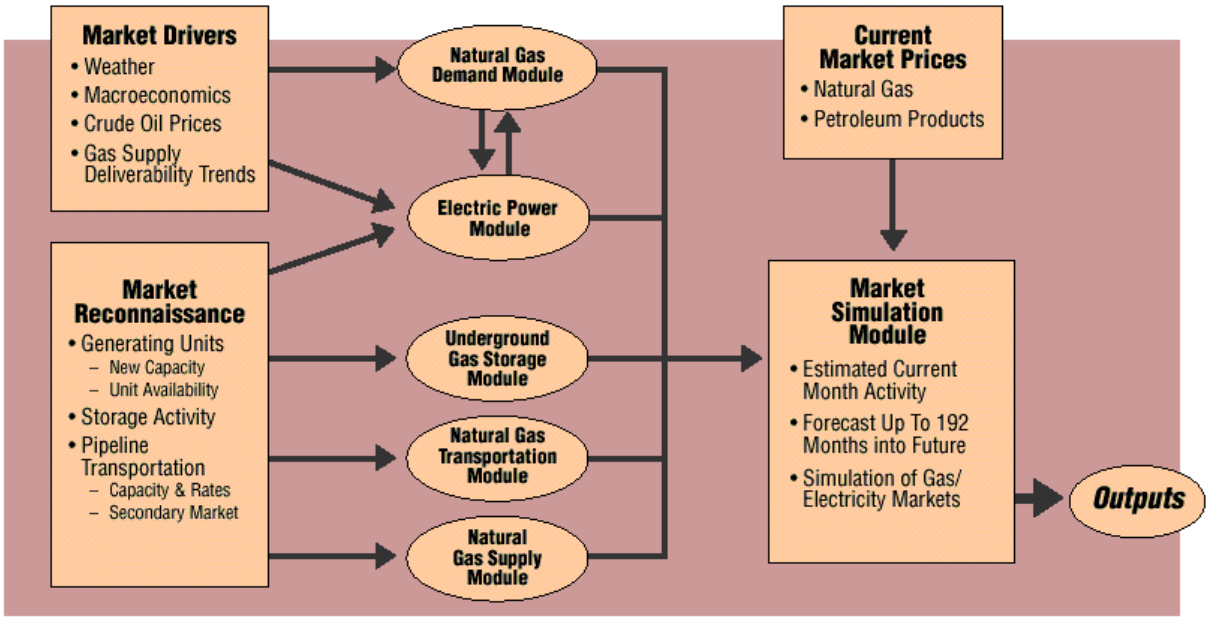
Figure A-5: Supply/Demand Curves



There are nine different components of EEA's model, as shown in Figure A-6. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. EEA's

market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Figure A-6: GMDFS Structure



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure A-7 and the nodes are identified by name in Table A-2. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. A few other charts that summarize input/output and regional breakout for the EEA Model are shown as Figures A-8 through A-12.

The EEA model resides on a MS-Windows PC. The model relies on easy-to-use MS-Excel and MS-Access programs developed by EEA. Contact EEA at (703) 528-1900 or at inquiries@eea-inc.com for more information about the EEA modeling system.

Figure A-7: GMDFS Transmission Network

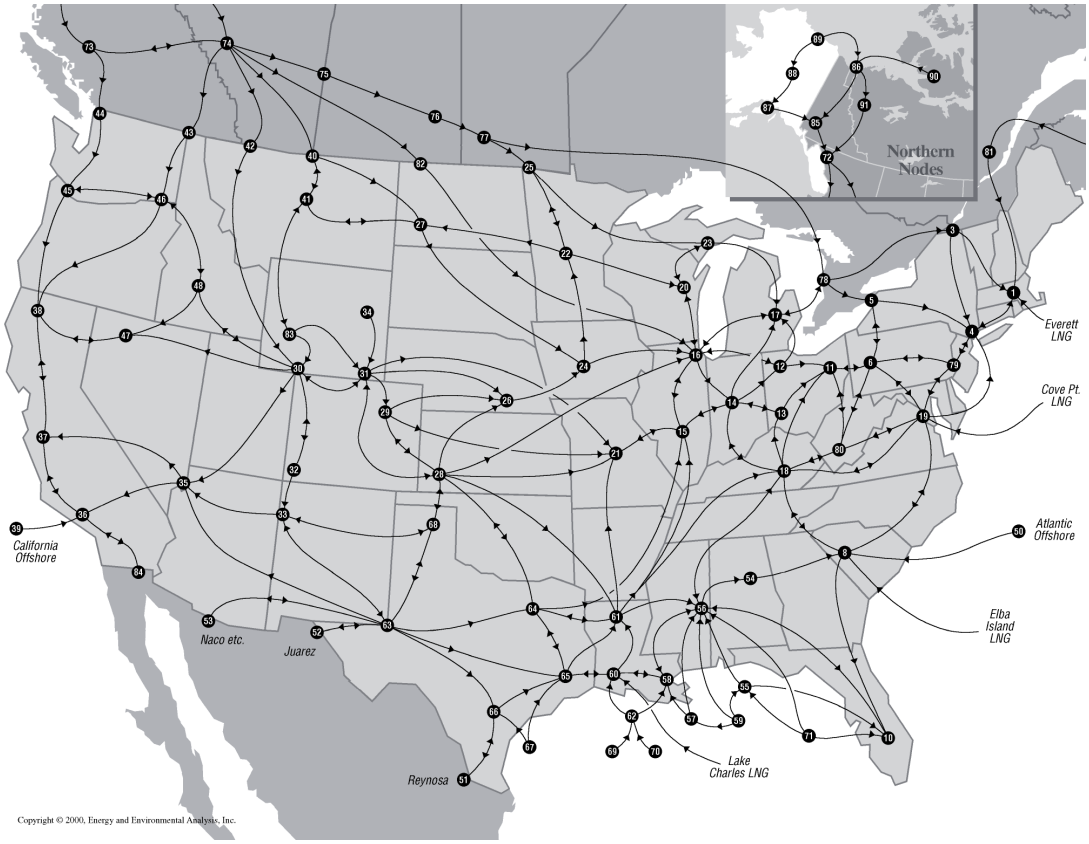


Figure A-8: Model Input/Output

Model Drivers And Output

R/C/I Natural Gas Demand

DRIVERS	OUTPUT
• Heating Degree Days • Economic Activity • Gas & Petroleum Prices	► *Residential, Commercial, & Industrial Gas Demand*

Gas Supply

DRIVERS	OUTPUT
• Base Deliverability Trends • Gas Prices • LNG Supply	► *Natural Gas Production* ► *Wellhead and Gathering System Deliverability*

Gas Transportation

DRIVERS	OUTPUT
• Pipeline Capacity – *Existing Capacity* – *Capacity Expansions* – *Operating Conditions* • Transportation Rates – *FERC Tariffs* – *Discounted Rates* – *Brokered Capacity Prices*	► *Flow on pipeline corridors* ► *Value of gas transmission, i.e. forecast rates based on corridor load factors.*

Electric Utility Gas Demand

DRIVERS	OUTPUT
• Total Electricity Generation • Non-fossil Generation • Unit Availability – *New Capacity On-Line* – *Scheduled Downtime* – *Maintenance & Availability Conditions* • Fuel Prices • Heating & Cooling Degree Days • Economic Activity	► *Gas Consumed by Power Generators*

Gas Storage

DRIVERS	OUTPUT
• Storage Capacity • Deliverability	► *Storage Inventory*
• Withdrawal Season: – *Market Demand* – *Usage Patterns* – *Cycling Requirements*	► *Net Storage Injections/Withdrawals*
• Injection Season: – *Inventory Targets* – *Refill Patterns* – *Spot/Futures Price Spread*	► *Net Storage Injections/Withdrawals*

Figure A-9: Model Input/Output

Outputs Of The Forecasting System

Monthly Data	*DATA CONTENT*	*GEOGRAPHIC DETAIL OF DATA*
Gas Pricing	Delivered to Pipeline and Citygate Prices	91 Points
Pipeline Transportation	Inter-Regional Capacity Tariffs Caps Market Value of Capacity	215 Network Corridors
Gas Storage	Working Gas Capacity Inventories Injection /Withdrawal Activity	26 Storage Regions
Natural Gas Demand	By Sector (R/C/I)	32 U.S. Regions and 7 Canada/Alaska Regions
Natural Gas Supply	Deliverability Dry Production Gas Imports/Exports Supplemental Fuels	32 U.S. and 6 Canada/Alaska Regions
Electricity Markets (U.S. Only With Explicit Imports)	Natural Gas Demand Electricity Demand Power Generation Balance Gas-fired Generation	10 "NERC" Regions

Figure A-10: Demand Regions

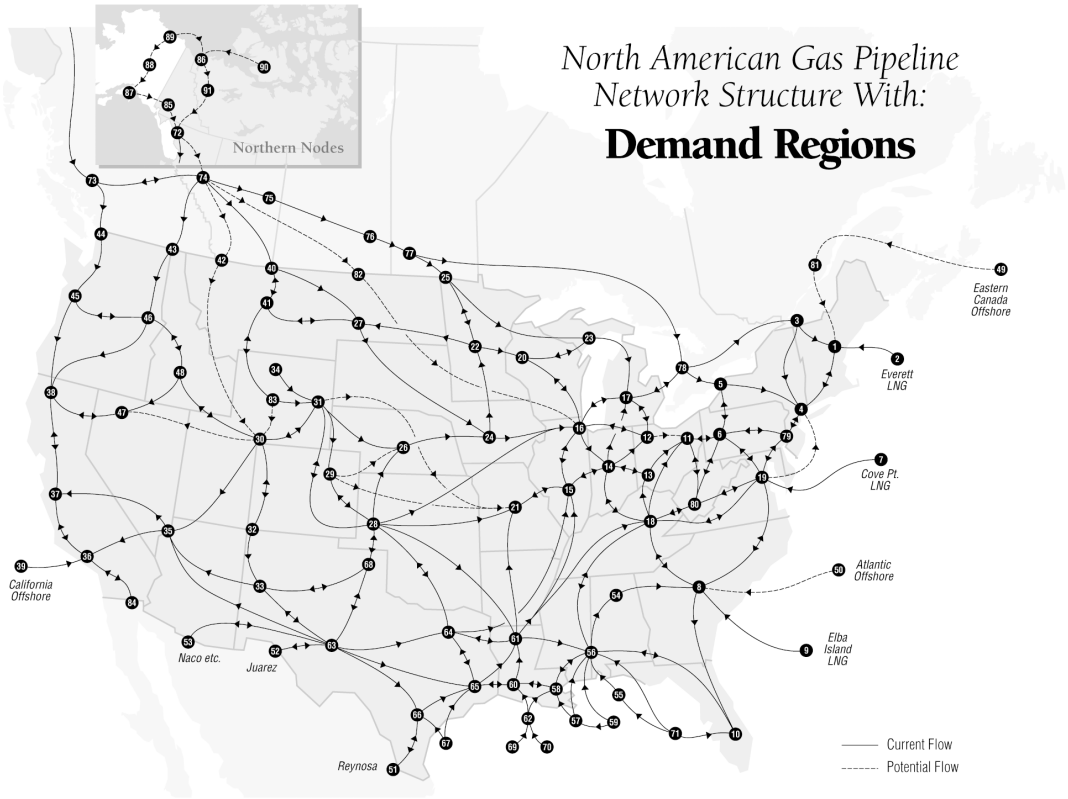


Figure A-11: Production Regions

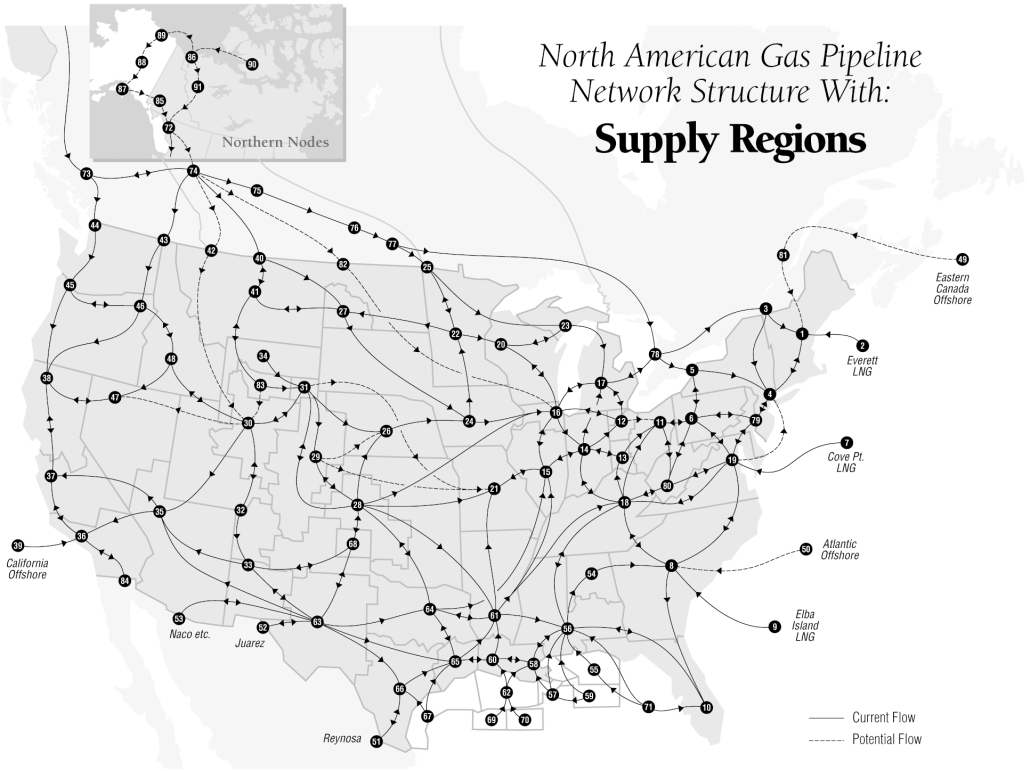


Figure A-12: Storage Regions

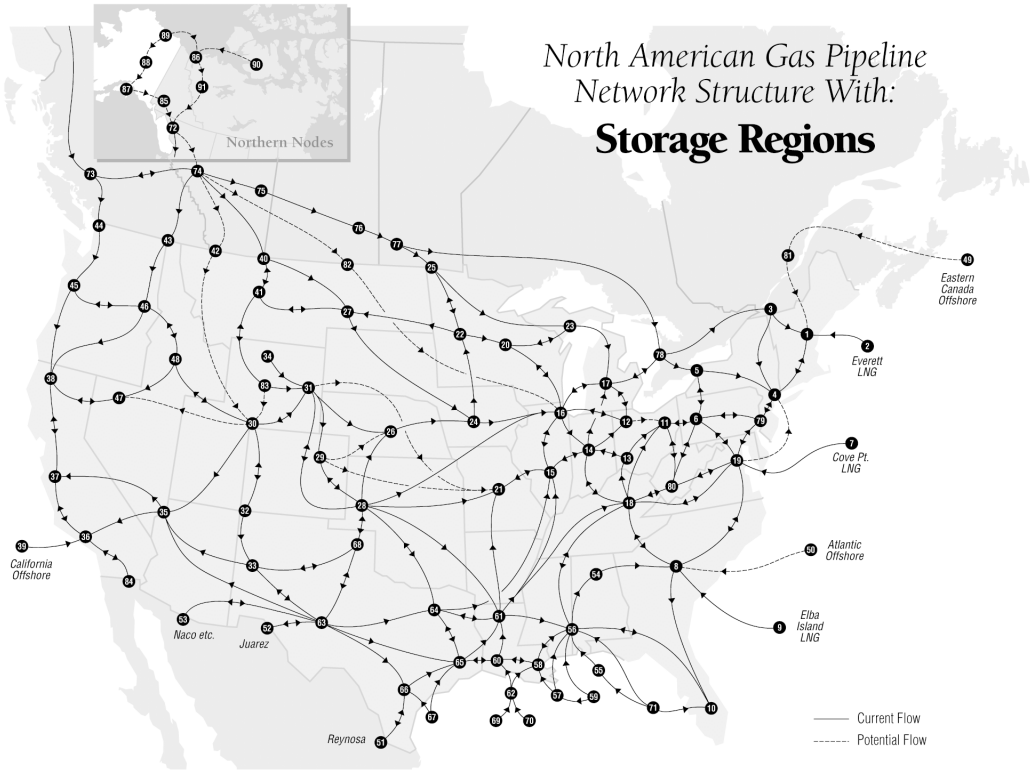


Table A-2: GMDFS Network Node List

Node	Name
1	New England
2	Everett LNG
3	Quebec
4	New York City
5	Niagara
6	Leidy
7	Cove Point LNG
8	South Atlantic
9	Elba Island LNG
10	Florida
11	East Ohio
12	Maumee/Defiance
13	Lebanon
14	Indiana
15	South Illinois
16	North Illinois
17	Michigan
18	Tennessee/Kentucky
19	DELMARVA
20	Wisconsin
21	Missouri
22	Minnesota
23	Crystal Falls
24	Ventura
25	Emerson Imports
26	Nebraska
27	Great Plains
28	OK/KS
29	East Colorado
30	Opal
31	Cheyenne
32	San Juan Basin
33	EPNG/TW
34	North Wyoming
35	South Nevada/Arizona
36	SOCAL Area
37	Enhanced Oil Recovery Region
38	PGE Area
39	Pacific Offshore
40	Monchy Imports
41	Montana/North Dakota
42	Wild Horse Imports
43	Kingsgate Imports
44	Huntingdon Imports
45	Pacific Northwest
46	NPC/PGT Hub
47	North Nevada
48	Idaho
49	Eastern Canada Offshore
50	Atlantic Offshore
51	Reynosa Imp/Exp
52	Juarez Imp/Exp
53	Naco Imp/Exp
54	North Alabama
55	Alabama Offshore
56	Mississippi/South Alabama
57	East Louisiana Shelf
58	Eastern Louisiana Hub
59	Viosca Knoll S./Desoto & MS Canyon
60	Henry Hub
61	North Louisiana Hub
62	Central and West Louisiana Shelf
63	Southwest Texas
64	NE TX (Carthage)
65	E. TX (Katy)
66	S. TX
67	Offshore Texas
68	NW TX
69	Garden Banks
70	Green Canyon
71	Eastern Gulf
72	North British Columbia
73	South British Columbia
74	Caroline
75	Empress
76	Saskatchewan
77	Manitoba
78	Dawn
79	Philadelphia
80	West Virginia
81	Eastern Canada Demand
82	Alliance Border Crossing
83	Wind River Basin
84	S. CA Mexican Exports
85	White Horse/Yukon
86	McKenzie Delta
87	S. Alaska
88	Central Alaska
89	N. Alaska
90	Arctic
91	Norman Wells

U.S. RELIANCE ON INTERNATIONAL LIQUEFIED NATURAL GAS SUPPLY

A POLICY PAPER PREPARED FOR THE

NATIONAL COMMISSION ON ENERGY POLICY

February 2004

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I. EXECUTIVE SUMMARY

Principal Conclusions

- LNG will play a significant role in supplementing U.S. gas supply, but that role is widely misunderstood
- While substantial growth in LNG imports will add to North American gas supply and thus moderate the pressures for higher prices, it will not serve to "cap" U.S. prices at some predetermined LNG cost level; LNG is inherently a "price taker", not a "price maker", and its influence on prices will be determined by how many suppliers are willing to compete for growing demand in the U.S. and how rapidly they make that supply available
- Since the lion's share of the capital expenditures required to provide LNG supply are upstream of the receipt terminal in production facilities, liquefaction plants and tankers, developments upstream are likely to have a much greater effect on the availability of LNG to the U.S. than the widely discussed terminal siting issue
- The U.S. will be in competition with other markets, such as Europe and Asia for LNG; while it is clear that the U.S. cannot import LNG if it does not have the receipt terminal capacity, a solution to the terminal siting problem does not guarantee supply; it simply gives the U.S. a seat at the table to compete with other markets for that supply
- While international LNG markets will undergo substantial liberalization, the long term contract is not dead and will continue to act as a "filter" to determine the flow of new LNG projects into the marketplace
- The linkage between gas and oil prices was explicit in the traditional long term contract; the worldwide move to restructure the gas industry has removed the direct contractual linkage in favor of a more complex one based on interfuel competition; it appears that the competitive relationship between gas and oil pricing is itself volatile and when superimposed on the existing volatility of oil markets, it suggests that gas prices may continue to remain more volatile than oil prices; they may at times also be subject to oil price shocks
- U.S. industrial competitiveness with Europe and Asia has been prejudiced by the rapid rise in prices; while LNG benefits from the higher price levels we now experience, it did not cause them; a specific cause for concern about reliance on LNG is that the U.S. tends to be more distant from most supply sources than its competitors, a distinct disadvantage in an industry with inherently high transportation costs
- The increased reliance on imported gas supply clearly has national security implications; however, the sources of LNG are somewhat different from the major sources of imported oil, providing a degree of risk diversification
- One of the greatest barriers to terminal siting is the public concern for LNG safety; there is a great deal of misinformation in the public domain about this issue which tends to cloud the public discussion; since industry tends to lack the credibility to address the problem, it suggests the need for a government-sponsored information agency to provide factual support for the debate; such an agency could sponsor safety research where it appears to be needed

Summary

Since the "gas shock" of the winter of 2000/2001, LNG has become the "fashionable" new source of energy for U.S. markets. The most recent Annual Energy Outlook 2004 (released in December 2003) of the Energy Information Administration foresees a level of gross imports of LNG of 6.1 Bcfd by the year 2010, implying a growth rate of over 25% per year for the decade. The recently released study of natural gas by the National Petroleum Council was even more optimistic than the EIA with an estimate of 7.3 Bcfd for 2010 in its "Reactive Path" scenario. As evidence of how dramatic the change in the outlook for LNG has been, as recently as the 2001 AEO, the EIA was anticipating a demand of only 1.5 Bcfd for 2010.

Figure 1-1 illustrates the changing perceptions about the role of natural gas in the U.S. energy economy and of LNG in natural gas supply. It compares the EIA's 2001 Annual Energy Outlook projections (made before the price shock of the winter of 2000) with its most recent AEO 2004. In 2001, the EIA expected natural gas to represent 28.0% of primary energy consumption by 2020. It has now reduced that estimate to 24.4%. However, it has raised its estimate of gross[1] LNG imports in 2020 by nearly six times while cutting the earlier estimate of Canadian imports by more than half.

The strong interest in LNG obviously reflects the forecasters' growing pessimism about the ability of North American gas supply to sustain the substantial projected increase in gas demand primarily for power generation. But it also reflects some significant positive changes within the LNG industry itself. The development of combined cycle gas turbine technology (CCGT) has made natural gas the fuel of choice throughout the world for the generation of electricity. A substantial reduction in LNG costs has made previously uneconomic LNG trades now economic. And oil companies that once treated international gas discoveries as "dry holes" now speak of the necessity of finding ways to monetize "stranded gas assets".

But for all of the enthusiasm for LNG, there remains a widespread lack of understanding of the way in which this complex international business functions. However, it is critically important to understand its complexity if one is to make a realistic judgment of the role that LNG is likely to play in the U.S. energy mix. This paper attempts to advance this understanding by providing a general overview of the industry while addressing several key issues surrounding the potential growth of the LNG industry in the U.S. and the implications of this growth.

Most U.S. analyses of the likely growth of LNG imports are highly introspective, focusing on future North American gas prices and the likely construction of import terminal capacity. There is a widespread tendency to assume that if the terminal siting controversy can be resolved, LNG will flow into the U.S. at some price to offset any shortfall in other sources of natural gas. But such an assumption ignores the critical importance of decisions taken upstream to make that supply available and those taken in other consuming countries to compete with us for the available supply.

The LNG business has been described as a "chain" whose ultimate success is at risk to the possible failure of its weakest link. There are four principal links to the LNG chain - field development, liquefaction, tanker transportation, and regasification. In some cases a pipeline may also be required to move the gas from the field to a coastal liquefaction facility. Despite all of the attention being paid to the terminal siting issue in the U.S., terminals are a comparatively small part of the capital investment required for the total LNG chain. They are the "tail"; the "dog' is upstream. In a typical capital investment commitment for expanded LNG deliveries, terminals

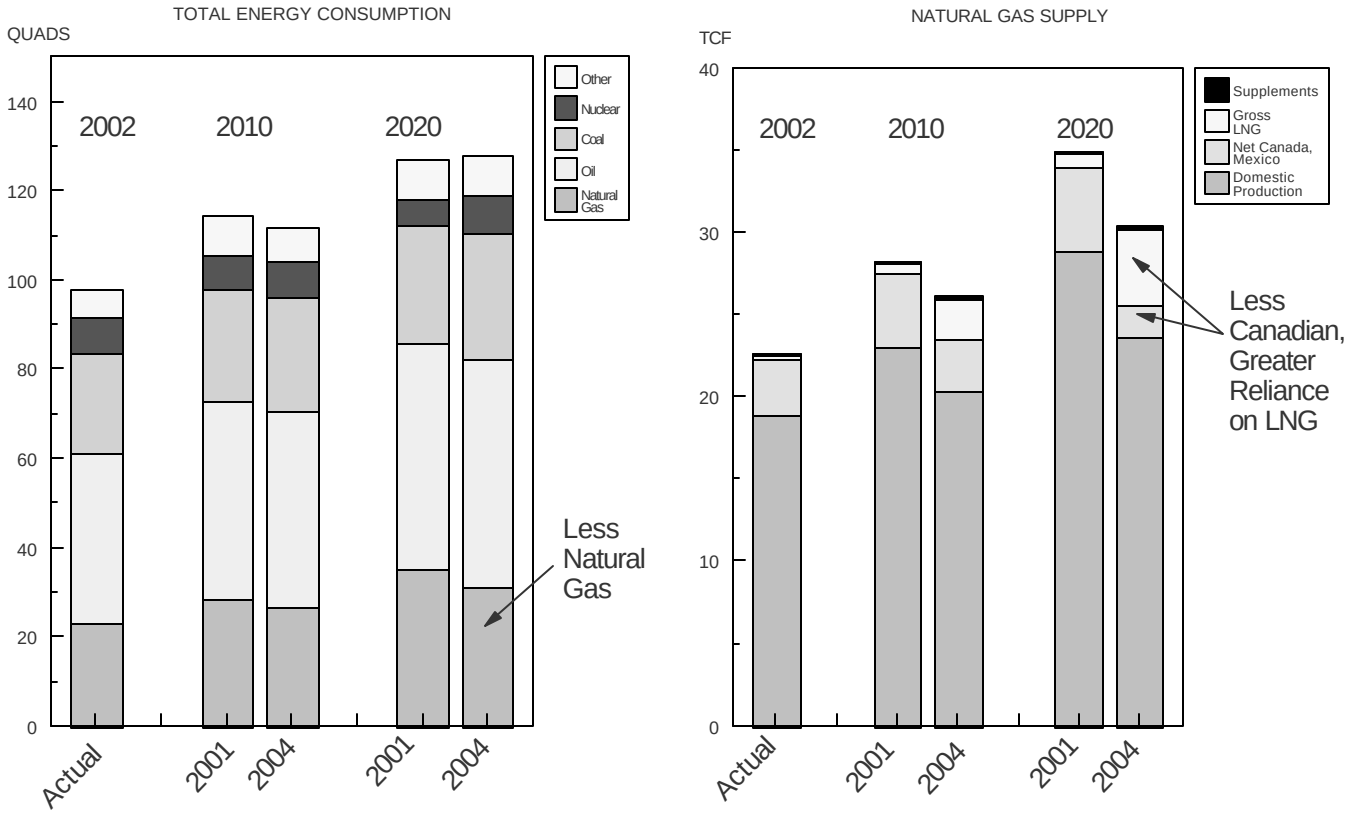
[1] The reported net LNG estimates have been corrected to a gross basis by adjusting for LNG exports to Japan and LNG imports into California by pipeline from Mexico

Figure 1-1

THE CHANGE IN PERCEPTION ABOUT ENERGY AND NATURAL GAS

TWO EIA ANNUAL ENERGY OUTLOOK FORECASTS COMPARED

AEO 2001 VERSUS AEO 2004



represent only 10% to 12% of the total CAPEX. Field development and liquefaction - both sited in the producing country - may represent 50% to 60% of the total, with tankers accounting for the remainder. The fact that more than half of the CAPEX are located in the producing country emphasizes the fact that the often complex negotiations to initiate an LNG liquefaction project - commonly including the producing government as a critical stakeholder - are often the key to how much and how quickly LNG supply will be made available for world markets.

The LNG chain has traditionally been held together by a complex system of risk sharing agreements, of which the Sale and Purchase Agreement (SPA) between an LNG seller and buyer was the centerpiece. The SPA was a long term contract, usually of twenty years or more. In it the buyer guaranteed that he would take a specified minimum volume regardless of market conditions through the medium of a take-or-pay clause and the seller guaranteed that he would take the risk of changes in world energy prices through the medium of a price escalation clause. These price escalation clauses have typically been tied to oil prices as a measure of fluctuations in world energy price levels. The contracts were fairly rigid, typically linking specific gas reserves, liquefaction capacity, tankers, and regasification facilities to the contract.

Throughout most of the 1980s and 1990s, LNG trade was predominantly an Asia Pacific phenomenon, with Japan as the focus of activities. As recently as 1996, LNG imports into Japan, Korea and Taiwan accounted for 78% of world LNG trade. Japan alone accounted for 62%. But within the past six years, Europe together with the U.S. have accounted for nearly half of incremental growth in LNG demand.

The opening up of LNG markets east of Suez comes at a time when the U.S., in particular, has led the move toward a restructuring of its gas industry, a market pattern that is antithetical to the inflexible long term contract structure. Thus the traditional way of doing business in LNG is confronting a highly flexible, short term market that features a large percentage of spot trading, some short term contracts, and a reliance on gas market indicators, such as the Henry Hub quotation, as evidence of gas-to-gas competitive pricing. This pattern has worked well in the pipeline markets of North America and the U.K. and the one that is emerging on the Continent. It has not yet been really tested in LNG. This confrontation between the old and the new has shifted the balance of risks and rewards among the parties to LNG trade in ways that are not fully understood. Thus the way in which this industry will develop in North America is still far from certain.

LNG has been developing a short term market of its own - although still less than 10% of total trade - giving ammunition to those who believe that the open flexible markets of North America are the wave of the future. But no new LNG project has yet been launched without some long term contract coverage, suggesting that the long term contract in LNG will remain alive and well, if perhaps much more flexible in the future than it has been in the past.

The tendency to focus on the U.S. market and assume that the supply will be there if the U.S. needs it is reinforced by the accounts in the trade press that seem to suggest a large number of projects competing for a limited market. But LNG observers have learned to take these optimistic press reports with a degree of skepticism. With projects typically formed as joint ventures among a number of different partners and with Governments as stakeholders, it is often difficult for the parties to reach a final agreement. LNG projects typically operate much like a game of musical chairs. Those left standing without a contract or an essential partner often abandon their projects.

Many of those who analyze LNG markets maintain a list of LNG projects often breaking them down into “firm”, “probable”, “possible” and “remote” categories. One such analysis, summarized in Chapter 11 of this report, suggests that there are not enough “firm” and “probable” projects in the pipeline to achieve the more optimistic

forecasts of U.S. LNG demand by the year 2010. But such analyses have obvious weaknesses and it is by no means a foregone conclusion that the more optimistic estimates cannot be met.

The judgement of which projects will go forward is inherently made within the economic and political climate of the present, and its accuracy obviously deteriorates the farther out in the forecast one goes. The inherent time lags in the development of LNG projects means that most of the capacity that will be on line by the year 2007 is already well under way, so a 2010 forecast is speculating largely about the period out beyond that. In addition, the restructuring of the gas industry has created new flexibility to adapt to changing market conditions. There remains an active short term market, free to seek out the markets with the best economic returns. These volumes could clearly be available to the U.S. if conditions warranted it.

Another source of potential adaptation to a strong U.S. market, is the availability of company-flexible volumes. One feature of the new LNG market is that some of the larger companies have elected to write their long term contracts with their own marketing affiliates, thus effectively integrating downstream. These volumes, like the short term market volumes, are free to seek out the U.S. market if it is attractive enough.

This ability to provide flexible destinations is most apparent in the Atlantic Basin, where an active arbitrage market has developed involving shipments from Trinidad, Nigeria and Algeria and destinations is the U.S., Spain and Belgium. These volumes, some seemingly committed to one market or another, have been moving to those destinations with the best market prices.

When the U.S. began to move into the short term market in a significant way, LNG supplies were in surplus, both because of rapid growth of new liquefaction capacity and because of a slowdown in the major LNG markets in Northeast Asia. At that time it was taken for granted in some quarters that the industry would always maintain an overhang of reasonably-priced short term supply that the U.S. could call on if needed. These were the conditions that prevailed in the winter of 2000/2001, and the short term market responded as expected.

The concept that merchant terminals could exist free of the traditional contract commitments that have existed elsewhere in LNG was reinforced by the perception that the restructured North American gas industry represented the wave of the future and could depend on market forces to balance supply and demand. It was a period when the North American merchants - such as Enron and Dynegy - were in the ascendancy and many of the initial terminal proposals uncommitted merchant ventures.

But in the year following the price shock, U.S. prices softened at a time when European prices were strong and much of the flexible volume flowed eastward. Most recently, an upset at Tokyo Electric from the shutdown of seventeen nuclear plants has upset international LNG markets and drawn supplies to the Far East.

These developments have lent a new perspective to the U.S. terminal siting debate. While it is clear that the U.S. cannot import LNG if it lacks the terminal capacity to handle it, the converse is not necessarily true. The existence of adequate terminal capacity merely gives the U.S. a seat at the table to compete with other markets for supply: it does not guarantee that our requirements will be met. And, Europe enjoys a transportation advantage for all LNG supplies other than Trinidad.

The Commission has expressed an interest in several policy issues that arise from greater reliance on imported LNG:

- What is the likelihood that imported LNG will become the marginal supply for the U.S. and if so, what are the pricing implications for U.S. markets?

- Will past patterns of price linkage between oil and gas reoccur, and if so will LNG intensify the exposure of the U.S. economy to oil price shocks?
- What are the economic implications of U.S. competition with Europe and Asia for LNG?
- What are the national security implications of increasing U.S. reliance on imported LNG?

What is the likelihood that imported LNG will become the marginal supply for the U.S. and if so, what are the pricing implications for U.S. markets?

One of the most common myths about LNG imports is that they represent a potential "backstop" to North American supply and thus can put a "cap" on U.S. prices. This myth implicitly assumes that economics determines the flow of supply into the marketplace; that prices are driven by costs; and that the adjustments to equilibrium among supply, demand and price take place instantaneously. For LNG, which comes in large, lumpy increments with long lead times and complex negotiations among the supplying parties - including governments - these assumptions severely oversimplify the supply process. And they fail to recognize the difference between cost-based and market pricing.

The myth is a reincarnation of what might be described as "area pricing, cost-of-service" logic. In 1954, a U.S. Supreme Court decision extended utility ratemaking to gas at the wellhead, thus introducing the failed U.S. experiment with gas price controls. The Federal Power Commission, charged with regulating the industry quickly found that cost-based ("cost-of-service") pricing applied to individual producers was completely unworkable for a fungible commodity.

Finally, the FPC hit upon the idea of regulating against broad area cost averages, thus coming up with the concept of "area pricing". Congress's final acceptance of deregulation ended the struggle with "cost-of-service" pricing and with it, the attempt to assign costs to the wellhead. It substituted instead the concept that competition in the marketplace would determine prices for the commodity and individual producers could "net back" prices to the wellhead regardless of their individual cost structures.

And that is the way in which international LNG prices work. LNG projects have always been "price takers", netting back prices to the wellhead from a reference price that is deemed to represent the market. LNG suppliers operate on the assumption that it is the U.S. price level that will determine their netbacks; not that their costs will determine the U.S. price level. Thus, the effect of LNG on U.S. prices is likely to be the same as that of any other gas supply; it will be reflected in the overall supply/demand/price balance. Obviously, U.S. prices will be lower with LNG as a part of the supply mix than they would be without it, but that does not mean that they will necessarily reach cost-based levels.

If enough LNG producers find it profitable to compete for the U.S. market, it will increase supply and weaken prices. Conversely, if geopolitical or investment constraints slow the flow of supply into the market below the level necessary to meet growing demand, or if competition from other markets is too strong, LNG may not be that effective in disciplining prices. There is no magic cost-based price "bench" at which LNG takes over the responsibility for price determination.

Will past patterns of price linkage between oil and gas reoccur, and if so will LNG intensify the exposure of the U.S. economy to oil price shocks?

The Commission has expressed an interest in whether gas and oil prices will be linked so that the increased reliance on LNG imports will intensify the exposure to oil price shocks. The traditional LNG "chain" was held together by a comparatively rigid set of long term contracts featuring the "Sale and Purchase Agreement" or SPA.

The risk sharing logic of the SPA was embodied in the phrase ... "The buyer takes the volume risk and the seller takes the price risk". Hence, contracts typically included a take-or-pay provision to ensure buyer offtake at some minimum level and a price escalation clause to transfer market price uncertainty to the seller.

The early contracts viewed oil as the competitive target that set world energy prices; hence price escalation clauses usually keyed on oil prices. This was direct in the case of Asian markets. The escalator - JCC - was the Japanese Customs Clearing Price for crude oil (sometimes called the "Japanese Crude Cocktail").

When the early Japanese contracts were written, over 70% of power generation was based on oil and oil-linked pricing was reasonable. But by 2002, oil's market share had fallen to about 11% undermining the original logic of keying energy price levels to oil. In fact, widespread dissatisfaction exists for oil-linked pricing but in much of the world, no one seems to have come up with a better answer.

North America has become the principal exception to reliance on oil for energy price linkages. The restructuring of the North American gas industry has created "gas-to-gas" competition and made it possible to utilize gas-linked, rather than oil-linked, escalators in contracts. It has also become apparent that North American prices in a restructured world have become more volatile than oil prices.

For a time it appeared that gas-to-gas competition had made oil price levels irrelevant, but the recent tight markets have reintroduced some market linkage between oil prices and gas prices through switching in dual-fired boiler markets. The U.S. has had a significant inventory of boilers capable of switching from gas to residual fuel oil, and the assumption has been that the switching capability would put a cap on U.S. prices at residual fuel oil levels. However, it now appears that the volume range where effective residual fuel oil linkage exists is relatively small and thus the relationship is fragile. During the price shock of 2000/2001 and again this past winter, prices quickly rose above residual fuel oil levels, suggesting that the effective resid-switching capacity had been quickly exhausted and that switching to distillate oil - or "demand destruction" was setting prices at a much higher level.

These observations suggest that the linkage between gas and oil prices through interfuel competition is itself quite volatile and if that volatility is superimposed on the volatility of oil prices, it is difficult to see how gas price volatility will be significantly reduced with LNG imports.

But the fact that there is some market linkage between gas prices and oil prices - even though no longer direct as it has been in contractual pricing clauses - suggests that there will undoubtedly be some sympathetic relationship between international gas prices and oil prices in the event of an oil market upset. This will be particularly true if it is brought about by events in the Middle East, since the region is likely to be a major source of LNG as well as of oil.

What are the economic implications of U.S. competition with Europe and Asia for LNG?

The Commission has also been interested in understanding the economic implications of U.S. competition with Europe and Asia for LNG. Much of the current discussion about the negative impact of natural gas markets on U.S. industry is a result of the seemingly rapid - and possibly permanent - transition of North American prices to a much higher level than they have experienced historically. While LNG has benefited from these higher prices, it is important to recognize that it did not cause them.

The transition to the higher price levels is most likely to affect competition with the producing countries for gas-intensive chemical products such as ammonia fertilizers and methanol. Since Europe and Northeast Asia have already had higher gas prices, they have already lost much of these industries to the producers. The principal

place where the higher prices will have an adverse affect on U.S. competitiveness with the OECD countries is in the olefin-based petrochemical industry, such as ethylene.

The traditional source of olefin feedstock for European and Northeast Asia has been petroleum naphtha, a gasoline boiling range material. The U.S. demand for gasoline, when combined with our plentiful supply of gas-liquids rich natural gas, has made heavier hydrocarbons from natural gas, such as ethane and propane, the preferred feedstocks in this country. If gas is priced significantly higher than it has historically been, there is less incentive to extract these hydrocarbons and the U.S. industry will suffer accordingly.

One potentially adverse result that can be attributed to LNG, however, is the adverse consequences of the U.S.'s distance from most of the major LNG sources of supply. The high costs of LNG transportation make the regional pairings of sources and markets very important in determining the relative costs of LNG in various markets.

This poses an important problem for the U.S. for two reasons. First, except for Trinidad, all existing sources of LNG for U.S. Gulf Coast and Atlantic markets are closer to Europe than to the U.S. And second, if the U.S. imports most of its LNG via Gulf Coast terminals it will forfeit the lower transportation costs for the shorter East Coast hauls and resulting "basis differentials" (up-country pipeline tariffs) that East Coast terminals enjoy.

Thus Europe is likely to enjoy somewhat of a pricing advantage (perhaps $0.35 to $.70/MMBtu) over the U.S. in bidding for LNG. And, while Northeast Asia enjoys a significant price advantage over Europe for Asian sources of supply, it is slightly farther away from the Middle East than is Europe. Thus, if the Middle East becomes the marginal source of LNG supplies to both the Atlantic Basin and the Pacific Basin, Europe will be in the best economic position. For Northeast Asia this is compounded by the fact that Japan has shown a willingness to pay higher prices for gas than other markets (as it does for oil), a disadvantage that may be difficult to overcome.

What are the national security implications of increasing U.S. reliance on imported LNG?

The Commission has expressed interest in the national security implications of increasing U.S. reliance on imported LNG. The concern for our substantial dependence on the Middle East for our oil supply has led some observers to view LNG as a means of diversifying the risks. While this is true to some extent, it seems inevitable that the U.S. will become significantly dependent on the Middle East for LNG, as well.

While gas forecasters do not like to project individual country gas exports, the International Energy Agency does forecast "interregional gas flows" in its World Energy Outlook (2002). Comparing recent interregional flows (excluding the pipeline-only trades) with forecasts to 2030 indicates that the dominant growth in demand for interregional gas will come from the U.S. and the dominant source of LNG supply is likely to be the Middle East. While the potential major Middle East LNG exporters - Qatar, Oman and possibly Yemen - are different from the principal oil exporters, increased reliance on Middle East gas seems inevitable (and Iran is the largest holder of gas reserves in the region).

Recommendations

LNG imports represent a significant potential addition to U.S. gas supply. But LNG is a complex international business with challenges and problems that are different from those that the country has faced in its other energy supply options. It is therefore important for policy-makers to develop an understanding of those challenges to maximize the benefits that will come from access to this important energy source.

The world-wide trend towards gas industry restructuring, which tends to favor market solutions, also tends to limit the effective actions the government can take to encourage an orderly addition of LNG to the U.S. supply mix. Nonetheless, there are several policy initiatives which can smooth the transition to greater reliance on LNG.

The terminal siting problem is a serious one and threatens to make it difficult - and costly - to bring increasing quantities of LNG into the U.S. One focal point of the local siting resistance is the LNG safety issue. While industry tends to be much less concerned about hazards of LNG than the lay public, it has suffered from a lack of credibility in its efforts to make its case. The recent fatal accident at the Skikda, Algeria LNG facility has complicated the debate.

Many of the charges that have been leveled at LNG by the protestors are factually inaccurate, or have already been addressed in research studies. Government could provide a valuable service to the debate by making unbiased factual information available to counter inaccuracies where they occur. An Office of LNG Safety, while less concerned with accident investigation than such similar organizations as the Office of Pipeline Safety or the National Transportation Safety Board, could perform such an informational function. It could also be the focal point for sponsoring further safety research where the nature of the debate indicated that it would be valuable.

A second function that a government organization could provide would be to act as the focal point for coordinating the many individual Federal, state and local permitting processes that are required to permit a new LNG terminal. While it might be desirable to streamline some of these permitting activities to speed the overall process, such an effort to provide “one stop shopping” in the complex U.S. democratic system may be difficult to achieve. But the ability to guide terminal applicants through the process would provide a valuable service.

II. THE LNG INDUSTRY - AN OVERVIEW

The low density of natural gas makes it more costly to contain and transport than either oil or coal. Prior to the development of liquefied natural gas (LNG) technology, the transportation of natural gas was limited to movements that could be served by pipeline. Gas was unable to utilize that mainstay of international oil trade - marine transportation. The development of LNG has changed all that, and with the improvements in technology and costs, gas is rapidly becoming an internationally traded commodity.

The Basic Elements, Technology and Cost Structures

Liquefaction depends on the refrigeration of natural gas to cryogenic temperatures (approximately minus 260ºF) where it becomes a liquid at atmospheric pressure and occupies a volume that is 1/600th that of the fuel in its gaseous form. It can thus be stored in heavily-insulated tanks or moved overseas in special cryogenic tankers. While LNG is often used to store natural gas for peak sendout in temperature-sensitive markets (peak shaving), the current interest in LNG is focused primarily on its role as a method of moving natural gas in international trade.

An LNG project has been described as a "chain" whose ultimate success is at risk to the possible failure of its weakest link. The chain consists of four (occasionally five) links - field development, in some cases a pipeline to the coast, the liquefaction facility, tanker transportation and the receipt/regasification terminal. Each element is capital-intensive and the investment is usually front-end loaded so that revenue does not begin to flow until the project is complete. Hence breakdowns and delays in any part of the chain have adversely affected capital recovery and a project's internal rate of return (IRR).

Field development involves the drilling of production wells (including production platforms in offshore fields), field gas treatment and the laying of a gathering system to deliver the gas to the plant or to a pipeline for further transportation. LNG projects tend to be large to benefit from economies of scale, and thus the supporting gas reserves must be large enough and of high enough economic quality to support a liquefaction facility over its economic life. Designers usually try to maintain a field deliverability that will support full plant operation over a twenty year period, thus requiring a reserve significantly in excess of the underlying plant needs over the period. Today, the minimum size for a new greenfield LNG facility is about 3 million tons of LNG per year. To support such a liquefaction facility requires a proved reserve[2] of natural gas of about 4.5 Tcf . Most new plants are substantially larger making correspondingly higher demands on gas supply.

This requirement for a large block of quality reserves tends to restrict LNG plants to those locations where there is either a giant field or a cluster of smaller fields that can "anchor" the plant. Thus small and scattered gas fields may not be useful supplies for LNG plants. The selection of the best supporting gas supply can often best be described as "cherry picking". This implies a possible deterioration in the economic quality of the reserves as exports increasingly tap into a country's reserve base, possibly offsetting some of the economies that come from the expansion of the facilities.

While it is common to assume that flared associated gas is a "free good" and thus desirable as feed to a liquefaction plant, highly productive non-associated gas fields are usually better sources of supply than flared gas.

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[2] To maintain deliverability to the end of a contract requires a reserve over and above contract volumes that perform the same function as the unavailable "cushion gas" in underground storage fields. These analyses assume it takes 28 years of reserves to support a 20 year contract

The flared gas frequently occurs in small scattered locations at low pressure, necessitating high gathering and compression costs to deliver it to the plant gate. Gas condensate fields on the other hand, (fields containing gas liquids in the form of a high quality light crude oil) are often highly prized since the coproduct credits from the sale of the liquids contribute significantly to the economics of the project.

Although it is often possible to deliver the gas from the field directly into the liquefaction plant from the gathering system, where the supporting fields are in the interior of the country it may be necessary to pipeline the gas to a coastal location for liquefaction. This was the case in both Algeria and Libya, for example, and the proposals for gas from Sakhalin and from Bolivia also envision pipeline delivery systems. This step burdens the feed gas with additional costs, a problem for a process in which the final delivery volumes to the customer are reduced by process fuel, tanker boiloff and possibly regasification fuel.

There are several variations of the process used for liquefaction, but they all rely on compression of the gas followed by expansion cooling through a valve (the Joule-Thompson effect used in refrigeration). The size of an individual liquefaction module - known as a liquefaction "train" - has been a function of compressor technology. Early train sizes tended to be limited to 2 million tons by the compressors then available, and it might require three trains of that size to justify a new greenfield facility. However, recent improvements in compressors have broken free of the 2 million ton limitation. While the largest current operating train is smaller than 4 million tons, there are a number of trains in the planning stages that will exceed that level and Qatar is considering the possibility of 7.5 million ton trains. Larger trains benefit from economies of scale, and it is now possible to justify a new greenfield facility with a single larger train.

There are also several tanker designs, but all feature an exterior hull and an insulated interior containment system for the liquid. The number and size of tankers tend to be dictated by the trade. While smaller tankers were common for the original Mediterranean trades from Algeria and Libya to southern Europe, longer hauls favor larger tankers and sizes have been increasing. Tanker capacities are stated in cubic meters of liquid and the most common sizes today are in the 135,000 to 137,500 cubic meter size range. Such a tanker can deliver about 2.6 Bcf per trip. The volume that can be delivered over a year depends on the distance of the haul. If dedicated to a run from Nigeria to the U.S. Gulf Coast, such a tanker could deliver about 30 Bcf over the year. The largest existing LNG tanker is 140,500 cubic meters, but Qatar has been considering vessels in the 200,000 to 250,000 cubic meter range.

The final link in the LNG "chain" is the regasification terminal which receives the LNG, stores it in cryogenic tankage until needed, and then regasifies it for delivery into the takeaway pipeline system. Regasification terminals may use either gas-fired or seawater regasification systems. The seawater gasifiers are more expensive to build but cheaper to operate. They are thus well suited for base load sendout. Gas-fired units are more costly to operate but are well suited to locations which are designed to meet highly peaking sendout requirements.

It has become increasingly difficult politically to site receiving terminals (the NIMBY problem), so much work is being done on offshore solutions. These seem to be growing in interest in the U.S. where the siting problem is especially severe.

The centers of population in large Asian LNG importing countries - Japan, Korea and Taiwan - are coastal, which makes it easy to deliver LNG without serious concern for onward pipelining. For markets with an established pipeline grid, such as the U.S. or Europe, the introduction of LNG can easily alter the geographic pricing relationships (basis differentials) among different points on the pipeline system. This "basis risk" is a factor to consider in determining how much LNG a regional market can absorb before it affects the market pricing

structure. In a new market, such as India, the costs of reaching the interior of the country with regasified LNG delivered by pipeline can seriously affect the competitiveness of the fuel.

Figure 2-1 provides a graphic illustration of the balance of capital expenditures (CAPEX) and margins for a hypothetical LNG project. It uses a West African source supplying a U.S. Gulf Coast regasification terminal (at Nigeria's distance from the U.S.Gulf Coast) and designed for two 3.3 million ton trains. This illustration has a total CAPEX of $5 billion and could deliver to the Gulf Coast for a cost of service of $3.39. In the illustration, 58% of the CAPEX are located in the host country, 10% are located in the U.S. and the remaining 32% are required for the tankers.

Despite the growth in international gas trade, the costs of moving natural gas are still significantly higher than the costs of moving oil or even waterborne coal. And the relative costs of moving gas or oil by pipeline or by tanker differ substantially, as well. This influences regional interfuel competition and thus natural gas markets.

The costs of pipelining natural gas benefit substantially from economies of scale, since large diameter pipelines are not that much more expensive to lay than smaller lines but carry much greater volumes. A gas pipeline of twice the diameter costs roughly twice as much to lay as the smaller line but has roughly four times the capacity. Older pipelines in the U.S. tended to be limited to operating pressures of about 1,000 psi, but newer high pressure technology has raised that to 2,400 psi or more. Offshore pipelining has significantly benefited from higher pressures, since the higher pressure lines can go longer distances without recompression, thus eliminating some of the costly compressor riser platforms that plagued the older low pressure offshore systems.

Pipeline costs rise linearly with distance, but LNG - requiring liquefaction and regasification regardless of the distance traveled - has a high threshold cost but a lower increase in costs with distance, though not nearly as low as the costs of moving oil in a tanker. Shorter distances tend to favor pipelining, but longer distances favor LNG. These relationships are illustrated in Figure 2-2.

History of World LNG Trade

The first tanker shipment of LNG took place from Lake Charles, LA bound for Canvey Island in the U.K. in 1958 aboard the experimental vessel, the Methane Pioneer. It was followed in 1964 by the first commercial trade - the CAMEL project to deliver Algerian gas to the U.K. and France. By 1969, three more trades had started - an additional delivery from Algeria to France, one from Libya to Italy and Spain, and one from the Cook Inlet of Alaska to Japan, the first Pacific project.

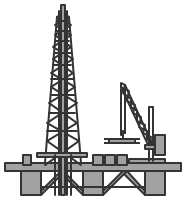
Initially, the technology developed in the Atlantic Basin and Algeria became the principal supplier. While the first deliveries from Algeria were comparatively short hauls to Europe, the U.S. entered the market first in 1972 when deliveries began for a small Distrigas (Cabot) project at Everett, MA. Deliveries began in 1978 for the much larger contracts by El Paso Natural Gas to Columbia Gas for Cove Point, MD and Southern Natural at Elba Island, GA. They were followed by the startup of the Trunkline project for Lake Charles, LA in 1982.

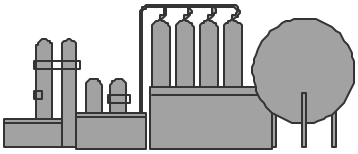
The period from 1972, when Distrigas started up, and 1982, when Trunkline started, was a period of almost unprecedented change in world energy markets. It included the first "oil price shock" with its sharp changes in world oil price levels. And for the U.S., it included the appearance of the regulation-induced gas shortages and the beginning of a dismantling of the previous regulatory structure in favor of market competition. In Algeria, a change in oil ministers during the time when OPEC governments were taking control of their own industries, brought about a much tougher stance on LNG price negotiations.

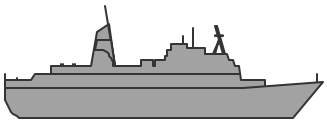
Figure 2-1

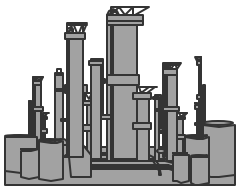
ELEMENTS OF AN LNG DELIVERY SYSTEM

BASIS: GREENFIELD FACILITY, TWO 3.3 MMT TRAINS,
6,200 NAUTICAL MILES (ROUGHLY NIGERIA TO THE U.S. GULF)
REQUIRES ABOUT 9.5 TCF OF RESERVES TO SUPPORT A 20 YEAR CONTRACT









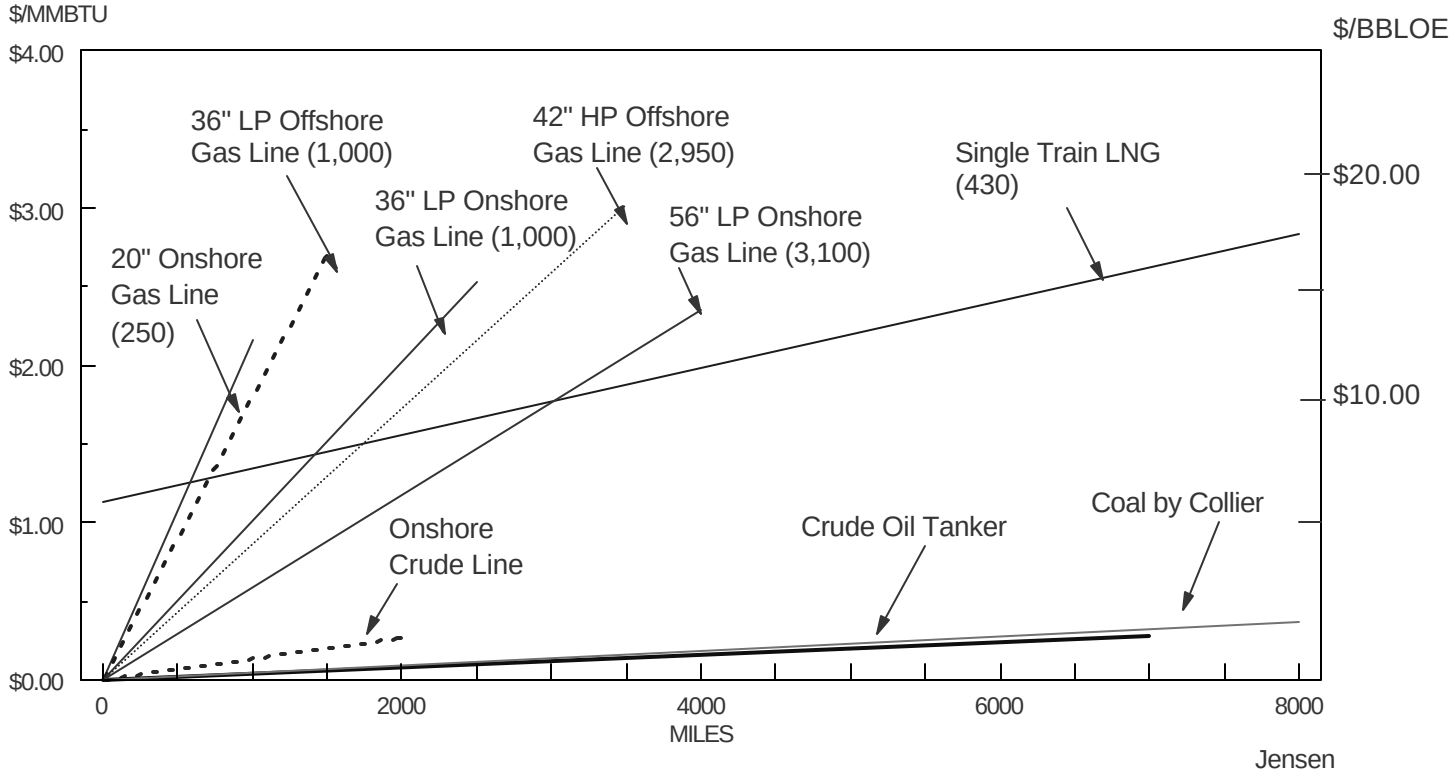
	CAPEX	MARGIN
Field Development (Varies)	$1.3 Bn	$0.80
Liquefaction	$1.6 Bn	$1.22
Tankers (10 @$180 Mn)	$1.6 Bn	$0.98
Regasification (Varies)	$0.5 Bn	$0..39
Total	$5.0 Bn	$3.39

Figure 2-2

ILLUSTRATIVE COSTS OF GAS, OIL AND COAL TRANSPORTATION

SHOWING GAS'S HIGHER COSTS AND THE EFFECT OF SCALE

(Gas Delivery Capability in MMcfd)



This clash between a U.S. that wanted lower gas prices through competition and Algeria that wanted higher prices for its resources, proved to be almost insurmountable. All four U.S. terminals closed down for a time and the Cove Point and Elba Island terminals remained idle until these last two years. The loss of the long haul U.S. market had a significant effect on LNG tanker markets with some vessels laid up for fifteen years or more.

The Pacific Basin LNG trade started up slightly later than the Atlantic trade with the Cook Inlet/Japan deliveries in 1969 followed by Brunei/Japan in 1973. But with the substantial slowdown in interest in LNG in the Atlantic, the balance of interest shifted to the Pacific as Korea and Taiwan joined Japan as importers. Figure 2-3 shows the growth of imports by region, indicating the strong contribution of Asian markets to demand. Between 1975 and 1996, the Asia Pacific demand increased by an average of 117 Bcf per year (about 2.4 MMT, slightly more than the capacity of the typical LNG train at the time). In contrast, Europe and the U.S increased only 27 Bcf per year. Since 1996 Atlantic Basin markets have begun to take off, so that average Atlantic growth has been 140 Bcf per year compared to Asia's 149 Bcf. These are roughly equivalent to the capacity of a more modern 3 MMT train.

With the continuing growth of Asian markets, the principal suppliers were from the Asia Pacific region - Indonesia, Malaysia, Australia and Brunei. (See Figure 2-4) The first Middle East project from Abu Dhabi dates back to 1977, but there was no significant expansion until the major new projects from Qatar and Oman in the late 1990s. Similarly, the slow growth of European and U.S. markets until recently limited the Atlantic Basin suppliers to Algeria and Libya. With the startup of new liquefaction plants in Trinidad and Nigeria in 1999 the Atlantic Basin suppliers is now poised for substantial growth.

Table 2-4 shows the balance of LNG exporting countries for the year 2002, showing the dominance of the Pacific Basin trade. Japan alone accounts for nearly sixty percent more demand than the entire Atlantic Basin combined.

Table 2-1
LNG Imports by Country - 2002
BCF

	BCF		**BCF**
Japan	2,568	Spain	433
Korea	849	France	407
Taiwan	247	U.S.	251
		Italy	201
		Turkey	189
		Belgium	116
		Greece	18
		Portugal	15
Pacific Basin	3,664	Atlantic Basin	1,631

Figure 2-3

GROWTH OF LNG IMPORTS BY REGION

BCF

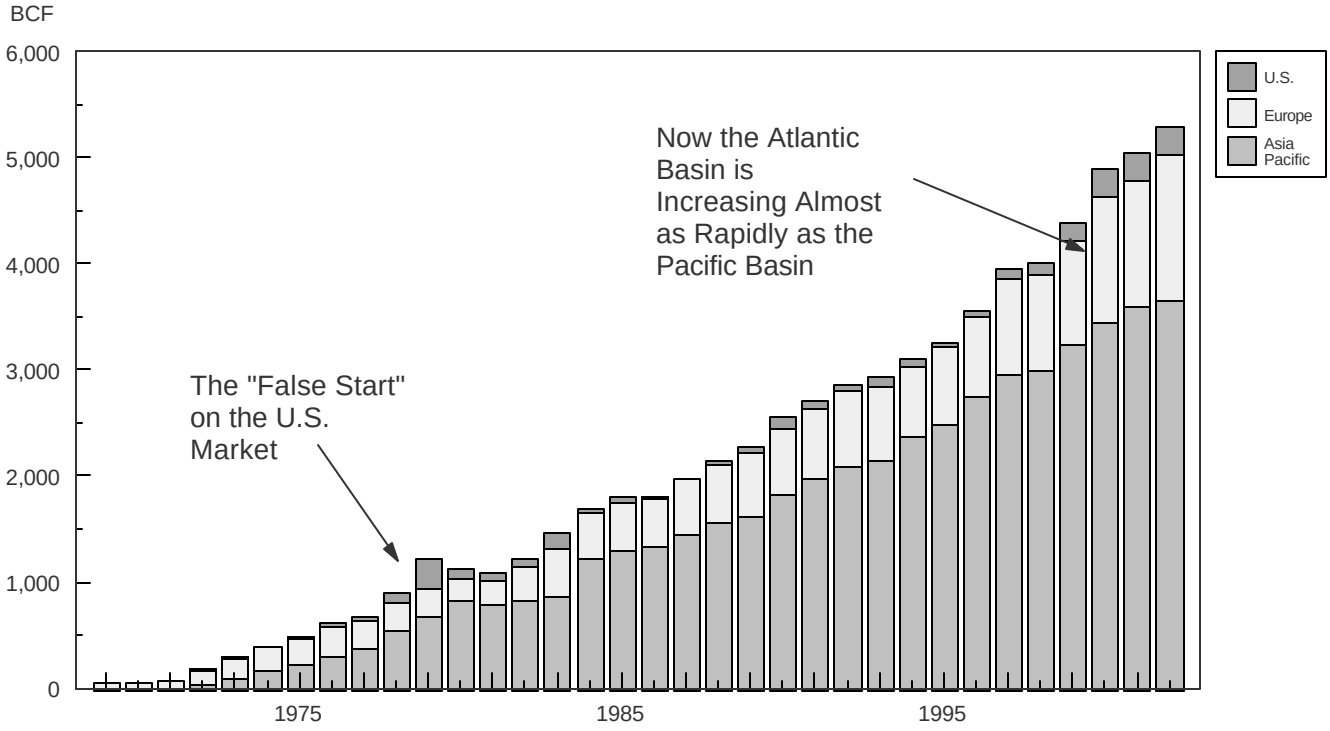


Figure 2-4

GROWTH OF LNG EXPORTS BY REGION

BCF

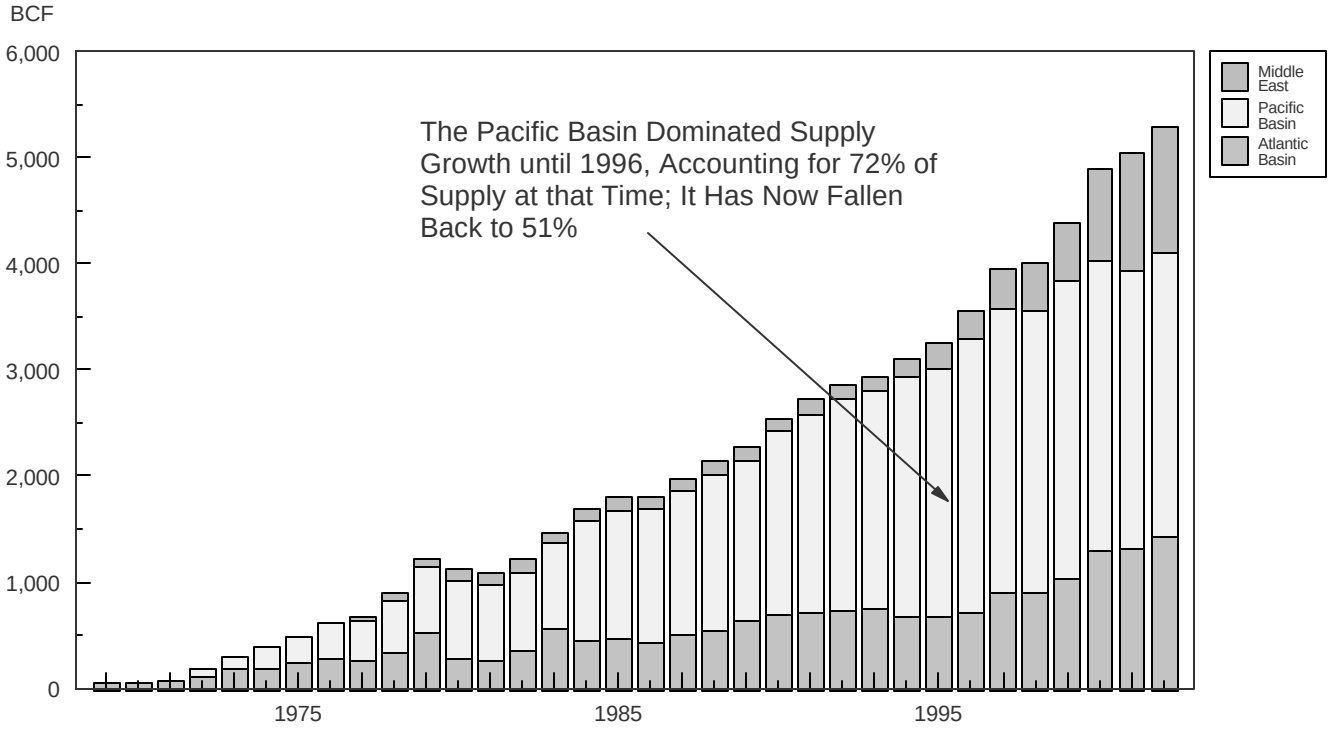


Table 2-2 provides similar information about the exporting countries.

Table 2-1
LNG Exports by Country - 2002
BCF

	BCF		BCF		BCF
Indonesia	1,212	Qatar	656	Algeria	949
Malaysia	724	Oman	281	Nigeria	277
Australia	354	Abu Dhabi	242	Trinidad	188
Brunei	323			Libya	22
Alaska	60				
Pacific	2,673	Middle East	1,179	Atlantic	1,436

Indonesia has been the world's largest supplier, but both Qatar in the Middle East and Nigeria in the Atlantic Basin are increasing their exports substantially. Egypt, while not yet an exporter, has two LNG facilities under construction with a capacity of 584 Bcf and seems destined to be a major LNG supplier.

Forces Driving the Renewed Interest in LNG

A number of factors have combined to stimulate the renewed interest in LNG.

Combined cycle power generation for growing electric power markets
The effects of technology on cost reduction making previously uneconomic trades attractive
Environmental concerns
The embrace of gas by previously "gas poor" economies
The growing concern for traditional supplies in the face of growth
The "stranded gas" phenomenon

Combined Cycle Power Generation - The thermal efficiency of traditional steam boilers for power generation is limited thermodynamically to about 38%. But by placing a high-temperature gas turbine on the front end, and then recovering the high temperature turbine exhaust for steam generation in a heat exchanger, the combination - a "combined-cycle" (or CCGT) unit - can achieve thermal efficiencies approaching 60%. In addition these units have relatively low capital costs, come in smaller, market-friendly sizes and have short planning lead times. The turbines are similar to those on jet aircraft and thus the fuel must be either natural gas or a very high-quality distillate product. CCGT units have become the power generation systems of choice for electric markets around the world.

Technology - In the past five to ten years, technology has made it possible to design new LNG liquefaction facilities and tankers for substantial cost reduction. Hence, trades that once seemed uneconomic have become attractive. The liquefaction cost reduction has been due to a number of factors. With more activity and more

design constructors, plants have benefited from greater competition and higher productivity. The maturing of the industry with diversified supply sources has led to less concern to "gold plate" plants to ensure reliability. But substantial improvements have come from increasing plant sizes and the resulting economies of scale. Expansion by means of one modern 4 MMT liquefaction train can cut the costs of liquefaction by about 25% compared with the two 2 MMT trains that were common ten years ago.

Tanker costs have come down as well. Perhaps more of this improvement has been the result of greater activity and the resulting competition among shipyards for business. But increased tanker sizes have also improved economics, although the scale improvements are not as marked since the size increases have been less dramatic. A new 140,000 cubic meter tanker could probably cut costs by about 5% relative to the 125,000 cubic meter tanker of ten years ago.

Nigeria provides an illustration of the evolution of today's optimism about LNG economics. In the mid-1990s, a consortium of Shell, AGIP, Elf and Nigerian National Petroleum Company, started negotiations on what has become the Bonny LNG project in that country. Initially the sponsors could not demonstrate economic feasibility for a project destined for Italian and U.S. markets. But by taking very low-cost options on seven laid-up LNG tankers at a time when the price of newbuilds was at an all-time high, they cut project costs enough to make it economic

Figure 2-5 illustrates the economics that a new Nigerian greenfield project destined for the U.S. Gulf Coast might have faced in 1998, given the designs, costs and market price expectations of the period.. As is evident, the project was a non-starter since the initial netback[3] from the expected Gulf Coast market price to the inlet of the liquefaction plant was negative (-$0.21) . Figure 2-5 then traces the improvements in netback as a result of using current cost estimates for the original design, as well as the design improvements in plant economics from increasing plant sizes - two 3.75 MM ton trains, instead of three 2.5 MM ton trains. The common mid 1990s view of relatively low prices for 2010 - represented by the 2001 Annual Energy Outlook of the EIA - has now changed and the 2003 AEO price projection is 22% higher for 2010.

The result of these improvements is striking. From a netback of ($0.21), the changes have boosted the netback into the plant gate to $1.04.

Environment - Environmental concerns are clearly a driving force in growing interest in natural gas and in LNG. Not only is gas essentially free of sulfur and particulate matter, but the increasing concern for global warming also benefits gas. Not only does gas have a higher hydrogen-to-carbon ratio, minimizing CO_2 emissions, but CCGT's higher thermal efficiency requires less fossil fuel per MWH generated. By comparison with a coal-fired boiler, gas-fired CCGT units can cut CO_2 emissions by about 40%. However, after factoring the CO_2 evolved in liquefaction, transportation and regasification, the emissions savings are reduced to about 26%.

Interest From "Gas Poor" Countries - The underlying economic growth of some of the emerging market countries, when coupled with the advent of gas-fired CCGT power generation, has made them targets for LNG imports where they were not previously able to justify natural gas. India, China and Turkey are prime examples of this group.

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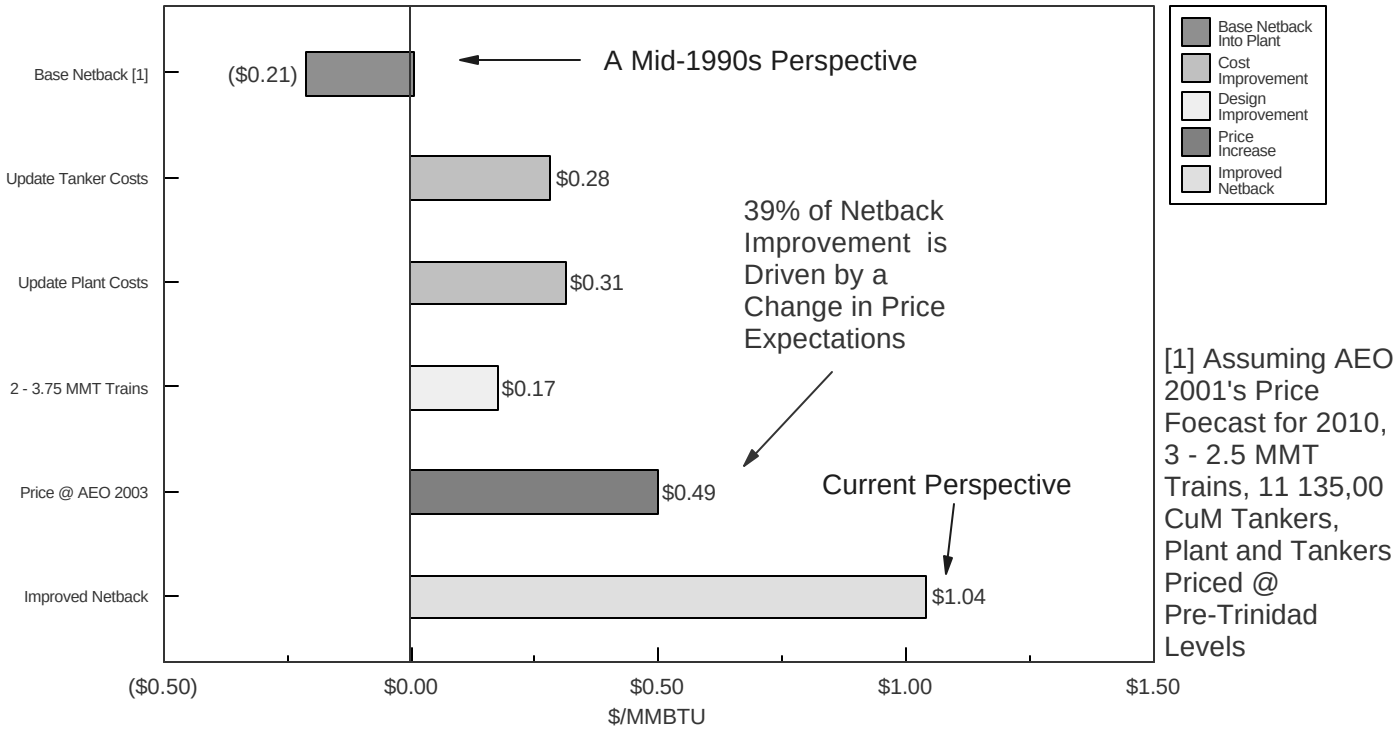
[3] "Netback" refers to the calculation commonly made in determining the economics of developing gas fields. It refers to the remaining value of the gas after deducting all downstream costs from the price that the gas would command in the marketplace.

Figure 2.5

THE EVOLUTION OF OPTIMISM ABOUT LNG IMPORTS

THE CHANGING PERSPECTIVE OF U.S. NETBACKS FROM THE U.S. GULF TO A NIGERIAN GREENFIELD PLANT FROM 1998 TO 2003



[1] Assuming AEO 2001's Price Foecast for 2010, 3 - 2.5 MMT Trains, 11 135,00 CuM Tankers, Plant and Tankers Priced @ Pre-Trinidad Levels

Supply Concerns - But some economies that have utilized natural gas are now interested in LNG to offset problems with traditional supply or to provide supplier diversification. This is certainly the case in the U.S. And it is also the case in the U.K. As recently as 1998, when the Interconnector Pipeline was inaugurated to link Bacton in the U.K. with Zeebrugge in Belgium, the U.K. was expected to be a major exporter to the Continent. Now with declining prospects for North Sea production, the U.K. is about to develop LNG imports and may emerge as a major competitor to the U.S. for LNG supply. In a somewhat different motivation, Spain has attempted to diversify its heavy reliance on one country - Algeria - by entering LNG import markets in a major way.

"Stranded Gas" - Another factor that has led to the higher interest in LNG is the emergence of concern for "stranded gas". At one time, companies searching for oil in international concession areas treated a gas discovery as a "dry hole" and abandoned further effort in the area. Now with the possibility of major oil discoveries narrowing in many areas and with a mounting inventory of gas discoveries, companies are much more willing to concentrate on gas development possibilities.

But it is one of the common myths about LNG that the large surpluses of stranded gas throughout the world guarantee that companies will be eager to invest in new LNG supply if only the markets develop. In the last analysis, companies will only invest if they are persuaded that the project will earn a return on investment sufficient to cover the peceived risk - market as well as geopolitical. Anyone who has followed the often protracted negotiations over new LNG projects and seen companies opt out of ventures rather than step forward with their own capital realizes that the existence of a significant gas discovery does not of itself assure that a project will proceed. As one observer once remarked, " The only thing worse than discovering that your remote drilling prospect is a dry hole is to find gas. At least you can walk away from a dry hole with a clear conscience".

III. WORLD GAS SUPPLY

Proved Natural Gas Reserves Compared to Oil

While the energy content of the world's gas reserves is nearly as large as that of its oil reserves, the regional distribution of gas reserves is somewhat different from that of oil. Whereas the Middle East accounts for 65% of the world's oil, it accounts for only 36% of its gas. On the other hand, the Former Soviet Union accounts for nearly as much gas - 35% - as the Middle East, but has only 7% of the world's oil reserves. There is also uneven distribution of gas in the Middle East. The two largest holders of gas reserves - Iran and Qatar - account for 67% of that region's gas, but only 15% of its oil. Figure 3-1 shows the comparison of hydrocarbon reserves (in barrels of oil equivalent) for key countries and regions.

Where the Potential Exporters are Located

The common comparison of oil and natural gas reserve-to-production ratios - currently 62 years in the case of gas and 39 years in the case of oil - implies that natural gas is in relative surplus compared to oil. But such comparisons overlook the fact that much of the natural gas, unlike oil, cannot access world markets since it is not connected to any transportation system. The term "stranded gas" has no counterpart in oil terminology.

Natural gas is much more costly to transport than oil, so its economics are sensitive to the geographic location of the gas reserves. It is common to see regional distributions of proved gas reserves (somewhat similar to that shown in Figure 3-1), but they do not capture the fact that most of the reserves near major market areas in North America or in Europe have access to transportation and are usually in production and thus are not "stranded".

One way of looking at regional reserve estimates is to separate out those reserves that are already committed to markets or are otherwise unavailable for early utilization because of their involvement in oil recovery. The remaining reserves can be considered excess to any immediate prospect of utilization. They are the exportable surpluses or "stranded gas" and unfortunately are often concentrated at some distance from the major markets. Jensen Associates has frequently made such estimates and they have been utilized in the following paragraphs to identify where such stranded gas supplies are located.

The regional markets for pipeline gas are defined by the layout of the pipeline system. But LNG, able to move much longer distances by tanker, has developed a much broader definition of gas market regions - the "Pacific Basin" and the "Atlantic Basin".

If one were to expand the LNG definition of regions to include pipeline gas, the Atlantic Basin might be redefined to include all of Europe and Africa together with the East Coast of the Americas, leaving the rest of the world in the Pacific Basin. This would draw the boundary line between the two basins along the Ural Mountains separating European Russia from Siberia and the Russian Far East and include the entire Mediterranean in the Atlantic (See Figure 3-2). By this definition, the world's three largest blocks of surplus gas - West Siberia, the Middle East and the Central Asian Republics are at the "seam" between regions and thus most remote from the major Atlantic demand centers in North America and Western Europe, and the center of Pacific demand on the Pacific Rim.

While 62% of the world's proved reserves lie in West Siberia, the Middle East and the Central Asian Republics, those regions contain 76% of the surpluses. The countries with the largest exportable surpluses in the Atlantic Basin are Algeria, Nigeria, Norway and Venezuela. The largest Pacific surpluses (outside the seam) are in

Figure 3-1

NATURAL GAS AND OIL RESERVES BY REGION

YEAR END 2002

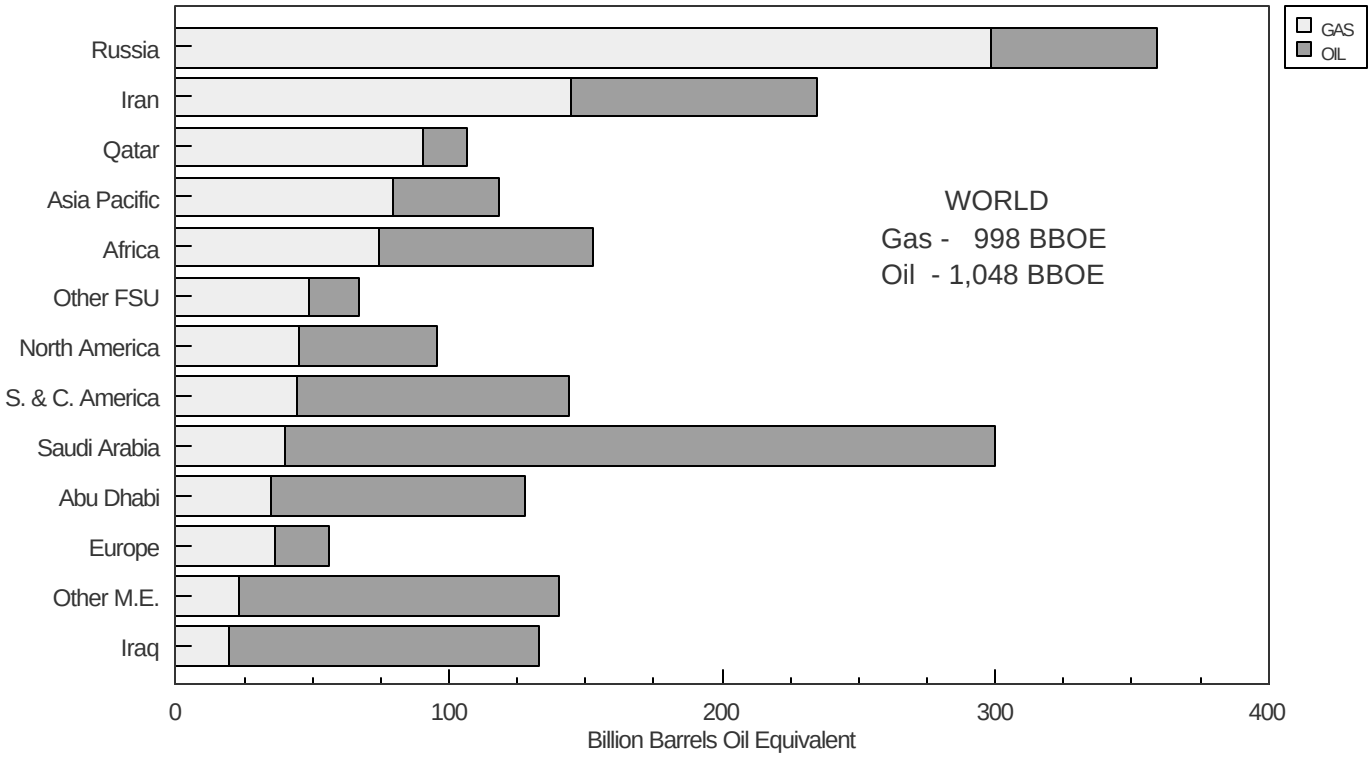
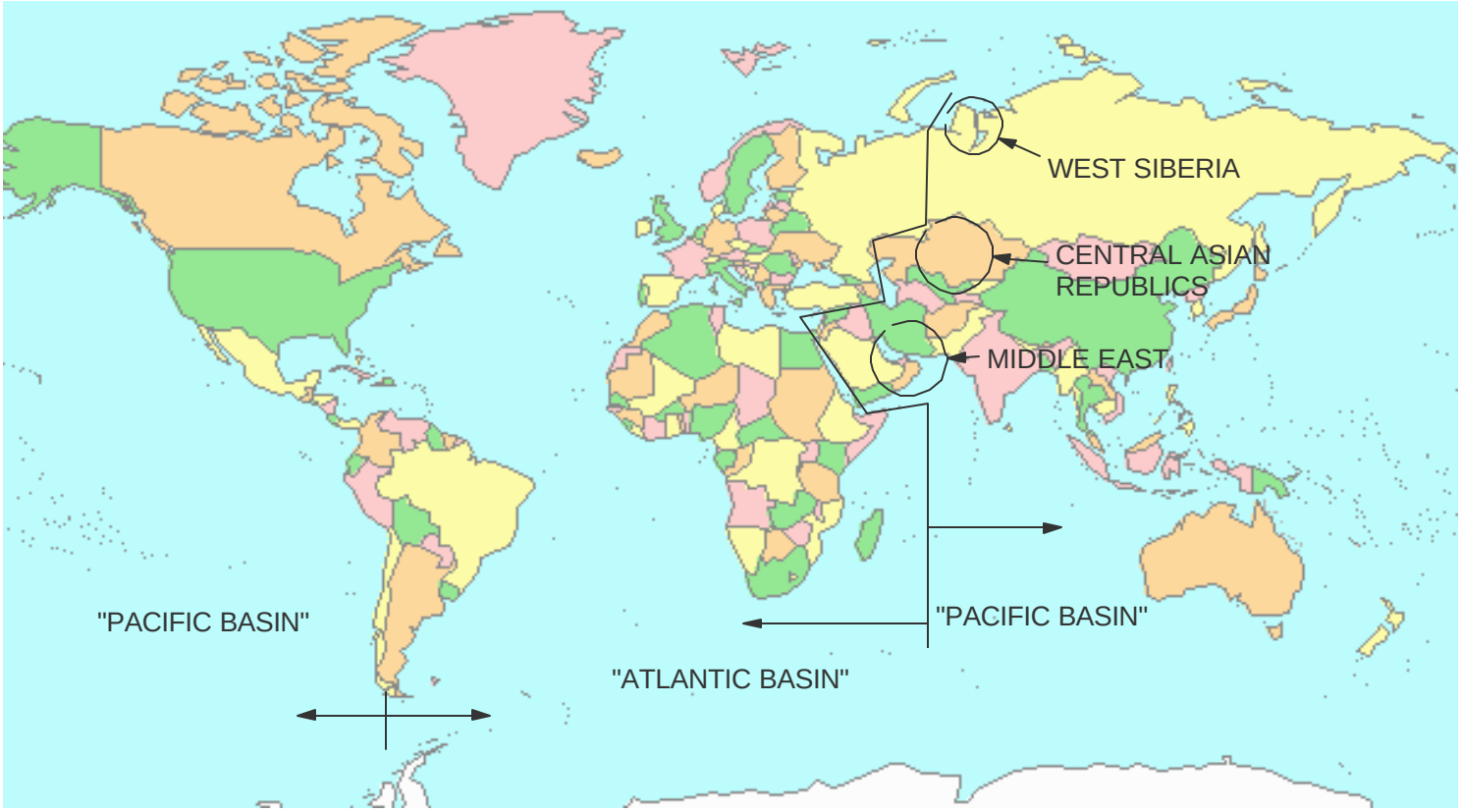


Figure 3-2

THE "ATLANTIC" AND "PACIFIC" GAS BASINS TOGETHER WITH "SEAM" SUPPLY AREAS



Indonesia, Australia, Malaysia and East Siberia/Russian Far East. Figure 3-3 shows the geographic distribution of both proved reserves and exportable surpluses.

Characteristics of Reserves Required to Support LNG Projects

Both field development and liquefaction investments in the producing country have commonly been based on significant gas discoveries. Hence companies holding the relevant exploration licenses have initiated most LNG projects. The discoveries have been dedicated to the contract to insure a reliable supply for the project. Since gas fields are subject to declining deliverability with field depletion and since the contract obligates the seller to deliver full contract quantities up to the final day of the contract period, the seller must provide additional reserves over and above the dedicated contract quantities to honor the contract obligation. These additional reserves - similar to the unavailable "cushion gas" in an underground storage field - may amount to as much as an additional eight years of reserves over and above the total contract volume. (In the days when the Federal Power Commission required twenty years of dedicated reserves for a pipeline expansion certificate, the rule of thumb was that a twenty year RP ratio was equivalent to twelve years of "full line deliverability").

Using the old FPC rule of thumb, it might take as much as twenty-eight years of reserve support for a twenty year contract. This amounts to a reserve of about 6 Tcf to support one new 4 million ton LNG train. And since developers prefer multiple train plants, the requirements for the gas supply may be a multiple of that number. These represent relatively large sized fields and are not common to many producing basins.

Project developers prefer to site their plants as near the source of the gas as possible. Exceptions, such as the Algerian LNG plants, the proposed Yukon Pacific project from the Alaskan North Slope to Japan, the new Sakhalin II project (which is distant from an ice-free port) or the proposed Bolivian project that may be sited at the Chilean seacoast, all must add a pipeline tariff to the value of the gas before it enters the liquefaction facility and is therefore costly.

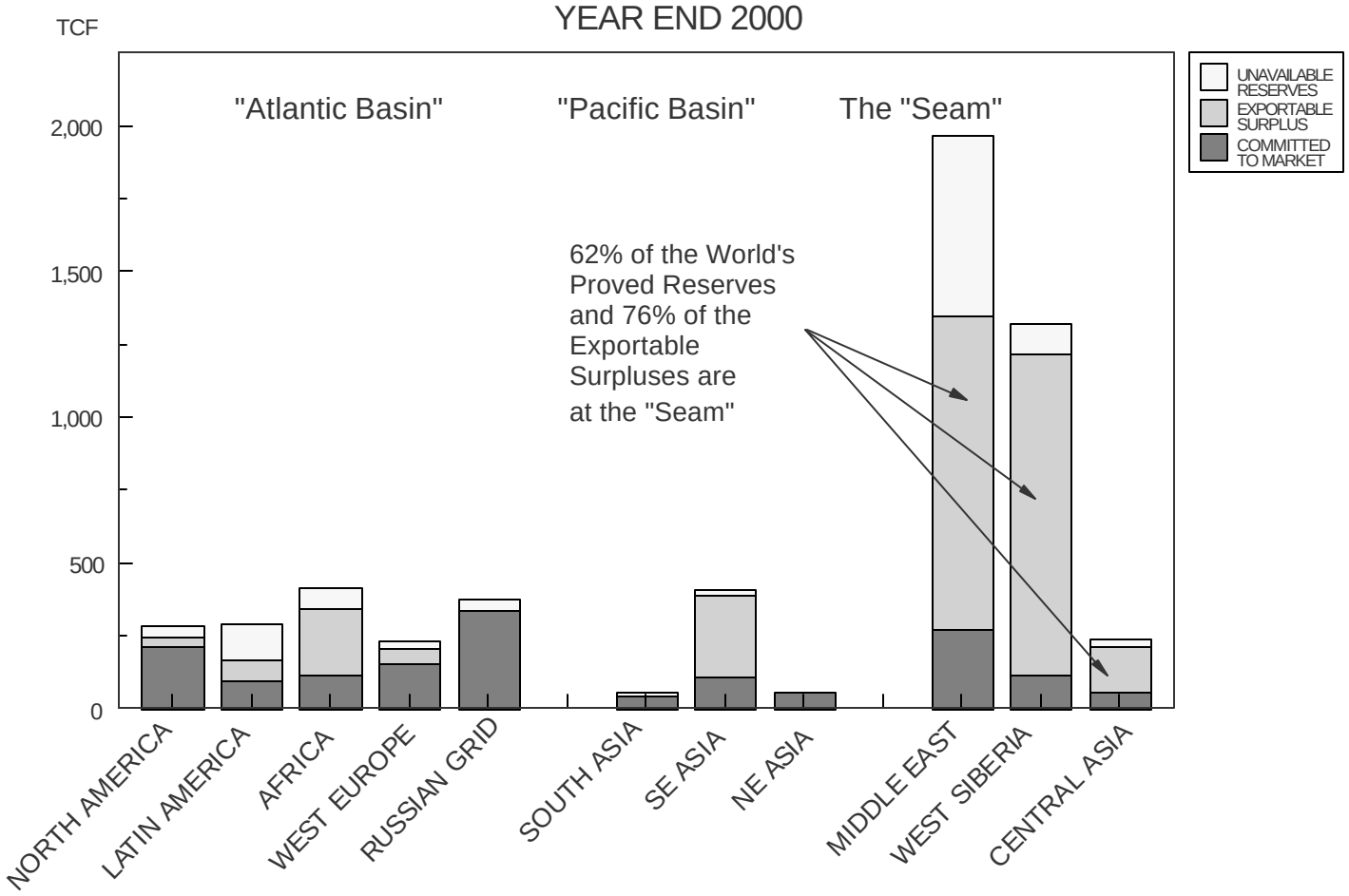
The Role of Gas Liquids in Gas Supply

"Non-associated" gas comes from free gas fields that do not contain crude oil. On the other hand**,** nearly all oil fields have some gas dissolved in the oil and some may be situated in a reservoir that has a "gas cap". These gas supplies are known as "associated/dissolved" or sometimes just "associated" gas. Natural gas flaring, which is deplored by governments everywhere, commonly occurs after the dissolved gas has been separated from the oil in a gas/oil separator, and if lacking a market, is simply burned off.

It is a common perception that flared gas is a "free good" and thus a very desirable feedstock for an LNG plant. This is usually not the case. Many oil wells produce comparatively small quantities of gas, and upon separation, the gas is usually reduced to atmospheric pressure. Thus the recovery of dissolved gas often involves expensive gathering and compression costs to deliver it to the plant gate. In addition, the evolution of dissolved gas from the oil varies over time as the reservoir pressure changes, and the fact that oil production scheduling dictates the rate at which it will be available, makes it an unreliable base load feed for most liquefaction plants. A high pressure non-associated gas field often provides much lower cost gas to the plant gate than the otherwise flared gas.

The only LNG facility originally designed to operate on associated/dissolved gas was the small Libyan plant. Nigeria flares more gas than any other country and the early pressures on the companies to reduce flaring led to the interest in LNG. However, the early feedstock to the Bonny, Nigeria liquefaction facility was almost entirely non-associated gas because it was lower cost at the plant gate. Now that the plant is operating on non-

Figure 3-3
NATURAL GAS RESERVES BY REGION
SHOWING THE CONCENTRATION AT THE "SEAM"
YEAR END 2000



associated gas as a base, it has been possible to blend in increasing quantities of associated gas in the mix. Government pressures on operators in Angola and in other Nigerian producing areas to reduce flaring will potentially accelerate the development of projects in those countries.

A high proportion of the natural gas reserves in some countries is in the form of associated gas. For example, 88% of Venezuela's 148 Tcf and 63% of Saudi Arabia's 225 Tcf of proved reserves are associated gas. Since associated gas is usually a less desirable basis for LNG development that non-associated gas, this heavy bias in favor of oil well gas complicates the development of LNG projects in such countries. While both Venezuela and Saudi Arabia have significant prospects of developing non-associated gas reserves if they expend the effort, Saudi Arabia shows little interest in LNG, while Venezuela has often considered LNG projects, but has as yet to launch an LNG venture.

While non-associated gas is found in fields that do not contain crude oil, it usually contains some natural gas liquids (NGLs) that can be recovered and sold to contribute to the economics of the project. Some of these are the lighter hydrocarbons, such as LPG (propane and butane) or natural gasoline, a light gasoline boiling range material. But many non-associated gas fields are "gas-condensate" fields in which the NGLs resemble a light crude oil. Some gas-condensate fields are so rich in liquids that the field operator could make a reasonable rate of return on his field investment if, lacking a market for the gas, he were to produce the field for the condensate and flare the gas. Since the gas-oil ratio for these fields are very much larger than for the normal oil field, the wasteful flaring of gas from gas condensate fields is usually not permitted by governments. However, if the operator is forced to reinject for conservation purposes, his gas is effectively available to him at a negative opportunity cost. He can thus effectively charge the gas into an LNG facility at a negative transfer price[4], reflecting the avoided cost of reinjection.

Most LNG projects are based on gas condensate fields and thus benefit from the co-product credits of selling the liquids. An example of a field with negative opportunity cost gas is Hassi R'Mel, the giant Algerian gas field that is the base for most Algerian LNG and pipeline exports. The Arun field in Indonesia was particularly rich in NGLs and thus was a highly profitable field. And the North Field in Qatar is also very rich in condensate.

Some gas condensate fields are in a state of matter called "retrograde condensation". The reservoir fluids are in a super-critical state and resemble a crushed fluid rather than a true gas. When the reservoir pressure is reduced in these fields, the fluids separate into a gas and a liquids phase. The liquids in the reservoir reduce the ultimate recovery of the reservoir hydrocarbons and especially the ultimate NGL recoveries.

This is an important issue in the Middle East. Qatar's North Field straddles the median line with Iran, where it is known as South Pars. The fact that Qatar is aggressively developing the North Field not only means that Qatar is "draining" the Iranian side of the reservoir, but is also reducing Iran's ultimate liquids recovery, as well. These factors are an important motivating factor on Iran to develop its own gas market outlets.

The Implications of the "Cherry Picking" Phenomenon

The need to select the gas supply with the best economic qualifications leads to "cherry picking", that is choosing the most attractive economic options from the fields that are potentially available. Thus many gas fields never meet the demanding qualifications for LNG supply and are passed over as a basis for export projects. They may

[4] A "transfer price" is the internal economic valuation of an unfinished product stream as it is transferred from one operation to the next in an integrated process.

be developed later as “satellites” for anchor fields if they are favorably located to the developing gas infrastructure. Or in many cases, they simply remain “stranded” without either a local market or the economic qualifications to support an export project.

Because of the cherry picking phenomenon, LNG projects frequently are named for individual fields that anchor the LNG facility. In Indonesia, for example, the Sumatra plant was named “Arun” after the anchor field, and it has retained that name ever since. The Kalimantan plant was originally named “Badak” after its anchor field, but that plant, unlike Arun, has seen a succession of additional nearby discoveries, so that it is now usually called “Bontang” after the plant location. Both the possible “Natuna” and “Donggi” LNG projects are named for their anchor fields, while “Tangguh” was originally named for the field , “Wiriagar” until additional gas was added to the mix.

The selection of the most economic fields first suggests that other nearby discoveries may have poorer economics and thus potentially rising costs. This tendency towards rising costs with declining economic quality tends to be offset by the infrastructure sharing, scale economies and learning curve phenomena, so that it is not clear whether the net result is rising or falling costs. The final balance of these pressures will be determined by individual characteristics of the fields themselves.

For example, Indonesia’s two LNG facilities exhibit opposite behavior. Arun in Sumatra is based on one giant field and as it has gone into decline, the possibility of bringing in smaller and more remote (and presumably more costly) fields to supplement the original supply has been considered. On the other hand, Bontang, in Kalimantan, has seen the continual addition of new nearby fields and presumably has seen its average costs decline with scale and infrastructure sharing.

IV. WORLD GAS MARKETS

Expected Growth in World Gas Demand

The development of gas-fired combined cycle power generation has stimulated the demand for gas throughout the world, not only in countries with their own natural gas resources, but in countries that previously were "gas poor" and had to rely on imports. The projections made by the Energy Information Administration in its International Energy Outlook 2003 foresee a 70% increase in worldwide gas demand between its base year, 2001 and the year 2020 and a 95% increase between 2001 and 2025. See Figure 4-1. While oil will retain its position as the largest source of primary energy over the period, gas will steadily gain in market share rising from 23% of primary energy supply in 2001 to 28.4% by 2025.

The growth of natural gas demand is expected to be somewhat uneven. In 2002, North America together with Europe and the former Soviet Union accounted for 71% of total world gas demand and their dominant share of gas demand is expected to continue. But the highest growth rates are expected to occur in Central and South America, developing Asia (Including India and China), and in Africa. The share of gas in primary energy in all of these regions has been below average, but the increasing availability of pipeline infrastructure and LNG imports will enable them to utilize gas more effectively. The EIA's projections of world gas demand are shown in Figure 4-2.

The Role of Electric Power Generation in the Growth of Gas Demand

The principal driving force behind the strong growth in gas demand is its use in power generation. Power generation accounts for about one third of anticipated growth in primary energy demand (see Figure 4-3) through the end of the EIA's forecast period, and gas-fired generation will drive those increases. Figure 4-4 illustrates that the EIA foresees that about half of all worldwide increases in primary energy supply from 2001 for power generation will go to gas.

Competitive Fuel Prices and Their Influence on the Dispatch of Gas Units for Power Generation

The share of the generation market that gas can command in the power generation sector depends on the way in which gas units are dispatched relative to alternate sources of generation. The term "dispatch" refers to the scheduling of units to serve electric loads which vary both daily and seasonally. In general, units are classed as "base load" (roughly 7,000 hours per year), "intermediate load" (about 4,000 hours) or "peaking" depending on the way in which they are scheduled. A base load unit will operate at high capacity factors and thus consume much more fuel for a given nameplate capacity rating than will a peaking unit.

Under the common practice of "economic dispatch", units are scheduled according to their marginal costs with those units having the lowest marginal costs dispatched as base load. In markets where gas is relatively inexpensive compared to alternatives, it will often be dispatched as base load, but as gas prices rise, gas may be at risk to reduced utilization rates as other energy sources displace it in base load operation.

In competing with oil, coal or nuclear generation, gas benefits from its comparatively low capital costs. It, therefore, is often able to trade off its lower capital costs against its higher fuel prices and still be dispatched as base load. However, its high marginal generating costs - the result of its often higher fuel prices - may make it unable to retain base load dispatch in some competitive fuel pricing environments and may make it vulnerable to reduced utilization where surplus generating capacity exists.

Figure 4-1

PROJECTED GROWTH IN WORLD PRIMARY ENERGY DEMAND TO 2025

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS

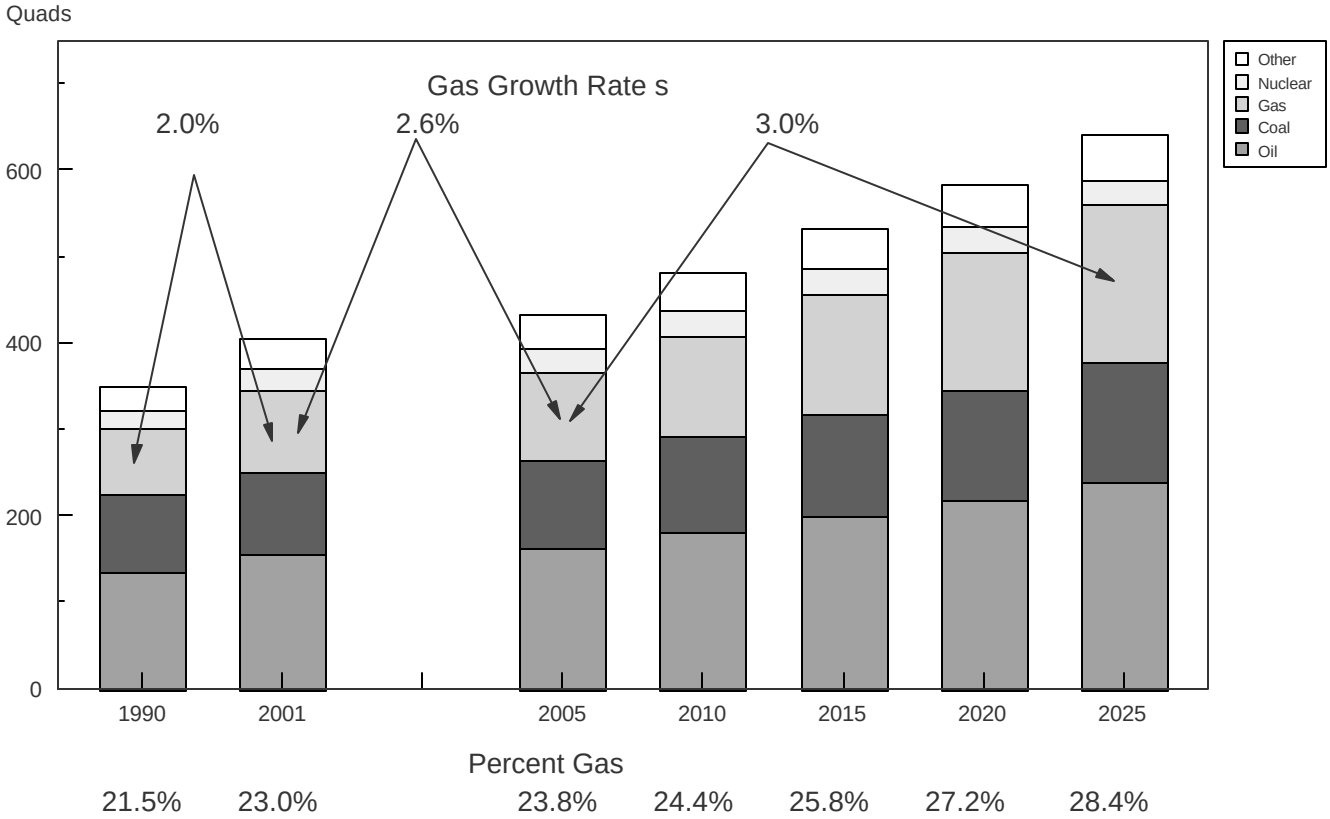


Figure 4-2

PROJECTED GROWTH IN WORLD GAS DEMAND TO 2025 BY REGION

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS

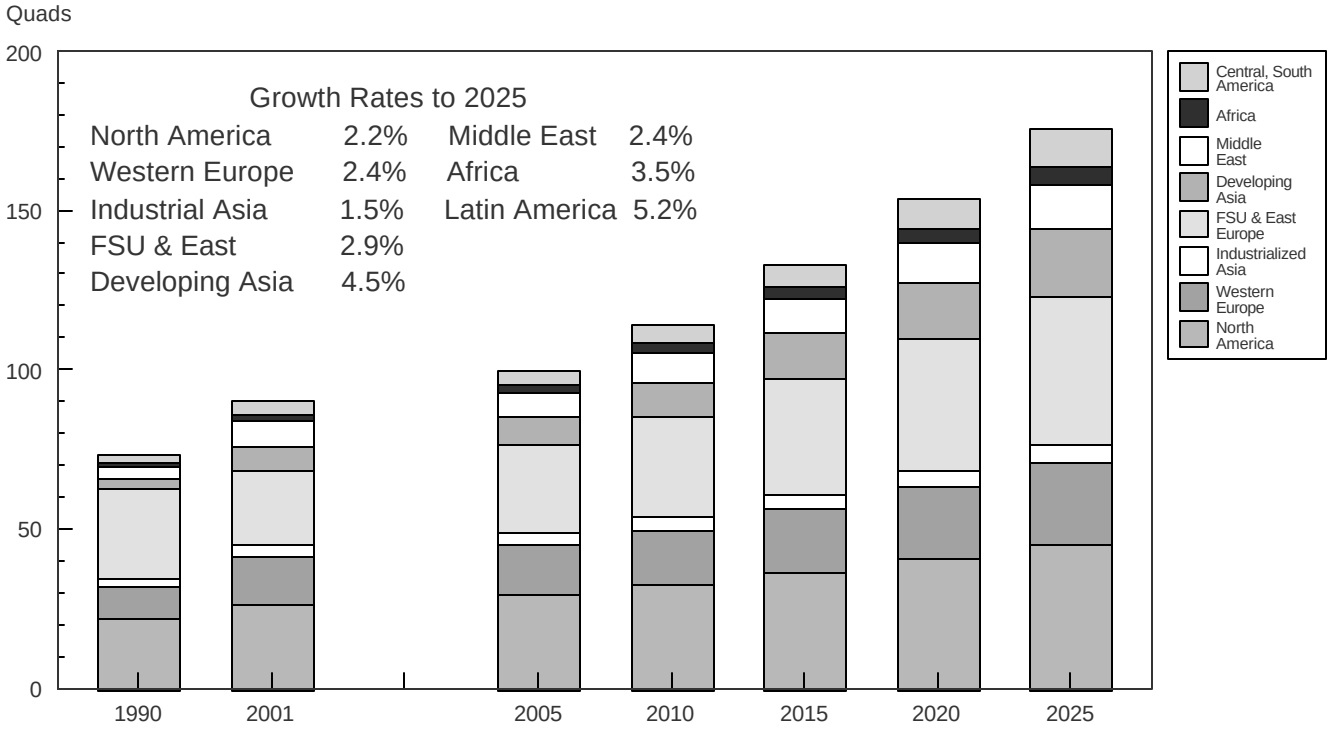


Figure 4-3

INCREMENTAL PRIMARY ENERGY FROM A 2001 BASE SHOWING THE IMPORTANCE OF POWER GENERATION

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS

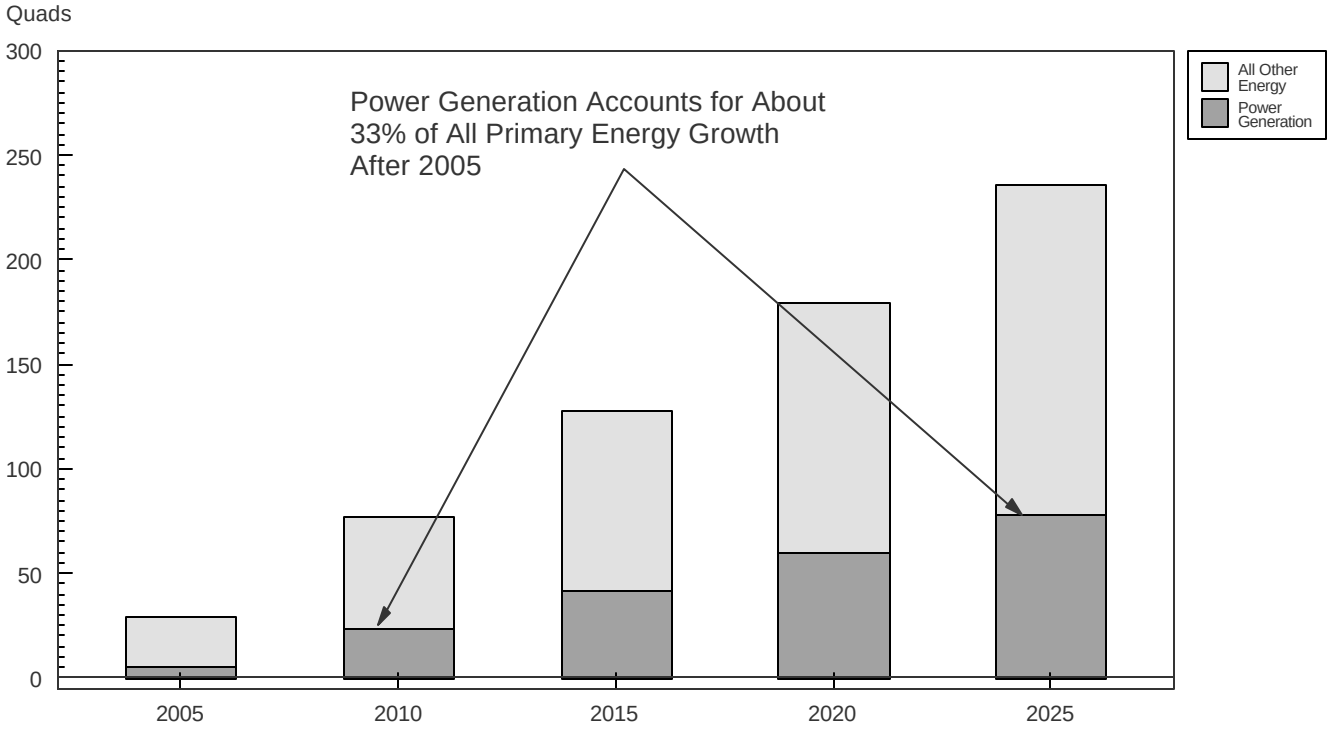
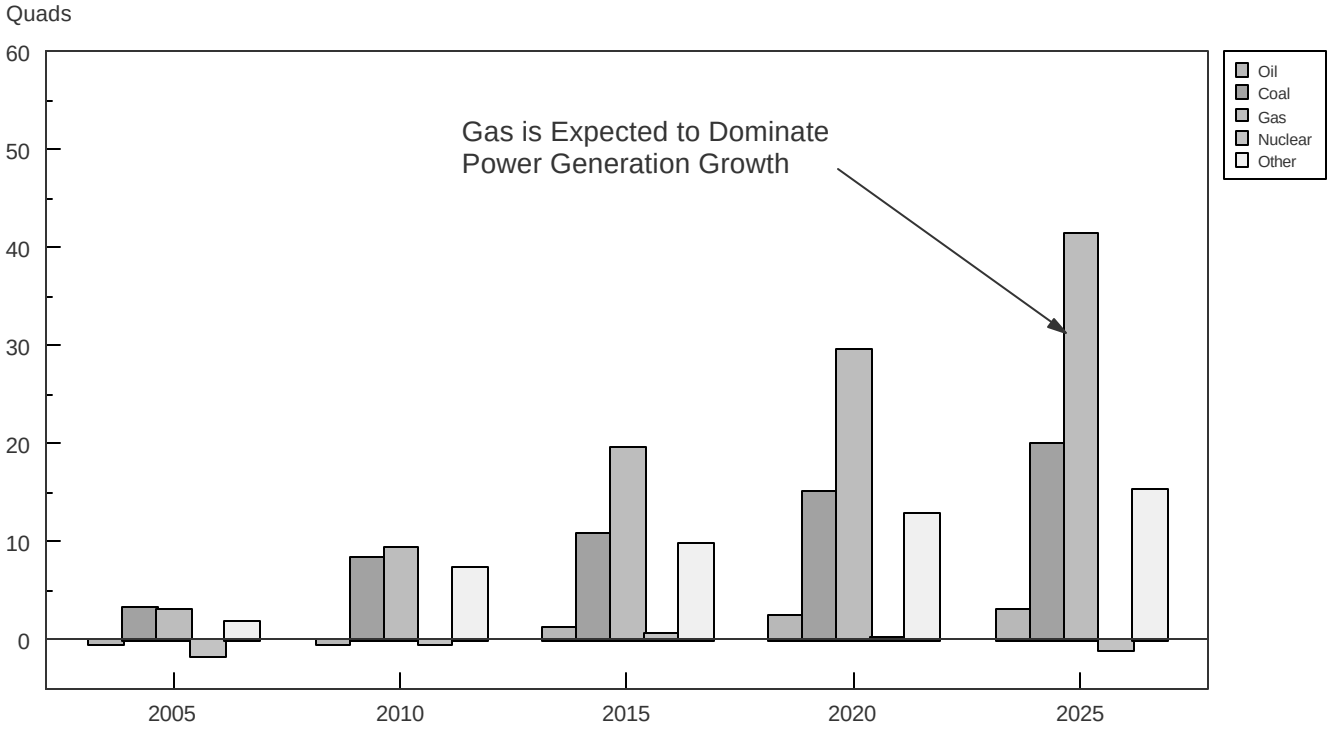


Figure 4-4

INCREMENTAL PRIMARY ENERGY UTILIZATION FOR ELECTRICITY GENERATION FROM A 2001 BASE

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS



Percent Gas

2005	2010	2015	2020	2025
50%	39%	46%	49%	53%

It may appear to LNG suppliers that Japanese electric power is a base load market, since the electric utilities buy on the traditional 90% take-or-pay contract. However, gas-fired CCGT units are actually fired as intermediate load by the Japanese utilities, where they commonly concede base load to coal and nuclear units. And the Bolivia-to-Brazil Pipeline has failed to live up to expectations because it has been difficult to guarantee base load dispatch treatment for CCGT units in an environment where hydro power dominates and utilities are reluctant to "spill water"when it is available.

Figure 4-5 illustrates the competitive dispatch problem that gas-fired units commonly face. It illustrates the economics of CCGT units (at 4000 hours where gas excels) with hydro, coal, nuclear and oil units using average Japanese imported fuel costs for 2002. While gas is second only to hydro when dispatched at this intermediate load, it has higher marginal costs than all units but oil, making it vulnerable to underutilization in times of over capacity.

The influence of competitive fuel prices on dispatch levels and thus on gas demand is illustrated in Figures 4-6 and 4-7. They compare the economics of gas-fired CCGT units under base load conditions (7000 hours) in Figure 4-6 and under intermediate load conditions (4000 hours) in Figure 4-7. The four cases are Japan in 2002, the U.K. in 1995 and the U.S. in both 1995 and 2002.

The Japanese dispatch balance is based on expensive gas (imported as LNG) and cheaper imported coal. In the Japanese case, coal - (nuclear is similar) - is less costly to dispatch under base load conditions, but CCGT units are better for intermediate load. The U.K. case tries to capture the competitive economic climate in the mid 1990s, when the country experienced its "dash for gas". This was set off by the privatization of the U.K. electric utilities thereby eliminating their political requirement to purchase high-cost British coal. Here the comparative economics of coal versus gas are the reverse of the Japanese case. Not only is gas the preferred choice for both new base and intermediate loads, but it displaced coal in existing units as well.

In 1995, the U.S. had both low coal and gas prices, and as the illustration shows, gas is preferred for both base and intermediate loads (the Figure uses average national prices and thus does not attempt to capture the significant regional differences in generating patterns). With the sharp rise in gas prices during 2002, these relative competitive patterns have shifted. In the national average example, gas is no longer favored for base load over coal even though it retains its preferred position for intermediate dispatch. While the case shown in general, and not region-specific, it does illustrate that some of the gas-fired units that were originally justified for base load, may now be at risk to downgrading in the dispatch merit rating.

Environmental factors will clearly play a role in determining the way in which gas competes with coal and nuclear in the dispatch cycle. The concern for global warming places coal in a particularly unfavorable light. Both Europe and Japan have considered the possibility of carbon taxes, which if enacted, would tend to shift the balance more in the direction of gas-firing.

The Prime Targets for LNG Imports

Only 23% of world gas consumption in 2002 was imported and only 26% of that was in the form of LNG. Thus forecasts of gas demand or even of gas trade do not necessarily indicate how rapidly LNG is likely to grow.

The EIA projections indicate the total expected increase in world gas demand broken down by broad groups of countries. It anticipates an increase in worldwide demand of 60.2 quads between 2001 and 2020, an amount roughly three times the gas consumption of the U.S. in 2001. About one third of the increase is expected to take place in countries that are expected to be self-sufficient - such as Canada, the Netherlands, or the former Soviet

Figure 4-5

COMPARATIVE POWER GENERATION COSTS BY UNIT TYPE

ILLUSTRATED USING 2002 JAPANESE IMPORTED FUEL COSTS

500 MW UNITS, 4000 HOURS PER YEAR

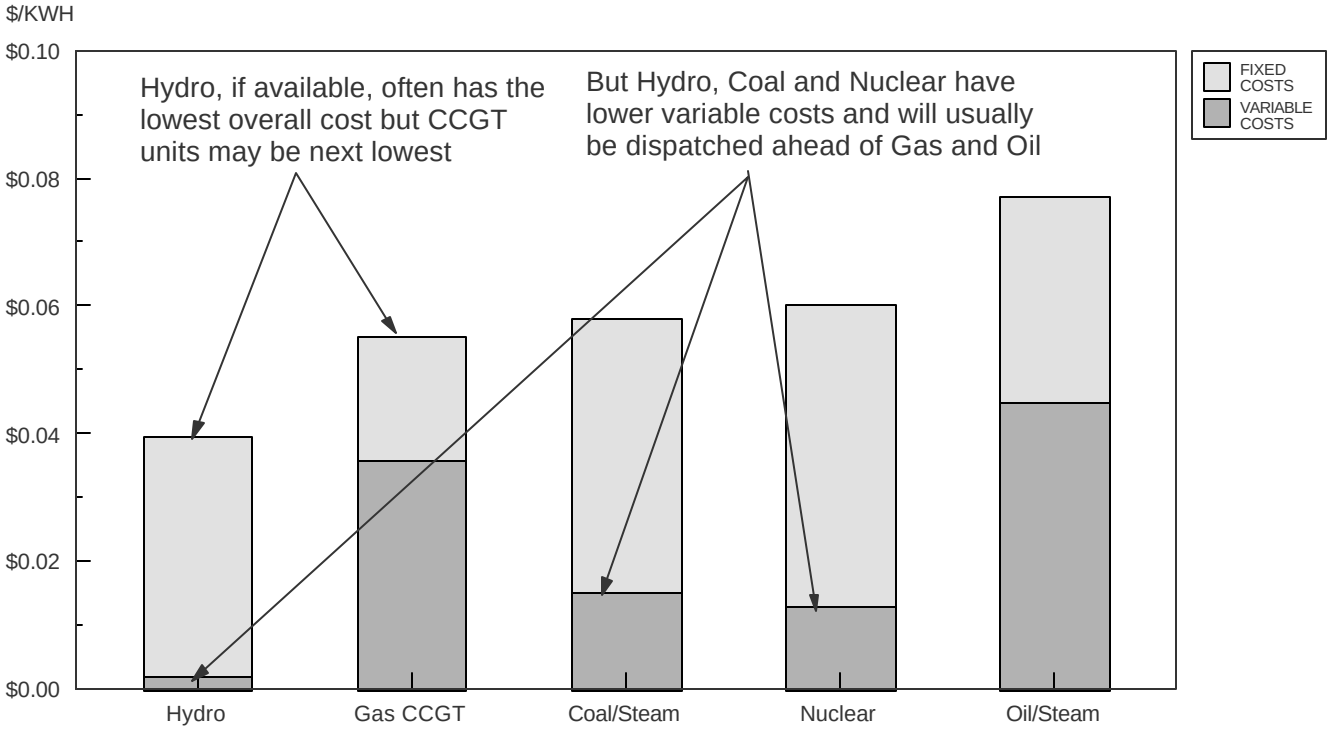


Figure 4-6

ILLUSTRATIVE COST OF POWER BY TYPE OF GENERATION AND FUEL COSTS

BASELOAD OPERATION - 7000 HOURS (80% CF)

COMPARING JAPAN 2002, U.K. 1995 AND U.S. 1995 FUEL PRICES

$/KWH

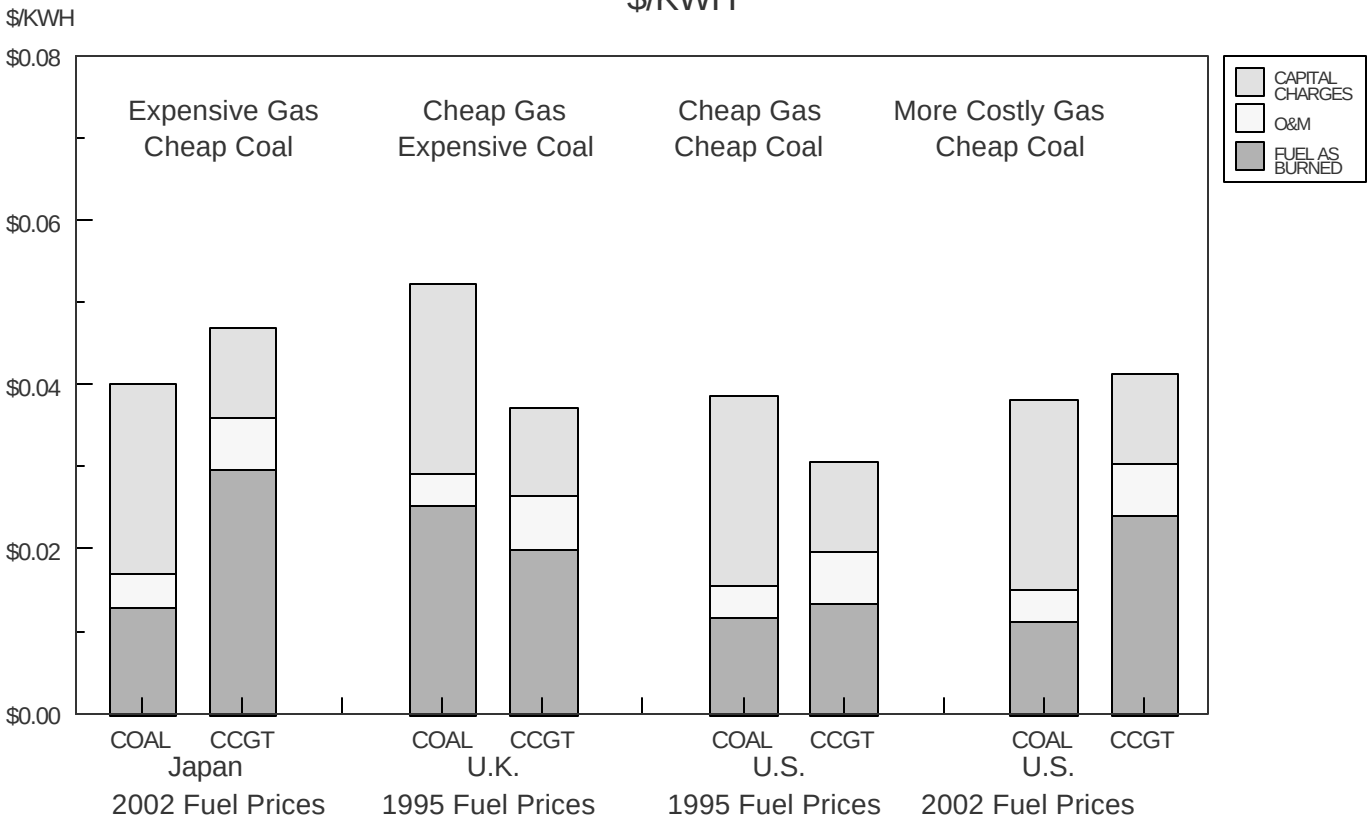
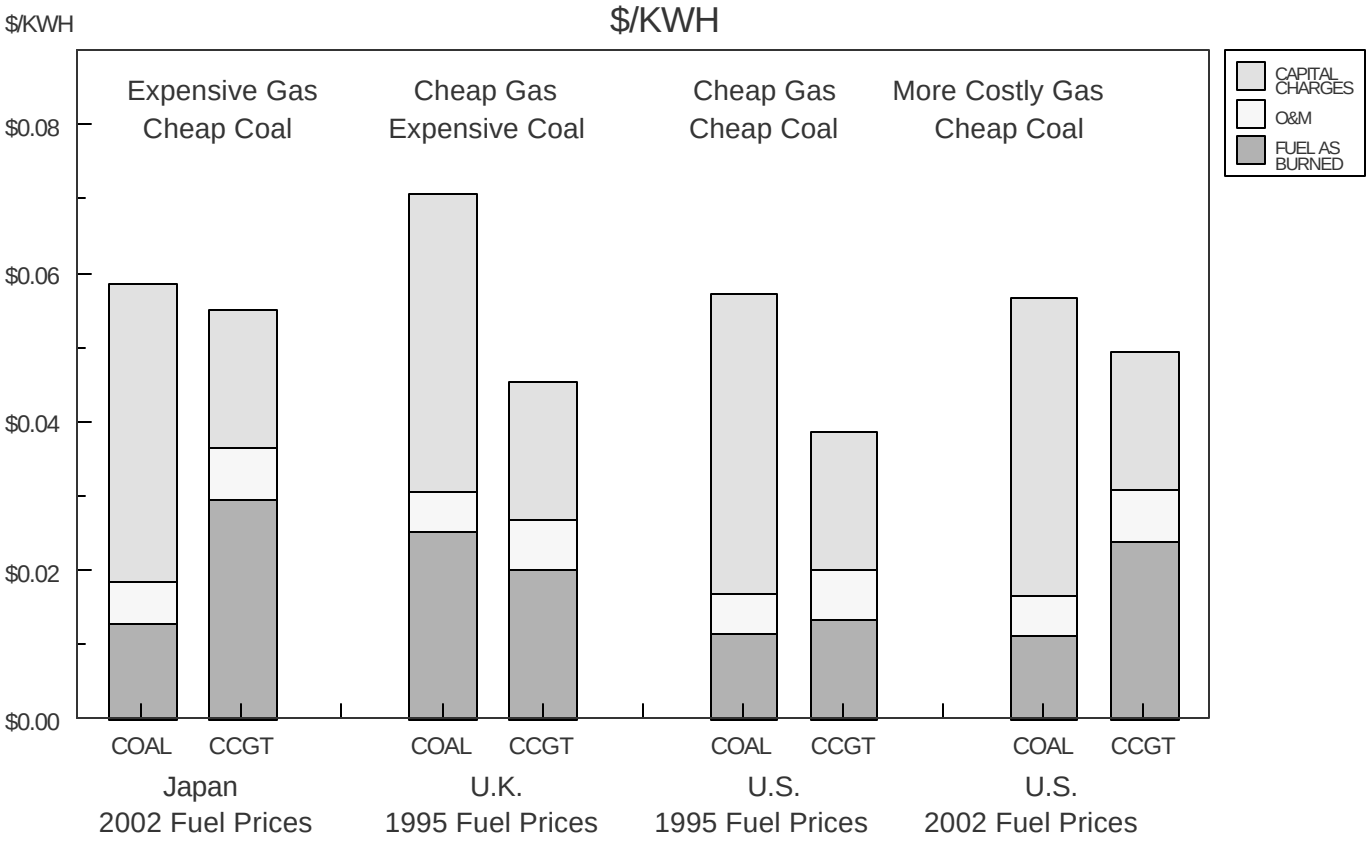


Figure 4-7

ILLUSTRATIVE COST OF POWER BY TYPE OF GENERATION AND FUEL COSTS

INTERMEDIATE LOAD OPERATION - 4000 HOURS (45.7% CF)

COMPARING JAPAN 2002, U.K. 1995 AND U.S. 1995 FUEL PRICES



Union - or are expected to be rely on pipeline imports. Of the remaining two-thirds, 10% are included in broad groups and are not detailed (Taiwan or Spain, for example). But 57% of the growth is expected to occur in specific countries where LNG is an option.

The EIA does not attempt to apportion this growth in gas demand among indigenous production, pipeline imports or LNG, so it does not supply a forecast of LNG as such. Figure 4-8 shows the incremental growth in gas demand between 2001 and 2020 for groups of countries.

LNG imports into the U.S. have not been a substantial part of supply to date, but that is expected to change as a result of the disappointing experience with traditional U.S. and Canadian production. Neither the U.K. or Mexico have imported LNG in recent times, but both are now LNG targets as problems with indigenous supply have made it necessary to turn to imported gas. The U.K. is considering substantial LNG imports later in this decade, although their extent will depend on whether or not there is pipeline competition from a Baltic offshore pipeline from Russia. Mexico now imports gas from the U.S., but is considering LNG terminals in both the Gulf of Mexico and the Pacific Coast (primarily for domestic use) and Baja California, where the bulk of the imports would be reexported to Southern California.

Elsewhere in Latin America, but not broken out in the EIA projections are small countries that may utilize LNG for power generation. The construction of a small import terminal in Puerto Rico initiated this potential trend for the Caribbean and the Dominican Republic opened a terminal in 2003 as well.

France, Italy and Turkey have relied both on LNG imports and pipeline supply and are expected to continue to do so. Spain, which is not detailed in the EIA projections, has been a strong importer of LNG as well. Turkey, however, has committed more on long term contracts than its demand seems to warrant and is in trouble with its suppliers. Since it also seems to have decided to emphasize pipeline supplies over LNG for growth, the prospects for LNG are more limited in that country. The Turkish pipeline commitments include pipeline deliveries from Russia - both via the Balkans and via Blue Stream, the innovative deep water crossing of the Black Sea - and Iran. Pipeline projects from Turkmenistan and Azerbaijan have also been proposed.

Both China and India are viewed as strong new markets for gas imports, but both are facing pipeline and LNG competition. In India's case, the economics of pipeline delivery from Iran via Pakistan or Turkmenistan via Afghanistan and Pakistan appear to be superior to those of LNG. However, concern for the reliability of supply from Iran and Turkmenistan and the political risks of transiting Afghanistan and Pakistan have shifted the balance in favor new LNG projects. There is one firm new import terminal under construction at Daheej to supply gas from Qatar to Petronet and a number of others variously rumored in the trade press to be nearing contract signing. But Enron's well-publicized troubles with its project at Dabhol and the difficulty suppliers are having finding credit-worthy buyers has cast a significant degree of doubt about how rapidly LNG imports will actually grow.

China, too, has proven difficult to predict. To some outside observers, its market does not seem large enough to support its ambitious East-West Pipeline from the Tarim Basin to Shanghai and extensive LNG imports as well. As the International Energy Agency points out in is recent world investment study[5], ..."the pace of development of gas infrastructure will ultimately depend on policy reforms to clarify the investment and operating environment and proactive government measures to boost the competitiveness of gas against cheap local coal." However,

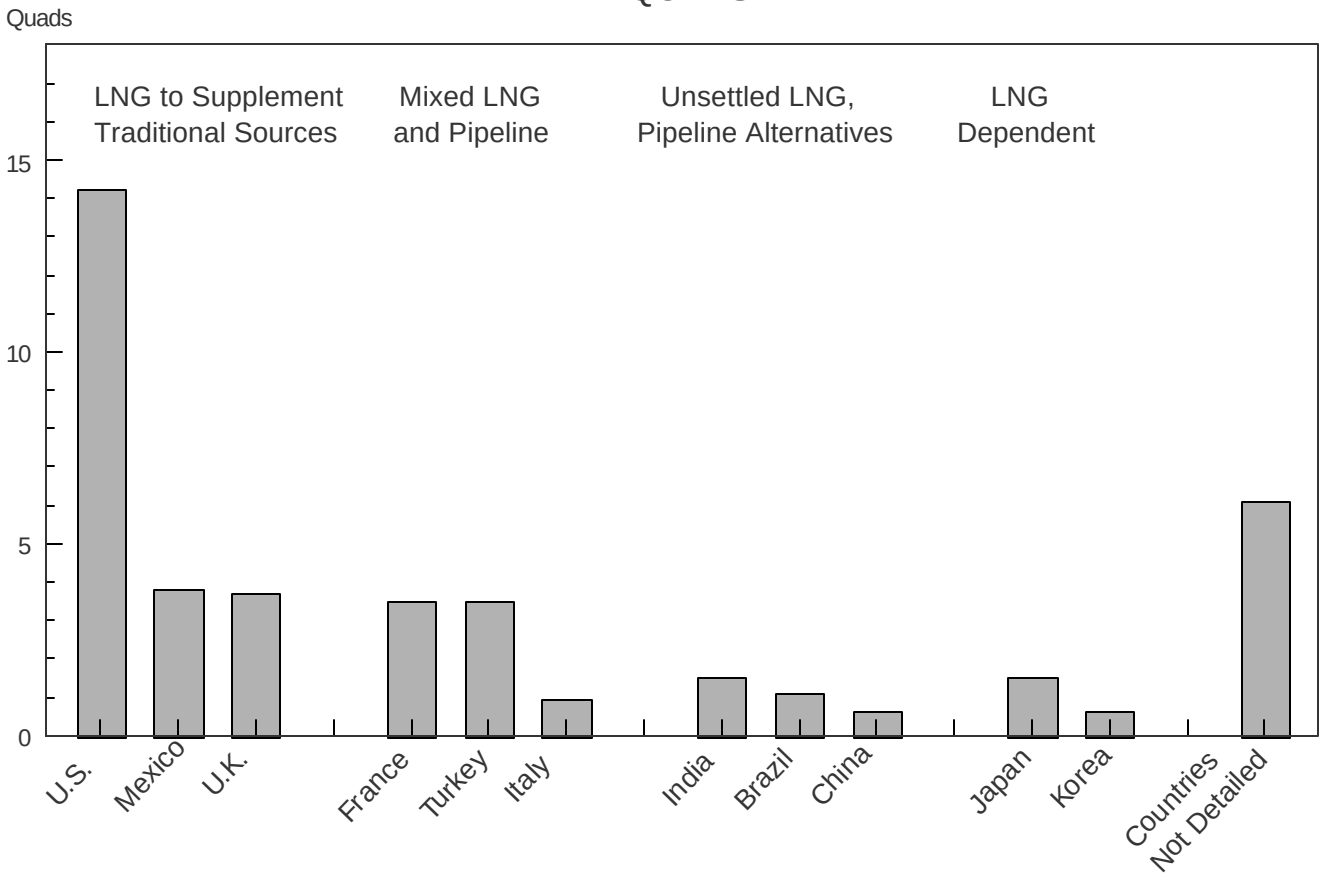
[5] Page 244, World Energy Investment Outlook, 2003 Insights, International Energy Agency, Paris

Figure 4-8

FORECAST OF GROWTH IN TOTAL GAS DEMAND 2001/2020 BY POTENTIAL LNG IMPORTING COUNTRIES

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS



China has contracted with the Australian Northwest Shelf project to supply Guandong in the south and with Indonesia's Tangguh project for supply to Fujian in the North.

Brazil's anticipated rapid shift towards a gas-based energy economy has also not gone as many previously expected. The original idea was for pipeline supply to the major population centers, supplemented by LNG imports into the remote Northeast. However, the Bolivia-to-Brazil pipeline is operating well below design capacity as it has proved to be difficult to sign up gas-fired generation customers in a hydroelectric economy. Moreover, a recent large gas discovery has raised the possibility that Brazil might become an LNG exporter, rather than an LNG importer.

To date, the gas markets of Japan and Korea (as well as Taiwan, which is not detailed in the EIA projection) have been almost exclusively supplied by LNG. While LNG's dominant role is likely to continue, both Japan and Korea have considered pipeline alternatives - Japan most likely from Sakhalin, and Korea most likely from East Siberia via China.

The International Energy Agency has been somewhat more explicit about increases in international trade in its World Energy Outlook 2002. In its Figure 3-13, the IEA shows "Net Inter-Regional Gas Trade Flows, 2030." By converting the estimates on the graphs into Average Annual Increases in flows and specifying whether the flow in question is likely to be purely LNG (such as Africa/North America) or mixed LNG/Pipeline (such as Africa/Europe), it is possible to get some idea of where the IEA anticipates that the major flows will occur.

Figure 4-9 summarizes the flows as either LNG or mixed LNG/Pipeline into the principal importing regions (excluding pure pipeline trades such as those from the former Soviet Union to Europe). While North America has shown little historical growth in inter-regional imports, its increases - all as LNG - for the forecast period will become the largest. Europe has been heavily dependent on the former Soviet Union for pipeline imports (not included in the Figure), but will substantially increase its dependence on other inter-regional imports. The North African trade has been a mixture of trans-Mediterranean pipelines and LNG, but its growing reliance on the Middle East and on Latin America will be heavily oriented towards LNG.

The IEA sees a slowing of the growth in LNG or LNG/Pipeline trade to Northeast Asia. Both India and China emerge as important markets for inter-regional trade, although they remain small compared to North America and Europe. While LNG should be the early winner, the possibility of overland pipelining to India remains if the political climate improves, and China has seriously considered pipeline supply from East Siberia.

Figure 4-10 summarizes the same information summarized by exporting regions. The Middle East has increased slightly more rapidly than Africa between 1996 and 2002, but will gain significantly during the forecast period. Latin America will also increase its average level of exports over the period. The Asia Pacific region, which dominated export supply until the late 1990s, has slowed considerably since 1996. The EIA does not expect it to increase its exports that significantly in the forecast period.

The small export potential from the former Soviet Union (again ignoring the very large pipeline-only flows to Europe) will enter the LNG/Pipeline supply figures for its potential Sakhalin and East Siberian exports.

Some indication of the prime LNG targets come from the trends that have been established by recent trading patterns. With the collapse of the U.S. market in 1980, the focus of international LNG shifted from the Atlantic Basin to the Pacific Basin. Between 1980 and 1996, Japan, Korea and Taiwan accounted for 80% of all growth in LNG trade, with Japan alone accounting for 56% of it. Figure 4-11 illustrates the dominant role of Japan, Korea and Taiwan during this period.

Figure 4-9

IEA FORECASTS OF AVERAGE ANNUAL INCREASE IN "NET INTERREGIONAL" IMPORTS TO 2030 COMPARED TO 1996/2002

LNG OR MIXED PIPELINE/LNG IMPORT TRADES ONLY

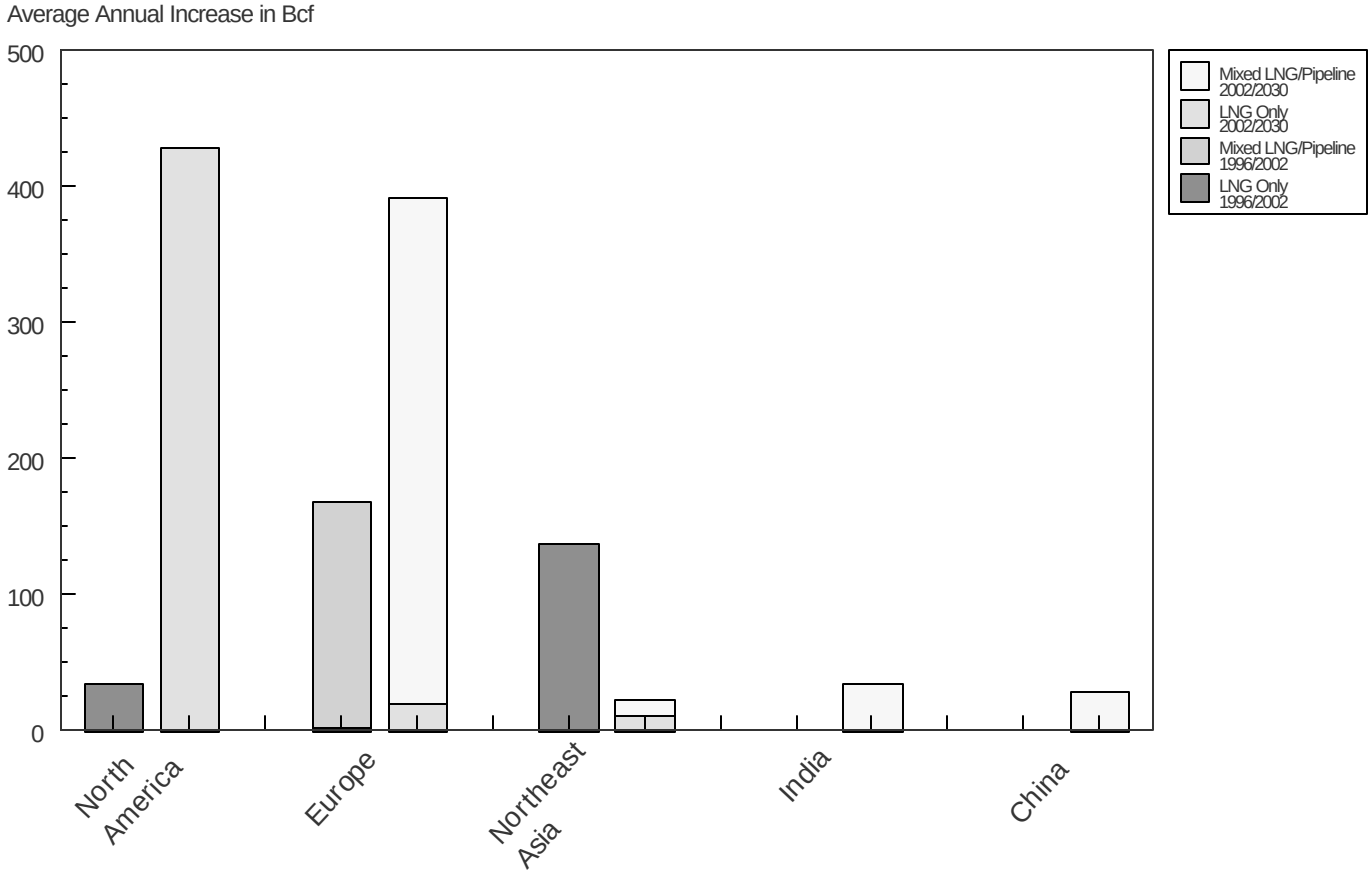


Figure 4-10

IEA FORECASTS OF AVERAGE ANNUAL INCREASE IN "NET INTERREGIONAL" EXPORTS TO 2030 COMPARED TO 1996/2002

LNG OR MIXED PIPELINE/LNG EXPORT TRADES ONLY

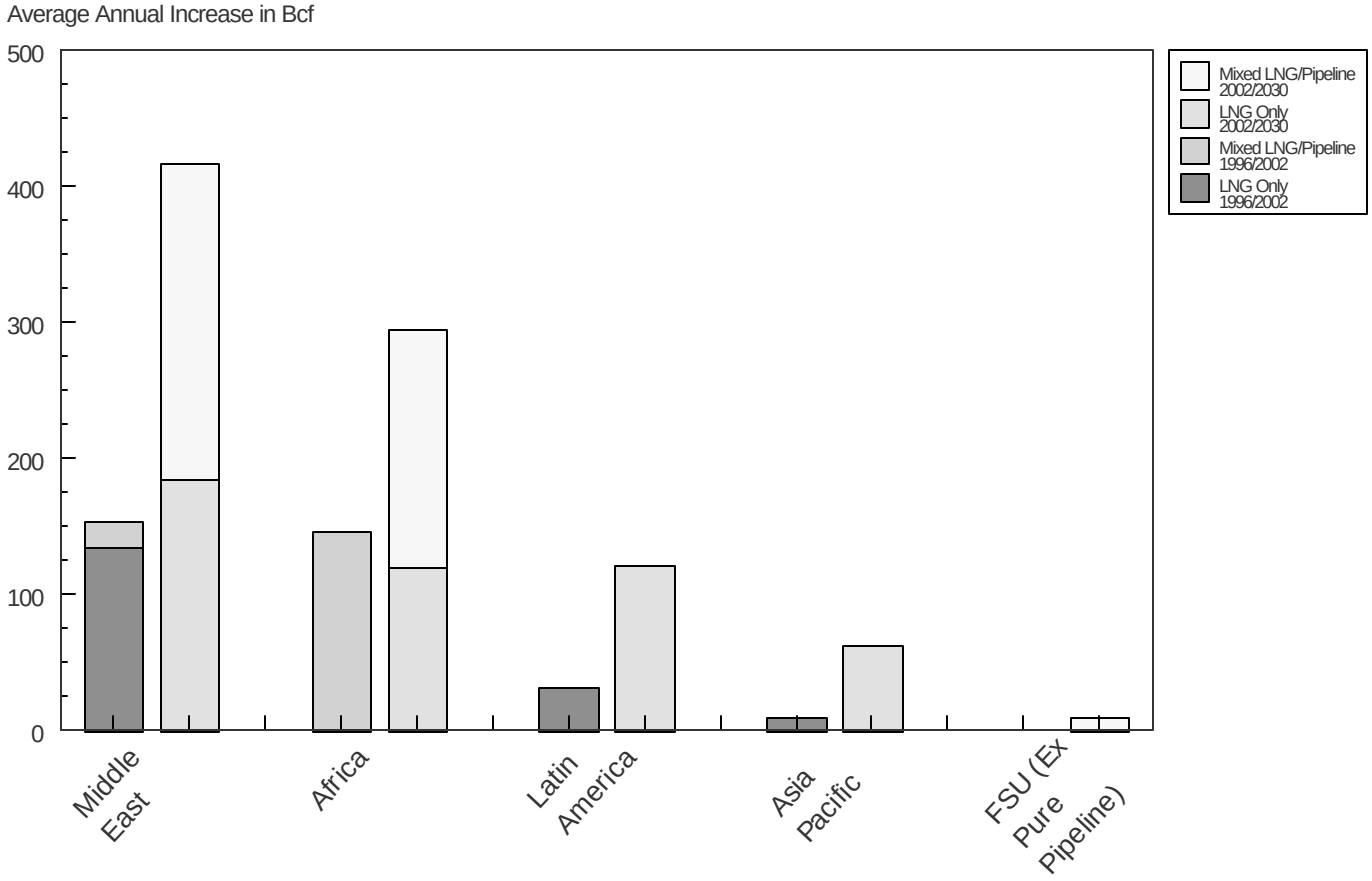
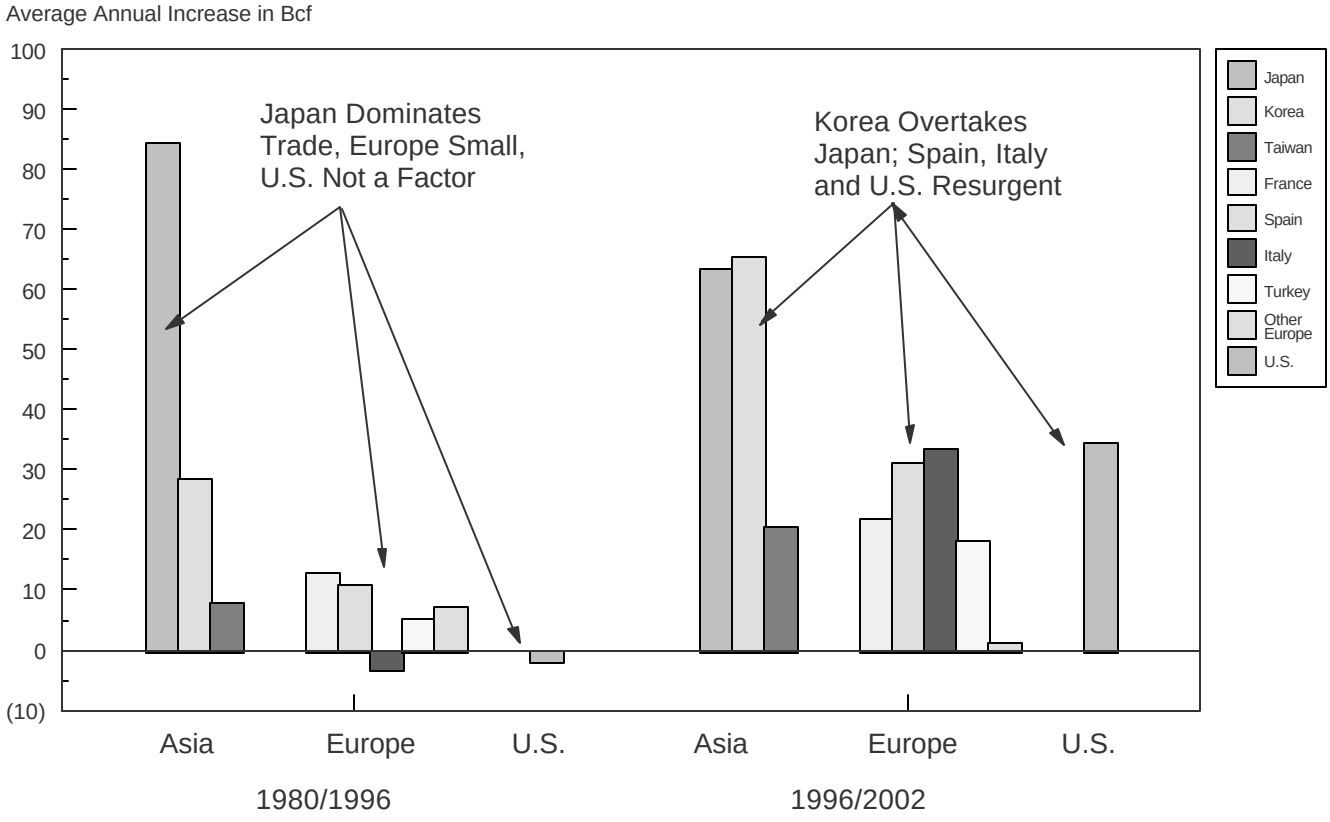


Figure 4-11

AVERAGE ANNUAL INCREASE IN LNG IMPORTS BY COUNTRY FOR TWO SELECTED PERIODS

1980/1996 and 1996/2002



However, beginning in the mid 1990s, the Japanese economy began to slow, while interest in LNG revived in countries such as the U.S., Italy and Spain. Thus Korea overtook Japan in growth and the Atlantic Basin market became much more important. Now, the U.K. seems poised to become a major LNG importer as it finds itself with growing demand and poorer prospects for meeting its requirements from traditional North Sea sources.

In summary, the patterns of potential LNG trade indicate the emergence of North America, the U.K., India and China to join the ranks of major importers such as Japan, Korea, Spain, France, Taiwan and Italy. The historic growth of the Asia Pacific as a supply region is expected to slow, while the Middle East, Africa and to a lesser extent Latin America emerge as more important incremental exporters.

V. LIQUEFACTION

Technology and Cost Structure

An LNG liquefaction plant can best be described as a giant refrigerator, which takes gas at ambient temperatures and cools it to minus 260º Fahrenheit, where it becomes a liquid at atmospheric pressure. The processes used for liquefaction utilize the Joule-Thompson effect in which the gas is first compressed and then subjected to expansion cooling through a valve.

While there are a number of processes by which gas can be liquefied, more than 90% of the world's installed capacity uses a process licensed by Air Products and Chemicals, Inc. known as the propane pre-cooled mixed refrigerant (C_3/MR) process. An early design utilized in the Cook Inlet Alaska plant, the cascade process, has been revived in the Trinidad LNG plant. This process is licensed by ConocoPhillips. The growing complexity of offshore gas sources has led to renewed interest in some of the other alternatives to C_3/MR.

Liquefaction facilities come in modules, called "trains". The size of the train has been limited by compressor technology. Early train sizes were limited - typically to about 2 million tons per train - by the compressors then available, and it might require three trains of that size to justify a new greenfield facility. However, recent improvements in compressors have made it possible to design much larger trains. While the largest current operating train is smaller than 4 million tons, there are a number of trains in the planning stages that will exceed that level and Qatar is considering the possibility of 7.5 million ton trains. Larger trains benefit from economies of scale, and it is now possible to justify a new greenfield facility with a single larger train.

Figure 5-1 illustrates the cost improvements that come with scale in increasing train sizes as well as the reduced incremental costs of expansion trains versus greenfield construction. There is a 20% reduction in liquefaction costs in going from three 2 MMT liquefaction trains ($1.63) to two 3 MMT trains ($1.30) in a greenfield facility. And adding two more 3 MMT trains in an expansion reduces the cost ($1.10) of the first two by another 15%. The changes in individual train costs have gone from $1.32 in the 2 MMT size to $0.97 in the current 4 MMT size. If Qatar proceeds with a scale up to 7.5 MMT trains, this should reduce the costs by an additional 22% from the current range.

The Overhang of Excess Liquefaction Capacity - Its History and Prospects

The industry has maintained a surplus of liquefaction capacity over and above the demand for LNG throughout its history. Figure 5-2 shows the history of LNG exports compared with plant capacity from 1969 through 2002. Figure 5-2 compares actual exports, including short term trade, with capacity and thus does not attempt to measure surplus capacity relative to long term contract commitments.

The early surpluses are largely attributable to the collapse of the Algeria/U.S. trade in 1980. It came about as a result of a politically-motivated change in Algerian export policy following the change of regime in 1978, when combined with the coincident restructuring of the U.S. gas industry. At the same time that Algeria wanted more for its LNG exports, the U.S. was introducing market-responsive pricing policies that made it impossible to sell higher- priced gas. Under the new aggressive pricing policies, Algerian exports to the U.S. fell well below originally-planned levels and a significant liquefaction capacity surplus resulted. Figure 5-3 illustrates how much of the early excess capacity was concentrated in the Atlantic Basin and figure 5-4 illustrates that the Atlantic Basin surpluses were almost entirely concentrated in Algeria until the recent startup of new facilities in Trinidad and

Figure 5-1

LNG LIQUEFACTION COSTS AS A FUNCTION OF SIZE OF LIQUEFACTION FACILITY

$/MMBTU

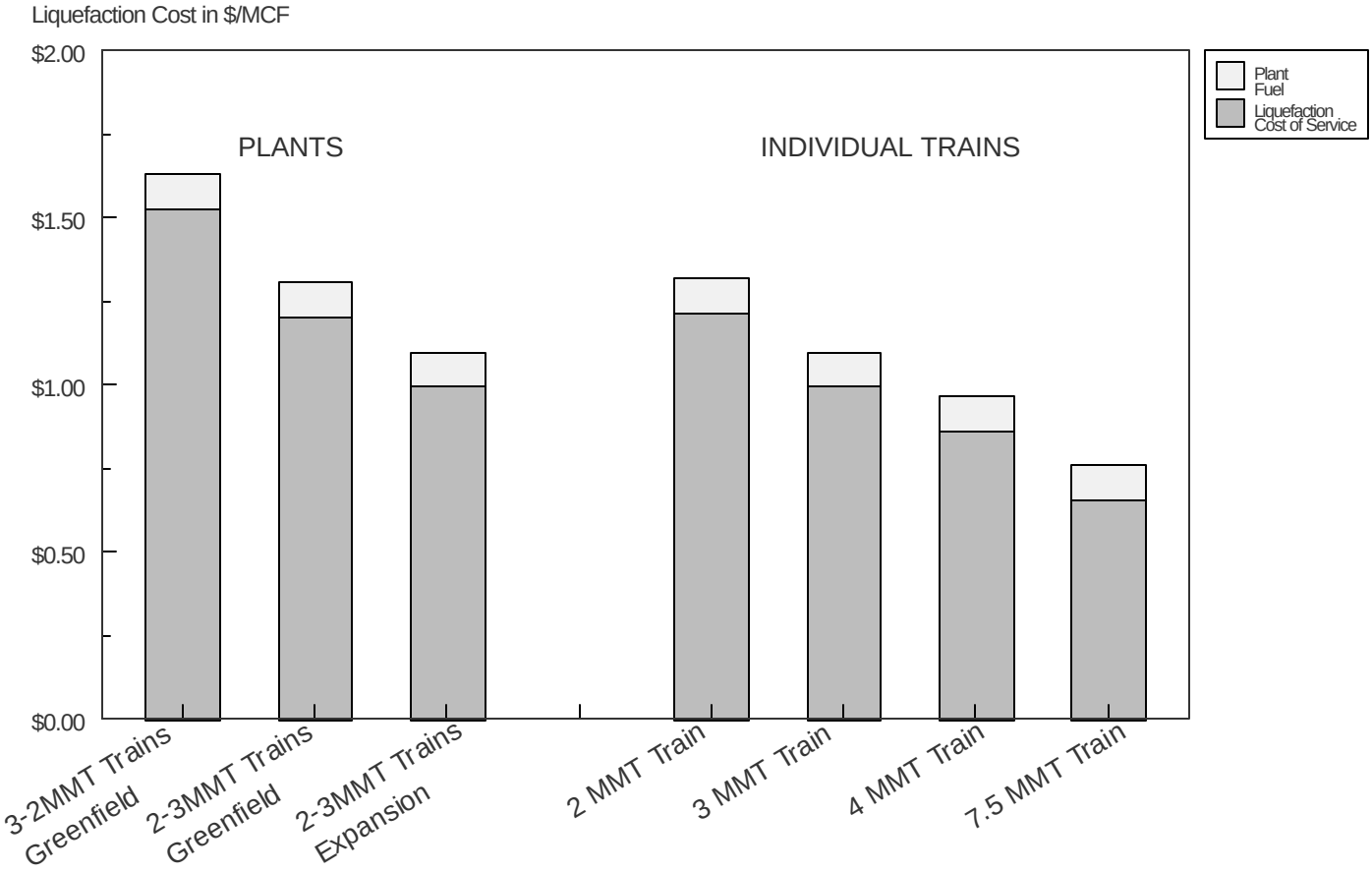


Figure 5-2

LNG EXPORTS COMPARED WITH LIQUEFACTION CAPACITY BY YEAR

BCF

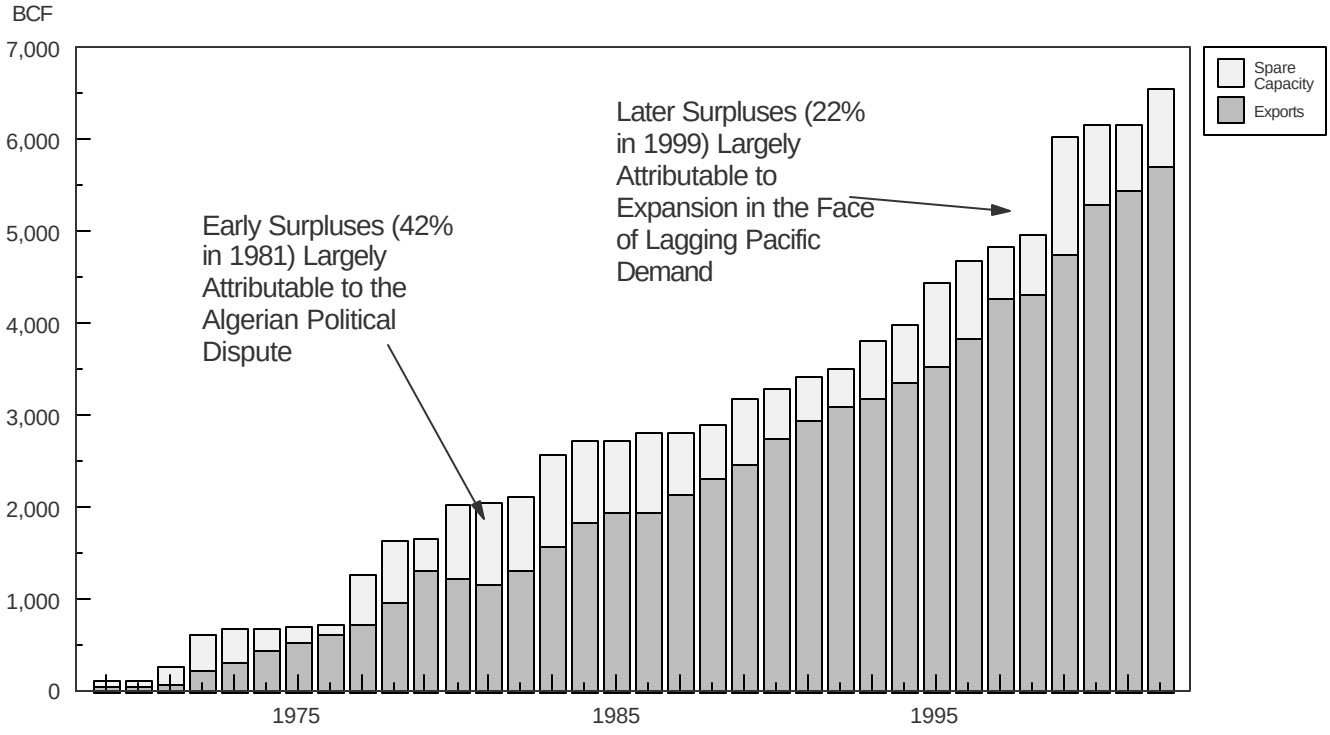


Figure 5-3

EXCESS LIQUEFACTION CAPACITY BY KEY EXPORTING REGIONS

BCF

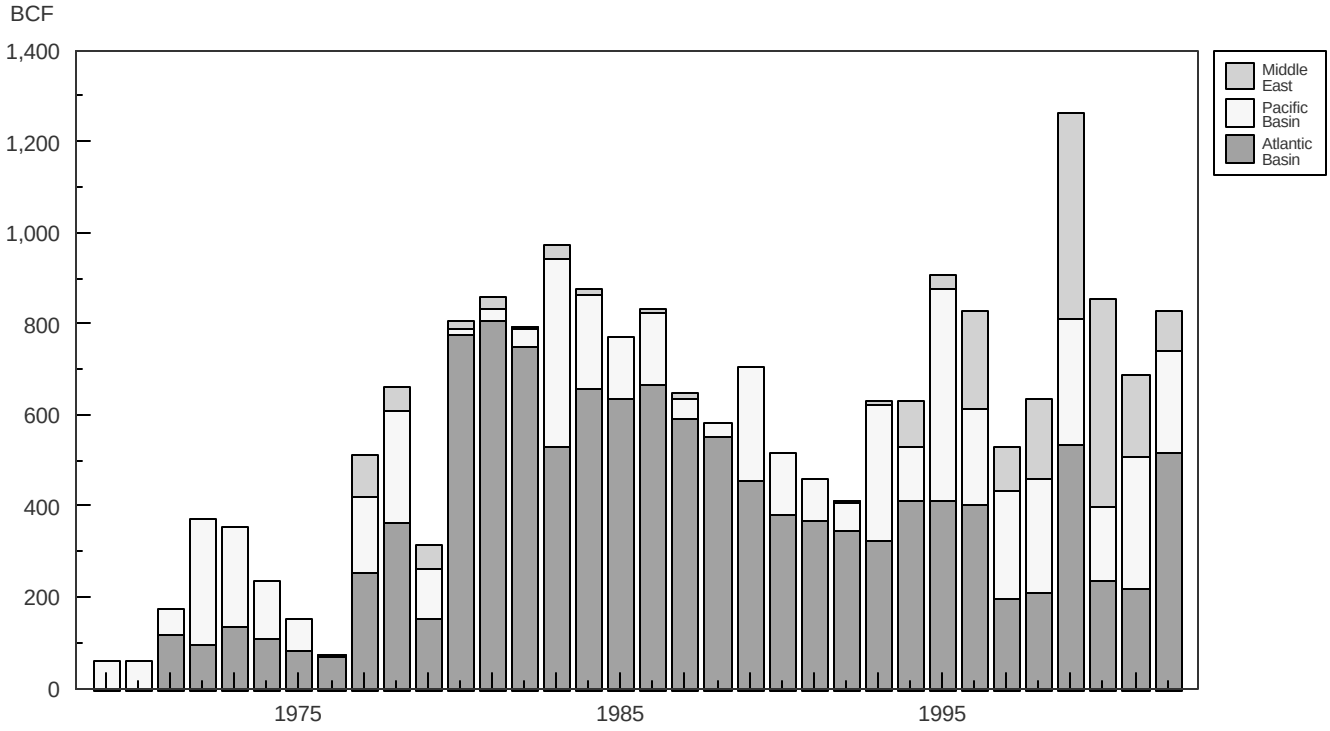
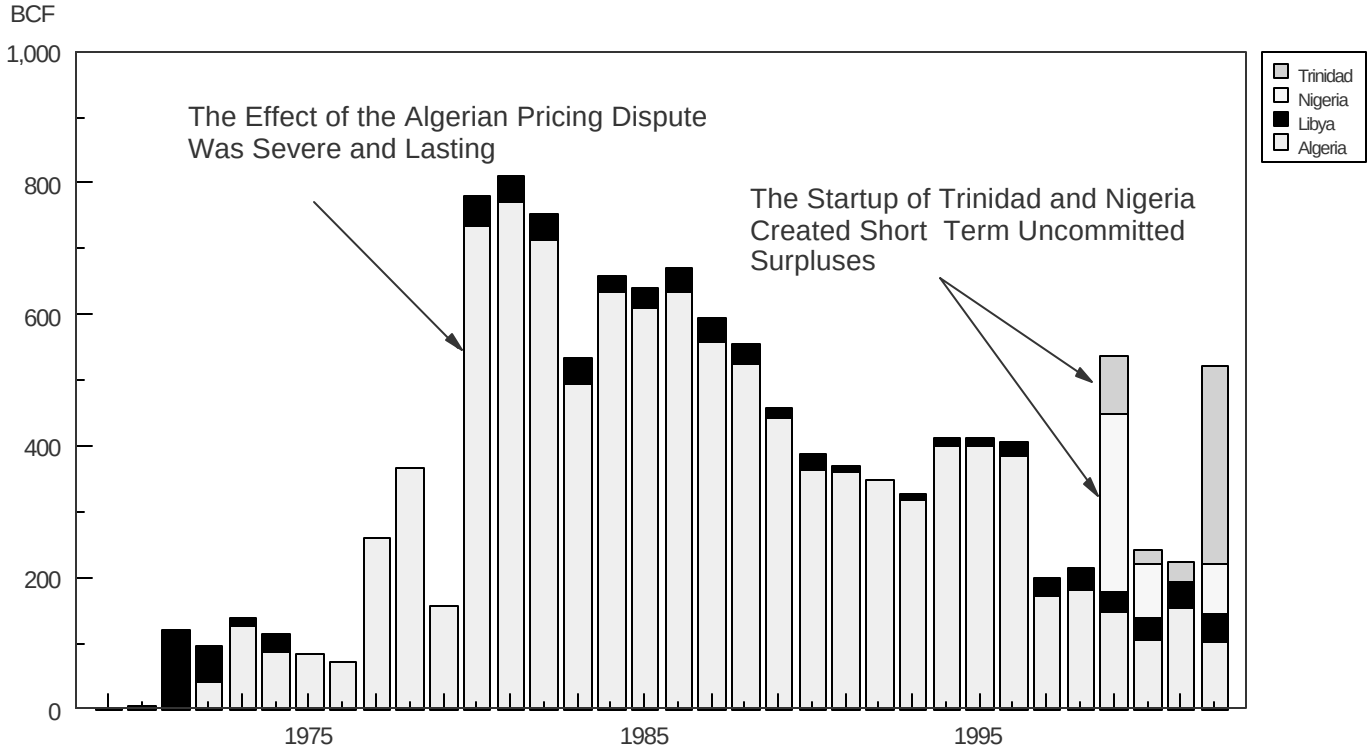


Figure 5- 4

EXCESS LIQUEFACTION CAPACITY BY KEY ATLANTIC BASIN EXPORTERS

BCF



Nigeria. These recent surpluses are more characteristic of current patterns, whereby expansion of new capacity is completed before the markets - and the underlying contract commitments - have reached planned plateau levels.

Figure 5-5 details the excess liquefaction capacity history of the Pacific Basin. In contrast with the Atlantic Basin, every exporter has contributed to the capacity surplus, usually after plant expansion or debottlenecking. These post-expansion surpluses have provided much of the gas that has fueled the short term market.

Figure 5-6 shows a similar history of surplus capacity in the Middle East. The recent aggressive expansion of capacity in Qatar has been the dominant source of these surpluses.

Figure 5- 5

EXCESS LIQUEFACTION CAPACITY BY KEY PACIFIC BASIN EXPORTERS

BCF

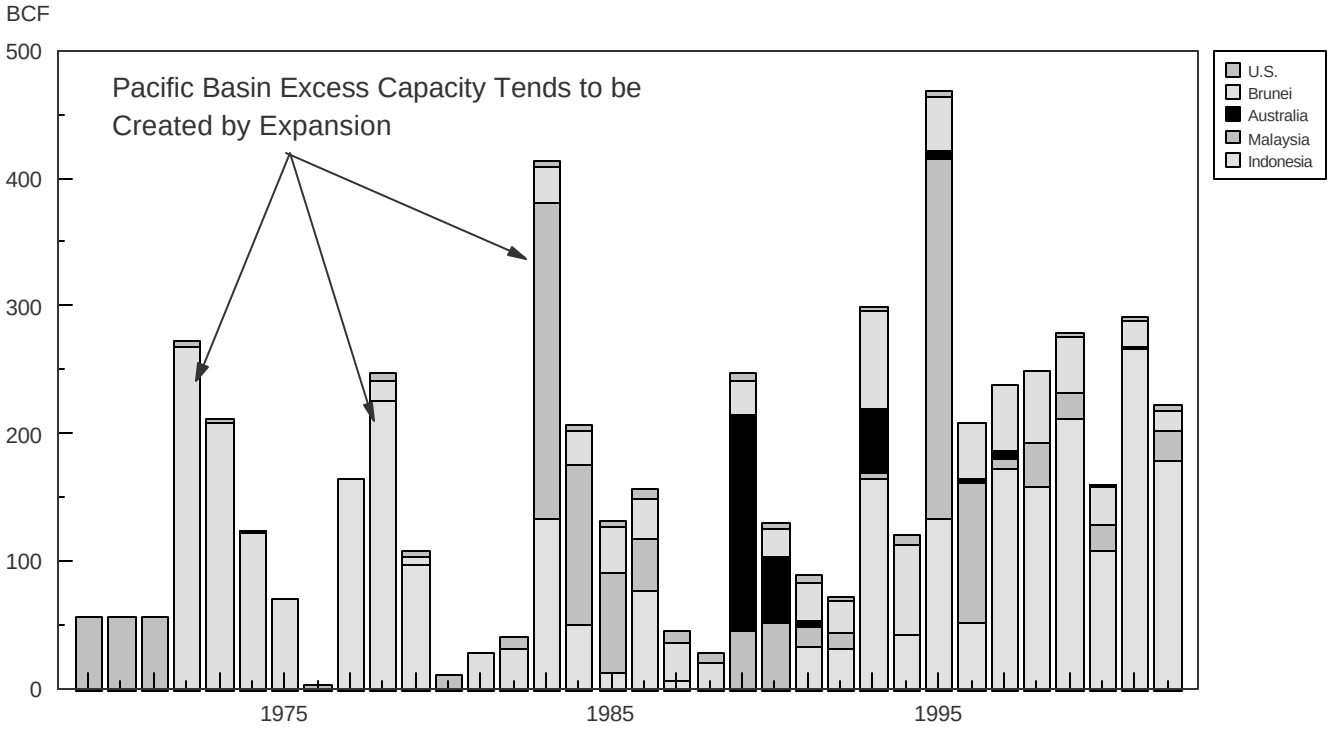
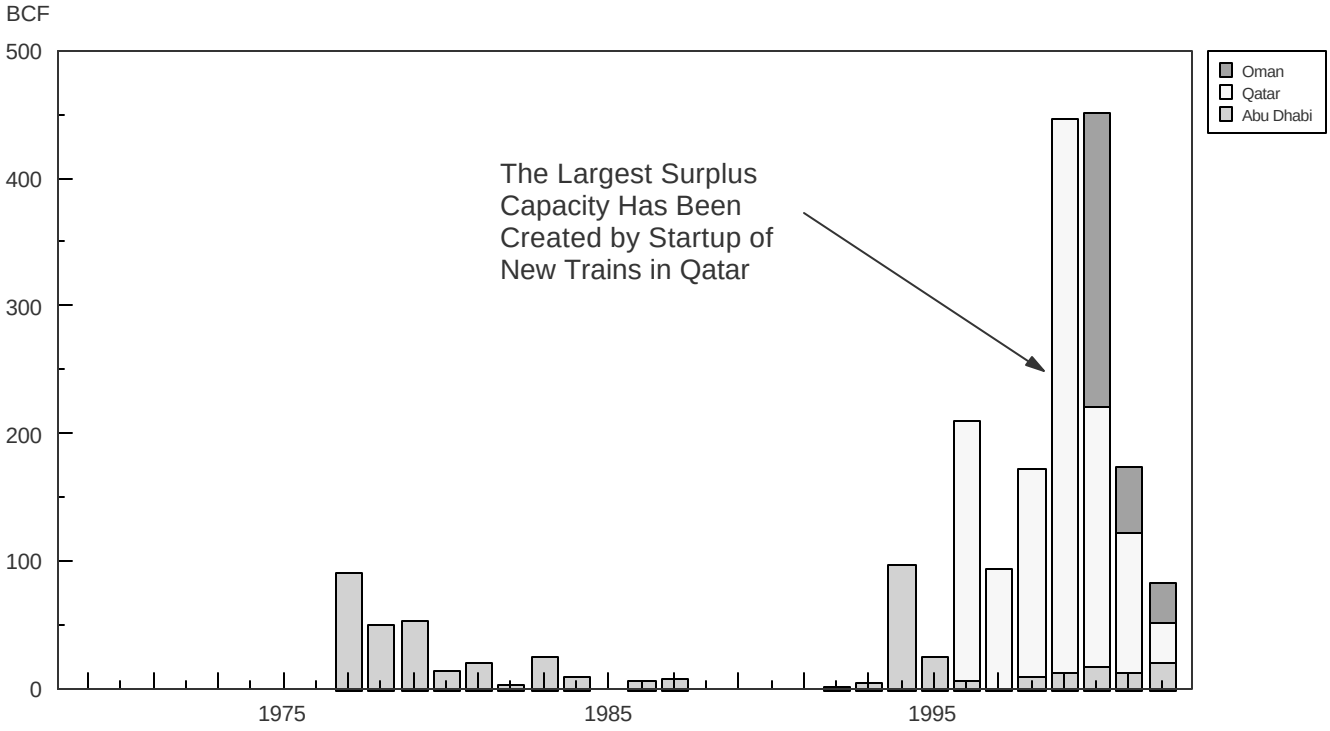


Figure 5- 6

EXCESS LIQUEFACTION CAPACITY BY KEY MIDDLE EAST EXPORTERS

BCF



VI. TANKER TRANSPORTATION

Technology and Cost Structure

The LNG tanker requires a heavily insulated containment vessel within its outer hull to preserve the cryogenic temperatures of its cargoes. While there have been a number of tanker designs developed over the years, three main designs now dominate the LNG tanker fleet. Two of these - the Gaz Transport and the Technigaz systems - are "membrane-type" designs in which an invar membrane acts as the containment and the insulation separates it from the external hull. The third type - the Moss Rosenberg system - utilizes spherical insulated tanks made of an aluminum alloy. Moss Rosenberg tankers can be easily identified the appearance of the top of the spheres protruding above the surface of the deck.

LNG tankers are much more costly than oil tankers of similar dimensions. The fact that the density of LNG is roughly half that of crude oil requires a large vessel to carry a given quantity of energy and the cost of the sophisticated insulated containment systems adds to that cost. Thus LNG will always be much more expensive to transport than oil. This suggests that if oil-to-gas competition ultimately influences natural gas prices and the Middle East becomes the world's marginal source of both energy sources, the U.S. will be at a competitive disadvantage over Europe and Japan in gas relative to oil.

The costs of tanker transportation have declined significantly in recent years. While some of this is attributable to economies of scale, as tankers have been increasing in size, the greatest driving force has been the increasing competition among shipyards to build these sophisticated vessels and ship prices have come down. In 1991, the price of a newbuild 125,000 cubic meter tanker, a size typical of the period, was on the order of $280 million. See Figure 6-1. By 2001, sizes had increased but the cost of a newbuild 125,000 cubic meter tanker had fallen to about $165 million.

In 1990, the cost of delivering LNG from Algeria to the U.S. Gulf Coast in a 125,000 cubic meter tanker would have been approximately $1.29/MMBtu. By 2001, the typical tanker size had increased to 138,000 cubic meters. The larger tanker could deliver somewhat more LNG over the same distance at a reduced cost of $0.84/MMBtu. However, most of the reduction in unit costs would have come about because of the competitive reduction in tanker prices, while very little of it would have accrued to scale economies. See Figure 6-2.

Some of the early trades were from Algeria to Europe, a distance well suited to smaller tankers. But as the longer hauls, such as Indonesia to Japan and Algeria to the U.S. began to appear, tanker sizes quickly escalated into the 120,000 cubic meter plus range. As Figure 6-3 indicates, the weighted average capacity of the tanker fleet at the end of 2002 was 116,000 cubic meters and the largest operating tanker was 140,500 cubic meters. Figure 6-4 illustrates that only 23% of the fleet now has capacity less than 120,000 cubic meters.

To date the maximum size of LNG tankers has tended to be set by the draft limitations of the receiving terminals. But the trend towards longer hauls that favor the larger tankers and the increasing interest in offshore receipt terminals makes it possible to consider much larger vessels. Qatar has tanker sizes in the 200,000 to 250,000 cubic meter range under study. A 250,000 cubic meter tanker might reduce transportation costs by about 14% on the Algeria/U.S. Gulf Coast run illustrated earlier.

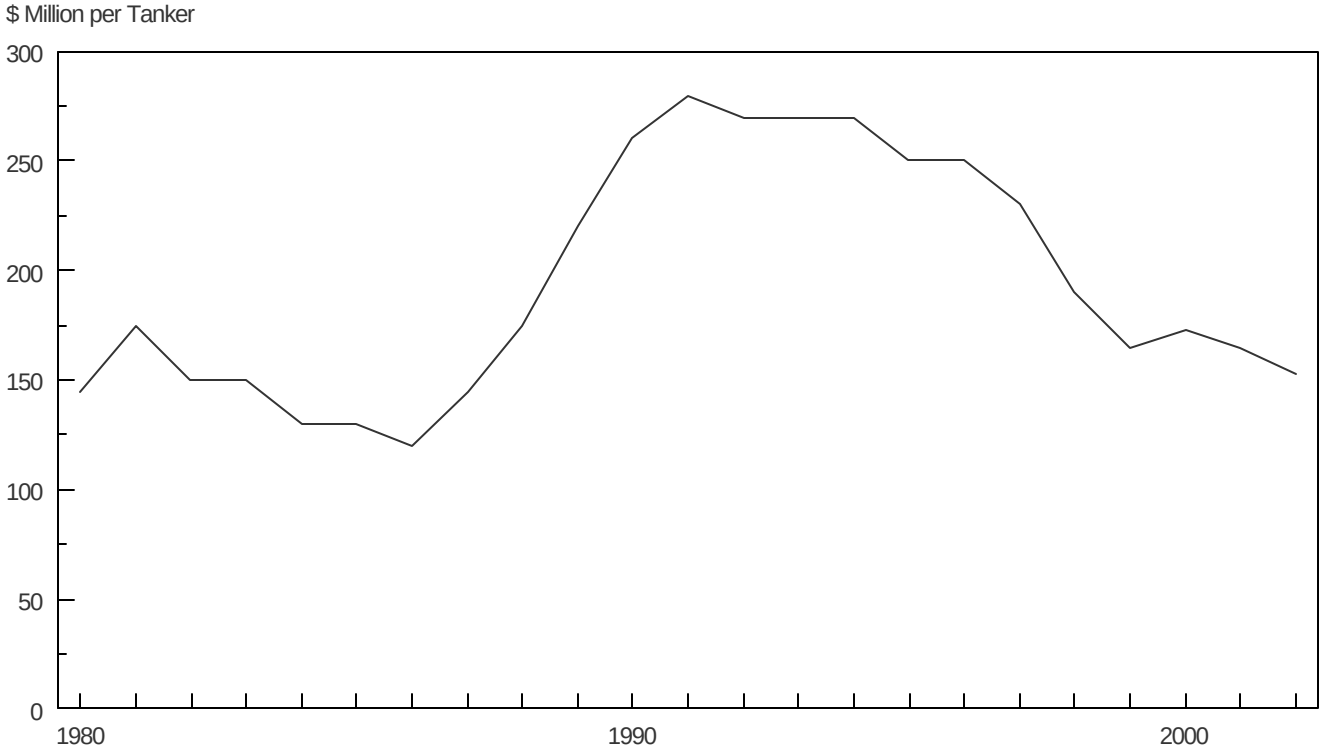
The History of the LNG Trade and Its Effect on Tanker Availability

The first wave of enthusiasm for LNG occurred during the 1970s some time after commercial feasibility had first been demonstrated with the CAMEL project from Algeria to France and the U.K. in 1964. It featured Algeria as

Figure 6-1

COST OF LNG TANKERS BY YEAR OF LAUNCHING

$MM



Source: DVB Nedship Bank

Figure 6-2

LNG TANKER COST REDUCTION ILLUSTRATED

BASIS: ALGERIA TO U.S. GULF COAST - 1991 VERSUS 2001

125,000 CUBIC METER VERSUS 138,000 CUBIC METER TANKER

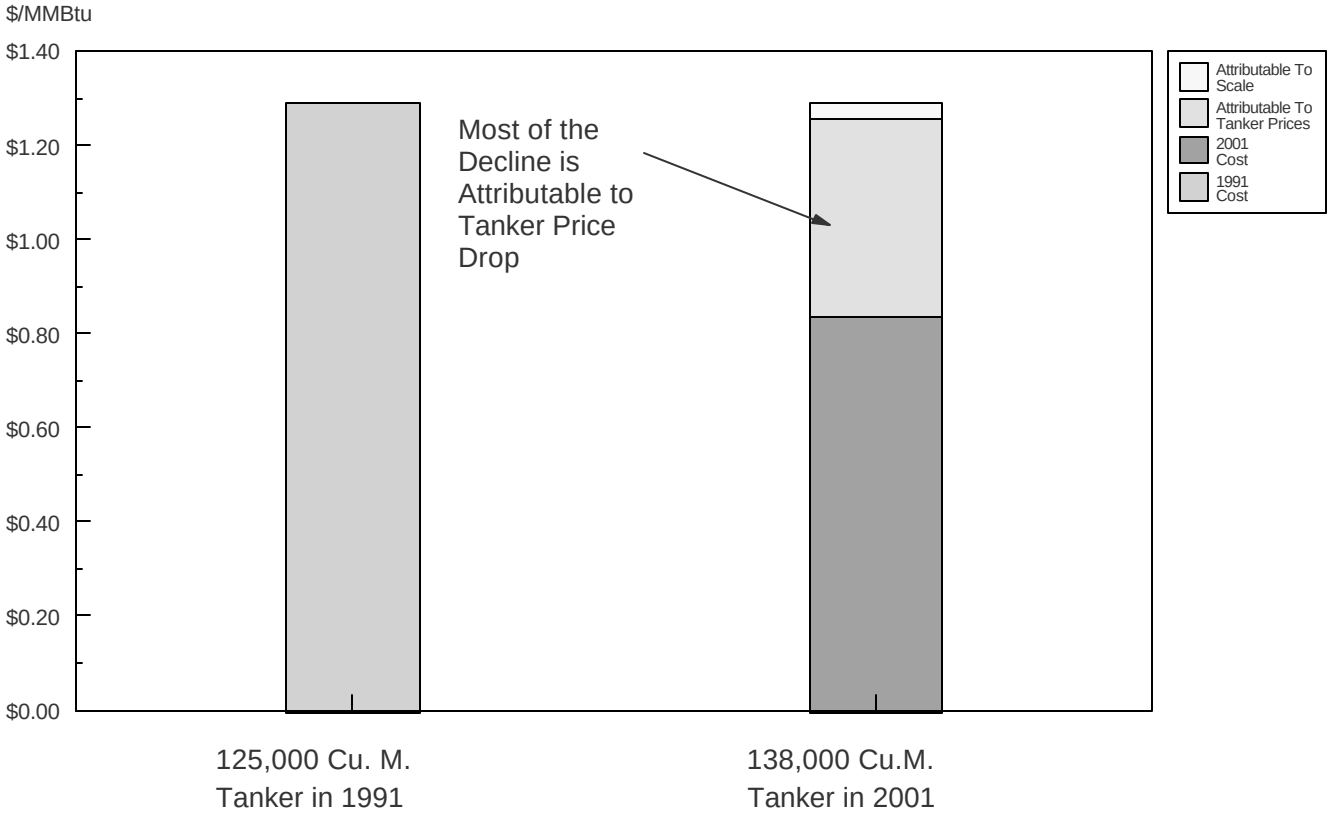


Figure 6-3

EVOLUTION OF LNG TANKER SIZES

TANKER CAPACITY - AVERAGE AND LARGEST IN SERVICE

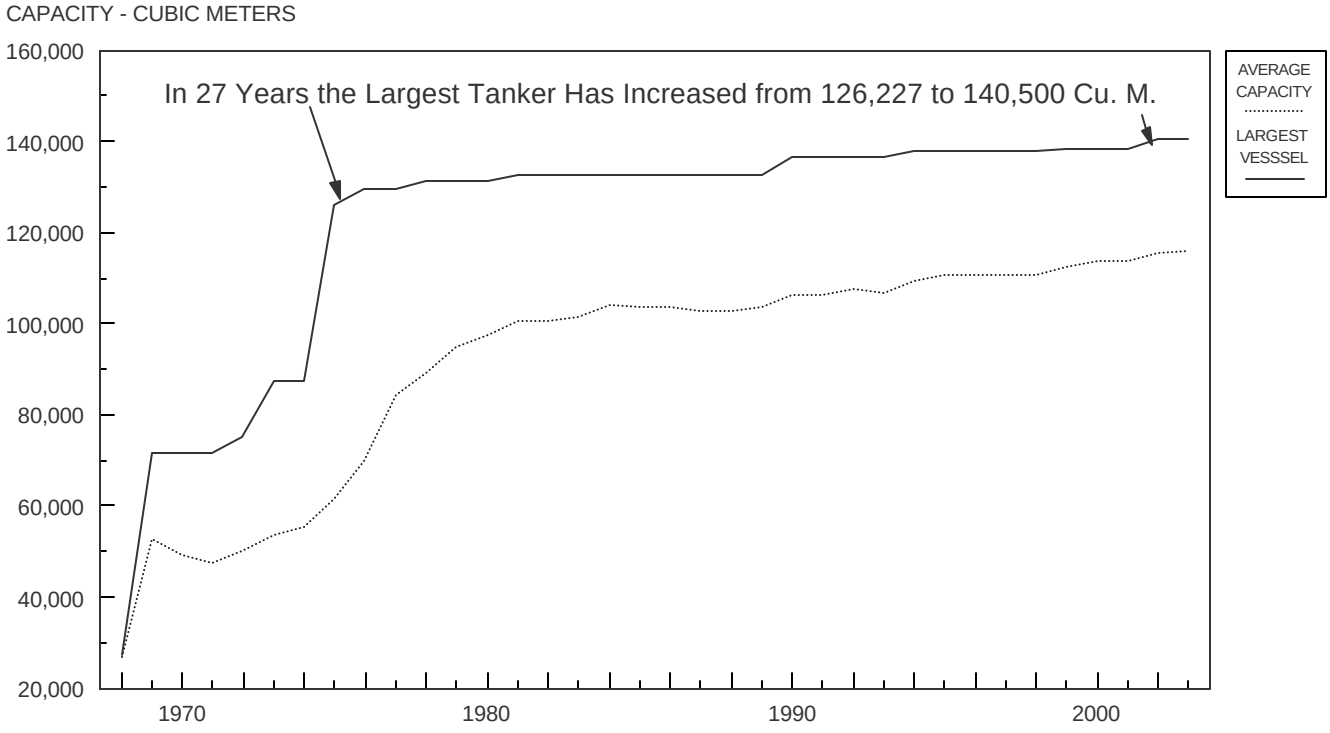
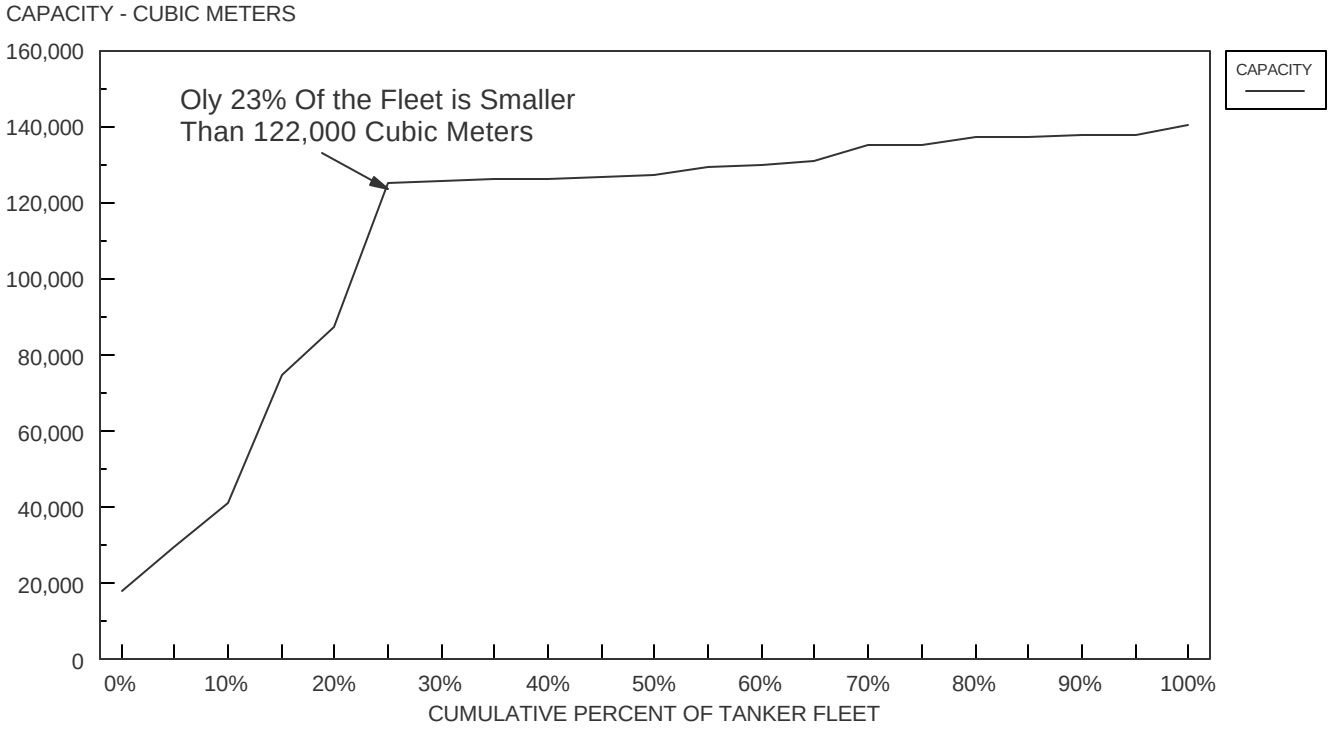


Figure 6-4

DISTRIBUTION OF LNG TANKER SIZES

PERCENT OF TANKERS SMALLER THAN INDICATED SIZE



a potential seller to Europe and the U.S. and Japan as a buyer from Alaska, Brunei and Indonesia. As a result there was a wave of tanker orders for these trades, and while most orders were for vessels dedicated to specific contracts, some tanker owners built on speculation as well. The pattern of these early orders is shown in Figure 6-5.

But the strong growth trend was aborted by actions taken both in Algeria and in the U.S. The U.S., having experienced severe natural gas shortages as the result of its price controls in the 1970s, finally began to dismantle regulation and restructure its industry. The shortages disappeared to be replaced by a "gas bubble" severely dampening the enthusiasm of the U.S. buyers for LNG.

Meanwhile, Algeria, in the face of the upheavals in world energy markets accompanying the oil price shocks, took a more aggressive line towards gas pricing. The result was a rebellion among its customers, particularly in the U.S. and it never operated at the levels for which plants and tanker capacity had been designed. Tankers that had been ordered for the Algerian trades to the U.S. East and Gulf Coasts, either did not operate at all or were idled after a short period of service. A failed U.S. West Coast project - the PacIndonesia project - also ordered tankers but never operated.

The Japanese market, however, remained strong. But the Japanese, seemingly interested in promoting business for their own shipyards, insisted on newbuilds for their imports and the idled tankers were not utilized. The resulting overcapacity in tankers led to a sharp fall off in orders for new vessels as some of the existing fleet were mothballed. During the 1980s there was even some scrappage of relatively new surplus vessels. (Figure 6-5). Only with the revival of interest in LNG in the Atlantic Basin and in the Middle East in the 1990s did tanker orders again turn optimistic.

Figure 6-6 shows an estimate of the historic delivery capacity of the LNG tanker fleet (in thousands of Bcf statute miles) compared with the actual deliveries in a given year. The surplus of capacity is subdivided into a group of thirteen tankers that never effectively operated on the trades for which they were designed (such Algeria/U.S. or PacIndonesia) and the remaining surplus. With a low capacity factor of 38% in 1983 following the collapse of the U.S. trade, it reached level of 73% at the start of the recent wave of tanker construction and actually hit 89% in 2001.

It is unlikely that the fleet can approach a utilization rate of near 100% in a normal market. Tankers that are dedicated on 90% minimum take-or-pay contracts will be idled during periods when the customer is operating at his minimum. Tankers normally anticipate a 15 day period in layup for maintenance during the year and it would typically be scheduled for periods of seasonal low demand. But even if the tanker layup is carefully scheduled to coincide with the customer's anticipated seasonal slowdown, there will still be some idle capacity remaining if the customer is on his minimum take level.

In planning the Bonny LNG project in Nigeria for startup in 1999, the sponsors took options on seven of the laid up tankers (one of these was acquired by Distrigas - now Tractebel - for the Trinidad/Everett trade). Several of these were taken out of layup early and operated in the emerging short term market of the late 1990s, thereby shrinking the overhang of surplus tanker capacity.

The Outlook for New Tanker Construction

Although thirty shipyards have built LNG tankers at some time or another, there are now only eight shipyards that are specializing in these tankers and have vessels on the order books. In addition, China, India and Poland are considering the development of yards that can build LNG tankers. Table 6-1 indicates the yards, their

Figure 6- 5

NUMBER OF LNG TANKERS LAUNCHED AND SCRAPPED BY YEAR

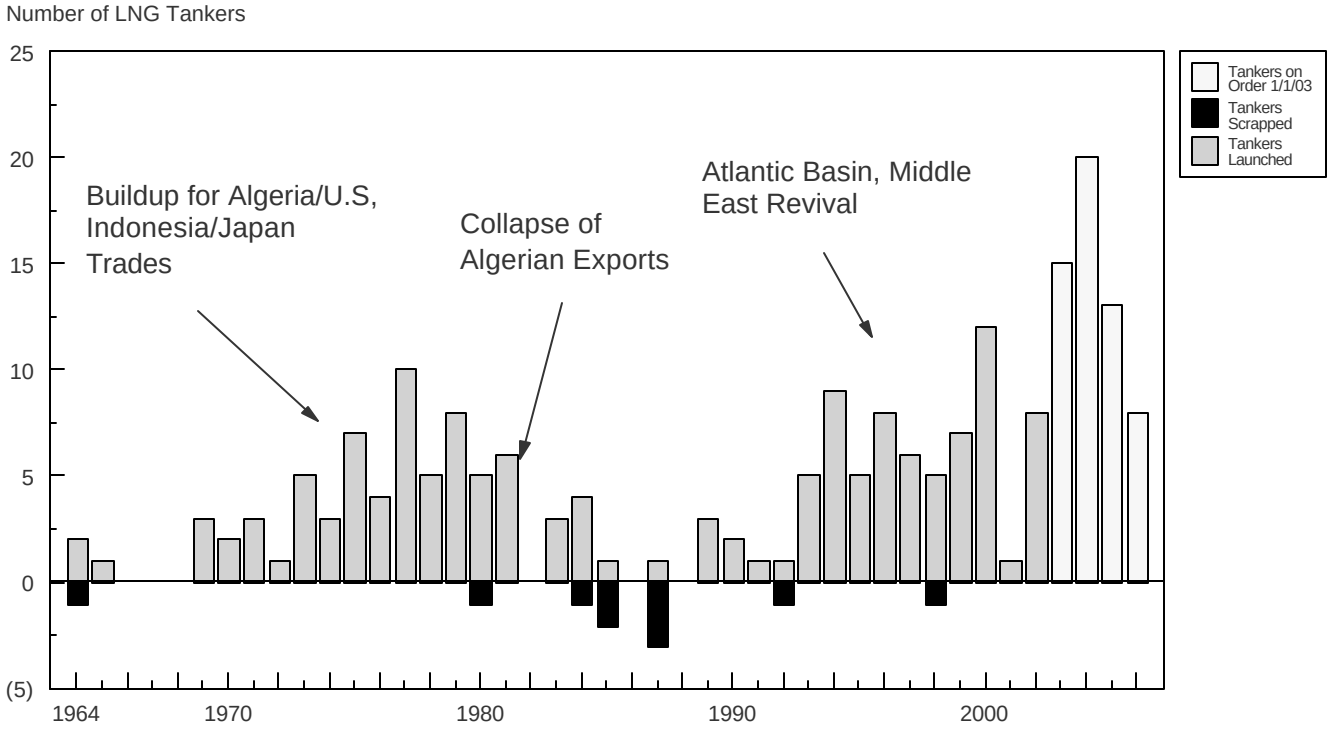
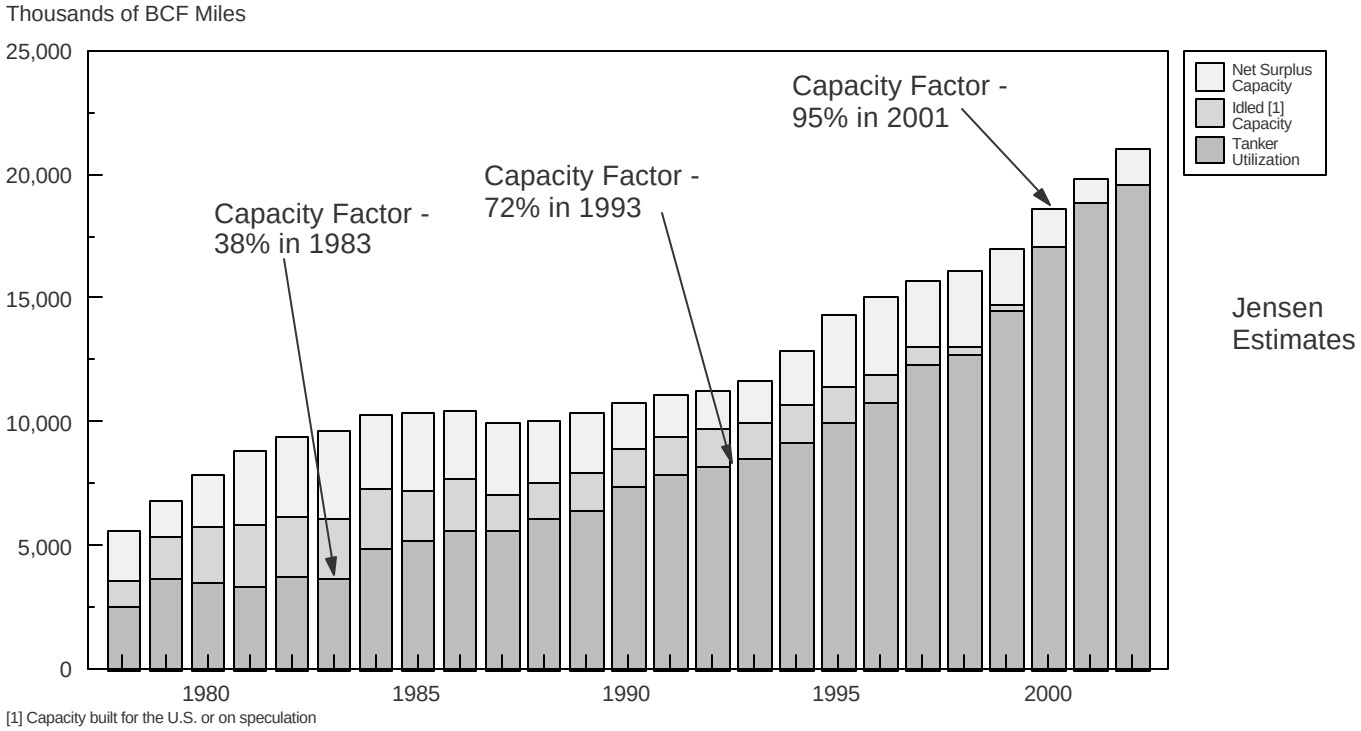


Figure 6- 6

LNG TANKER CAPACITY COMPARED WITH TANKER DEMAND

THOUSANDS OF BCF MILES (STATUTE)



[1] Capacity built for the U.S. or on speculation

construction capacity and their orders as of January 1, 2003. Figure 6-5 included an estimate of the delivery schedule for these vessels.

TABLE 6-1
SHIPYARDS WITH LNG ORDERS

SHIPYARD	LOCATION	ANNUAL CAPACITY	ORDER BOOK
Daewoo, H.I.	Korea	8	20
Hyundai H.I.	Korea	6	7
Samsung S.B.	Korea	5	6
Mitsubishi H.I.	Japan	3	7
Mitsui S.B.	Japan	2	4
Kawasaki H.I.	Japan	2	6
Izar Sestao	Spain	2	5
Alstom	France	2	1

In addition to their order books, which will take several years to complete, the yards have a number of options on new vessels, which can be exercised if the customer so elects.

VII. RECEIPT AND REGASIFICATION

Technology and Cost Structure

The receipt terminal and regasification facility constitutes the final link in the LNG chain. There are three basic elements of the receipt terminal - marine and unloading facilities, cryogenic storage to receive the cargoes and vaporizers for sendout. Terminal costs vary widely based on local conditions. It is probably more difficult to generalize about terminal CAPEX than it is for either liquefaction or tanker transportation.

The site-specific costs associated with harbor facilities and land preparation can vary widely. Storage tanks are more predictable but stringent safety regulations in some urban areas can add to their cost. Two types of vaporization are utilized. Sea-water vaporizers are roughly three times as costly as gas-fired vaporizers but they do not require the use of some of the LNG as fuel. In general, sea-water vaporizers are favored for base load (high capacity factor) sendout, but gas-fired units are more suitable for highly variable loads.

The CAPEX for a representative terminal of 1 Bcfd sendout capacity would be about $500 million. Perhaps one third to one half of the cost would be in storage, with the remainder divided among marine, vaporization and offsites[6].

The Interchangeability Problem

Although natural gas consists primarily of methane, it almost always includes a number of higher hydrocarbon components such as ethane, propane, butane, etc. It may also include some inert gases such as nitrogen and carbon dioxide. Methane, itself has a heating value of 998 thousand Btus per cubic foot (gross heating value) while all of the higher hydrocarbons have higher heating values. Since natural gas nearly always includes some of these higher hydrocarbons, it usually has a heating value exceeding 1,000 Btu/cf.

The U.S. industry has always extracted a large portion of the higher hydrocarbons, either for LPG sales or for feedstock for ethylene manufacture. Thus the average U.S. heating value is 1,026 Btu, a relatively lean natural gas. Most gas imported as LNG has much higher heating values, reflecting a much lower recovery of the higher hydrocarbons at the source.

There are two disadvantages to the distribution of a significantly higher Btu gas than that for which the system was designed. The richer gases are not fully interchangeable with the design gas, potentially causing problems with burner operation. And since most meters read volume, not heat content, the higher Btu sendout complicates the recovery of the value of the additional energy in the “hot” gas. As a result, pipelines have Btu specifications to assure that the gas that is tendered is acceptable.

The four existing U.S. terminals were built to handle Algerian LNG (typically less than 1,100 Btu) and although there were some early problems accepting LNG into the system, they have now been largely ironed out. Some of the newer LNG supplies, particularly from Nigeria, the Middle East and Southeast Asia exceed the 1,100 Btu threshhold and thus represent potential interchangeability problems.

In theory, it would be possible to have LPG extraction at the receipt terminal to bring these higher Btu gases within specification - thus earning a co-product credit - but the economics of such an investment are complicated

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[6] Supporting utilities, buildings and other structures

and it would be justified only under certain circumstances. It also is possible in theory to blend the richer LNG with leaner domestic supplies, but again that will work only when conditions are right and an acceptable blending gas is readily available.

The most common alternative is to blend the rich gas with a "ballasting" gas, such as nitrogen or air. These blends will be fully interchangeable, but an equilibrium "ballasted" gas still has a slightly higher Btu value than the base gas, thereby not totally solving the value recovery problem.

The Everett, MA terminal has air injection and the Cove Point, terminal is considering nitrogen injection. The installation of injection facilities does increase the capital costs of the terminal, but it is not an insurmountable problem. New terminals are likely to install injection to increase their flexibility to accept a wider range of LNG supplies.

Existing Terminals

The U.S. mainland has four existing terminals and there is one additional one in Puerto Rico. All except the Puerto Rican terminal were built for the first wave of enthusiasm for LNG. The original four terminals were designed for Algerian supply. The new Puerto Rican terminal, with a capacity of 186 MMcfd and owned by Eco Electrica, is served primarily by Trinidad. The locations and current capacities of the mainland terminals are shown in Table 7-1.

Table 7-1
EXISTING LNG TERMINALS

LOCATION	OWNERSHIP	PEAK CAPACITY (MMCFD)	BASE LOAD CAPACITY (MMCFD)	EXPANDED CAPACITY (2005) (MMCFD)
Everett, MA	Tractebel	710	580	915
Cove Point, MD	Dominion	1,000	750	1,000
Elba Island, GA	El Paso	675	460	806
Lake Charles, LA	CMS	1,000	630	1,200

The first of the terminals to go into operation was the Everett facility developed by Distrigas, a subsidiary of Cabot Corporation. It commenced operation in 1973 and was quickly immersed in the turmoil surrounding the first oil shock. Its design was unique among LNG receipt facilities in that it received cargoes throughout the year but held them in storage for winter peaking requirements in the temperature-sensitive New England market. It still has a very large LNG trucking business that delivers LNG to satellite peaking storage throughout the region. But it has increasingly moved towards a more base load operation, with three 135,000 cubic meter tankers committed to the trade, where its original concept envisioned only one dedicated 50,000 cubic meter vessel. In 2002, Everett imported 300 MMcfd of LNG, which is equivalent to about 28% of the gas consumption of Massachusetts.

The Cove Point and Elba Island terminals were originally put into service in 1978 by El Paso Natural Gas. The last of the original terminals to commence operation was the Lake Charles facility of Trunkline Gas Company, which started up in 1982.

The startup of the four terminals took place during an almost unprecedented change in the outlook for international energy supply, demand and pricing. While the Everett terminal, with its peak shaving focus, was not primarily driven by the U.S. natural gas shortages that began in the late 1960s, the other three were clearly attempts to offset the shortages. And since price controls on domestic gas had the effect of cross subsidizing uncontrolled imports, there was no market discipline on pricing.

The first oil shock not only drove up international oil prices, but also set in motion the wave of nationalization of oil industry operations in many of the main producing countries. This change was accompanied by a change in administration in Algeria that replaced the "technocrats" who had built the LNG industry in that country by a more politically minded group who wanted to demonstrate that LNG prices - like oil prices - could be unilaterally increased by the producers.

The conflict between a U.S. move towards deregulation and market-dictated pricing on the one hand and an Algerian move towards setting export prices at high levels on the other proved to be nearly fatal to the U.S. LNG industry. While Everett continued to operate in all but 1974 and 1987, at one point it went into bankruptcy. Cove Point and Elba Island only operated for two years before being shut down for more than twenty years. And Lake Charles operated in 1982 and 1983, but was shut down for six years before its dispute with Algeria was finally settled.

Proposed New Terminals

The wave of enthusiasm for LNG has led to a rash of proposals for new receipt and regasification terminals. While the list of proposed new terminals continues to grow, Table 7-2 lists most of the terminal proposals for the North American Atlantic Basin that have appeared in the trade press.

East Coast terminals such as Everett have two very strong economic advantages. They are downstream from the major southwest producing areas and thus enjoy a pricing advantage (basis differentials) over the main gas pricing point in Henry Hub, Louisiana. And they are closer to the major LNG supply points, thereby minimizing tanker transportation costs.

Unfortunately, it has proved extremely difficult to gain siting approval for such East Coast locations because of local popular resistance. Therefore, Atlantic Basin terminal options seem to have settled on three different alternatives.

1) Gulf Coast locations where the long history with oil and chemical sites minimizes local opposition
2) Foreign locations, such as Nova Scotia, New Brunswick, the Bahamas or Mexico, where siting approvals may be easier to obtain but the gas must be further moved by pipeline
3) Offshore, where environmental approvals are less stringent

One additional terminal proposal, a facility at Altamira, Mexico, by Shell is generally assumed to be dedicated to the Mexican market, although it might be later adapted to U.S. delivery.

One of the problems of terminal siting, not only on the East Coast but in other locations, as well, is the complexity of regulations - Federal, state and local - that impact a decision to proceed. Many of these regulations have

developed for specific reasons that may not apply to the siting of a new terminal, but must be addressed by the terminal developer before he can proceed. While a desire for "one stop shopping" for terminal permitting is probably unrealistic in our complex democratic political system, better coordination among the permitting agencies might speed the process and provide the necessary receipt capacity more quickly and efficiently. This suggests that a Federal agency, acting as a kind of permitting coordinator and ombudsman, would be desirable.

The Gulf Coast terminal options are easier to approve and integrate into the pipeline grid, but they forfeit the basis advantage and the shorter distance from sources that favor the East Coast. The foreign locations lose some of their basis advantages through additional pipeline costs to reach the grid and they can easily overload local markets, thereby depressing prices. The offshore locations have come into greater favor with the November 2002 enactment of the Deepwater Port Act Amendment (DWPA), which shifts regulatory responsibility for offshore LNG facilities from the Federal Energy Regulatory Commission to the Maritime Administration and the U.S. Coast Guard.

Table 7-2

PROPOSED ATLANTIC BASIN TERMINALS[7]

PROPOSAL	SPONSOR	CAPACITY MMCFD
ATLANTIC BASIN FOREIGN		
Canaport, New Brunswick	Irving Oil	550
Bears Head, Nova Scotia	Access Northeast Energy	750
Calypso, Bahamas	Tractebel	830
Ocean Express, Bahamas	AES	842
U.S. EAST COAST		
Harpswell, ME	ConocoPhillips	500
Weavers Cove, MA	Poten & Partners	400
Somerset LNG, MA	Somerset LNG	400
Crown Landing. NJ	BP	1,000
Providence, RI	BG/Keyspan	140
U.S. GULF COAST		
Mobile Bay, AL	ExxonMobil	1,000
Main Pass Energy Hub, Offshore LA	Freeport Sulfur	1,500

[7]Source: World Gas Intelligence, September 17, 2003 supplemented by other trade press

PROPOSAL	SPONSOR	CAPACITY MMCFD
Port Pelican, Offshore LA	ChevronTexaco	1,500
West Cameron 182, Offshore LA	Shell	1,000
Vermilion 179, Offshore LA	Conversion Gas Imports	1,000
Cameron, LA	Liberty LNG	1,000
Hackberry, LA	Cameron LNG (Sempra)	1,500
Sabine Pass, LA	Cheniere Energy	1,500
Sabine Pass, TX	ExxonMobil	1,000
Freeport, TX	Freeport LNG	1,500
Corpus Christi, TX	Cheniere Energy	1,500
Corpus Christi, TX	ExxonMobil	1,000

The Pacific Coast has similar siting problems to the Atlantic/Gulf Coasts. The early PacIndonesia project that was supposed to deliver LNG from Indonesia to California in the 1979/1980 time frame, but it was canceled for a number of reasons, one of which was powerful popular resistance to siting the terminal in California. Thus, many of the new West Coast LNG proposals are based on deliveries into Baja California and transmission across the Mexican/U.S. border by pipeline. Table 7-3 lists the West Coast proposals.

Table 7-3
PROPOSED WEST COAST TERMINALS[8]

PROPOSAL	SPONSOR	CAPACITY MMCFD
CALIFORNIA		
Cabrillo Port, Off Oxnard, CA	BHP Billiton	1,500
Offshore Ventura, CA	Crystal Energy	1,000
Long Beach, CA	Mitsubishi	1,000
BAJA CALIFORNIA, MEXICO		
Off Coronado Islands	ChevronTexaco	1,500
Costa Azul	Sempra	1,500

[8] Source: World Gas Intelligence, September 17, 2003

PROPOSAL	SPONSOR	CAPACITY MMCFD
Costa Azul	Shell	1,500
Ensenada	ConocoPhillips	680
Tijuana Regional Energy Center	Marathon	750

The Open Access Issue

One of the thrusts of U.S. policy in its restructuring of its gas industry is the emphasis on "open access" to transportation facilities. This eliminates monopolistic control of capacity and is a means of encouraging new entrants and enhanced competition. Under such a policy, capacity can still be controlled on a long term contract but the rights to capacity can be bought and sold making it a part of the market economy.

The initial view of LNG terminal capacity was that it would be treated the same way as pipeline capacity and would be subject to open access regulations. All of the existing mainland terminals, with the exception of Everett, are open access. However, the large producers with LNG assets upstream argued that they would not be prepared to invest in downstream terminal capacity unless they had control of throughput.

In its "Hackberry" decision involving the then Dynegy, now Sempra, proposal for a new terminal at Hackberry, LA, the FERC waived the open access provisions. This decision, together with the financial problems of the gas merchants and the obvious risks of investment in a terminal without some upstream control, seems to have shifted the balance of power in favor of the integrated majors and away from the merchants.

Efforts to Solve the Siting Problem Through Offshore Development

The NIMBY problem, when combined with the greater flexibility to locate terminals offshore, has stimulated the interest in offshore receipt terminal designs. The most-advanced project is that of ChevronTexaco. Its proposed Port Pelican terminal envisions a deepwater platform 36 miles offshore that would enable the company to utilize existing Gulf gathering and transmission facilities. There are at least six other offshore proposals for Gulf Coast or West Coast terminals.

Two of the more innovative design concepts are the "Energy Bridge" tanker design proposed by El Paso, and the Gulf Coast salt dome gasifiers proposed by Conversion Gas Imports. El Paso has ordered tankers that have the regasification facilities located on the tanker itself. They thus can deliver the regasified LNG directly onshore via pipeline. The advantages are clearly the proposal's flexibility and the ability to overcome the opposition of local groups. It has several disadvantages. Its high rate discharge system requires that the pipeline grid have the capability to absorb large flows and, while tankers can presumably be scheduled on a shuttle basis to minimize time off line, it probably needs backup storage to cover delays in tanker arrivals. And its higher tanker cost may restrict it to shorter, dedicated runs where the expensive vessels can achieve high capacity operation.

The technology developed by Conversion Gas Imports (CGI) is based on the concept of pumping LNG under high pressure from the vessel through a heat exchanger directly into salt caverns, where it is stored in high pressure gaseous form, thereby avoiding the use of traditional LNG vaporizers and storage tanks. Salt caverns are widely available in the Gulf Coast and are used for gas and liquid storage. Although the Liberty LNG Import

Terminal Project, which CGI is trying to develop, is an onshore venture in Calasieu and Cameron Parishes in Louisiana, the technology is readily adaptable to offshore platform operation as well.

How Many Terminals Will Be Built?

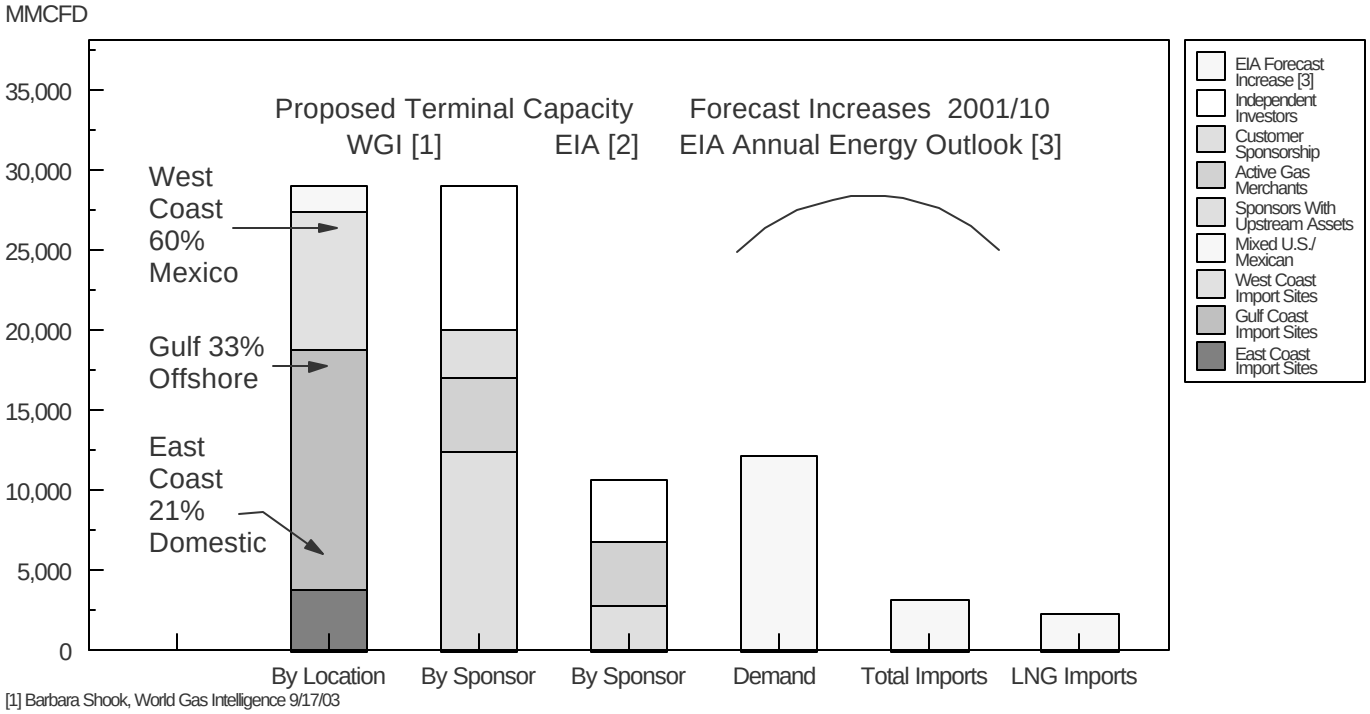
It is very difficult to answer that question explicitly, what is clear is that most of the terminals shown in the previous tables will *not* be built. The LNG business, both in liquefaction and in receipt terminals, has always been characterized by a great deal of "gaming" - that is a large number of competitive proposals by sponsors who hope to beat out competitors and exploit a particular opportunity.

Some measure of the gaming that is going on in North American receipt terminal proposals is shown by the capacity that would be available compared to any reasonable expectation of need. Figure 7 - 1 compares the total capacity of the proposals discussed in Tables 7 - 2 and 7 - 3 with the forecasts by the EIA in its Annual Energy Outlook 2003 for incremental gas demand and imports between 2001 and 2010. The total proposed LNG terminal capacity is over nine times the EIA's projected increase in imports over the period and even 2.4 time the total increase in gas demand.

Figure 7 - 1

CAPACITY OF PROPOSED NEW NORTH AMERICAN TERMINALS COMPARED WITH ESTIMATES OF DEMAND GROWTH - 2001/2010

MMCFD



[1] Barbara Shook, World Gas Intelligence 9/17/03
[2] EIA - U.S. Natural Gas Markets 12/01
[3] EIA Annual Energy Outlook 2003 Forecsts

VIII. THE ROLE OF GOVERNMENTS IN SUPPLY

The Concern for Political Stability

The LNG industry got its lessons in political risk at an early point in its development. In the 1970s, the rapidly evolving Atlantic Basin LNG market was shaken by a pricing dispute between Algeria and its customers. With the startup of the last major liquefaction train at Arzew in 1980, Sonatrach achieved an export capacity of 19.1 MMT of LNG. However, the dispute caused a sharp drop in exports so that in 1980 Algerian capacity utilization fell to 23%. Not until 1990 would Algerian exports rise sufficiently to bring capacity utilization above 60%.

The dispute was compounded by the U.S. drive towards restructuring its gas industry, making it difficult to sell formula-priced gas in a gas-to-gas competitive market. The dispute shut down all four U.S. terminals for a time and both Elba Island, which reopened in 2001 and Cove Point, which reopened in 2003, were shut down for over twenty years. It also caused a severe surplus of LNG tankers, some of which did not come out of layup until their commitment to the Trinidad and Nigerian projects in the late 1990s.

However, many of the early problems of political risk seemed to have stabilized until new problems of political uncertainty have recently arisen in Indonesia, the world's largest LNG exporter. The guerilla activity of the Aceh separatists in western Sumatra was responsible for the temporary shutdown of the Arun liquefaction plant in 2001. And the secession of East Timor from Indonesia (final as of May 2002) caused the 1999 cancellation of the agreement with Australia for the Australia-Indonesia Joint Cooperation Area in the Timor Sea. While this dispute, which affects both the Bayu Undan and Greater Sunrise LNG proposals, was finally settled in 2003, it was a clear source of delay.

The companies have adjusted for these types of political risk by requiring higher hurdle rates where such risks are a factor in development. And they have caused companies to delay projects that were otherwise deemed economic. During the 1990s following the Gulf War, the Qatargas project found it difficult to sign up Japanese customers because of the perceived political instability of the Middle East.

Political concerns affect several of the prospective LNG projects that are currently in the planning stage. One of the prime candidates to serve the West Coast market has been significant gas discoveries in Bolivia. Because Bolivia is landlocked, the gas must be pipelined to a coastal location in an adjoining country for liquefaction. The most economic choice would be a pipeline directly to Meijillones in Chile, but it might also be possible to utilize a longer pipeline route to deliver the gas to the port of Lio in Peru. However, Bolivian relations with Chile remain tense because of the 1883 war in which Bolivia lost its outlet to sea to Chile. Any effort to utilize the most economic alternative for the project runs into powerful military and popular resistance. While other issues were also involved, this boiled over in late 2003 with public demonstrations that forced the fall of the government.

Last winter major opposition to the government of Hugo Chavez by oil workers in Venezuela led to a sharp reduction in Venezuelan oil production for a time, and similar unrest in Nigeria caused a temporary cutback in oil production in that country as well. This unrest may well affect the investment climate for the major new greenfield LNG projects in both countries.

At the buyers' end of the LNG chain, political problems in India - including, but not limited to Enron's Dabhol project - have set back a number of planned LNG projects. India has also been affected by concern for the creditworthiness of some of the power generation buyers.

The impact of these risks on the newly restructured industry, is that it is very difficult for planners to lay out a reliable forward estimate of capacity that is expected to come on stream to meet projected demand. This of itself introduces a potential source of instability in a market whose prices may be becoming increasingly volatile.

Government Regulations in Consuming Countries

Political uncertainty is by no means limited to producing countries. The problems of environmental and siting regulations have complicated the development of adequate receipt terminal capacity, not only in the U.S. but in other countries as well. The difficulties of siting in the U.S. were discussed in Chapter VII.

In Italy, - Enel, an electric utility - signed a contract for Nigerian supply for an Adriatic terminal. The opposition to this terminal nearly caused a cancellation of the contract, but it was rescued by delivering by exchange agreement with Gaz de France, whereby Nigerian LNG bound for Italy is landed in France and the Italian contract is covered by pipeline deliveries from France. These siting and environmental problems in the receiving countries have led to a strong interest in offshore terminals where local resistance can be minimized.

The Role of National Oil Companies (NOCs) in Projects

LNG projects have usually been joint ventures of several companies in the interests of spreading exploration risks. Their interests have been bound together in a "shareholders agreement" or a "joint venture agreement", depending on the nature of the license, with one of the group appointed as the operator. While share ownership in both field development and the liquefaction facility may be the same, they often differ.

In many license areas, particularly those using production sharing agreements, a national oil company (NOC) may be a stakeholder in the venture. Of the twelve existing LNG exporting countries, all bu the U.S. and Australia have NOCs (or direct government) stakeholders in their projects. These NOCs at one extreme may operate much like commercial oil companies and at the other simply as a device for tax collection, but most of them mix the two functions. This complicates the development of LNG projects.

In Algeria, Sonatrach has until recently held the government monopoly for both exploration and for LNG liquefaction, and thus was responsible for both functions. In Indonesia, Pertamina had monopoly rights to marketing and had a share in the liquefaction facility. Since this was operated as a tolling facility, the liquefaction and marketing were both operated on behalf of the producing partners, of which Pertamina had a share through the production sharing agreement. In most of the projects destined for the Japanese market, it has been common to offer a share of the upstream investment to the Japanese trading houses. In those cases where there are varying interests between production and liquefaction, some form of transfer pricing agreement is required to allocate revenues among the parties.

Fiscal Terms - Implications of the Common "Discount" in Gas Terms Relative to Oil Terms

Throughout much of the producing world, tax regimes have been devised to capture a substantial part of the economic rent for the host government. Since oil has usually been the primary target, most tax regimes are designed for oil discoveries. In some countries there is a single petroleum fiscal system that applies throughout the country, but many governments will vary their tax regimes to promote special exploration and development opportunities. Since oil-focused tax terms commonly overtax gas, modifications to the government's tax code are often part of host country negotiations in LNG projects. These may take the form of reduced tax rates or in the case of those countries with production sharing contracts, the NOC's share of the venture may differ from

what it would expect if oil production was the target. For example, in Indonesia the government's share of an oil discovery (that is, tax and Pertamina's share) is 85% after cost recovery. For a gas discovery it is 70%.

These variations in tax regime, particularly where the NOC is both an operating company and a part of the tax collection system, are a source of major complications in the development of an LNG project. The existence of a buyers' market for LNG with its implied competition among governments has served to discipline government demands in these negotiations, but a return to sellers' market conditions could alter this dynamic for those governments that do not have a uniform mineral tax code.

IX. LNG - A MARKET IN STRUCTURAL TRANSITION

The Role of the Long Term Contract in the Traditional LNG Project

The major links of the traditional LNG project "chain" - field development, liquefaction, tanker transportation and receipt and regasification - must be carefully integrated if the project is to be successful. Since LNG projects are usually international ventures, parts of the chain are subject to different laws and regulations - production and liquefaction subject to the fiscal and legal system of the producing country, regasification to consuming country regulations, and tankers operating in a kind of international no-man's-land. The fact that differing regulatory systems impact the success of the project introduces an element of political risk into the process.

Figure 9-1 illustrates a representative balance of the capital expenditures for several selected LNG trades. In the examples shown, the portion of the CAPEX budget in the receiving country is small - ranging from 9% to 13%. In contrast, the portion of the capital expenditures in the producing country ranges from 51% to 70%, indicating the critical importance of the host country negotiations in the development of a project. Tanker expenditures vary with distance, the long haul Qatar/U.S. East Coast run having the highest percentage at 41% of the CAPEX budget.

The traditional way of doing business featured a carefully structured system of risk sharing among the participants. Central to the project was the Sale and Purchase Agreement (SPA), the contract between buyer and seller for LNG. The point of delivery might be either f.o.b or ex ship, depending on which party assumed the tanker transportation responsibility, but in either case the operation of the receipt and regasification terminal was downstream of the point of delivery and thus outside the scope of the contract. Tankers might be owned by either buyer, seller or independent shipowners, but traditionally were dedicated to the specific trade, usually for the life of the contract.

Early contracts were typically for 20 years duration, although longer contracts were common. The risk sharing logic of the contract was embodied in the phrase ..."the buyer takes the volume risk and the seller takes the price risk". Hence most contracts featured take-or-pay provisions to assure buyer offtake at some minimum level and a price escalation clause to transfer responsibility for energy price fluctuations to the seller. The early contracts viewed oil, not gas, as the competitive target and thus "price risk" in the escalation clauses was principally defined in oil terms, a pattern that persists to this day.

The contractual terms binding creditworthy buyers and sellers enabled LNG projects to obtain favorable financing, giving them a debt-equity ratio and cost of capital more nearly resembling utility financing than that of corporate equity investments. In the original pattern of LNG project development, nearly all buyers were either government monopoly or franchised utility companies from OECD countries, and thus buyer creditworthiness was usually not an issue.

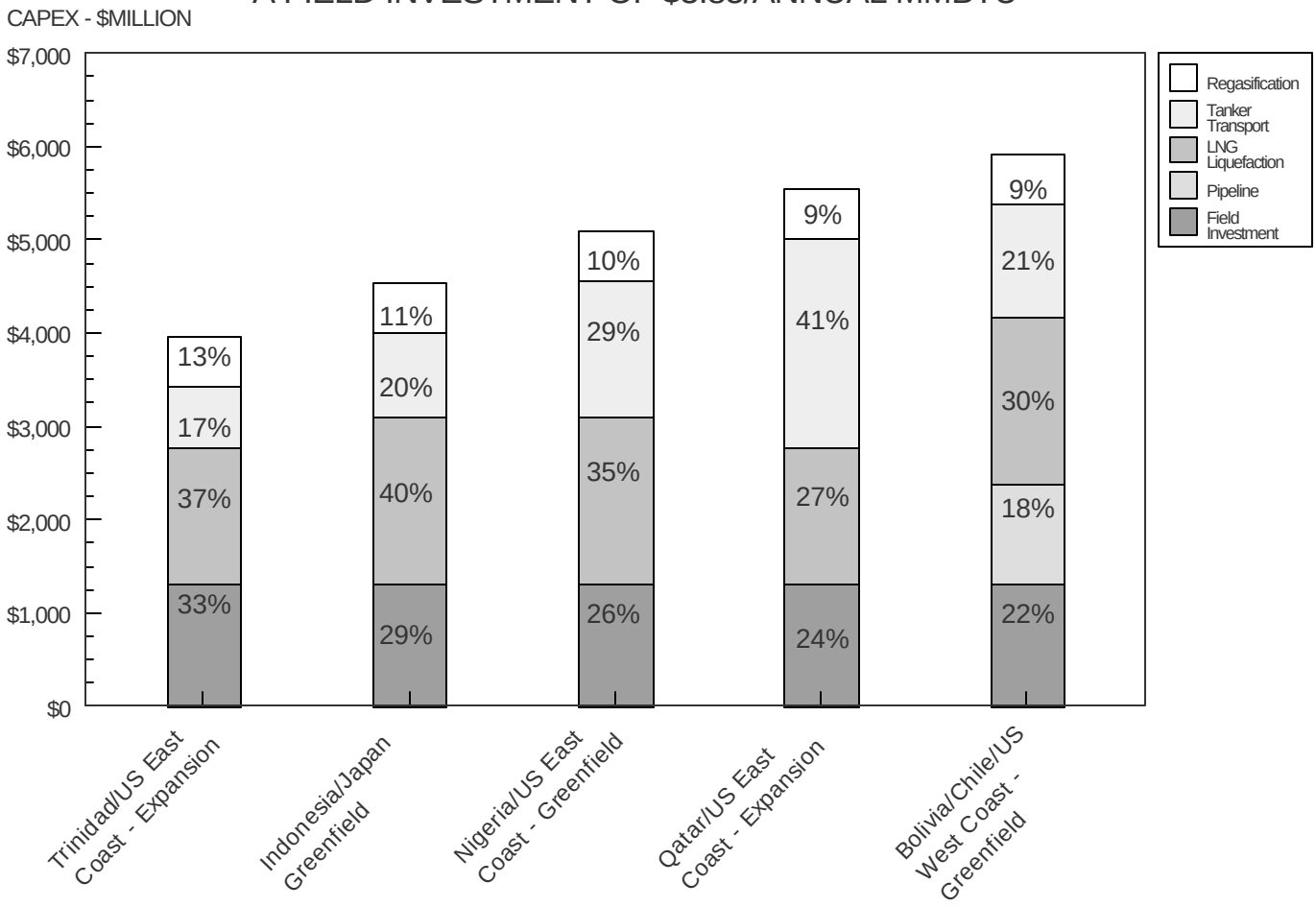
Most of the early purchasers were regulated utilities or government monopoly companies and thus were effectively able to lay off some of the market risk to their end use customers. Once a contract was approved by the regulators or government overseers, the price and volume terms became part of the regulated resale rate structure and end users picked up the tab.

Since field development and liquefaction investments in the producing country have usually been based on significant gas discoveries, companies holding the relevant exploration licenses have typically been the project developers. They have dedicated enough reserves to the project, not only to cover full contract commitments, but an additional volume of inaccessible "cushion gas" to support full contract deliverability to the end of the

Figure 9-1

ILLUSTRATIVE CAPITAL EXPENDITURE PROFILES FOR SELECTED LNG PROJECTS

ASSUMING TWO 3.3 MMT TRAINS AND A FIELD INVESTMENT OF $3.85/ANNUAL MMBTU



contract period. For a twenty year contract, for example, it might take as much as twenty-eight years of reserve support to provide such a supply guarantee. A twenty-eight year RP ratio represents a conservative rate of field depletion with adverse consequences to the time value of money and hence to the IRR of field development. economic consequences for field economics. More flexible access to additional reserves near the liquefaction facility might well enable the project to utilize higher depletion rates.

The project developers have usually been joint ventures of several companies, bound together in a "shareholders agreement" or a "joint venture agreement", depending on the nature of the license, with one of the group appointed as the operator. The effect of this structure is that companies have operated as if they were shareholders in a corporation, rather than as independent and competitive corporate entities. Thus marketing has usually been done by the venture rather than by the individual partners, a system which has reduced the number of competing marketers. Competition exists but it has been between projects rather than among the individual participants in the venture.

The growing participation of major companies in a diverse portfolio of potential LNG supply projects has created special strains on the partnership agreements. Partners with interests in several potential projects frequently find themselves in competition with themselves, a potential conflict of interest that has not been lost on governments or other partners. In the Pacific Basin, for example, Shell has shares in Australia's North West Shelf, Gorgon and Greater Sunrise, Malaysia's Tiga and Sakhalin II projects, all of which are seeking expansion in a weak Northeast Asian market. BP has a share in both Gorgon and Indonesia's Tangguh projects and finds itself in a similar self-competitive position.

While share ownership in both field development and the liquefaction facility may be the same, they often differ. In many license areas, particularly those using production sharing agreements (PSCs), the national oil company (NOC) holds different interests in field development and in liquefaction even if the companies maintain their relative shares of the private sector portion. In all but two of the twelve exporting countries, a NOC plays some role in the LNG project.

In Indonesia, some of the strains of competitive projects have been very much in evidence. Pertamina's historic role as sole marketing agent for LNG projects has been challenged by some of the newer political forces in the country at a time when it faces a decision as to whether to promote the ninth train at Bontang (favored by Total) or place its emphasis on getting the new greenfield Tangguh project off the ground (a position favored by BP).

The Trend Towards Gas Industry Restructuring and Its Challenge to the Traditional Structure

The theoretical model for the restructuring of the gas - and electric power - industries represents the antithesis of the traditional highly-structured, contract-dependent organizational structure. The restructuring process - first begun in the U.S., Canada and the U.K. - is predicated on the assumption that the traditional form of government monopoly or regulated public utility operation of electricity and gas is inefficient and that a system that introduces market competition inherently provides lower prices and more desirable service options for consumers. It envisions free market competition among buyers and sellers to set commodity prices for gas - "gas-to-gas competition". But since the supply of gas is usually geographically removed from its ultimate consumption, the model also envisions a competitive market for transportation capacity in a system that is subject to open - or third-party - access. For LNG, the model thus sees the "LNG chain" reconstructed efficiently through independent competitive offerings of each of the relevant links which are free to operate independently of one another. And since many market decisions involve time lags between buyers' and sellers' revenue objectives with volatile price behavior in the meantime, it also envisions a system of "risk management" through the use of various types of financial derivatives - futures contracts, options and swaps.

This theoretical model of a restructured industry challenges the traditional structure in a number of ways. It tends to assume that the inflexibilities associated with long term contracting are inherently inefficient, and thus that the recent trend towards short term markets represents the wave of the future. It seeks to increase the level of competition by multiplying the number of players.

Since combined cycle power generation is the dominant driver for international natural gas demand growth, the restructuring of the electric power industry is an integral part of this new approach to LNG markets. By eliminating government or franchised monopoly positions, the restructuring process greatly multiplies the number of potential customers for LNG thereby enhancing the liquidity of the market. Not only are those power companies that have been previously served by a monopoly gas supplier now able to purchase on their own, but the emergence of the independent power producer (IPP) has created a whole new class of customers who are free to compete for their own gas supplies.

To further facilitate competition, the new system prefers open access to receipt terminals to increase the number of buyers and a move away from joint marketing among the partners in an LNG project to increase competition among sellers. And for tanker transportation it envisions a move away from tankers that are dedicated to specific trades, enabling a much more flexible matching of transportation supply and demand.

And finally, the new model of gas competition would substitute financial derivatives for the older, more rigid constraints inherent in long term contracts for the management of project risk. Nothing prevents a buyer and seller from entering into long term contracts, but the working assumption is that in a theoretical free market world, effective financial risk management should make traditional long term contracts much less relevant.

The Emergence of Short Term LNG Markets

While a very small short term LNG market has been in existence for nearly a decade, it has grown rapidly in the past several years. As recently as 1997, short term LNG transactions accounted for only 1.5% of international LNG trade. In the ensuing five years, the volume of short term transactions increased six fold and in 2002 accounted for nearly 10% of international trade. Many of these transactions, particularly in the Pacific Basin are better described as “short term”sales rather than genuine “spot” sales. Rather than representing open offerings of short term volumes as is the case in the spot market at Henry Hub, for example, they represent buyers and sellers attempting to manage shorter term LNG over or under-supply through bilateral deals with other parties.

The early appearance of the short term surpluses east of Suez in the early 1990s seemed to be more by accident than by design. It was the result of over eight million tons of debottlenecking capacity additions in Southeast Asia during a period when both Indonesia and Malaysia were adding expansion trains. It was sustained later in the decade by the slowdown in Asian markets and by the emergence of new export capacity from Qatar and Oman in the Gulf. But by 1999, further Middle East expansions (as well as the startup of Trinidad and Nigeria in the Atlantic Basin) institutionalized the surpluses and by now some of the excess capacity appears to have been created deliberately to enable companies to participate in spot and short term trading opportunities.

As the rigidities associated with the old style contract have softened, more volumes have become available for short term and spot sales. The flexible volumes originate in several ways. As the industry ages, more and more gas is coming to the end of the original contract period, enabling the sellers to renew the original agreement or to take back the volumes for more flexible sales. Debottlenecking of existing facilities creates capacity that has already been financed by the original contract. And most long term contracts have a “ramp up” period to allow the customer to grow into his contract commitments. With increased competition among projects for the market, companies seem more willing to commit to a project with some portion of the output “uncovered”. And

since the seller's greatest concern is debt service while the loan obligation is still outstanding, it may increasingly be possible to tailor the contract length to the shorter period of loan payout, giving the seller greater flexibility to put volumes on the short term market.

One new feature of the "uncommitted" market is the emergence of self-contracting. Some of the larger LNG suppliers that are also large gas marketers, such as Shell or BG, have contracted some volumes with their own marketing organizations, thus effectively integrating downstream.

Some buyers have been particularly active in the short term markets. Korea, faced with a temperature-sensitive space heating demand, has found it difficult to accommodate its seasonal requirements within the traditional 90% take-or-pay delivery restraint and has utilized short term markets to cover seasonal peaks. Its quick withdrawal from short term purchases at the onset of the Asian economic crisis triggered a substantial upset in Asian LNG markets.

The U.S., with its much less rigid contractual situation has been a large buyer in short term markets. When coupled with Spain's willingness to purchase flexibly, it has laid the basis for an active short term arbitrage market in the Atlantic Basin.

While all of this creates uncommitted volumes that are available for short term markets, there is little evidence that sellers are prepared to justify new LNG projects without a portion of the volume "anchored" by long term contracts. Both Mobil in Qatar and Shell in Oman in 1996 supposedly considered the option of justifying new LNG trains on the basis of large spot volumes, but rejected it as too risky. Since no supplier has yet undertaken to build a new facility on a speculative basis without a contracted outlet, the long term contract appears to be still alive and well, and long term contracted volumes should remain as the mainstay of international trade.

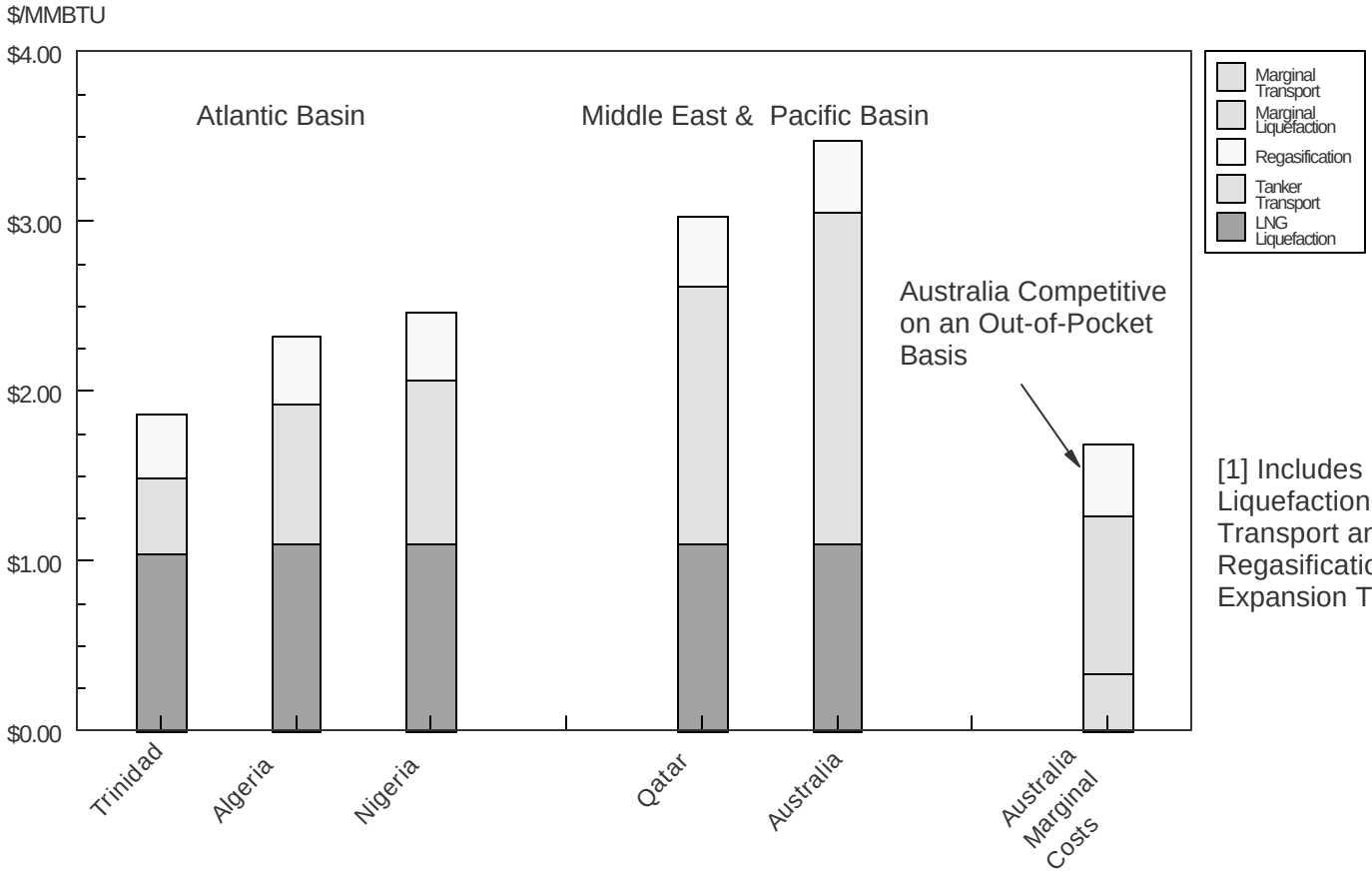
"Spheres of Influence" for Various Supply Sources

Although short term transactions have moved over very long distances (a 1997 shipment from the Northwest Shelf in Australia to Everett traveled more than half way around the world), these depend on a willingness to apply marginal cost economics to the transaction in the face of surplus capacity. For fully allocated transactions that are expected to earn their planned return on investment, the effective shipment distances are much shorter. This tends to lead to an environment where certain sources enjoy a sphere of influence for certain markets.

Figure 9-2 shows the costs of transportation (including liquefaction, tanker transport and regasification) for selected sources of supply to the U.S. Gulf Coast. Obviously, the Atlantic Basin (including the Mediterranean) enjoys a substantial transportation advantage over the Middle East and Pacific Basin sources. Trinidad shows the lowest costs of all, and Venezuela (not shown), if and when it develops and LNG export project would be similarly situated. However, its costs would be higher since it would require a larger investment in new infrastructure.

Both the Middle East and the Pacific Basin are more distant from U.S. markets and pay a corresponding transportation penalty to Atlantic Basin sources. The Australia/U.S. short term transaction is illustrated by including only out-of-pocket liquefaction and tanker costs (together with fully allocated regasifcation costs) in the transportation estimate. The ability of LNG to compete under surplus conditions, even from distant sources, is illustrated by the degree to which the fully-allocated cost estimate from Australia is reduced by including only marginal cost elements.

Figure 9-2
ILLUSTRATIVE TRANSPORTATION COSTS [1] TO A U.S. GULF COAST TERMINAL
ASSUMING EXPANSION WITH 3.3 MMT TRAINS



[1] Includes Liquefaction, Transport and Regasification for Expansion Trains

Figure 9-3 provides a similar evaluation of transport costs to Europe (using Spain as a market destination). Again the Atlantic Basin sources are lower in cost than the Middle East or Pacific Basin sources, although Qatar is only slightly more costly to Spain than is Nigeria. Again, the marginal costs of Pacific Basin LNG make it competitive for spot markets during surplus conditions.

Except for an early contract from Abu Dhabi, Northeast Asia relied almost entirely on Pacific Basin sources - Alaska, Australia, Brunei, Indonesia and Malaysia - until the mid 1990s. However, with expansion of the Abu Dhabi facility and new greenfield LNG plants in Qatar and Oman, the Middle East has been supplying an increasing portion of Northeast Asia's LNG requirements since that time.

The cost increases involved in moving to Middle East supplies are not as dramatic as would be the case of a similar transition in the U.S., as is evident from Figure 9-4. Compared with new greenfield projects that have at least some contract coverage, shipments from a Qatar expansion are somewhat more costly than Indonesia's Tangguh, but somewhat less so than Sakhalin II. The latter has a comparatively short tanker haul to the Japanese market but suffers from the need to pipe gas from the field over 500 miles to an ice-free port for liquefaction.

Until the November fall of the Bolivian government - in large part because of its proposed LNG project for U.S. West Coast markets - Bolivia was a prime candidate for new LNG facilities. However, trans-Pacific shipments from Bolivia to Japan would have been quite costly, both because of the long tanker haul across the Pacific and because of the cost of pipelining the gas to a coastal liquefaction plant.

Shipments from Algeria are significantly more costly than from the traditional Pacific Basin sources. However, in the summer of 2003 Algeria made spot sales to Northeast Asia. The out-of-pocket cost of this movement from surplus Algerian supplies was quite competitive, as is evident in Figure 9-4.

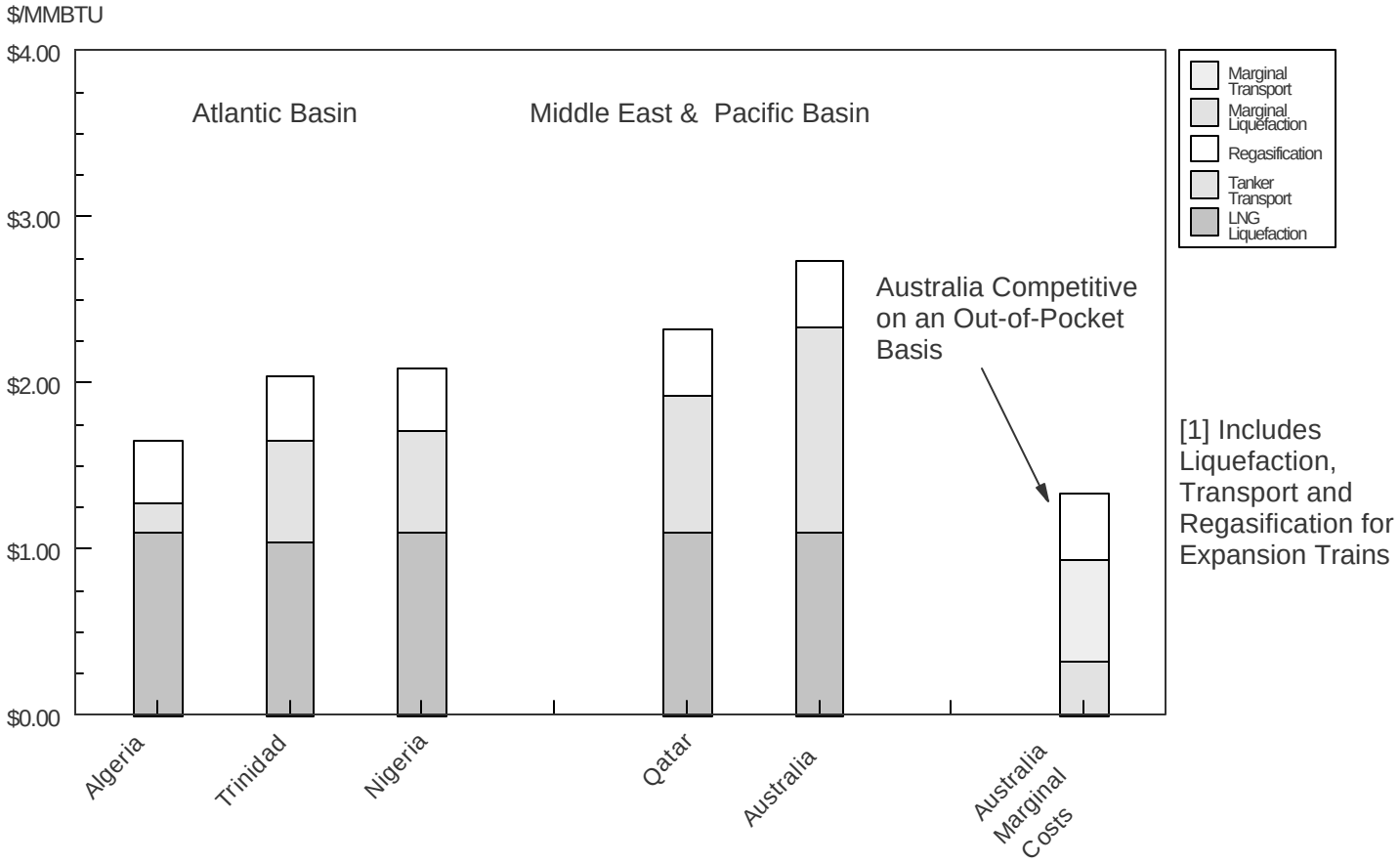
The efforts to site an LNG receipt terminal on the West Coast, either in California or across the border in Mexico, have led to a number of proposals for supply both from expansion at existing sites and from new greenfield facilities. Figure 9- 5 summarizes the transportation costs for selected supply sources. Expansions of existing plants in Indonesia or in Australia appear to provide lower costs than any of the four greenfield facilities shown in the Figure. However, both Tangguh and Sakhalin have "starter contracts" with Asian markets and thus are in a position to take somewhat of a marginal cost view to sales to the West Coast. The Bolivian and Peruvian projects, on the other hand, are predicated on the development of a North American West Coast market and presumably would have to take a more disciplined view of project economics to proceed. Shipments from a Middle East expansion, while clearly more costly than the nearer Pacific Basin sources, still appear to be in the same ball park as the new greenfield projects.

U.S. Transportation Advantages and Disadvantages to Other Source and Market Pairings

There is competition among markets for supplies that lie within the "sphere of influence" of a particular basin. For example, both the U.S. and Europe are competing for Atlantic Basin and Middle East supplies. All things being equal, transportation cost advantages will tend to give one market a competitive advantage over another in attempting to access some of these supplies.

Figure 9-6 compares the transportation economics of supplying the U.S. and Europe from Atlantic Basin sources. These include supplies from Latin American (Trinidad), West Africa (Nigeria) and the Mediterranean (Algeria). Only Trinidad is closer to the U.S., a condition that would also apply to Venezuela, were that country to develop an LNG project. In the other cases, transportation differentials favor Europe by anywhere (in the illustration) from $0.13 for Belgium over Cove Point, MD to $0.59 in the case of Spain over Lake Charles, LA.

Figure 9-3
ILLUSTRATIVE DELIVERY COSTS [1] FOR A SPANISH TERMINAL
ASSUMING EXPANSION WITH 3.3 MMT TRAINS

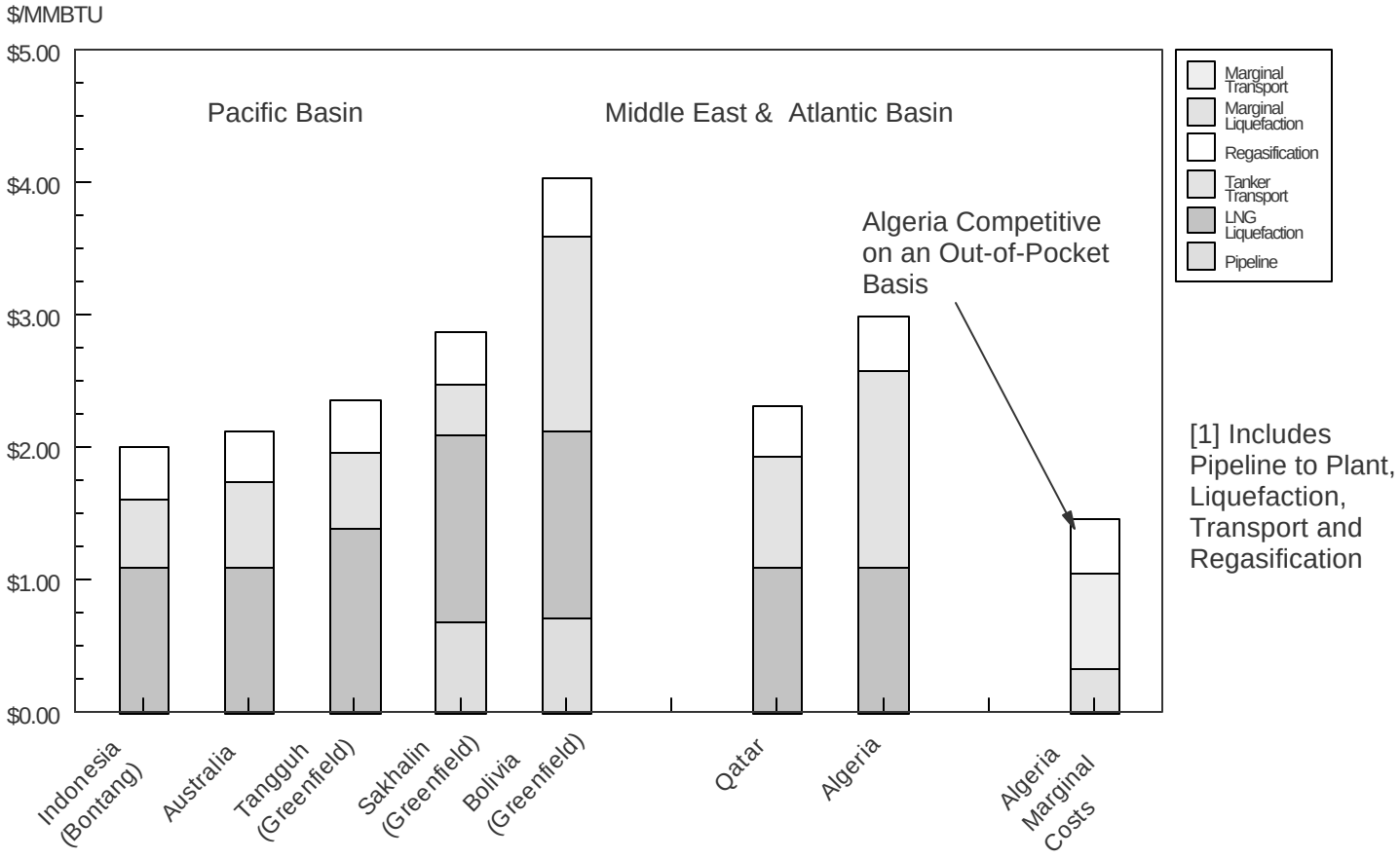


[1] Includes Liquefaction, Transport and Regasification for Expansion Trains

Figure 9-4

ILLUSTRATIVE TRANSPORTATION COSTS [1] FOR A JAPANESE TERMINAL

ASSUMING GREENFIELD OR EXPANSION WITH TWO 3.3 MMT TRAINS

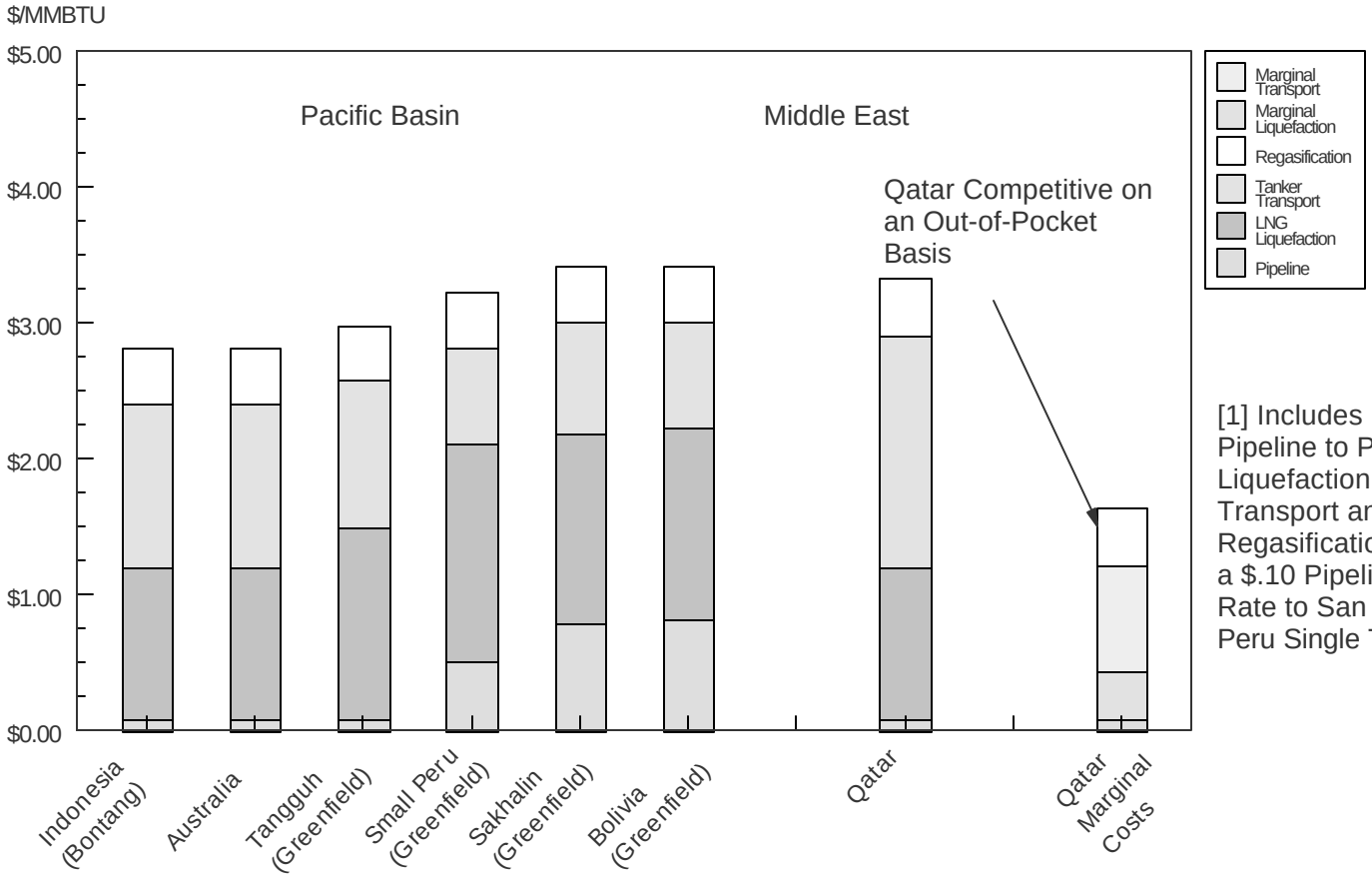


[1] Includes Pipeline to Plant, Liquefaction, Transport and Regasification

Figure 9-5

ILLUSTRATIVE TRANSPORTATION COSTS [1] FOR A BAJA CALIFORNIA TERMINAL

ASSUMING GREENFIELD OR EXPANSION WITH TWO 3.3 MMT TRAINS

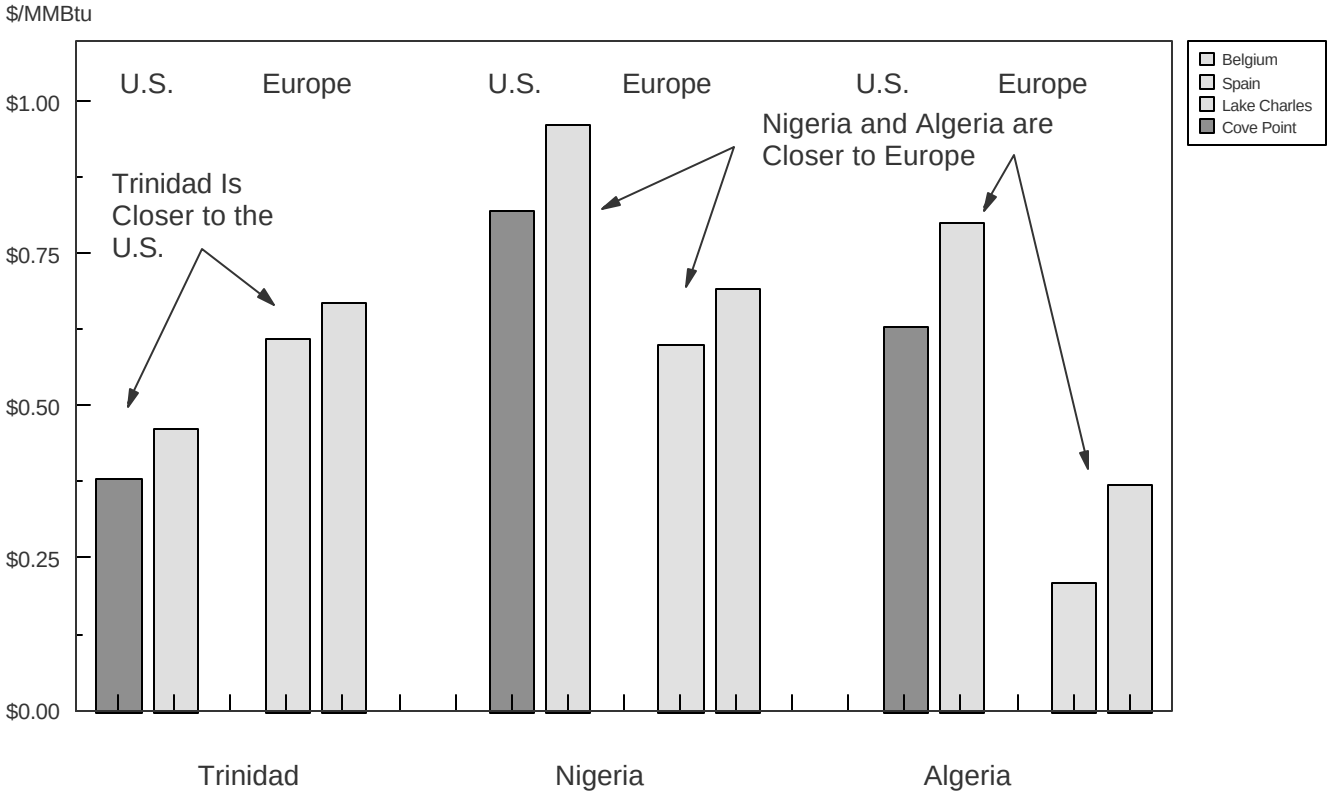


[1] Includes Pipeline to Plant, Liquefaction, Transport and Regasification and a $.10 Pipeline Rate to San Diego Peru Single Train

Figure 9-6

TRANSPORTATION COSTS FOR SELECTED ATLANTIC BASIN LNG TRADES

$/MMBTU



From Figure 9-6, it is also apparent that the U.S. Gulf Coast terminals suffer a transportation disadvantage compared with the East Coast terminals because they are farther from the supply sources. Figure 9-6 is based on LNG transportation costs and thus does not capture an additional advantage that East Coast terminals enjoy - the cost of transporting gas by pipeline from the Gulf Coast. These favorable "basis differentials" further enhance the economic advantages of East Coast terminal locations.

Figure 9-7 compares Europe and the U.S. for East-of-Suez sources of supply. The Middle East (Qatar) is $0.44 closer to Europe than to the U.S., but Qatar prefers Spain to Japan. The Pacific Basin sources all favor Japan over both the U.S. and Europe.

It is not surprising that Western Pacific sources of LNG favor Japanese markets, while the West Coast of South America is closer to California markets (see Figure 9-8). In the illustration, the Western Pacific transportation differentials range from $0.49 in the case of Sakhalin to $0.71 in the case of Bontang in Indonesia.

Regional Market Integration and the Emergence of Arbitrage

For many years, world gas markets consisted of a series of isolated pipeline or LNG trade pairings with little communication among them. The rigidities of the long term contract with its dedicated links of supply sources, tankers and receipt terminals made it difficult to initiate short term or spot transactions. Pipelines, with their inflexible physical links between sources and markets were, if anything, even more regionally constrained. The result was that international gas trade operated within a series of isolated regional markets with little or no communication among them.

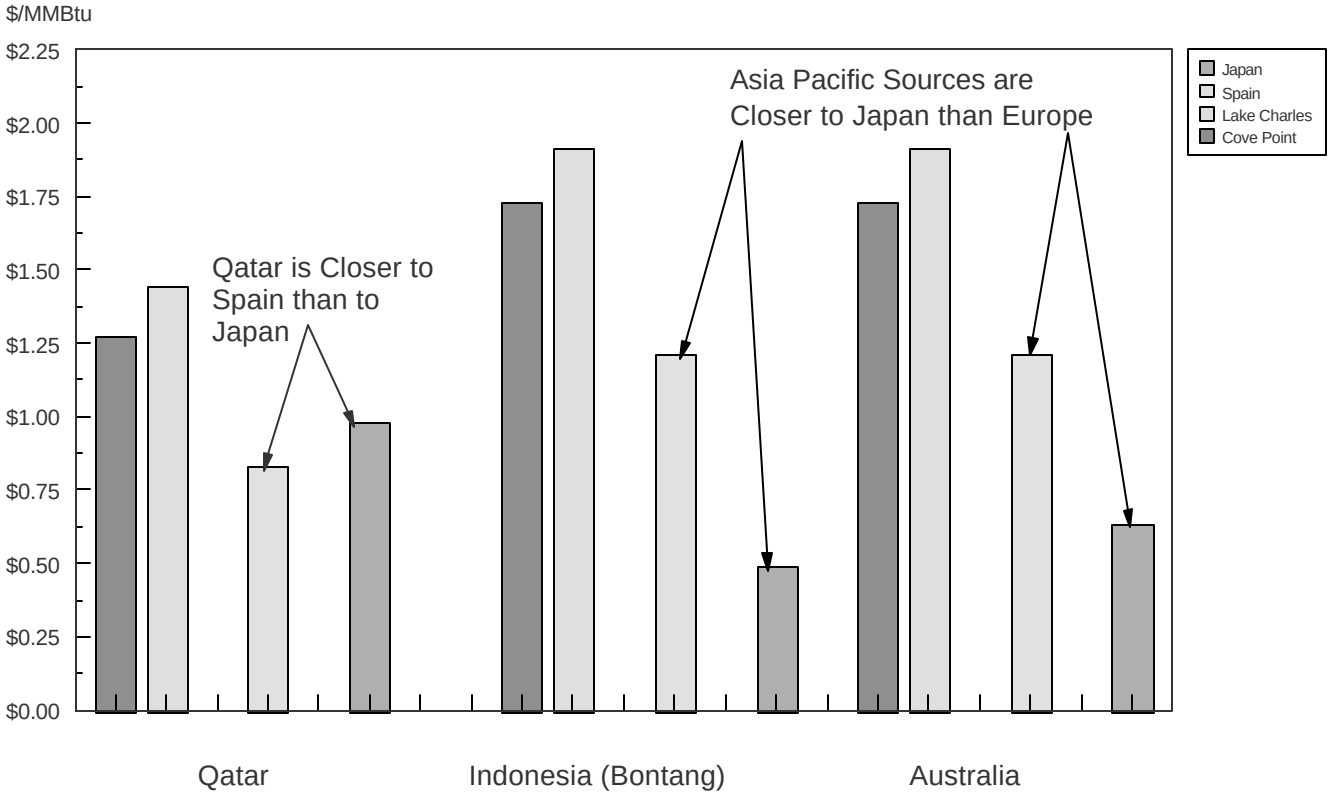
These rigid patterns began to break up in the 1990s as LNG surpluses in the Asia Pacific market and uncommitted receipt terminal capacity - especially in the U.S. - made short term transactions possible. While still small as a percentage of total international trade, these short term transactions began to create price-driven linkages outside the traditional restricted regional markets. Thus a real "world gas market" began to emerge.

An important part of this new trading pattern is the emergence of arbitrage between markets. This phenomenon is the furthest developed within the Atlantic Basin, primarily involving supplies from Trinidad and Nigeria and markets in the U.S. and Europe (primarily in Spain). Thus gas moves to whichever market will offer the highest netback and flows shift accordingly. Another pattern of arbitrage has developed between Northeast Asian markets and Atlantic Basin markets via shipments from the Middle East. Middle East suppliers, principally Qatar, are in a position to ship either to Asia or to the Atlantic Basin as markets dictate.

Figure 9-7

TRANSPORTATION COSTS FOR SELECTED EAST OF SUEZ LNG TRADES

$/MMBTU

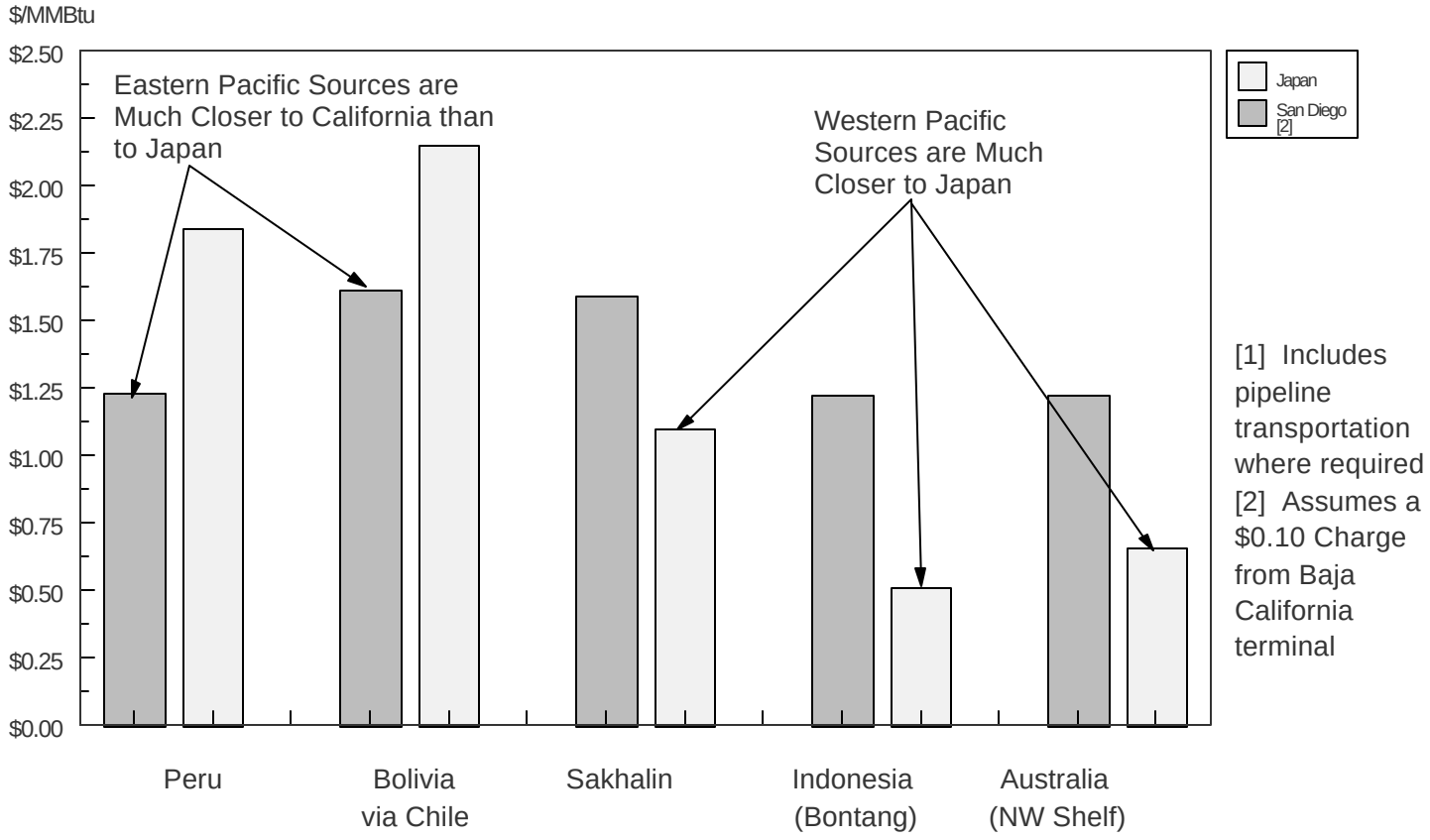


All Sources East of Suez are Closer to Europe and Japan than to the U.S.

Figure 9-8

TRANSPORTATION COSTS [1] FOR SELECTED PACIFIC BASIN LNG TRADES

$/MMBTU



[1] Includes pipeline transportation where required

[2] Assumes a $0.10 Charge from Baja California terminal

X. LNG PRICING

"Netback" Pricing Versus "Cost-of-Service" Pricing

Many of the misconceptions about the future role of LNG in the U.S. energy economy stem from misunderstandings about natural gas pricing. Natural gas has always stood at the interface between two conflicting views of price formation. On the one hand, transmission and distribution have traditionally been regarded as "natural monopolies" where competition is ineffective in disciplining prices and preventing suppliers from earning monopoly rents. On the other, natural gas is a fungible (interchangeable) commodity in the marketplace in competition with other sources of gas as well as other fuels. In such a market environment, it is difficult for any supplier to exert monopoly control on prices.

Natural monopolies are economic activities which are subject to declining costs with increasing scale of activity. For such systems, the existing supplier's declining costs effectively preclude price competition from new entrants, and the seller enjoys a monopoly position. The remedy for such natural monopoly activities has traditionally been utility rate regulation - most common in North America - or government-owned monopoly suppliers - common in many other parts of the world. And while the world wide movement towards natural gas industry restructuring has sharply narrowed the scope of regulation, it remains in place for much of the gas transmission and distribution system.

Utility rate regulation has been designed to permit the utility to recover its operating costs together with a "just and reasonable" return on investment. This method of price formation is commonly described as "cost-of-service" pricing. It has been utilized by state public service commissions throughout the U.S. and has been the basis of Federal regulation of gas and electricity by the Federal Energy Regulatory Commission (FERC), formerly known until 1978 as the Federal Power Commission (FPC).

But where workable competition exists, markets are more efficient in providing commodities and services. The underlying assumption is that competition will prevent that marginal supplier who is necessary to balance supply and demand from capturing monopoly profits (economic rent[9]).

The classic supply/demand curve of basic economics is illustrated in Figure 10-1. In it, an increase in price causes a decline in demand and an increase in supply. Where the two curves intersect, the market "clears" with a market clearing price and a market clearing volume. However, at the market clearing price there are buyers who would still buy if prices were higher and sellers who would still sell if prices were lower. This is illustrated in Figure 10-2. In a world of regulated utility ratemaking, the low-cost supplier illustrated in Figure 10-2, would be constrained to sell at his cost-of-service, but in a free market environment he is able to capture some economic rent for himself over and above his cost-of-service.

In LNG, the pricing mechanism that allows the seller to value his production at its value in the marketplace (after deducting the costs to deliver it there), is termed "netback" pricing. Figure 10-3 illustrates the differences between "cost-of-service" and "netback pricing" using a hypothetical LNG project delivering to the U.S. Gulf Coast from a greenfield liquefaction plant 6,200 nautical miles distant (roughly the distance from Nigeria to Lake Charles). If the supplier's wellhead cost is $0.80, he could justify his project on a cost-of-service basis if regasified LNG were priced at $3.26. If he were subject to utility regulation, that is the price he would be

[9] "Economic rent", sometimes called "windfall profits", refers to the margin over and above that necessary to bring forth the necessary supply

Figure 10-1

THE THEORETICAL BEHAVIOR OF SUPPLY, DEMAND AND PRICE ACCORDING TO "ECONOMICS 101"

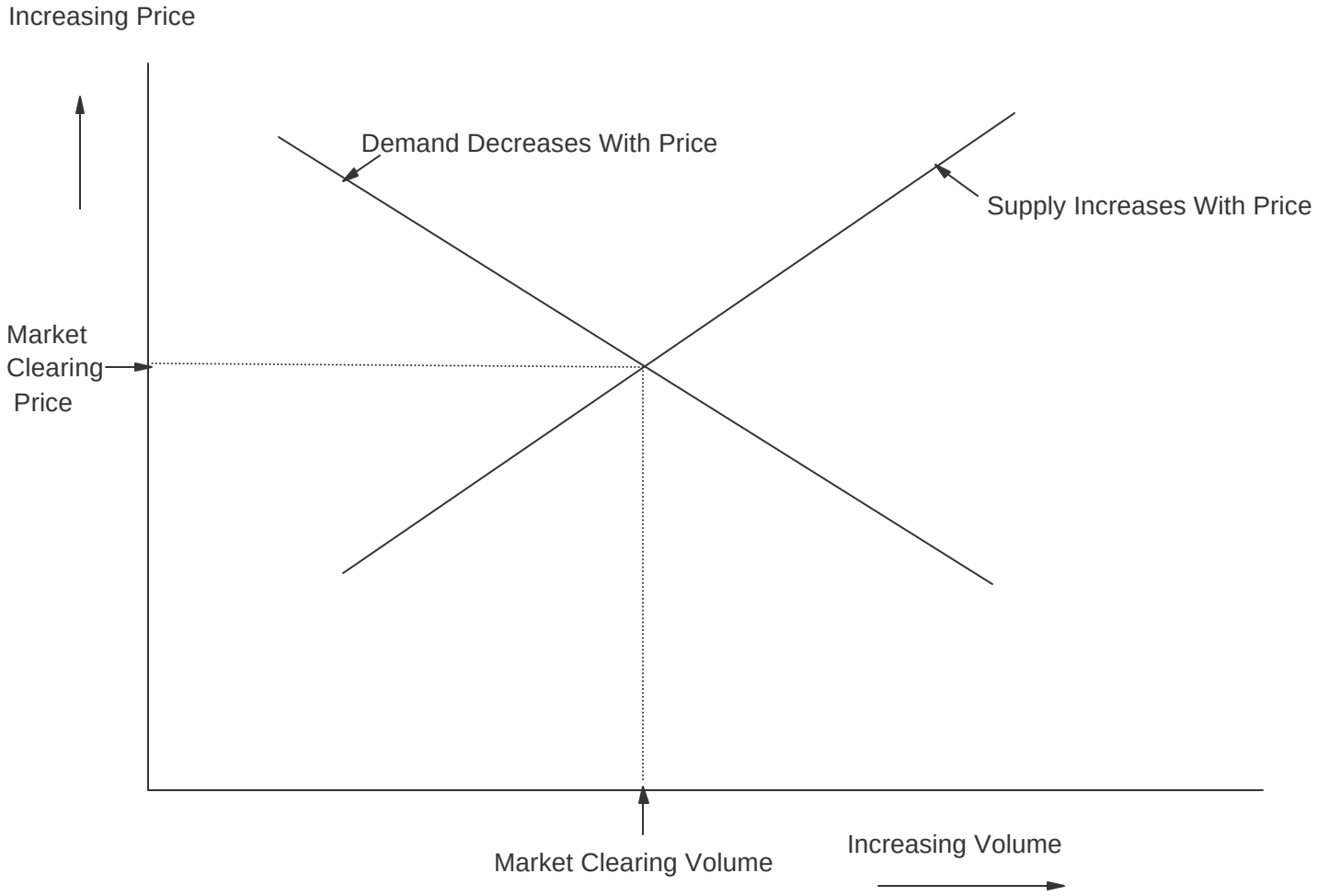


Figure 10-2

WHILE THE MARGINAL SELLER IN A CLEARED MARKET EARNS NO ECONOMIC RENT, NOTHING PREVENTS LOW COST SELLERS FROM DOING SO

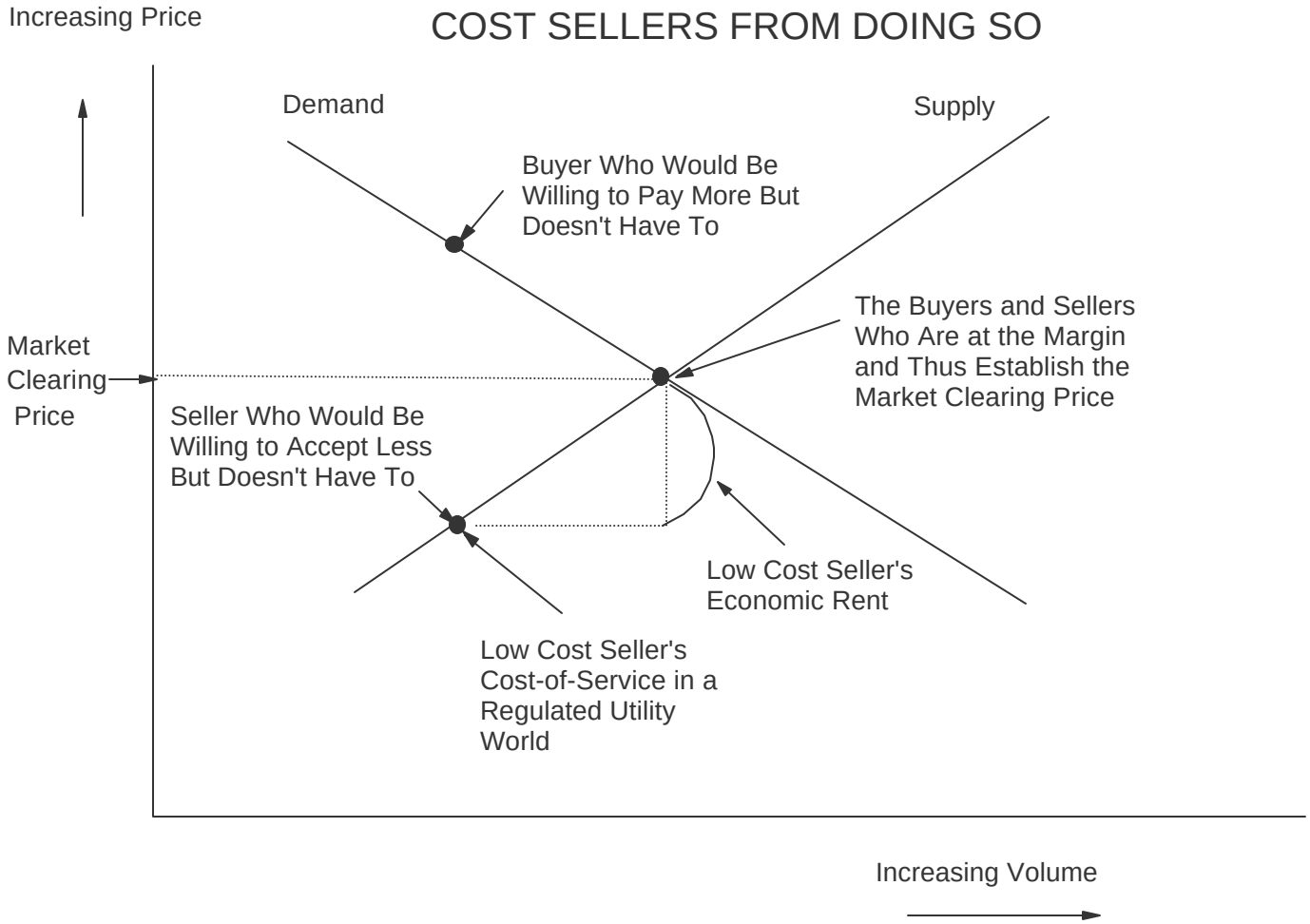
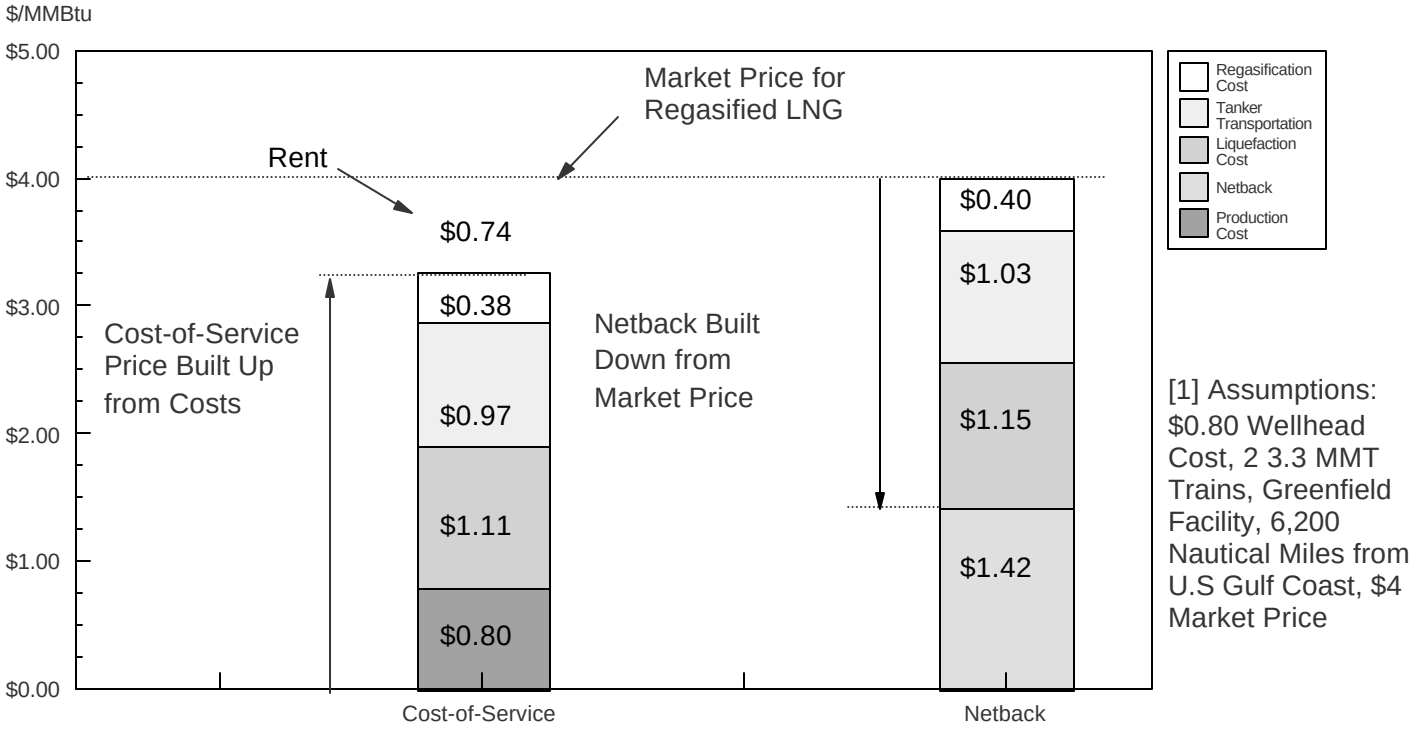


Figure 10-3

"COST-OF-SERVICE" LNG PRICING CONTRASTED WITH "NETBACK" PRICING - A HYPOTHETICAL [1] LNG TRADE INTO THE U.S.



[1] Assumptions: $0.80 Wellhead Cost, 2 3.3 MMT Trains, Greenfield Facility, 6,200 Nautical Miles from U.S Gulf Coast, $4 Market Price

allowed. However, in a $4 competitive market, his netback is $1.42, rather than the $0.80 price he would have gotten under cost-of-service pricing, enabling him to retain some economic rent.

This conflict between a cost-of-service view of price formation and market pricing was at the heart of the failed U.S. experiment with natural gas wellhead price controls in the 1950s and 1960s. The Federal government has the authority, conferred by the Natural Gas Act of 1938 to regulate the rates of natural gas pipelines engaged in interstate commerce. And although subsequent restructuring of the natural gas industry has sharply changed the way in which it exercises its authority, it still retains jurisdiction over interstate pipeline tariffs.

In 1954, the Supreme Court, in its landmark “Phillips Decision” , extended utility ratemaking to gas at the wellhead, thus introducing wellhead price controls. The FPC, charged with regulating the pipeline industry, quickly found that cost-of-service regulation applied to individual producers was completely unworkable in the regulation of gas prices.

While individual producers experienced very different costs, their product was a fungible commodity. In addition, the question of joint costing reared its head. Were wildcatters just looking for hydrocarbons, in which case exploration costs had to be allocated between gas and oil? Or were they actually able to target their exploration for gas, in which case all exploration costs could be assigned to gas?

Some gas was dissolved gas from oil wells while other gas was rich in gas liquids. How did one allocate costs between gas and liquids? Finally, the FPC hit upon the idea of regulating against broad area cost averages, thus coming up with the concept of "area pricing". The first two test cases were the South Louisiana Area Rate Case, where natural gas liquids (NGLs) were important, and the Permian Basin Area Rate Case, which featured associated gas; the FPC thus met the joint liquids/gas cost allocation problem head on. Yet despite the efforts of the FPC, natural gas shortages developed and worsened.

Wellhead price controls failed in the last analysis because they gave incompatible signals to buyers and sellers in a competitive commodity market. To sellers, price controls suggested that any price above historic experience was not “just and reasonable”, thus discouraging the pursuit of higher cost supply that might be necessary to satisfy a growing market. To buyers they suggested that prices would not rise above cost-justified levels regardless of the extent of that demand, thus encouraging buyers to over-consume. Severe shortages were the result.

Congress's final acceptance of deregulation after 1978 ended the struggle with "cost-of-service" pricing and with it, the attempt to assign costs to the wellhead. It substituted instead the concept that competition in the marketplace would determine prices for the commodity and that individual producers could "net back" prices to the wellhead regardless of their individual cost structures.

The Myth That LNG Will Set a “Cap” on U.S. Gas Prices

One common perception is that LNG represents a potential “backstop” for North American gas supply - that is that at some price level LNG will flood into the market and “set a cap” on North American prices. Those who hold this point of view cite LNG cost estimates that suggest that LNG costs are well below recent price levels, and contend that the import of LNG will drive North American prices to down to LNG’s cost levels. This is a myth that reflects a lack of appreciation of the difference between cost-of-service and netback pricing as well as the role of competition in disciplining prices.

The issue is not whether increased LNG imports into the U.S. will put downward pressure on gas prices. They obviously will. But in netback pricing, LNG is a "price taker". For it to become the "price maker" that the "backstop" or "cap" concept implies, there must be enough competitive LNG supply offerings at cost-of-service levels to drive North American gas prices to parity with LNG costs.

In North America, the distinction between netback pricing and cost-of-service pricing has become blurred because of the highly competitive nature of the conventional gas supply offerings. The gas supply models, for example, assume that there is enough competition in every producing basin - and that individual basins are economically homogeneous enough - that netback prices will be driven by competition to cost-of-service levels. But there is a tremendous difference between the nature of competitive supply offerings for conventional gas and those of LNG projects. For the two years 2002 and 2003, hundreds of U.S. producers, responding within months to market price signals, drilled a total of nearly 36,000 gas wells to help satisfy U.S. demand. In contrast, there were only six new LNG trains that started up during the same period worldwide. And they had widely disparate individual cost structures, heavy involvement of governments in the projects, and were initiated for international markets on a four year planning and investment cycle. If geopolitical or investment constraints slow the future supply of LNG into the market below the level necessary to meet growing U.S. demand, or if competition with other markets is too strong, there may be insufficient supply competition to drive LNG prices to cost-based levels.

Real world supply/demand curves are much more complex than those illustrated in Figures 10-1 and 10-2. There may be some blocks of highly elastic supply that create stable "benches" where prices may not change significantly despite large changes in demand. Similarly, there may be "benches" of highly elastic demand that can accomodate substantial variations in supply without causing a significant change in price. Absent these elastic "benches", prices may exhibit substantial volatility. Figure 10-4 illustrates the way in which such a supply bench might function. Because there are substantial offerings of supply at very similar prices, large increases in demand can be accomodated without putting significant upward pressure on prices.

Most gas supply models have assumed that North American gas supply basins exhibit just such elastic supply benches. Most models construct their gas supply curves using the costs of drilling and developing gas reserves in individual producing basins. The working assumptions are [1], that there is a substantial inventory of drilling prospects having similar cost structures within each basin, [2] that the decision to invest in new supply is solely motivated by economic considerations., [3] that the supply response to price signals is rapid (if not instantaneous) so that supply/demand/price balances quickly adjust to new equilibriun conditions, and [4] that the wellhead is sufficiently competitive that wellhead prices will be driven to cost-of-service levels within each basin. Figure 10-5 illustrates the way in which one such model - the NARG model in use by the Canadian National Energy Board in the 1990s - treated supply elasticity.

The idea that the same logic can be applied to LNG is encouraged by the fact that the margins required for liquefaction, tanker transport and regasification appear to fit the classic cost-of-service model. Thus, if one assumes that LNG comes from just another "basin", and that there are many potential LNG suppliers with similar costs waiting to compete for U.S. markets, it is not a major leap to assume that cost-based pricing also applies to the gas production function for LNG. Therefore at some cost-based "trigger price" LNG will flow in to forestall the development of more costly supplies, thereby "capping" gas prices.

However, the working assumptions outlined above do not apply to LNG as they do to North American gas supply. North American gas supplies are competitive commodity offerings. LNG supplies represent large, discrete project investments. The individual projects have widely different underlying cost structures and are

Figure 10-4

THE EFFECT OF A HIGHLY ELASTIC SOURCE OF SUPPLY - A "BENCH" - ON STABILIZING PRICES

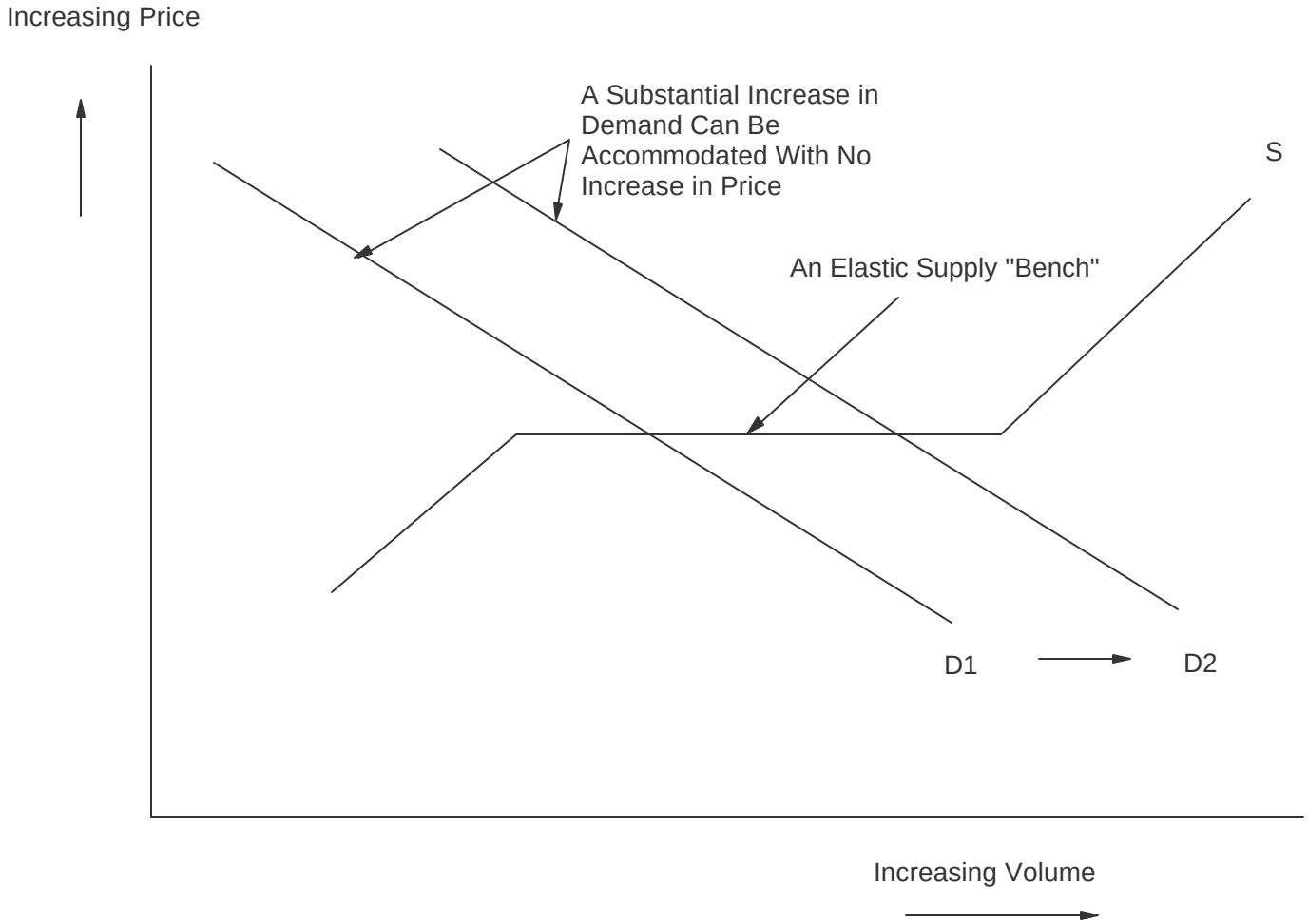
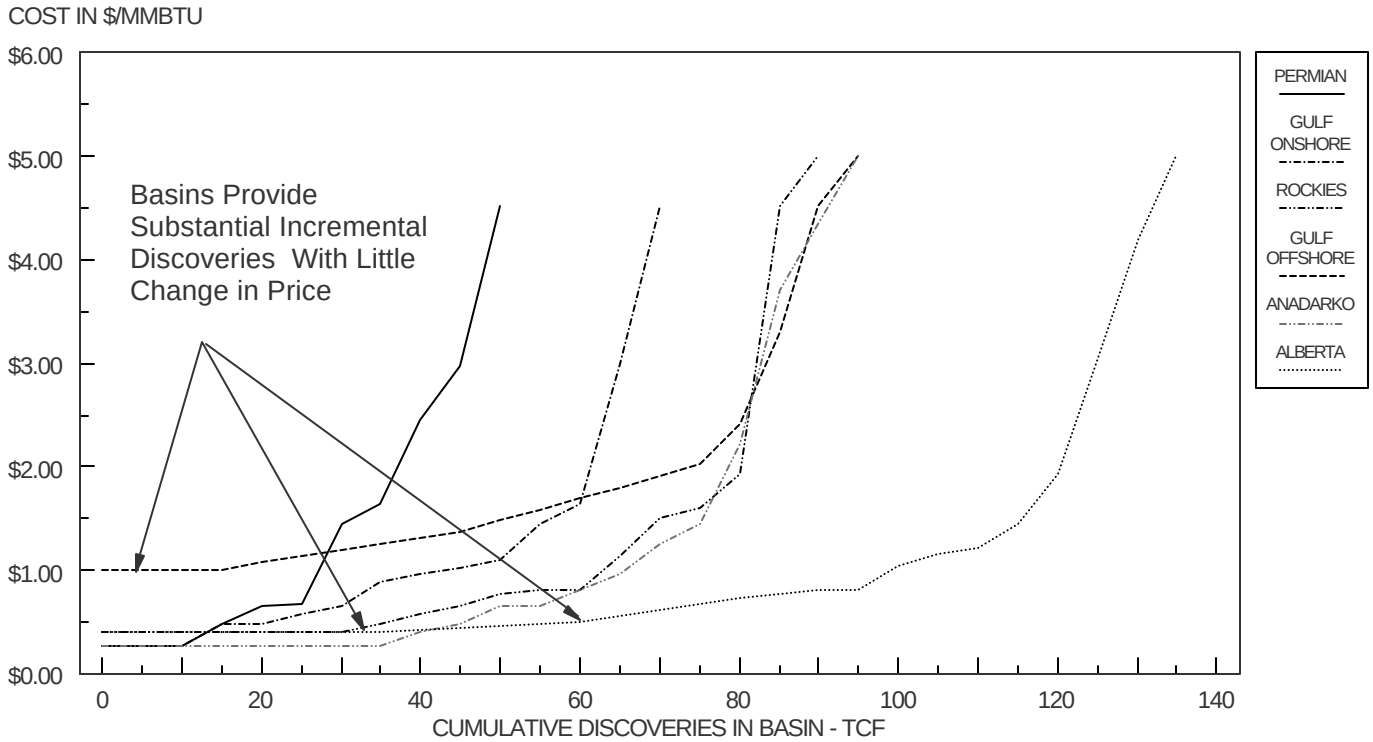


Figure 10-5

LONG TERM SUPPLY ELASTICITY RELATIONSHIPS ILLUSTRATED [1]

COST OF DEVELOPING INCREMENTAL GAS RESERVES IN VARIOUS PRODUCING BASINS AS A FUNCTION OF CUMULATIVE DISCOVERIES



[1] Illustration Derived from 1994 Canadian National Energy Board Study

subject both to geopolitical constraints and to substantial time lags between the investment decision and the physical supply.

There is probably more variation in production costs for LNG projects than there is for conventional North American supply. Most LNG projects are based on non-associated gas fields that are very rich in liquids. In fact some of the LNG sources are so rich in NGLs that they could be developed profitably - in the absence of a market - by recovering the liquids and flaring the gas. Since no government is likely to permit such waste, the operator in such a case can be better off transferring the gas into an LNG plant at a negative value based on the avoided cost of reinjection.

Similarly, there have been growing pressures to curb flaring of associated gas in producing countries. Delivering such associated gas to the plant gate usually involves gathering and compression costs for often small quantities, often making it more costly to utilize than high pressure non-associated gas from productive gas wells. If governments are strict about anti-flaring regulations, they may create similar "negative opportunity cost" gas in such situations. These variations in producing costs, while common in LNG, are not usually a factor in conventional North American supply.

In 2003, the gas industry completed nearly 20,000 gas wells with an average rig count of 870 drilling rigs and the response time lags for gas rig counts and completed gas wells was measured in months. In contrast, the entire international LNG industry completed ten new liquefaction trains during the 1989/1998 decade. With the renewal of recent interest in LNG, it completed twelve trains for the five years ending in 2003 and if construction schedules do not slip, it will complete three more in 2004 and as many as seven in 2005. But with an average period of four years for the completion of a new project, the plants that will start up in 2004 were initiated under the price expectations of the year 2000, and new investment decisions finalized today will probably not go on line until 2008.

LNG projects do not smoothly respond to short term - and volatile - price signals when demand calls for new supply. Thus, while increased LNG supply will serve to moderate gas prices, LNG is likely to retain its "netback pricing" role.

Establishing a "Market Price" For LNG Netbacks

The early introduction of LNG into markets rarely found gas prices determined independently by commodity competition. Thus the "market price" was a contractually-determined surrogate for energy price levels and was contained in the price escalation clause of the contract. And since gas was most commonly competing with oil for market share in stationary energy markets, these price clauses were usually tied to oil. Europe, with an existing international trade in pipeline gas, often tended to adopt contractual structures from the pipeline contracts and these were usually tied to some mix of oil products, occasionally with coal. Japan, which was introducing significant quantities of gas for the first time, elected to tie the LNG price escalator directly to crude oil. Although the Indonesian contracts tied price escalators to Indonesian crude, nearly all of the other contracts tied the price escalator to the Japanese Customs Clearing price for crude oil (JCC) - the average price in $/barrel of all crude oil imported into Japan regardless of source or quality of the crude oil. This price reference is often referred to as the "Japanese Crude Cocktail" and has become the standard for most Asian contracts. The most common formula is $P=a*(JCC)+b$, where P is the LNG price as liquid ex ship, a is a constant reflecting the heating value of a barrel of oil, and b is constant (in $/MMBtu) subject to contract negotiation.

The volatility of oil prices has also been a source of difficulty, so that many contracts now include a “floor price” that protects the seller from oil market collapses. Sometimes the buyers have negotiated some protection of their own, so that some contracts utilize “S curves”, setting floors and ceilings on the variability of pricing.

When Japan first introduced LNG into its power generation fuel mix, the dominant source of primary energy for electricity was residual fuel oil. Hence, an oil linkage had some logic. However, oil has increasingly become marginalized so that in 2002 it constituted only 16% of Japanese power generation. Although original logic of oil-linked pricing no longer seems valid - in Japan, as well as in most markets. - it seems to have been difficult to find a satisfactory substitute.

The Emergence of Gas-to-Gas Competition And Gas-Linked Pricing Clauses

The worldwide restructuring of the gas and electric industries, already largely in place in North America, envisions free market competition among buyers and sellers to set commodity prices for gas - “gas-to-gas competition”. The most obvious solution to the dissatisfaction with oil-linked pricing in a restructured gas industry in gas-to-gas competition is a price tied to a gas market indicator. In the U.S., the Henry Hub quotation is the obvious candidate for such a role. And as a forerunner to the possible spread of gas-linked pricing to Europe, Statoil recently signed a pipeline contract with Centrica in the U.K. that was to be linked to a gas market indicator.

There are three disadvantages to the use of a gas market indicator relative to an oil indicator as a measure of changes in energy prices. Gas prices appear to be more volatile than oil prices, even after accounting for their relatively more seasonal behavior. Second, the great geographic dispersion of market transactions together with gas’s much higher transportation cost means that some geographic “place differential” or “basis differential” must be utilized to relate dispersed sales prices to the market indicator. And finally, if gas is delivered to a sufficiently liquid market that it does not move the market price, the effect is to eliminate much of the buyer’s risk. In an oil-linked contract, he must take the volume whether or not he can profitably resell it, but if the price is gas-linked, he can resell the volume at the same price at which he bought it. Thus the effect of moving to gas-linked pricing is to shift more of the market risk upstream.

The existence of a world oil market is largely predicated on the low costs of tanker transportation coupled with the role of the Gulf as a supplier of last resort. Therefore the issue of oil “place” or “basis” differentials has usually not been a significant issue in oil price escalators. However, the much higher costs of gas transportation can cause substantially differing prices at different geographic locations. In the U.S. these basis differentials from the Henry Hub market are regularly monitored by trade press pricing services and market trading activity is often based on estimates of their future behavior.

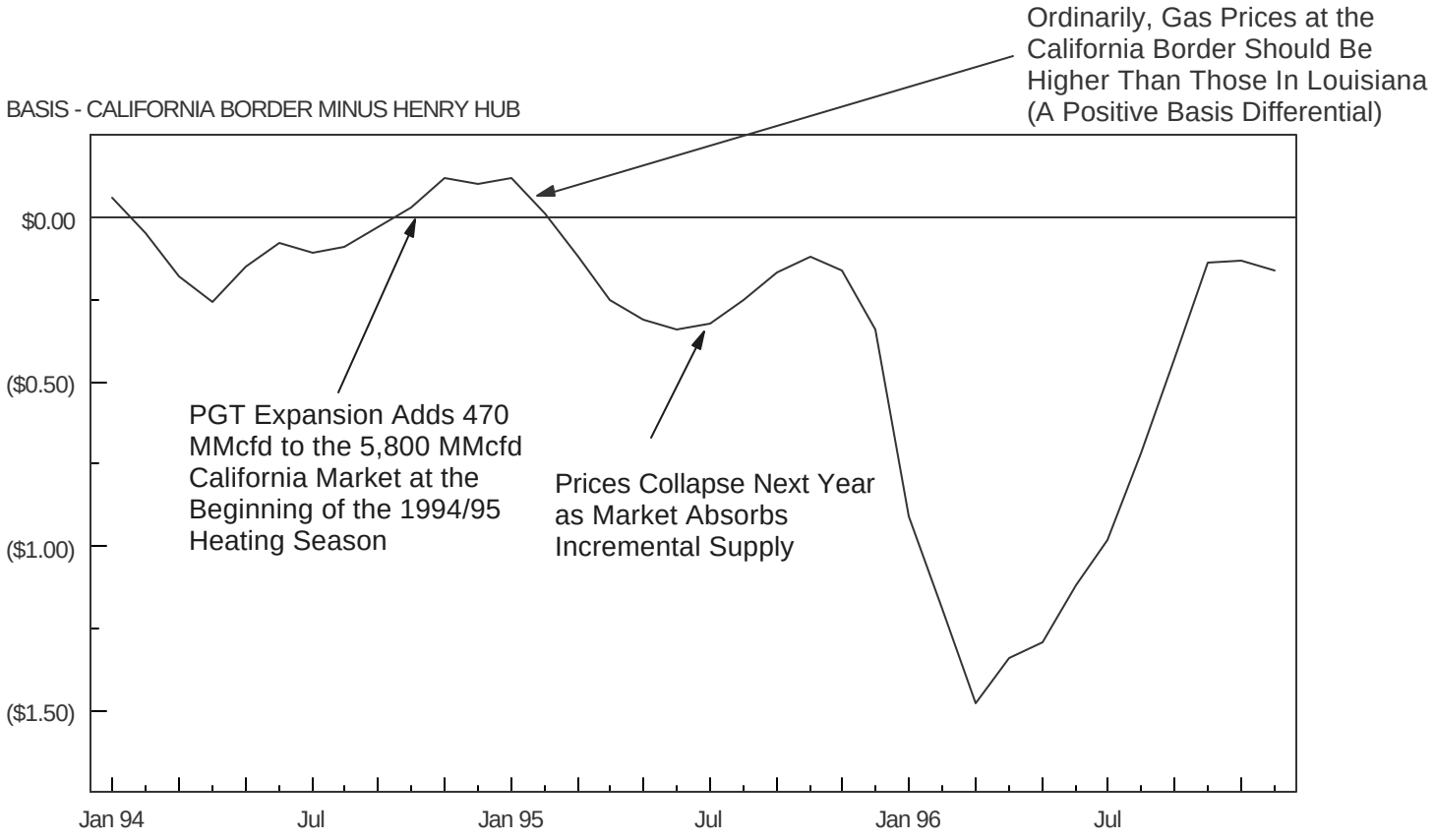
The fact that basis differentials for markets removed from the pricing reference point can themselves vary quite widely introduces a further element of “basis risk” into the pricing equation. For the U.S. market, for example, an LNG delivery to the Everett, MA or Cove Point, MD terminals would be expected to enjoy a higher price than a delivery to Lake Charles, LA near the Henry Hub pricing point because of the basis differentials to Northeastern markets. Similarly, proposals to deliver LNG to California (or to Baja California in Mexico for reshipment to the U.S.) might normally expect a positive basis differential over Henry Hub.

However, the fact that local markets can easily be overloaded, sharply affecting the historic differential, introduces a new element of risk into the transaction. This phenomenon was illustrated in 1994/1996 when a pipeline expansion by Pacific Gas Transmission into the California market caused a collapse of the normally positive basis differential over Henry Hub (see Figure 10-6).

Figure 10-6

"BASIS RISK" - COLLAPSE OF THE CALIFORNIA BASIS DIFFERENTIAL FOLLOWING THE 1994 EXPANSION OF PACIFIC GAS TRANSMISSION

THREE MONTH MOVING AVERAGE



The closer the transaction is to the market reference location, the less the degree of basis risk in the transaction. An LNG delivery into Lake Charles might be expected to have little or no basis risk to Henry Hub. However, such a delivery, if made on a contract that was keyed to Henry Hub as a gas market indicator, would involve little volume risk to the buyer since he could quickly resell the volume in the highly liquid Louisiana market.

The effect of many of these new pricing and volume changes is to shift the market risk towards the seller. Thus the way in which sellers ultimately adapt to this new risk profile will have much to do with the future shape of the industry. One response is already in evidence - that of a tendency for suppliers to integrate downstream and for sellers with some remaining market control to attempt to integrate upstream.

Is Oil-Linked Pricing on the Way Out Or on the Way Back In?

The gradual disappearance of oil as a competitor for natural gas in stationary applications and the emergence of gas-to-gas competition in the restructured North American gas industry has led many to conclude that oil-linked pricing is now an obsolete concept. Were this to be true, the Commission's concern that increased reliance on LNG imports would simply increase the U.S.'s exposure to international oil price shocks could be put to rest.

However, it is not that simple. For much of the period since the restructuring of the North American gas industry got under way, the U.S. operated with an overhang of surplus natural gas - the "gas bubble". In that environment, all dual-fired oil/gas capacity was fully satisfied (except for normal seasonal interruptible sales) and oil was effectively not price-competitive. It was common to assume that oil and gas prices were decoupled and gas-to-gas competition at prices below oil levels was the normal state of the industry.

The gas price shock of the winter of 2000/01 drastically changed that perception. As prices quickly rose above oil-competitive levels, significant switching to oil in dual-fired boilers quickly took place and oil and gas prices were once again competitive.

North American gas pricing is more complex than the simple supply/demand shown in Figure 10-1. There is potential price competition between oil and gas in dual-fired boilers, but in the environment of surplus, gas can take all of the market that is available to it in the short term and gas prices are effectively decoupled from oil prices.

A more realistic way of viewing the gas demand curve is to show it in relationship to oil prices, rather than in the absolute level of gas prices themselves. Figure 10-7 provides such a relationship by using the ratio of gas prices to oil prices as the price determinant.

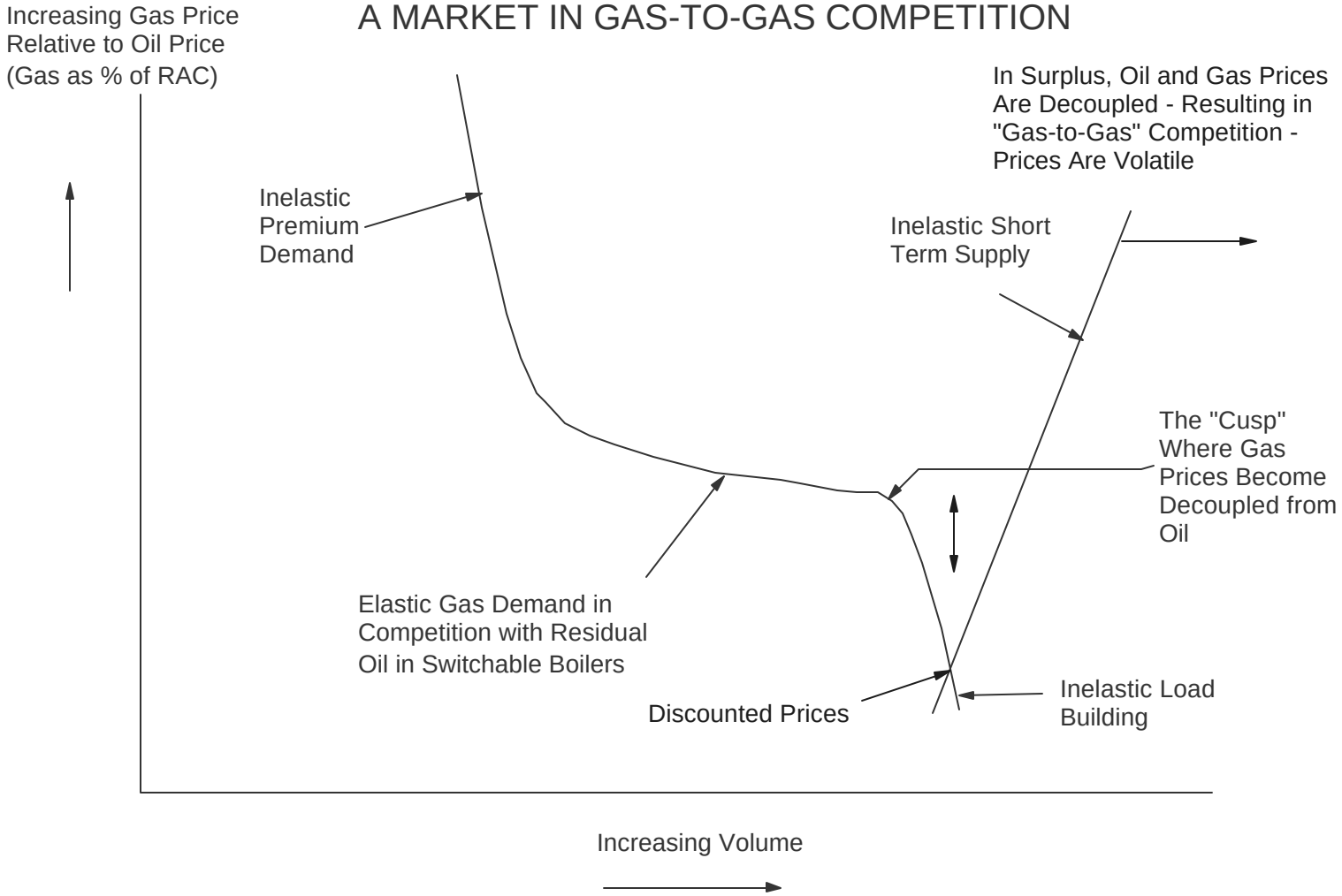
Premium markets for residential, commercial and process industrial fuel are comparatively inelastic and do not respond significantly to large changes in price levels. Similarly, markets in surplus, where all existing gas-fired capacity is largely satisfied are also inelastic in the short term. For such markets, oil prices are largely irrelevant since gas prices are decoupled from oil levels and markets are in gas-to-gas competition.

In between is an elastic "bench" where small changes in gas prices relative to oil prices cause a significant shift from gas to residual fuel oil in dual-fired power generation and industrial boilers. This zone of elastic demand or "bench" occurs at a price relationship of about 90% between Henry Hub and the average price of crude oil to U.S. refiners - the Refiners Acquisition Cost or RAC.

Figure 10-7

A MORE REALISTIC SHORT TERM GAS SUPPLY/DEMAND CURVE

A MARKET IN GAS-TO-GAS COMPETITION



One of the features of that gas price shock of 2000/2001was how quickly residual fuel oil switching capability was exhausted and competition moved to a higher level representing competition with distillate fuel oil. The evidence is that only about 1.5 to 2.0 Bcfd or about 2 - 3% of total demand switched to residual fuel oil on the basis of price. Figure 10-8 illustrates this higher zone of interfuel competition against distillate fuel oil. This relationship is at significantly higher levels - perhaps as much as 40% above RAC. These higher price levels have often been in evidence during the recent gas price runups.

The fact that the "bench" of residual fuel oil competition is quite narrow suggests that there is a fragile relationship between the two. And the ability of distillate/gas competition to place a reliable "cap" on gas prices has not been comfortably demonstrated suggesting that more stress in balancing supply and demand in the higher price ranges may be placed on demand elasticity.

The conclusions for the Commission is that the earlier contractual linkage between gas and oil prices is no longer as straightforward as when the Japanese set the oil-linked pricing precedent. In the earlier contracts the linkage was explicit and direct (except when overridden by floor prices and S curves). To the extent that a liberalized U.S. gas market moves to gas-linked pricing terms the linkage will be indirect as influenced by the nature of interfuel competition between gas and oil. And if contractual oil price linkages were sometimes troublesome in volatile oil market pricing, it is likely that gas-linked pricing will be even more troublesome. If the competitive relationship between oil and gas prices is itself a changing target, it is difficult to see how gas-linked pricing can be anything but more volatile than oil pricing.

However, even if the linkage is no longer direct, there may be some sympathetic movement of gas prices in the event of an oil shock. Trade press newsletters that follow daily gas markets frequently explain a changing gas price as caused by a change in oil prices. But if the underlying linkage is not fundamentally supported, such sympathetic price moves may be of comparatively short duration. The fact that LNG will increasingly come from Middle East sources, suggests that gas prices may be especially sensitive to oil price shocks if those are the result of political upheavals in the Middle East.

How Effective Will Financial Risk Management Techniques Prove To Be For LNG?

Before the gas trading companies got into their financial difficulties, many were promoting an ambitious concept of using financial derivatives for long term as well as short term risk management. Taken to its extreme, the seller no longer had to rely on long term contracts for his future cash flow but could utilize the longer term derivatives market in order to lock in prices and manage risk.

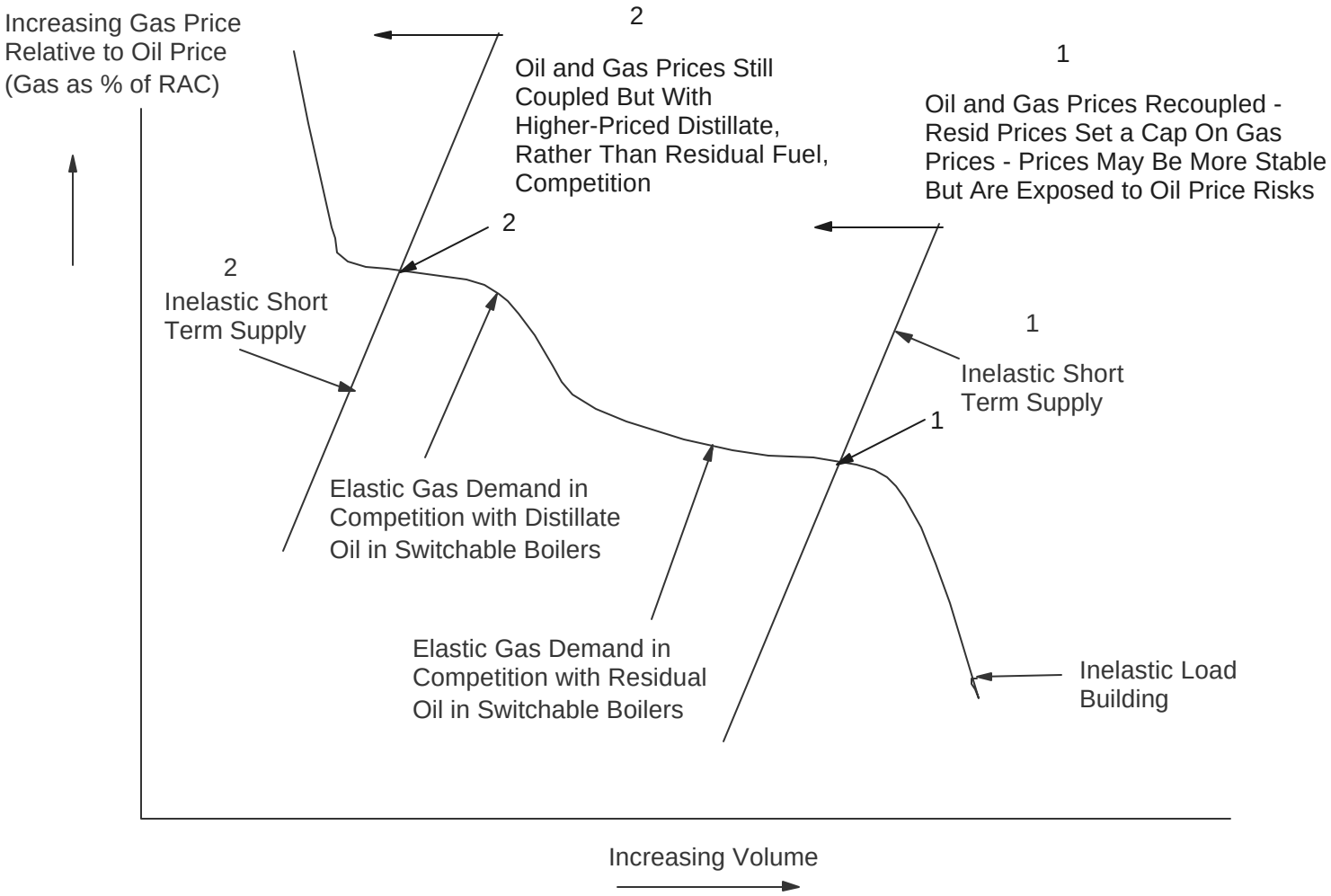
The NYMEX futures market has proved to be highly successful. It has provided a very liquid vehicle for hedging U.S. gas market transactions. It has enabled companies to stabilize revenues and profitability when market volatility would otherwise cause them to fluctuate unacceptably. And it has enabled buyers and sellers to lock in current market pricing conditions for physical transactions that will not take place until some time in the future. Applied to LNG, it would enable the parties to offset the sometimes irregular delivery of LNG cargoes. And a transaction for Middle East LNG for the U.S. East Coast can be locked in to the current market price despite the fact that it might take forty days for the vessel to deliver the cargo.

Futures quotations on the NYMEX exchange are available for thirty-six months into the future, and for longer term risk management, the over-the-counter swaps market extends the hedging period years into the future. While the NYMEX transactions are fully transparent, the swaps market lacks the transparency of the NYMEX exchange quotations.

Figure 10-8

ANOTHER SHORT TERM GAS SUPPLY/DEMAND CURVE

TWO MARKETS WITH OIL-TO-GAS COMPETITION RESTORED



The liquidity of the NYMEX market drops off significantly for later transactions, making it increasingly difficult to move large volumes without affecting the market. To pick a day at random, the report on NYMEX activity for December 18, 2003 showed an open interest[10] of 48,125 contracts for January, the near month[11]. For the July contract the open interest had fallen to 12,917 and for January 2005 it was down to 10,151. The December 2005 contract showed an open interest of only 4,160. There are no published figures for swaps activity, but the controversy of whether or not it can ever be liquid enough to hedge large, long term LNG investments is not new.

All financial derivatives depend on counter parties to offset the positions of those who want to hedge prices. For near months, market speculators contribute significantly to that role, but as contracts lengthen the market has relied more and more on the specialist market trading companies as the counter parties. The near collapse of the trading companies has markedly changed the outlook for long term risk management in LNG. Since some of the affected companies were leaders in the effort to develop the long term derivatives market, their problems - and in some cases complete withdrawal from trading activities - has sharply reduced the number of players who are prepared to accept that risk. If the idea that a financial derivatives contract could be used to hedge multi-billion dollar LNG investments was questionable before, it is now almost completely discredited. Who wants to buy a long term insurance policy if the insurer may go bankrupt before the policy has a chance to pay off?

The troubles of the marketing companies have revealed another difficulty with price monitoring. For market transactions that are not openly traded on the NYMEX, the trade press relies on contacts with buyers and sellers. It now appears that a number of company traders have deliberately misled the pricing services in an effort to manipulate the market. Several traders have been indicted for allegedly providing false price information. Since the trade press is the source for basis differential information, this suggests that the judgment of basis risk is riskier than it might otherwise appear.

The Pricing Implications of Arbitrage and Its Effect on North American Markets

The U.S. has been in the forefront of restructuring its natural gas industry to make it highly competitive. This has led to an active spot market, the emergence of marketing and trading companies and the development of financial derivatives as a risk management tool.

The “gas price shock” of the winter of 2000/2001 sent gas prices much higher than they had been throughout the previous decade (See Figure 10-9). It occurred at a time when international LNG prices were relatively weak and spot prices were low.

The price rise brought forth a large number of proposals for new LNG terminals to supply the perceived gas shortage. The early proposals were heavily oriented towards gas trading companies without upstream LNG assets, such as Enron, Dynegy and El Paso.

For a time it appeared that very large scarcity rents (windfall profits) could be made by those with terminal capacity by buying in the LNG spot market and selling into the high-priced U.S. market - a "license to print money". However, when prices collapsed in late Spring 2001, prospective terminal economics also collapsed.

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[10] The number of outstanding contracts - a reflection of the amount of trading activity

[11] The month immediately following the date of the transaction

Figure 10-9
THE NEW GAS "PRICE SHOCKS"
BID WEEK SPOT NATURAL GAS PRICES @ HENRY HUB, LOUISIANA
MONTHLY DATA 1990/2003 - $/MMBTU

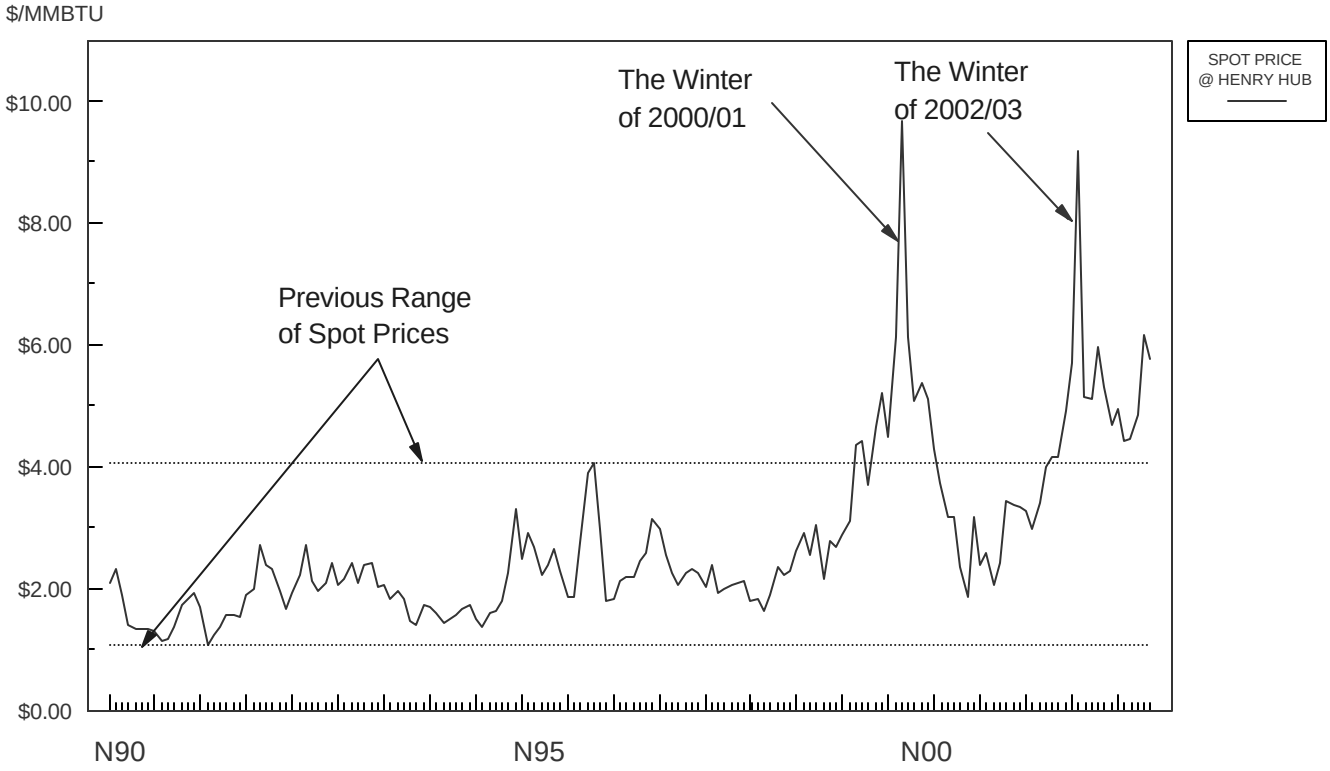


Figure 10-10 compares the estimated pre-tax cash flow as a percent of capital investment in a new independent Gulf Coast terminal, an estimated hurdle rate to justify the investment, and the return that the investment might have experienced in July/June 2000/01 and again the following year. The margins are based on actual imports into Lake Charles against Henry Hub pricing. On this basis, Everett did even better. The profitability of both an upstream operation selling to an independent merchant terminal and a hypothetical fully integrated trade were similarly affected, although independent terminal profitability was much more volatile, indicating the high level of risk in a "naked" terminal investment.

Figure 10-10 is based on price margins and assumes terminal operation at design levels. Actual terminal utilization has been much lower, reflecting competition with other markets for cargoes. In the 12 months ending July 2001, U.S. LNG terminals operated at a 70% capacity factor. In the following twelve months operations dropped to a 38% capacity factor as cargoes that might have come to the U.S. were diverted to Europe. Thus an early and dramatic demonstration of market arbitrage made its appearance. Figure 10-11 shows the LNG imports into the U.S. compared to terminal capacity during the period.

During the period, the primary arbitrage has involved Trinidad, Nigerian and Qatari supplies on the one hand and Spanish, Belgian and U.S. markets on the other. Figure 10-12 illustrates the way in which Atlantic Basin arbitrage works. It assumes a situation in which the balance between U.S. and European markets is struck by equal netbacks to Trinidad out of either Huelva in Spain or Everett in the Northeast U.S. In the example shown, Lake Charles is at a buying disadvantage relative to Everett and neither Nigeria nor Qatar find the U.S. markets as attractive as does Trinidad.

The significant swings in capacity utilization in Figure 10-11 can be directly attributed to changes in the arbitrage pricing in European and Asian markets compared to that in the U.S. During the early part of the period, U.S. prices were very strong, reflecting the gas price shock of the winter of 2000/01. But when U.S. prices collapsed in the Spring, European prices remained stronger, thereby attracting volumes from the U.S. More recently, Tokyo Electric's problems with its nuclear plants has led to the shut down of seventeen units with an extremely disruptive effect on markets for replacement LNG and residual fuel oil.

Figures 10-13, 10-14 and 10-15 illustrate the netbacks to Trinidad, Nigeria and Qatar from actual import prices in Lake Charles, Spain and Japan for three periods. (The U.S. prices are actual spot import prices but those for Spain and Japan are average import prices, taking into account contract volumes.) The shift in relative attractiveness of the three markets to the different suppliers is very apparent.

There is a tendency to assume that if the U.S. successfully builds new terminal capacity, LNG imports will automatically follow. While it is clear that the U.S. cannot import LNG if it does not have the necessary terminal capacity, the converse - that eliminating the terminal bottlenecks guarantee LNG supply - is not necessarily true. Having adequate terminal capacity simply gives the U.S. a seat at the table enabling it to compete with Europe and Asia for LNG supplies.

Figure 10-10

PRE TAX CASH FLOW AS A PERCENT OF CAPITAL INVESTMENT FOR AN INDEPENDENT GULF COAST MERCHANT TERMINAL

THE SHARP CHANGE IN PERCEIVED PROFITBILITY BETWEEN JULY/JUNE 2000/01 AND JULY/JUNE 2001/02

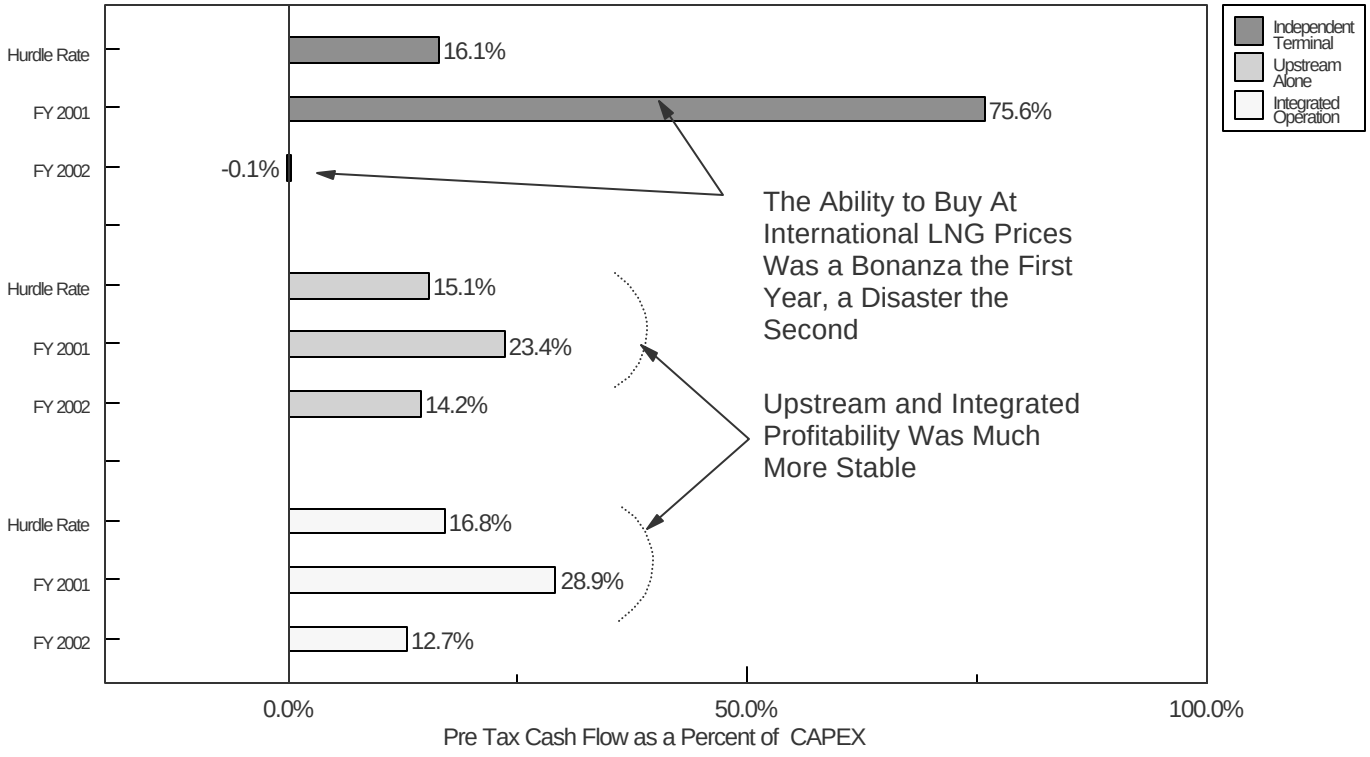


Figure 10-11

COMPARISON OF U.S. LNG TERMINAL IMPORTS WITH CAPACITY

MMCFD

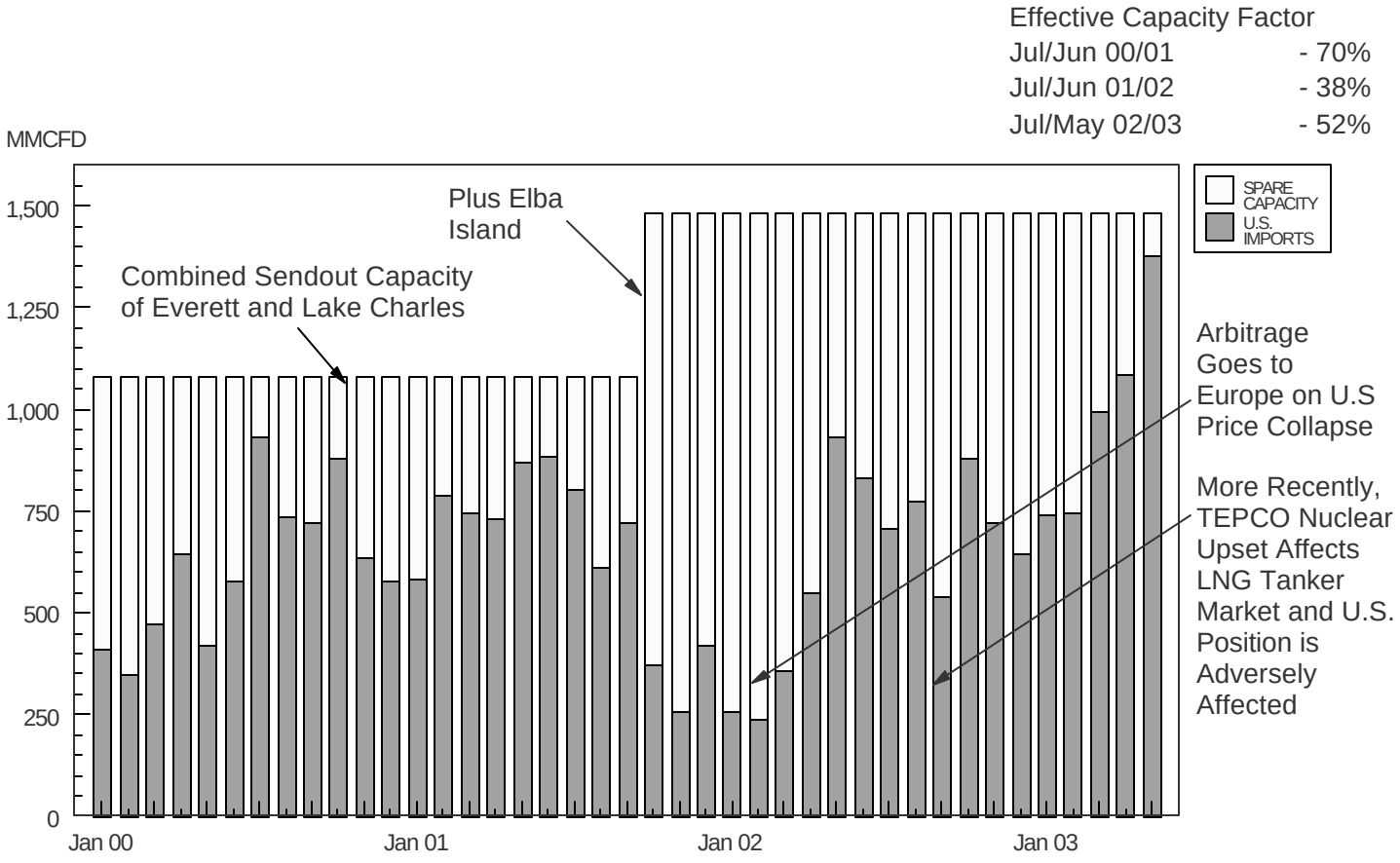


Figure 10-12

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN AND U.S. TERMINALS

ASSUMING THAT A $3.00 EX SHIP DELIVERY FROM TRINIDAD TO HUELVA, SPAIN IS ARBITRAGED AGAINST A TRINIDAD DELIVERY TO EVERETT, MA

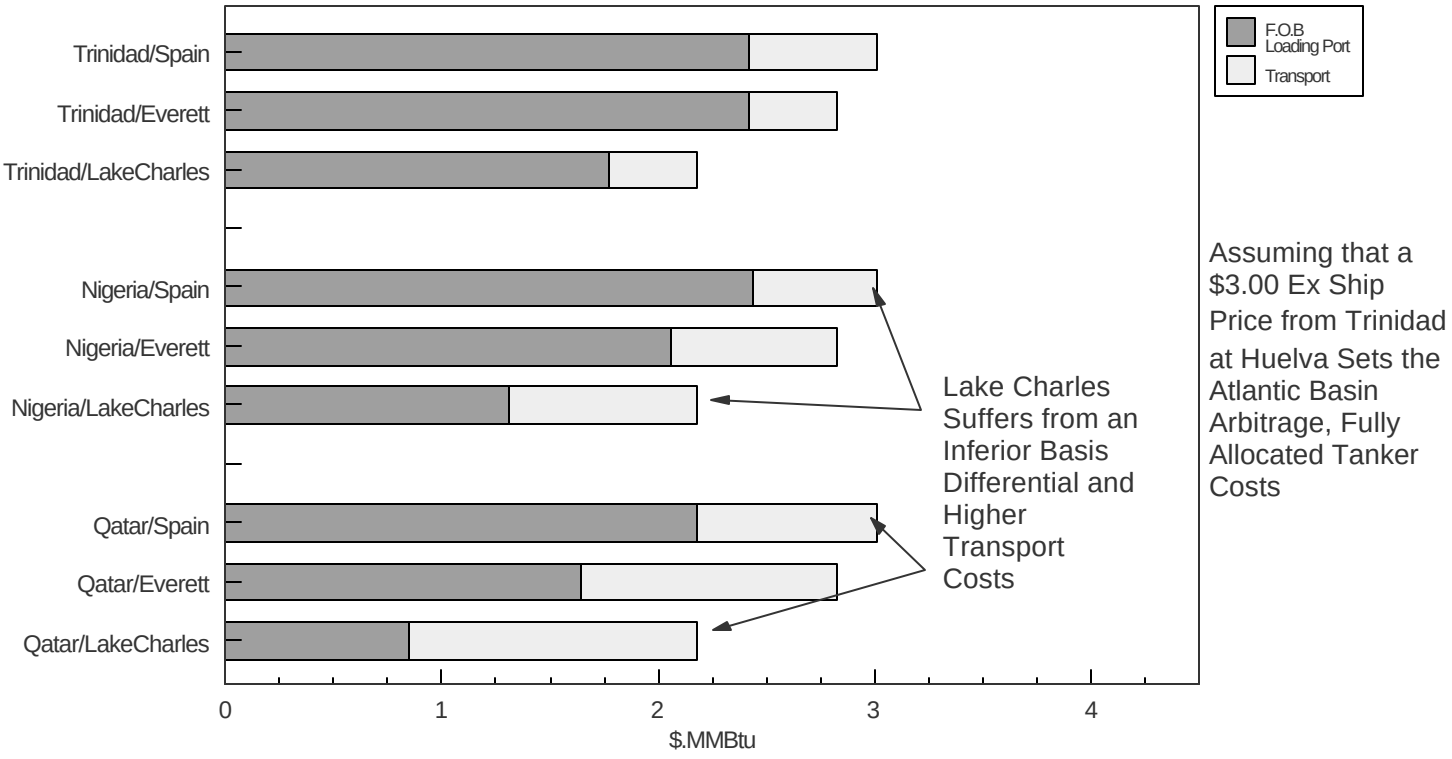


Figure 10-13

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN, U.S. AND JAPANESE TERMINALS

SITUATION IN DECEMBER 2000 WHEN THE U.S. MARKET WAS VERY STRONG

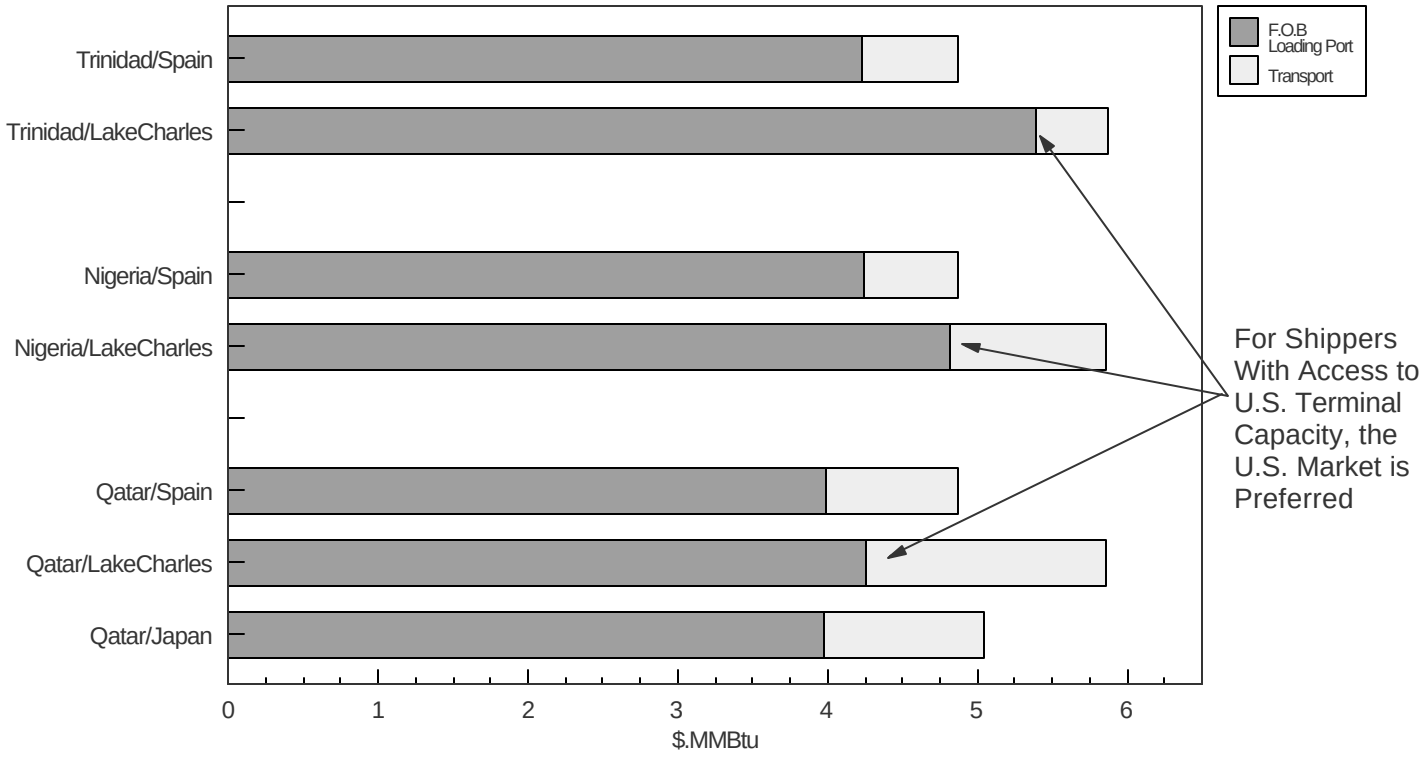


Figure 10-14

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN, U.S. AND JAPANESE TERMINALS

SITUATION IN SEPTEMBER 2001 WHEN THE U.S. MARKET WAS VERY WEAK

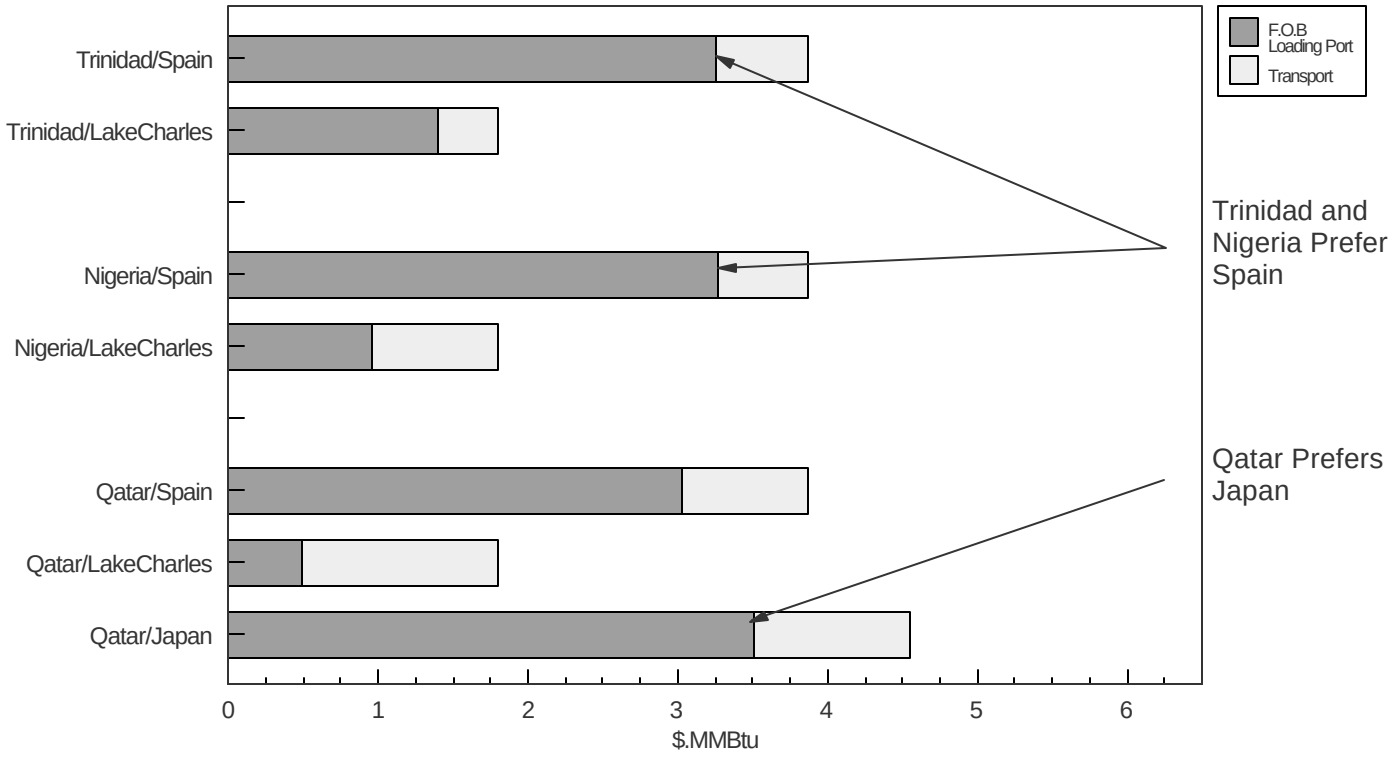
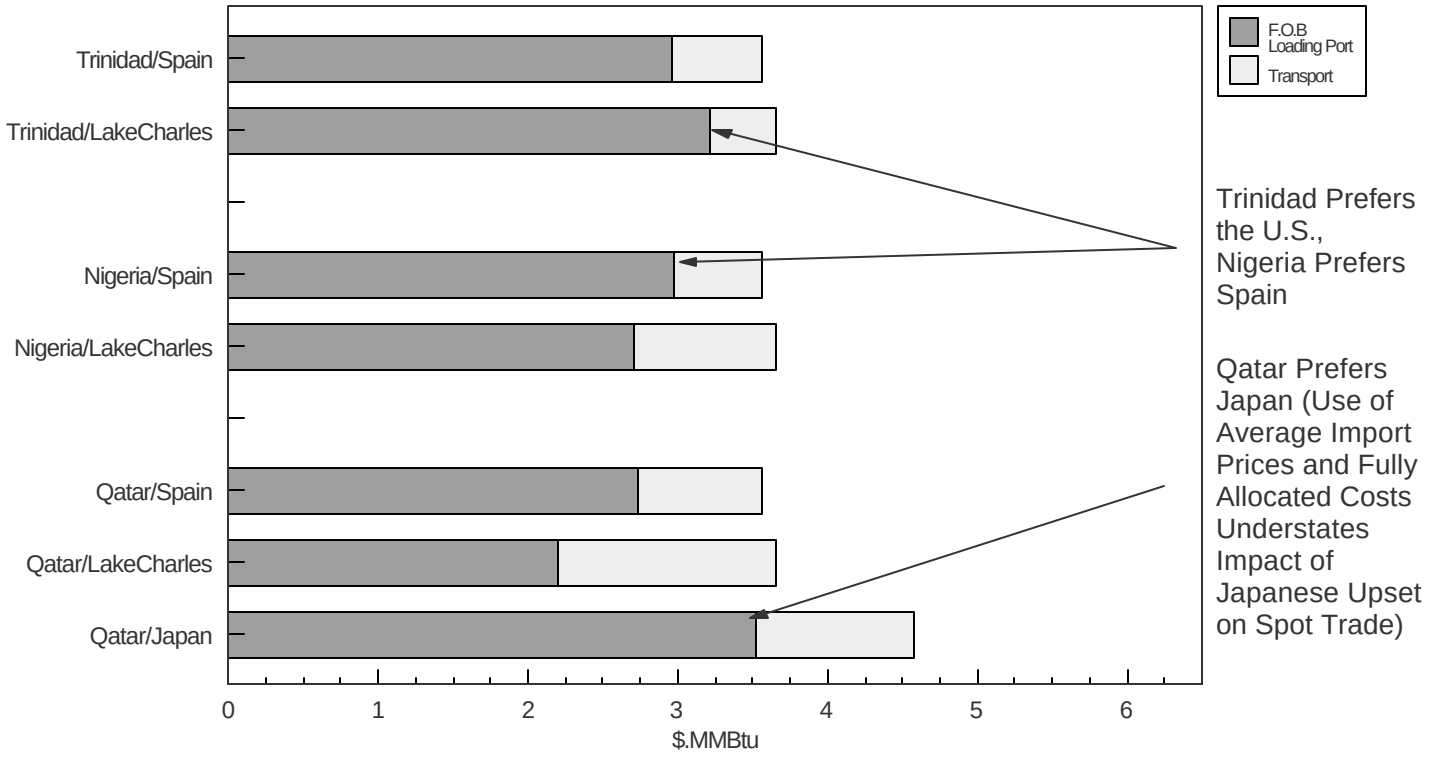


Figure 10-15

NETBACKS TO TRINIDAD, NIGERIA, AND QATAR LOADING PORTS FROM EUROPEAN, U.S. AND JAPANESE TERMINALS

SITUATION IN NOVEMBER 2002 WHEN ASIAN MARKETS WERE VERY STRONG



XI. THE EVOLUTION OF A NEW MARKET STRUCTURE

How Much LNG and When?

The outlook for LNG imports into the U.S. has changed dramatically over the past several years. Nowhere is this more evident than in the changes that the Energy Information Administration has been making in its estimates of gross LNG imports over the past three years. In its 2001 edition of its Annual Energy Outlook, the EIA was projecting 1.5 Bcfd of gross LNG imports by the year 2010. In each subsequent year, it has raised its estimate so that the just-released AEO 2004 figure now stands at 6.1 Bcfd. Furthermore, the new National Petroleum Council estimates (in its "Balanced" case) are even higher at 7.5 Bcfd. The evolution of these estimates is shown as Figure 11-1

Many of the projections of LNG estimates are essentially introspective, focussing largely on decisions taken within the U.S. market. Several of the computer models, for example, assume a construction schedule for new LNG import terminal capacity and allow imports to flow into the U.S. at some "trigger price". This U.S.-centric view of the factors that will govern LNG import levels inherently assumes a restructured international gas industry will always maintain an overhang of competitively-priced and freely-available LNG supply. It thus ignores the many factors - geopolitical as well as economic - that will govern the rate at which new LNG export capacity is made available for world markets as well as the rate at which Europe and Asia will develop competing demands on that capacity.

In an industry with a four year planning and construction cycle, factors that can reduce anticipated LNG supplies, such as political conflict in a potential supplying country, will affect the level of competition for LNG and strengthen prices. An unanticipated economic boom in Europe or Asia that increases competition for that supply will have a similar effect. Conversely, an overbuilding of LNG export capacity or economic recessions elsewhere will weaken prices.

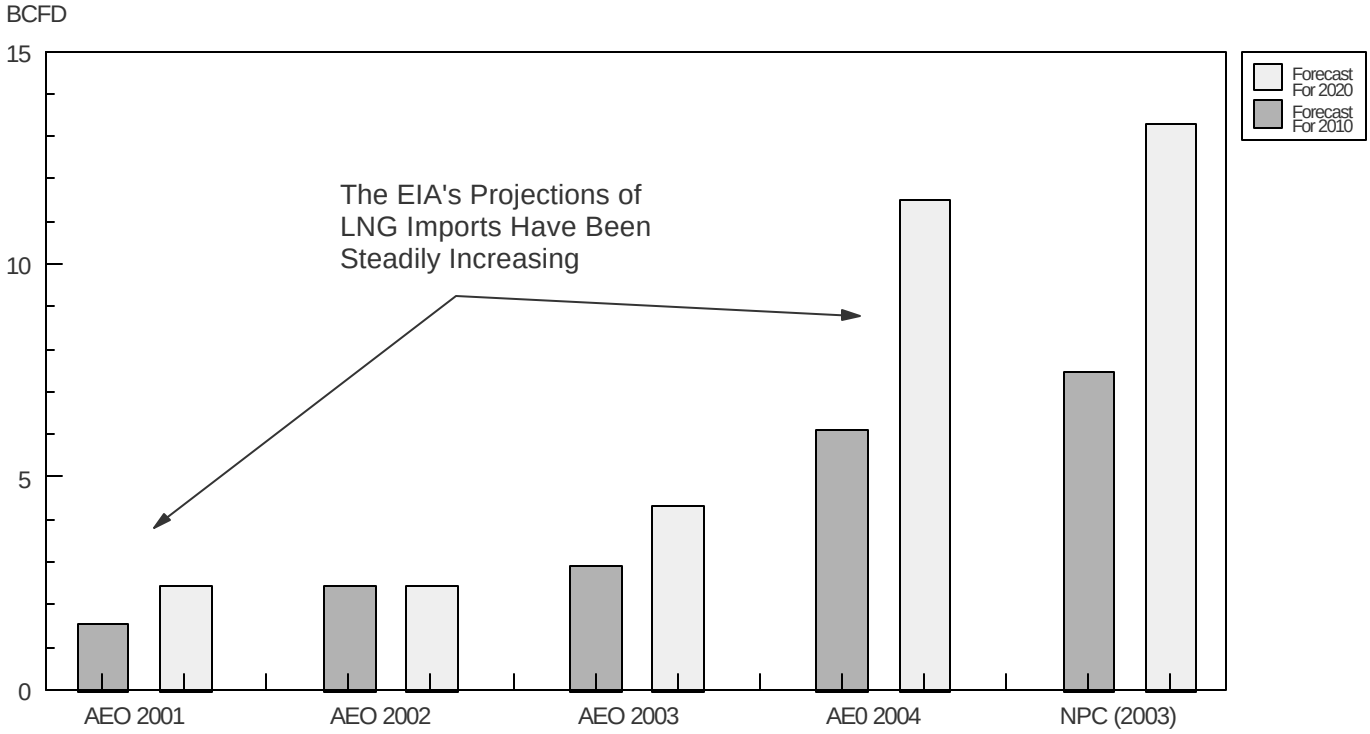
The somewhat sanguine U.S. view of international LNG supply is encouraged by trade press reports that commonly give the impression that potential LNG supply is virtually unlimited. But LNG observers have learned to be highly skeptical about such optimistic trade press reports, not only about whether the projects will actually go forward, but also about their timing.

Schedule slippage on projects is routine because the complexity of negotiations commonly causes delays. Because they are usually joint ventures and because they are large compared to the sponsors' capital budgets, it is often difficult to get an agreement among partners. Also, some companies have more than one entry in the horse race. As one company executive once remarked, "We can't afford to walk away from that situation, but we sure hope nobody moves very fast on it".

Because producing governments are usually important stakeholders in the project (commonly affecting more than half of the entire project capital budget), LNG projects are politically complicated. This raises questions of political risk, not only about the stability of the governments but also of their fiscal systems. Political problems have been in the news this past year in such potential LNG suppliers as Bolivia, Indonesia, Nigeria, Peru and Venezuela.

LNG projects sometimes operate like a game of musical chairs. Those left standing without a contract or an essential partner often drop out of the running . Others who stay in the game may delay their plans. Hence, many supply projects will not meet their publicized schedules or may even be abandoned altogether.

Figure 11-1
THE EVOLUTION OF LNG IMPORT FORECASTS [1]
EIA'S ANNUAL ENERGY OUTLOOK AND NPC
BCFD



[1] EIA Reference and NPC "Balanced" Cases

Many LNG market watchers classify potential new supply projects according to the likelihood of their becoming commercial. Figure 11-2 shows one such classification broken down by region, as well as by "firm", "probable" and "possible". A "remote' category is not shown. Until the recent burst of enthusiasm for new projects, new commitments were averaging 4.2 MMTPY (equivalent to one large modern train); from 1998 to 2002, that average rose to 7.8 MMTPY. Firm projects are scheduled to add an average of 5.6 MMTPY by 2010. Adding in the probable group increases the average to 11.9 MMTPY. And if one were to take the possible group and its publicly-stated schedule seriously, additions would rise to 24.9 MMTPY, implying a capital outlay in the vicinity of $16 - $20 billion per year.

The best way to track the likely availability of supply, recognizing the possibility of schedule slippage, is to maintain a list of contract commitments. Figure 11-3 is such a list for the Atlantic Basin and the Middle East (the Pacific Basin is not shown). The principal market focus of Atlantic Basin projects is on North America; the Middle East is on Europe.

One of the new features of the contracting process is the availability of uncommitted volumes. These can be the result of inherent contract flexibility, of contract expirations**,** developers proceeding without full train commitments, or sales to the companies' own marketing organizations as a means of downstream integration. The newer integrated internal sales volumes are most prominent in the Atlantic Basin where U.S./European arbitrage is common. They are largely absent in the Middle East, and just beginning to appear in Asia. Interestingly enough, except for one new Middle East train, all new train commitments to the U.S. also include European commitments, demonstrating the producers' desire to hedge their exposure to the U.S. market.

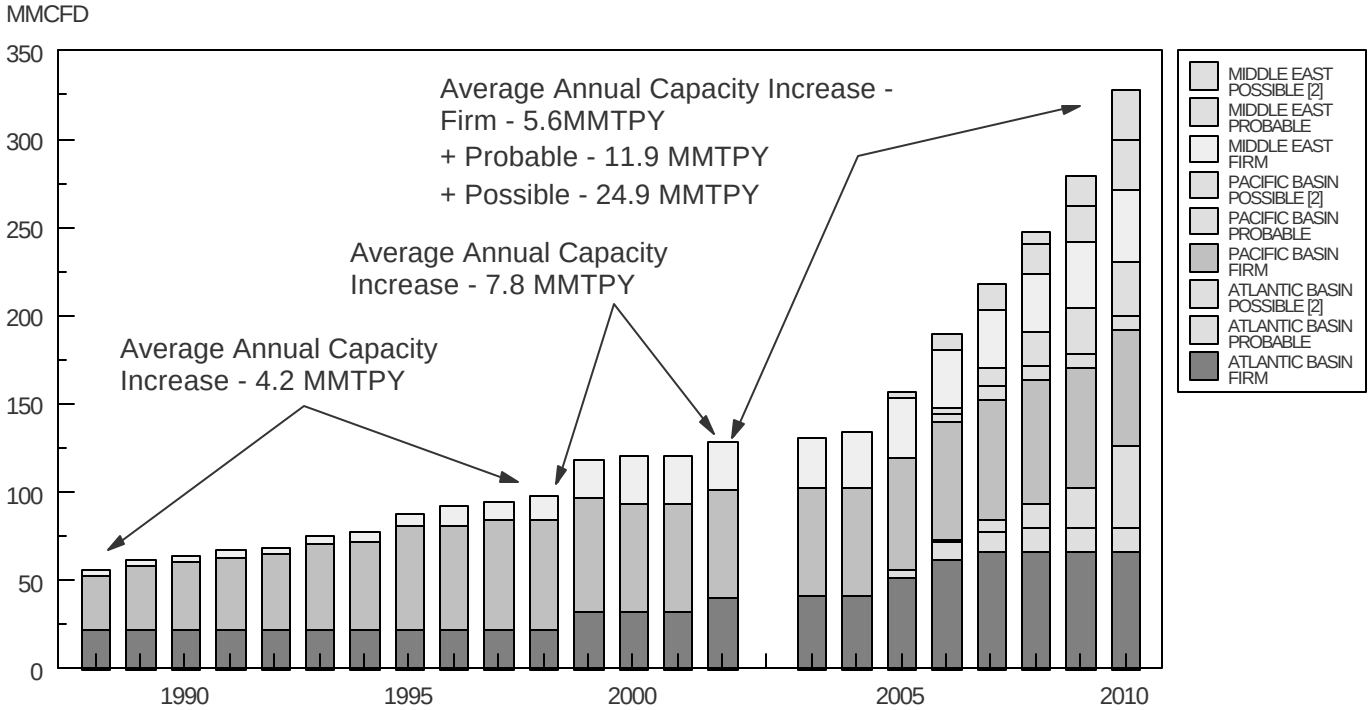
By monitoring contract commitments, it is possible to get some idea of how realistic it may be to satisfy some of the optimistic forecasts of LNG imports into the U.S. Figure 11-4 is such an estimate based on contract commitments in place as of the middle of 2003. Clearly, the contracted volumes, while greater than the earlier EIA projected imports, fall significantly below the most recent EIA and the NPC estimates. This suggests caution in assuming that these optimistic projections will actually be attained.

It is important to recognize that the projections shown in Figure 11-4 represent only the contracted commitments for the U.S. market. There are two possible sources of additional supplies that could increase the availability to meet projected demands. Since project lead times are about four years, the commitments through the year 2007 are now largely in place (although they are still potentially subject to delay or cancellation) and thus further commitments from the "possibles" category are certainly a possibility by 2010. And there is a substantial volume of uncommitted supplies (See Figure 11-3) that are flexibly available to move to U.S. or European markets as comparative netbacks dictate. Much of this Atlantic Basin volume is now on contracts currently committed to European markets but are reaching the end of the contract period. However, clearly the U.S. would have to "buy" these volumes out of Europe if they are to help make up the shortfall implied by Figure 11-4.

What Do the New Trends Say About Industry Structure?

The first burst of enthusiasm for LNG imports following the "gas price shock" of 2000/2001 came from companies that had been active traders in the restructured North American industry. However, the early perception of highly profitable operations for owners of import terminals quickly gave way to evidence that profitability could be extremely volatile (as was discussed in Chapter 10 and illustrated in Figure 10-5). While many of the import terminal projects that were initiated by the merchant group are still on the lists of projects in the trade press, much of the momentum has gone out of the traders' proposals. There remain several potentially viable projects among the merchant candidates, but many of them could now be classed as "remote" in any ranking of likely successes.

Figure 11-2
HISTORY AND FORECAST [1] OF POSSIBLE
LNG LIQUEFACTION CAPACITY BY REGION
MMT

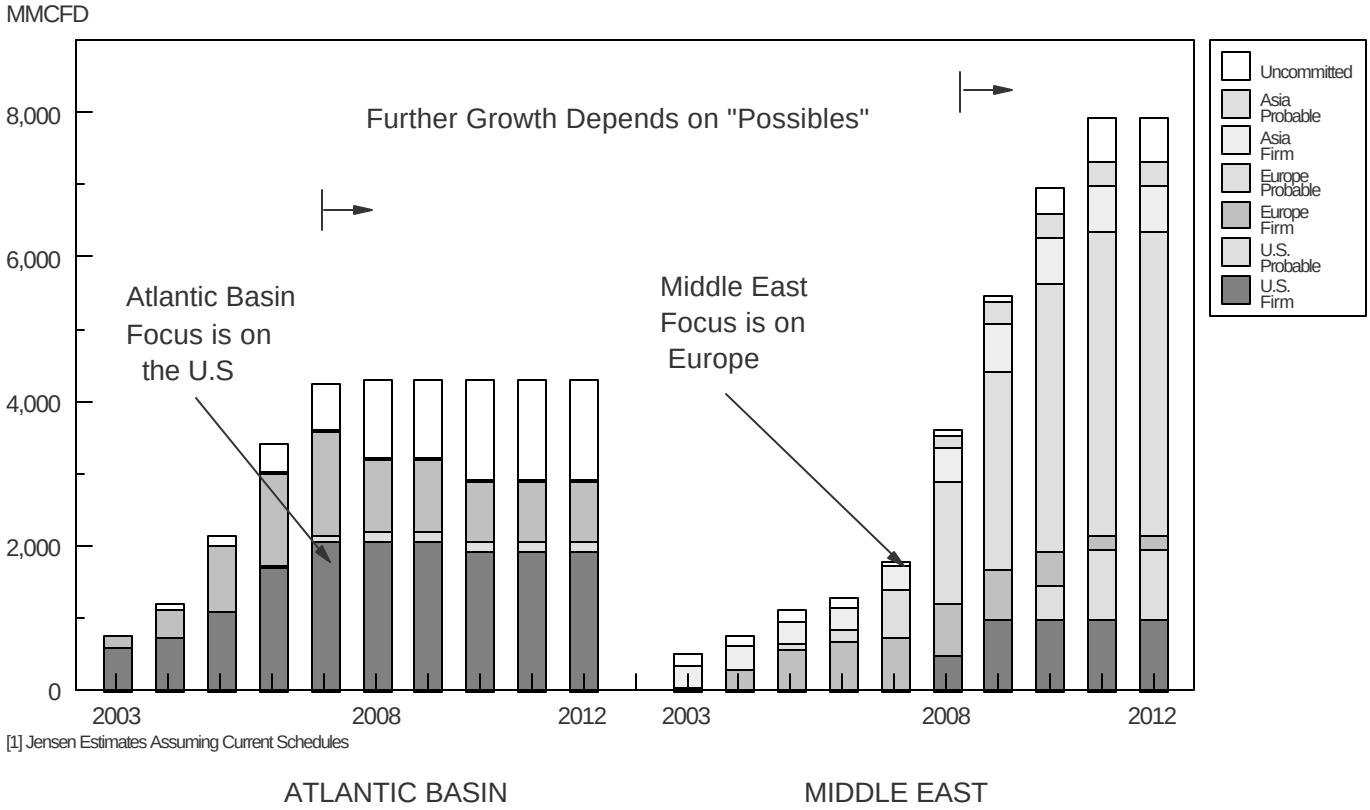


[1] Jensen Estimates
[2] Placing Unscheduled Possibles in 2010

Figure 11-3

REGIONAL DESTINATION OF NEW LNG CONTRACT SUPPLIES FROM OPERATING, "FIRM" AND "PROBABLE" [1] LIQUEFACTION PLANTS IN THE ATLANTIC BASIN AND THE MIDDLE EAST

MMCFD

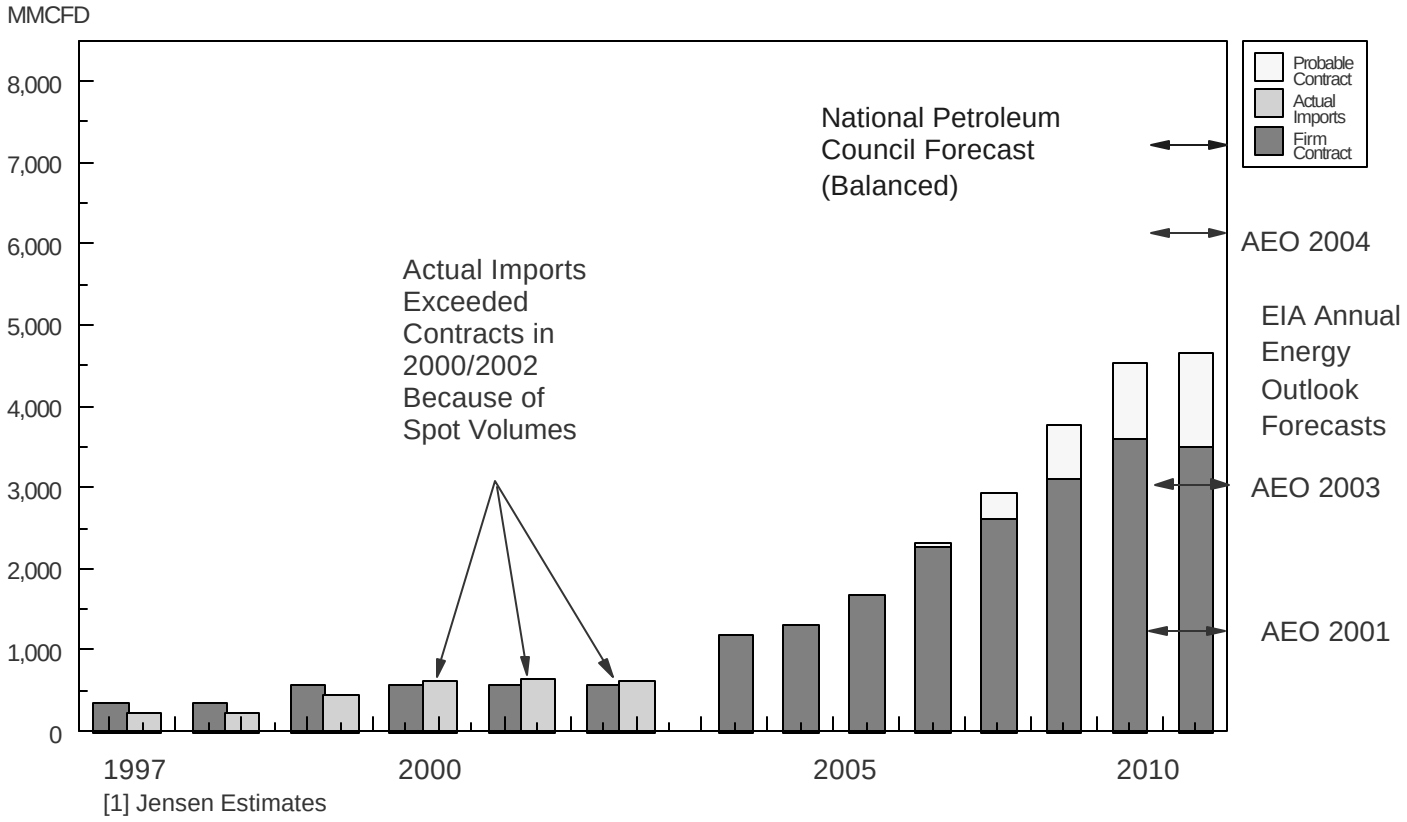


[1] Jensen Estimates Assuming Current Schedules

Figure 11-4

LNG CONTRACTUAL DEDICATION TO U.S. MARKETS FROM OPERATING, "FIRM" AND "PROBABLE" [1] LIQUEFACTION PLANTS COMPARED WITH ACTUAL AND FORECAST IMPORT LEVELS (DOES NOT INCLUDE UNCOMMITTED VOLUMES)

MMCFD



[1] Jensen Estimates

The clash between the two structural models of the international LNG industry - the traditional, risk-averse, contract-dependent model and the free market, trading model - has substantially shifted the balance of risks and rewards among the parties in ways that are not yet fully understood. The long term contract gave sellers the assurance that they had secure outlets without the need to integrate downstream as the industry has traditionally done in oil. However, it appears that it is increasingly difficult to find buyers who can deliver on the traditional volume commitment (an obligation tied to a gas market indicator is substantially weakened since it is so easy to lay off in the market; and the captive ratepayers are largely gone). Hence, a significant part of the market risk appears to have migrated upstream, and political risk has never really gone away. While the growing diversity of supply sources tends to insulate buyers from these political risks, sellers with investments in affected countries can only spread the risks by investing in a portfolio of supply sources.

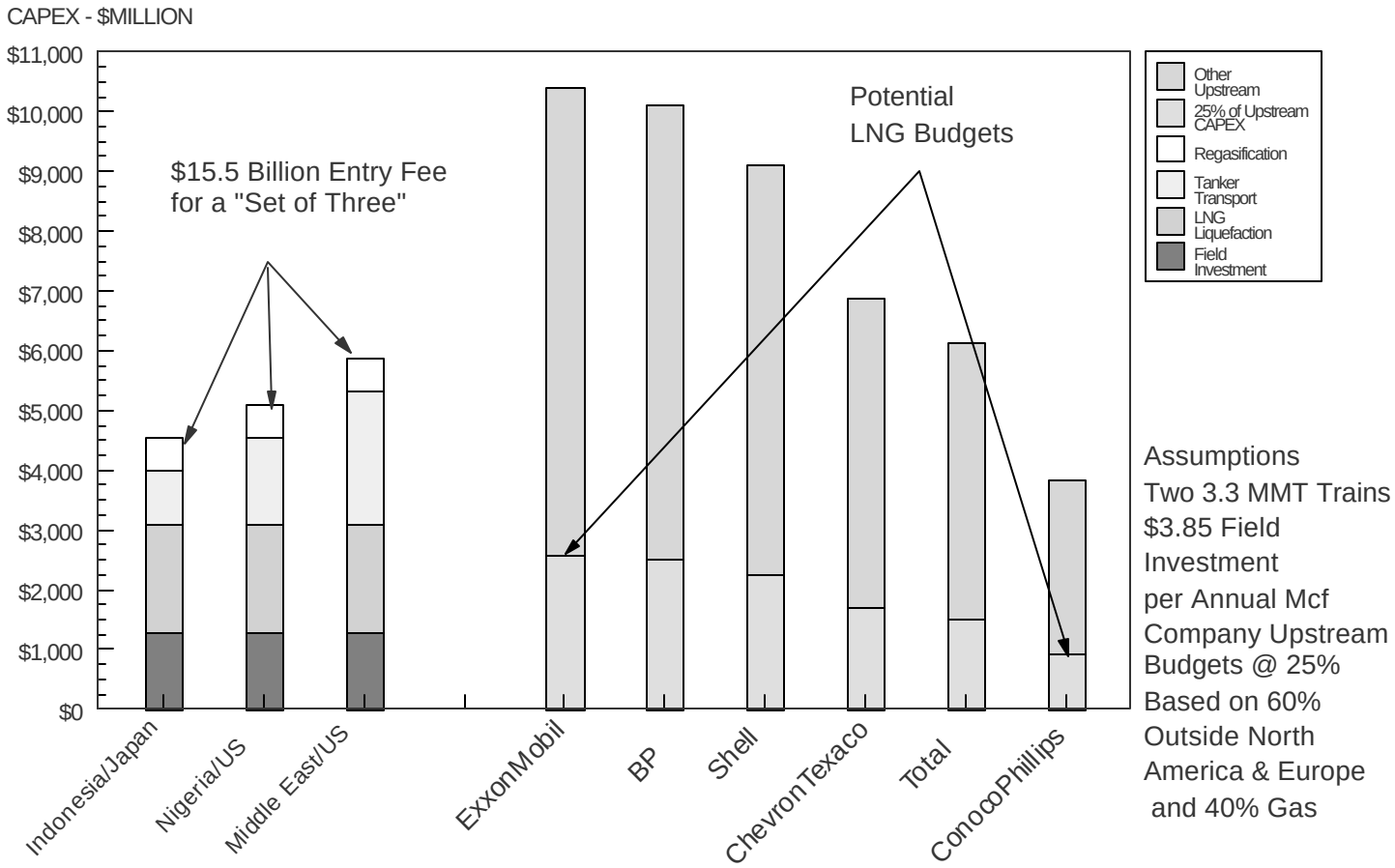
In the face of these market and political risks, integrating downstream and creating a diversified supply portfolio would seem to make good sense as an investment strategy for producers. The problem is that the price tag for the highest degree of diversity is so large that few companies can afford it.

Figure 11-5 compares a "greenfield entry fee" for what might be described as a fully diversified LNG portfolio to the 2002 capital expenditures of the five super majors - the "five sisters" - together with the smaller ConocoPhillips (BG is also a major player but, as a gas company, difficult to compare with the upstream oil producers).

The Figure assumes that 25% of total upstream capital budgets are available for LNG (taking 60% of the budget for the world outside North America and Europe and 40% of that is targeted on gas). It is apparent that the "entry fee" remains large compared to available investment dollars for these very large companies. While there will be many individual "niche" opportunities for other companies in this growth business, it is not for the faint of heart or the undercapitalized.

Figure 11-5

THE GREENFIELD LNG PROJECT "ENTRY FEE" COMPARED TO THE UPSTREAM 2001 CAPEX BUDGETS OF SELECTED COMPANIES



XII. WHAT ARE THE RISKS TO GREATER RELIANCE ON LNG?

What Are the National Security Implications of Steadily Increasing Reliance on Imported LNG?

Although the growth of LNG trade provides buyers with a highly diversified series of supply options, LNG transportation tends to be somewhat less flexible than is oil. The high cost of tanker transportation makes it costly to maintain a transportation capacity surplus against supply contingencies. Thus, a market upset for short haul trade may be difficult to replace with more distant supply during periods when tanker markets are tight. Thus to some extent, there will inevitably be greater risks to national security from increased reliance on imported LNG. Fortunately however, the increasing diversity of supply sources tends to moderate these risks to some degree.

Some of the inherent inflexibilities associated with the earlier bilateral contract structure have eased with the restructuring of the gas industry and the growing diversity of suppliers. When Algeria attempted to change the terms of trade with its LNG customers in the 1980s, the customers had virtually no alternatives and some simply shut down. In the early 2000s, markets were upset by the rebel unrest in Aceh province in Indonesia and later by a demand burst as Tokyo Electric shut down its nuclear plants and went into the market for more LNG. But the market absorbed these upsets and no customer was left without supply.

One of the major concerns about the reliance on oil imports is the heavy dependence on the Middle East with all of its political turmoil. The sources of LNG supplies are somewhat different from the sources of imported oil, although some of the same countries are important in each trade. Figure 12-1 shows the principal sources of LNG and oil imports, both for the world and for the U.S.

The world is somewhat more dependent on OPEC for LNG than it is for oil, but less dependent on the Middle East. That is because of the importance of non-Gulf OPEC members, such as Indonesia, Algeria and Nigeria, as LNG suppliers.

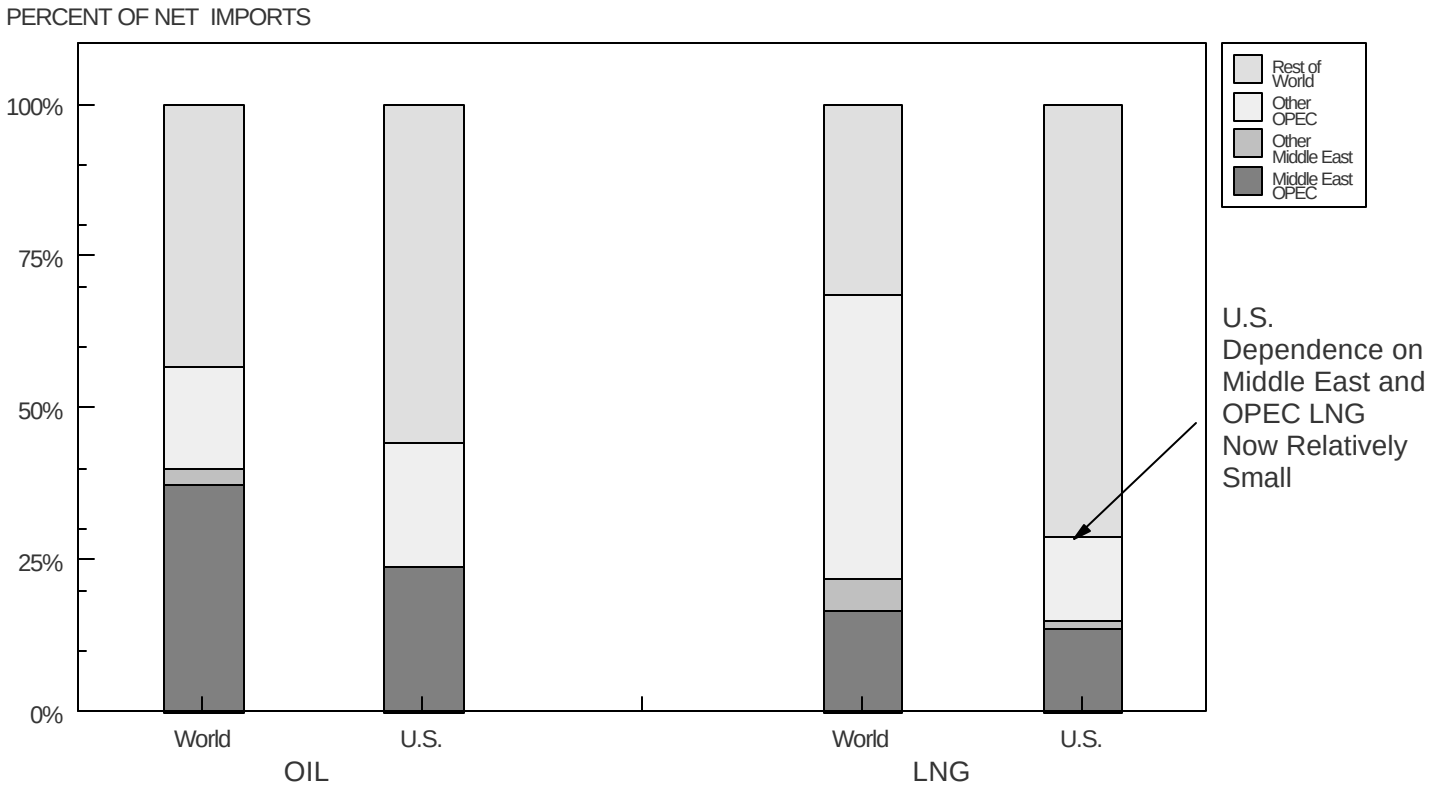
The U.S. has historically relied somewhat less than the rest of the world on oil imports from OPEC and from the Middle East. And because of the heavy reliance on Trinidad for LNG, it is much less dependent on either OPEC or the Middle East for LNG than are Europe and Northeast Asia. However, the new flexibility of LNG trade suggests that regional supply relationships may not provide much security. When any source of supply goes down, the markets will react in price terms and the U.S. - at the end of the supply chain - will not escape unscathed.

The balance of LNG exporters in the Middle East is quite different from that of its oil exporters. Only Qatar and the U.A.E. are LNG exporters, while Saudi Arabia, Iraq and Kuwait exhibit little interest in the trade. Iran, however, has the largest gas reserves in the Middle East (second only to Russia in the world) and is actively pursuing LNG options. With Qatar's ambitions to expand its LNG role and with the possible success of Iran in developing LNG projects in the future, the Middle East is destined to play a more important role.

One of the greatest differences between LNG and oil sources is the importance of countries that are substantial LNG suppliers, but less significant in oil trade. This includes Trinidad, Oman, Malaysia, Brunei and Australia. Egypt is already slated to become a major LNG supplier and with the development of new projects, Angola, Bolivia, Peru could join this group as well.

Clearly, the increased reliance on LNG will increase U.S. exposure to the problems of the Middle East.

Figure 12-1
SOURCES OF LNG IMPORTS COMPARED WITH OIL IMPORTS
PERCENT



Efforts to find other sources of natural gas, such as the Alaska Pipeline, will serve to moderate the risks to some degree. And emphasis on non-Middle East sources of LNG will help, as well. There has been discussion of the interest of Russia in becoming a major factor in LNG. The development of its Sakhalin II project for supplying Japan will represent its first venture into LNG, and that project remains a front-runner for supplying the U.S. West Coast as it develops.

But Russia's Atlantic Basin ambitions are much more complex. Interest seems to center on its giant Shtokmanov field in the Barent's Sea as a source of gas, but this field - in the high arctic offshore - will prove to be a substantial challenge for the foreseeable future.

What is the Vulnerability of Tanker LNG Shipping Routes (Choke Points)?

The new world of international terrorism raises obvious questions about terrorist targets that could do great damage to the West and particularly the U.S. The terrorist attack - whose consequences were minor - on a French oil tanker departing from the Gulf in 2002 suggests that such an effort to sabotage a LNG tanker would have to be taken seriously.

Both Qatar's and the U.A.E.'s liquefaction plants are located within the Gulf - as with any potential Iranian facility - and thus would be subject to some of the same risks as oil in passage through the Straits of Hormuz. Both Oman and a possible plant in Yemen would be outside this choke point. However, the fact that the Gulf is a relatively smaller supplier of LNG than it is of oil moderates these risks to some degree.

Shipments to Northeast Asia from the Gulf would normally transit the Straits of Malacca, but so much of Northeast Asia's LNG - Brunei, Malaysia, Kalimantan in Indonesia, Australia and Alaska utilize other routes. Thus Northeast Asia is much less exposed to risks in the Straits of Malacca for LNG than it is for oil.

Another major historic oil choke point has been the Suez Canal. LNG vessels, unlike oil supertankers, do not go around the Cape of Good Hope and thus rely on the Canal for shipments east of Suez to Europe and North America. But the fact that the Atlantic Basin has so many major suppliers that do not depend on Suez transits, gives Europe and North America a substantial degree of protection from any possible problems with the Canal. Nonetheless, any shutdown in the Suez Canal would require that vessels bound for west of Suez detour around the Cape. This would substantially increase the demand for tanker capacity. For example, it would take 97% more tanker capacity to haul the same LNG volumes from the Middle East to Europe via the Cape as it would via the Canal. The impact on shipments to the U.S. would be somewhat less severe, requiring an increase of 26% in capacity to deliver the same volumes.

The perception seems to be that LNG tankers are tempting terrorist targets. The fact that so many LNG shipments transit traditional choke point waterways, suggests that securing these routes will be essential. This will be particularly important in Middle East targets such as the Straits of Hormuz and the Suez Canal.

LNG Safety Concerns

The LNG industry was exposed to a safety tragedy in its infancy and has been especially safety-conscious ever since. In 1941, East Ohio Gas Company built an LNG peak shaving plant (the second ever constructed in the U.S.) in the heart of a residential area in Cleveland, Ohio. Unfortunately at the time, engineers did not fully understand the behavior of carbon steels at cryogenic temperatures and in 1944 one of the Cleveland storage

tanks ruptured. It spilled its contents into residential storm sewers which thereupon ignited with a causing 128 fatalities. This disaster all but stopped all commercial interest in LNG in the U.S. for more than twenty years.

However, the history of the disaster has made the LNG industry especially conscious of safety issues, and it is widely regarded within the industry as a very safe industrial operation. This view of LNG safety is attributable to the special physical characteristics of LNG and to the large body of research and development that has gone into creating better materials and safety practices. Both the Institute of Gas Technology and the Gas Research Institute (now merged into the Gas Technology Institute) have devoted significant portions of their research budgets towards LNG safety research over the years.

Liquid LNG will not burn or explode without vaporization, a process that requires the input of heat, a process that is not instantaneous. If spilled on water, LNG acts much like water dropped on a hot plate. Droplets will sizzle on the surface as they take on heat of vaporization, but will take some time for the LNG to vaporize completely.

Methane is lighter than air and the flammable range of methane is 5 to 15%. Any mixture with air that is outside this narrow flammable range is either too rich or too lean to ignite. These physical characteristics are at the heart of the industry's belief in the safety of LNG if properly handled and stored. It takes heat input over a period of time to vaporize it; being lighter-than-air, it quickly dissipates; and the explosive range is fairly narrow.

Nonetheless, the industry has stringent safety regulation regarding tank materials of construction and diking of storage. It has conducted extensive programs of safety testing and simulated accidents over the years. The safety regulations tend to focus on four areas - primary containment, secondary containment to protect the surrounding areas from leaks and spills, safety systems to contain and control fires, and separations restrictions to isolate tanks and other facilities to prevent the spread of damage.

The industry's perception of safety has tended to be reinforced by industry experience following the Cleveland disaster. The problem of carbon steel embrittlement that caused that rupture was identified and corrected, and although it took twenty years thereafter for the industry to reemerge, it has had a good safety record since that time.

The Institute for Energy Law & Enterprise at the University of Houston completed a detailed study of LNG safety in October 2003[12]. The study listed twenty-two LNG accidents that had occurred in the forty years since the industry restarted in the mid 1960s. Ten of these occurred on LNG tankers, five at LNG terminals and two at LNG liquefaction plants. There was one large fatal accident in the construction of an LNG storage tank on Staten Island in 1973 involving the deaths of 40 construction workers. However, it was a construction accident occurring before the startup of the facility and is not attributable to LNG.

Of the remaining accidents, only two - one at a terminal and one at a plant - involved fatalities and they were single deaths. Many accidents were minor and involved such things as valve malfunctions which were quickly contained. The tanker accidents involved such incidents as grounding and mooring failures but again the damage was minimal.

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[12] LNG Safety and Security, October 2003, Institute of Energy Law & Enterprise, University of Houston

The University of Houston study went to press before two recent additional accidents. In late August a fire on startup at Malaysia's new Tiga Train 1 shut down the facility for more than six months. There were no reported fatalities. But in January 2004, a major explosion at Algeria's Skikda LNG plant killed 29 people and totally destroyed three of the facilities six liquefaction trains. This accident received much publicity and has intensified the debate in the U.S. over LNG safety.

The immediate cause of the explosion appeared to be a boiler located near the gas handling equipment, rather than a failure of the LNG processing plant itself. But the boiler explosion caused three of the trains to explode as well. While the LNG industry likes to point to its safety record, the fact that the trains were involved in a disastrous fire does some damage to the industry's credibility on the safety issue.

Although much as been made of the contention that the Skikda explosion proves that "LNG is not safe" by those who oppose new terminals in the U.S., there are significant differences between the operation of a liquefaction plant and that of a regasification terminal. While both handle LNG as liquid, the liquefaction plant utilizes hydrocarbon refrigeration recirculation systems. The refrigerant in these loops - either mixed refrigerant or ethylene and propane - are flammable. In a regasification terminal with submerged combustion, no other flammable materials are present outside the LNG itself and the potential fire risk is far lower.

There is a common perception among the lay public that LNG is inherently unsafe, a view that has enabled groups that are active in fighting terminal siting to develop widespread local support in their efforts. There are even websites devoted to promoting popular resistance to LNG terminals. The concern for safety has been especially important in terminals near metropolitan areas. Mayor Menino of Boston got the Everett terminal closed temporarily after 9/11 and Senator Mikulski of Maryland led a movement to prevent the reopening of the Cove Point terminal. Safety concerns were also behind the popular move to bar the location of an LNG terminal at Mare Island in San Francisco Bay.

Following the Boston dispute, the Coast Guard commissioned a safety study from the safety consulting firm, Quest Consultants, Inc. Although the results have not been made public, the Department of Energy and FERC have used the study as evidence that there is little significant risk to LNG tanker traffic in metropolitan areas. The study has come into some controversy from those who contend that its conclusions are being misused. This has been reinforced by some public statements of one of the authors.

While the LNG industry has tested containment vessels, diking systems and construction materials extensively, the terror threats following 9/11 raise new concerns that have not been subjected to physical testing. The possible consequences of a fuel-laden jet aircraft crashing into an LNG tanker, a vessel bomb of the type used on the U.S.S. Cole in Yemen or a rocket propelled grenade have never been considered. Short of conducting a large scale, dramatic test with an old tanker and a terrorist attack, it is probably impossible to know what would actually happen. And even if such a test were conducted, it might not satisfy the critics of LNG safety.

Another testing challenge is one that features a potential scenario that has been raised by some of the foes of the California LNG terminals. It postulates a situation whereby a major LNG spill occurs offshore under conditions of a weather inversion (such as those that occasionally occur in California) which would trap the methane allowing it to fan out over a wide area close to ground level. If it were then accompanied by a wind that provided a mixing effect between air and the methane, thus creating an explosive mixture (which must reach a 5 to 15% mixture), it is possible to conceive of a large and devastating explosion. The statistical odds on such a combination of events occurring together may be very low, but it may be nearly impossible to satisfy committed critics of LNG terminals that there is no risk.

Many of the protests appear to be NIMBY protests that seize on any argument - whether or not actually supported by the facts in the situation - to try to defeat the terminal proposal. If the U.S. is to move to higher reliance on imported LNG - as seems almost inevitable - these safety concerns must be dealt with. But it may be inevitable that most terminals will be limited to those locations, such Gulf Coast sites with an industrial history, where the popular resistance is limited.

While the LNG industry seems satisfied with the safety of LNG, industry credibility is not high making it very difficult to respond to critics. This suggests that the Government should play a larger role in developing factual responses to distortions where they occur in public debate. The Government has an Office of Pipeline Safety and a National Transportation Safety Board to represent the public interest in pipeline and air transportation safety. While much of their responsibilities are focused on accident investigation rather than on disseminating safety information, they represent a possible model for such a Federal Agency.

An Office of LNG Safety could become the focal point for providing factual information to localities where terminal siting is an issue, and could sponsor selected research activities where gaps in safety knowledge suggested that research was needed.

Will There be Greater Vulnerability to Oil Price Shocks?

As discussed in the oil-linked pricing section of Chapter X, the early price escalation clauses - particularly in Asia - linked contract gas prices directly to oil prices. Were such contracts to serve as a model for today's contracts for U.S. supply, they would clearly sensitize U.S. gas markets to oil price shocks except in those special cases where the effect of a substantial oil price movement was constrained by floor prices or S curves. But under the contracting patterns that appear to be evolving for North American trade, gas-linked clauses now seem favored for pricing clauses. This makes the linkage between oil and gas prices dependent on the relative prices of the two fuels in interfuel competition. Thus the linkage is more complex and is indirect .

Gas-to-oil competition can take place in three broad pricing zones - [1] in surplus where gas-to-gas competition is the pattern and oil price movements are largely irrelevant, [2] more balanced markets where competition is centered on dual-fired boiler loads with residual fuel as the alternative, and [3] even tighter markets where the competition moves to dual-fired distillate borders. If there is to be gas/oil linkage volatility superimposed on the current volatility of oil prices themselves, it suggests that gas is pricing is likely to remain volatile, and gas will not escape its exposure to oil price shocks.

A longer term, but more complex, interfuel price relationship between gas and coal may be more relevant since the principal interfuel competition takes place in power generation. Nonetheless, the competitive short term linkage to oil prices will remain (except during periods of gas surplus) and gas pricing will not escape a sharp increase in international oil prices. This will be particularly true if it is caused by a Middle East political crisis, since the region is likely to be a major source of LNG as well as of oil.

XIII. THE ROLE OF LNG IN FUTURE INTERNATIONAL COMPETITION

The Potential Consequences of Competition for LNG Among the U.S., Europe and Asia

Until recently, the gas industry in North America has been essentially self-contained with only minor imports from other regions as LNG. The gas price shock of 2000/2001 has sharply changed the perception of self - sufficiency. Prices have sharply increased and generated strong interest in Arctic gas and imported LNG. There is now growing concern about the impact of the new gas market environment on the relative competitiveness of U.S. industry in world markets and its potential effect on the economy.

There are three distinct issues in the evaluating the effect of this new environment on U.S. industry. They are; [1] the impact on industry of higher prices for natural gas, [2] the potential for competition with Europe and Asia for LNG supplies, and [3] the implications of relative LNG transportation costs to the gas pricing structures of the three major regional competitors.

Much of the concern about industry competitiveness is directed at what appears to be a new, and permanent, higher level of gas prices and how it will affect selected industries. This is directly attributable to the price change, itself, and though LNG benefits from the higher prices, it is not the cause of the problem.

The gas price shock of 2000/2001 appears to have established a much higher price structure for North American natural gas than that which previously prevailed. The average U.S. wellhead price for gas during the five years ending in 1999 was $1.98 per million Btus. From 2000 through the first six months of 2003, it averaged $3.69, an 86% increase. Gas prices also rose more rapidly than oil prices. During the two periods, average U.S. oil prices increased only 58%.

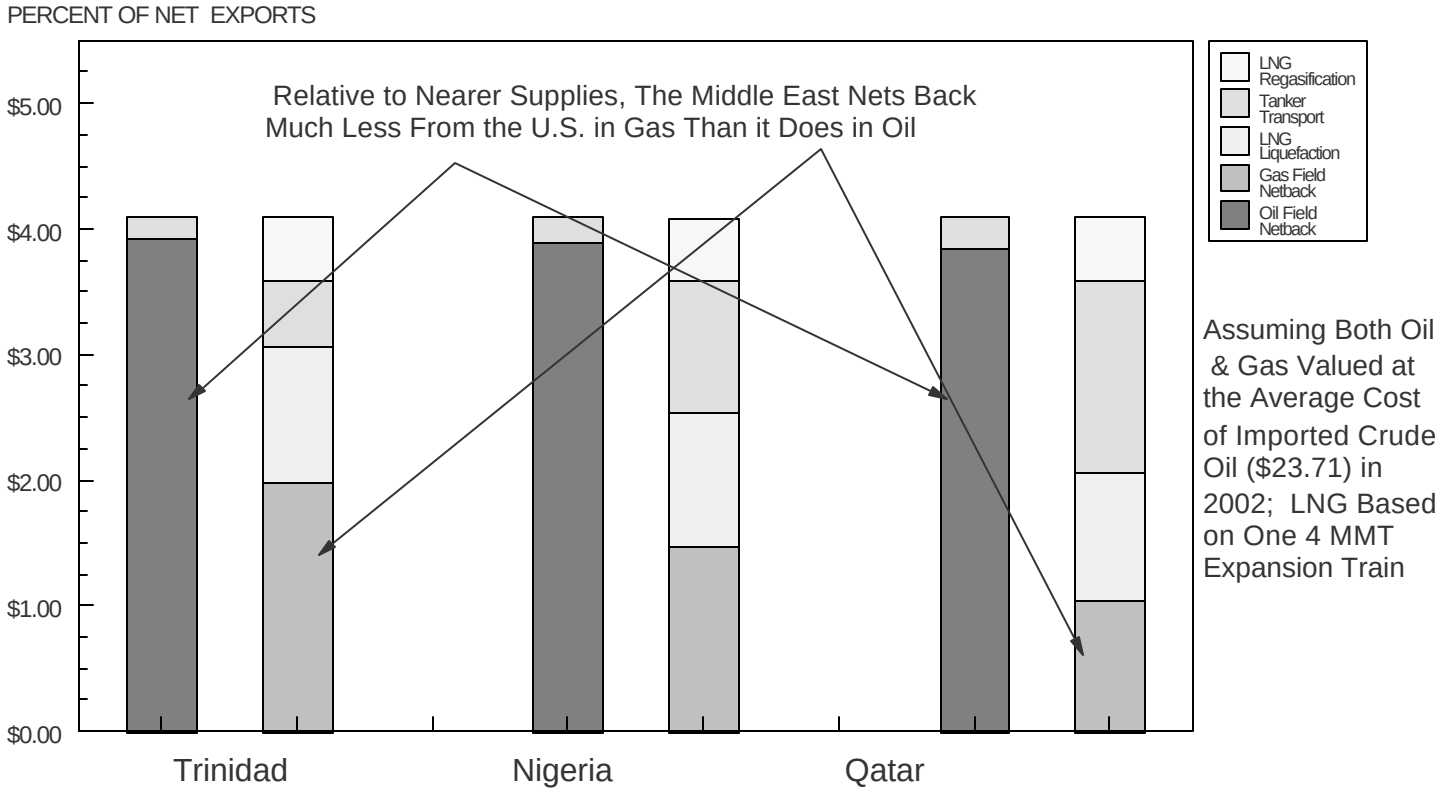
It is possible to lose sight of the fact that gas prices in both Europe and Asia also rose, so that the competitive impact of the price increase was somewhat moderated. Figure 13-1 compares the change in gas prices in the U.S. for the two periods with those of Germany (the largest gas importing country in Europe) and of Japan. Still, while U.S. prices increased by 86%, the Japanese increase was held to 32% and the German increase to 35%. Both Europe and Northeast Asia started out with much higher gas prices than the U.S., but in the case of Europe, prices are now more nearly comparable.

This significant change in the prospects for U.S. natural gas pricing has had a substantial impact on the economic viability of some U.S. industries. While gas for fuel is an important part of the economics of many industries, the ones that rely on gas for chemical feedstock are most seriously affected.

The two principal chemicals that utilize methane from natural gas are ammonia (for fertilizer) and methanol. The major competition for these materials has tended to come from the gas producing countries who have access to low cost feedstock rather than from Europe or Northeast Asia. In the face of higher gas prices, the trend towards increased reliance on the producing countries for these supplies is likely to continue. Some ammonia capacity located in the farm belt of the U.S. Midwest may remain somewhat immune to these competitive pressures, but coastal facilities will be under severe pressure. Methanol is a chemical intermediate and some integrated capacity may also be partially protected.

The principal area of competition between the U.S., Europe, and Northeast Asia that will be affected by the higher U.S. price structure is likely to be the petrochemical olefin derivatives, such as those produced from ethylene. Europe and Asia have tended to utilize naphtha (a gasoline boiling range material) for ethylene, while the U.S. has predominantly relied on ethane and propane feedstocks extracted from natural gas. These feedstock patterns

Figure 13-1
COMPARISON OF OIL AND GAS NETBACKS FROM U.S. GULF COAST TO TRINIDAD, NIGERIA AND QATAR
$/MMBTU



have been logical for each region. The heavy demand for gasoline in the U.S. has tended to make naphtha an uneconomic feedstock for olefin manufacture, while our availability of domestic natural gas rich in gas liquids has favored liquids extraction for feedstock. The economic forces driving feedstock selection in Europe and Northeast Asia have been the reverse of those in the U.S.

Now, with higher natural gas prices, the ethane and propane will command higher valuations within the gas stream and the incentive to extract them for feedstock is significantly diminished. Adding to the problem is that much of our ethylene production capacity is old and may require retrofitting to meet higher pollution standards. One factor that may protect some plant capacity is the fact that it is integrated into complex downstream derivative operations and may not be so easily abandoned.

North American gas prices were a significant factor in the competition between Europe and the U.S. when the U.S. first undertook to restructure the gas industry. At the time, U.S. prices sharply declined giving the U.S. a competitive advantage over the naphtha-based olefin industry in Europe.

The European chemical industry was a moving force behind the efforts to restructure the gas industry on the Continent to compete with the U.S. Wintershall, a subsidiary of the German chemical company BASF, led the movement to liberalize the Continental gas industry by joining forces with Russia's Gazprom in Wingas and WIEH as major competitors to the established European gas suppliers. Now the competitive advantage appears to have shifted back to the naphtha-based industries. Many other U.S. industries have benefitted from lower cost natural gas and will be affected to some degree by the relatively higher prices, but the gas-intensive chemical industry is most at risk.

The second issue is that of increased competition with Europe and Asia for supplies of LNG. In the 1990s world where Northeast Asia was the prime market and market growth was moderate, the demand for new LNG projects was constrained. The industry averaged only one new liquefaction train per year during this period. Now with both Europe and the U.S. entering the market for LNG, the pressures on LNG supplies will increase and there could be some upward pressure on prices. As a potential offset to this concern, however, is the strong interest among the international oil companies to find outlets for stranded gas. This will provide incentive for investment in new projects to meet the increased demand. But if the flow of new liquefaction capacity on offer should lag for any reason - economic or geopolitical - the competition for supply could pose problems.

The third issue is that of the effect of transportation costs on the relative competitive pricing of LNG in the three major markets. Here the U.S. is at some cost disadvantage which may influence relative prices among the competitive economies.

The high costs of LNG transportation make the regional pairings of sources and markets very important in determining the relative costs of LNG in various markets. This poses an important problem for the U.S. for two reasons. First, except for Trinidad, all existing sources of LNG for U.S. Gulf Coast and Atlantic markets are closer to Europe than to the U.S. And, second if the U.S. imports most of its LNG via Gulf Coast terminals it will forfeit the lower transportation costs for the shorter East Coast hauls and "basis differentials" (the result of up-country pipeline tariffs) that East Coast terminals enjoy.

These relative transportation costs and differentials were discussed in Chapter IX and illustrated in Figures 9-6 through 9-8. These estimates suggest that Europe is likely to enjoy somewhat of a competitive transportation advantage (perhaps $0.35 to $.70/MMBtu) over the U.S. Thus in those situations where the U.S. and Europe are competing for the same supply, Europe will be in a favored position to acquire it.

And, while Northeast Asia enjoys a significant price advantage over Europe for Asian sources of supply, it is slightly farther away from the Middle East than is Europe.. However, it is closer to the Middle East than is the U.S., and thus would normally be expected to have a transportation advantage in the range of $0.30 to $0.50 in the cases illustrated in Figure 9-7. Thus, if the Middle East becomes the marginal supplier of LNG to both the Atlantic Basin and the Pacific Basin, Europe will be in the best economic position..

While Northeast Asia would appear to have an advantage over the U.S., that advantage could be at least partially offset by the fact that Japan has shown a willingness to pay higher prices for gas than other markets (as it does for oil), a disadvantage that may be difficult to overcome.

How Likely is the Emergence of an Organization of Gas Exporting Countries?

OPEC was founded in 1960 in response to the major oil companies' unilateral decision to reduce posted prices on which the governments' tax revenue was based. It was initially comparatively ineffective until 1973 when tight oil markets brought on in part by the Arab Oil Embargo resulted in the first "oil price shock" and the transfer of much of the balance of oil power to the governments.

OPEC has been discussed as a possible governmental model for gas production control and, indeed, some OPEC members have openly discussed the possible formation of an Organization of Gas Exporting Countries. Obviously, one question is the likelihood of such an attempt being successful and if so its potential effect on gas prices.

Oil and gas markets are very different, and their differences will substantially complicate any effort to emulate OPEC in natural gas, raising serious doubts if such an effort can ever succeed. Nearly five times as much gas moves across international borders by pipeline as LNG. Although much of the pipeline movement is shorter haul and might not qualify as "interregional trade", major pipeline exporters such as Russia and Norway are major factors in international gas supply, demand and price. And these are countries that have shown little interest in cooperating with OPEC in oil.

Also the balance of existing and potential LNG exporters is much different in gas than in oil. Saudi Arabia, whose very large oil reserves and low production costs enable it to dominate OPEC, is seemingly not interested in the LNG business. At the same time, major LNG exporters, such as Trinidad, Malaysia and Australia are not a part of the OPEC grouping and may have little interest in signing on to an OPEC-like scheme.

The major feature of OPEC, however, is the extent to which the low marginal costs of production are concentrated in the Middle East. This coupled with the low costs of oil tanker transportation, makes it possible for a Saudi Arabia, for example, to lower its wellhead prices and affect prices throughout the world. But if the Gulf is the low cost producer in OPEC that enables the system to work, the same is not true for LNG. The high costs of transportation as well as liquefaction and regasification, make the costs of delivering LNG from the Middle East to world markets relatively high. The Middle East is not the low cost supplier to the world in LNG as it is in oil.

This is illustrated in Figure 13-1, which compares the netback to production of oil an LNG shipments from three locations to the U.S. Gulf Coast. The Figure assumes the value of both crude oil and regasified LNG as $4.09 in the U.S. Gulf Coast (the average Refiner Acquisition Cost of Crude Oil in 2002 at $23.71 per barrel). The netbacks in oil for near in suppliers are not that much more than those of the Middle East, but in gas their netbacks are far higher. And the costs of production of gas vary widely with the nature of the deposit. Some

nearer-market fields, such as Arun in Indonesia, may have much lower production costs than some in the Middle East, such as Abu Dhabi.

Given the relatively high long run marginal costs of adding new LNG supply in a growing market, the ability to control production really gets down to an ability to control capital investments in new LNG projects. That implies a system of coordination that doles out "expansion licenses " to parties according to the central organization's direction.

All things considered, it is difficult to see how such a system would work, suggesting that an Organization of Gas Exporting Countries is an unlikely possibility. Perhaps the greatest possible threat to competitive supply offerings is some sort of coordinated effort by the two largest holders of Middle East gas reserves, Qatar and Iran. However, politically this does not seem an immediate threat.

NCEP Staff Background Paper –
The Safety of Liquefied Natural Gas

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IV. Regulation of the LNG Industry
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V. Conclusions: Is LNG Safe Enough?

I. Introduction

Natural gas is an important source of energy for the U.S. economy, accounting for approximately one-fourth of the nation's primary energy needs. Historically, domestic demand for natural gas has been met by indigenous supplies and imports from Canada. Recent trends, however, indicate that traditional supply sources cannot keep pace with continued demand growth and traditional domestic gas resources are in decline. As a result, natural gas prices have risen to unprecedented levels and many experts expect that an increased reliance on imports—in the form of liquefied natural gas (LNG) which can be transported over long distances in large ocean vessels—will be necessary in coming years to help close the supply gap. The prospect of a significant increase in LNG carrier traffic off U.S. shores, and the need for additional coastal receiving facilities to transfer, store, and re-gasify LNG shipments has led to considerable public anxiety surrounding the safety and vulnerability of such infrastructure. In fact, several recent proposals to construct new LNG terminals have been stalled or even cancelled due to strong local opposition. It is clear that public perceptions concerning the hazards posed by LNG must be addressed if imported natural gas is to emerge as a significant supply option for the United States.

This paper presents basic information about LNG in an effort to clarify and provide perspective on the particular safety issues it raises. In doing so, this paper relies heavily on several comprehensive assessments of LNG safety and security that have recently been prepared by the University of Houston Institute for Energy, Law & Enterprise (IELE), the California Energy Commission (CEC), the Federal Energy Regulatory Commission (FERC), and the Congressional Research Service (CRS), among others. By and large, these assessments have concluded that the safety hazards involved in transporting and handling large quantities of LNG—while certainly real and requiring careful management—are not fundamentally different in kind or degree from those associated with other major energy products routinely used in the United States. Accordingly, safety issues, properly addressed, should not prevent the needed expansion of LNG infrastructure.

II. LNG Hazards and Characteristics

What is LNG?

Liquefied natural gas is simply natural gas that has been extensively cooled to minus 260 degrees Fahrenheit so that it changes from a gas to liquid. Natural gas consists primarily of methane (more than 85 percent) mixed with small amounts of propane, butane, ethane, and nitrogen. The natural gas is pre-treated to remove impurities such as water, nitrogen, carbon dioxide, hydrogen sulfide and other sulfur compounds to prevent them from forming solids when the gas is cooled. As a result, LNG is typically made up of about 95 percent methane. The liquefaction process reduces natural gas to roughly $1/600^{th}$ of its original volume as a gas, allowing for efficient transport over long distances via ship. Once the LNG reaches its destination, it is usually converted back into a gas at a receiving terminal and inserted into the terrestrial pipeline network. As discussed more extensively in later sections, this process is well-established and has been conducted with little incident in countries all over the world.

LNG is a cold, colorless, odorless liquid that, although non-toxic and non-corrosive, is considered a hazardous material due to its high energy content and potential flammability in vapor form.[1] It is lighter than water and its gaseous vapors are lighter than air, giving LNG several favorable environmental characteristics. In the event of a spill, for example, LNG will quickly warm and begin to boil off into vapor form, causing the surrounding moisture in the air to condense and creating a large white vapor cloud that closely resembles ordinary ground fog.[2] Because it is lighter than air, the vapor cloud will gradually rise and dissipate into the atmosphere. Unlike an oil spill, moreover, an LNG spill leaves no pollution or residue behind. If spilled at sea, LNG will float on top of the water until it vaporizes, leaving no fuel residues to mix into the water.[3]

What properties of LNG create potential hazards?

Several characteristics of LNG, however, do necessitate special handling and—as with all energy products—create potential hazards. A recent report by the California Energy Commission describes three major accident hazard categories that must be considered and vigilantly managed during LNG utilization. These three categories are (1) its extreme (cryogenic) temperature characteristics, (2) its flammability characteristics, and (3) its dispersion characteristics.[4] Key considerations and sources of hazard in each of these categories are summarized below. There are also other, less significant hazards such as direct exposure to an accidentally released vapor cloud. However, the circumstances under which this might occur are so remote that it can be considered a second order concern.

1. Temperature

Because of its low temperature, physical contact with LNG can lead to serious injury and freezer burn. Therefore, all workers and facility personnel who could come in direct contact with LNG are required to wear gloves, face masks, and appropriate protective clothing. To address exposure hazards more broadly, on-shore LNG facilities are equipped with emergency spill containment systems that are designed to control up to 110 percent of an LNG tank's contents.[5] Besides minimizing the hazard of direct exposure, these systems mitigate the potential for rapid vaporization of LNG by capturing any unintended releases and containing them quickly. Finally, all piping and instrumentation at LNG facilities are equipped with built-in expansion loops to accommodate the expansion and contraction that can result from temperature changes. In general, the cryogenic hazard associated with LNG is likely to be a concern only within or near facility boundaries and is unlikely to pose a significant threat to outside communities or to the general public.[6] Thus, it is generally thought to be a lesser concern than the dispersion or combustion hazards discussed below.

2. Flammability

In a liquid state, natural gas cannot explode or burn under any circumstances.[7] However, natural gas vapors are flammable under specific conditions. Methane can burn in air only when

[1] CEC (2003), Pg. 2
[2] CEC (2003), Pg. 2
[3] CRS (2004), Pg. 6
[4] CEC (2003), Pg. 2
[5] CEC (2003), Pg. 5
[6] UH IELE (2003), Pg. 18
[7] FERC (Website)

its concentration is between five and fifteen percent by volume. If the concentration is below the lower flammability limit, there is not enough methane to burn. If the concentration of methane is greater than fifteen percent, there is not enough oxygen for combustion.[8] In the event that LNG vapors ignite, the resulting fire will burn until either all of the fuel is gone or the concentration of gas to air is no longer within flammability limits. In sum, the combustion hazard associated with an uncontrolled release of LNG is limited to the resulting vapor cloud which must form a concentration of methane within applicable flammability limits and encounter an ignition source in order to burn. In addition, LNG vapors have an auto-ignition temperature of 1004°F which is the lowest temperature at which the gaseous vapors will ignite spontaneously.[9]

One of the most common misperceptions regarding LNG is that it is a pressurized substance and thus highly susceptible to explosion. LNG is not pressurized and is not explosive.[10] In fact, the energy contained in LNG cannot be released fast enough to create the overpressures necessary for explosion in an open environment.[11] Explosion is possible, however, if LNG vapors are concentrated in a confined environment and if they encounter an ignition source (LNG vapors will not spontaneously combust unless exposed to high temperatures). Modern LNG facilities are designed to address the hazards associated with vapor build-up in confined spaces and utilize simple venting techniques to ensure that dangerous concentrations do not occur. LNG storage tanks today have impoundment systems that drain into an open topped concrete basin in the event of a spill. This significantly diminishes the surface area of the spill and reduces the size of the resulting vapor cloud. In addition, in the event of a spill, some LNG facilities are equipped to deliver high-expansion foam to the spill immediately. Initially, this foam can help to move LNG vapors away from potential ignition sources and, in the event of a fire, the foam provides some control over the rate of burning.[12]

3. Dispersion

The general dispersion characteristics of LNG in the event of a spill were described previously. As has already been pointed out they compare in some ways favorably to the dispersion characteristics of oil and refined petroleum products. However, there is a concern that the vapor cloud that would result from an LNG spill could, if it encountered an ignition source as it rose in the atmosphere, burn back to the source of the spill and cause a serious fire. In general, LNG will boil off much faster on water than on land because water provides a more significant thermal source for heat transfer. This is why an LNG vapor fire cannot be fought with water: the water would simply accelerate the liquid's vaporization and fuel the blaze. Also, an LNG spill on water is much more difficult to contain and spreads over a larger area than a spill on land. The evaporation disperses at a faster rate because of the high heat transfer rate and the water does not cool significantly. For these reasons, it is generally considered that shipping, on-loading, and off-loading of LNG present the greatest safety threats.[13] At modern LNG terminals, systems are in place to ensure that natural gas vapor cloud dispersion is enhanced, thus lessening the likelihood of a vapor fire.

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[8] UH IELE (2003), Pg. 13
[9] UH IELE (2003), Pg. 15-16
[10] UH IELE (2003), Pg. 12
[11] FERC (Website)
[12] CEC (2003), Pg. 5
[13] CEC (2003), Pg. 3

How do the hazards associated with LNG compare to those of other fuels?

Like nearly all energy resource options, LNG presents some risks of unintended energy release and is potentially susceptible to accidents and malicious attacks. The relevant question is less whether LNG can be made absolutely free of risks than whether the risks involved are greater than those associated with other common energy products (such as petroleum). The dialogue and efforts should be directed toward whether these risks can be reduced to levels that are both manageable and acceptable to the public.

In answering this question, the obvious comparison is to petroleum and petroleum products, which—like LNG—are characterized by high energy density and are routinely transported via large ocean-going vessels. In terms of simple energy content, a typical large oil tanker transporting 200,000 tons of crude oil contains some eight trillion Btu's of energy.[14] For comparison, a standard LNG vessel can contain up to 150,000 cubic meters of LNG, which equates to about three trillion Btu's of energy.[15] While crude oil does not combust as readily or with the same intensity as natural gas, refined products of oil, which are also routinely transported in large tankers, can be just as flammable (or more so) than LNG vapors. In fact, LNG vapors have a higher auto-ignition temperature than gasoline or propane[16] vapors, meaning that a higher temperature is necessary for spontaneous ignition.[17] In addition, the lower flammability limit for LNG is higher than that for gasoline, meaning that a greater concentration of fuel is necessary for combustion. The point of this comparison is not to suggest that tankers carrying petroleum products are unsafe. The important differences in the properties of these fuels combined with the manner in which they are handled and transported allow their risk profiles to be site-specific and case-specific. However, it is not clear that LNG poses a significantly greater hazard to society than, say, gasoline or propane.

Table 1 below reproduces, with some modifications, a table developed by the University of Houston Law Center Institute for Energy Law and Enterprise that compares gasoline, liquefied petroleum gas, and LNG across a number of key characteristics.[18] These factors provide a framework for evaluating the risk/benefit comparison with more familiar energy activities. One important distinction to be made here is that the safety risk for LNG and propane

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[14] Ultra-large crude carriers and very large crude carriers are among the largest ships in the world. They can carry anywhere from 200,000 to 500,000 tons of crude oil (http://generalmaritimecorp.com/newgencor5.html). According to the EIA (http://www.eia.doe.gov/pub/international/iealf/tablec2.xls) there are roughly 7.3 barrels of crude oil per metric ton and there are 5.8 million BTU's per barrel of oil (http://www.eia.doe.gov/kids/unitsindex.html). Combining these factors leads to a range from 8.1 to 20.9 trillion BTU's of energy per typical tanker-load.

[15] This LNG tanker size is from a report by the University of Houston Law Center Institute for Energy Law & Enterprise entitled "LNG Safety and Security" October 2003, Pg. 23. According to this report, most new LNG ships are designed to carry between 125,000 and 150,000 cubic meters of LNG or between 2.8 and 3.1 billion standard cubic feet of natural gas. With approximately 1,026 BTU's of energy per cubic foot of Natural Gas, this equals 3.1 trillion BTU's of energy in a 150,000 cubic meter LNG vessel.

[16] Propane is a hydrocarbon that is produced from both natural gas processing and crude oil refining in roughly equal amounts. It is often referred to as liquefied petroleum gas, LP-gas, or LPG.

[17] ABS (2004), Pg. 4

[18] UH IELE (2003), Pg. 14-15. Note that information on fundamental burning velocity was gathered from a similar table in an ABS consulting report prepared for FERC (ABS, 2004. p. 4). Fundamental burning velocity is the burning velocity of a laminar flame when ignited in a flammable vapor cloud. Lower fundamental burning velocities tend to generate lower overpressures. Also note, the autoignition temperature is the lowest temperature at which a flammable gas vapor will ignite spontaneously.

is most significant in the vapor phase, whereas the safety risk for gasoline lies in the liquid phase. In the event of a spill, a liquid like gasoline would have more manageable dispersion characteristics and be easier to contain but it would also have more unfavorable environmental impacts.

Table 1: Comparison of Properties between LNG, Gasoline, and Propane

	Gasoline	Propane	LNG
Hazardous Material?	Yes	Yes	Yes
Autoignition Temperature (°F)[18]	495	850-950	1004
Cryogenic Temperature[18]	No	Yes, if refrigerated	Yes
Environmental Clean-up if Accidentally Spilled?[18]	Yes	No	No
Stored Under Pressure?[18]	No	Yes, unless refrigerated	No
Forms Vapor Clouds?[18]	Yes	Yes	Yes
Flammable Vapors?[18]	Yes	Yes	Yes
Toxic?[18]	Yes	No	No
Fundamental Burning Velocity (ft/s)[18]	1.3	1.5	1.3
Risk of Catastrophic Event	Similar	Similar	Similar

In sum, no single characteristic can be used to assess the relative risks associated with different energy options. Rather these risks must be evaluated in a comprehensive and methodical manner. The studies cited in this briefing paper, together with ongoing research and analysis being conducted by the federal government and others, attempt to provide a balanced analysis of the specific risks associated with LNG. As indicated in the introduction, they generally conclude that safety concerns can be managed and need not stand in the way of expanding domestic LNG infrastructure.[19]

III. Risk of Catastrophic Accident or Malicious Attack

Public concern about the potential for a catastrophic LNG-related incident has understandably risen in recent years by the emergence of terrorist threats to the nation, and by the recognition that large energy infrastructure (of various types, not just LNG) could pose an attractive target for future attacks. In an effort to address the added risks of terrorism, most oil and natural gas companies are in the process of working with the Department of Homeland Security to ensure the security of ships and storage facilities, including those handling LNG.[20] The Maritime Transportation Act of 2002 required all ship and terminal operators to submit security plans to the U.S. government by the end of 2003. Some of the measures that have been

[19] Federal Energy Regulatory Commission, "FERC Chairman Welcomes Fed Chairman's Focus on LNG", Press Release, June 11, 2003, Available: http://www.ferc.gov/industries/gas/indus-act/LNG-wood.pdf
[20] CLNG (Website), LNG Facility and Ship Security

taken so far call for much more restricted access to LNG facilities, tighter security, and increased patrols. In light of current terrorism concerns, of course, all energy products must be handled with increased care. Here again, moreover, most available analyses conclude that LNG is not necessarily any more attractive or vulnerable to terrorist threats than other energy sources.

Historical Safety Record of the LNG Industry

Historically, the LNG industry has had an extensive and relatively safe track record with very few accidents. This is especially true for the LNG shipping industry. Since international shipping began in 1959, LNG ships have transported more than 33,000 shipments without any serious accidents at sea or in port.[21] Currently there are roughly 150 active LNG ships transporting 110 million metric tons of LNG annually (equivalent to more than 5 trillion cubic feet of natural gas).[22] Asia is more reliant on LNG trade than any other region and consequently has accumulated an extensive track record with handling the substance. In 2000, roughly eight LNG vessels a week safely entered Tokyo Bay. Comparatively, Boston Harbor received on average one ship a week.[23] Last year, the United States imported over 500 billion cubic feet of LNG without incident (approximately 2 percent of total U.S. natural gas consumption).[24] While LNG vessels have experienced some groundings and collisions, none have experienced major cargo spills or fatalities.[25]

The fact that most LNG ships have extensive safety features may partly account for the industry's largely successful marine safety record. The ships are typically double-hulled and surrounded by thick insulation, which makes them more robust and less prone to accidental spills than single-hulled tankers (such as the Exxon Valdez.).[26] Most LNG ships are also equipped with global positioning systems, radar, and automatic distress systems to signal when they are in trouble. Finally, these vessels are equipped with sophisticated fire and gas detection systems.

For the most part, the safety record of onshore LNG terminals has also been exceptional but there have been a small number of serious accidents over the past 50 years. Onshore LNG marine terminals are preferentially located on large plots of land, with safety features such as full containment tanks. They consist of docking stations, LNG handling equipment, LNG storage tanks, and interconnections to distribution pipelines. These large ports are equipped to handle high winds, tidal, and wave forces. In the event of an emergency, their emergency shutdown (ESD) systems will rapidly cut off the flow of LNG during on and off-loading.[27]

Federal safety regulations require that LNG facilities have exclusion zones. These zones specify the area surrounding an LNG facility where an operator legally controls all activities. Moreover, they are required to ensure that structures and public activities beyond the immediate LNG facility boundary are safe in the event of an accident. Federal regulations identify two types of exclusion zones—flammable vapor-dispersion protection zones, and thermal-radiation

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[21] CRS (2004), Pg. 6
[22] CLNG (Website), LNG Vessel Safety
[23] CLNG (Website), LNG Vessel Safety
[24] EIA (Website)
[25] CRS (2004), Pg. 6
[26] CRS (2004), Pg. 6
[27] CEC (2003), Pg. 4

protection zones.[28] The first of these, flammable vapor-dispersion protection zones, are required to provide the maximum safe distance from LNG vapor clouds which have not been ignited but could migrate (with the wind) to an ignition source. Thermal-radiation protection zones are required to ensure that the heat released from an LNG pool fire within the facility boundary would not be severe enough at the property line to cause death or third degree burns.[29] These zones are highly site-specific dependent on unique characteristics of the area such as terrain roughness, weather conditions, and average gas concentrations in air. For example, the vapor-dispersion exclusion zone for the Cove Point facility in Maryland is 1,017 acres, as opposed to only 840 acres for the Elba Island LNG facility in Georgia.[30] These federal exclusion zone requirements are identified in 49 CFR 193.

Since 1944 there have been roughly 13 serious accidents at the approximately 40 LNG terminals located worldwide.[31] A brief description of three particularly notable incidents follows:

1. Cleveland, Ohio 1944

One of the most serious LNG accidents to date occurred at a Cleveland, Ohio storage facility in 1944. An LNG tank was built using what was later proved to be improper materials, leading to a material brittle fracture and major spill. Some of the LNG drained into a confined storm-sewer system, forming a confined vapor cloud that accidentally ignited within the sewer and spread the fire in a residential area. The resulting explosion and fire killed 128 people.[32]

The Cleveland incident highlights the fact that large LNG storage tanks likely represent one of the most vulnerable points in the LNG supply chain. A large-scale spill or leak from one of these tanks (which may hold as much as 3.5 million cubic feet of liquid natural gas) could produce a massive and potentially very dangerous vapor cloud. However, modern LNG storage tanks have a number of safety features that significantly reduce the risk of another Cleveland-like disaster. Modern types of storage containers include double-walled "single-containment" tanks with surrounding impoundment dikes; "double containment" tanks that have both primary and secondary tanks; and "full containment" tanks that are reinforced to withstand "realistic impacts from missiles or flying objects."[33] In addition, modern tanks are equipped with safety-vent valves (to prevent pressure buildup), in-tank cameras (to allow for visual safety inspections), and integrated fire detection and response systems.

2. Cove Point, MD 1979

The only other LNG related death in the United States occurred at the Cove Point, Maryland receiving terminal in 1979. An inadequately tightened electrical penetration seal on an LNG pump led to a leak into the electrical conduit leading to an electrical equipment building. The vapors accumulated in the building and they were ignited by a circuit breaker within the

[28] CEC (2003), Pg. 6
[29] CEC (2003), Pg. 6
[30] CEC (2003), Pg. 6
[31] CRS (2004), Pg. 6
[32] CEC (2003), Pg. 8
[33] CEC (2003), Pg. 4-5

substation building. The buildup of pressure within this confined space led to an explosion that caused the roof to collapse, and a falling beam killed one person and injured a second.[34]

3. Algeria 2004

The most serious recent international LNG incident occurred on January 19, 2004 at a liquefaction facility in Skikda, Algeria and involved an explosion that killed 27 workers and injured more than 70.[35] Officials at Sonatrach (Algeria's state-owned energy company) claim that a cold hydrocarbon leak from a pipe occurred in one of the liquefaction facilities. A gas vapor cloud formed within the facility. This cloud then encountered an ignition source (likely a steam boiler) which led to an explosion. The explosion destroyed three of the six liquefaction units – termed "trains" within the industry – at the plant. It did not affect the second separate processing plant nearby or three large LNG storage tanks located some distance from the accident location. This was the worst fire at an Algeria petrochemical plant in their 40 year history. It is commonly believed that it was caused by poor maintenance and safety procedures rather than by a facility design flaw. Nevertheless, the incident has raised questions concerning the relative safety of LNG. According to a report prepared by James T. Jensen for the National Commission on Energy Policy, "the fact that the trains were involved in a disastrous fire does some damage to the industry's credibility on the safety issue."[36] The relevance of the Algeria incident to domestic safety concerns is unclear. In general, the vaporization process (used by the receiver of gas) does not require the same equipment as the liquefaction process (used by the gas exporter). This accident is still under investigation and the most significant question that remains is whether or not the vapor cloud that created the explosion was methane or other heavier hydrocarbons (i.e. butane and propane) used in the refrigeration process. This is important for determining whether the LNG processing was the source of the explosion or if it was related to other hydrocarbon fuels.

Risk of Malicious Attack

The fact that the LNG industry has amassed a relatively good safety record may, of course, go only so far in assuaging more recent concerns about the potential for terrorist attacks. The Commission acknowledges that there are endless possibilities for malicious attacks on LNG infrastructure at countless points along the LNG supply chain. This report focuses on three major risk scenarios most relevant to the U.S. The first of these is the hijacking of an LNG vessel so that it can be grounded ashore and used as a weapon. The second is the potential for detonating an explosive beside the hull of an LNG vessel, spilling its contents, and igniting the gaseous vapors. The third type of event would involve a terrorist attack at an onshore LNG receiving terminal or storage facility.

It is important to realize that vulnerabilities are not unique to LNG and should be addressed across the range of energy products and hazardous materials utilized in the United States. A detailed report released by the city of Vallejo California in January of 2003 concludes that LNG terminals and carriers generally do not make good targets for terrorists because both

[34] CEC (2003), Pg. 8-9
[35] CRS (2004), Pg. 7
[36] Jensen (2004), Pg. 123

the LNG ships and terminal facilities have very robust design characteristics.[37] However, they do acknowledge the serious risks associated with such infrastructure.

1. Vessel Grounding

The Commission could not locate any existing literature or analysis on the potential consequences if an LNG vessel were hijacked and commandeered for use as a weapon against a coastal target. However, the safety record of LNG shipping to date suggests that it would be difficult to use an LNG vessel effectively against an on-shore target. On those occasions where LNG vessels have grounded or experienced collisions in the course of normal business activities in the past, no spills, deaths, explosions, or fires have occurred as a result. In addition there are limited coastal targets that can be attacked with a vessel collision because of the lack of adequate water depth outside of designated shipping channels. The few areas of the US where adequate water depth for an LNG ship exists near shore are under control of the USCG and surveillance of security agencies.[38]

2. Terrorism near the Coast

Professor James A. Fay of the Massachusetts Institute of Technology has explored the possibility that a boat bomb, such as the one that was used against the USS Cole in 2000, could be detonated alongside an LNG vessel to trigger an enormous LNG spill and fire. Fay uses a mathematical model to simulate the potential consequences of such an event at specific U.S. sites.[39] In one scenario, Fay has compared the modeled impacts of an LNG spill versus an oil products tanker spill in Boston Harbor. Importantly, Fay's analysis assumes that the volume of the oil products spill (at 1140 m^3) is much smaller than the LNG spill (14,300 m^3), because typical oil product tanker compartments are roughly one-tenth the size of LNG vessel storage compartments. Fay's analysis further assumes an essentially instantaneous release, vaporization, and ignition of all LNG energy content in the ship. While this assumption is standard convention for modeling LNG spills, in reality, it would likely take some time for the LNG to spill out, vaporize, and acquire the appropriate flammability concentration before combustion. Fay's analysis suggests that significant damage could occur as far as 1.1 km from the source of the spill in the case of the LNG vessel, and 0.9 km in the case of the oil products tanker. Fay also concludes that the LNG spill (and resulting vapor fire) would have an average heat release rate of 1.5 Terawatts as opposed to only 0.12 Terawatts for an oil products compartment vapor fire (this difference appears to be due largely to the assumed difference in spill size).[40] In the Vallejo study cited above, it is noted that in a worst case scenario of this type, a flammable vapor plume could disperse several miles, encounter an ignition source, and then burn back to the spill resulting in a very serious fire. Although such a scenario is possible, the Vallejo study also points out that this is unlikely because most LNG released through acts of terror would be ignited and burned immediately without having time to disperse.

In a recent senate hearing, Professor Jerry Havens, an LNG expert at the University of Arkansas, expressed his concern for the lack of offshore exclusion zone requirements. He acknowledged the fact that current regulations for land based zones as present in 49 CFR 193 are

[37] Vallejo (2003), Pg. 43
[38] Lewis
[39] Fay (2003)
[40] Fay (Boston)

based on good science and "adequate" for their purpose, but expressed "that it is imperative that the dangers to the public from possible releases from a LNG carrier onto water be considered in the siting of LNG terminals in our country."[41]

3. Onshore Terminal Attack

A third concern is the potential risk of a terrorist attack against onshore LNG infrastructure (e.g. LNG storage tanks). An attack on an LNG storage tank could be a serious event simply due to the volume of liquid involved and to the resulting hazard of a major LNG vapor fire. In evaluating the consequences of an attack, the rate of release is the more significant factor than the total volume. Acting to mitigate this hazard are the many safety features already built into the design of onshore LNG terminals and storage tanks to address accidental spills. In assessing this hazard, FERC has acknowledged that LNG-based fires are unpredictable but maintains that

> "the more extreme scenarios suggested by some LNG terminal opponents are too theoretical and do not realistically reflect the actual configuration and physical characteristics of LNG terminal infrastructure, including the comprehensive safety and security features required in terminal design."[42]

In addition, opponents' worst-case scenarios of this type tend to assume instantaneous liquid release, vaporization and delayed ignition. FERC seems skeptical of such a scenario, suggesting that it would be analogous to lifting an upside-down Dixie cup and releasing all of its contents at once – an event that is unlikely to occur because of the strength and design of LNG storage tanks.[43]

Finally, also in the Vallejo study, a worst case scenario involving the crashing of a 747 airplane with a full load of jet fuel into a land based storage tank is discussed. A catastrophic event of this type could cause a fireball with very high temperatures and extensive heat radiation. A fireball results when a large rich mixture of fuel and air are ignited creating buoyancy and turbulence that rapidly burns the rest of the fuel and causes it to rise into the atmosphere. The Vallejo study ultimately concludes that the circumstances necessary to cause a fireball of such intensity is unlikely.[44]

IV. Regulation of the LNG Industry

The LNG industry in the United States falls under the regulation of several different federal agencies including the Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), the U.S. Coast Guard (USCG), the Department of Transportation (DOT), the Environmental Protection Agency (EPA), the U.S. Minerals Management Service (MMS), the U.S. Fish and Wildlife Service, the U.S. Department of Labor Occupational Safety and

[41] Havens (2004)
[42] CRS (2004), Pg. 14
[43] CRS (2004), Pg. 14
[44] Vallejo (2003), Pg. 50-51

Health Administration (OSHA), and the U.S. Army Corps of Engineers. It is also falls under state environmental protection agencies, and local police and fire departments. Finally, the non-governmental regulators and standards organizations that oversee LNG include the National Fire Protection Association (NFPA), the American Society of Mechanical Engineers (ASME), the American Society of Civil Engineers (ASCE), the American Petroleum Institute (API), the American Concrete Institute (ACI), and the American Society for Testing and Materials (ASTM).

Of these, DOT and FERC have the primary responsibility of onshore LNG terminals. The USCG is primarily responsible for the LNG ships and offshore terminals.

Department of Transportation (DOT)

DOT is responsible for security patrols, protective enclosures, lighting, monitoring equipment, and alternative power sources.[45] DOT operates under the authority of the Pipeline Safety Act of 1995 and is responsible for prescribing "minimum safety standards for determining the location of a new liquefied natural gas pipeline facility"[46] including:

- Design and construction guidelines for LNG facilities to withstand fire, wind, hydraulic forces, and erosion from LNG spills.
- Consideration of geophysical hazards, proximity hazards (i.e. to major cities), and the existing and proposed land use near the location.
- Regulation of the operations, maintenance, employee qualification, and security.

Finally, the Department of Transportation is also responsible for issuing the licenses for new LNG offshore terminals under the authority of the Deep Water Port Act.

Federal Energy Regulatory Commission (FERC)

While the DOT regulates these aspects of an onshore LNG terminal, it does not have authority to approve or deny specific LNG sites; this is the role of FERC under the Natural Gas Act (NGA) of 1938. Under Section 3 of the NGA, FERC requires that LNG terminal applicants provide evidence (with detailed site engineering and design information) that an LNG site will be able to properly and safely receive or deliver LNG. In addition, under Section 7 of the NGA, FERC is charged with authorizing the construction and operation of interstate natural gas pipelines that may be associated with LNG facilities.[47] Finally, under the National Environmental Policy Act of 1969, FERC must prepare an environmental impact statement in its review of an LNG terminal siting application.

United States Coast Guard (USCG)

The USCG is primarily responsible for the regulation of offshore marine terminals and LNG ships and marine terminals under the Magnuson Act, the Ports and Waterways Safety Act of 1972, and the Maritime Transportation Security Act of 2002.[48] As indicated above, this includes primary responsibility for the security of incoming LNG ships and docked vessels, as

[45] DOE (Website)
[46] CRS (2004), Pg. 7
[47] Interagency Agreement (Website)
[48] Interagency Agreement (Website)

well as matters relating to vessel engineering, safety standards, and navigation safety. In addition, under the authority of the Deep Water Port Act, the USCG is the lead agency for conducting the environmental review for proposed offshore terminals.

Department of Energy (DOE)

The Department of Energy's Office of Fossil Energy is the federal entity that improves the importation of LNG (the commodity). This office has recently asked Sandia National Laboratory to undertake a detailed examination of LNG safety. This report is expected to be completed in 2004. In addition, FERC, the USCG, and DOT all recently announced an interagency agreement in 2004 to "provide for the comprehensive review of land and marine safety and security issues at the nation's LNG import terminals."[49]

V. Conclusion: Is LNG Safe Enough?

It is clear that the cryogenic nature of LNG, its flammability under certain conditions, and its dispersion tendencies do present a number of potential safety hazards during transport and handling. However, the empirical evidence – based on the extensive track record of the industry – indicates that these hazards can be adequately managed under normal operating conditions. Based on current understanding, LNG does not appear to pose a greater societal safety hazard than other widely used sources of energy such as petroleum and its by-products.

The emergence of an ongoing terrorist threat in recent years has added a new and potentially more challenging dimension to existing concerns about the risks involved in importing large quantities of LNG. As a result, the specific vulnerability of LNG transportation and storage facilities to malicious attack must be convincingly addressed before policymakers, insurers, investors, and the public consent to considerable expansion of the existing LNG infrastructure. Potential attacks on LNG vessels or storage facilities are, of course, likely to be most concerning if they occur near a populated area. Hence some recent proposals would locate the offloading process many miles offshore. In such a scheme, energy-laden LNG vessels need not approach the coastline but would instead offload their cargo via a pipeline connection at sea. An off-shore receiving facility of this type is currently being constructed 116 miles off the coast of Louisiana and others are under consideration.[50]

To what extent improved understanding of the genuine hazards posed by LNG would actually translate to greater public support for new receiving terminals and increased carrier shipments remains an open question. NIMBY-type opposition to the siting of major energy infrastructure is, after all, not unique to LNG. (This more general issue is addressed elsewhere in other Commission work and not explored in this paper.) While more research is underway on the full range of hazards involved—in particular research on the damage potential associated with a large LNG vapor fire—several recent assessments by knowledgeable sources suggest that these hazards are not different in kind or degree from those associated with other fuels or types of energy infrastructure and can be successfully managed with existing market and regulatory arrangements. Given the nation's need for adequate and reasonably priced supplies of natural

[49] DOE (Website)
[50] Globe (2004), Pg. A1

gas, the Commission recommends that concerted efforts be made to educate the public regarding LNG-safety issues, and ensure that safety concerns are addressed during the siting process.

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A REVIEW OF ENERGY DEVELOPMENT IN THE WEST

For

National Commission on Energy Policy

By

Izaak Walton League of America

Wildlife Management Institute

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INTRODUCTION

The nation's federal lands play roles both in meeting the country's energy needs and in sustaining a wide variety of the fish and wildlife species relied upon by many interests, including sportsmen, nature lovers, and tourist-dependent businesses. As a result of these competing demands on federal lands, the establishment of management policies historically has generated philosophical debates about the appropriate priority given each of the uses and tension among the various stakeholders. Recently, these tensions have been exacerbated, as the nation's federal land management agencies have accelerated the issuance of leases and permits for thousands of acres of these lands for oil and gas development in an attempt to produce more energy domestically (Shore 2004).

The current system of energy development on federal lands does not appear to be satisfactory to any of the stakeholders. Energy developers face delays in processing lease and permit applications. Sportsmen and other wildlife enthusiasts are concerned that the pace of development, the lack of scientific data and monitoring, and the uneven application of environmental restrictions is jeopardizing fish and wildlife resources and related economic activity.

In 2003, the National Commission on Energy Policy (NCEP) asked the Theodore Roosevelt Conservation Partnership and three of its partners, Trout Unlimited, the Izaak Walton League of America, and the Wildlife Management Institute to write a report focusing on the process of leasing and permitting the extraction of oil, gas, and coal bed methane on federal lands. The NCEP asked that the report review the effectiveness of the current leasing program and put forth a model for future development of energy resources that minimizes conflicts among stakeholders by ensuring adequate protection of water resources and fish and wildlife habitat, and that explores policies that will benefit both fish and wildlife resources and resource extraction efforts.

To accomplish this goal, the status of energy development on key federal lands in the Rocky Mountain states was examined through a review of the literature and through participation in professionally-facilitated stakeholder meetings held in Cody, Wyoming; Roswell, New Mexico; and at the U. S. Fish and Wildlife Service's National Conservation Training Center in West Virginia. The purpose was to better understand the strengths and shortcomings of the current management of energy development projects on federal lands. In particular, this report examines the following two broad questions:

- Are restrictions preventing legitimate development of energy resources on federal lands?
- Can a process be established to more efficiently facilitate energy development, while protecting fish and wildlife resources and other amenity values associated with the federal lands?

This final report to the Commission synthesizes that information and presents findings and conclusions in the following manner:

- Section I summarizes the extent of energy development on federal lands;
- Section II summarizes the potential impacts of energy development on fish and wildlife habitat;
- Section III summarizes the permitting process;
- Section IV discusses the Wyoming, New Mexico, and West Virginia meetings;
- Section V proposes a model process to promote energy production in other basins that is consistent with water resource and habitat protection; and
- Section VI offers specific and substantive recommendations to better harmonize the dual goals of energy production and habitat and resource protection on our nation's public lands.
- Section VII provides a list of the citations used in the report.

SECTION I. THE EXTENT OF ENERGY DEVELOPMENT ON FEDERAL LANDS

The United States economy depends substantially on the use of natural gas and oil, much of which is imported. In fact, the U.S. currently imports roughly 59.5 percent of its oil (US Department of Energy 2003) and 11.5 percent of its natural gas (US Department of Energy 2001). As domestic demand for these fuels grows, imports are also expected to grow, leaving us more vulnerable to world events that can disrupt foreign supplies. Moreover, this dependence on foreign sources of fossil energy results in a massive transfer of wealth out of the country, contributing to our trade deficit. Consequently, there is considerable value in developing domestic sources of oil and natural gas.

The federal lands for decades have been the focus of efforts to produce oil and natural gas. While the federal lands in the West do not contain sufficient economically-recoverable oil and gas to substantially reduce our dependence on foreign sources of energy, the development of these resources can have localized economic benefits and may marginally ease supply constraints, which are likely to become more severe in the future.

Natural Gas

The United States Geological Survey (USGS) estimated in 2002 that 1 trillion cubic feet of technically recoverable natural gas remain in the United States (exclusive of federal waters; Energy Information Administration 2002). The ultimate technically recoverable volume of gas in conventional fields (onshore) not yet discovered was estimated to be 320 billion cubic feet on federal lands, with 27 percent of these located in the Rocky Mountain region.

The U.S. is producing roughly 19 billion cubic feet of natural gas per year (2002), with 2.1 billion cubic feet (11%) coming from federal lands (onshore). In contrast, total consumption of natural gas in the U.S. exceeds 22 billion cubic feet per year, and consumption has remained relatively steady for the past 5 years (1999-2003). Therefore, technically recoverable natural gas reserves on federal lands (onshore), if fully developed, could supply the nation with natural gas for 175 months; 320 bcf available, 1.8 bcf US consumption per month. Technically recoverable natural gas in the Rocky Mountain region could supply the U.S. demand for about 4 years; 86 bcf available, 1.8 bcf US consumption per month. The amount of economically-recoverable natural gas available from federal lands in the Rocky Mountain region is considerably smaller.

Crude Oil

The USGS estimated in 2002 that 92 billion barrels of technically recoverable crude oil remain in the United States (exclusive of Federal waters;

Energy Information Administration 2002). The ultimate technically recoverable volume of crude oil in conventional fields (onshore) not yet discovered was estimated to be 30 billion barrels on federal lands, with 25 percent of these located in the Rocky Mountain region.

During 2003, the U.S. is estimated to have produced around 7.9 million barrels per day (MMBD) of oil. The US contains over 500,000 producing oil wells, the vast majority of which are considered "marginal" or "stripper" wells, generally producing only a few barrels of oil per day. During 2002, top oil producing areas included the Gulf of Mexico (1.6 MMBD), Texas onshore (1.1 MMBD), Alaska's North Slope (0.954 MMBD), California (0.707 MMBD), Louisiana onshore (0.274 MMBD), Oklahoma (0.181 MMBD), and Wyoming (0.150 MMBD).

The U.S. is estimated to be consuming an average of about 19.9 million barrels of oil per day in 2003, up from 19.8 MMBD in 2002. Total 2004 petroleum demand is projected to grow by 420,000 barrels per day, or 2.1 percent. At this rate, the technically recoverable oil reserves on federal lands, if fully developed, could supply the nation with oil for 49 months. Technically recoverable oil in the Rocky Mountain region could supply U.S. demand for about one year. The amount of economically-recoverable oil reserves in the Rocky Mountain States fluctuates with the price of crude oil, but is significantly less than technically recoverable reserves.

Availability of Federal Lands for Energy Development

The vast majority of federal lands within the Rocky Mountain States are available for oil and gas development (US Department of Energy and US Department of the Interior 2003). In fact, about 90 percent of BLM lands within the “Overthrust Belt” allow energy development (see Table 1). The only state that falls below this level is Utah, where 88 percent of the federal lands are available for energy development.

Table 1

State	Acres open to drilling	Acres closed to drilling
Colorado	16 million	600,000 (3.5%)
Montana	18 million	400,000 (2%)
New Mexico	28 million	1.3 million (4%)
Utah	20 million	3 million (12%)

Wyoming	28 million	700,000 (2.5%)

More than 110 million acres -- 31% of the federal land area in the Rocky Mountain Region -- fall within areas known to have recoverable gas and oil. The most well-known of these areas include the Book Cliffs (UT), Grand Mesa (CO), Greater Red Desert (WY), High Plains (NM), Otero Mesa (NM), Powder River Basin (WY and MT), Roan Plateau (CO), Rocky Mountain Front (MT), San Juan Basin (NM), Upper Green River Valley (WY), and Valle Vidal (NM).

Extent of Energy Development on Leased Federal Lands

In certain areas of the West, energy development is occurring rapidly. For example, the Powder River Basin in Montana and Wyoming is in the midst of a rapidly developing boom in exploration and development of coal bed methane reserves. Industry sources and the Bureau of Land Management (BLM) suggest that as many as 40,000 to 50,000 new wells may be developed in this area. With the possible addition of over 10,000 new sites in the Green River Basin alone, and the potential of this huge new development in the Powder River Basin, it is quite clear that the habitat of many wildlife and fish species will be affected directly in various ways as these energy resources are developed.

Similarly, 95 percent of the public land administered by the BLM in the High Plains of eastern New Mexico with technically recoverable oil and gas reserves already has been leased and is being developed for oil and gas (personal communication, Roswell Field Office, Bureau of Land Management). The only areas that remain undeveloped have been reserved by the BLM for lesser prairie-chickens and the sand dune lizard; both of which have been identified by the US Fish and Wildlife Service as needing protection under the Endangered Species Act. Very few prairie chickens have been documented in the leased areas during the past decade and numbers continue to decline to dangerously low levels.

While a great majority (88%) of the federal lands are available for energy development (particularly in the Rocky Mountains), and 32 percent of federal lands in the Rocky Mountains have been leased for this purpose, most of the leased lands in the Rocky Mountain states are not producing any energy (Pace 2004). In fact, of the roughly 36 million acres of federal lands that have been leased for energy development, only about 10 million of these acres actually are producing energy. See Table 2.

Table 2

State	Leased Lands Not Producing Energy (%)

Wyoming	80
Colorado	71
Nevada	99
Montana	83
Utah	77
New Mexico	36

It is not entirely clear why these leased lands are not being developed for energy production. According to the AP report (Pace 2004), the Bureau of Land Management does not have any data on the extent to which these lands have been the subject of exploratory efforts to determine their production potential. Probably many factors are responsible. Difficulties in obtaining leases or permits to drill do not appear to have hindered energy development. As stated previously, three-fourths of the federal lands under lease have not been developed, while over the last decade, more than 25,000 permits have been issued, leading to the drilling of about 19,000 wells. The following factors all may be playing a role in discouraging development of leased lands:

- price volatility in the oil field supply and service sectors (National Energy Policy Development Group 2001),
- fluctuating world prices of natural gas and crude oil, although now it appears that higher oil and gas prices may become the norm,
- some of these leased lands are the subject of existing permits-to-drill applications (APD) that are in various stages of evaluation, but have yet been approved for active drilling,
- some energy companies may be resisting pursuing APDs if they believe that permit stipulations or new requirements to cover the costs of monitoring will make drilling uneconomical, and
- since energy companies list their entire federal lease holdings, including those that are undeveloped, as assets in their financial records, they have an incentive to put as much ground under lease as possible even if they do not have immediate plans to development them (Pace 2004). This asset can attract future investors and may explain why a number of companies have exceeded federal limits on the acquisition of leased acres in any one state.

SECTION II. POTENTIAL IMPACTS OF ENERGY DEVELOPMENT ON FISH AND WILDLIFE HABITAT

Although the physical impacts of traditional oil, gas, and wind developments may disturb a relatively small area, actual production requires an infrastructure that can have significant impacts on fish and wildlife populations and their habitat over large areas. Roads, pipelines, transmission corridors, power poles and lines, guy wires, and related activities can impact surface and ground water, degrade and fragment fish and wildlife habitat, disrupt nesting and calving grounds, and impair migration routes over an entire landscape in which the development is occurring. Densities of oil and gas wells and wind turbine towers of one per section may have minor impacts of the health of fish and wildlife populations, but densities of four to eight wells or towers per section may begin to disrupt animal behavior, and habitat quality and continuity.

Despite the fact that energy development is known generally to harm fish and wildlife in certain circumstances, historically, areas are leased by the BLM before the agency has a complete understanding of specific, local landscape issues, concerns, and potential ecological impacts. Most Resource Management Plans (RMP) were prepared several decades ago, and subsequently probably fail to address the environmental impacts of most new technologies related to energy development. Agency staff and research and monitoring efforts are underfunded, leading stakeholders to question whether the agency has the personnel or data to make appropriate decisions that protect the natural resources on federal lands. In 2001, BLM identified 21 “high priority” RMPs and planned to finalize them within 3 years; most have not been finalized yet in 2004. Many concerned citizens argue that the decision to lease (or drill) vests the lessee with a property right, making the subsequent imposition of restrictions on development difficult at best.

On a local level, landscape changes associated with intensive energy developments are dramatic. Most of these public lands are considered by many to be in relatively pristine condition before energy development begins. In areas where development of the gas or oil resources is extensive (i.e., a high well density), the natural characteristics of the landscape have changed to an industrialized-appearing setting, dramatically affecting the aesthetic appearance of the area, and as noted above, the value of the habitat.

Fish and Wildlife Impacts

More than 50 percent of the healthiest trout streams in the U.S. occur on public land (Stalling 2004). These have high recreational and ecological value. For example, in southwest Wyoming, the Green River, New Fork, East Fork, and other tributaries in the Green River Basin support blue ribbon trout fisheries. Also, Colorado’s Roan Plateau is home to one of the world's most genetically pure populations of Colorado River cutthroat trout. The entire Plateau

demonstrates extraordinary species richness. In fact, the Colorado Natural Heritage Program notes, "We are aware of only three additional areas of comparable size in western Colorado that document such a high richness of species of concern." Extensive oil and gas developments in this area could affect water quality and threaten this important fisheries resource.

Coal bed methane developments often result in significant amounts of ground water pumped to the surface, which frequently is discharged into nearby rivers and streams. The quality of this water is such that it may not be suitable for fish, wildlife, or native vegetation due to high levels of salts, minerals or heavy metals; individual wells can produce up to several million gallons of process water per year. Potential gas and oil developments on public land may occur within 50 percent of Yellowstone cutthroat trout habitat, within 40 percent of fine spotted and Bonneville cutthroat habitat, and within 20 percent of Colorado cutthroat habitat. In addition to direct pollution effects on fish, the primary foods they consume, aquatic invertebrates, may be affected severely by energy development (Stalling 2004).

Energy development can affect bird and bat populations adversely in a variety of ways. Early concerns about wind energy development focused on bird and bat deaths that resulted from collisions with wind generator blades, support structures, and power lines. This was a readily observable phenomenon, so it was easy to garner support for research studies and for corrective actions. There also is significant fragmentation of habitat associated with wind power facilities. Much is unknown about how wind power production affects birds, mammals and other wildlife, but there exists sufficient information to warrant deliberative consideration of the issue. Some recent studies document impacts that are less immediately apparent. For example, recent studies conducted by Kansas State University and Oklahoma State University show that lesser prairie chickens avoid vertical structures (e.g., wind towers, power poles, windmills, barbed-wire fences, trees) and actively-used roads during nesting and brood-rearing, even when the habitat surrounding these developments is in excellent condition. (Manes In Press). Finally, recent evidence of mortality among sage grouse caused by the West Nile virus has led to speculation that process water from coal bed methane operations, which is held in surface impoundments, creates breeding grounds for mosquitoes, the primary vector for this disease (Naugle et al. 2004).

The placement of wells throughout regions used by mammals can be very disruptive and ultimately harmful, particularly to migrating ungulates. For example, for the past decade, accelerated energy development has been underway in southwest Wyoming, with a recent focus on the Upper Green River Basin near Pinedale. About 8,500 wells currently are active in Southwest Wyoming and thousands more are planned. An impressive array of big game animals winter in the Green River Basin. From Interstate 80 north to Pinedale, 15,000 elk, 52,000 mule deer, 40,000 pronghorn, 3,500 moose, and 150 bighorn sheep all depend on these habitats. Mule deer and pronghorn in this basin travel farther between winter and summer ranges than any other population in North

America. Development that forces animals to take significant detours around efficient migration routes can lead to greater expenditures of energy in winter months and result in higher mortality. Without a coordinated and well-planned approach to energy development on this public land, migration corridors and basic habitat used by this rich wildlife resource could be impacted severely.

Economic Impacts

Impacts on fish and wildlife have far-reaching economic effects in the recreation-based economy of the region, fueling local concerns over energy development. Supporting a population of about 10 million people; the area has nearly 1.5 million anglers, 700,000 hunters, and 2.6 million citizens who simply enjoy hiking, camping, and watching wildlife in these beautiful landscapes. Nearly 4 million residents of other states and countries visit the area to hunt, fish, or watch wildlife.

Rural towns report that half of their annual income is collected during fishing and hunting seasons by motels, restaurants, grocery stores and the like. The U.S. Fish and Wildlife Service's 1996 National Survey of Hunting and Fishing indicates that annually $1.8 billion in retail sales and 43,000 jobs are realized by the states in the Northern Rocky Mountains from hunting alone; add fishing and observing wildlife, and the value is about three times that figure. Together, they contribute more than $5.2 billion per year to local economies in the region. These are long-term, substantial benefits that accrue regularly to local communities only if fish and wildlife and their habitats are relatively secure, absent irreparable harm to the natural resources of the region. This is one reason why local residents have become increasingly more engaged in the permitting process.

SECTION III. THE PERMITTING PROCESS

Under federal law and regulation, the permitting process for oil and natural gas development theoretically involves a number of steps that begins with a landscape-level evaluation of the federal lands in question and ends with the issuance of permits, including protective stipulations designed to allow for the environmentally-responsible development of a discrete area. If the federal agencies were able to carry out this process in a manner that always was faithful to the letter and spirit of the law and was based on extensive scientific research, then conflicts over the implementation of the energy development program could be minimized. The fish and wildlife needs of these areas would be well reviewed and understood; Resource Management Plans (RMPs) would reflect not only the best science, but also a transparent public process that was fully informed of the needs of the resource. At the end of the process, the public would have a high degree of confidence that natural resources were being protected as energy development took place.

Instead, the imperfect implementation of this process, due in part to resource constraints faced by the federal land management agencies, interacts synergistically with the philosophical tensions over the appropriateness of energy development of federal lands to create a controversial program that does not fully satisfy any stakeholder group.

Critics of energy development on federal land argue that the highest and best use of these lands is for other uses, such as hunting, fishing, recreation and wildlife viewing. Moreover, they point out that federal land management agencies are not able to implement this process consistently in an ideal fashion due to lack of funding and related staffing resources and for other reasons (Horwitt et al. 2004). Many of the RMPs have not been revised in years. Delays in processing lease and permit applications routinely occur, averaging 84 days to process an Application for Permit to Drill (APD) in 2001 (range = 34-197 days), whereas, state agencies that oversee energy development on state lands in the Rocky Mountains report that they are processing similar permits in an average of 9 days (Independent Petroleum Association of Mountain States 2002). The lack of monitoring data hampers the establishment of permit stipulations that are adequately protective of the resource. In short, even assuming that there is agreement among stakeholders that the federal lands should be managed to accommodate, to the extent possible, a wide range of extractive and non-extractive uses, the process is not implemented in a manner capable of fairly and effectively achieving that goal.

Resource Management Planning

Under federal law and agency regulation, the basic energy development permitting process completed by the BLM is supposed to begin with a landscape-level evaluation of the natural resources and potential impacts. This evaluation

should be included in and form the foundation of a Resource Management Plan (RMP). The landscape-level evaluation completed by the BLM should include an inventory and evaluation of important fish and wildlife resources and the impacts on those resources from extensive energy developments. Once the RMP is drafted, the BLM is required under law (National Environmental Policy Act 1969) to invite the public to provide comments on the plan for a specific time period, usually 60 to 90 days. The BLM then must finalize the RMP based on the information provided by the public, and the agency must be responsive to the concerns expressed by the public. The decision documents that authorize leasing of public land administered by the BLM often predate some existing environmental laws and RMPs. However, if the existing decision documents do not address the impacts of new decisions, such as developing energy with new technology, e.g. coal bed methane extraction, then an environmental analysis of those impacts of those new technologies must be completed.

Environmental Evaluations

Once the RMP is finalized, the BLM must prepare an environmental assessment (EA), environmental impact statement (EIS), or a coordinated activity plan (CAP) to provide a more detailed evaluation of the resources and impacts of development within specific areas. At this point, the BLM often will decide to offer to sell leases for energy development on those specific areas covered by the RMP that have the greatest potential for energy development. Also at this point, the BLM may decide to apply stipulations needed to mitigate the impacts of development on fish and wildlife or other natural resources. Stipulations from an RMP would then be adopted within a subsequent EA, EIS, or CAP. Again, the BLM must invite the public to review and comment on these documents (EA, EIS, CAP) and address their concerns before the documents are finalized (a NEPA requirement). Usually, a 30- to 60-day comment period is provided, but a longer timeframe may be necessary if the agency determines extraordinary resource concerns may surface from the public.

Permits to Drill

Once a lease is sold, the lessee then submits one or more applications for permits to drill (APD) at their convenience, but within the term of the existing lease. When the BLM receives an APD, the agency is required by law to complete a more site-specific evaluation of the natural and cultural resources and impacts of development. When the BLM gets to the site-specific APD stage, they should be able to determine potential impacts on natural and cultural resources and select the appropriate stipulations from the EA, EIS, or CAP to be applied under that permit. This tiered approach ensures that stipulations are applied only in areas when and where they are determined necessary. Often, this is where

the most specific and detailed stipulations must be developed by the BLM to protect fish and wildlife habitat and other natural resources.

Stipulations

To minimize the effects of energy development on fish and wildlife, the BLM often will develop protective stipulations that are designed to control where and when development may occur. The BLM may grant energy developers exceptions from these protective stipulations. The restrictive stipulations applied to leases are a point of contention between those who seek to expand development and those concerned about the effects of development on fish, wildlife, and water resources. Protective stipulations have been viewed by some as a complicated patchwork of requirements that increase costs and delay energy development activity. Lands are not as heavily restricted, however, as some may imply. All leased lands are subject to Standard Lease Terms, and additional stipulations are applied only as needed to protect fish, wildlife, or other resources.

Only 25 percent of public lands in the Rocky Mountain West are subject to any added stipulations beyond the Standard Lease Terms. Standard Lease Terms generally are applied to all leases, regardless of special circumstances. These include prohibiting development on slopes of 25 percent or greater, within 500 feet of riparian areas, and on saturated or frozen soil.

Stipulations are mandatory mitigation measures that are applied to a lease or application for permit to drill (APD). As development brings about conflicts, stipulations function as the only protection to ameliorate these impacts on fish and wildlife. Below are a few examples of actual stipulations used by the BLM to reduce the impacts of energy development on fish and wildlife:

Upland Birds

- **Impact:** Lesser prairie chicken and sage grouse nest initiation and success often are reduced because of noise, vertical structures and human activity,
- **Protective Stipulation:** Restrict energy development activities from February 1 to July 31 each year and limit drill rigs in area to no more than two at any one time;
- **Impact:** Noise disrupts lek (male display areas) attendance by sage grouse and lesser prairie chickens,
- **Protective Stipulation:** Restrict energy development activities from midnight to 9:00 a.m. during breeding season;

Elk

- **Impact:** Elk avoid areas with active energy development, and critical winter habitats may be abandoned for less favorable habitats,
- **Protective Stipulation:** Restrict energy development activities on crucial elk winter range from November 15 to April 30;

Deer

- **Impact:** Harassment reduces deer recruitment rates (reproduction),
- **Protective Stipulation:** Restrict energy development activities from May 1 to June 30 on big game parturition (fawning) areas; and

Trout

- **Impact:** Roads contribute to sedimentation into rivers and streams, trout reproductive success is reduced in rivers and streams with heavy sedimentation,
- **Protective Stipulation:** Measures to decrease erosion and impacts on water quality include avoidance of slopes >25 percent, 500 ft. of riparian areas, and avoiding construction when soil is frozen or saturated.

Stakeholders

Stakeholders play an important role in the permitting process, particularly in identifying issues and concern that must be considered before public land is leased and developed for energy. There are at least two general types of stakeholders that participate in the permitting process:

- Local residents; and
- Regional and national interest groups.

Local Residents: This group includes those who, as a result of their physical proximity to the development, must live with any economic, social, and ecological impacts related to energy development. Some in this group may perceive the ecological impacts as negative, but many will view the economic and perhaps social impacts of energy developments as positive. These people must live with the day-to-day impacts of developments and they can see these impacts in their every-day lives. The bottom-line concerns for this group often are related to quality of life issues.

Regional and National Interest Groups: This group of stakeholders tends to take a broad look at the impacts of energy development. Often they are concerned with the widespread economic gains of energy development, or they may be threatened by the ecological impacts of tens of thousands of wells and related infrastructure. These stakeholders may not be concerned about the impacts of any specific development, but rather, they are concerned about energy extraction over large landscapes. These people may live and work in the local area or they may be from great distances away from the area, but they express their concerns in the permitting process through comments and, in some cases, litigation.

Stages of Energy Development on Federal Lands

In considering federal policies to govern energy development on federal lands, it is useful to think of three stages of development:

- Federal lands where leasing of recoverable gas and oil reserves has not occurred;
- Federal lands where leasing of recoverable gas and oil reserves have been leased but have not been fully developed; and
- Federal lands where leasing of recoverable gas and oil reserves already has been completed and resource extraction is fully developed.

Federal Lands where Leasing of Recoverable Gas and Oil Reserves has not Occurred: Five states in the Rocky Mountain region contain about 110 million acres of federal land (32% of the total land area of the region; Stalling 2004). Seventy-four million of those acres have not yet been leased for mineral development because of concerns about threatened or endangered species, other important natural resources, or because the technology to develop potential energy resources was not available. Once development occurs, the condition of fish, wildlife, and water resources in the area often changes dramatically. Two important questions need to be answered by policymakers regarding these lands. First, do some of these lands deserve to be placed off limits to development as a result of their aesthetic value, competing economic value, such as tourism or hunting, fishing and other types of outdoor recreation, or because they provide unique habitat for sensitive species? Second, if they are going to be developed, what restrictions should be imposed to ensure that energy development is compatible with other uses of the land?

In answering these questions, policymakers need to determine if sufficient scientific data exist, and what the public desires and expects these lands to

provide. In this regard, involving stakeholders at the earliest phases of the energy permitting process is essential to avoid not only unnecessary disturbances to fish, wildlife, and water, but also to ensure that energy development is not incompatible with other public economic, recreational, and aesthetic expectations for those lands. The BLM can expect considerable controversy associated with any energy development proposals that appear to be on the "fast-track" (Stalling 2004). The basic energy development permitting process described in Section III should be adopted fully by the BLM for these undeveloped public lands.

Federal Lands where leasing of Recoverable Gas and Oil Reserves have been Leased but have not been Fully Developed: Of the roughly 36 million acres of onshore federal lands in the Rocky Mountain region that have been leased for energy development, about 25 million acres (71%) have not yet been developed, and consequently, are not producing energy (Stalling 2004). There is an expectation that these lands will be developed for energy, and they are attracting considerable and immediate attention from energy developers and public stakeholders who are concerned about the potential impacts of energy development. The BLM has not had the funds or staff to considered the impacts of potential energy developments on fish, wildlife, or water resources prior to leasing. As a result, the initial leasing decisions may not have addressed all resource concerns related to subsequent development efforts. If the agency failed to address some resource issues prior to leasing, then it is likely that considerable conflict will lie ahead for the BLM, the lessee, and the respective stakeholders. These lands are expected to be the main near-term battlegrounds in the ongoing debate over the appropriate use of federal lands in the West. To minimize conflicts over subsequent permitting and development decisions, which can slow the process, generate uncertainty, and discourage development, the federal agencies will need to do a better job of involving the public as early and as often as is reasonably appropriate in each stage of the permitting and development process.

If the BLM fails to adequately involve the public in the early stages of the planning, leasing and permitting process for these lands, they should provide the public with an opportunity and a reasonable time frame to review existing plans, environmental documents, lease proposals and the entire energy development permitting process for the area. If the public identifies legitimate concerns during this comment period, then the agency should attempt to address the concerns in a timely manner and amend existing environmental documents, leases, permits and plan accordingly. This may include the collection of additional data on the impacts of energy development on other resources. If additional stipulations need to be added to existing or pending permits or leases, then the agency should modify them accordingly.

Federal Lands where Leasing of Recoverable Gas and Oil Reserves already has been Completed and Resource Extraction is Fully Developed: Of the roughly 36 million acres of federal lands in the Rocky Mountain region that

have been leased, about 11 million acres (30%) have some level of energy development (Stalling 2004). In most of these cases permits have been issued, development is ongoing and impacts on fish and wildlife from development probably have occurred. As a result, attempting to involve stakeholders at this late stage in a meaningful way is very difficult. Nevertheless, agencies can monitor the impacts of existing and expanding developments on fish and wildlife and identify ways to help ameliorate impacts that are identified in the process. Since extensive development already has occurred on these lands, the primary public interest is in ensuring that ongoing operations are conducted in a manner that minimizes natural resources damage or disruption of fish and wildlife populations. This includes determining the appropriateness of waiving stipulations and ensuring that these areas are appropriately reclaimed once energy development is completed.

One of the main challenges facing federal land managers in the future on these lands will be to remove drilling rigs no longer in use from the landscape and restore the habitat to a beneficial state. Large, national and multi-national energy companies should have the resources and incentives to ensure that they behave responsibly in this regard. Smaller companies, that have fewer financial resources and may not be concerned about protecting a national reputation, may be less inclined to ensure that they reclaim these lands when it is no longer economical to pursue resource extraction. Federal policymakers and land managers will need to ensure that plans are developed to reclaim these lands and financial resources are available to implement those plans (Western Organization of Resource Councils 2004).

SECTION IV. FACILITATED MEETINGS IN NEW MEXICO, WYOMING, AND WEST VIRGINIA

To examine the implementation of the federal energy development program in the West, a number of stakeholder meetings were held in 2003 and 2004. Hunting, angling, and conservation organizations encouraged the Bureau of Land Management and the respective state fish and wildlife management agencies to conduct professionally facilitated stakeholder meetings that would lead to the development of a model for decision-making consistent with existing planning processes of federal and state land management agencies.

The resulting meetings brought together 20 to 40 representative stakeholders interested in the effects of energy development on water, wildlife, and fish resources, including BLM, U.S. Fish and Wildlife Service as observers, the USDA Natural Resources Conservation Service, oil and gas company representatives, conservationists, environmentalists, and state government officials (see Appendix I and II).

The meetings provided an opportunity to evaluate the strengths and weaknesses of the program and determine whether there are specific steps that can be taken to make the federal land energy development process work more effectively for all interested parties. Formal reports from the facilitated stakeholder meetings are attached at the end of this report as Appendices I and II.

SECTION V. A MODEL PROCESS TO PROMOTE ENERGY PRODUCTION ON FEDERAL LANDS

While philosophical debates will persist with respect to the basic question of the appropriateness of energy development on federal lands in the West, specific reforms in the permitting process could be implemented that would reduce public anxiety over the program and, in some cases, even speed energy development.

The basic energy development permitting and leasing process to be completed by the BLM should begin with a landscape-level evaluation of the cultural, natural, and physical resources and potential impacts over the planning landscape. This evaluation should form the foundation of a Resource Management Plan (RMP). Once the RMP is drafted, the BLM should invite the public to provide comments on the plan. This comment period should be consistent with the complexity of the RMP, but at least 60 days. The BLM then should analyze the public comments, seek reasonable solutions to public issues and concerns, and finalize the RMP based on this information.

Once the RMP is finalized, the BLM should complete an evaluation of the environmental impacts of proposed energy leasing and subsequent developments on the cultural, natural, and physical resources within areas for potential leasing via an EA or an EIS. At this point, the BLM should identify and apply stipulations needed to protect or mitigate the impacts of development on other resources. The BLM should not offer to sell any leases for energy development until these protective stipulations have been identified and can be incorporated into the lease offer. The basic concept is that each phase enables the BLM to make a more specific evaluation. Stipulations from an RMP are adopted within a subsequent EA or EIS and then again in specific lease offers and APD approvals. Again, the BLM would invite the public to review and comment on the EA or EIS and address public issues and concerns before the documents are finalized. The comment period should be commensurate with the complexity of documents reviewed, at least 30 to 60 days.

Once a lease is sold, the lessee would submit one or more applications for permits to drill (APD) that address not only the proposed development activities, but also how they plan to incorporate the protective stipulations into their operation. Along with the APD, the lessee should be required to submit a Plan of Development (POD) for each energy development project. Lessees seeking to develop a energy project on BLM-administered lands should be required to develop a project-specific POD that incorporates all proposed best management practices (BMPs) and, as appropriate, the requirements of other, existing and relevant BLM mitigation and guidance. It should include a site plan showing the locations of proposed roads, drill pads, power lines, other infrastructure, and areas of short- and long-term disturbance.

Once an ADP and POD are received by the BLM, the agency would complete a site-specific evaluation of the cultural, natural, and physical resources and

impacts of the proposed development. When the BLM gets to the site-specific APD stage, they should be able to determine potential impacts and select the appropriate stipulations from the EIS to be applied under that permit. This tiered approach ensures that stipulations are applied only in areas where and when they are determined necessary, and that the lessee will not be surprised with new stipulations that were not disclosed in the approved lease and ADP. Often, this is where the most specific and detailed stipulations are developed by the BLM to protect fish and wildlife habitat and other natural resources. To avoid contention among the BLM, the lessees, and the public concerning restrictive stipulations, sufficient information and data should be provided in the RMP and associated environmental documents to clearly explain why the protections are necessary.

Key Differences Between the Ideal Process and the Actual Process

The primary differences between our proposed model for the development of federal energy resources and the actual process that often is employed by the BLM are:

- a landscape-level inventory of cultural, natural and physical resources should be completed prior to leasing;
- impacts of potential energy development on other resources should be evaluated fully and disclosed in the RMP;
- stipulations to protect resources should be developed in the RMP and refined as new and more site-specific information is gathered;
- the BLM should require energy development lessees to submit plans of development at the same time that they submit applications for permits to drill; and
- public review and comments should be regular and frequent and should be addressed clearly in all associated documents.

Our model requires more time at the outset to collect and analyze data, develop protective stipulations, and involve the public. In comparison, the current process involves more time addressing public concerns, appeals and litigation at the end. We believe our model ultimately will reduce time and frustration for all stakeholders. This is because if public concern, appeals, and litigation occur after an RMP and associated environmental documents are completed, leases are let, APDs are approved, or protective stipulations are waived, long delays and contention among stakeholders often will occur.

SECTION VI. CONCLUSIONS AND RECOMMENDATIONS

The New Mexico, Wyoming, and West Virginia meetings, which provided a forum for airing the concerns and objectives of a number of interested stakeholders, were very useful in crystallizing the issues, identifying common ground, and in pinpointing the strengths and weaknesses of the current processes.

Conclusions

There are a number of conclusions that can be drawn from an evaluation of current energy development efforts on federal lands in the West:

- The vast majority of federal lands — roughly 90 percent — are open to energy development;
- Three-fourths of the 36 million acres of federal lands (onshore) that currently are leased for energy development are not producing any energy;
- The current leasing and permitting process is not a substantial hindrance to developing federal lands for energy, but it could be improved;
- Fluctuations in the price of oil field supply and services, as well as the historically low world oil and natural gas prices have hindered investment in efforts to develop leased lands;
- Consistently higher prices for oil and natural gas, which we currently are experiencing, may lead to greater investment in exploration and production on leased and permitted sites;
- Fully developing energy resources on federal lands will not significantly reduce U.S. dependence on foreign sources of natural gas and oil, but could have positive localized economic impacts;
- The federal lands leasing program is underfunded, leading to lack of data necessary to protect natural resources and leading to delays in the leasing and permitting process;
- Federal energy policy can marginally encourage greater energy development on federal lands by reducing royalty payment requirements and fully funding federal land management agencies so that applications can be processed more rapidly;
- There is little public confidence in the ability of federal land management agencies to adequately protect natural resources with the current state of data gathering, leasing, establishment and enforcement of permit conditions, ongoing monitoring and program funding.

Discussion of Conclusions

The availability of federal land is not a significant impediment to energy development. Nearly ninety percent of federal lands are available for energy development. However, roughly two-thirds of the federal lands that have been leased for energy development are not producing any energy, suggesting that the ability to obtain leases is not a serious impediment to energy development.

Some of the reasons why energy development is not occurring on federal land are outside the control of federal policy-makers. For example, fluctuations in the world market price of oil and natural gas will largely determine the profitability of investing in new production.

Federal policies can marginally improve the economics of production through adjustments to the federal royalty payment rates. Moreover, increasing funding for the federal agencies to implement the energy development program will reduce lease- and permit-application processing delays. The fact that energy companies have leased considerably more land than they currently are developing may indirectly encourage increased production. Since energy companies are able to list federal lands under lease in their financial statements, and more easily refinance debt, it ultimately may improve the financial strength of the industry and make more capital available for exploration. This, in turn, could lead to greater production. However, until world crude oil and natural gas prices stay consistently high, energy development companies may find it more profitable to invest in marginally-productive domestic wells.

A legitimate hindrance to energy development may be the delay, and hence uncertainty, in obtaining permits to drill. The chronic underfunding of the federal agencies contributes to this problem, and both industry and conservation organizations agree that full funding would substantially improve the process for all concerned. At the same time, there is little confidence among many stakeholders that the land management agencies, using their current leasing and permitting procedures, are capable of adequately protecting natural resources from the effects of energy production.

Recommendations

Three overarching recommendations naturally flow from the conclusions described above:

- Substantially improve the leasing and permitting process to ensure that energy development is approved only in places and with stipulations that avoid adverse impacts on natural resources;
- Fully fund the federal agency staff working on energy development, so that more data on fish, wildlife and their habitat needs can be collected

and evaluated, better natural resource planning can be done, and decisions to grant leases or permits can be made without delay;

- Reduce federal royalty payment requirements on lands determined by new RMPs to be of negligible value to fish and wildlife.

I. Improve the Leasing and Permitting Process

The acceleration of leasing activity in recent years, along with Executive Order 13212 (Bush 2001) and the issuance of related memos in 2003 from BLM headquarters (United States Department of the Interior Bureau of Land Management 2003), providing direction to field officials, led to the perception that energy development has taken a higher priority than other uses of these federal lands. Based on the issuance of these policies, some stakeholders are concerned that resource uses such as grazing, hunting, fishing, other forms of public recreation and science-based fish and wildlife management may be neglected in the rush to develop federal land energy resources.

Moreover, at least 90 percent of the existing 162 BLM land use plans (RMPs) are out of date and agency staff and research and monitoring efforts are chronically underfunded, leading stakeholders to question whether the agency has the personnel or data to make appropriate decisions that protect natural resources on federal lands. In 2001, BLM identified 21 “high priority” RMPs and planned to finalize them within 3 years; most have not been finalized yet in 2004. Many stakeholders do not believe that leasing and permitting decisions are made with a fully informed understanding of the ecological significance of these lands or public expectations for competing uses. This is true particularly in places where leasing decisions were made in the absence of updated RMPs, or any landscape-level analysis of resources.

The belief that federal agencies have placed energy development above all other uses of these lands has led to a more combative attitude that threatens to generate more confrontation, uncertainty, and delay for all involved. For example, a Wyoming BLM field office recently published in local newspapers that they would be selling energy leases in the Pinedale area. Mule deer and antelope in this basin travel farther between winter and summer ranges than any other population in North America, and the proposed leases were located directly on top of these migration routes. At a subsequent stakeholder meeting, the public expressed extreme aggravation over the BLM’s decision to sell the leases without consideration of these migratory herds and their habitats. Eventually, the BLM withdrew the leases and has since taken the time to incorporate considerations for wildlife into the process. This also undermines public support for legitimate types of energy development on federal lands. Before taking steps to accelerate energy production on federal lands, these issues need to be adequately addressed so that confidence in the program from all stakeholders can be established. Recommendations to improve the process are divided into

general recommendations and into three additional categories, based on the stage of development discussed above:

- Federal lands where leasing of recoverable gas and oil reserves has not occurred;
- Federal lands where recoverable gas and oil reserves have been leased but have not been fully developed; and
- Federal lands where leasing of recoverable gas and oil reserves already has been completed and resource extraction is fully developed.

Not only will these proposed changes help minimize the impacts of this activity on fish and wildlife populations and their habitats, public recreational opportunities, and local tourist-based economies, adopting common-sense reforms will increase the public acceptability of this program in the future. Ultimately, energy development should be done with much more attention to detail and with careful evaluation of a broad range of costs and benefits, including intangible costs and benefits that are important to various stakeholders. In doing so, the federal agencies in charge of these lands should make much greater efforts to avail themselves of the expertise of various stakeholders, including state agencies and local associations, in determining whether certain lands should be leased at all, in evaluating the adequacy of data to make such decisions, and in establishing temporal and spatial limits to development.

A. General Process Reform Recommendations

Improve Monitoring

Current monitoring efforts by federal and state agencies of the effects of oil and gas development on fish, wildlife, and water resources are extremely limited by funding and adequately trained staff. Most BLM field offices have one or fewer trained fish or wildlife biologists, and most of those report that they spend little time working on fish and wildlife management issues. Instead, they are overwhelmed by environmental documents, appeals, public meetings, and litigation. When monitoring data are collected, generally they lack statistical validity and are rarely based on sound science.

The federal agencies should seek the assistance of state fish and wildlife agencies to review their monitoring needs and develop a strategy to fund and undertake necessary monitoring in order to:

- Determine which areas are appropriate for energy development, and, importantly, which are not appropriate, based on the dependence of these areas for habitat by fish and wildlife species, the susceptibility of those

species and their habitat to energy development, and the aesthetic demands of the public;

- Understand the development practices that are most detrimental to fish and wildlife, and to adjust management decisions accordingly;
- Establish a baseline for evaluating changes due to energy development activity, since in less than 5 percent of cases is there adequate baseline data from which to evaluate changes; and
- Document changes in wildlife migration patterns, water quality and quantity, fish and wildlife reproductive success and associated habitats, and other impacts on species due to energy development.

Only by implementing a comprehensive and readily accessible monitoring program will the federal agencies be able to justify decisions to lease and permit new areas and shore up public confidence in the energy development program. Effective gathering of complete and credible information is necessary for appropriate prioritization of monitoring efforts in order to focus on the most critical species, problems, and needs. Not only is it important to be clear about why and when monitoring is needed, it is equally important to understand and identify when and/or where it is unnecessary and should be discontinued. Continuation of monitoring activities in places or at times beyond which it is no longer useful, diverts limited agency and industry resources from other areas with critical monitoring needs.

Effective monitoring is more than merely counting numbers of individuals or species. In order to understand the impacts of land use activities on populations, other factors that can affect species viability need to be measured, such as survival and recruitment. The agency monitoring plans should include the following elements:

- Goals of the program;
- Secured funding;
- Monitoring targets;
- Duration of monitoring under various circumstances;
- When will the monitoring take place;
- Whether the agency or industry should pay for the monitoring;
- What skills are necessary to and who will conduct the monitoring;
- How the monitoring data and information will be stored and retrieved (data should be stored electronically and securely available to all interested parties); and

- Most important, how the monitoring data and information will be used to adjust management practices as warranted and necessary.

Clarify Roles of Stakeholders

There needs to be clearer agreement on the roles/responsibilities/timing for involvement by BLM, state fish and game agencies, industry, contractors, citizens/NGOs in monitoring plans. The agency should seek opportunities to enhance the role of individuals and interest groups while assuring credibility of data and standards, and transparency of the process. BLM has ultimate responsibility for "monitoring the monitoring", and is the final decision maker about all aspects of monitoring programs as they relate to federal minerals and for initiating action to correct problems. Decisions on energy development should be made carefully, based on specific consideration of geographically distinct areas and impacts on wildlife populations and their seasonal ranges. So far, non-energy development interests such as state fish and wildlife agencies, private conservation organizations, and hunters and anglers, do not play a significant role in decisions over whether to open federal lands to more exploration and development.

Affirm Multiple Use Management of Federal Lands in Leasing Decisions

There is a growing perception that energy development has become the top priority for use of the federal lands in the West. This has contributed to a sense of unfairness among many of the stakeholders and exacerbates the potential for conflict over leasing and permitting decisions. Some additional guidance is needed to federal land field managers to clarify the multiple-use mandate. It appears that these managers seem to operate primarily under an accelerated leasing mandate that allows the deferment of existing problems until well after leases have been sold.

Therefore, the BLM should reaffirm its commitment to multiple use, and issue direction to field offices to sell new leases and to authorize development only when reliable information on the natural resources that affect other uses, such as hunting, fishing, water resources, bird watching and camping is available. The President's mandate of orderly development of energy resources in an environmentally safe manner would benefit from top-level clarification of responsibilities to meet this goal (Remarks by the President on Energy Independence. February 6, 2003. The White House Office of the Press Secretary).

B. Recommendations for Federal Lands where Leasing of Recoverable Gas and Oil Reserves has not Occurred

These lands include roughly 74 million acres of unleased federal lands. The BLM and the Department of the Interior have an established track record of

approving most if not all Applications for Permits to Drill (ADP) once a lease has been sold. This usually means that if the BLM puts a lease up for sale without including protective stipulations within the lease offer, then the ADPs that follow approval of the sale likely will be approved by the BLM without any protective stipulations. As a result, more work needs to be done at this stage — prior to leasing — to determine the appropriateness of these lands for subsequent development. Two important questions need to be answered by policy makers regarding these lands. First, do some of these lands deserve to be placed off limits to development as a result of their aesthetic value, competing economic value, such as tourism or hunting, fishing and other types of outdoor recreation, or because they provide unique habitat for sensitive species? Second, if they are going to be developed, what restrictions should be imposed to ensure that energy development is compatible with other uses of the land? Ideally, these decisions should be made as part of the RMPs as they are being revised, following clear guidance from the heads of the federal land management agencies to the staff performing this work.

Involving stakeholders at the earliest phases of the energy permitting process to identify public expectations regarding the use of specific areas of federal land and important fish and wildlife habitat is essential to avoid not only unnecessary disturbances to fish, wildlife, and water, but also to ensure that energy development is not incompatible with other public economic, recreational, and aesthetic expectations for those lands. This stakeholder input should be solicited during the RMP revision process and used to shape the final RMPs.

Set Aside Unique and Important Areas

The Administration should acknowledge that some federal lands that may be technically eligible for energy development are simply too important for other uses to allow for this purpose. Within six months, specific policy criteria should be developed to assist managers in identifying and protecting these places and specific guidance should be issued to ensure that such a review and subsequent action takes place in a timely manner.

The designation of Areas of Critical Environmental Concern (ACECs) by the Bureau of Land Management is authorized in Section 202 (c)(3) of the Federal Land Policy and Management Act of 1976 (FLPMA, P.L. 94-579). Once designated, these ACECs are managed to protect and maintain specific resources within that area. Unlike Wilderness designation by Congress, the BLM may continue to manage multiple resources within the an ACEC as long as they do not threaten the specific resources of concern within that area. ACECs include public lands where special management attention and direction is needed to protect and prevent irreparable damage to important historic, cultural, and scenic values, fish or wildlife resources or other natural systems or processes; or to protect human life and safety from natural hazards. ACEC designation

indicates BLM recognizes the significant values of the area and intends to implement management to protect and enhance the resource values.

ACEC designation and management prescriptions apply only to public lands and minerals activities on Federally reserved mineral estate. Private lands within or adjacent to ACEC boundaries are not affected by these designations or management prescriptions. Existing permittees and other authorized land uses are recognized as valid and grandfathered rights to the extent applicable under the land use authorization. In addition to the identification of areas to be designated as ACECs, the RMP outlines management objectives and prescriptions for each ACEC. The management objectives and prescriptions provide guidance for the BLM to implement a resource management regime for the special resources of the area, in responding to public uses of the areas and in responding to applicants for land use authorizations. All ACECs are considered land use authorization avoidance areas, as they are known to contain resource values that will pose special constraints for and possibly denial of applications for land uses that can not be designed to be compatible with the management objectives and prescriptions for the ACEC.

Should additional management direction beyond that included in this RMP become necessary to meet management objectives, deal with public uses or respond to applications for land use authorizations, an activity plan may be prepared for the ACEC. All parties of interest, including private landowners, permittees, other state and federal agencies and local governments, should be encouraged to become involved in the activity level planning processes.

Take a Conservative Approach to Leasing

Currently, there are more than twenty "Time Sensitive" Resource Management Plans (RMPs) being revised by the BLM. The Administration has mentioned several times it would like the fish and wildlife community to let them know where problems lie with the existing RMP process. This planning process should be a means to forestall leasing in areas of known resource importance to fish and wildlife. For example, the RMP process should allow appropriate conservation input to be provided by state, federal, or private partners before irreversible commitments are made by selling leases. Nevertheless, the BLM on August 3, 2001 issued an Instruction Memorandum (United States Department of the Interior Bureau of Land Management 2003) that instructed BLM field managers to issue leases and drilling permits on lands that are the subject of uncompleted plans, reversing existing policy. Erring on the side of caution, and returning to the policy of withholding decisions pending completion on revised RMPs would help minimize controversy and help build public trust among fish, wildlife, and water interests.

Identify Issues of Concern Prior to Announcing Leasing Opportunities

Fish and wildlife resources and recreational and historical sites should be identified in advance of leasing or other actions through a well-documented, highly publicized process. Too often, the public, not the BLM, must identify issues for public discussion and informed resolution; the reverse should be the case. Given the high profile of some issues, the BLM should go beyond just "scoping" and *pro forma* public processes. The BLM must take the lead and call together the public and other interests to explore opportunities to avoid specific problems prior to decisions about leasing, as well as afterward as problems arise.

Maintain Federal Control and Management Flexibility

The federal land managers should include in all leases a standard stipulation that preserves the government's flexibility to control and, if necessary, to prohibit activities on leases that prove to pose risks to important fish, wildlife, and water resources. If, for whatever reason, an area is leased in the absence of sound information on fish, wildlife, and water resources, then the BLM might decide to address site-specific information in the Application for Permit to Drill (APD) process. Unfortunately, by the time the APD process is underway, energy companies are viewed by the BLM as maintaining a "right" to develop energy resources. Consequently, habitat and other resource conservation measures are perceived as implying a federal "taking" of a private right. Administrative or congressional authority is needed to protect important fish, wildlife, and water resources in a more adaptive and flexible manner.

C. Recommendations for Federal Lands where Recoverable Gas and Oil Reserves have been Leased but have not been Fully Developed

Of the roughly 36 million acres of federal lands in the Rocky Mountain region that have been leased for energy development, about 25 million acres (70%) have not been developed and consequently are not producing energy. In these areas, there is an expectation that there will be future development, so they are attracting considerable and immediate attention from energy developers and public stakeholders who are concerned about the potential impacts of energy development. The federal land manager may or may not have considered the impacts of potential energy developments on fish, wildlife, or water resources. As a result, questions may arise about the legitimacy of the initial leasing decisions and about subsequent development efforts.

These lands are expected to be the main near-term battlegrounds in the ongoing debate over the appropriate use of federal lands in the West. To

minimize conflicts over subsequent permitting and development decisions, which can slow the process, generate uncertainty, and discourage development, the federal agencies must involve the public as early and as often as is reasonably appropriate in each stage of the permitting and development process. There is relatively little that can be done at this stage to avoid conflict if earlier decisions have failed to adequately address public concerns.

Revisit Leases Issued without Sufficient Data

Consistent with the recommendation above, we believe leases already sold with insufficient information on wildlife, fish, and water resources should be revisited and some action taken if indeed parcels with critical fish, wildlife, or water resources are involved. Whether leases should be modified, or some other actions taken through cooperative work, should be left to field BLM offices to determine. However, fish, wildlife, and water resource values should not be abandoned because of inappropriate leasing. Otherwise, opportunities to carefully develop energy resources, in stages, will be subject to controversy and litigation, and potentially, foregone.

D. Recommendations for Federal Lands where Leasing of Recoverable Gas and Oil Reserves already has been Completed and Resource Extraction is Fully Developed

Of the roughly 36 million acres of federal lands that have been leased in the Rocky Mountain region, about 11 million acres (30%) have some level of energy development. In most of these cases, permits have been issued, development is ongoing and impacts on fish and wildlife from development in these areas probably have occurred. Since extensive development already has occurred on these lands, the primary public interest is in ensuring that ongoing operations are conducted in a manner that minimizes natural resources damage or disruption of fish and wildlife populations. This also should include determining the appropriateness of waiving stipulations, and in ensuring that these areas are appropriately reclaimed once energy development is completed.

Evaluate Impacts of Stipulation Waivers

The practice of federal agencies waiving permit stipulations has contributed to the public controversy over the program and to the perception that environmental concerns are less important than the efforts to extract energy. Changes can be made to stipulations through waiver, modification, and exception. A waiver removes a stipulation entirely from a lease or APD, but waivers are rare; so are modifications, which change the content of a stipulation. Exceptions, however, commonly are granted. An exception is a one-time, case-

by-case exemption from a lease stipulation or a permit condition of approval for a certain portion of a lease. Exceptions ensure that seasonal restrictions are not applied when seasonal weather patterns determine them to be unnecessary. The BLM often can and does grant exceptions to seasonal restrictions if the agency wildlife biologist, in consultation with the state wildlife agency, determines that granting an exception will not jeopardize the population being protected. Field Offices also must consult with the USFWS when threatened and endangered species are involved.

Exceptions are granted with great frequency by BLM field offices. As referenced above, seasonal weather patterns can sometimes create situations where stipulations are not needed. The exceptions that cause the most concern in the Rocky Mountain region are those granted during crucial winter months and during nesting and brood-rearing seasons for grouse. The BLM granted at least one exception in each of the six winter months in the Pinedale, Wyoming Field Office, though most of January was avoided (unpublished data collected by Trout Unlimited and the Wildlife Management Institute, 2003-2004). In 2001, the same office granted a two-and-a-half month exception, and in 2002, granted two exceptions through the winter months. The same was done in the Rawlins, Wyoming Field Office. Rawlins granted 86 percent of exception requests, but granted just 11 of 27 requests (41 percent) between January 1 and March 15. The fact remains, however, that the BLM is granting exceptions throughout the year, even when wildlife is under the most stress.

Questions also have been raised about whether the number and type of stipulations in permits are sufficient to protect fish and wildlife or are overly restrictive. It would be useful to evaluate the effectiveness of stipulations to determine if they are accomplishing their intended purpose. Existing management and ongoing operations can provide the basis for answering these questions. The evaluation must be designed to answer specific resource questions rather than simply gathering general information. In particular, adequate, effective monitoring must be in place to obtain reliable information about resource conditions, and all interests must be prepared to accept the outcomes. The relationship between stipulations and monitoring is critical. Monitoring data are essential to support both imposition as well as waivers of stipulations.

Better population and habitat mapping – spatially and temporally explicit – is needed to support decision-making about where stipulations need to be applied. Surface use restrictions as an alternative and/or supplement to timing stipulations can accommodate significant wildlife needs.

Ensure Adequate Financial Resources for Reclamation

The availability and use of adequate oil and gas bonds serve the public interest so that the industry meets all federal and state requirements for

reclaiming sites (Western Organization of Resource Councils 2004). Reclamation of an oil or gas site should be a cost of doing business and if the lessee cannot guarantee adequate funds for this purpose, then it should not be permitted to develop federal oil and gas resources. Taxpayers also have a direct interest in adequate bonding so that they are not stuck with the costs of reclamation.

There are two main federal laws under which the BLM has authority to require bonding: the Stock Raising Homestead Act (SRHA) of 1916 and the Mineral Leasing Act (MLA), as amended. Under the SRHA, before entering a surface owner's property to drill, the mineral operator must secure a written consent or waiver from the landowner and obtain a surface damage agreement, or post a bond to cover damages. The bond must exceed $1,000 and is supposed to cover damage to crops, improvements, and any loss of income from using the land.

Under the MLA and its implementing regulations, the oil and gas lessee or her/his operator must furnish a bond in the amount of at least $10,000 per lease to ensure compliance with all the lease terms, including protection of the environment. Hundreds of oil and gas wells can be drilled on one lease, and companies can bypass the $10,000 per lease requirement and post a blanket bond of $25,000 for all the wells they drill in one state. A company that operates in more than one state can post a bond of $150,000, regardless of the number of wells it plans to drill. The BLM also has the flexibility and authority to increase bonding amounts in particular situations.

Estimates of the actual costs of reclamation often are much higher than the financial guarantees required by the federal government. According to the BLM Office of Fluid Minerals, the estimated costs of plugging and rehabilitating abandoned wells range from $2,415 to $75,000 each, and the costs of reclaiming the associated well sites vary from $200 to $5,000 each. The Wyoming Oil and Gas Conservation Commission estimates that the average cost to reclaim a coal-bed methane well is between $2,500 and $7,500 per well. This estimate includes the costs of plugging the well and restoring the site around the well, but does not include the reclamation of roads, compressor station sites, and produced water containment ponds. The State of Wyoming requires an additional bond for wells that have been idle for more than two years, as well as for containment ponds. The State of Colorado conducted a survey in 1997 and concluded that the average cost to "plug" a coal-bed methane well in the Fruitland Coal Formation was $11,240. Plugging a well includes pulling out the casing and tubing and cementing the well hole, but does not include surface reclamation.

BLM records show that there are approximately 12,000 shut-in and temporarily abandoned oil and gas wells on lands administered by the agency. One BLM estimate puts the cost of reclaiming 90 abandoned oil and gas wells at $1.7 million, or about $19,000 per well. On two occasions the BLM has spent

$38,000 plugging one abandoned well and reclaiming the site, even though the posted bond was only for $25,000. Therefore, the total cost of reclaiming 12,000 abandoned wells could range from $228-$456 million, a significant portion of which could come out of taxpayer pockets.

There are a number of specific steps that should be taken. Within 6 months, a comprehensive assessment should be conducted by each federal agency with management responsibility over energy developments to evaluate the long-term financial needs for removing drilling rigs and related infrastructures from the lands and mitigation/restoration of the landscape potentially impacted by energy development. If current bonding or other financial requirements are determined inadequate, then the agencies should establish more sufficient requirements. Specific recommendations include:

- ***Require bonds for entire fields or project areas:*** Congress should amend the Federal Onshore Oil and Gas Leasing Reform Act so that a bond covers a specific oil and gas field or project area. As additional fields or project areas are developed, the operator would post additional bonds. Bonds must cover not only wells, but also all other associated facilities. The amount of the bond required for each field or project area would depend on the type and intensity of oil and gas operations, and reflect the probable difficulty of reclamation considering such factors as topography, geology, hydrology, vegetation, and fish and wildlife populations. The amount of the bond would be determined by the regulatory authority, and must be sufficient to ensure the completion of the reclamation plan if the work had to be performed by the regulatory authority in the event of forfeiture. The regulatory authority could adjust the amount of the bond as affected land acreages increase or decrease, or where the cost of future reclamation changes. The bond must be based on the worst-case scenario. The BLM would encourage the public to participate in bond release proceedings, attend an on-site inspection during bond release proceedings, and file written objections to a proposed bond release.

- ***Impose a per-well bond of $20,000***: In lieu of the first approach outlined above, Congress could amend the Federal Onshore Oil and Gas Leasing Reform Act to require companies to post a $20,000 per well bond. Such bonds must cover not only the costs of plugging the well and restoring the site around the well, but the costs of reclaiming roads, compressor station sites, produced water containment ponds, and all other associated facilities and impacts for which a bond is not otherwise provided.

- ***Finalize BLM's rulemaking to strengthen bonding regulations:*** The BLM needs to finalize the rule making it initiated in 2001. In January 2001, the BLM issued draft rules that proposed modest increases in oil and gas reclamation bonds under the Mineral Leasing Act. Since that

time, the rules have languished. One proposal is to increase the per-lease bond from $10,000 to $20,000 and the statewide bond from $25,000 to $75,000. Another proposal to consider is to require that the "operating rights owner(s)" and the "record title lessee(s)" be held jointly liable for reclamation.

Explore Mitigation in Some Circumstances

Avoiding substantial fish and wildlife impacts may not be possible in all places and at all times. Mitigation is a tool that may be appropriate when resource impacts are unavoidable, or applying the best practices to minimize those impacts is inadequate to protect the integrity of local fish and wildlife populations. In areas where exploration and development of oil and gas resources would conflict with the protection or management of other resources or public land uses, the NEPA (National Environmental Policy Act of 1969) process identifies measures to mitigate impacts. These mitigation measures usually are applied as lease stipulations, which restrict how operations are conducted or where they can be located. The purposes of mitigation guidelines are to reserve, for the BLM, the right to modify the operations of all surface-disturbing activities as part of the statutory requirements for environmental protection. They also are used to inform a potential lessee, permittee, or operator of the requirements that must be met when using BLM-administered public lands.

An oil and gas operator also must comply with a set of standard lease terms contained in the Federal lease. The lease terms discuss "Conduct of Operations," which states that the "lessee shall conduct operations in a manner that minimizes adverse impacts to the land, air, and water, to cultural, biological, visual, and other resources and other land uses or users." The lessee must take reasonable measures deemed necessary by the BLM to accomplish the intent of this section – such measures may include, but are not limited to, modification to siting or design of facilities, timing of operations, and specification of interim and final reclamation measures. Lessee may be required to complete minor inventories or short-term special studies under guidelines provided by the BLM. If in the conduct of operations, threatened or endangered species, objects of historic or scientific interest, or substantial unanticipated environmental effects are observed, lessee must immediately contact the BLM. Reasonable modification to siting or timing of operations has been defined as movement of a specific drill site up to 200 meters or delay of new surface disturbing activities for up to 60 days.

Off-site mitigation should be an option in many cases. This option must be evaluated carefully on a case-by-case basis and viewed as an option of last resort. One example of a mitigation program that might be considered is for the lessee to deposit voluntary contributions on a per-well basis to a privately administered fund that is used for monitoring and for other purposes related the development.

There are two ways the standard mitigation guidelines should be used in the RMP/EIS process: 1) as part of the planning criteria in developing the RMP alternatives, and 2) in the analytical processes of both developing the alternatives and analyzing the impacts of the alternatives. In the first case, an assumption is made that any one or more of the standard mitigations will be appropriately included as conditions of relevant actions being proposed or considered in each alternative. In the second case, the standard mitigations are used 1) to develop a baseline for measuring and comparing impacts among the alternatives; 2) to identify other actions and alternatives that should be considered, and 3) to help determine whether more stringent or less stringent mitigations should be considered.

II. Increase Federal and State Agency Resources

There is broad agreement among stakeholders, including oil and gas companies and natural resource organizations, that more funding needs to be provided to federal agency staff, particularly fish and wildlife biologists. These are necessary so delays in processing permit applications can be avoided, additional research and monitoring can be completed, and potential problems can be identified early in the process. In addition, state agencies are responsible for managing fish and wildlife, and they have considerable expertise in habitat needs. These state agencies should be provided with sufficient resources to study potential development areas, provide meaningful and timely input into the leasing and permitting processes, and monitor the impacts of development on fish and wildlife. These agencies need additional financial resources to manage and protect fish and wildlife and their habitats from the effects of energy development.

Additional funding would allow federal land management agencies to perform a more thorough review of the sensitivity of natural resources to oil and gas development and to make timely decisions on lease and permit applications. If these goals can be accomplished, then the program should instill much greater confidence in the public that leasing and permitting decisions are well-thought out and industry should have quicker decisions from the agency and be able to expect that those decisions will be less vulnerable to public opposition. In short, there appears to be a way to improve the program for all stakeholders.

Some progress is being made with regard to funding, but more needs to be done. In the last three budget years, the oil and gas portion of the BLM's budget has been increased from $57.5 million in fiscal year 2000, to $88.2 million for fiscal year 2004, a 53 percent increase. The oil and gas portion of the agency's budget proposed for fiscal year 2005, is $85.6 million, and the administration has proposed to impose $3 million in user fees on energy companies that drill on lands administered by the BLM. However, the BLM initially had requested $91.8 million for oil and gas management for fiscal year 2005, indicating that they believe more is needed to administer this program. As

an example, BLM officials estimated the cost of just one of the major federal energy development programs, the Powder River Basin EIS, at $3 million. Although the BLM has been requesting more funds to deal with the increased workloads associated with accelerated energy development, there has been no indication that those additional funds would include additional fish and wildlife biologist staff.

It will take some time to determine if current funding levels will allow the agency to perform a more thorough review of the sensitivity of natural resources to oil and gas development and to make timely decisions on lease and permit applications. The agency indicated it needs at least 7 percent more funding in fiscal year 2005 than it received in fiscal year 2004, and 60 percent more than it received in fiscal year 2000. Assuming full annual funding for the BLM's oil and gas program is around $91.8 million, and that they are approaching that funding level, then the average time to process lease and permit applications might be reduced from an average of 84 days experienced in 2000, to an average of about 40 days, based on their own calculations. Moreover, organizations and members of the public file appeals and lawsuits on 15 percent of applications, and it is reasonable to expect that a better process could alleviate some of this legal and administrative activity, and the associated delay in the process.

To ensure that states and tribes can monitor the impacts from oil and natural gas developments effectively, the federal government should provide them with at least $10 million per year (FY2005-FY2009) and perhaps as much as $20 million per year (FY2010-FY2014). This also will allow them to assess the data and recommend adjustments to permit conditions necessary to ameliorate the effects of specific energy developments on fish and wildlife (i.e., Green River in WY and High Plains in NM). Finally, Congress should establish a trust fund of $1 billion for states and tribes to ameliorate the long-term and cumulative effects of energy development on fish and wildlife populations and habitats.

One potential, source of funds for these purposes is the revenues from energy development, which currently are collected from onshore oil and gas producers. We recommend that the Administration and Congress consider dedicating a percentage of these funds for administration of the program and for state agency involvement in the process.

Another option is to authorize energy development lessees to voluntarily provide funds and other resources to assist federal and state agencies in their resource management responsibilities. These voluntary contributions provided by lessees could be made in lieu of paying a portion of rents and royalties normally collected by the federal treasury for energy and mineral extraction.

III. Reduce Federal Royalty Rates in Certain Cases

The nation faces increasing demand for oil and gas, as well as greater dependence on foreign sources of these resources. To address this challenge, some development of federal energy reserves on some federal lands is rational and in the national interest. One of the impediments to development of federal lands for energy production is the historically low and fluctuating market price of natural gas and crude oil. Improving the economics of appropriate energy development on federal lands could spur increased exploration and production. Therefore, the federal government should consider reducing the royalty payments for production on those federal lands determined by new RMPs to be of negligible value for fish and wildlife. By reducing federal royalty payments on oil and natural gas produced on relatively non-controversial federal lands, the federal government could simultaneously catalyze additional domestic energy production and focus it on areas of less natural resource value. In combination with the general increase in world oil and natural gas prices, this could lead not only to greater domestic energy development, but also could better target less controversial lands for immediate production.

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NCEP Staff Background Paper –
Methane Hydrates in Context – U.S. Natural Gas Overview

In 2003, the United States consumed 22 trillion cubic feet (tcf) of natural gas.[1] By 2025, the U.S. Energy Information Administration (EIA) projects that national consumption will rise to between 29.1 and 34.2 tcf per year.[2] Currently, the United States has proven natural gas reserves of 185 tcf;[3] ultimate technically recoverable domestic reserves are estimated at 1280 tcf.[4] By comparison, the U.S. Geological Survey(USGS) estimates that gas hydrates in Alaskan permafrost and in Outer Continental Shelf (OCS) sediments hold 200,000 tcf of methane, and perhaps much more.[5]

Methane Hydrates – Background

- **Hydrates are unique structures that concentrate methane under particular conditions of low temperature and high pressure.**
- **Hydrates are believed to contain more carbon than all other fossil fuel reserves combined.**

By conservative estimates, more than 53% of the organic carbon on earth that is not dispersed in rocks and sediments is contained in methane hydrates. These structures thus contain more carbon than the atmosphere, oceans, soils, and other fossil fuel reserves combined.[6]

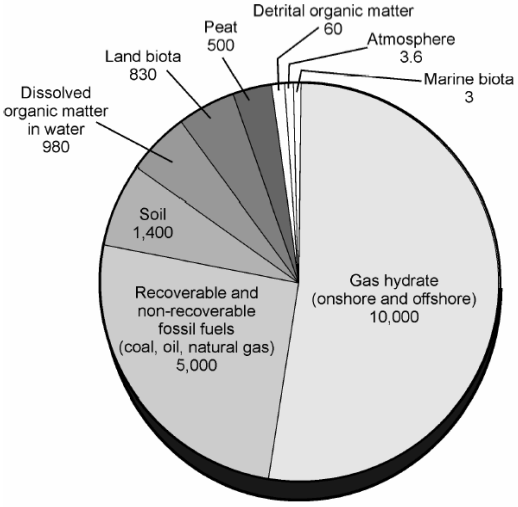

Image from Kvenvolden, 1993, published in Boatman and Peterson, 2000.

Methane hydrates, which are more properly referred to as methane clathrates, are comprised of a unique combination of water and methane in solid ice-like formations. These formations "lock" methane molecules into cages of water molecules, trapping them in highly concentrated form (the term clathrate means "cage"). A given volume of fully saturated methane hydrate contains up to 164 times that volume of gaseous methane.[7] Sea-floor and cold-climate gas

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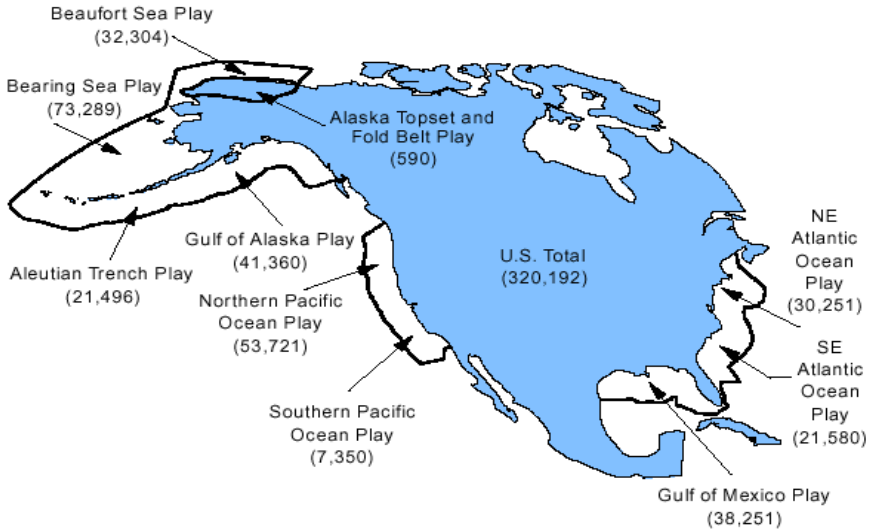
[1] Energy Information Administration. Natural Gas Navigator. http://tonto.eia.doe.gov/dnav/ng/hist/n9140us2m.htm. Visited 7/6/2004.
[2] Energy Information Administration. "Market Trends – Oil and Natural Gas". *Annual Energy Outlook 2004*. http://www.eia.doe.gov/oiaf/aeo/gas.html
[3] *BP Statistical Review of World Energy, 2004.* British Petroleum. http://www.bp.com/subsection.do?categoryId=95&contentId=2006480
[4] Energy Information Administration. "Market Trends – Oil and Natural Gas". *Annual Energy Outlook 2004*. http://www.eia.doe.gov/oiaf/aeo/gas.html
[5] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000
[6] Dillon, William and Kent Kvenvolden. U.S. Geological Survey, Marine and Coastal Geology Program. "Gas (Methane) Hydrates – A New Frontier." http://marine.usgs.gov/fact-sheets/gas-hydrates/title.html. September 1992. Accompanying figure from same source.
[7] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000.

and oil drilling operations frequently pass through hydrates, either as finely-disseminated grains, nodules, small layers, or massive consolidated sructures.[8]

Methane clathrates form within a specific range of temperatures and pressures, in the presence of either biogenic or thermogenic methane and water. These conditions may be found under permafrost soils or in sea-bottom sediments. Under sufficiently high pressure, these ice-like systems can exist at temperatures several degrees higher than the normal freezing point of water. Clathrates can be formed with a variety of captured gases, including other small hydrocarbons and carbon dioxide.[9]

When exposed to conditions outside their temperature/pressure stability zone, hydrates decompose rapidly. Hydrates transported from the sea-bottom or from deep underground to the earth's surface often fizz vigorously, releasing trapped gases to the atmosphere and dripping as the water cage transforms to a liquid. As they rapidly off-gas methane, these "icy" structures can be ignited. The end-goal of most gas hydrate research is to find practical and economic ways to extract this gaseous methane as a substitute for conventionally-produced natural gas.

Current plans to produce methane from hydrate deposits rely on relatively conventional drilling technology. Though the resource base is potentially huge, great uncertainty exists as to the quantity of hydrates that may be commercially extracted. If current obstacles can be overcome, methane trapped in hydrates could theoretically provide an abundant, clean-burning, domestic source of energy well into the foreseeable future.



USGS = U.S. Geological Survey.
Source: **Volumes:** T.S. Collett, *Gas Hydrate Resources of the United States*, Table 2. **Map:** U.S. Geological Survey, *Digital Map Data, Text, and Graphical Images in Support of the 1995 National Assessment of United States Oil and Gas Resources*, Digital Data Series (DDS) 35 (1996), Figure 5.

Distribution of probable methane hydrate deposits. The Ocean Drilling Program, a joint effort led by the USGS, is responsible for a recent upward revision of the estimated total resource base to 200,000 tcf.[10]

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[8] Energy Information Administration. "Natural Gas 1998: Issues and Trends". Washington, DC. 1998
[9] Sloan, Dendy. *Clathrate Hydrates of Natural Gases.* Marcel Dekker. Monticello, NY: 1998.
[10] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000.

Methane Hydrates Potential

- **If 1% of the estimated domestic hydrate resource base proves commercially viable, this would more than double current technically recoverable domestic natural gas reserves.[11]**
- **Commercial methane hydrate production is likely one to two decades away.**

In the United States, methane hydrate deposits are concentrated onshore in Alaskan permafrost, and offshore, along the coasts of Alaska, Washington, Oregon, California, New Jersey, North Carolina, South Carolina, as well as in deep waters of the Gulf of Mexico.[12] Most domestic off-shore hydrates are located in OCS waters at depths greater than 500 meters[13] (the federal government would have jurisdiction over development of these resources).

As has already been noted, if only 1% of projected domestic methane hydrates prove commercially accessible, this would more than double the nation's technically recoverable natural gas reserves.[14] At a global level, the estimated resource base associated with methane hydrates is as much as 400 million tcf[15] (though actual amounts are probably smaller), with much of that resource base concentrated in ocean floor and permafrost areas under the jurisdiction of Canada[16] and other friendly nations. Currently, Japan, South Korea, India, Germany, and Canada have all expressed high levels of interest in developing methane hydrate resources.[17]

Commercial production of methane from hydrates may be decades off, however, and entails a number of significant uncertainties. The U.S. Department of Energy's (DOE's) *Strategy for Methane Hydrates Research and Development* states 2015 as its goal for methane production.[18] More recently, Jan Boon, director of Canada's geological survey has estimated that commercial extraction of methane hydrates is likely 20 years away.[19]

Near-term Opportunities

- **Permafrost deposits in northern Alaska and Canada hold the greatest promise for large-scale methane extraction in the near-term.**
- **A consortium project in northern Canada has successfully demonstrated methane production from buried hydrates.**

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[11] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.
[12] Energy Information Administration. "Natural Gas 1998: Issues and Trends". Washington, DC. 1998
[13] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000.
[14] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.
[15] Platt's Energy Economist, Sept. 2003.
[16] Natural Resources Canada. "Mallik 2002 Gas Hydrate Production Research Well Program". Press Release. 10 December 2003. http://gashydrate.nrcan.gc.ca/mallik2002/news_dec_10_2003_b.asp.
[17] Logan, Eloise. "Methane Hydrates: Environmental Time Bomb or New Energy Source." *Inside Energy*. September 2003.
[18] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.
[19] Logan, Eloise. "Methane Hydrates: Environmental Time Bomb or New Energy Source." *Inside Energy*. September 2003.

The best hope for near-term extraction of methane hydrates appears to be from permafrost deposits, especially those located in northern Alaska and northern Canada. In the past two years, public-private consortia have conducted experimental programs in both areas. In the United States, Hot Ice, a drilling project jointly sponsored by Anadarko Petroleum, Mauer Technology, Noble Drilling, and DOE, failed to encounter predicted methane hydrates, but did succeed in pioneering an on-site core analysis lab as well as an experimental elevated drilling platform.[20] The Canadian Mallik drilling project proved successful in both locating and producing methane from buried hydrates. Members of the project team included the Japan National Oil Company[21] and subsidiaries, the Geological Survey of Canada, the USGS, DOE, Germany's Geo-Research Center, Gas Authority of India Ltd., and industry partners BP, Burlington Resources, and ChevronTexaco. The project demonstrated the viability of heat and pressure stimulation, and also proved that the site's hydrate-rich layers were highly permeable[22] and could be effectively fractured to increase production.[23]

Uncertainties and Barriers to Extraction

- **Hydrates are deeply buried and sensitive to temperature and pressure fluctuations.**
- **Hydrate decomposition may threaten production capability and infrastructure and, by generating large-scale releases of methane — a potent greenhouse gas — to the atmosphere, could further contribute to climate change.**
- **Little is known about effectively producing methane from deep see hydrate deposits, or about the potential environmental impacts of doing so.**

Several significant barriers exist to the production of methane from hydrates. Most of these barriers relate to the temperature and pressure conditions necessary to maintain hydrate stability. The presence of hydrates in sediment layers or as an obstruction to pipelines has long been recognized in conventional oil and gas production. In some cases, heat and pressure changes created by drilling equipment can destabilize hydrates and may even jeopardize drill-hole integrity. Similarly, layers of underwater hydrate buried by sediment may prove somewhat unstable, especially in places where hydrates overlay free gas. This common condition occurs as temperatures in deeper sediments rise outside the hydrate stability zone. As hydrates are less dense than seawater, they may also break free and float to the surface. Continental margins bear signs of underwater landslides that may have been caused by hydrate decomposition or release.[24] Considerable uncertainty exists about what events are necessary to trigger this instability and whether and how it may threaten infrastructure put in place to extract methane from hydrates.

Significant uncertainty also exists regarding the role of methane hydrates in climate change. As hydrates primarily contain methane — a greenhouse gas that is 21 times more potent than carbon dioxide in terms of its heat-trapping effect on the atmosphere — and contain it in quantities

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[20] Spangler, Matt. "Lab Study of Methane Hydrates in Alaska Comes up Empty; Testing Said a Success". *Inside Energy*. 5 April 2004.
[21] Japan currently spends approximately $65 million per year on gas hydrate development research - Burnham, Michael. "Secrets of Frozen Gas Melting Away, But Commercial Viability Still a Mystery." *Land Letter*. 8 January 2004.
[22] Market View. "Successful Arctic Test Well Shows Hydrates Have Potential". *Natural Gas Week*. 2 January 2004.
[23] Natural Resources Canada. "Mallik 2002 Gas Hydrate Production Research Well Program". Press Release. 10 December 2003. http://gashydrate.nrcan.gc.ca/mallik2002/news_dec_10_2003_b.asp.
[24] Energy Information Administration. "Natural Gas 1998: Issues and Trends". Washington, DC. 1998

far larger than remaining fossil fuel reserves, they have the potential to drastically exacerbate the risk of global climate change. Slight warming of permafrost areas may release hydrates, as could a slight warming of the deep oceans. It is uncertain, however, if methane released from the ocean floor would rise to the surface in meaningfully large quantities. Methane in sea water is typically oxidized or otherwise consumed by marine microorganisms. It is possible, however, for blocks of solid hydrates released from the sea floor to survive the trip to the surface and there release stored methane. The aggregate effect of sea level rise or temperature change on gas hydrates is uncertain, as is their ability to contribute to global warming.[25]

To date, no viable techniques for extracting hydrates from deep ocean deposits have been developed. Testing programs, such as the internationally-sponsored Ocean Drilling Program, have considerably expanded current knowledge concerning seafloor hydrates, but questions persist regarding the characteristics of these structures and their potential impacts on seafloor ecosystems and carbon cycling.

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Current Research Funding

- **DOE is the largest funder of hydrates research in the United States.**
- **Funding levels for methane hydrates research is slated to decline in FY 2005.**
- **DOE funding for methane hydrates research totaled $47.5 million over the period from 2001 to 2005. By comparison, Japan authorized roughly $90 million and India authorized $56 million for methane hydrates research over the same time period.**

Efforts to overcome current barriers to utilizing methane hydrates are currently distributed across a wide range of entities, including governmental entities in the United States and abroad, private industry, and universities. Industry estimates indicate that as of 2001, approximately $15.3 million was spent on public and private hydrate research efforts in the United States across all sectors.[26] In a 1999 consensus estimate, the DOE, industry and academic researchers concluded that $150–$200 million in research funding over ten years would likely be necessary to achieve the ambitious goals of the national *Strategy for Methane Hydrate R&D.*[27]

Since 1982, the major U.S. funder of hydrate research has been DOE. Most importantly, the *Methane Hydrate Research and Development Act of 2000* authorized $47.5 million in spending over five years,[28] in response to a 1997 recommendation by the President's Council of Advisors on Science and Technology (PCAST) for $44 million in DOE investment.[29] In 2003, DOE received $9.2 million for hydrate research,[30] $1.8 million short of the authorized amount, followed by $9.4

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[25] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000.
[26] Logan, Eloise. "Methane Hydrates: Environmental Time Bomb or New Energy Source." *Inside Energy*. September 2003.
[27] Federal Energy Technology Center. *National Methane Hydrate Multi-Year R&D Program Plan.* U.S. DOE Office of Fossil Energy. 1999.
[28] 106th Congress. H.R. 1753: Methane Hydrate Research and Development Act of 2000. Accessed through thomas.loc.gov.
[29] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000.
[30] U.S. DOE. "FY 2005 Statistical Table by Appropriation." Available at http://www.mbe.doe.gov/budget/05budget/content/appstat.pdf. 2005.

million in 2004,[31] a reduction from the $12 million authorized in the bill. The allocation for FY05 has been further reduced, from $12 million authorized to $6 million budgeted. A status report on DOE's future methane hydrate research needs was due to Congress by September 30 of 2004.[32]

DOE is not the sole funder of methane hydrates research, however. The USGS, Materials Management Service (MMS), National Science Foundation (NSF), and Naval Research Laboratory (NRL) all fund hydrate-related research. As of 2000, USGS supported $700,000–$800,000 yearly in research funding, NSF allocated approximately $750,000–$1 million, and NRL planned $1 million per year through 2004.[33]

Industry efforts, once limited to research into preventing hydrate formation in gas-extraction pipelines and equipment, has significantly evolved toward interest in commercial production. From 2002 to 2004, Anadarko Petroleum contributed $3.4 million to the $7.4 million Hot Ice project in Alaskan permafrost.[34] In a nearby area of Alaska's North Slope, BP and DOE are currently working on a multi-year $21.6 million effort to produce gas from hydrates at another field. BP's share of the project is $8.1 million.[35]

Research efforts have frequently been international in scope, as participation by DOE and USGS in the Canadian Mallik project and the ongoing involvement of a range of countries in the Ocean Drilling Projects indicate. In terms of funding dollars, Japan is the international leader in gas hydrate research, having dedicated $90 million to a five-year research program that is set to conclude in 2005.[36] India also has a great interest in hydrates, having allocated $56 million to a multi-year development program.[37] Other countries engaged in related research efforts include Canada, the UK, Brazil, Germany, Russia, South Korea, and Norway.

Next Steps

- **Locate and characterize methane hydrates domestically and worldwide.**
- **Determine the role of hydrates in climate change and the potential for carbon sequestration.**
- **Develop the Alaska North Slope gas pipeline to foster immediate conventional gas development and future hydrate production.**
- **Develop techniques for deep-sea production.**

Following the success of Mallik and given continued interest by both government and industry in the potentially massive methane hydrates resource base, several major research needs

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[31] U.S. DOE. "FY 2005 Statistical Table by Appropriation." Available at http://www.mbe.doe.gov/budget/05budget/content/appstat.pdf. 2005.
[32] Logan, Eloise. "Methane Hydrates: Environmental Time Bomb or New Energy Source." *Inside Energy*. September 2003
[33] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.
[34] Morehouse, David F. "Natural Gas Hydrate Update 2000-2002". Energy Information Agency. 2002.
[35] Morehouse, David F. "Natural Gas Hydrate Update 2000-2002". Energy Information Agency. 2002.
[36] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.
[37] U.S. Department of Energy, Office of Fossil Energy. *A Strategy for Methane Hydrates Research and Development.* August, 1998.

exist. Considerable research is necessary to accurately locate and characterize methane hydrate deposits around the world, both on- and off-shore. This research includes determining the type and uniformity of deposits, as well as their relative stability. With respect to deep ocean hydrates, it will be necessary to determine viable means of production, assess whether hydrate stability poses a threat to platforms and other infrastructure, and better understand the roles hydrates play in seafloor ecosystems. Most ocean-floor hydrates to date have been located by bottom-simulating reflector (BSR) signals on seismic imaging — a detection technique that is capable of effectively locating all hydrates.[38] Much of this research can be accomplished in concert with other countries, using the current Ocean Drilling Program and the recent Mallik project as models. Future research into potential production methods should rely to an increasing extent on cost-sharing with industry.

Research is also needed to better understand the potential role of hydrates with respect to climate change. On a related topic, some research indicates that hydrates may have significant potential for sequestering carbon dioxide. This is an area that merits further exploration. In the presence of carbon dioxide, methane hydrates release their stored methane and absorb carbon dioxide, though the in-situ rates for this reaction, as well as the feasibility of exploiting it for methane production and long-term carbon storage have not yet been determined.[39]

Infrastructure in general presents a major challenge for future methane hydrate production. Off-shore methane hydrates, though frequently found on continental shelves, are generally not located near existing infrastructure. For this reason, and based on a wealth of test data, on-shore formations in Alaska and Canada are likely to be the first major sites for hydrate development in North America, potentially followed by the Gulf of Mexico, which also benefits from highly porous deposits. Alaska's future production potential will be determined by both the quality and quantity of available resources and the presence of a pipeline for transporting natural gas or methane from the North Slope to markets in the lower-48 states.[40]

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[38] Boatman, Mary C.; Jennifer Peterson, preparers. *Oceanic Gas Hydrate Research and Activities Review*. Minerals Management Service. New Orleans: 2000

[39] Yarborough, Mary Helen. "DOE-Industry Partnership Targets Carbon 'Swap' Technology". *Inside Energy*. New York: 2 December 2002.

[40] Burnham, Michael. "Secrets of Frozen Gas Melting Away, But Commercial Viability Still a Mystery." *Land Letter*. 8 January 2004.

IGCC: Next Step on the Path to Gasification-Based Energy from Coal

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November 2004

Abstract

The integrated gasifier combined cycle (IGCC) makes it feasible to provide coal electricity as cleanly as natural gas combined cycle (NGCC) plants and to deal with the climate challenge via CO_2 capture and storage (CCS) with much lower energy and cost penalties than with coal steam-electric technologies. Moreover, IGCC is a stepping stone to provision of clean, secure, and climate-friendly supplies of synthetic fuels manufactured via gasification of coal and biomass with capture and storage underground of CO_2—synthetic fuels that will often be provided in polygeneration plants that also make electricity, as well as chemicals and process steam. Although IGCC technology has evolved to the point where electricity generation costs based on use of bituminous coals are about the same as for steam-electric plants, there are three major *institutional* challenges that must be overcome. The first is that coal IGCC technology is not likely to be launched in the market without appropriate promotion by the public sector, because much of what the technology offers are public (rather than private) benefits not yet reflected in energy market prices. The second is that, although all components of current IGCC CO_2 capture (CC) systems are fully proven and commercially available, no IGCC systems with CC have been built. Early field experience with CC technologies is needed even before a climate mitigation policy is put into place. The third is that the concept of a major future for coal in a climate-constrained world hinges on the viability of CO_2 storage at "gigascale"—the determination of which requires, along with more R&D on CO_2 storage, the conduct of many "megacale" CO_2 storage demonstration projects during the next 10-15 years.

Introduction

Gasification of coal or other low-quality carbonaceous feedstocks[1] in oxygen and steam generates "syngas," more precisely, synthesis gas [made up mostly of hydrogen (H_2) and carbon monoxide (CO)] from which a panoply of high-products can be made—heat and power, chemicals, clean synthetic fuels (Figure 1). Gasification is a booming activity worldwide. A world-wide survey of commercial gasification projects identified 128 operating gasification plants with a total of 366 gasifiers producing about 42,700 MW_t of syngas (NETL-DOE, 2002). There are also about 24,500 MW_t syngas of gasification projects under development or construction, with an annual growth rate of 4,000 – 5,000 MW_t syngas (Figure 2).

Although about 27,000 MW_t of this syngas capacity is based on coal (Figure 2), only a modest fraction is operating or planned for integrated gasifier combined cycle (IGCC) power generation.[2] Most recent commercial gasification development has been associated with

[1] Petroleum coke, other oil refinery residues, biomass, municipal solid wastes.

industrial ammonia production and industrial polygeneration (in which clean syngas is used to make electricity and/or steam along with chemicals) based on gasification of petroleum coke and other petroleum residuals at petroleum refineries and chemical process plants.

Coal IGCC technology was successfully demonstrated between 1984 and 1989 at Cool Water in the United States. Since then the following IGCC plants based on oxygen gasification of coal have been built:

- The 250 MW_e Demkolec plant at Buggenum, The Netherlands (Shell gasifier, Siemens gas turbine), started up in January 1994;
- The 262 MW_e Wabash project in Indiana [E-Gas gasifier (now ConoccoPhillips), GE gas turbine), started up in October, 1995;
- The 253 MW_e Tampa Electric project in Florida [ChevronTexaco gasifier (now GE), GE gas turbine), started up in September 1996; and
- The 310 MW_e ELCOGAS project in Spain [Prenflo gasifier (now joint with Shell), Siemens gas turbine)], started up in December 1997.

These projects are commercial-scale demonstration units that have had subsidy support—in contrast to the many polygeneration projects at oil refineries and chemical process plants (based mainly on gasification of petroleum residues) that have gone forward without subsidy (Simbeck, 2001). Most industrial polygeneration projects have not required subsidy because: (*i*) syngas is a required intermediate product in the chemical process/refining industries—compared to being only "an option" for stand-alone power generation; (*ii*) syngas generation via gasification of petroleum residuals is often less costly on a lifecycle cost basis (though more capital intensive) than making syngas by steam reforming of natural gas; and (*iii*) these industries are "culturally comfortable" with the manufacture of syngas—whereas the electric power is not (more on this later).

It is perhaps surprising that coal IGCC has not "taken off" in power markets—especially since Cool Water stands out as being one of the most successful US energy technology demonstration projects; the project was completed ahead of schedule and under budget and met all of its objectives (PCAST, 1997). There are four very different but mutually reinforcing reasons for this: (*i*) lousy luck on the first draw; (*ii*) concerns about IGCC reliability; (*iii*) cultural barriers to IGCC in the power industry; and (*iv*) imbalanced allocation of benefits and risks.

Lousy luck on the first draw

By the time the first praises for Cool Water were being sung, the world oil price had already collapsed (1986), natural gas was following oil in becoming remarkably cheap[3] and far more

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[2] About 11,200 MW_t of coal syngas is accounted for by synfuels production in South Africa, 5,200 MW_t by plants that make ammonia and other chemicals in China, and 1,900 MW_t by the Dakota Gasification Company's Great Plains Synfuels Plant in the US that makes synthetic natural gas.

[3] The price of natural gas to US electric generators fell more or less continually in real terms from its peak 1982 value of $5.6/MBTU (in 2002$) until it reached a low of $2.2/MBTU in 1996 before it began rising again.

abundant in North America than had been thought previously thought, and the natural gas combined cycle (NGCC) was becoming well established worldwide as the technology of choice for thermal power generation wherever natural gas was readily available. New coal power plants of any kind could simply not compete in most areas. For IGCC in particular this was a "no brainer"—with a NGCC specific capital cost ($/kW$_e$) less than half of that for a coal IGCC plant and expected lifecycle generation costs in the range 2.5-3.0 ¢/kWh compared to 4.5-5.0 ¢/kWh for IGCC.

But the new hand being dealt to the IGCC and other coal power generation vendors offers promise in addressing the NGCC challenge. Low and stable coal prices stand in sharp contrast to rising and volatile natural gas prices and make coal power options increasingly attractive. Natural gas prices seen by electric generators are now in the range $4-$5 per MBTU (or higher) and are expected to stay high because of constrained North American natural gas supplies.[4] A recent National Petroleum Council report concluded that natural gas production from the US Lower 48 and Sub-Arctic Canada has plateaued (Figure 7, top) and that additional supplies will have to be provided by relatively costly and difficult-to-acquire Arctic gas and liquefied natural gas (LNG) (Figure 7, bottom), which will set the natural gas price.

A superficial analysis would suggest that, even with today's high gas prices, the NGCC still beats the coal IGCC in terms of cost: as shown by the calculations presented in Tables 6 and 7 the lifecycle cost of a NGCC[5] would be about 10% less than for a coal IGCC when both plants operate at 85% capacity factor. But if new coal power plants are added to the power supply system to compete with natural gas power plants in economic dispatch, it wouldn't be possible for NGCC plants to operate at 85% capacity factor[6]—simply because the dispatch cost (short-run marginal cost) of coal IGCC electricity is less than half of that for the NGCC (Table 6).[7]

Over the last year or so a large number (many GW) of merchant NGCC plants have been taken over by banks[8] because dispatch competition has forced many NGCC plants to operate at such

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[4] Unless indicated otherwise coal and natural gas prices presented in this paper are based on prices forecast by the Energy Information Administration (EIA, 2004) that are levelized over the period 2005-2025 and expressed in 2002$: $4.43/MBTU for natural gas and $1.22/MBTU for coal. Electricity generating costs (in ¢/kWh) are 30-year levelized costs estimated using the financing rules presented in Table 5.

[5] For the cases with CO_2 vented.

[6] The average capacity factor for NGCC plants in the United States is about 37% (SAIC, 2004). High NGCC capacity factors *are* feasible for new NGCC plants in regions where new baseload power is needed and there are environmental or other constraints that make it difficult to build new coal power plants.

[7] The dispatch order would not change if regulations were adopted that require valuation of CO_2 emissions in determining the dispatch order—even though the CO_2 emission rate for coal IGCC plant is more than twice that for a NGCC plant (Table 6). The value of CO_2 emissions would have to exceed $150 per tonne of carbon before the dispatch cost would be less for the NGCC than for a coal IGCC plant when the CO_2 is vented. But when the value of carbon reaches ~ $100/tC, a coal IGCC plant with ~ 90% CO_2 capture and storage would be less costly than an IGCC plant with CO_2 vented (see, for example, Tables 6, 7, and 8). In contrast, a carbon value of the order of $300 per tC would be needed to induce CO_2 capture and storage for a NGCC (Table 5).

[8] In February 2004, it was reported that in the previous 14 months 15 merchant NGCC plants with a total capacity of more than 14 GW in 7 states defaulted on their loans and were taken over by banks. And, in a recent report, ABN

low capacity factors that inadequate revenue generation rates have forced plant owners into default on their debt-servicing obligations (SAIC, 2004).

For the United States, at least, the competition from the NGCC is no longer a significant impediment to establishing the IGCC in the market.[9] But competition from coal steam-electric technology is a major challenge.

Reliability concerns

In 2002 the electric power generated by coal-fired power plants in the United States amounted to, on average, 70% of the rated capacity—with "capacity factors" higher for new plants and lower for older plants that are used mainly during periods of high demand. A reasonable goal for IGCC plants is to realize availabilities[10] in the range 80-90%, so that in baseload power markets capacity factors in this range can be realized for this capital-intensive technology, thereby generating revenues that would be adequate both to service debt and remunerate equity investors with the returns they expect.

A concern that has been raised about IGCC is system reliability. Availabilities were much lower than 80% in the early years of some of the IGCC demonstration projects. In particular, the Buggenum plant, designed with a high degree of integration between the gas turbine compressor and the air separation unit (ASU) as a strategy for realizing high energy conversion efficiency (43%), was initially unreliable. However, IGCC availability has improved significantly in recent years in commercial-scale demonstration units[11] (Wabash River Energy, 2000; McDaniel and Hornick, 2002). Notably, the best availabilities have been registered at the Wabash plant,[12] where there is no integration between the gas turbine compressor and the ASU. Also, availability has been good for industrial polygeneration projects at oil refineries and chemical plants where personnel are experienced with the chemical processes involved.

As a result of concerns raised by the Buggenum experience, the consensus in the IGCC design community is that in future plants there should be only a partial integration between the gas turbine compressor and the ASU.

Another way to improve reliability is to build redundancy into the system—as illustrated by the experience of Eastman Chemical Company in Kingsport, TN, with its coal-gasification-based

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AMRO reported that altogether some 33 GW could be classified as distressed NGCC capacity (Power Magazine, 2004). For comparison total NGCC capacity in the US is about 114 GW.

[9] But competition from the NGCC may well continue to inhibit coal IGCC expansion in Europe and other natural gas-rich regions where there are diverse supplies of relatively less costly natural gas and coal is relatively more costly and much less widely used for power generation than in the US.

[10] The availability is the percent of time that a plant is available to operate when called upon.

[11] For Buggenum an average availability of 72.5% is estimated for 2003.

[12] At Wabash, the availability averaged 62.4% during the "demo period" (3.1.98 to 2.28.99) but subsequently increased steadily: 73.3% (2000); 72.5% (2001); 78.7% (2002); 82.4% (2003).

syngas plant for chemicals manufacture. With its spare gasifier, Eastman has realized continually improved system performance since start-up in 1983[13] and, during 2000-2002, the gasifier system was on stream 97.7% of the time.[14]

Most early fully commercial coal IGCC plants are likely to have excess gasifier capacity.[15] Recent studies by EPRI and the International Energy Agency's GHG R&D Programme project average capacity factors of 90% and 85%, respectively, for IGCC units with excess gasifier capacity (Tables 6 and 7). Installing excess capacity adds to capital cost—but even with this extra capital cost, generation costs for such coal IGCC plants are likely to be comparable to those for coal steam-electric plants (compare generation costs for IGCC in Tables 7 and 8 with those for coal steam-electric plants in Table 6).

It will take more than such theoretical arguments to give prospective power system investors the confidence that high levels of reliability will be realized. Cost and performance guarantees by constructors/vendors or other risk-sharing arrangements are probably needed.

System reliability is a concern that is hardly unique to IGCC. For any new technology there is a transition "shake-out period" during which field experience is key to establishing investor confidence in system reliability. But until recently, appropriate gasification technology stakeholders have not come forward to shoulder enough of the initial commercial risks associated with reliability concerns for the first few plants to satisfy prospective buyers. This surprising phenomenon for such a promising technology probably arises both because of cultural barriers to IGCC in the power industry and the fact that private stakeholders acting alone cannot capture the full benefits offered by IGCC and thus are reluctant to bear all the risks of introducing this radically new technology.

Cultural barriers to IGCC

One reason stakeholders have not emerged to shoulder more of the commercial risks of launching this new technology in power markets is discomfort with the technology on the part of many coal power system practitioners who are accustomed to thinking that coal is a resource that is dug out of the ground and burned in a boiler to raise steam to spin a steam turbine to make power. A cultural mismatch arises because an IGCC does not "burn coal" but is instead a chemical process plant involving much technology that is unfamiliar to the power industry.

The cultural mismatch problem is compounded by a high level of general technology risk aversion in the power industry today as a result of the difficulties that industry is having in evolving toward more competitive power markets—as a result of the California power crisis of 2000, the Enron fiasco, and, more recently, the virtual collapse of the merchant NGCC power

[13] For example, the yearly average time before switching gasifiers has increased from 10 days (1983-1985) to 57 days (2000-2002).

[14] 1.2% planned outage rate and 1.1% unplanned outage rate.

[15] But excess capacity might not be needed to realize an 85% capacity factor with the Shell gasifier, which (unlike the ChevronTexaco and E Gas gasifiers) does not have a refractory liner for the gasifier and thus requires significantly less scheduled maintenance (Foster Wheel Limited, 2003; van der Ploeg et al., 2004).

market as a result of the bearish outlook for natural gas supplies in North American markets. No longer the investment haven of "widows and orphans," many power companies today have such poor credit ratings that they are reluctant to embrace any new technologies.

If policies are put into place that provide adequate incentive to commercialize IGCC technology, these problems will ultimately be solved—either by bringing into the power industry the needed industrial expertise or by enticing industries that already have the needed expertise to become major power producers.

Already the seeds are being planted for growing the kind of industrial infrastructure needed to establish gasification in energy markets. Eastman Chemical Corporation, with a quarter of a century of successful experience with coal gasification in the manufacture of chemicals, has created a new corporation Eastman Gasification Services, which offers the services of operating and maintaining IGCC and other gasification systems. ConocoPhillips, which recently purchased the E Gas gasification business,[16] has just announced a strategic worldwide alliance with the architectural engineering firm Fluor Corporation to facilitate the development, design, construction, and operation and maintenance of E Gas gasifier-based systems that provide a wide range of energy and chemical products derived via gasification of coal and petroleum residuals. And the recent acquisition of the ChevronTexaco gasifier by GE, the world's technological leader in providing gas turbines, many of which are already used in IGCC and polygeneration projects, bodes well for evolving reliable IGCC systems.

And, as argued in a companion report (Williams, 2004), the most promising longer-term future for coal gasification is probably not in electricity production *per se*, but rather in the co-production of electricity and super-clean liquid fuels and ultimately hydrogen (H_2) as well—in systems where, to address climate concerns, the CO_2 co-product would be captured and stored underground, and biomass might often be co-processed with coal so as to be able to provide synfuels with low fuel-cycle-wide CO_2 emissions. Introducing such "polygeneration" technology requires either that power producers take on new responsibilities for making synthetic fuels or that new major industries evolve to make electricity and liquid fuels—building perhaps on the extensive experience to date with the polygeneration of chemicals and electricity at refineries and chemical process plants (Figure 2).

Imbalanced benefit/risk allocation

Many detailed reports have been carried out in recent years showing that IGCC technology has evolved and costs have dropped to the point where the technology has nearly reached breakeven with both supercritical and ultracritical steam (SCS and UCS)-electric plants in terms of lifecycle costs (¢/kWh) for plants using bituminous coals (Tables 5 and 6).[17]

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[16] The E Gas gasifier is one of the three entrained-flow gasifiers that are commercially available. The other two are the ChevronTexaco (now GE) gasifier and the Shell gasifier.

[17] For the cases in which CO_2 is vented. Note that there are three capital cost parameters characterizing a power plant: the total plant cost (TPC); the total plant investment (TPI), and the total capital requirement (TCR). TPC = "overnight cost" for constructing the physical plant (a depreciating asset); TPI = TPC + interest charges that accumulate during construction of the plant; TCR = TPI + owner costs. Owner costs are costs associated with non-depreciating assets (prepaid royalties, startup costs, inventory capital, and land). For the least-costly IGCC option

But breakeven is a wholly inadequate measure of market acceptability. Because a new technology will always disrupt the status quo, the benefits it offers have to be markedly greater than the benefits offered by the incumbent technology before the new technology is adopted. The consumer will opt for the tried-and-true in the case of a tie in terms of cost.

Arguably, the IGCC and gasification technology more generally *are* markedly more attractive—as required to be able to displace the incumbent coal combustion-based technology. The IGCC makes it feasible to realize for coal power plants, without large increases in cost, air-pollutant emission levels about as low as for NGCC systems (Table 1).[18] The cost of reducing CO_2 emissions for plants burning bituminous coal with CO_2 capture and storage (CCS)[19] is only about half as much for IGCC (Figure 6) as for coal steam-electric plants.[20] And, uniquely, gasification-based polygeneration systems that provide, besides electricity, super-clean high H/C-ratio synthetic fuels and ultimately H_2 with CO_2 capture and storage make it possible for coal to address effectively oil-supply-security concerns as well as air-pollutant and climate concerns (Williams, 2004).

But the rub is that these benefits are mainly public, not private—benefits that are not adequately valued in energy market prices. The first two of these benefits are elaborated in the next section; the third, which relates to coal gasification more generally, in a companion report (Williams, 2004).

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from Table 7 (ChevronTexaco) these are: TPC = \$1158/kW_e, TPI = \$1305/kW_e, and TCR = \$1412/kW_e, respectively. For the least-costly steam-electric option from Table 6 (ultra-critical steam) these are: TPC = \$1161/kW_e, TPI = \$1308/kW_e and TCR = \$1353/kW_e, respectively.

[18] An additional environmental benefit of IGCC that is the greatly reduced solid waste management problems compared to flue gas desulfurization systems used with conventional coal combustors.

[19] Although commercial entrained-flow gasifiers can process coal of all ranks, efficiencies are lower and costs are higher for IGCC systems that use sub-bituminous coal or lignite that have higher moisture and/or ash contents than bituminous coals. Relative generation cost based on Powder River Basin (sub-bituminous) coals is an important consideration, because about half of all US coal power generation is based on PRB coal. However, a recent report by Shell analysts (van der Ploeg et al., 2004) argued that although the specific capital cost for an IGCC based on the Shell gasifier and used with Powder River Basin (PRB) coal would be about 3% higher than for a plant burning bituminous coal, the generation cost would be less because PRB coal would cost about 20% less per MBTU.

A recent Canadian Clean Power Coalition (CCPC) study (Stobbs and Clark, 2004) estimated that the generation cost for IGCC power with CO_2 capture (ChevronTexaco gasifier) is only 5% less than for an ultra-supercritical steam-electric plant based on use of Alberta sub-bituminous coal. The recent Shell report (van der Ploeg et al., 2004) did not present costs for the CO_2 capture case.

[20] An appropriate yardstick is the cost of CO_2 emissions avoided [measured in \$/tC (tonne of carbon)]: if the market value of carbon is greater than this value, it would be more profitable for the power producer to capture and store CO_2 than to vent it. Note, for the current technology IGCC examples shown in Tables 7 and 8, the cost of CO_2 emissions avoided is \$73/tC to \$119/tC (equivalent to a gasoline price of 17 to 28 ¢ per gallon) for coal IGCC compared to \$186 to \$194 per tC for the coal steam-electric options shown in Table 6.

The Public Benefits Case for IGCC

There is no plausible coal alternative to gasification-based synfuels and H_2 in mitigating oil-insecurity risks (Simbeck, Dickenson, and Moll, 1981; Williams and Larson, 2003). But even when considering air-pollution and climate-change issues, IGCC stands out as being far preferable to combustion-based technologies—for fundamental reasons.

Air-pollution-mitigation case for IGCC

Until the mid-1990s, scholarly estimates of environmental damage costs from air-pollutant emissions from coal-fired power plants were tiny in relation to private economic costs for making electricity from coal (ORNL and RfF, 1994). But that situation changed with the publication of the first studies of chronic mortality impacts of small-particle ($PM_{2.5}$) air pollution (Pope et al., 1995).

Recent studies carried out under the ExternE Programme of the European Commission[21] estimate that the environmental damage costs [mostly accounted for by chronic mortality impacts of small particle ($PM_{2.5}$) air pollution] are substantial—although the scientific uncertainty about these damage costs is high (see Appendix A for a detailed discussion). Estimates of these damage costs for the US are presented in Table 1. Even the low estimates of damage costs for existing coal power plants are comparable to direct economic costs for these plants[22] and are still significant even for new coal steam-electric plants equipped with best available control technologies (BACT), while damage costs posed by IGCC plants are comparable to damage costs for the NGCC.

$PM_{2.5}$ is not the only substantial new air-pollutant issue of concern about coal power generation. For example, mercury (Hg) is a neurotoxin to which developing fetuses are especially sensitive. People are exposed to Hg primarily through eating fish that have been contaminated with Hg deposited on water bodies from emissions by coal power plants[23] and other sources. Eventually Hg will be stringently regulated.[24] And it is very likely that other emissions concerns will emerge in the future.

IGCC technology is inherently well-equipped to deal with the trend toward ever-tightening air-pollutant emissions regulations. The air-pollutant emissions mitigation benefits offered by IGCC (Table 1) arise in large part by the ease of realizing low levels of air-pollutant emissions when

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[21] The 1994 ORNL/RfF study was the fruit of a collaboration between these US organizations supported by the US Department of Energy and an ExternE group supported by the European Commission. The US DOE ceased funding of this ORNL/RfF work because of the negative results, but the European Commission continued to support the ExternE research, which ultimately led to results such as those presented in Table 1.

[22] The cost of electricity is ~ 2 ¢ per kWh for coal steam-electric plants that are largely already written off.

[23] Mercury emissions from US coal power plants, about 48 tons per year, account for 42% of total US Hg emissions.

[24] The 1990 Clean Air Act Amendments require the EPA to develop regulations to reduce Hg emissions 90% by 2008. But EPA rules issued in 2004 that were less demanding, calling for reductions of 29% and 70% by 2008 and 2018, respectively.

contaminants are removed from pressurized syngas compared to stack gases where they must be recovered at atmospheric pressure diluted with N_2 from fuel oxidation in air—the latter approach being required for combustion systems.

The ease of pollutant control is illustrated by the case of mercury (Hg). Removal in a carbon bed of more than 90% of the Hg from the compressed syngas of an IGCC at near ambient temperatures has been estimated to cost $1,200 - $1,300 per lb (Klett and Rutkowski, 2001), compared to estimates for flue gas recovery systems for coal steam-electric plants that range from $38,000 per lb (EPA, 1997a) to $85,000 per lb (EIA, 2001). The corresponding cost penalty for electricity generation is ~ 0.01 ¢/kWh for IGCC vs ~ 0.5 ¢/kWh for coal steam-electric technology (Table 2).

Climate-change mitigation case for IGCC

The goal of the United Nations Framework Convention on Climate Change is to stabilize atmospheric composition to "prevent dangerous anthropogenic interference with the climate system" and to achieve that goal in ways that do not disrupt the global economy. What constitutes "dangerous anthropogenic interference" is highly uncertain. However, recent studies suggest that we are much closer to dangerous anthropogenic interference than is generally realized and that mitigating climate change now is desirable (O'Neill and Oppenheimer, 2002; Hansen, 2004).

Electricity generation, which accounts for 36% of global CO_2 emissions (Table 3) has to be a major focus of efforts to mitigate climate change, and, within the power sector, the focus should be on coal (the most carbon-intensive fossil fuel), which accounts for 2/3 of the power-sector's CO_2 emissions. It is expected that more than 1400 GW_e of coal power plant construction will take place between now and 2030 (Figure 4), with China and the US accounting for 35% and 15% of the total increment, respectively (Figure 5). Over the likely 50-year lifetimes of these plants, CO_2 amounting to 130 GtC (equivalent to about 20 years of CO_2 emissions from global fossil fuel combustion at present) would be emitted if CO_2 capture and storage were not pursued.

Resource and cost considerations also indicate that attention should be focused on coal, which is far more abundant than oil and natural gas combined[25] and is not likely to be abandoned if cost-effective ways can be found to use coal in climate-friendly ways.

In 2000, coal accounted for 37% of global CO_2 emissions (Table 4). China is the world's largest coal consumer (accounting for 26% of total world consumption), followed by the United States (at 21%). Developing countries are expected to account for 88% of incremental coal consumption, 2000-2025, and ¾ of this increment is likely to come from China (Table 4).

[25] If we stopped using coal today and eventually used up all the conventional oil and natural gas, the atmospheric CO_2 level would stabilize at 350 ppmv. Using up also non-conventional natural gas (excluding methane clathrate hydrates) would increase the stabilized concentration level to 500 ppmv. Thus coal and unconventional oil and methane clathrate hydrates pose the greatest climate mitigation challenges.

A simple calculation highlights the climate challenge for coal electricity. Consider the goal of stabilizing atmospheric CO_2 at no more than 550 ppmv—double the pre-industrial level.[26] The red emissions trajectories in Figure 3 represent alternative paths for stabilizing at 550 ppmv—a late stabilization effort (broken-line) path[27] and an early (solid-line) path. Consider the early stabilization path, which implies that emissions in 2025 should be no higher than 8.5 GtC (compared to 6.4 GtC in 2000). Relative to the US Energy Information Administration's Business as Usual (BAU) projection that emissions in 2025 will be 10.4 GtC (Table 4), this implies that global total and coal emissions in 2025 should be, respectively, 1.9 GtC and 0.6 GtC less than the BAU amounts. Assuming, simplistically, that the US share of coal emissions reductions in 2025 is proportional to its share of projected coal emissions,[28] some 0.135 GtC/y of emissions from US coal would have to be eliminated (Table 4). If all of this reduction for US coal were realized by capturing and storing underground CO_2 emissions from coal power plants, some 92 GW_e of US coal capacity [accounting for 82% of the new US coal generating capacity expected to be built, 2010-2025 (EIA, 2004)] would have to be decarbonized by 2025, when the US CO_2 storage rate would be about 400 million tonnes of CO_2 per year.[29]

As noted earlier, meeting the climate-change-mitigation challenge with IGCC would be much less costly than with coal steam-electric technology for bituminous coals. The cost of capturing and storing 400 million tonnes of CO_2 recovered annually from coal power plants in the US would be $7 billion with present-day IGCC technology and $5 billion per year with projected advanced (2020-vintage) IGCC technology[30] (Table 8)—compared to $14 billion per year using ultra-critical steam-electric plants (Table 6).

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[26] Which might not be enough to "prevent dangerous anthropogenic interference" with the climate system.

[27] The argument for late stabilization is that in the future we will be "smarter and richer." "Smarter" refers to the expectation that advanced technology will make climate-change-mitigation cheaper. But most technological change takes place, not as a result of new technologies springing forth from the laboratory into the market but rather as a result of a large number of small incremental improvements that take place as a result of accumulating commercial experience. And while we indeed will be richer in the future, pursuing the late-stabilization path runs the risk that a lot of capital would have to be turned over prematurely—which can be very costly.

[28] Developing countries will argue instead for a more equitable distribution of CO_2 emission rights, so that the share of global emissions reduction required on the part of the industrialized countries should be much greater than for developing countries, where per capita CO_2 emission rates are much lower.

[29] If instead the goal were to stabilization at 500 ppmv, global emissions in 2025 should be no higher than 7.3 GtC (Figure 3), which implies that global total and coal emissions in 2025 should be, respectively, 3.1 GtC and 1.0 GtC less than the BAU amounts, and that the US share of coal emissions reductions in 2025 would be 0.222 GtC/y. If all of this reduction goal for US coal were realized by capturing and storing underground CO_2 emissions from coal power plants, some 151 GW_e of US coal capacity [accounting for 100% of new US coal generating capacity expected to be built, 2010-2025, along with the retrofit of 39 GW_e or 13% of "old" coal generating capacity in 2025] would have to be decarbonized by 2025, when the CO_2 storage rate would be about 650 million tonnes of CO_2 per year.

[30] These costs are relatively modest relative to the replacement cost with CO_2 vented for the 2975 TWh per year of US coal electricity generation projected for 2025 (EIA, 2004)—some $121 billion per year [@ 4 ¢ per kWh (Table 8)].

The cost of avoiding CO_2 emissions is so much less for IGCC than for steam-electric power because of fundamental differences between post-combustion and pre-combustion approaches to decarbonizing fossil fuels—as reflected in the relative partial pressures for the CO_2 in the gases from which the CO_2 is extracted. For steam-electric power plants, the only decarbonization option at present is the post-combustion approach, which involves the removal of CO_2 from "flue gas." In the flue gas, the CO_2 is heavily diluted with N_2 from the air used for coal combustion. For coal steam-electric power plants, CO_2 makes up only about 15% of flue gas, which is at 1 atmosphere (1 atm) of pressure, so that the partial pressure of CO_2 is 0.15 x (1 atm) = 0.15 atm. For IGCC plants, one could also recover CO_2 from flue gas, but a much less costly approach involves pre-combustion recovery of CO_2 from "fuel gas" (i.e., syngas) at very high partial pressure (Figure 6). The initial steps involve: (*i*) gasification of coal in oxygen[31] at high pressure (70 atm[32]) and temperature, (*ii*) a water quench (bath) to remove particles and to cool and saturate the syngas with water vapor, (*iii*) reaction of the carbon monoxide in the syngas with steam to produce mostly H_2 and CO_2 in so-called water-gas-shift[33] (WGS) reactors, and (*iv*) use of physical solvents to remove from the syngas, in turn, first H_2S (a syngas contaminant) and then the CO_2. Because of the high pressure of the gasifier and the high concentration of CO_2 in the shifted syngas, the partial pressure at which the CO_2 removed is high (25-30 atm), which makes the CO_2 recovery cost much less than for recovery of CO_2 from flue gases. The H_2S and CO_2 are then recovered from the solvents by depressurization and, in the case of H_2S, by heating with steam as well. The H_2S is then reduced to elemental sulfur, and the CO_2 is dried and compressed to perhaps 150 atm for pipeline transmission to a suitable geological storage site.[34] The H_2-rich (CO_2-depleted) syngas is then burned in the gas turbine of a gas turbine/steam turbine combined cycle power plant to produce electricity.

For IGCC the amount of coal required to produce a kWh of electricity with CO_2 capture and storage (CCS) is 20-30% more than with CO_2 vented (Table 7), compared to 38-40% more for coal steam-electric technologies (Table 6). Also, the generation cost for IGCC electricity with CCS is 35-47% more than with CO_2 vented (Table 7), compared to a 71-78% increase for coal steam-electric power plants (Table 6).

In principle, the pre-combustion approach to decarbonization can be carried out for NGCC technology as well—by making syngas from natural gas,[35] shifting the syngas to produce mostly H_2 and CO_2, capturing the CO_2 from the shifted syngas and storing it underground, and finally burning the H_2–rich (CO_2–depleted) syngas in the gas turbine of a combined cycle plant.

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[31] The O_2 is obtained from air in a cryogenic air separation unit (Figure 6). In principle air could be used for gasification instead, but when air is the gasifying agent, the syngas product is heavily diluted with N_2, and, as a result, CO_2 removal from shifted syngas would be much more costly than removal when O_2 is the oxidizing agent.

[32] For an IGCC that uses the ChevronTexaco gasifier (Chiesa et al., 2004; Kreutz et al., 2004).

[33] The water-gas-shift reaction ($CO + H_2O \rightarrow H_2 + CO_2$) is a mildly exothermic reaction that transfers most of the chemical energy in the CO to H_2.

[34] Storage options include depleted oil and natural gas fields, deep beds of unminable coal, and deep saline aquifers.

[35] This is typically done by steam reforming methane (CH_4, the main constituent of natural gas) at high temperature in the presence of an appropriate catalyst: $CH_4 + H_2O \rightarrow CO + 3\ H_2$.

However, in contrast to the coal case, pre-combustion decarbonization is not cheaper than post-combustion decarbonization. Moreover, the cost of CO_2 emissions avoided is \$100 to \$250 more per tC than even for coal steam-electric plants (Table 6)—a result that stems mainly from the fact that the CO_2 concentration in flue gas is even less (~ 6%) for the NGCC than for coal steam-electric plants (~ 15%), owing to the need for a large amount of excess air in the NGCC combustor. Thus with current NGCC technology, decarbonization is not especially interesting from an economic perspective. However, the need for decarbonization of the NGCC is also less pressing—since the CO_2 emission rate is less than half of that for the most-efficient coal power generating technologies when CO_2 is vented (Table 6).

If IGCC can be successfully launched in the market, the technology will be improved both as a result of many modest incremental changes that arise from growing field experience and, occasionally, as a result of "quantum" changes in the technology. Table 8 presents estimates of IGCC performance and cost for advanced (vintage ~ 2020) IGCC technology relative to current technology[36] made recently by Foster Wheeler Energy (FWE) in a study carried out for the International Energy Agency's GHG R&D Programme. If these performance and cost projections could be realized, the efficiency of coal power generation with CCS would be 26% higher than for the average US coal steam-electric plant today,[37] and the generation cost for coal electricity with CCS would be just 6% higher than for today's new IGCC plant with CO_2 vented. The cost of CO_2 emissions avoided would be ~ \$50/tC—equivalent to a 12 ¢ a gallon tax on gasoline.

It is the opinion of the author that the improvements in IGCC technology projected by FWE for the 2020 time frame are sensible and plausible. Most of the suggested improvements represent marginal improvements that are likely to come about as a result of private-sector R&D investments made in conjunction with growing field experience. For example, most of the suggested gasifier improvements involve combining, in a single gasifier, the best feature of each of the three commercial entrained-flow gasifiers. The only "quantum" technological change in the suggested 2020 IGCC design involves use of ion transport membrane (ITM) technology for air separation as an alternative to present-day cryogenic air separation technology. ITM is being intensively developed by both Air Products and Praxair with support from the US Department of Energy. This technology will have many uses other than for making syngas via coal gasification and is widely expected to become commercially available during the second decade of this century.

The Outlook for Coal IGCC

The analysis presented here shows that integrated gasifier combined cycle (IGCC) technology has evolved to the point where electricity generation costs with CO_2 vented are essentially the same as for steam-electric plants for bituminous coals. It also envisions a technologically and

[36] Except for scale, the current IGCC technology considered by Foster Wheeler Energy in Table 8 is essentially the same as the ChevronTexaco gasifier case presented in Table 7; note that generation costs are about the same for both the CO_2 vented with current technology case and the CO_2 captured with advanced (~ 2020) technology case.

[37] Some 41.3% for an advanced coal IGCC plant (Table 8) compared to an average efficiency of 32.7% for all US coal power plants in 2003.

economically promising future for (IGCC) technology in addressing concerns about both air pollution [coal IGCC plants can be as clean as natural gas combined cycle (NGCC) plants] and climate change [a coal IGCC with CO_2 capture and storage (CCS) is potentially a less costly option for climate mitigation in the US than either a coal steam-electric plant with CCS or a NGCC].

This analysis also highlights the good prospects for realizing technological improvement and lower costs for coal IGCC over the next two decades. Of course, as coal IGCC technology improves, one can expect coal steam-electric technology to continue improving as well, so that the coal IGCC will be competing with a moving target. However, it is reasonable to expect that, with field experience, the coal IGCC will pull ahead of coal steam-electric technology. This is because for most technologies there is a tendency for the unit cost of a manufactured good to fall as a function of cumulative production experience. Cost reductions are typically very rapid at first but taper off as a technology matures. This relationship is called a "learning curve" or "experience curve" when it accounts for all production costs (Figure 8). Early investments are needed to "buy down" the costs of new technologies along their experience curves to levels where they can be widely competitive (Figure 9). If both coal IGCC and coal steam-electric technology were to have identical "learning rates" *per doubling of cumulative production*, IGCC would soon pull ahead simply because cost reductions *per unit time* would be faster for IGCC in light of the much more extensive experience with the coal steam-electric technology.[38] Despite this promising *technological* outlook, there are three major *institutional* challenges that must be overcome:

The first is that coal IGCC technology is not likely to be launched in the market without appropriate promotion by the public sector. Although various recent analyses indicate IGCC costs have fallen to the level for steam-electric plants for bituminous coals, the technology will not be adopted by prospective users unless it is perceived as offering marked benefits relative to steam-electric generating technology. Although, as shown, coal IGCC does offer substantial benefits relative to coal steam-electric technology, those benefits are mainly public benefits not yet reflected in energy market prices.

The second is that, although all components of current IGCC CO_2 capture (CC) systems are fully proven and commercially available, no IGCC systems with CC have been built. Early field experience will be needed with CO_2 capture technologies—well before the "trigger" carbon market price (manifest as a carbon tax, market price under cap-and-trade, or the equivalent) at which CC becomes profitable is reached. This prospect poses a great difficulty for coal on the path to a climate management regime because market forces will not provide adequate incentives for coal IGCC electricity providers to gain early experience with CC technologies—experience that would both help prepare the industry to deal with the rigors of a carbon management regime

[38] Suppose, hypothetically, that costs for each technology are currently equal, that costs fall 20% for each cumulative doubling of production, and that, to date, 10,000 units and 10 units each have been produced for coal steam-electric and coal IGCC technologies, respectively. By the time 10 more IGCCs have been produced, its costs would be 20% less, but 10,000 more coal steam-electric units would have to be produced to gain a 20% cost reduction.

without having to abandon coal and to help, with this early experience, buy down the cost of CC technologies.

The third, and probably the most fundamental, is that the whole notion of a viable future for coal in a climate-constrained world hinges on the viability of CO_2 storage at "gigascale." Determining this viability requires not just more R&D on CO_2 storage (which is very important) but also the conduct of many "megacale" CO_2 storage demonstration projects during the next 10-15 years and the accumulation of some commercial experience with CCS, well before a carbon management policy is in place that makes CO_2 capture and storage profitable for coal.

Acknowledgments

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Appendix: ExternE Air Pollution Damage Cost Estimates for Fossil Fuel Power Generation

Air pollution from fossil fuel burning gives rise crop, forest, and ecological damage, as well as health damages, the costs of which are not adequately reflected in market energy prices. In recent years health damages, especially from chronic exposure to small particle air pollutants has been a focal concern about air pollution. Recent epidemiological research indicates major mortality impacts from long-term, low-level exposure to particulates (Pope *et al.* 1995)—both particles emitted directly in combustion and sulfate and nitrate particles formed in the atmosphere from gaseous precursor emissions of SO_2 and NO_x. Lippman and Schlesinger (2000) survey the recent literature, concluding that the correlation of ambient particulate exposure levels commonly found in U.S. cities with increased human mortality and morbidity remains robust to all attempts to identify possible confounding variables. The available literature generally suggests a linear dose-response function for any given type of particulate, but Dockery *et al.* (1993) indicates that particulates smaller than 10 microns (PM_{10}) are more damaging than larger particles, while particles smaller than 2.5 microns ($PM_{2.5}$) show the strongest correlation with mortality by far.

It is estimated that those in the US who have died from exposure to $PM_{2.5}$ air pollution particles had their lives shortened, on average, by 14 years (EPA, 1997b). About 75% of those who have died prematurely have been age 65 and older, but this age group accounts for only about half of the average (14 y) life-shortening, because the years of life lost (YOLL) for this age group is modest relative to that for deaths among younger groups.[39] Reducing small-particle air pollution can have substantial impacts on mortality. The US Environmental Protection Agency has estimated (EPA, 1997b) that, as a result of implementing the Clean Air Act of 1970, premature deaths in 1990 were 184,000 less than if this legislation had not been enacted—i.e., if the Clean Air Act had not been in place, total US deaths in that year would have been 8.5% higher in 1990. Similarly, the EPA projects that the Clean Air Act Amendments of 1990 will reduce the US death rate in 2010 by 23,000/y (EPA, 1999). But even with these laws in place, the premature death rate associated with residual small particle air pollution is significant. For example, Abt (2002) projects 6,000 premature deaths from emissions from 80 U.S. coal-fired power plants in the year 2007 (even accounting for new control technologies mandated by that year).

These recent findings translate into much higher costs for air pollution damages than was the case for studies before chronic mortality impacts were taken into account. The ExternE (External Costs of Energy) Project of the European Commission has supported for more than a decade research aimed at quantifying environmental damage costs associated with energy production—focusing on health impacts but considering other impacts (including climate impacts) as well. The ExternE assessment of air pollution damage costs for fossil fuel power plants involves: (*i*) quantifying air-pollutant emissions from specified power plants (g/kWh), (*ii*) calculating the resulting increased air-pollutant concentrations in all affected regions, taking into account both dispersion of pollutants and atmospheric chemistry as appropriate, (*iii*) calculating impacts of increased air-pollutant concentrations (e.g., using dose-response functions in estimating health

[39] About 10 years of lost life (YOLL), on average, for those 65 and older, who account for 75% of those who have died prematurely, compared to 48 YOLL for those age 30-34 who make up 2% of those who have died prematurely.

impacts), and (*iv*) making economic valuations of these impacts.[40] In assessing Europe-wide impacts a key parameter of these studies is the value of the years of life lost (YOLL) per death due to pollution exposure—which the ExternE studies estimate to be 83,000 Euros (91,000 USD) for chronic mortality and 155,000 Euros (170,000 USD) for acute mortaliy.[41] Rabl and Spadaro (2000) estimate for "average" European conditions (including a population density of 80 persons/km^2) that the air-pollution damage costs for a new baseload coal steam-electric power plants equipped with electrostatic precipitators and flue gas desulfurization equipment would be 0.045 Euros ($0.05) per kWh for coal plants[42] (~ 1 ¼ times the cost of electricity from a new coal steam-electric plant without internalization of the externalities). Most of the estimated environmental damage cost is associated with chronic mortality arising from small particle air pollution, and most of that arises from nitrate and sulfate particles generated in the atmosphere from gaseous precursor emissions of NO_x and SO_2. There are considerable uncertainties underlying these damage cost estimates. For example, Rabl and Spadaro (2000) estimates that the mean estimates of damages from NO_x and SO_2 (mostly via nitrate and sulfate particle formation in the atmosphere) and from PM_{10} are 16.0, 10.55, and 15.4 Euros per kg (1 Euro = 1.1 USD), respectively, but the damage values at 1 geometric standard deviation are, on the low side, 0.15 times these mean values and, on the high side, 2.5 times these mean values. Moreover, the mechanisms of action for health damages are not well understood, some of the issues involved are controversial, and uncertainties underlying these air pollution damage cost estimates are high.[43,44] Nevertheless, the ExternE environmental damage cost estimates represent the state-of-the-art in estimating costs of externalities for energy production systems.

To get rough estimates of damage costs arising from air pollution for the United States, adapting unmodified the ExternE findings for Europe to US regions with comparable population densities [for example, the US region East of the Mississippi (76 persons/km^2 in 2000)] is not unreasonable, in light of the fact that crucial dose-response function for chronic mortality (which dominates ExternE air pollution damage cost estimates) is based on studies in the United States (Pope *et al*., 1995) and the comparability of US and European per capita incomes.

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[40] The economic impacts are estimated on the basis of estimates of "the willingness-to-pay," the amount of money a person is willing to pay to eliminate or reduce the adverse impact.

[41] Calculated from an assumed value of a statistical life (VSL) of 3.1 million Euros (3.4 million USD).

[42] For comparison, a study by the Oak Ridge National Laboratory and Resources for the Future (ORNL and RfF, 1994) carried out in collaboration with ExternE researchers but *which did not take into account chronic mortality impacts*, estimated that the health damage cost for a new coal plant in the Southeast US would be $0.0003 per kWh.

[43] For example, at 1 geometric standard deviation from the median damage cost estimates, the value of NOx damage costs via nitrate particle formation in the atmosphere are about twice the median estimate on the high side and about 1/5 of the median estimate on the low side (Rabl and Spadaro, 2000).

[44] Following current ExternE practice, the Rabl and Spadaro (2000) analysis assumes that SO_2 and NO_x emissions generate secondary aerosols that can be treated as $PM_{2.5}$ and PM_{10}, respectively, although there is much uncertainty about this assumption. The authors caution that, although there are studies that report correlations of mortality with sulfates, there are no concentration-response functions for nitrates, because in the past nitrates have not been monitored as a separate component of air pollution.

Table 1: Emission Rates and Low Estimates of Air-Pollutant Damage Costs for Fossil Fuel Power Plants[a]

	Emission rate (g/kWh)			Low/mean/high estimates of environmental damage costs (¢/kWh)[e]				Damage costs relative to NGCC
Primary air pollutant	SO_2	NO_x	PM_{10}	SO_2	NO_x	PM_{10}	Total	Total
Average US coal power plant (1997)	6.10	3.47	0.16	1.1/7.1/17.7	0.92/6.1/15.3	0.04/0.27/0.68	2.0/13.5/33.7	84
New coal steam-electric plant (BACT)[b]	0.46	0.87	0.15	0.08/0.53/1.33	0.23/1.5/3.8	0.04/0.25/0.63	0.35/2.3/5.8	14
Coal IGCC plant[c]	0.078	0.086	0.0026	0.01/0.09/0.23	0.022/0.15/0.38	0.001/0.004/0.01	0.033/0.24/0.62	1.5
NGCC plant[d]	-	0.093	-	-	0.025/0.16/0.41	-	0.025/0.16/0.41	1.0

[a] Source: Willams (2000).

[b] For steam-electric plants, the technology for reducing S emissions 95% is commercially available. It is assumed that the coal contains 479 g S/MBTU (1.08% S), the average for coal power plants in the United States in 1997. An NO_x emission rate of 91 g/MBTU is assumed; such a rate is feasible with state-of-the-art low-NO_x burners for coal steam-electric plants. The efficiency of a new coal steam-electric plant is assumed to be 35.5% (HHV basis).

[c] Based on the actual emissions for the Buggenum coal IGCC plant (Netherlands). The measured emission rates (g/MBTU of coal input) are 10.55 for NO_x and 0.32 for particulates, as well as 99% S recovery, corresponding (for coal with 479 g S/MBTU—1.08% S) to 9.6 g SO_2/MBTU. These emission rates are applied to a coal IGCC plant based on the use of GE's Frame 7H combined cycle, which has a 43.1 %-efficient (HHV basis, Table 6).

[d] For a natural gas combined cycle (NGCC) based on the GE Frame 7H combined cycle (the same technology assumed here for use in the coal IGCC) with an efficiency of 53.6 % (HHV basis, Table 6), the NO_x emission rate is 9 ppmv (dry) at 15% O_2, corresponding to an emission rate of 0.093 g/kWh..

[e] Specific environmental damage costs ($/kg) are based on valuations of environmental damage costs developed in Rabl and Spadaro (2000) for typical power plant sitings in Europe. The Rabl and Spadaro (2000) calculations were carried out under the European Commission's ExternE Programme. Nearly all the estimated costs of environmental damages are associated with adverse health impacts; the economic values of health impacts were estimated on the basis of the willingness to pay to avoid adverse health effects. Rabl and Spadaro (2002) considered a wide range of pollutants but the only significant damage costs were from SO_2, NO_x and PM_{10} emissions, for which their mean estimates of damage costs (in dollars per kilogram) were $11.6 for SO_2, $17.6 for NO_x, and $16.9 for PM_{10}, respectively, and damage costs at standard deviation below and above the mean are 0.15 and 2.5 times the mean values (Appendix A).

Adapting the Rabl and Spadaro (2000) ExternE valuations of environmental damage costs (in $/kg for each criteria pollutant) to the United States without modification is not unreasonable because: (*i*) the dose-response function for chronic mortality (which dominates ExternE air pollution damage cost estimates) is based on studies in the United States (Pope et al., 1995), (*ii*) the comparability of per capita incomes in Europe and the United States, and (*iii*) the fact that population densities are similar in the regions of interest [for example, the US region East of the Mississippi had an average population density of 76 persons/km^2 in 2000, compared to the value of 80 persons/km^2 estimated in Rabl and Spadaro (2000) for "average" European conditions].

Table 2: Cost of Controlling Mercury Emissions from Alternative Coal Power Plants		
	Steam-electric plant[a]	IGCC plant
Specific capital cost ($/kW)	6.3	1.85
Fixed O&M costs ($/kW-year)	0.51	0.15
Capacity factor (%)	85	80
Levelized annual capital charge rate	0.15	0.15
Cost per kWh of electricity generated (¢/kWh)		
Capital charge	0.0127	0.0040
Fixed O&M	0.0068	0.0021
Variable O&M	0.5380	0.0041
Total cost	0.5575	0.0102

[a] Cost estimate for 90% mercury removal (Brown et al., 1998).

[b] Cost estimate for 98% mercury removal (Klett and Rutkowski, 2001).

Table 3: Distribution of Global CO_2 Emissions from Fossil Fuel Combustion (%)			
Year	2000	2020	2050
Electricity generation	36	25-38	22-43
Industry	32	28-32	24-37
Transportation	21	21-25	18-33
Residential/commercial	12	12-20	11-19

Source: International Energy Agency data for 2000. Projections are for the A1B-AIM, AIT-Message, A2-Image, B1-Image, B2-Message scenarios of the Intergovernmental Panel on Climate Change (IPCC, 2000).

Table 4: Coal Use Worldwide and Associated CO_2 Emissions[a]						
	Coal use by world region (Quads/year)			CO_2 emissions from coal (10^6 tC/year)		
	2000	2025	2000-2025 increment	2000	2025	2000-2025 increment
Industrialized world	38.6	45.9	7.3	985	1,172	187
US	19.8	26.8	7.0	579	753	174
Rest of industrialized world	18.8	19.1	0.3	406	419	13
EE/FSU	12.2	10.2	- 2.0	307	257	- 50
Developing world	42.8	82.9	40.1	1,078	2,085	1,007
China	24.1	54.5	30.4	595	1352	757
Rest of developing world	18.7	28.4	9.7	483	733	250
World	93.6	139.0	45.4	2,370	3,514	1,144
Global perspective	Total primary energy use (Quads/year)			Total CO_2 emissions (10^6 tC/year)		
	2000	2025	2000-2025 increment	2000	2025	2000-2025 increment
World	398.9	640.1	241.2	6,417	10,361	3,944

[a] Source: EIA (2003).

Table 5: Assumed Financing Rules for Energy Systems[a]		
	Coal plants	Natural gas plants
Construction period (years)	4	2.5
Number of equal payments for plant during construction	4	3
Inflation rate (%/year)	2	2
Book life (years)	30	30
Tax life (years)	20	20
Depreciation for tax purposes[b]	MACRS	MACRS
Corporate income tax rate (%)	38.2	38.2
Property taxes and insurance (%/year)	2	2
Nominal return on equity (%/year)	16.7	16.7
Nominal return on debt (%/year)	6.5	6.5
Equity share (%)	45	45
Debt share (%)	55	55
Real discount rate[c] (%/year)	8.0	8.0

[a] Based on EPRI *Technical Assessment Guide* financing rules for regulated utilities (EPRI, 1993).

[b] MACRS = modified accelerated capital recovery system.

[c] After-tax weighted real average cost of capital.

Table 6: Performance and Costs of Alternative Fossil Fuel Power Plants[a] (*CO_2 vented vs. CO_2 captured and stored*)

Tech-nology	CF (%)	Net output (MW_e)		Overnight cost ($/$kW_e$)		Emissions (*g CO_2/kWh*)		Efficiency (*%, HHV basis*)		Generation cost (*¢/kWh*)			Dispatch cost (*¢/kWh*)		CO_2 storage rate (t CO_2 /hour)	CO_2 storage cost (*$/t CO_2*)	Cost of CO_2 emissions avoided[b] (*$/t C*)
Fate of CO_2:		V	C	V	C	V	C/S	V	C/S	V	C	C/S	V	C/S			
Coal SCS	85	462.1	329.3	1143	1981	774	108	40.5	28.9	4.54	7.52	8.07	1.67	3.11	322.5	5.57	194
Coal UCS	85	506.2	367.4	1161	1943	734	101	42.7	31.0	4.53	7.25	7.74	1.61	2.91	335.0	5.46	186
Coal IGCC	85	424.5	403.5	1263	1642	718	73	43.1	37.0	4.56	5.71	6.12	1.32	1.97	308.6	5.38	89
NGCC	85	384.4	310.8	496	943	338	40	53.6	43.3	4.15	6.21	6.54	2.95	4.29	117.5	8.54	293
NGCC	65	384.4	310.8	496	943	338	40	53.6	43.3	4.52	6.90	7.23	2.95	4.39	117.5	11.2	345
NGCC	45	384.4	310.8	496	943	338	40	53.6	43.3	5.22	8.21	8.82	2.95	5.58	117.5	16.1	443

[a] Based on EPRI/DOE (2000) except that: capacity factors in all cases are assumed to be 85% for all but the last two cases shown; it is assumed that coal and natural gas prices are as indicated: these prices ($1.22/MBTU for coal and $4.43/MBTU for natural gas) are average levelized prices for US electric generators for the period 2005-2025, as projected by the Energy Information Administration (EIA, 2004); financing is according to the "conventional financing" scheme described in Table 5 (which implies ALCCR = 0.150 for the coal systems and ALCCR = 0.148 for the NGCC systems); and costs for CO_2 transport and storage have been added. [It is assumed that CO_2 is transported by pipeline 100 km for storage (in an aquifer 2 km underground) and that the maximum injection rate is 2500 tonnes per day per well.]. Dispatch costs = fuel cost + variable O&M cost + (for C/S cases) cost for CO_2 transport and storage.

Here: V = CO_2 vented, C = CO_2 captured, S = CO_2 transported/stored; NGCC = natural gas combined cycle; IGCC = integrated gasifier combined cycle; SCS = supercritical steam-electric plant; USC = ultracritical steam-electric plant; ALCCR = annual levelized capital charge rate. The NGCC and the IGCC both involve use of the GE Frame 7H gas turbine (with steam-cooled blades); the E-Gas gasifier is used in the IGCC.

[b] Cost of CO_2 emissions avoided (calculated relative to the same technology with CO_2 vented, as the reference case)
= (cost, CO_2 captured/transported/stored - cost, CO_2 vented)/(emissions, CO_2 vented – emissions, CO_2 captured/transported/stored).

Table 7: Current CGCC with Alternative Gasifiers and CO_2 Capture Strategies[a] (*EPRI*)								
	ChevronTexaco (*now GE*)				E Gas (*now ConocoPhillips*)			
Fate of CO_2	Vented		Captured		Vented		Captured	
Preinvestment for CO_2 capture?	No	Yes	No	Yes	No	Yes	No	Yes
Plant output (MW_e)	509.3	509.3	424.8	448.9	513.2	513.2	395.6	429.7
Capacity factor (%)	90	90	90	90	90	90	90	90
CO_2 emission rate (g CO_2 /kWh)	876	876	154	154	794	794	146	135
CO_2 storage rate (g $_{CO2}$ /kWh)	-	-	897	896	-	-	889	889
Efficiency (%, HHV)	35.4	35.4	29.5	29.5	39.5	39.5	30.5	30.5
Owner costs[a] (10^6 \$)	54.6	54.6	54.6	54.6	53.6	53.6	53.6	53.6
Overnight construction cost (10^6 \$)	589.9	619.6	678.2	683.0	628.9	696.9	742.8	762.0
Total plant cost[b] (\$/kW_e)	1158	1217	1596	1522	1226	1358	1878	1773
Total plant investment[b] (\$/kW_e)	1305	1370	1798	1714	1380	1530	2115	1997
LACCR[b]	0.156	0.156	0.155	0.155	0.156	0.155	0.154	0.154
Generation cost (¢/kWh)								
Capital charge	2.59	2.71	3.54	3.37	2.73	3.00	4.14	3.90
Fuel @ \$1.22/MBTU (HHV)	1.18	1.18	1.41	1.41	1.05	1.05	1.37	1.37
Fixed O&M	0.27	0.28	0.35	0.33	0.30	0.32	0.42	0.40
Variable O&M	0.38	0.40	0.49	0.47	0.40	0.44	0.57	0.55
Total generation cost	4.42	4.56	5.78	5.58	4.48	4.82	6.50	6.21
Avoided costs with $_{CO2}$ capture [\$/t CO_2 (\$/t C)]								
Reference plant without pre-investment for CO_2 capture			18.9 (69.3)	16.1 (59.0)			30.9 (113.3)	26.0 (95.3)
Reference plant with pre-investment for CO_2 capture			-	14.1 (51.8)			-	21.1 (77.4)
Cost of CO_2 transport and storage (\$/t CO_2)			4.80	4.66			5.01	4.79
Cost of CO_2 transport and storage (¢/kWh)			0.430	0.42			0.45	0.43
Generation cost with storage (¢/kWh)			6.212	6.00			6.94	6.63
Avoided costs with $_{CO2}$ capture and storage [\$/t CO_2 (\$/t C)]								
Reference plant without pre-investment for CO_2 capture and storage			24.9 (91.1)	21.9 (80.1)			37.8 (138.6)	32.5 (118.9)
Reference plant with pre-investment for CO_2 capture and storage			-	19.9 (72.9)			-	27.6 (101.0)

[a] From EPRI (2003) except that: (*i*) the coal price is assumed to be \$1.22/MBTU instead of \$1.32/MBTU, (*ii*) costs for CO_2 transport and storage are added [assuming CO_2 is transported by pipeline 100 km for storage (in an aquifer 2 km underground) and that the maximum injection rate is 2500 tonnes per day per well], and (*iii*) financing is according to the scheme described in Table 5. In EPRI (2003) interest charges during construction are included in owner costs, which are assumed to be constant at \$129.1 million across all ChevronTexaco cases and at \$133.0 million across all E-Gas cases. In order to compare the EPRI (2003) results with the results of the other studies described here on a self-consistent basis: (*i*) interest charges during construction are calculated here separately as = 0.1263 x (overnight construction cost), assuming an 8%/y discount rate and 4 years for construction (Table 5); and (*ii*) for each gasifier the owner cost for the case with CO_2 vented, without pre-investment for CO_2 storage, is calculated as = [owner cost as presented in EPRI (2003)] – (interest charges during construction), and this cost is held constant across all other cases.

[b] Total plant cost (TPC) is the overnight construction cost per unit of net generating capacity. Total plant investment (TPI) = 1.1263 x TPC (i.e., TPI includes interest during construction). LACCR = levelized annual capital charge rate. The capital charge component of generation cost = 100 x LACCR x TPI/(CF x 8760 hours/y). LACCR varies somewhat across the different options considered because the ratio of owner costs (OC—made up of prepaid royalties, startup costs, inventory capital, and land) to overnight construction costs varies across options. [Note: it is not correct to include a term 100 x LACCR x OC/(CF x 8760 hours/y) in the capital charge, because LACCR applies only to the depreciating assets (represented by TPI), whereas OC is a non-depreciating asset; OC costs are accounted for in the calculation of LACCR using the EPRI *TAG* financing methodology (Table 5).]

Table 8: Current and Future CGCC (*IEA GHG R&D Programme*)

	Current technology (*ChevronTexaco gasifier*)		Advanced (~ 2020) technology	
Fate of CO_2	Vented	Captured	Vented	Captured
Plant output	826.5 MW_e	730.3 MW_e	879 MW_e	776 MW_e
Capacity factor (%)	85	85	85	85
CO_2 emission rate (g CO_2/kWh)	833	152	647	110
CO_2 storage rate (g CO_2/kWh)	-	858	-	623
Efficiency (%, LHV/HHV)	38.0/36.33	31.5/30.12	48.9/46.75	43.2/41.30
Owner costs (10^6 \$)	51.9	57.5	50.9	49.9
Overnight construction cost (10^6 \$)	938.2	1042.8	949	926.4
Total plant cost (\$/kW_e)	1135	1427.9	1080	1194
Total plant investment (\$/kW_e)	1278	1608	1216	1345
Electricity generation (TWh/y)	6.154	5.438	6.545	5.778
Annual expenses other than fuel (10^6 \$/y)				
Maintenance	32.4	35.1	34.2	32.3
Waste disposal	5.3	5.6	1.9	1.9
Chemicals and consumables	2.5	3.9	1.7	2.6
Labor	8.3	8.3	8.3	8.3
ALCCR	0.152	0.152	0.152	0.152
Generation cost (¢/kWh)				
Capital charge	2.61	3.29	2.48	2.75
Fuel @ \$1.22/MBTU (HHV basis)	1.15	1.38	0.89	1.01
Operation and maintenance				
Maintenance	0.526	0.645	0.523	0.559
Waste disposal	0.086	0.103	0.029	0.033
Chemicals and consumables	0.041	0.072	0.026	0.045
Labor	0.135	0.153	0.127	0.144
Total operation and maintenance	0.79	0.97	0.71	0.78
Total generation cost	4.55	5.64	4.08	4.54
Avoided cost with CO_2 capture [\$/ $_{CO2}$ (\$/ tC)]	-	16.1 (58.9)	-	8.50 (31.2)
CO_2 transport and storage cost[b] (\$/t CO_2)	-	4.36	-	4.67
CO_2 transport and storage cost (¢/kWh)	-	0.37		0.29
Total generation cost with CO_2 capture + storage (¢/kWh)	-	6.02[a]	-	4.83
Avoided cost with CO_2 capture + storage [\$/t CO_2 (\$/t C)]	-	21.6 (79.0)	-	13.9 (51.0)

[a] Plant performances, capital costs, and O&M costs are from Foster Wheeler Energy (2003). In the original FWE study property taxes and insurance (PTI) were included in O&M costs. With the assumed EPRI TAG financing model, PTI is accounted for in the ALCCR instead (Table 4).

[b] Assuming CO_2 is transported by pipeline 100 km for storage (in an aquifer 2 km underground) and that the maximum injection rate is 2500 t/d per well.

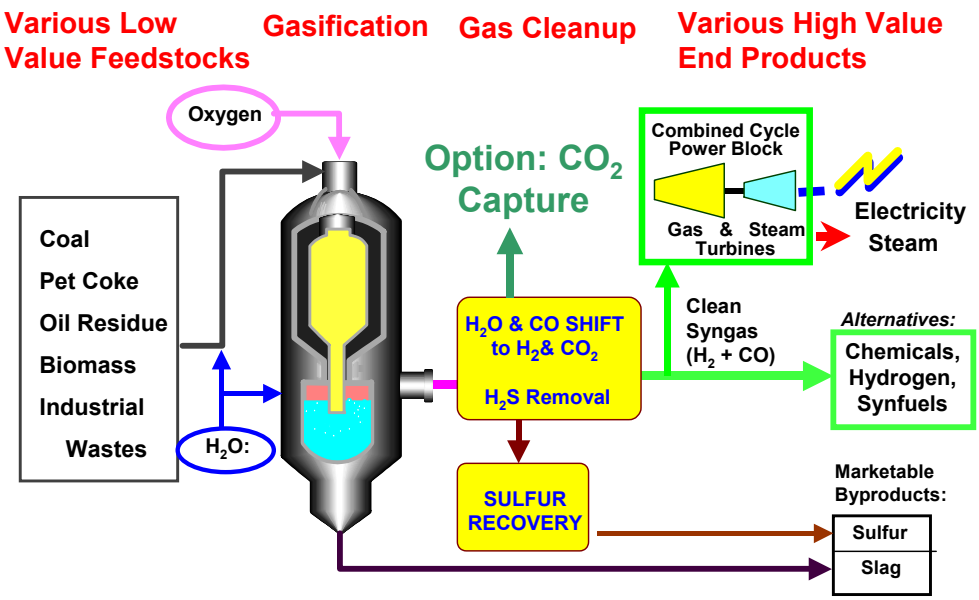

Figure 1: Generic Oxygen-Blown Gasification System

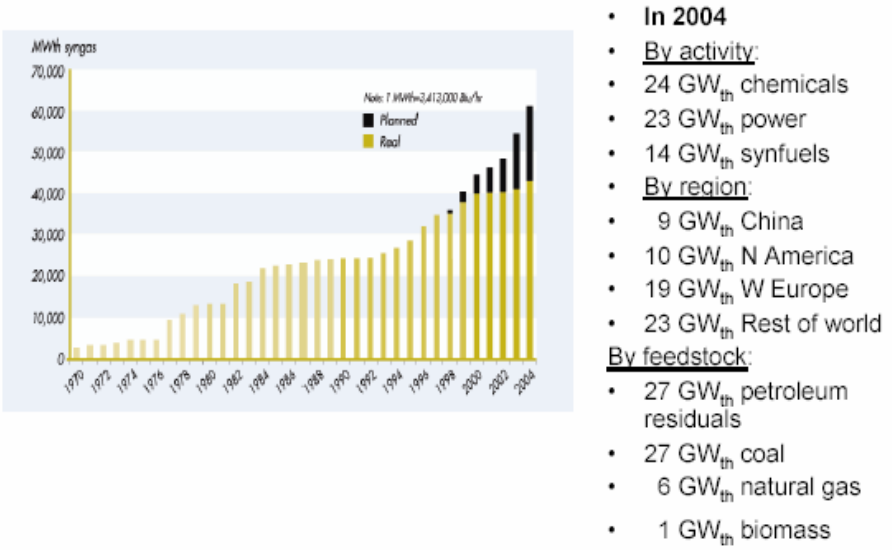

Figure 2: Cumulative Worldwide Gasification Capacity and Growth

Gasification is a booming activity worldwide, with total installed and planned synthesis gas capacity amounting to 61 GW_{th} and new capacity being added at a rate of 4-5 GW_{th} per year.

Source: SFA Pacific (2000).

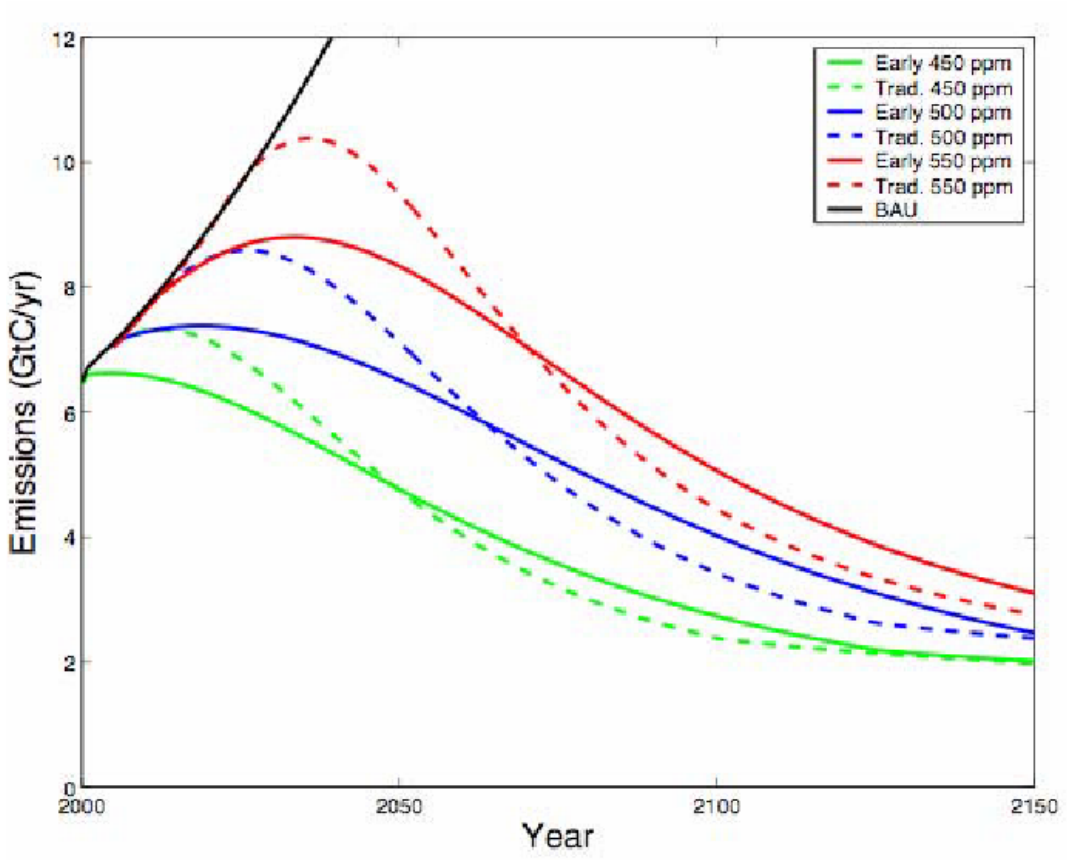

Figure 3: Alternative CO_2 Emissions Trajectories for Stabilizing Atmospheric CO_2 at Levels Not Greater Than Twice the Pre-Industrial Level

The stabilization (colored line) trajectories (prepared by Jeff Greenblatt, Princeton Environmental Institute) assume a constant CO_2 absorption rate by the biosphere amounting to 0.5 GtC/y. A reference (Business as Usual) scenario (black line) is also shown.

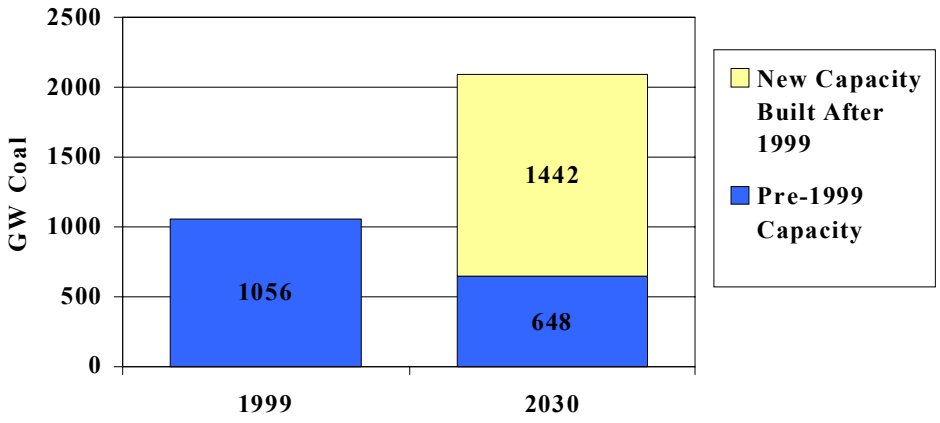

Figure 4: IEA Projection of Worldwide Coal Electric Generating Capacity

Source: IEA (2002).

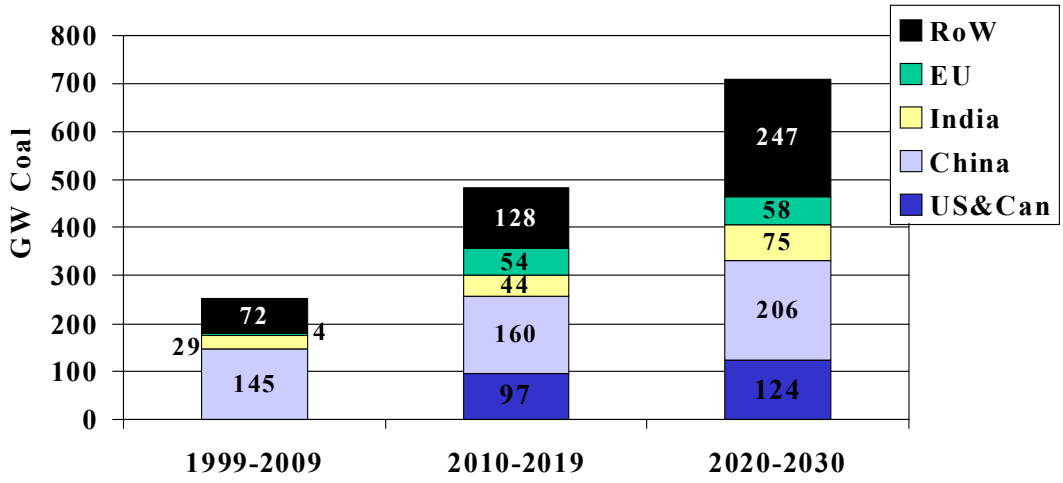

Figure 5: IEA Projection of Coal Generating Capacity Construction by Decade and Region

Source: IEA (2002).

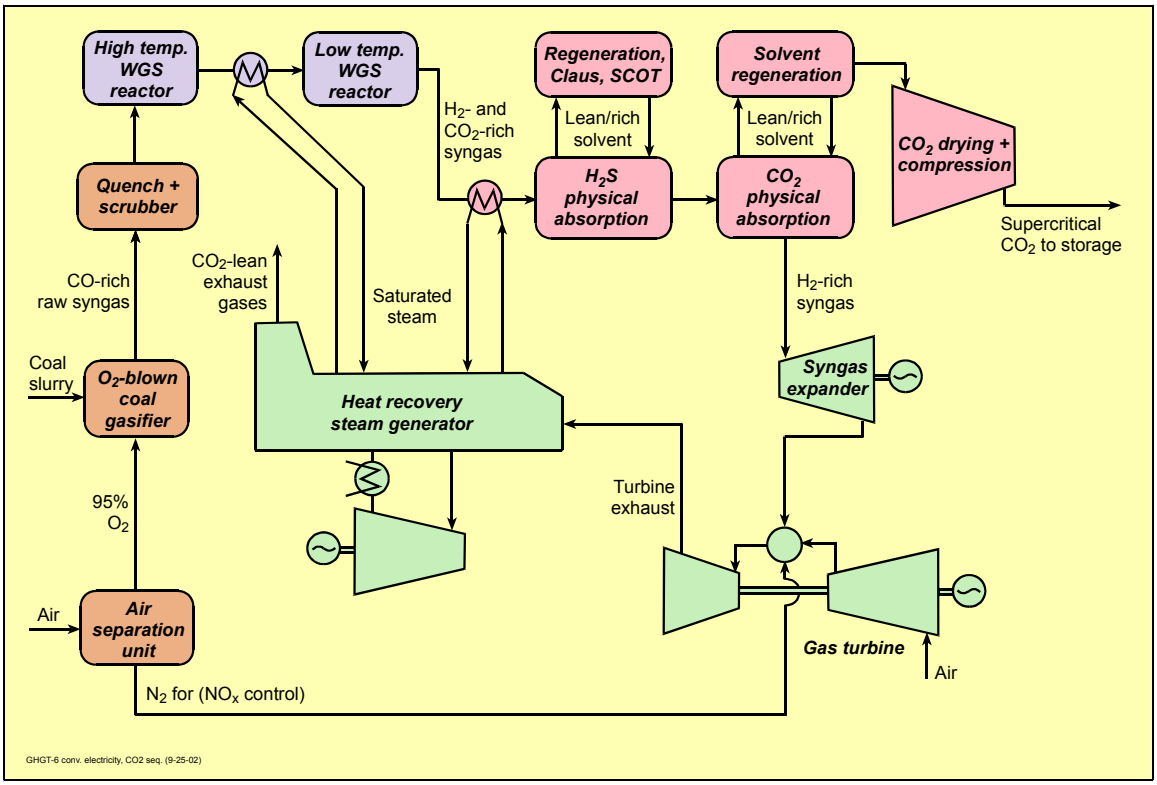

Figure 6: Coal Integrated Gasifier Combined Cycle Power Plant with CO_2 Capture

The IGCC system shown here is based on current technology. Although an IGCC system with CO_2 capture such as this has not yet been built, all components of this system are well established commercially.

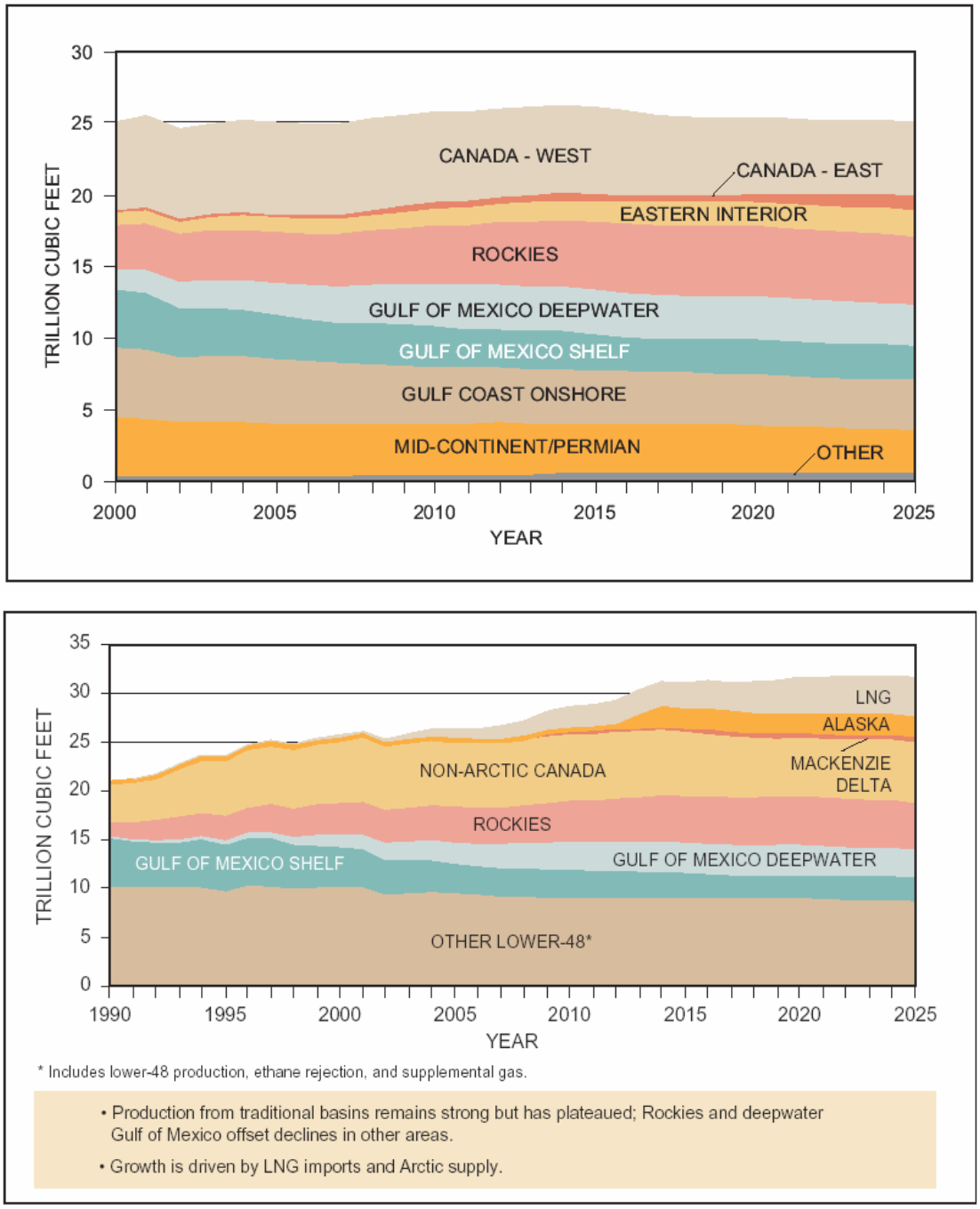

Figure 7: Prospective Natural Gas Production in Lower 48 States and Sub-Arctic Canada (*top*) **and Prospective Natural Gas Supplies for North America** (*bottom*)

Source: National Petroleum Council (2003).

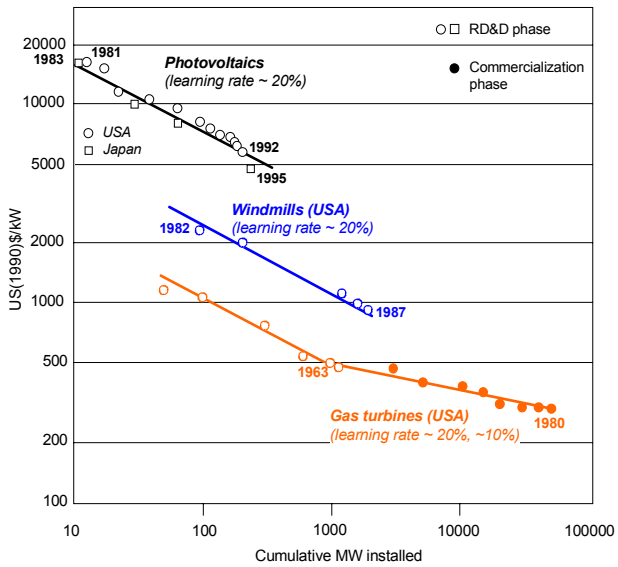

Figure 8: Learning Curves for Photovoltaics, Wind Generators, and Gas Turbines

These curves illustrate that for new products amenable to the economies of mass production, costs tend to decline with cumulative production ("learning by doing"). Typically costs fall 10–30% for each cumulative production doubling. For all technologies shown costs declined initially about 20% per doubling (80% progress ratio). A progress ratio of 80% is the median value for a large number of industries. Although all three technologies in the above graph have similar progress ratios initially, it is notable that after 1963 the progress ratio for gas turbines increased substantially, indicating attenuated learning effects as the technology matured.

Source: Nakicenovic, Grübler, and MacDonald, 1998.

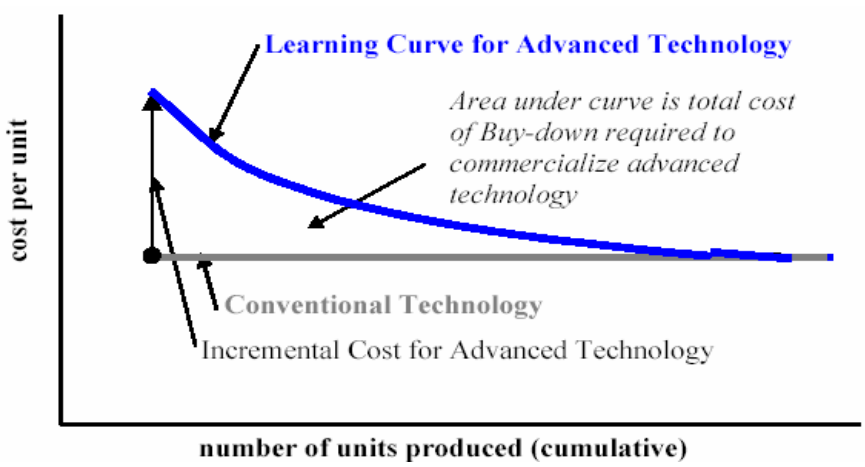

Figure 9: Learning Curve and Buy-Down Cost for an Advanced Energy Technology

The triangular area between the curves indicates the total cost for buying down the cost of the advanced technology to the level at which it is competitive with the conventional technology. The point where the cost equals the cost of the conventional technology is not necessarily the assymptotic (long-term) market price for the advanced technology.

Source: PCAST Panel on International Collaboration in ERD[3], 1999.

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Coal: Planning Its Future and Its Legacy

Overview

Coal is by far the most abundant of the nation's fossil fuels and the source of more than 50 percent of the electricity generated in the United States. A national energy policy aimed at sharply reducing U.S. dependence on foreign oil and gas supplies could result in significantly increased demand for domestic coal, perhaps even to the point of doubling production over the course of the next 25 years.

Such a development would have far-reaching implications. Historically, the coal industry has remained competitive partly by externalizing many of its production costs — in other words, by passing on to society the job of cleaning up after the industry. The nation as a whole, acting through government, labor, and private organizations, has had to assume much of the burden of preventing mine accidents, caring for disabled miners and their dependents, providing medical and social services to aging coal communities, cleaning up polluted streams and reclaiming battered mountains, coping with hazardous mine waste impoundments, and guarding against the needless degradation of the air we breathe.

Many of the most severe effects of insufficiently regulated mining have been mitigated to some extent over the past three decades, thanks in large part to the enactment of comparatively strong laws governing occupational health and safety and protection of the environment, and to the gradual evolution within the industry of a more positive attitude toward constructive regulation. Yet coal mining remains intensely controversial, even in those parts of the nation where it still provides significant employment.

At some point, superior alternative fuels will replace coal as a power source. That day, however, is still many years away. Meanwhile, for at least the next quarter-century, we have a shared responsibility to ensure that the challenging issues

arising at each stage of coal's "life cycle" — from upstream extraction to downstream consumption — are anticipated, understood, and addressed as an integral part of any effort to promote greater energy self-sufficiency for the United States. Only by doing so can we ensure that mining's legacy will be as beneficial for future generations as coal profits are for producers today.

Energy prices in general are expected to continue to rise in the years ahead. If so, coal producers will presumably experience profit margins sufficient to allow internalization of the production costs that historically have been externalized. Coupled with accelerated research on clean coal technologies, and with employment policies conducive to the maintenance of a stable, well-compensated workforce, this could lead to a new era for coal — an era in which our most abundant fuel helps achieve energy independence for the United States, makes important contributions to the national economy, and spurs global innovation in the environmentally appropriate extraction and consumption of fossil fuels.

Part 1: Baseline 2004

The coal industry is vital to the present and future well-being of the United States. Coal currently accounts for more than half of the nation's electric power output and is capable of meeting substantially increased power demand for many decades. Coal arguably has some significant advantages over competing fuels: domestic reserves are abundant, and there is thus no problem of relying unduly on unstable foreign sources, as in the case of oil; coal can be transported safely and without serious risk of vulnerability to terrorist attacks and their consequences, as in the case of liquefied natural gas; coal-fired power plants do not have the safety, security, and spent-fuel risks and hazards of nuclear plants; and at this point in the evolution of alternative technologies, coal is a far more valuable, reliable, and economical source of energy than alternatives such as solar, wind, biomass, and hydrogen-based fuels. Coal clearly has the potential to play a central role in any strategy to promote greater national energy independence.

With more than two centuries of experience, the U.S. coal industry can be characterized as fully evolved and mature. The major problems associated with the production and consumption of coal have long since been identified. Solutions, whether technological or regulatory, are generally available and practicable. We

know how to produce coal economically and safely. We largely know how to mitigate its impact on the environment both at the point of production and at the point of consumption. The essential challenge is to do so effectively and consistently without driving up the costs of production and consumption to the point where, depending on the prices of competing fuels, coal's ability to help meet the nation's energy self-sufficiency objectives could be jeopardized.

U.S. coalmines produced just over 1.1 billion tons in 2001, an all-time record. Production in 2003 stood at about 1.07 billion tons, and over the past decade has averaged about 1 billion tons annually. Approximately 92 percent of that output goes to produce electricity in about 500 coal-fired power plants nationwide. There is no shortage of U.S. coal: recoverable domestic reserves are estimated to exceed 270 billion tons, significantly greater than the recoverable reserves of any other nation.[i]

Reserves are distributed in three major regions: Appalachia, the Interior, and the West. Although Appalachian coal is typically superior in heat value, much of it tends to be relatively high in sulfur content. As a result, largely because of the Clean Air Act, production of lower-sulfur coal from the West has been increasing for many years, while output from the Appalachian region has been stable or declining, as has production from the Interior.

Wyoming, West Virginia, and Kentucky are the three leading coal-producing states today. Wyoming, which has been the nation's top coal-producing state for 17 years, produced a record 375.5 million tons in 2003, accounting for about 35 percent of total U.S. output and more than the output of the next four largest coal-producing states combined. West Virginia, the most important coal-producing state in the Appalachian region, produced 138.4 million tons in 2003, a 7.8-percent drop from the previous year and down about 15 percent from 2001. Much of West Virginia's output has shifted from the higher-sulfur northern coalfields to the lower-sulfur seams in the southern part of the state. Eastern Kentucky produced 91.7 million tons, down about 7.7 percent from the previous year. (Western Kentucky, part of the Interior region, produced 21.4 million tons.) For the Appalachian region as a whole, production in 2003 was 5.4 percent lower than in 2002, and about 13 percent below 2001.[ii] Meanwhile, during the first six months of 2004, while production grew by 12.7 million tons over the first six months of 2003, virtually all of that production increase — 97 percent — occurred at mines west of the Mississippi.[iii]

Nationwide, production today comes predominantly from surface mines, which account for about two-thirds of total output. Relying primarily on heavy earth-moving equipment to expose coal seams, surface mines employed about 40,900 miners nationwide in 2003, compared to underground mines, which employed about 43,600.[iv] Because of productivity increases, brought about in part by the increase in surface mining and in part by the evolution of more productive underground mining techniques, employment overall has been declining for many years. During World War II the U.S. coal industry employed more than 500,000 miners; in 1990, it employed 149,000; as of 2003 total employment stood at about 105,000, including approximately 20,000 preparation-plant and office workers.[v]

Coal mining has differing socioeconomic impacts in the three principal coal-producing regions. In Wyoming, for example, while coal is the major employer in the Powder River Basin region it has not had the kind of longstanding statewide impact that it has had in West Virginia, where thousands of communities have traditionally depended on coal as the major local employer. Today, because of declining employment in Appalachian mines — the result of a combination of increased productivity and mine closures — coal is less often the dominant employer in any given Appalachian county, but it continues to have a major impact on local economies, largely because miners' wages are typically two to three times higher than the low-wage jobs prevalent in such counties.[vi] According to the West Virginia Coal Association, the 310 coal companies operating in the state paid an average of $53,086 each to full-time miners in 2002.[vii]

In much of Appalachia coal has traditionally been the only industry of importance, with the result that changes in coal's fortunes have had a disproportionate impact on the region. This continues to be the case today even though coal extraction no longer requires vast armies of pick-and-shovel miners. A 2001 study by the Appalachian Regional Commission, based on 1997 data from 118 coal-producing counties within the region, found that despite declining employment, the coal industry still accounted for as much as 52 percent of total gross county product in selected counties in West Virginia and throughout the region. "In some counties," the study noted, "coal mining represents such a significant part of the economy that even small changes in demand and output often have a dramatic impact on the well-being of the residents. In recent years, improvements in mining productivity, competition from Western U.S. coal, coal imports from abroad, and environmental legislation all have contributed to substantial job losses in Appalachia. They have also reduced local business opportunities and have generally undermined social well-being in the region."[viii]

The decline in coal employment has been particularly striking in West Virginia. Twenty years ago there were about 63,000 miners working in the state, producing about 129 million tons of coal. By 1997, when the state set an all-time production record of 182 million tons, only about 18,000 miners were needed to set that record. By the end of 2003, fewer than 15,000 miners were working in West Virginia — 3,700 fewer than in Wyoming.[ix]

Equally striking has been the decline in unionized employment, both in absolute numbers and as a percentage of the total coal mining workforce. Thirty years ago, the United Mine Workers of America (UMWA) represented about 76 percent of the roughly 182,000 coal miners working in the United States.[x] Today the UMWA and other unions represent somewhat less than 25 percent of a much smaller total coal-mining workforce.[xi] As a result, although the UMWA remains influential in West Virginia and in some other parts of the coalfields, its ability to influence the overall course of the nation's energy policy is uncertain.

Another important development in recent years has been the increase in the number of independent contractors retained by coal companies to hire workers, operate equipment, and produce coal. In 2002, according to data reported to the federal Mine Safety and Health Administration (MSHA), a total of 2,820 contracting companies reported employing 30,332 workers, corresponding to 16,795 full-time employees — an 8.4-percent increase from 2001. About two-thirds of these contract workers were employed at surface mines, primarily as heavy equipment operators; about 21 percent were working in preparation (processing) plants, and the remaining 12 percent were working in underground mines.[xii] This is a development with significant implications for the future of the coal mining workforce, since contractors can generally hire and fire at will; contract workers may or may not be properly trained; and health and safety risks are certain to increase, while at the same time there is a greater likelihood that work-related accidents and illnesses will be under-reported (an issue discussed further below).

Consolidation of mine ownership and production has been a major trend in coal mining for many decades, and one that continues today. During the past 20 years, while production was generally climbing, the number of mines producing more than 10,000 tons per year diminished from nearly 4,000 to fewer than 1,500. Today the top 10 mines (all of which are in Wyoming) account for more than 30 percent of total nationwide production.[xiii] (The largest mine in the nation —

Peabody Energy's North Antelope Rochelle Complex in Wyoming's Powder River Basin — produced more than 80 million tons in 2003, exceeding the output of all but three coal-producing states.[xiv]) Similarly, just five producers (Peabody Energy, Arch Coal, Kennecott Energy, Consol Energy, and RAG American Coal) account for more than 50 percent of total production.[xv] This level of concentration means, among other things, that a relative handful of major producers could have a disproportionately significant influence in shaping and advancing the goals of a national energy independence policy.

U.S. coal production today essentially breaks down into four key elements:

- **'Supermines'** — About 20 enormous surface mines in the West, averaging more than 20 million tons of output annually apiece, account for nearly half of all U.S. production.[xvi]

- **Longwalls** — About 100 underground mines use longwall mining machines to remove nearly all of a seam of coal (allowing the overburden to subside as the machine moves on), in contrast to traditional room-and-pillar mines that leave much of the coal in place to support the roof of the mine and prevent subsidence. Operating primarily in Pennsylvania, West Virginia, and Kentucky, and requiring relatively few miners, longwall mines account for more than half of all underground production and about 20 percent of total U.S. production.[xvii]

- **Appalachian surface mines** — Approximately 600 strip mines, including mountaintop-removal operations, produce about 145 million tons annually, accounting for about 13 percent of the U.S. total.[xviii]

- **Room-and-pillar underground mines** — Dominated by mines relying primarily on continuous mining machines to remove coal, room-and-pillar mining produces about 163 million tons annually, just under 15 percent of the U.S. total, but its share of total output has been on the decline for many years.[xix]

In addition to these four principal categories of production, there are hundreds of marginal underground mines, primarily in southern Appalachia and generally operated by small crews of miners who typically use explosives and loading machines to remove coal, often from previously worked seams. These mines, on average producing about 10,000 tons apiece annually, in the aggregate produced an estimated 5.9 million tons in 2003, about one-half of one percent of the total.[xx]

The four-part structure outlined above is dramatically different from the industry profile of 30 years ago. Then, there were relatively few mines in the West, and none approaching today's supermines in size; longwall mining was just being introduced in the United States; strip mines in Appalachia typically girdled mountains rather than entirely removing mountaintops; and room-and-pillar mines of moderate size were the underground norm. The industry was, in short, far more fragmented than today and thus, in many respects, much less well-positioned to gear up for the kind of expansion that would be called for by a national energy independence policy.

Given the present structure of the coal industry, could coal production be ratcheted up to levels substantially higher than those being achieved today? Would it be possible, for example, to meet the goals of a national energy independence policy calling for significant substitution of coal for oil and gas during the next 25 years?

The answer to these questions is, in theory, affirmative. The industry is currently working at considerably less than full capacity.[xxi] Reserves are certainly adequate to support an industry of up to twice the present scale throughout the 21st century. Production and transportation capabilities would need to be scaled up rather than created from scratch. Power plants are generally able to substitute one fuel for another, and construction of additional coal-fired plants — beyond the approximately 90 plants now under construction or consideration[xxii] — could be explicitly encouraged as part of an energy independence strategy. Depending on trends in energy prices in general, the capital needs of an expanding industry could be met in part from profits and in part, perhaps, through tax credits and other incentives incorporated in a national energy independence policy.

There are, however, many issues that will influence whether coal plays the role envisioned for it in such a scenario. At each stage of coal's life cycle, from upstream extraction to downstream consumption, there are major challenges that must be addressed if coal is to meet more of the nation's energy needs and if, as a transitional fuel sustaining the nation until superior fuels become practicable, it is to leave a legacy — economic, environmental, and human — that will justify and reward public support for increased production.

Historically, the coal mining industry has had a reputation for taking a cavalier attitude toward many of the problems it has created — from safety and health to its many environmental impacts — and as a result there is a legacy of fear,

distrust, and disrespect for the industry in coal communities as well as regionally and nationally. In an obvious effort to address this problem, the industry's current public relations efforts doggedly accentuate the positive (referring to coal as "buried sunshine" and describing electricity from coal as "essential, affordable, and increasingly clean"). But more than upbeat propaganda will be needed to make coal broadly acceptable as a fuel for the future. "King Coal" must become "Citizen Coal," and its traditional arguments against fully internalizing its costs ("not essential... unaffordable... will cost miners their jobs") must be replaced by a demonstrable willingness to meet its obligations to workers, mining communities, and the environment. Otherwise, powerful public opposition may stymie even the most sophisticated lobbying efforts by the industry and its political allies, and the industry will fall far short of its future potential.

Part 2 of this report discusses the major 'upstream' challenges facing the coal industry — that is, issues associated with the production and transportation of coal.

Part 2: Upstream Coal Production Issues

Coal production must take place within a strong system of safeguards if mining activities are to be carried out at acceptable cost to society in the future. This section describes some of the principal problems associated with coal mining, the measures necessary to ensure compliance with appropriate standards, and the additional challenges that must be met if coal production is to increase under a national energy self-sufficiency scenario.

2.1 Extraction

Several trends are under way that will affect how and where coal is mined in the future. First, there is the continuing shift of production from East to West. Based on current trends and conditions (i.e., absent a national energy independence policy and the resulting impetus for dramatically increased coal production nationwide), the Energy Information Administration anticipates that production from Appalachian mines will remain nearly flat through 2025, while Western coal is expected to experience an annual growth rate of about 1.7 percent. This would have the effect of increasing Western production to nearly 1 billion tons annually by 2025, almost equal to total nationwide production today.[xxiii]

Second, there is the general depletion of thicker coal reserves, again a factor that primarily affects Eastern and Interior mines, and one that becomes more important as the readily accessible thicker seams are increasingly mined out. Producing coal from thinner seams is relatively costly, of course, thus affecting the competitive balance between regions. It also raises attendant issues, such as the safety and health hazards of working in low coal.

Third, there is the trend to longwall mining in major Appalachian underground mines, which has a range of impacts. Longwall mining is more productive than conventional room-and-pillar mining, both because it removes more of the coal seam and because fewer miners are needed to operate a longwall section than are needed to mine equivalent amounts of coal with continuous miners, shuttle cars, roof-bolting machines, and conveyor belts (the basic configuration in room-and-pillar mining, with each machine requiring one or more operators). Thus, although longwalls are much more capital-intensive, in the short term they can improve Appalachian competitiveness by increasing productivity and reducing labor costs.

On the other hand, because longwalls require access to a large, flat seam of virgin coal, they face inherent geological limitations which, over the long run, will limit their ability to contribute to increased coal production overall.

Longwalls can also create both occupational health and environmental problems. Because production is concentrated at one location, dust control is difficult and longwall operators are likely to be exposed to dust levels that may significantly increase their risk of contracting coal workers' pneumoconiosis (black lung), an irreversible, degenerative and ultimately disabling affliction. In 2002, the most recent year for which such data are available, 118 new cases of black lung were reported to MSHA, a disturbing statistic both because black lung is often thought of as a disease of the past and because the actual incidence is almost certainly higher than reported.[xxiv] Continuing concerns about the prevalence of black lung (discussed below) could result in slowing the speed of longwall operations (to control dust) to the point where their competitive advantages may be largely offset by health precautions. And because longwalls remove virtually the entire coal seam, leaving no supports in place, subsidence can and does occur (discussed below). In mountainous Appalachian terrain, where settlement may be minor and uneven, subsidence has been a less conspicuous problem than in the more gently contoured terrain of northern West Virginia, western Pennsylvania, and eastern Ohio. Whether additional regulatory constraints will be required to limit longwall mining under such terrain remains to be seen, but in affected communities there will doubtless be strong public support for such restrictions.

Further study of the above trends will be needed to determine how they might impact, and be impacted by, a national energy independence policy. One obviously important variable is price. For example, coal producers operating at or near the margins of profitability cannot be expected to have or to be able to attract the investment capital needed to develop new longwall sections and the processing and transportation infrastructure needed to make them viable, stable long-term sources of production. Accordingly, in the planning of a national energy independence policy, consideration may need to be given to incorporating some form of price supports, either directly or through tax credits or other incentives, to encourage regionally balanced development that takes advantage of the nation's large Appalachian and Interior as well as Western reserves.[xxv]

In the absence of such balancing incentives, it is not difficult to envision a scenario in which coal's role in achieving the nation's energy independence goals largely takes the form of scaling up western production by developing a few more

supermines on coal lands leased from the federal government, which oversees reserves that would be more than adequate to meet the need.[xxvi] To increase production at a western surface mine by 10 million tons per year, for example, requires little more than adding a 56-cubic-yard shovel for overburden removal, a 40-cubic-yard shovel for coal production, and a few 240-ton haul trucks.[xxvii] Such a development, were it to occur, could have profound implications for the Appalachian region, drastically curtailing the need for its mines (including controversial mountaintop removal, discussed below) and significantly affecting regional employment projections and stability.

While the conventional view holds that one million tons of new production creates 90-100 new mining jobs, this is not the case at western supermines (nor, for that matter, at longwall mines). For example, Arch Coal's Black Thunder Mine in Wyoming required only 580 miners to produce 62.6 million tons in 2003.[xxviii] By comparison, the nation's largest underground mine — Consol's Enlow Fork Mine in Pennsylvania — required 510 miners to produce 9.9 million tons in 2003.[xxix] Other things being equal, Wyoming enjoys a six-to-one advantage in productivity. So it is entirely possible to envision a scenario in which doubling U.S. coal production results in creating only a few thousand new mining jobs nationwide.

In addition to addressing questions about where coal will be mined, a national energy policy will also need to focus on how to maximize recovery of the resource. Methane gas, for example, occurs naturally in coal seams underground, and in the course of mining is liberated — first into the mine atmosphere and then, via the mine's ventilation exhaust fans, into the global atmosphere. Although removal of methane from the mine atmosphere is necessary to guard against explosions, methane vented to the surface can and should be captured and used as a fuel. Pilot projects have long since demonstrated the technological feasibility of methane recovery, and rising natural gas prices are making recovery a more commercially attractive prospect. Methane recovery should be explicitly encouraged as part of an energy policy committed to the goal of capturing every Btu buried underground.

Similarly, substantial amounts of fine coal — perhaps more than 2 billion tons — now lie buried in mine waste impoundments (discussed below), deposited there as part of the process of cleaning coal as it comes raw from the mine. The technology exists to recover much of this fine coal, and a National Academy of Sciences task force has estimated that remining can be profitable in impoundments containing at least 1 million tons of coal slurry.[xxx] As one remining advocate notes, "We kill two

birds with one stone. The process recovers valuable coal from waste and, at the same time, eliminates coal impoundments that are a significant environmental concern."[xxxi] In addition to several ongoing waste-recovery operations, a project is just now getting under way in West Virginia to demonstrate the feasibility of recovering virtually all of the coal in an impoundment.[xxxii] One goal of a national energy self-sufficiency policy should be to encourage replication of such projects throughout the coalfields — thereby turning buried waste into buried treasure.

2.2 Employment

Depending on where and how coal is mined in the years ahead, increased demand could pose a dilemma: Where will the miners come from? Today's workforce is relatively old: the average age in many underground mines is 50 or higher, and the median age of the mining workforce overall has been rising faster than that of U.S. workers in general.[xxxiii] When energy prices increased rapidly in 2001, creating unexpected demand for coal, underground mine owners in Appalachia reported great difficulty in locating, attracting and hiring the experienced miners they needed to work with inexperienced new hires.[xxxiv] Indeed, the coal industry estimates that it will need to replace about 50 percent of the underground workforce within the next five to seven years.[xxxv] A national energy independence policy must take this problem into account.

The coal mining workforce is far from monolithic. On the one hand, surface mines primarily require skilled heavy equipment operators, including truck drivers and dragline operators — occupations that to a large extent require the same kinds of skills needed in highway construction and heavy machinery operation of other kinds. Thus, depending on variables such as location (and willingness to relocate), as well as prevailing unemployment rates, there may be a pool of readily available labor to draw upon when a surface mine opens or expands. Many of the jobs in underground mines, on the other hand, are relatively specialized and, because of the inherent working conditions, do not appeal to men and women who, given other opportunities, would prefer not to work under such conditions — notwithstanding the substantial improvements that have been made over the years.

Moreover, local and regional economic conditions play a major role in determining the availability of labor for mining. As previously noted, mining typically provides wages and benefits far superior to those available elsewhere in

the mostly low-wage Appalachian economy. Unless the region experiences greater economic diversification than has thus far been generally achieved, there will be a continuing impetus for men and women entering the workforce to seek mining jobs. The strength of that impetus will depend, however, on several key variables, including whether mining is perceived as a relatively safe and healthful occupation, whether mining jobs are regarded as stable, long-term sources of employment, and whether alternative sources of employment are available both within and beyond the region. Because of these variables, a crucial question will be whether a national energy independence policy is designed and carried out in such a way that it represents a long-term commitment conducive to the creation of stable economic conditions in the coalfields. Absent such a policy, recruitment and retention of a skilled mining workforce will remain problematic.

It should also be noted that the employment challenge extends beyond the mining workforce as such. Mining engineers, for example, are in increasingly short supply, and the National Mining Association warns that as today's engineers retire, "the capability to provide new mining professionals has significantly deteriorated through the downsizing and disappearance of university degree and other programs offering this very specialized education."[xxxvi] Ten mining departments in U.S. universities have closed since 1985, and two more are reportedly on the verge of closing, largely because students are gravitating to more lucrative high-tech careers rather than to careers in natural resources.[xxxvii] Similarly, equipment manufacturers and sales companies are victims of the same trends — with Caterpillar dealers reporting, for example, that their mechanics are typically in their 50s and that relatively few younger men and women are seeking such employment.[xxxviii] Developments such as these underscore the need to ensure that an energy independence policy is designed to provide some assurance of both creating and sustaining jobs.

2.3 Occupational safety and health

Since 1900, coal mining has claimed the lives of nearly 105,000 miners and injured or crippled perhaps ten times that many in mine accidents or from the disabling effects of occupational diseases such as black lung.[xxxix] Coal mining has always ranked high among the nation's most hazardous occupations and continues to do so today, with fatality rates five times the average for all private industry. According to the Department of Labor's Bureau of Labor Statistics, only a handful

of occupations — such as deep-woods timber-cutting and deep-sea fishing — are more dangerous.[xl]

Historically, coal mining has also had a well-deserved reputation as an industry reluctant to adopt progressive occupational safety and health policies and practices. In the early days, many mine owners treated miners — often immigrants — as expendable commodities, an attitude that was slow to change. Although the nation's first federal mine safety law was enacted in 1910, it was only with the rise of the union movement in the 1930s that miners and their allies began to successfully challenge dangerous management practices on a wide scale. Even then, progress continued to be slow until the late 1960s, when televised coverage of a West Virginia mine disaster coupled with increased awareness of economic conditions in Appalachia and the social activism of the era spurred public support for stronger legislation.

The federal Coal Mine Health and Safety Act of 1969, the first of the major occupational and environmental protection laws enacted by Congress over the next several years, gave federal mine inspectors and their supervisors new authority to enforce compliance with statutory and regulatory standards. The law was amended and strengthened with enactment of the federal Mine Safety and Health Act of 1977, which covers all minerals and under which enforcement responsibility was transferred from the Department of the Interior to the Department of Labor. Although the federal Mine Safety and Health Administration (MSHA) has had a decidedly mixed track record, coal miners' working conditions have generally improved, mine hazards have been more effectively addressed, and large-scale mine disasters, once commonplace, have become increasingly rare. The number of miners killed in coal mine accidents declined from 260 in 1970 to an all-time low of 27 in 2002. (There were 30 fatal accidents in 2003, and there have been 17 through August 31, 2004.)[xli] Although the decline can be partly explained by the parallel decline in employment, historically there has also been a slow but reasonably steady decline in both fatal and non-fatal accident frequency rates.

Similarly, health protection has improved. Although an estimated 1,500 mostly older and retired miners still die annually from the long-term effects of black lung, the number has dropped by about 50 percent since the early 1980s. That does not mean, however, that this killer disease, caused by failure to control respirable dust in the mine atmosphere, has been eradicated. The federal mine safety law requires periodic, free x-rays for miners who request them, and reviews by the National Institute for Occupational Health (NIOSH) have determined that about two miners

per every 100 tested show evidence of black lung.[xlii] As noted above, 118 new cases were reported in 2002, and longwall miners are particularly at risk. (The actual number of cases may be significantly higher than reported, since participation rates have varied greatly from mine to mine but are generally low.[xliii]) Moreover, MSHA's efforts to accurately measure respirable dust and to enforce the statutory control standard have encountered ongoing difficulties, and falsification of measurements by mine operators has been a recurrent problem.[xliv] Furthermore, the prevailing practice of taking multiple measurements at a specific underground work site and then averaging them — to determine whether the work site as a whole is in compliance — has had the effect of masking the fact that workers performing certain jobs at such sites, such as longwall operator and continuous-miner operator, are routinely exposed to excessive dust levels, making it virtually certain that they will contract black lung if they remain in those jobs long enough.[xlv]

It should be noted that MSHA has also had varying but generally limited success in addressing other respiratory hazards, including asbestos, silica, and diesel exhaust. After a long struggle, MSHA in January 2001 issued a diesel-particulates control regulation, but the agency's enforcement efforts in this area have been criticized by mineworkers' union leaders and others, and there have been continuing delays in implementing a final rule on particulates. Indeed, the current administration has rescinded numerous proposals made in the late 1990's intended to improve mine safety and health.[xlvi]

Another health and safety issue of concern is the increasing use of labor supplied by independent contractors, as noted above. While overall employment in coal mining has steadily declined, reliance on independent contractors has steadily increased, and the number of employee-hours reported to MSHA by independent contractors more than tripled between 1980 and 1999.[xlvii] By the end of the 1990s, contractor employees accounted for 16 percent of underground fatalities, 30 percent of the fatalities at surface mines, and 44 percent of the fatalities at preparation plants.[xlviii] The fatality rate among contractor employees in 2002, at 41.7 per 100,000 full-time-equivalent employees, was 64 percent higher than for coal operator employees, with a fatality rate of 25.4 per 100,000 FTE employees.[xlix]
Protecting contractors' employees against health and safety hazards is inherently more problematic than providing protection for coal operators' employees. For example, MSHA and state agencies are unlikely to know whether a contractor's employee has actually been trained or whether the documentation for such training

is largely meaningless. With no job security and without the protection of union representation, contractors' employees are less likely to speak up about safety problems. Accident statistics can be skewed by under-reporting and/or shifting injured workers to make-work tasks in order to avoid lost-time injury reporting requirements. The only effective way to address such problems is through "blitzes" — intensive spot inspections involving multiple inspectors — coupled with meaningful citations for regulatory violations, but to mount such inspections on an ongoing industry-wide basis is beyond MSHA's present staffing and budget capabilities, as well as inconsistent with its current operating style.

Clearly, a national energy independence policy, with a resultant scaling-up of coal production, would call into question MSHA's ability to carry out its statutory responsibilities. For Fiscal Year 2004 the agency has a budget of $250 million, essentially unchanged from its budget for FY2000, with which it oversees safety and health at all U.S. mining operations — not just coal. To monitor the coal industry it currently fields a force of approximately 800 inspectors, a number considered insufficient by some observers. Critics also believe that penalties for violations of MSHA's regulations are inadequate. Moreover, there is concern about MSHA's current strategy of "shifting the emphasis of regulatory programs from after-the-fact enforcement to education and training and accident prevention."[l] MSHA's primary statutory mission is enforcement, and a shift in emphasis of this kind raises legitimate concerns about the extent to which a taxpayer-funded federal enforcement agency should spend its limited funds on education and training functions that are properly the responsibility of mine owners and managers.

Any substantial increase in coal production would require a comparable scaling-up of MSHA's regulatory enforcement capabilities. This could include increasing the number of inspectors, but comparable emphasis should be given to ensuring that they are backed up by strong sanctions to ensure compliance with the laws and regulations governing mining. Fines for violations should be increased sufficiently to act as a more effective deterrent than is now generally the case. Moreover, MSHA should be assured of the authority to take such measures as may be necessary to anticipate and address problems proactively rather than reactively. For example, MSHA should take the lead in determining and enforcing the healthful operating parameters of longwall mining sections, as discussed above; should ensure that all miners, whether employed directly or through contract mining, are properly trained; and should require more stringent engineering and monitoring of mine waste impoundments (discussed below) to guard against both

catastrophic failure and stream pollution. Absent such initiatives, coupled with a renewed and sustained philosophical commitment to its role as an enforcement agency, MSHA will not be able to do the job required of it by statute — and will continue to be regarded with concern, if not outright distrust, by two of its most important constituencies: miners and the public.

2.4 Public health, safety, and the environment

2.4(a) *Mountaintop removal*

In the hills and hollows of Appalachia, surface mining — or strip-mining, as it is commonly called — has always been a highly controversial practice. Prior to the 1960s, however, it was carried out on a relatively small scale. Then, as cheap oil and natural gas became widely available, the subsequent decline of coal prices forced mine owners to find ways to extract coal more inexpensively than was possible with labor-intensive underground mines.

Strip mining provided the answer. But the process — removing part of a hillside (the overburden) to get at a coal seam, and dumping the waste overburden down the slope and into the hollows below — transformed forested mountainlands into wastelands and did extensive damage to homes and streams. Early reclamation efforts, haphazard at best, were memorably described by the writer Harry Caudill as "putting lipstick on a corpse." Often, mine operators simply abandoned the mined land rather than reclaim it. The resulting public backlash, led by regional citizens' groups with the aid of national advocacy organizations and media coverage, after a long struggle culminated in the enactment of the federal Surface Mining Control and Reclamation Act of 1977 (SMCRA), administered by the Office of Surface Mining (OSM) in the Department of the Interior, with states sharing responsibility for enforcement. Among other things, SMCRA requires reclamation plans and timetables and compliance with all applicable environmental regulations and performance standards. To help combat the problem of abandoned lands, mine operators must post performance bonds and provide financial guarantees to cover the estimated reclamation costs.

Although OSM, even more than MSHA, has had a highly uneven record of enforcement — in part because SMCRA provides for broadly shared federal-state

enforcement authority, a weaker approach than the clearly dominant federal role provided for by the federal mine safety law — most observers would probably agree that over the years there has been substantial progress in mitigating the damage done by conventional strip mines. Although strip mining by its very nature remains controversial, reclamation practices have improved to the point where, in many cases, forested areas and grasslands have recovered and streams run clear.

This progress has now been overshadowed, however, by a relatively recent development that makes the earlier strip mines seem like minor challenges by comparison. Mountaintop removal (MTR) mining — which involves not just the girdling of a mountainside but the entire removal of everything above a coal seam — has become an increasingly widespread practice, especially in southern West Virginia and eastern Kentucky. Made possible by the development of huge draglines and power shovels that can remove 100 tons of earth at a bite, MTR essentially consists of blasting a mountaintop into manageable pieces and then dumping the overburden into the adjacent hollows, burying everything, including streams, beneath the waste. The coal is then removed by giant end-loaders and trucks, and after that the mine is reclaimed. But total reclamation of a mountain that has been decapitated is impossible, of course, and streams that have had their headwaters buried under debris are permanently altered. Gone, too, are the hollows that fed the streams, and the wildlife habitat they provided.

MTR has other impacts, as the Charleston, W.Va., *Gazette* noted in a 1999 report: "People who live near mountaintop removal mines say they are harassed day and night by dust, noise and blasting that shakes their homes, destroys well-water supplies, and sends rocks flying into their communities."[li] One such rock — actually a half-ton boulder — recently plummeted down a southwestern Virginia hillside in the middle of the night, crashed through the wall of a house and killed a sleeping three-year-old boy.[lii]

MTR is clearly an economical way to expose and recover coal, particularly from relatively thin seams that might not otherwise be economical to mine. With MTR, multiple seams can be exposed and mined at the same time. But as this method of mining has become more widespread, it has generated bitter opposition from those living close to or downstream from MTR operations, as well as from regional and national environmental groups, who argue that MTR as currently practiced is incompatible with the goals of the Environmental Protection Act, the Clean Water

Act (CWA), SMCRA, and regulations intended to protect streams from adjacent mining operations.

Unless a federal law is enacted that explicitly outlaws MTR (and in today's political environment there is little likelihood of such legislation being enacted or, if enacted, going unchallenged in the courts on constitutional grounds), it seems clear that this type of mining will continue, at least in the near future, and will thus by default have a place in any strategy to increase U.S. coal production as part of a national energy independence policy. But the scope of its role remains to be determined, and will be influenced by whether a workable balance can be found between the nation's energy needs and the concerns of those most directly affected by MTR practices.

For the past six years the MTR controversy has been playing out in the courts as well as in federal and state regulatory rulemaking procedures. In 1998, a coalition of West Virginia environmental groups and coalfields residents filed a lawsuit in federal court aimed at compelling federal and state agencies to more stringently enforce the Clean Water Act and the Surface Mining Act. The plaintiffs specifically targeted the West Virginia Department of Environmental Protection, which has enforcement responsibilities under both the Clean Water Act and SMCRA, and the U.S. Army Corps of Engineers, which issues permits for disposal of wastes and fill material in navigable waters.

The Clean Water Act prohibits discharging any pollutant into the waters of the United States except in compliance with permits issued under two permit programs established by the law. Section 402 of the Act, administered by the Environmental Protection Agency (EPA), primarily addresses pollution from industrial sources and sewage treatment plants. Section 404, jointly administered by EPA and the Corps of Engineers, covers fill material, and requires that in the granting of a permit consideration must be given to both the positive and negative impacts of discharges. Under Section 404 the Corps can grant individual site-specific permits and general (nationwide) permits for categories of discharges deemed to have only minimal adverse impacts on the waters of the United States. MTR spoil-dumping has been permitted under a general permit (Nationwide Permit 21) authorizing discharges from surface mines that have only minimal impact.

In 1999, U.S. District Court Judge Charles H. Haden sided with the plaintiffs, ruling that dumping spoil in valley streams violated both the CWA and state and

federal mining laws. He ruled that mine spoil was waste subject to the higher standard of Section 402 permit requirements. The judge's decision was intensely controversial in West Virginia, prompting coal operators to claim that if enforced it would essentially shut down the surface mining industry and throw thousands of miners out of work. Mine owners joined forces with the United Mine Workers and the state's congressional delegation to oppose the ruling, which Judge Haden agreed to stay pending the outcome of an appeal. In 2001 the Fourth Circuit Court of Appeals overturned the decision on procedural grounds, and in 2002 the Supreme Court declined to review the appeals court's decision. In a related case, a decision by Judge Haden to block the Corps from issuing Section 404 nationwide permits for mine waste was similarly overturned on appeal.

Despite these setbacks, legal and regulatory challenges continue. In pending cases, attorneys for citizens' groups are pursuing their goal of stopping the Corps from granting Section 404 nationwide permits for valley fills, and are trying to force West Virginia state agencies to enforce SMCRA's buffer zone rule, which prohibits mining within 100 feet of intermittent and perennial stream segments if the mining will lead to violations of federal or state water quality standards. Meanwhile, the Bush administration is seeking to modify that rule, arguing that it was never intended to impede mining permits or to protect headwaters from being buried by mine waste and that mine operators should be required only to protect streams "to the extent possible, using the best technology currently available."[liii]

In the latest development, U.S. District Court Judge Joseph R. Goodwin ruled on July 8, 2004, that the Corps' practice of granting blanket mining permits under Section 404 violates the Clean Water Act's requirement that the impact of mining on streams must be determined "before, not after" a permit is granted, and that the use of a blanket permit "allows an activity with the potential to have significant effects on the environment to be permitted without being subject to public notice or comment."[liv] The ruling (which applies only to southern West Virginia) revoked 11 permits that the Corps had issued, authorizing construction of 40 sediment ponds, 36 valley fills and other activities that would have buried about 26 miles of streams, and had the effect of blocking any MTR mining project not already under way at the time of the ruling.[lv] Under the ruling, the Corps will have to require and review site-specific documentation and analysis of a proposed project's environmental impact and will have to hold public hearings and provide opportunities for public comment prior to issuing a permit.

The Bush administration, arguing that Judge Goodwin's ruling "put a halt to the work that West Virginia miners do for their communities," appealed the ruling early in September.[lvi] Although the ruling may be overturned on appeal, as Judge Haden's earlier rulings were, in the meantime the fact remains that not one but two federal judges in West Virginia have now held, in effect, that MTR should be allowed to continue only within a more restrictive regulatory framework that puts a greater burden on the coal industry to demonstrate, on the basis of scientific evidence, that its practices are consistent with the Clean Water Act's mission to "restore and maintain the chemical, physical, and biological integrity of the nation's waters."[lvii] Whether the industry can do so remains to be seen. Meanwhile, the Bush administration's pursuit of a less environmentally protective stream buffer zone rule appears to be on a collision course with currently prevailing judicial interpretations of environmental protection.[lviii]

As with the earlier challenges, both proponents and opponents of MTR argue that the future of this kind of mining could be determined by the outcome of these issues. The mining industry, arguing that strict interpretation of the existing buffer-zone rule would be a "death sentence," has sponsored studies claiming that surface mine production in West Virginia could be cut by as much as 90 percent and that annual state tax revenues would thereby dwindle by hundreds of millions of dollars. Environmental lawyers argue that evisceration of the buffer-zone rule would mean the loss of their main weapon to curb the negative impacts of MTR.[lix]

A sustainable middle ground, to the extent that there could ever be one in such a contentious arena, would probably require development of a new regulatory framework for MTR and a good-faith effort by all concerned to implement it equitably. Such a strategy would acknowledge the short-term need for the coal produced by this method of mining, but it would also require more stringent protection of streams than the Bush administration contemplates, as well as additional constraints on mining near homes and other structures. And any such effort would need to be guided by an unbiased, independent analysis to assess the impacts on the mining industry of various enforcement scenarios. (Currently, for example, there are no reliable data on the actual number of jobs being provided by MTR operations nor on the percentage of total U.S. coal production that they account for, since their employment and production data are not dis-aggregated from other surface mining data. Thus it is virtually impossible to objectively assess the impact of proposed constraints on MTR production — a situation that allows proponents and opponents alike to make unverifiable claims.)

While a compromise approach might not entirely satisfy anyone, it may represent the only way to proceed without riding roughshod over someone's interests. Although mountaintop mining appears to employ relatively few miners, they hold high-paying jobs in a regional economy that has few alternatives to offer. Concerns about potential job losses thus should be taken seriously even though the industry's claims about the scope of such losses appear to be greatly exaggerated. On the other hand, if MTR is to be allowed to continue, mine operators must be able to do a better job of demonstrating that they can extract coal without causing undue damage to the surrounding environment and without endangering and alienating residents who live within sight and sound of their mining operations.

If there are any grounds for optimism, they may lie in the fact that similar conflicts have been addressed in the past, to at least the partial satisfaction of all concerned. An obvious case in point is mine safety. For many years the standard industry response to mine safety advocates was that more stringent regulations would have catastrophic effects, forcing the closure of thousands of mines and throwing tens of thousands of miners out of work. While this doomsday-scenario strategy may have been effective in delaying enactment of stronger laws and regulations, those delays carried a high cost in needless deaths and in the crippling of miners from avoidable accidents and diseases such as black lung. Gradually, however, the industry's most intransigent mine operators were replaced by a more enlightened group of managers who were able to see that a safe mine is a productive mine. The enactment of tougher laws did not, in fact, mean the end of the industry. On the contrary, in many respects it leveled the playing field, protecting conscientious mine managers against corner-cutting competitors. A similar scenario might help resolve the mountaintop removal mining controversy.

2.4(b) *Mine subsidence*

Underground mining causes surface subsidence problems in two ways: while mining is taking place and/or afterward, sometimes many years after mining has been completed. In conventional room-and-pillar mining, pillars of coal are left in place while the mine is active, to help protect miners against roof falls. Over time, supports remaining in place after mining has been completed may give way, gradually or suddenly, causing subsidence at the surface. In longwall mining, no pillars are left in place, and the overburden is allowed to collapse as the longwall section moves on. Increased use of longwall mining, particularly in northern Appalachian areas such as southwestern Pennsylvania, has caused widespread

subsidence problems for homeowners and local governments. Although some subsidence problems may be relatively limited and manageable, such as cracked foundations and ruptured water/sewer lines, in many cases subsidence has caused major structural damage to homes and other buildings and has opened up sinkholes in roads, creating hazards and necessitating costly repairs. Subsidence also disrupts the natural flow of water into wells, streams, and aquifers.

At the federal level, subsidence is primarily regulated under SMCRA, which prohibits mining beneath impoundments, aquifers providing water supplies, and public buildings, unless the federal Office of Surface Mining determines that such mining will not cause subsidence damage to such sites. OSM may also require backfilling or leaving coal in place to prevent subsidence. As a practical matter, however, the cost of backfilling is generally prohibitive, and with longwall mining there is by definition no effective way to leave large pillars of coal in place.

SMCRA also requires coal operators to "promptly repair, or compensate for, material damage resulting from subsidence caused to any occupied residential dwelling and structures related thereto, or non-commercial building due to underground coal mining operations" and to "promptly replace any drinking, domestic, or residential water supply from a well or spring in existence prior to the application for a surface coal mining and reclamation permit, which has been affected by contamination, diminution, or interruption resulting from underground coal mining operations."[lx] While these requirements theoretically provide some protection for affected residents, enforcing them has been a challenge, often requiring extended negotiations. It is also worth noting that the above requirements are accompanied by a statement, presumably inserted at the behest of coal industry lobbyists, that "nothing in this section shall be construed to prohibit *or interrupt* underground coal mining operations" (emphasis added).[lxi] Not surprisingly, many frustrated coalfields residents have purchased subsidence insurance (offered by Pennsylvania and some other states on a nonprofit basis) as a hedge against having to deal with the problem in a regulatory arena that they believe stacks the deck against them by giving coal production priority over other concerns — including protection of historic homes and other structures supposedly safeguarded by the National Historic Preservation Act.[lxii]

As with mountaintop removal mining, the problems associated with subsidence can be expected to increase, perhaps substantially, under any scenario calling for significantly increased coal production in the years ahead. For the most part, citizens affected by subsidence live in relatively small, scattered, largely rural

communities, and believe, rightly or otherwise, that their concerns are of little interest to lawmakers. Obviously this dynamic could change as the scope of the problem increases, and advocacy efforts to increase public protection by limiting underground mining in subsidence-prone areas could generate broader regional and national support. Energy policy makers cannot afford to ignore or downplay the subsidence problem. SMCRA may need to be strengthened to provide for (1) more centralized federal enforcement authority rather than the current structure under which neither OSM nor the states effectively regulate the surface effects of longwall mining; (2) more stringent enforcement of existing provisions limiting mining in subsidence-prone areas; and (3) greater use of preventive measures such as backfilling despite their impact on coal production costs. Such measures, however necessary to protect public well-being, would of course have an impact on coal prices and competitiveness, and thus on the role of coal in a national energy independence strategy.

2.4(c) *Abandoned mine lands*

With the enactment of SMCRA in 1977, Congress authorized the Office of Surface Mining to collect fees to finance reclamation of coal mine lands that had been abandoned prior to enactment. Thousands of long-abandoned mines are scattered across the nation (there are an estimated 4,600 in Pennsylvania alone[lxiii]), many of them posing threats to public health and safety. Scores of people die annually from falling into old underground mine shafts, tumbling over the sheer highwalls of old strip mines, or drowning in old mine quarries and impoundments — and, as the *Wall Street Journal* noted in a 2003 report:

> People falling into mine shafts are just part of the problem. Coal fires burn in abandoned mines for decades, belching dangerous levels of carbon monoxide. Mines silently flood for years before suddenly disgorging millions of gallons of red, acid-laced water, poisoning nearby streams and rivers. Sometimes the ground over shafts collapses, opening up huge holes [that] undermine the integrity of nearby roads and buildings... The U.S. Interior Department has recorded at least 81 deaths since the beginning of 1999 in abandoned mines... [lxiv]

OSM maintains a nationwide database of priority reclamation sites — a list that continues to grow as additional sites are discovered — and an Abandoned Mine Land (AML) Fund, supported by fees collected on current production, distributes funds to the states for reclamation projects. In theory, the AML Fund should have

facilitated the cleanup of the great majority of sites by September 2004, when fee collection authority expires. Many projects are uncomplicated and inexpensive, sometimes requiring little more than fencing off a mine shaft opening and posting warning signs. However, the AML program has never worked as well as expected, and one critic has charged that at current rates of progress "it will take 100 years to clean up these mines."[lxv]

The problem is partly logistical but largely reflects problems with the design, funding, and implementation of the AML Fund, which has collected more than $7 billion over its lifetime and currently contains an unspent balance of about $1.5 billion. To finance the AML program, OSM collects a fee of 15 cents per ton on coal produced in underground mines and 35 cents per ton on coal from surface mines. Funds are distributed to the states. This has led to the first design problem. Most abandoned mine sites are in the East, but the statutory AML allocation formula distributes funds largely on the basis of current production, which has shifted dramatically westward since SMCRA was enacted. As a result, some states, such as Wyoming, have completed their AML reclamation projects and have been using surplus AML grants for unrelated projects such as construction of a geology building at the University of Wyoming; similarly, Indian tribes in the West have used AML funds to build community centers and sewage-treatment plants.[lxvi]

The second problem has to do with the way AML funds are appropriated annually by Congress. Because the appropriation levels — and thus grants to the states — change every year, state officials say it is difficult to plan projects. Moreover, for several years Congress has maintained a large unspent balance in the AML Fund to help offset federal deficits. Meanwhile, annual funding for the program has rarely exceeded $200 million. Earlier this year the Bush administration, in announcing a plan that would allegedly accelerate reclamation of abandoned mine lands, acknowledged that under its reauthorization proposal it would take 25 years to eliminate all significant health and safety problems.[lxvii] (In comparison, the Interior Department estimated two years ago that all outstanding AML problems could be resolved within six years at a cost of $2.96 billion — about twice the amount now held in reserve in the fund.[lxviii]) Meanwhile, failure to address the remaining problems clearly constitutes a threat to public health and safety: a recent OSM analysis estimated that 3.5 million Americans live within a mile of a potentially hazardous abandoned mine site.[lxix]

A further complication is that, under the statute, the AML Fund pays interest from the unobligated AML Fund balance to the United Mine Workers Combined Benefit Fund (CBF) to help cover the health benefits of some 17,000 miners (and dependents) who were employed by companies that no longer exist. Thus there is an inherent conflict between the interests of states advocating accelerated distribution of AML funds and the CBF beneficiaries. In an election year, the issue is controversial. The Bush administration has proposed increasing the amount of interest that can be transferred annually (now capped at $70 million) and making all interest in the account available for transfer as needed.[lxx] Meanwhile, as Rep. Nick J. Rahall II (D.,W.Va.), an author of the AML law, has noted, it is unclear whether a reauthorization bill will muster sufficient support from western states to pass if it redirects more AML funds to Appalachia, as he believes it should.[lxxi]

It is worth noting that the conflict between spending AML funds to reclaim abandoned land versus retaining AML funds to help abandoned miners is a stark illustration of coal's 20th-century legacy. In abandoning miners and mined land alike, the industry externalized its costs by abandoning its responsibilities. Now, in the 21st century, we the people public acting through our lawmakers are being forced to confront this legacy and find ways to pay for the obligations that the industry walked away from. It is vitally important to absorb the lessons of this experience and to ensure that if the coal industry is to be promised a robust future, it will not be at the continued expense of land and people.

Although reclamation of long-abandoned mine sites would not be directly affected by an acceleration of current coal production under a national energy independence policy, the problem of AML fee collection and distribution could be exacerbated (assuming that the present program is reauthorized). Accordingly, a phased adjustment of the funding allocation formula should be considered, in conjunction with an objective actuarial assessment of the needs of the CBF. A reasonable goal would be to aim for the elimination or substantial mitigation of all known AML hazards within a defined timetable — such as ten years — and to fund the program accordingly, setting aside interest as necessary to continue supporting the CBF for a similarly defined period. That said, it should be acknowledged that any such proposal is sure to generate resistance. An adjustment that reduced fees on western coal in exchange for greater allocations of funds to the East, for example, would probably be opposed by Appalachian producers on the grounds that it would unfairly enhance the competitiveness of western coal. As things now stand, the likelihood of a reauthorization stalemate is great. To resolve it may require both a short-term compromise that satisfies no one and the

convening of a bipartisan, broadly representative task force specifically charged with overhauling the existing AML program.

2.4(d) *Mine waste impoundments*

Coal mining of all kinds generates waste. Removal of coal from underground mines is accompanied by various kinds of waste rock that must be separated from the coal before it is shipped. Mine waste impoundments are built to hold the slurry — the mix of water and waste — that is left after the coal has been processed. In Appalachia, impoundments are typically built in a valley, or hollow, near the mine's preparation plant. A retaining wall is built from coarse refuse across the mouth of the valley to hold the slurry pond. As coal fines settle to the bottom, the water is used repeatedly to process more coal. Impoundments vary in size but may be hundreds of yards across and hundreds of feet deep, holding hundreds of millions of gallons of slurry. When an impoundment threatens to overtop its retaining wall, water must be pumped out or diverted into other impoundments.

Because retaining walls built from mine refuse are not true earthen dams (as dam engineers have emphatically testified), the risk of collapse is always present. The potential for catastrophe became clear on the morning of February 26, 1972, when, after several days of heavy rains, an impoundment built by the Pittston Coal Company in southern West Virginia overtopped its retaining wall, which collapsed with explosive force, sending an estimated 132 million gallons of water and slurry cascading down the narrow Buffalo Creek valley. Trapped by the onrushing flood, 125 people were killed, more than 1,000 others were injured, and scores of homes and other buildings were completely destroyed, leaving 4,000 people homeless. The coal company denied responsibility, attempting to blame the disaster on an "act of God" — the rain — despite having had no system in place to control the level of the impoundment and despite having belatedly sent a bulldozer operator to cut a diversion ditch across the top of the dam just as it was beginning to fail.[lxxii]

Among other things, the Buffalo Creek disaster demonstrated that the federal Mining Enforcement and Safety Administration (MESA), which had been established three years earlier by the 1969 Coal Mine Health and Safety Act, was ill-prepared to inspect or monitor impoundments. Three years after Buffalo Creek, regulations were finally adopted requiring coal operators to develop engineering plans for the construction of impoundments and to obtain approval from MESA's successor agency, the Mine Safety and Health Administration (MSHA), prior to

construction. In addition, MSHA is charged with inspecting such impoundments while in use. MSHA currently oversees 733 active impoundments nationwide, primarily in West Virginia, Virginia, Kentucky and Pennsylvania. (There are relatively few impoundments in the West because most of the coal produced there is shipped unprocessed; in the East, about 50 percent of mined coal is washed.) Coal operators may temporarily inactivate an impoundment but may not abandon one without first reclaiming it to MSHA's satisfaction. Impoundments abandoned prior to enactment of SMCRA are part of the Abandoned Mine Lands program and as such are the responsibility of OSM.

Despite improved oversight, impoundment hazards continue to threaten coalfields communities. On October 11, 2000, the bottom of a 72-acre impoundment in Martin County, Kentucky, collapsed, releasing more than 300 million gallons of slurry into an abandoned underground mine, from which it burst forth and flooded two tributaries of the Tug Fork and Big Sandy rivers along the Kentucky-West Virginia border. Fortunately, no lives were lost this time, but the surging, chemicals-laced slurry — described by residents as resembling a lava flow, and smelling terrible — killed fish, turtles, and other aquatic life along 60 miles of waterway and forced several communities to shut down their drinking water systems to avoid contamination.

MSHA's subsequent investigation found, among other things, that the impoundment, built and used by a subsidiary of Massey Energy, the nation's sixth largest coal producer, was constructed in violation of regulations requiring at least 150 feet of rock and dirt between the bottom of a slurry impoundment and an underground mine; in this case there was only a 27-foot layer. MSHA also found that Massey had failed, in constructing the impoundment, to spread a layer of fine coal slurry around the perimeter as required to create a barrier against water seepage. MSHA concluded that "impounded water, seeping through underlying layers of slurry and rock, gradually formed a conduit for increasing flow that resulted in sudden failure of the impoundment."[lxxiii]

This was not the first time that the Martin County impoundment, constructed in the early 1980s, had failed. After a 1994 rupture that released 100 million gallons of slurry, an MSHA investigator had recommended fortifying both the impoundment and the adjacent underground mines before allowing any further dumping of slurry. The agency and the company, however, had agreed on less drastic remedial steps. Among the questions raised by the second failure was

whether MSHA had adequately responded to the first one, and whether the agency's oversight of impoundments in general was sufficiently vigilant.

In 2001, while MSHA's investigation of the 2000 spill was under way, the Bush administration took office, and soon thereafter apparently decided to narrow the scope of the investigation by excluding from consideration whether MSHA itself was to some degree culpable. Jack Spadaro, a member of the investigative team (who had also investigated the Buffalo Creek disaster in 1972), objected and filed a complaint with the Inspector General of the Department of Labor, accusing the Bush administration of obstructing the investigation. He was subsequently removed from his job as superintendent of MSHA's education and training facility, allegedly for various failures of conduct unrelated to the investigation, and reassigned to a non-managerial task at substantially lower pay. At this writing he is appealing that action, and continues to accuse the Bush administration of "interference with a federal investigation of the most serious environmental disaster in the history of the eastern United States."[lxxiv]

Meanwhile, MSHA imposed two fines, totalling $110,000, for the 2000 failure, only to have a federal administrative law judge dismiss one citation outright and lower the other to $5,500.[lxxv] The Department of Labor has asked the Federal Mine Safety and Health Review Commission to review the judge's decision.[lxxvi] Pending the outcome, however, it seems clear that the coal company responsible for the impoundment failure will not suffer materially as a consequence, and that the investigation, for whatever reasons, stopped far short of addressing the remedial steps necessary to guard against other failures among the approximately 240 slurry impoundments estimated to have been constructed above abandoned mines.[lxxvii]

Because of these two catastrophes and other impoundment failures — and because of concerns about the diligence and effectiveness of federal and state regulatory oversight — Senator Robert C. Byrd, Jr., of West Virginia and Representative Hal Rogers of Kentucky joined forces in late 2000 with the-then MSHA chief, Assistant Secretary of Labor J. Davitt McAteer, to initiate an analysis of impoundments by the National Research Council that encompassed both a review of engineering standards and practices (which found, among other things, that coal impoundments are ten times as likely to fail as earthen dams) and an exploration of alternative ways to process coal and dispose of mine waste. A subsequent initiative sponsored by Senator Byrd led to the development of the Coal Impoundment Location and Warning System, a pilot project developed by the Robert C. Byrd National Technology Transfer Center (NTTC), Wheeling Jesuit

University, West Virginia University and the National Energy Technology Laboratory in cooperation with MSHA, OSM, and the West Virginia Department of Environmental Protection and Office of Miners Health, Safety and Training.

The new system's Internet site (www.coalimpoundment.com) enables citizens living near West Virginia impoundments to access information such as location, capacity, risk level, impoundment owner, and emergency evacuation plans. The site also provides information on technologies to improve the safety of impoundments, alternatives to impoundments, and remediation techniques for the removal of existing impoundments. Part of the purpose of the pilot project, which currently covers 109 of approximately 135 permitted coal mine impoundments in West Virginia, is to empower citizens to protect themselves and to participate in the process of developing and implementing safer ways to process coal.

In addition to providing convenient access to critical information, the project includes training programs for emergency responders and facilitates cooperation among federal and state agencies, labor and citizens' groups, and researchers. An interesting development is that coal company officials as well as residents are accessing the site and reporting that it is a useful way for them to check on the status of impoundments and on progress in improving their safety.

The Coal Impoundment Location and Warning System project provides a good model for other efforts to make coal a better neighbor to coalfields communities. Driven by a clear need to improve protection of public health and safety and by a refusal to accept the status quo, the project also seeks to use public and expert input to prod both the coal industry and the industry's regulators to adopt superior technologies as they become available.

Expansion of coal production under a national energy independence policy would clearly provide a strong impetus to pursue such innovative technologies. Accordingly, there is a need to continue supporting efforts to research, develop, test, and implement such technologies, as well as to quantify their impact on the cost of coal mining and processing. The goal should be to ensure that as coal production increases, the hazards associated with impoundments diminish.

The need for alternative approaches to mine waste disposal is underscored by another problem related to mine impoundments: the slow leakage of toxic wastes from such impoundments into nearby streams and water supplies. Because this problem is essentially invisible, it has received much less attention from the

public, media, and regulators than the problem of catastrophic failure. Mine wastes typically include iron, lead, arsenic, copper, manganese, selenium, and mercury. There is growing evidence that impoundments are leaking such toxics and that they are finding their way into watersheds and wells, causing "significant contamination at concentrations well beyond what would be considered normal for effluent stemming from abandoned mine lands, and much greater than what could be considered safe for any domestic use."[lxxviii] In fact, water quality in wells adjacent to one West Virginia impoundment was found to be "among the poorest in the nation."[lxxix] At present there are no effective regulatory controls on the slow leakage of toxics from impoundments, and because of the nature of the problem it is doubtful that such leaks can be eliminated — other than by the accelerated development of alternative coal-processing technologies.

2.4(e) *Stream pollution*

Coal mining can pollute adjacent watersheds and streams both during and after mining. As previously noted, waste from surface mining operations, especially mountaintop removal, can entirely bury such watersheds; subsidence caused by longwall mining can disrupt streams and aquifers; impoundment leakage and failures can send toxic mine wastes into water supplies and streams; and highly acidic water draining from both underground and surface mines can cause pollution so severe that plant and animal life cannot survive.

Acid mine drainage (AMD) is caused when coal and bedrock high in iron sulfide (pyrite) are exposed to oxygen and moisture by mining. The resulting chemical reactions create iron hydroxide and sulfuric acid, both of which, if sufficiently concentrated, are lethal to waterborne life. The Environmental Protection Agency has identified AMD, primarily from abandoned coal mines, as the most severe water quality problem in Appalachia.[lxxx] The region's vast network of old underground mines is largely responsible for the scope of the problem, which affects thousands of streams, but active mining operations also contribute to it.

As a result, conflicts inevitably arise between mine operators and environmental protection advocates. For example, in October 2003 the West Virginia Department of Environmental Protection (DEP) denied a permit to a coal company because the application demonstrated that "the proposed operation will create acid mine drainage that will leave the permit area requiring chemical treatment for an indefinite period of time."[lxxxi] The company then filed a revised permit application,

proposing to treat mine water with alkaline injection to prevent acid mine drainage from leaving the site and pledging that in less than 17 years the site would no longer be producing acid water. Despite having previously rejected claims about the effectiveness of alkaline injection, DEP approved the permit, prompting a regional environmental group to charge that "this action has negated decades of citizen concern, comment, litigation and negotiation to prevent any further AMD destruction of our region's waters."[lxxxii]

Remediation of AMD is difficult, primarily because of the sheer scale of the problem. Alkaline injection to counterbalance acids is feasible and has been proven effective in some applications, but it is costly and requires diligent, ongoing monitoring, which makes it suitable mainly for active operations. A biological control technology developed some years ago by the U.S. Bureau of Mines diverts acid drainage through artificial wetlands that remove excess acidity and iron. Although the technology has been demonstrated successfully on a small scale, there has been insufficient experience thus far to predict whether it can provide an effective (let alone cost-effective) solution throughout the varying terrains of the region.[lxxxiii]

In addition, the Office of Surface Mining oversees the Appalachian Clean Streams Initiative, a public-private initiative to control AMD. The initiative is a cooperative effort among federal, state, and local governments working with citizen groups, mining companies, and academic researchers. OSM reports that the initiative, which has been in operation since 1994, has thus far funded 77 projects in 10 states. However, although examples of successful projects are posted on OSM's Web site, assessing the initiative's overall regional impact is difficult.[lxxxiv]

The AMD problem thus looms as yet another potentially significant barrier to the expansion of Appalachian coal mining as part of a national energy independence strategy. As with mountaintop removal mining and other issues, AMD is the kind of unresolved problem that prompts many residents of Appalachia to believe that they live in a "national sacrifice area" in which energy production takes priority over all other concerns. While it is probably true that relatively few people in Appalachia would wish to see the coal industry brought to a complete standstill, there is widespread resentment that the problems it has created for years seem to attract little attention from public agencies and go unresolved year after year. AMD is a good example: mines have been producing acid drainage for a century, but efforts to attack the problem head-on have been belated, haphazard, and underfunded. Accordingly, the whole idea of scaling-up coal mining at this point

strikes many people in the region as a direct threat to their personal well-being — as well as their health and the environment.

To prove their concerns unfounded will require a much more concerted effort by the mining industry and by regulators than has thus far been demonstrated. Federal and state agencies will need to hold mining companies to higher standards of accountability at active mines, and remediation of AMD at abandoned mines will require more robust funding for research and innovative applications than has thus far been available. AMD is a prime example of the type of problem that must be effectively addressed *prior* to scaling up coal production rather than after the fact.

Similarly, regulators must develop a firm and consistent position on enforcement of regulations intended to buffer streams against pollution by adjacent surface mines. The Bush administration's approach has not been encouraging. As a result of the litigation against mountaintop removal mining (described above), OSM in January 2004 published a proposed rule to "clarify" (in the agency's words) its interpretation of the existing rule, which requires the denial of permits for mining and waste disposal within 100 feet of a stream, whether intermittent or perennial, if such activities will lead to violations of Clean Water Act water quality standards.[lxxxv] Critics immediately denounced the proposed "clarification" as a thinly disguised payback to an industry that strongly supported George W. Bush's presidential candidacy in 2000, since the proposed rule modification would require only that mining companies use their best efforts to avoid filling streams with mine wastes. The coal industry, on the other hand, argues that environmentalists are using an interpretation of the buffer zone inconsistent with SMCRA's purpose to try to "halt coal mining in central Appalachia."[lxxxvi]

How this issue will be resolved — and whether there is a tenable middle ground — remains to be seen. Much is at stake, including the credibility of federal agencies such as OSM whose statutory mission is not to serve as an ally of the coal industry but to require and regulate mining practices consistent with the goals of environmental protection. Obviously this calls for a regulatory balancing act. Any effort to scale up coal production, however, should take place within a system of explicit safeguards that merit and generate broad public support. Otherwise the very real possibility exists that the goal of greater national energy independence, no matter how laudable, will be thwarted by public opposition to an inadequately regulated expansion of the coal industry. In that context, stream pollution — and how pending issues are resolved — offers a test case to determine whether the

objectives of energy independence and environmental protection are genuinely compatible.

2.4(f) *Other upstream issues*

There are a number of other issues that will need to be addressed as part of any comprehensive strategy to promote coal as the keystone of energy independence. They include:

Overweight coal trucks: Although western coal is almost entirely transported by rail, it is commonplace in Appalachia for coal to be trucked from the mine to preparation plants where, in most cases, it is shipped by rail to its final destination at a power plant. Problems with overweight coal trucks have plagued coalfields communities for many years. Overweight trucks damage back roads and highways and endanger other drivers. Accidents occur with disturbing frequency; a study found that fatal accident rates are twice as high on highways used by coal trucks.[lxxxvii]

In Kentucky, where the legal weight limit for a loaded coal truck is 120,000 pounds, a 1999 investigation found that 88 percent of the coal trucks traveling on U.S. 23, a heavily traveled artery, exceeded the legal limit, averaging 32,000 pounds overweight. Some weighed more than 200,000 pounds.[lxxxviii] In the coal industry the prevailing attitude for decades has been that running overweight is simply the norm. In a 1997 speech, Kentucky's then-governor, Paul Patton, a former coal operator, acknowledged that "I think it's safe to say I never contracted to have a ton of coal hauled legally" during more than 20 years in the business.[lxxxix]

Largely for political reasons, coal states have generally found it difficult to adopt effective enforcement measures. Fines are often minimal (in West Virginia the maximum fine is $1,600) and sanctions, to the extent they exist at all, generally apply only to the trucking company and not to the coal company shipping the coal or the preparation plant or power plant receiving it. Consequently, overweight coal trucks continue to operate with all but total impunity in some states.[xc]

At this writing, however, Kentucky is in the midst of a new crackdown, ordered by its new governor, Ernie Fletcher. In a departure from past policies, Department of Vehicle Enforcement officers have been writing citations to coal companies as

well as truckers, on grounds of aiding and abetting the breaking of the weight law.[xci] Independent truck drivers in Eastern Kentucky, meanwhile, have been striking — parking their vehicles — to force coal companies to increase the per-ton rates they pay the truckers, in order to compensate for their lost haulage revenues.[xcii] They have reportedly had some success, but it is not yet clear whether Kentucky's enforcement crackdown is more than a short-term phenomenon.

A substantial increase in Appalachian coal production would clearly exacerbate the truck haulage problem. Accordingly, there is a need for enforcement consistency not simply within coal states but from state to state — perhaps under the umbrella of strong federal regulations — and on a sustained basis, in order to level the field and discourage those disposed to take advantage of their competitors by squeezing extra profits from overweight trucks. There is also a need to research the feasibility and cost of improving both secondary and primary coal-haul roads in Appalachia as well as extending railheads to more mine locations (which in some cases might entail little more than reopening abandoned rail lines). A cost-benefit analysis is needed to assess this challenge and to develop recommendations regarding federal-state funding and tax policy, in part to ensure that there is adequate private-sector support for such transportation improvements.

Unmapped abandoned mines: At about 8:45 p.m. on July 24, 2002, miners working in the Quecreek Mine, a small underground operation in southwestern Pennsylvania, accidentally broke through into an adjacent abandoned mine, which then flooded the Quecreek Mine, trapping nine miners. They were brought out alive three days later after rescuers successfully drilled 240 feet down to within a few feet of their location.

While the nationally televised rescue was dramatic and miraculous, the accident itself should never have happened — and might not have occurred if the owner and operator of the Quecreek Mine had had an accurate map of the adjacent Harrison No. 2 Mine. But the map the miners were using, which showed a distance of 450 feet between the two mines, was undated and had not been certified by a mining engineer. MSHA's subsequent investigation found that the map dated from 1957 but that the Harrison No. 2 Mine had continued to produce coal until 1964.[xciii] Although MSHA acknowledged that a certified final mine map for Harrison No. 2 apparently did not exist — or at least was not on file in the State of Pennsylvania's mine map repository — the agency nevertheless cited the Quecreek owner and operator and their engineering consultant for failure to use an accurate, certified map. Citations totalling $14,100 were imposed and, not

surprisingly, are being appealed.[xciv] Meanwhile, eight of the nine rescued miners have sued the mine owner, operator, and engineering firm for negligence.[xcv]

In the wake of the Quecreek accident, Congress appropriated $10 million to MSHA to inventory and computerize old mine maps and to identify unmapped mines.[xcvi] Similarly, Pennsylvania's Department of Environmental Protection is working with the state's Historical and Museum Commission to create a comprehensive abandoned mine map database, and has developed stronger regulations requiring mine owners and engineers to use the best available maps, as part of a broad overhaul of its antiquated mining laws.[xcvii]

The Quecreek near-disaster clearly points up the importance of developing a more comprehensive and coordinated system to ensure that all mining operations are guided by accurate maps. The urgency of doing so is underscored by the fact that small, marginal operations like Quecreek, while not important to the goals of any foreseeable national energy independence policy, are likely to continue to operate at the fringe, as it were, typically by mining relatively small blocks of coal left behind by mines that closed long ago. The potential for disaster, triggered by circumstances similar to Quecreek, will be very real, and it will be important to ensure that the current interest in state-of-the-art mapping is not transitory.

Pollution from preparation plants: Run-of-mine coal, which may consist of as much as 60 percent rock and other impurities, is processed at more than 500 preparation plants throughout the coalfields. Mechanical and chemical removal of impurities can reduce the sulfur content and improve the heating value of coal as well as reducing shipping costs. Post-preparation mine wastes, either in refuse piles or in slurry impoundments, are regulated by MSHA and state mining agencies, and slurry spills are violations of the Clean Water Act. Emissions from preparation plants, which can include carbon monoxide, carbon dioxide, sulfur dioxide, nitrogen oxides, and volatile organic compounds (VOC), as well as trace amounts of mercury, chromium, copper and other hazardous air pollutants, are regulated by the Environmental Protection Agency and state agencies under Section 111 of the Clean Air Act.[xcviii] The goal, of course, is to protect preparation plant workers and neighboring communities alike against hazardous pollution.

Preparation plants are not always good neighbors, however. In West Virginia, for example, preparation plants operated by Massey Energy have had a long history of conflicts with nearby residents. In 2000, two Massey subsidiaries each paid $200,000 in Clean Water Act fines for blackwater spills. Meanwhile, a group of

Boone County residents who had been complaining for years about a Massey plant's failure to control dust brought suit in state court for damages and finally won a $473,000-plus-fees judgment against the company in 2003; at the trial a real estate appraiser testified that home values near the plant had been lowered by nearly 80 percent because of persistent pollution. Despite these developments, problems continue: early in 2004 a Massey plant discharged polluted water into the Guyandotte River, the third time in nine months that the plant had been cited for such discharges.[xcix]

Massey's track record is not necessarily representative, but because preparation plants are an essential part of coal production, any strategy to increase production under a national energy independence policy must take into account the need for more stringent enforcement of pollution controls. Efforts must also be increased to protect the approximately 11,300 men and women who work in preparation plants for coal companies and independent contractors.[c] There have been 15 fatal accidents in preparation plants since 2000, and with the trend to using more contractor-supplied workers (discussed above) there is a clear need to ensure both that they are properly trained and that they work in safe, healthful conditions.[ci]

. . .

This is not an exhaustive list of issues affecting future coal production strategies. The limitations of the present rail transportation network, for example, could seriously impede efforts to increase production both within Appalachia and, by creating or exacerbating bottlenecks at various points across the nation, in the West as well. The discussion above, however, indicates the range of upstream issues that must be addressed as part of any strategy to rely on coal to help meet the nation's energy independence goals. Coal may be vital to the nation's future, but to replace its lingering 20th-century legacy with a record that the nation can be proud of will require creativity, innovation, and diligence — in short, a sustained commitment to raising the bar of performance much higher than ever before.

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HARVARD UNIVERSITY
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

Deploying IGCC in This Decade With 3Party Covenant Financing

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FOREWORD

These two volumes emanate from fourteen months of research, discussion and countless drafts. The three authors, Bill Rosenberg, Dwight Alpern, and Michael Walker, conducted meetings with key players, including officials from both the federal and state government, representatives of the power, engineering, coal and chemical industries, environmental groups and academic experts. We are especially grateful for the cooperation of the Carbon Mitigation Initiative at Princeton University and two of its leaders, Robert Socolow and Robert Williams, and for the continuing advice from the MIT Laboratory for Energy and the Environment.

Both of these volumes have been extensively peer reviewed by a team of experts, including faculty at Harvard, Yale, and Princeton. The authors have consulted with officials from the Electric Power Institute, Center for Clean Air Policy (CCAP), and the National Association of Utility Regulatory Commissioners (NAURC). The authors also benefited from a workshop held at the John F. Kennedy School in February, 2004. Over eighty experts from across the country participated in a discussion on opportunities to overcome the financial and political challenges confronting the deployment and commercialization of Integrated Gasification Combined Cycle technologies (IGCC), (see the ENRP rapporteur's report: “Workshop on Integrated Gasification Combined Cycle: Financing and Deploying IGCC Technologies in this Decade,” #2004-06).

These reports are part of a three-year program in the Kennedy School's Energy Technology Innovation Project (ETIP), a joint effort of the Environment and Natural Resources Program (ENRP) and the Science, Technology and Public Policy Program (STPP). ETIP has fostered extensive work on the obstacles and opportunities for development and utilization of IGCC technologies in China and India, as well as in the United States.

These efforts are stimulated by three policy imperatives: the need to increase the use of indigenous coal supplies and to meet a growing demand for electricity; the need to clean up our air, and reduce the threat of global climate change; and the need to address the nation's energy security. These reports provide a blueprint of how the United States might take the initial steps to commercially deploy IGCC technology to significantly improve our air, economy, and national interest.

We are very grateful for the support of the National Commission on Energy Policy, the Department of Energy, the Hewlett Foundation, the Packard Foundation, the Roy Family Fund, and the hundreds of experts who have generously given the authors the benefit of their advice and counsel.

John Holdren and Henry Lee
Co-chairs, Energy Technology and Innovation Project

REPORT ORGANIZATION

The paper is divided into two volumes. Volume I describes IGCC technology, why it is an important advanced clean coal technology for generating electricity, the hurdles to near-term deployment, the 3Party Covenant financing and regulatory program to stimulate near-term IGCC deployment, and how the 3Party Covenant improves the economics of IGCC technology to make it competitive. Appendix A of Volume I outlines the components of federal legislation that are needed to implement the 3Party Covenant.

Volume II provides a detailed legal analysis of the federal and state authorities and regulatory mechanisms for implementing the 3Party Covenant, including a review of traditional electric utility regulatory systems, the current regulatory systems in 5 specific states, and a model regulatory mechanism for review and approval of IGCC project costs under the 3Party Covenant.

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EXECUTIVE SUMMARY

This paper describes a 3Party Covenant financing and regulatory proposal ("3Party Covenant") aimed at reducing financing costs and providing a technology risk tolerant investment structure to stimulate initial deployment of 3,500 MW (about six 550 MW plants) of Integrated Gasification Combined Cycle (IGCC) coal generation power plants in this decade. The 3Party Covenant is an arrangement between the federal government, state utility commission (state PUC), and equity investor[1] that serves to lower IGCC cost of capital[2] by reducing the cost of debt, raising the debt/equity ratio, minimizing construction financing costs, and allocate financial risk. The 3Party Covenant reduces the cost of capital component of energy costs from new IGCC facilities by approximately 38 percent and the overall cost of energy about 25 percent, making power produced from IGCC technology cost competitive with pulverized coal (PC)[3] and natural gas combined cycle (NGCC) generation.

ES-1. Integrated Gasification Combined Cycle Generation

IGCC is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block. As illustrated in Figure 1-1, the gasification system converts coal (or other solid or liquid feedstocks such as petroleum coke or heavy oils) into a gaseous "syngas," which is made of predominately hydrogen (H_2) and carbon monoxide (CO). The combustible syngas is used to fuel a combustion turbine to generate electricity, and the exhaust heat from the combustion turbine is used to produce steam for a second generation cycle and provide steam to the gasification process.[4]

Despite the worldwide commercial use and acceptance of gasification processes and combined cycle power systems, IGCC is not perceived in the U.S. to have sufficient operating experience to be ready to use in commercial applications. Each major component of IGCC has been broadly utilized in industrial and power generation applications, but the <u>integration</u> of a coal gasification island with a combined cycle power block to produce commercial electricity as a primary output is relatively new and has been demonstrated at only a handful of facilities around the world. The Overnight Capital

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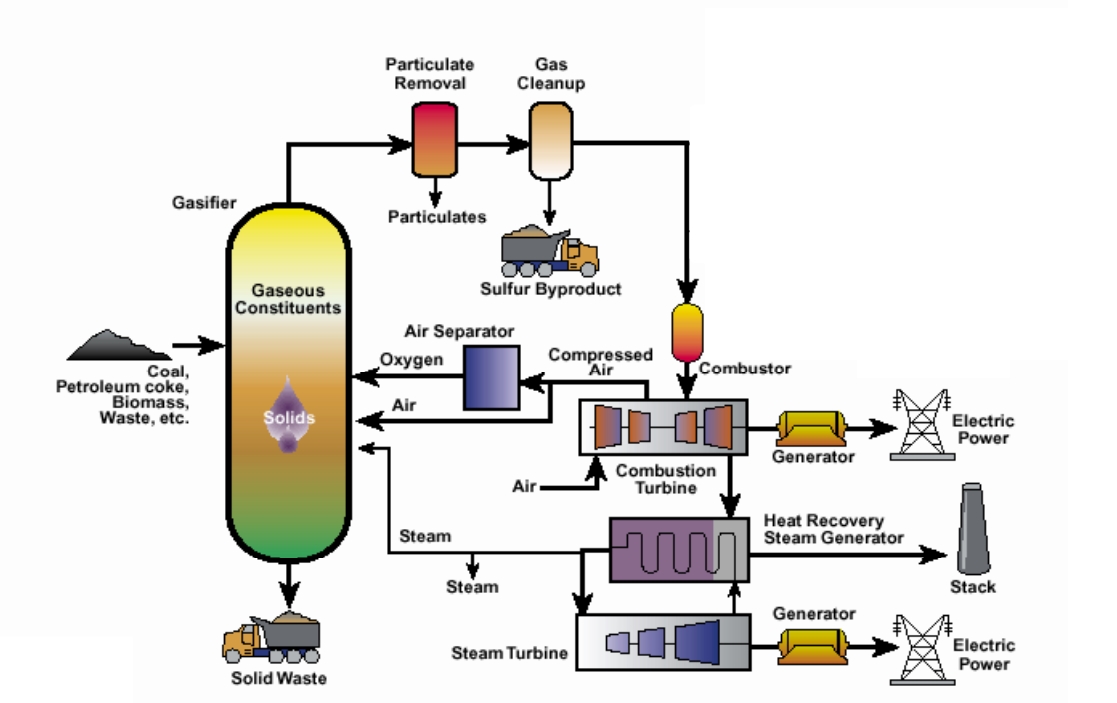
[1] The "equity investor" is likely to be either an electric utility company (or a municipal utility or rural electric cooperative), or independent power company with a purchase contract with a utility (or a contract with comparable credit rating), that provides the equity for a project.

[2] As used in this paper, the term "cost of capital" means debt interest and authorized return on equity.

[3] As used in this paper, the term "PC" or "super-critical PC"means a power generation process that uses a super-critical, pulverized coal-fired boiler incorporating the latest emissions control technologies, including fabric filter baghouses or electrostatic precipitators for particulate control, flue gas desulfurization (FGD) for sulfur dioxide control, and selective catalytic reduction (SCR) to control oxides of nitrogen.

[4] With minor adjustments, combustion turbines designed to operate on natural gas can use syngas. The primary difference that affects the turbine is that syngas has a lower heating value than natural gas, which makes for a larger mass flow of fuel through the turbine that requires different piping and increases turbine output. Natural gas has a heating value of 1,026 btu/ft^3, while syngas has a heating value of 200-300 btu/ft^3.

Figure ES-1. IGCC Power Plant



Source: NETL

Cost[5] of the engineering, procurement, and construction (EPC) contract for IGCC is currently estimated to be about 20 percent higher than PC systems[6] and commercial reliability has not yet been established. As a result, investments to build IGCC facilities to generate power have not materialized despite significant public and private sector interest in the technology.

ES-2. Why IGCC

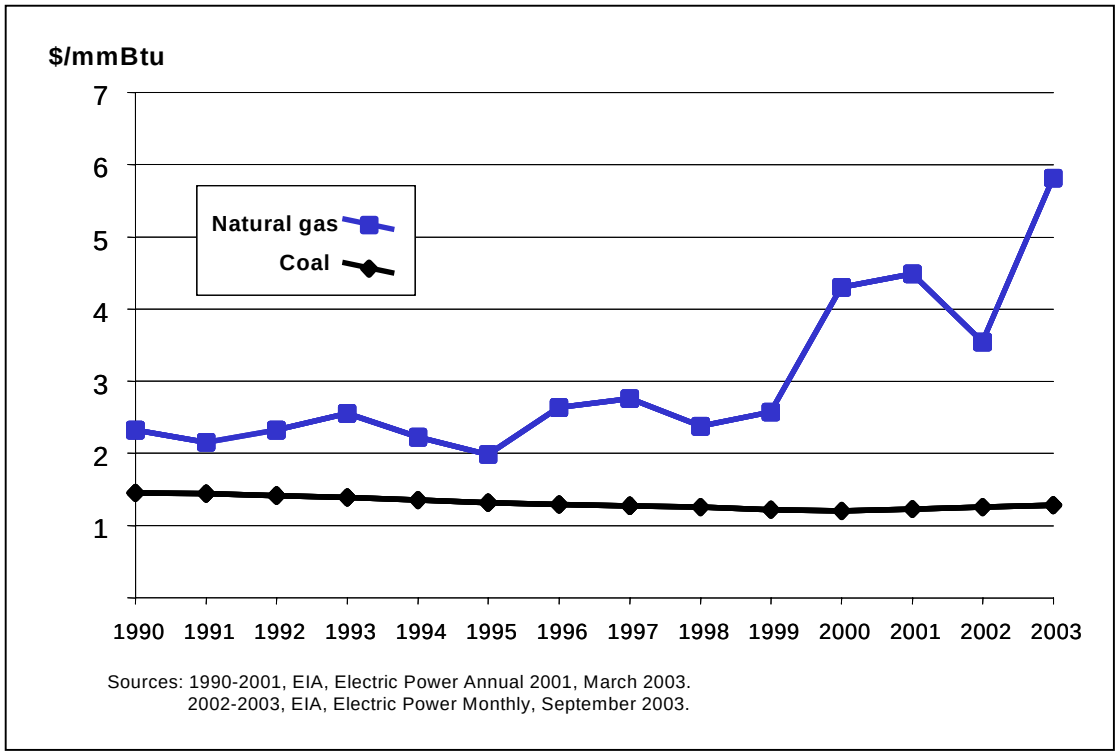
IGCC was selected as the focus of this paper because it is a commercially ready, advanced technology for generating electricity with coal that is widely supported and can substantially reduce air emissions, water consumption, and solid waste production from coal power plants.[7] The Department of Energy (DOE) has invested billions of dollars over the last 20 years to support the technology, and there are fully demonstrated and

[5] As used in this paper, the term "Overnight Capital Cost" means the bare cost of designing and building a power plant, including engineering, procurement, construction and contingencies, but not considering cost of capital.

[6] However, the current market for combustion turbines, a key component of IGCC power plants, is very soft, which may allow for more cost-competitive IGCC than most studies indicate. Completed natural gas combined cycle units and unused turbines that have never been installed are available for purchase at a very substantial discount. According to NETL, there are as many as 50 turbines currently in warehouses that could potentially be used for new power plants.

[7] The type of financing program described in this paper could also be effective for other technologies that have similar environmental characteristics.

Figure ES-2 Average Delivered Fuel Prices to Electric Generators



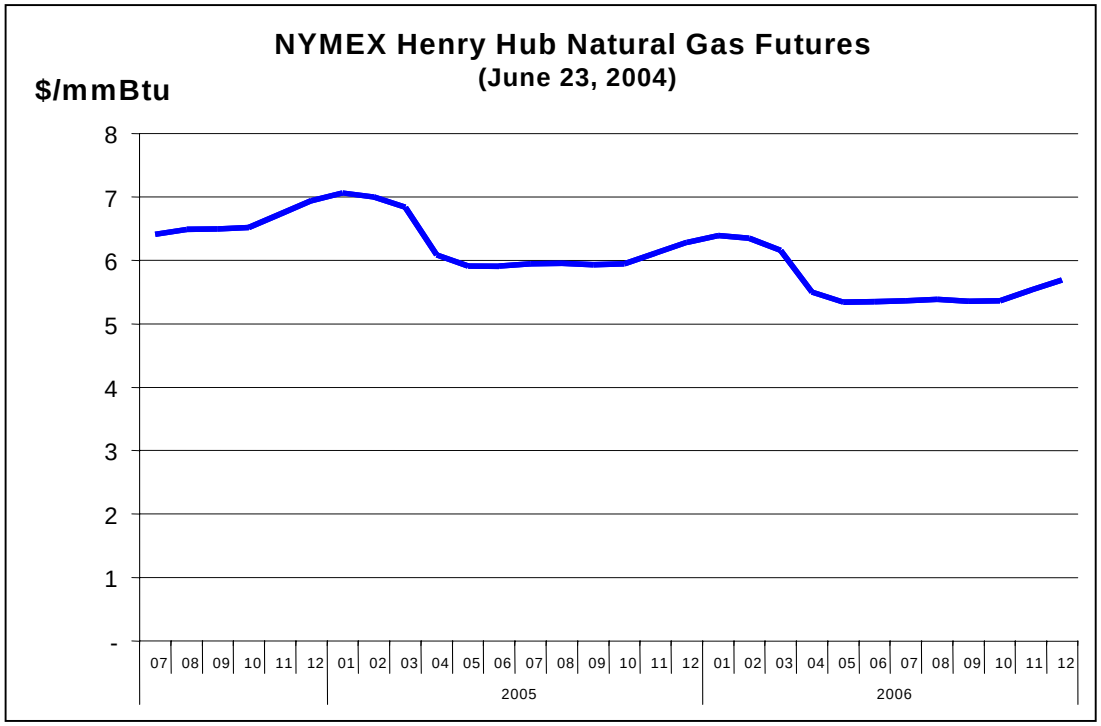
commercially operating plants in the U.S., Europe, and Japan. IGCC also offers the potential of a technical pathway for cost effective separation and capture of carbon dioxide (CO_2) emissions and for co-production of hydrogen. These environmental attributes make it an important technology for enabling the substantial energy, economic, and national security benefits of coal use for electricity generation to be achieved with minimal environmental impact.

Coal is a vital U.S. energy resource that currently fuels over 50% of U.S. electricity generation. The U.S. has 25 percent of the world's proven coal reserves, more than any other country in the world. This supply enables the U.S. to be a net coal exporter.[8] In contrast, the U.S. has less than 3 percent of world oil and natural gas reserves,[9] imports over 50% of its oil supply (compared to 28 percent just prior to the first Arab Oil Embargo), and is expanding natural gas imports from mid-eastern and other countries through development of liquefied natural gas (LNG) production and transport facilities. [10]

Real coal prices have declined 63 percent since 1980 and real retail electricity prices, which are directly affected by coal prices, have declined 21 percent over the same

[8] Estimated recoverable coal reserves in the U.S. are 275 billion tons, which is approximately 25 percent of world reserves and more than a 250-year supply at current consumption (See National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003).
[9] U.S. oil and natural gas reserves are estimated to be less than 2 percent and 3 percent of world totals, respectively. (See EIA, "International Energy Annual 2001," Table 8.1).
[10] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.

Figure ES-3. Henry Hub Natural Gas Futures



period.[11] The average price of coal delivered to electric generators in December, 2003 was $1.25/mmBtu, compared to $3.90/mmBtu for petroleum and $5.24/mmBtu for delivered natural gas.[12] As illustrated in Figure ES-2, electric generator natural gas prices have become increasingly volatile in recent years while coal prices have remained relatively stable and slowly declined for the past decade. Coal price stability translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel. Domestic coal, which is geographically dispersed across the country, transported by rail and barge, and can be stockpiled for 30-90 days at generating facilities, is a secure and reliable energy source.

Coal electricity generation can also help relieve pressure on natural gas availability and prices that are adversely affecting other sectors of the economy. Natural gas prices in 2003 were two to three times above historic averages and, as illustrated in Figure ES-3, natural gas futures suggest prices will remain high for at least the next several years.

These high natural gas prices caused widespread, adverse impacts on the U.S. economy and economic competitiveness, including significant job losses in manufacturing and chemicals industries.[13] One factor supporting high natural gas prices and price forecasts

[11] See EIA, "Annual Energy Review 2002," October 2003, Tables 7.8 and 8.6.
[12] See EIA, "Electric Power Monthly," April 2004, Table ES1.A.
[13] The economic consequences of high prices are described in the House Speaker's Task Force for Affordable Natural Gas report, which states: "Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are

is the increased demand resulting from construction of new natural gas-fired electric generation. According to EIA, natural gas consumption by electric generators increased 40% between 1997 and 2002 and will increase another 51% by 2025.[14] Coal generation in general, and IGCC in particular (which can be used to refuel natural gas plants to coal), can help reduce pressure on natural gas prices.[15]

For the nation to enjoy the energy and economic advantages of coal generation without risking significant adverse environmental and health impacts, advanced coal generation technologies need to be deployed that address air pollution, climate change, and other environmental concerns associated with traditional coal combustion technologies. IGCC offers the potential for coal generation with significantly improved environmental performance, particularly reduced air emissions, through gasification and removal of impurities prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases.[16] Because the syngas produced in the gasification process has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions.

For example, there is no single proven technology available today that can uniformly control mercury emissions from PC power plants in a cost-effective manner, while consistently achieving mercury removal levels of 90 percent.[17] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (95-99 percent) mercury control with established technology.[18] In addition, IGCC technology offers the potential for separating and capturing CO_2 emissions (and producing pure hydrogen) by adding water-gas shift reactors to the syngas treatment system and physical absorption processes to remove CO_2. These processes are commercially proven in industrial processes, and

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losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries." House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (Sept. 30, 2003).

[14] See http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm; See also EIA, Annual Energy Outlook 2004, Table A-13.

[15] In contrast to natural gas, increased use of coal for electricity generation, has very little impact on other sectors of the economy because coal use in the U.S. is essentially dedicated to electricity generation, with 90 percent of coal consumption in the U.S. attributable to electric generators. See EIA, "Annual Energy Outlook 2003 (AEO 2003)," Table A16, Jan. 2003.

[16] Typical combustion and post-combustion controls required of new PC power plants include Flue Gas Desulfurization (FGD, or "scrubbers") for SO_2 control, low NOx burners and Selective Catalytic Reduction (SCR) for NOx control, and Electro-Static Precipitators (ESP) or fabric filter baghouses for particulate control. These technologies add to the capital cost, size and complexity new PC power plants and decrease plant efficiency because of their energy consumption.

[17] NETL, "The Cost of Mercury Removal in an IGCC Plant," p. 1, Sept. 2002.

[18] Id.

several studies have shown this to be a more cost-effective approach to CO_2 capture[19] with proven technology than capturing CO_2 from the flue gas of a PC boiler.[20]

U.S. leadership in the deployment of IGCC technology also could be very beneficial in steering coal-intensive developing countries, such as China and India, towards more environmentally and climate friendly coal use. Near-term deployment of technology capable of addressing CO_2 emissions is critical to avoid locking in traditional steam coal technology for the 30 to 50 year life of new coal plants for the 1,400 giga-watts of new capacity projected to come on line by 2030.[21]

ES-3. IGCC Deployment

For IGCC to be perceived as mature, reliable, and economic, more commercial experience needs to be gained through deployment. However, in order to attract the investment needed for deployment, the technology needs to be perceived as commercially mature, reliable, and economic. Helping resolve this dilemma through commercial deployment of an initial fleet of IGCC power plants is the principal objective of the 3Party Covenant financing and regulatory program.

High natural gas prices, broad political interest, and a growing need for new base load electricity supplies are creating a window of opportunity for IGCC. Many diverse interests, from coal producers and utilities, to state and federal government officials, to environmental organizations, have expressed support for the technology.

At the same time, there has been a resurgence of proposals for PC coal power plant development, with over 94 new coal plants identified as under development in the U.S. as of February, 2004. As illustrated in Figure ES-4, during the period 2005 to 2015, EIA projects the addition of 57 giga-watts of new coal, nuclear, and combined cycle gas generating capacity to serve electricity demand, which is equivalent to about 100 new 550 MW power plants (average of 10 per year). If current fuel price trends continue, a substantial portion of the new capacity is likely to be coal fueled utilizing PC technology. A window of opportunity exists for IGCC technology to account for an important share of this new capacity and prove its commercial viability in the near term.

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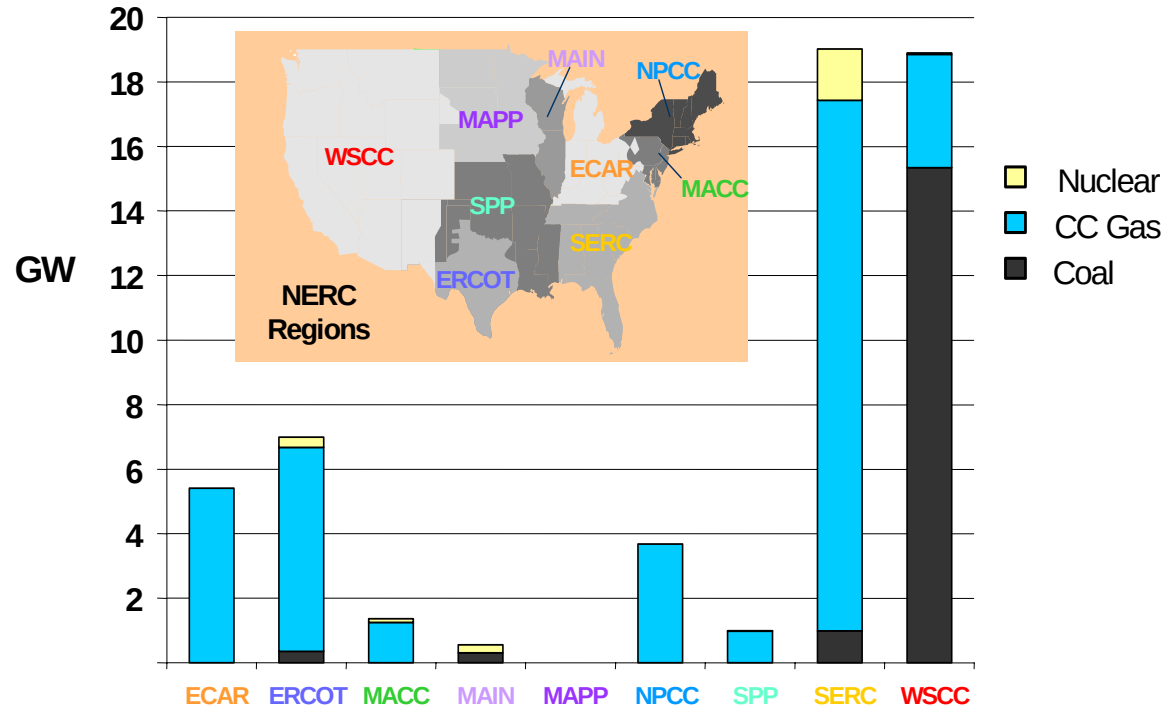
[19] Although capturing CO_2 is only the first step in controlling it (because it must be sequestered if emissions are to be reduced), most experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal power plant would be in a position to sequester its CO_2. Sequestration is not specifically addressed in this paper because it is viewed by the authors as beyond the scope of commercialization of a small initial fleet of IGCC plants, which is the objective of the 3Party Covenant proposal.

[20] See Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000; See also DOE—EPRI Report 1000316, Dec. 2000.

[21] See Fridtjof Unander and Carmen Difiglio, International Energy Agency, Energy Technology Policy Division, “Energy and Technology Perspectives: Insights from IEA modeling,” presented at the National Energy Modeling System/Annual Energy Outlook 2003 Conference, Mar. 18, 2003.

Figure ES-4. EIA 2005-2015 Coal, Nuclear, and NGCC Capacity Additions



Source: EIA, Annual Energy Outlook 2004, Supplemental Regional Data, Table 75.

In addition, market availability of underutilized NGCC generation assets at discount prices presents an opportunity for cost-effective coal gasification refueling. The combined cycle power block associated with a NGCC power plant is essentially the same as the combined cycle power block needed for an IGCC facility. To convert an existing natural gas turbine to use synthesis gas from a coal gasifier is a minor adjustment estimated to cost only $5 million for a typical 350 MW plant, or roughly $15/kW.[22] This cost is more than made up for by the savings associated with using a financially distressed asset to provide the combined cycle power block for the IGCC plant. Furthermore, for an owner of a distressed NGCC facility, refueling to IGCC means taking a depressed asset facing large write-offs that is operating at only a fraction of its capacity and repositioning it to operate as a base load coal facility that operates at a high (80-90%) capacity factor. With 3Party Covenant financing, the cost of energy from the resulting plant is as much as 19 percent below the cost of energy from a new PC plant (see Figure ES-10 below).

Despite these opportunities, investments to design and build commercial IGCC power plants in the U.S. have not yet materialized due to cost and risk concerns. A 2004 survey

[22] NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.

by DOE indicates that the three leading risk factors perceived by industry to be associated with IGCC investments are high capital costs, excessive down time, and difficulty with financing.[23] The financing hurdle is made all the more difficult by the fact the electric utility industry today is weaker financially than it has been in the past. A November 2003 analyst report by Standards and Poors indicated that:

> "the average credit rating for the electric utility sector is now firmly in the 'BBB' category, down from the 'A' category three years ago. Furthermore, prospects for credit quality remain challenging, as indicated by rating outlooks, 40 percent of which are negative."[24]

Lower credit ratings make if more difficult and costly for power companies to raise money for large, capital-intensive coal projects (whether PC or IGCC) costing close to a billion dollars. Add the uncertainty of a relatively new generating technology such as IGCC, and financing becomes a serious constraint to deployment.

ES-4. 3Party Covenant Financing and Regulatory Program

The 3Party Covenant is a financing and regulatory program for providing developers of IGCC power plants with ready access to capital at lower cost in an environment that tolerates technology risk. By so doing, the 3Party Covenant addresses the fundamental economic and financial challenges inhibiting IGCC deployment. The program is designed to facilitate development of an initial fleet of commercial IGCC plants this decade to establish the commercial viability of the technology and reduce costs.[25]

As illustrated in Figure ES-5, the 3Party Covenant is a financial and regulatory arrangement among a federal agency, a state PUC (or other utility rate setting body), and an equity investor. Under the 3Party Covenant, the federal government provides AAA credit, the state PUC provides an assured revenue stream to cover cost of capital and protect the federal credit, and the owner provides equity and know-how to build the IGCC project with appropriate guarantees from an EPC firm (which in turn has underlying warranties from equipment vendors). In return, the federal government stimulates IGCC deployment to support energy, national security, and environmental policy objectives at low federal cost; the state receives competitively priced power, economic development (investment and jobs), and environmental improvement; and the

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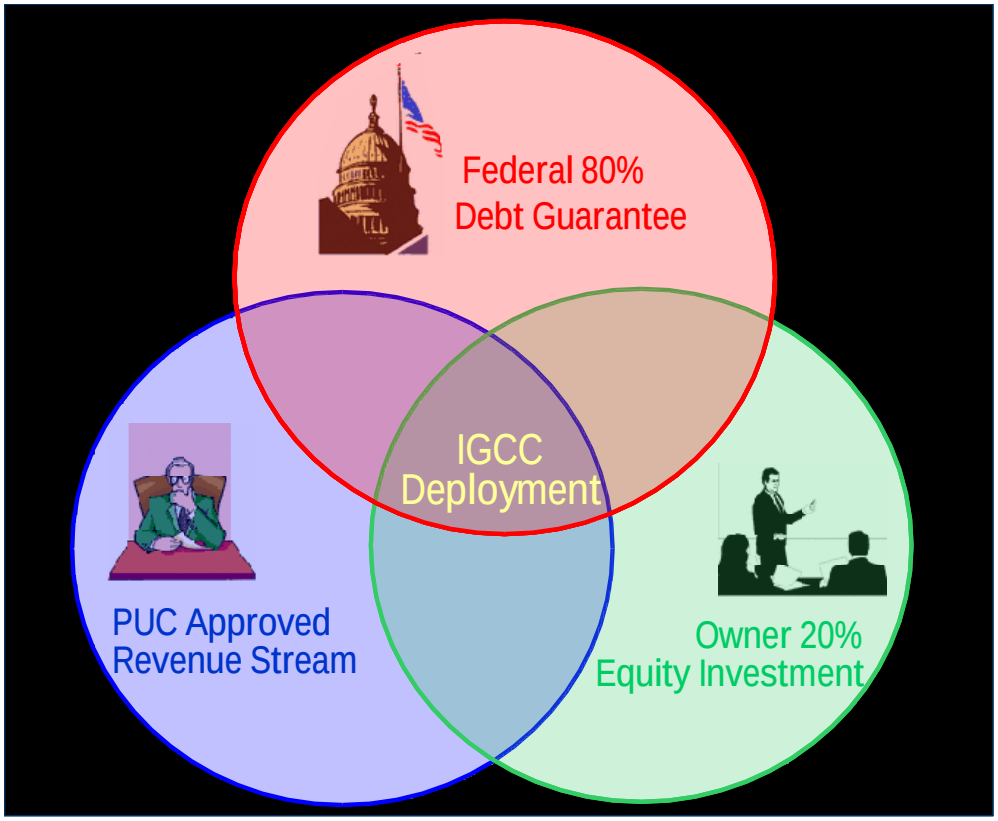
[23] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.

[24] Ronald M Baron, *"U.S. Power and Energy Credit Outlook Not Promising; Few Bright Spots,"* Standard & Poors, Nov. 11, 2003.

[25] Public sector support for commercialization of innovative new technologies was identified as an important recommendation of the PCAST Energy R&D Panel in 1997, which recommended among other things "targeted efforts to improve the prospects of commercialization of the fruits of publicly funded energy R&D in specific areas." (See PCAST Energy R&D Panel 1997, *Federal Energy Research & Development for the Challenges of the 21st Century*, Report of the Energy R&D Panel, The President's Committee of Advisors on Science and Technology, Nov., 1997).

Figure ES-5. 3Party Covenant Illustration



equity investor receives access to non-recourse, low-cost debt, assured equity returns, and an economic base-load power plant.

The three key elements are as follows:

Federal Loan Guarantee: The program for implementing the 3Party Covenant is established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee provide for an 80/20 debt to equity financing structure and require that a proposed project obtain from a state PUC an assured revenue stream to cover return of capital, cost of capital, and operating costs. The terms also require the project to capitalize a 10 percent Construction and Operating Reserve Fund, to have appropriate construction guarantees from the EPC firm hired to design and build the plant, and to meet stringent environmental performance specifications. The terms would also enable the project to have available an additional draw on the federally guaranteed debt ("Line of Credit") of up to 15 percent of project Overnight Capital Costs (to be matched with a 20 percent equity contribution when drawn).

State PUC Approval Process: States interested in participating in the program voluntarily opt-in by adopting utility regulatory provisions for state PUC review

and approval of IGCC project costs, which in some states will require legislative action to create appropriate enabling authority.

Specifically, a state PUC (or potentially another ratemaking body in the case of a municipal utility or rural electric cooperative), acting under state enabling authority, assures dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation and maintenance, fuel costs, and taxes).[26] The state PUC provides this revenue certainty through utility rates in states with traditional regulation of retail electricity sales, or through non-bypassable wires charges in states with competitive retail electricity sales, by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery of approved costs, including cost of capital. The certification by the state PUC occurs upfront when the decision to proceed with the project is being made, and the prudence review by the state PUC and cost recovery occur on an ongoing basis starting during construction, which reduces the construction risks borne by the developer, avoids accrual of construction financing expenses, and protects ratepayers.

Equity Investor: The equity investor under the 3Party Covenant is likely to be either an electric utility (or a municipal utility or rural electric cooperative) or an independent power producer that secures a long-term power contract with a utility (or a contract with a comparable credit rating). The investor contributes equity for 20 percent of project costs and negotiates performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return is determined and approved by the state PUC before construction begins.

The 3Party Covenant is distinguished from other federal financing programs because a principal party is a state PUC (or potentially another ratemaking body for a municipal utility or rural electric cooperative), which effectively assures the revenue stream needed to service the federally guaranteed debt. The regulatory body, operating under state enabling law, reviews and approves the IGCC plant proposal upfront, determines the need for power, establishes the mechanism for allocation of project risks and recovery of approved costs, conducts ongoing prudence review during construction and operation, and determines the amount and timing of project revenues. The 3Party Covenant requires states that want to participate to establish a review and approval process that provides for cost recovery assurances to protect the federal loan guarantee before the guarantee becomes effective.

[26] Depending on the ownership structure and sales profile (i.e., retail sales versus sales for resale) of the IGCC project, the Federal Energy Regulatory Commission (FERC) may take on some of the role otherwise assigned to the state PUC.

The 3Party Covenant is designed to benefit and protect ratepayers by enabling them to receive lower cost (because of access to lower cost financing)[27] and less polluting power without being required to take excessive risk. Ratepayer risks are mitigated under the 3Party Covenant by EPC contractor construction guarantees (and underlying equipment vendor warranties) required to cover construction risks, 10 percent Construction and Operating Reserve Fund and 15 percent Line of Credit (percentages based on Overnight Capital Costs) to cover construction and operating risks that are the responsibility of the owner, and the state PUC process evaluating the prudence of the IGCC investment decision and operation.[28] It is ultimately up to the state PUC, through a transparent public process, to determine whether the public benefits of building a new IGCC power plant under the 3Party Covenant outweigh the risks to ratepayers.[29] The decision will only be made where the PUC determines that there is a need for new base load power and will entail weighing the future benefits, risks, and cost of 3Party Covenant financed IGCC against the benefits, risks, and costs of conventionally financed alternative base load generation (PC).[30]

Once the state PUC assures revenues to service the federally guaranteed loan, the amount of the loan that must be scored as a federal budget expense is likely to be significantly lower, because risk of default is significantly reduced. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (FCRA). FCRA makes commitments of federal loan guarantees contingent upon prior budget appropriations ("scoring") of enough funds to cover the estimated present value cost associated with the guarantees. The present value cost is based on an estimate of the following cash flows at the time the loan guarantee is disbursed:

1. Payments by the Government to cover defaults and delinquencies, interest subsidies, or other payments; and

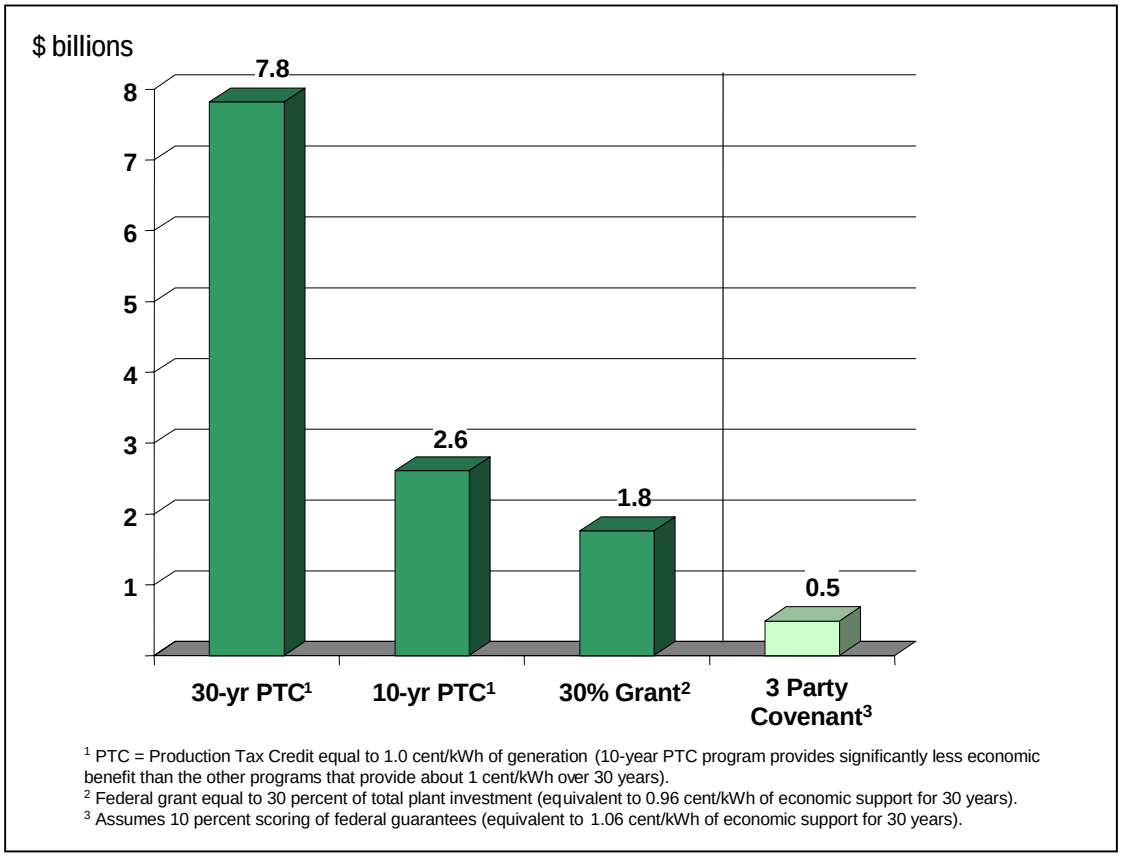
[27] The cost of capital component of energy costs on a capital intensive coal fueled generating plant is typically 60-70% of total energy costs. Substantially lower costs of capital under the 3Party Covenant, as explained in ES-5, reduce the ratepayer supported costs of IGCC to levels competitive with PC.

[28] Use of redundant gasifier capacity, which is assumed in the cost of energy assessment summarized in ES-5 below, also provides protection against operational difficulties that might otherwise reduce plant availability.

[29] This report has not attempted to quantitatively evaluate the costs or risks that ratepayers are being asked to take on, or to quantify the benefits that they will receive. Instead the paper outlines qualitatively how IGCC and the 3Party Covenant benefit ratepayers and quantifies the direct economic savings associated with 3Party Covenant financing. A comprehensive cost/benefit assessment is beyond the scope of the paper, but may be an appropriate future line of investigation.

[30] The cost risks to the ratepayer of a new IGCC plant would also be significantly diluted by the fact that the plant would constitute a small percentage of the total sources of power (generation and purchases) used by a utility. Typical large electric utilities in the U.S. have total sources of power that range between about 50 and 150 million MWh per year. (For example, in 2002 the total sources of power for Cincinnati Gas & Electric were 133 million MWh; Florida Power and Light, 105 million MWh; and PSI Energy, 63 million MWh (see EIA Form 861.) A new 550 MW IGCC facility would generate about 4 million MWh per year if operating at an 85 percent capacity factor. Therefore, in a worse case scenario, if the cost of energy from an IGCC facility ended up 20 percent more than the cost of energy of an alternative PC plant, it would represent a 0.5 to 1.6 percent increase in the overall cost of power procurement by the utility, due to the single plant's relatively small share of the total sources of power.

Figure ES-6. Federal Budget Cost of 1 cent/kWh Support for 3,500 MW of IGCC under Different Policy Approaches



2. Payments to the Government, including origination and other fees, penalties and recoveries.

Payments by the Government are estimated based on the dollar amount guaranteed and the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors. The risk of default provides for estimation of the expected payment (the risk of default times the amount guaranteed) to make the scoring determination. The Director of the Office of Management and Budget (OMB) is charged with making this determination, but may elect to delegate the OMB's authority to another agency. To the extent the rating agencies and OMB view the 3Party Covenant as reducing the risk of default by providing a state PUC approved revenue stream, the federal budget cost (scoring) of the loan guarantees should be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, then $5 billion of loan guarantees (enough for about 3,500 MW) would cost the federal budget $500 million.

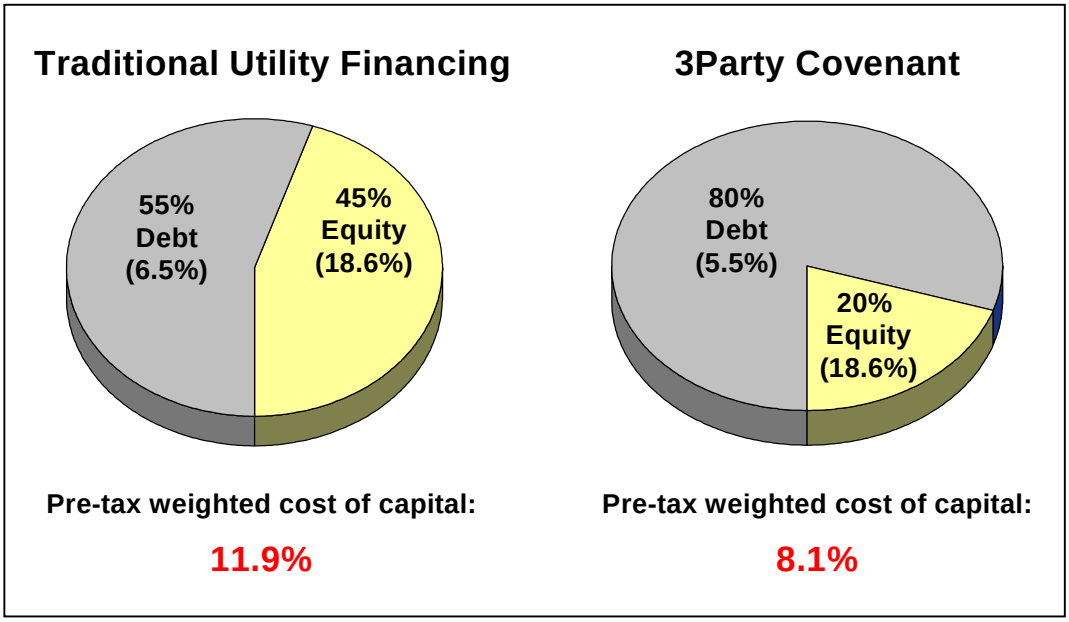
This budget impact is significantly less than alternative grant or energy production tax credit based incentive programs. As illustrated in Figure ES-6, a one cent/kWh production tax credit provided over a 30 year period (approximately the same economic

benefit as provided by the 3Party Covenant) for 3,500 MW of IGCC would cost the federal government $7.8 billion, or sixteen times more than the 3Party Covenant. If provided for only 10 years, the one cent/kWh production tax credit (providing the project significantly less economic benefit than the 3Party Covenant) would still cost $2.6 billion, or more than 5 times more than the 3Party Covenant. Similarly, if a 30 percent federal grant were offered to offset IGCC capital costs, the federal budget cost would be more than 3.5 times more than the budget cost of the 3Party Covenant. The 3Party Covenant loan guarantee approach is significantly less costly to the federal government than these alternative incentive approaches and has the advantage of addressing the major financial obstacles to deployment (e.g., capital availability) that would not be addressed by a production tax credit or grant program.[31]

The 3Party Covenant program reduces the cost of energy from an IGCC power plant approximately 25 percent. The cost of energy reductions result from:

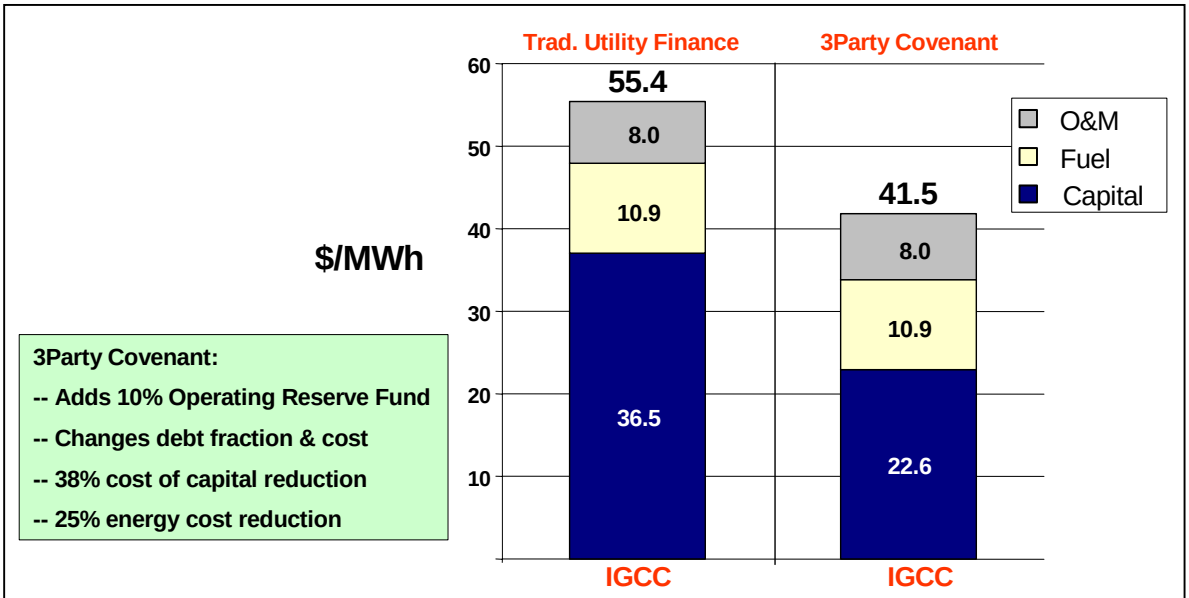
1. Providing for a significantly higher ratio of debt to equity than a traditional utility financing ratio (from 55/45 to 80/20 under the 3Party Covenant).
2. Lowering the cost of debt through the federal loan guarantee, which reduces the interest charge from a typical 6.5 percent for a mid-grade utility bond to the 5.5 percent rate associated with a federal agency bond, in January 2004. Funding construction financing costs on a current basis by adding construction

Figure ES-7. Cost of Capital Reduction under 3Party Covenant



[31] This is not to suggest that budget cost and capital availability are the only attributes that policy makers should consider. There may be other tradeoffs between a PTC and loan guarantee approach that policy makers may want to weigh, such as the requirements for administering the program and the risks associated with different approaches.

Figure ES-8. 3Party Covenant Impact on IGCC Cost of Energy



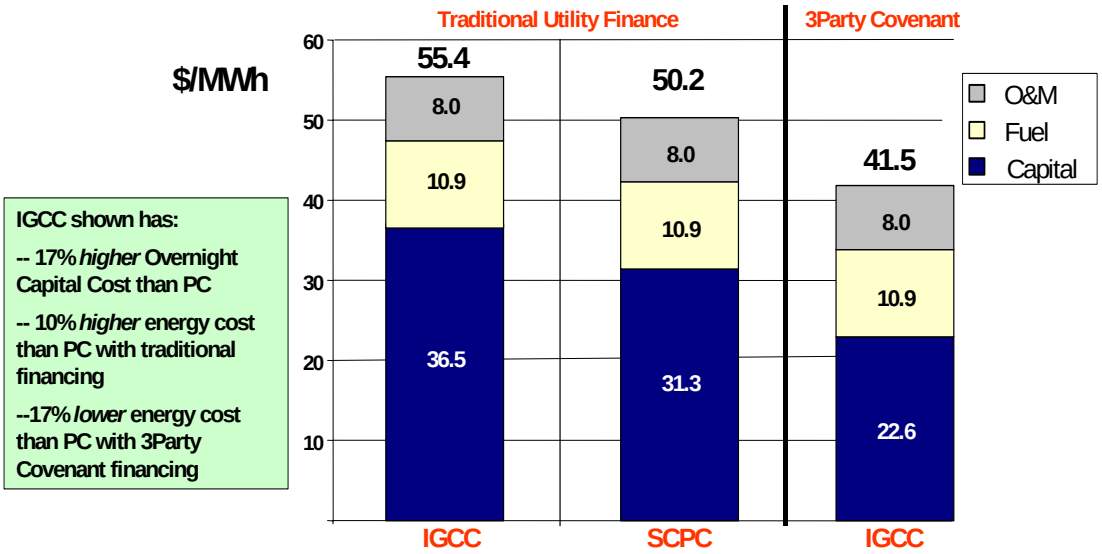
Overnight Capital Cost ($/kW)	$1,400	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25
Capacity Factor	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700
Debt Fraction	55%	**80%**
Debt Cost	6.5%	**5.5%**
Pre-Tax Equity Return	18.6%	18.6%

work in progress (CWIP) to the rate base and recovering these financing costs as they are incurred, rather than accruing these financing costs (which typically account for 10-15 percent of Overnight Capital Costs) and recovering them as part of the capital investment.

As illustrated in Figure ES-7, these changes reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant over 30 percent from about 12 percent (traditional utility financing) to 8 percent (3Party Covenant). Since the cost of capital accounts for over 60% of the total cost of energy in a capital intensive coal based PC or IGCC, this change in cost of capital (along with the reduction in construction financing costs) reduces the total energy cost about 25 percent.

The impact of the 3Party Covenant is demonstrated by comparing the cost of energy associated with a reference IGCC plant financed under a traditional utility financing scenario, with the same plant financed under the 3Party Covenant. As illustrated in Figure ES-8, the reference IGCC plant financed under traditional utility financing has a calculated cost of energy of 55.4 $/MWh, while the same plant financed under the 3Party Covenant has a cost of energy of 41.5 $/MWh. The 3Party Covenant reduces the cost of capital component of energy cost 38 percent and energy cost 25 percent. This energy cost

Figure ES-9. IGCC Cost of Energy versus Super-Critical PC



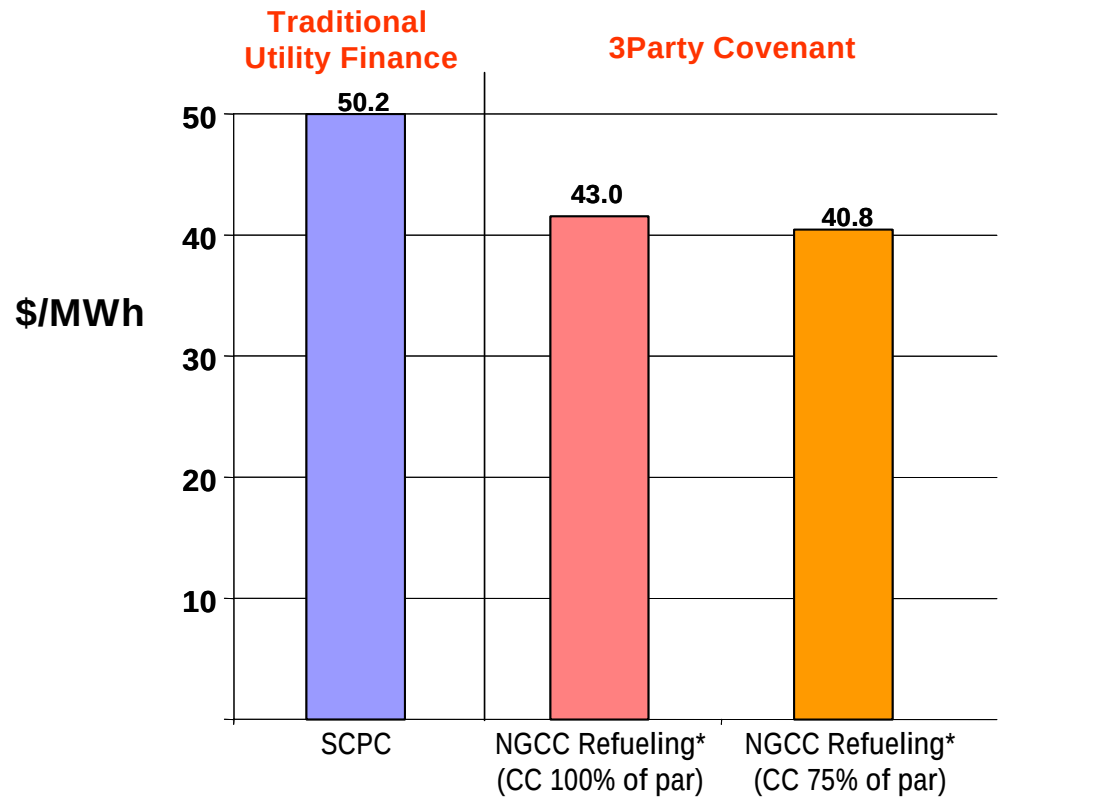
Overnight Capital Cost ($/kW)	$1,400	$1,200	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25	$1.25
Capacity Factor	85%	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700	8,700
Debt Fraction	55%	55%	80%
Debt Cost	6.5%	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%	18.6%

reduction occurs despite the addition of a 10 percent capitalized Construction and Operating Reserve Fund ($70 million) in the 3Party Covenant scenario, which is included to ensure that funds are available to cover any cash flow shortfalls in the initial years of operation due to lower than expected plant availability, cost overruns, or other operational problems.

Figure ES-9 illustrates how the 3Party Covenant affects the relative cost of energy of IGCC compared to PC. The figure illustrates the Reference IGCC plant assuming traditional utility financing and under the 3Party Covenant compared to a PC plant built with traditional utility financing. The figure illustrates that the Reference IGCC plant has a 17 percent higher Overnight Capital Cost than the PC plant, which results in a 10 percent higher cost of energy when both are financed traditionally. However, when 3Party Covenant financing is applied to the IGCC plant, its cost of energy is reduced to a level 17 percent below the PC plant. Even if the entire 15 percent Line of Credit available to cover cost overruns is drawn by the project, the cost of energy remains 10 percent below the PC plant.

Opportunities have recently emerged to create even more favorable IGCC economics by financing the refueling of distressed NGCC assets with coal gasification systems under the 3Party Covenant. Under the reference case IGCC, it is assumed that the gasifier island

Figure ES-10. Cost of Energy of NGCC Refueling under 3Party Covenant



*Assumes 1% efficiency penalty & 5% Overnight Capital Cost penalty in NGCC refueling scenarios vs. Reference IGCC.

accounts for about 65 percent of the $1,400/kW EPC cost, or roughly $900/kW and that the combined cycle power block costs about 35 percent, or $500/kW. In a distressed NGCC refueling scenario, the combined cycle power block may be available at a significantly reduced price. If available for refueling at 75 percent of par, the cost is about $375/kW, and at 50 percent of par, it is $250/kW. If these costs are applied as the combined cycle power block component of the IGCC EPC cost, the Overnight Capital Cost is reduced to $1,275/kW and $1,150/kW, respectively (well below the $1,400/kW reference case assumption).

In refueling scenarios, there is likely to be some inefficiency in design and construction of the gasification system and its integration due to retrofit requirements. For example, a $15/kW cost has been suggested by NETL for refitting the combustion turbine. Other costs might include the need for supplemental steam generation or site improvements. In addition, plant integration may be less than would be planned for a facility designed from the outset to be an IGCC, which may result in reduced efficiency. For this analysis, a five percent capital cost and one percent efficiency penalty is incorporated into the NGCC refueling scenarios to address these issues.

Figure ES-10 illustrates the cost of energy achieved in NGCC refueling scenarios assuming the combined cycle power block is contributed to the project at 75 percent of its original par value (assumed to be $500/kW). Figure ES-10 illustrates that combining 3Party Covenant financing and the potential cost savings associated with using existing distressed NGCC assets produces energy at levels below an all-new IGCC and at levels 19 percent below the reference PC plant built with traditional utility financing. Actual project savings will depend on the cost of the distressed asset to the project and the level of additional cost associated with retrofitting the combined cycle power block to work with a coal gasification system. For example, if the combined cycle power block were contributed to the project at 50% of par, the cost of energy would be about 23 percent below the traditionally financed PC, or $38.7/MWh.

ES-6. Implementation

Implementation of the 3Party Covenant requires federal legislation authorizing loan guarantees for qualifying IGCC projects. Consideration must be given to a number of implementation issues in developing legislation to ensure the program meets IGCC deployment objectives with minimal federal budget impact. Meeting deployment objectives will require determining the desired level of investment (in what timeframe), and ensuring that the economic and financial hurdles that have inhibited IGCC commercial deployment to date are adequately addressed. Section ES-7 below outlines recommended components of federal legislation for implementing the 3Party Covenant to stimulate 3,500 MW of IGCC deployment through authorization of $500 million of budget scoring appropriations to support $5 billion of federal loan guarantees.

The timing of 3Party Covenant implementation is dependent on enactment of federal legislation to establish a loan guarantee program. Proposed energy legislation debated by Congress in 2003 provided significant tax and loan guarantee incentives for clean coal technologies, including IGCC. Ongoing energy policy discussions and wide support for advancing clean coal technologies provide a window of opportunity for near term discussion and implementation. The sooner a program is put in place, the sooner the energy and environmental benefits of IGCC deployment (described in detail in Section 1 of this report) will be realized, a circumstance that should provide strong motivation for lawmakers to consider near-term legislative action.

Implementation of the 3Party Covenant also requires that states establish regulatory mechanisms for review, approval and recovery of IGCC project costs. Section 8 (Volume II) of this report, describes the status of state electric utility regulatory programs in three states with regulated retail electricity service (Indiana, Kentucky and New Mexico) and two states with competitive retail electricity markets (Ohio and Texas) to identify how the different regulatory programs affect 3Party Covenant implementation. Section 9 (Volume II) provides a model state regulatory mechanism for implementing the 3Party Covenant.

ES-7 Components of Federal Legislation for Implementing 3Party Covenant

The outline below describes recommended components of federal legislation to implement the 3Party Covenant. These components are designed to stimulate development of 3,500 MW of IGCC generation with federal loan guarantees of $5 billion. The program is targeted at stimulating deployment of IGCC technology, which is the focus of this paper. This or other incentive programs may be appropriate for IGCC and other advanced coal technologies.

Purpose

Establish a federal loan guarantee program that stimulates deployment of IGCC by reducing cost of capital, apportioning risk, and assisting with pre-development costs in order to:

- Support U.S. energy independence
- Promote homeland security
- Improve coal generation environmental performance
- Increase generation efficiency
- Refuel and revalue billions of dollars of financially distressed and underutilized natural gas combined cycle investments
- Reduce pressure on natural gas prices
- Provide affordable and reliable electricity supplies
- Position the U.S. as a global leader in advanced coal generation technology
- Minimize the burden to the federal budget

Scope

- $500 million appropriations to score up to $5 billion of federal loan guarantees for 3,500 MWs of base load capacity:
    - $450 million for scoring loan guarantees
    - $50 million revolving fund for pre-development engineering loans
    - Loan guarantees may be committed for a period of 10 years beginning with the first fiscal year the program is funded.
- Program shall be implemented through an accelerated rulemaking process to be completed within 12 months of enactment
- Program shall authorize the collection of application or other fees to cover administrative costs as well as insurance fees to the extent such fees are determined to be appropriate by the Secretary

Loan Guarantees

- Up to 80% of total plant Investment
- 30-year term, non-recourse, backed by full faith and credit of U.S. Government
- Owner contributes 20% equity investment

Qualifying Projects

- An IGCC or other coal-fueled power plant technology with the following performance characteristics:
    - Coal accounts for at least 75% of fuel heat input
    - In the case of IGCC, combustion turbine operates on syngas as primary fuel (natural gas or diesel may serve as an emergency back-up fuel only)
    - Design heat rate of 8,700 btu/kWh (HHV) or lower
    - New power plant, repowering of an existing coal power plant, or refueling of an existing natural gas combined cycle power plant
- Emissions Performance:
    - 99% sulfur reduction with SO_2 emission not to exceed 0.04 lb/mmBtu
    - NOx emissions not to exceed 0.025 lb/mmBtu (5 ppm)
    - Particulate emissions from stack not to exceed 0.01 lb/mmBtu
    - 95% mercury emissions control
- Determination by DOE that the technology provides a technical pathway for CO_2 separation and capture and for the co-production of hydrogen slip-streams.
- To minimize federal budget scoring, qualifying projects shall have:
    - 3Party Covenant assured revenue stream through state PUC or other regulatory body providing upfront and ongoing regulatory determinations of prudence of project costs and approvals of pass-through of project costs (reflecting ongoing inclusion of approved capital investments in rate base and inclusion of approved operating costs in the cost of service, or reflecting purchased power costs incurred under a power purchase agreement) under federal and state enabling laws ("Regulatory Determinations"); or
    - Comparable credit (and budget scoring) as that provided by 3Party Covenant Regulatory Determinations, which might be created through insurance, industrial guarantees, or other credit enhancements.
- Projects shall include EPC contractor performance and delivery guarantees (full wrap) for project construction.
- Initial financing shall include a Construction and Operating Reserve Fund of 10 percent of Capital Costs to cover revenue shortfall from startup operations, unscheduled maintenance, etc., and provide Line of Credit for additional draw of up to 15 percent of Capital Costs with an additional minimum matching equity contribution of 20 percent of the amount drawn.

- Secretary shall issue guarantees only for projects with budget scoring that does not exceed 10% of loan principal.
- Secretary shall develop criteria for issuing loan guarantee reservations (commitments prior to closing) for projects that have demonstrated feasibility and meet program qualifications

Pre-development Engineering Loans

- Non-recourse, interest-free loans shall be available for 75% of the cost of developing initial engineering and feasibility evaluations of potential projects
- Developer will be required to provide 25% cash match
- Loans not to exceed $5 million dollars
- Loans to be repaid out of long-term project loan disbursements and placed into a revolving loan fund
- Secretary shall develop criteria for selecting projects to receive Pre-development Engineering Loans, taking into account project timing, feasibility and ability to meet Project Selection Criteria (below)

Project Selection

- Secretary shall establish Project Selection Criteria, including consideration of the following elements:
    - Utilization of diverse coal supplies and types
    - Competitive electricity prices
    - Geographic diversity
    - Project feasibility
    - Financial strength of project
    - Environmental performance

10-28-04

Technical Memorandum – National Commission on Energy Policy

Supporting Documentation for Commission IGCC / CCS Recommendation

Contributing Authors: Tom Bechtel, Joe Chaisson, Rusty Mathews, and NCEP Staff

Recommendation

- The federal government should provide support for the deployment of roughly 10 GW of "sequestration-ready" IGCC plants via loan guarantees, capital grants, or production tax credits at a cost of $4 billion over 10 years.
- The federal government should provide support for the demonstration of geologic carbon storage on a large scale with an investment of $3 billion over 10 years.
- Federal funding for coal-related R&D should be refocused to target innovation in IGCC and carbon capture and storage technologies, with emphasis on gasifier cost/reliability and developments in oxygen production, gas separation, and other related processes.

Supporting Economic Analysis: IGCC Deployment

The cost estimate of $4.0 billion over ten years for financial incentives necessary to deploy roughly 10 GW of "sequestration ready" Integrated Gasification Combined Cycle (IGCC) generation capacity was derived as follows:

1. Basic IGCC power market entry economics were assumed as analyzed in "*Economics of Integrated Gasification Combined Cycle Coal Plant (IGCC) Investments*"[1]. This report was prepared by The NorthBridge Group as a joint MIT Laboratory for Energy and the Environment/Clean Air Task Force white paper.

   The assumptions and methods used in this analysis are described at pages four through 12 of the Northbridge report. Key assumptions include use of EPRI IGCC and pulverized coal development costs and performance characteristics as shown in Table 1, as well as implementation of additional power plant air emissions reduction requirements – generally consistent with the Bush Administration's Clear Skies proposal – by 2010.

   Table 1 New Power Plant Cost and Performance Characteristics[2]

	IGCC	NGCC	SCPC
Capacity (MW)	600	600	600
Capital Cost ($'02/kW)	1,480	608	1,461
Heat Rate (Btu/kWh)	8630	7120	8830
Fixed O&M ($'02/kW)	44.0	10.0	33.5
Variable O&M ($/MWh)	2.7	2.0	2.7
Availability	90%	95%	90%

[1] "*Economics of Integrated gasification Combined Cycle Coal Plant (IGCC) Investments*", The NorthBridge Group, June 1, 2004.

[2] As previously noted, this information comes from the NorthBridge Report cited above. The IGCC and SCPC cost and performance data are based on recent EPRI summaries. The NGCC assumptions were based on several sources of information including NGCC development in the mid-West, NorthBridge analyses, and other sources. The cost data above include all capital costs including interest during construction. IGCC costs also include a spare gasification train.

The analysis evaluates the economics of IGCC relative to two other new greenfield technologies – gas combined cycle (NGCC) and super critical pulverized coal (SCPC). Under baseline conditions it was concluded that widespread commercial deployment of IGCC using delivered coal to produce electricity is not anticipated by 2020. IGCC was determined to have a slight cost disadvantage as compared against traditional PC and both were found to be less competitive than NGCC, even despite recent increases in natural gas prices. Carbon emission restrictions would widen the gap between coal and gas economics.

2. The NorthBridge paper estimated incentive costs necessary to develop IGCC projects (in the Midwest and using eastern coals) that were competitive against a new NGCC installation. The analysis utilized a baseline natural gas price of $4.70/mmbtu Henry Hub and projected how incentive costs would vary at higher and lower gas prices and using different coal types. The estimated incentive needed for bituminous coal IGCC projects in ECAR at the base gas price is roughly $235/kW.[3] The implementation of a national carbon market, with a value of $20/metric ton[4], increases the needed incentive for IGCC to compete against NGCC by $115/kW.[5] Thus, the total size of the incentive under these conditions would be $350/kW. The cost for promoting 10 GW of coal-based (bituminous) IGCC would equate to $3.5 billion over ten years.

3. Because it is not possible to predict future gas prices with certainty, the following range of future gas prices were selected to plausibly "bound" potential financial incentive needs – which vary greatly across this gas price range as can be seen below. The carbon adder of $115/kW stays constant but must be included for all scenarios.

Scenario	Gas Price ($/mmbtu)	Incentive ($/kW)	$20/ton Carbon Adder ($/kW)	Total 10 GW Program Cost
Low Gas Price	3.52	660	115	$7.75 billion
Baseline Gas Price	4.70	235	115	$3.50 billion
High Gas Price	5.87	180	115	$2.95 billion

4. Incentive funding of $4.0 billion was selected as a program funding commitment that could be reasonably expected to move 10 GW of IGCC into the market under a range of reasonable future market conditions, with the following factors in mind:

   - Natural gas prices have become highly unpredictable and volatile in recent years, making price forecasts increasingly unreliable. If prices were to trend lower over time a larger incentive would be needed to overcome the improving economics of gas versus coal. This suggests that financial incentive support for a 10 GW program should be prepared to adjust to somewhat lower gas prices (and higher incentive

[3] Northbridge report p. 25
[4] $20/metric ton carbon is equivalent to roughly $5.50/metric ton CO_2. This value is consistent with the carbon value in the Commission's proposal of $7/metric ton of CO_2 in 2010 ($6/metric ton CO_2 when adjusted for expected inflation to $2004).
[5] Northbridge report p. 21

costs) than the baseline gas price used in this assessment. The Commission provided for some flexibility on this issue but determined federal expenditures should be capped at no more than $4 billion.

- The cost estimates utilized by the Commission focus on Bituminous coal-based systems, because these are felt to be the most competitive and the most well understood configurations. The program should also include some projects utilizing lower rank coals (sub-bituminous and lignite), which might require somewhat higher incentives than those in the base analysis using bituminous coals.

- Some cost reductions and performance improvements (relative to the base analysis assumptions) would likely occur within the initial 10 GW of IGCC plant deployment. These costs reductions would tend to lower incentive requirement for later units, which would help offset higher costs of non-bituminous projects and higher costs if low gas price scenarios occur.

Supporting Rationale: CCS Demonstration Recommendation

The funding requirement of $3 billion over 10 years for Federal support for demonstration of geologic carbon storage (GCS) on a large scale was derived as follows:

- No well-developed and researched "road map" has yet been drafted for the types of GCS demonstration projects that would be necessary to establish substantial confidence that GCS could be developed on an operational basis.

- Absent such a credible demonstration plan, a "straw" GCS program was sketched out as follows:

  IGCC with CCS Demonstration

  - Approximate costs of adding fifty-percent carbon capture and geologic sequestration to two 500MW IGCC units and ninety-percent carbon capture and geologic sequestration on an additional two 500MW IGCC units has been estimated to be about $100 - $150 million per year over roughly a ten year span using information in the NorthBridge white paper[6] and in a recent MIT analysis, *"The Economics of CO2 Storage"*, by Gemma Heddle, Howard Herzog & Michael Klett, April 2003.[7]

    i. All IGCC plant characteristics were assumed to be as shown in Table 8 at page 13 of the MIT study (represented below).

[6] Carbon capture and storage costs are addressed at pages 19 to 21 and are estimated as a range of cost per MWh of electricity produced.

[7] Can be found at: http://lfee.mit.edu/publications/PDF/LFEE_2003-003_RP.pdf

Table 8: Summary of parameters for IGCC power plant with CO_2 removal

Parameter	Unit	Value
Thermal Input, HHV	10^6 Btu/hr	3,723
Gross Power Output	MW	490.4
Net Power Output	MW	403.5
Efficiency, HHV	%	37.0
Capacity Factor	%	80
CO_2 Captured	t/d	7,389
	mega scm/d	3.76
CO_2 Emitted	kg/kWh	0.073
CO_2 Avoided in Capture	t/d	6,246
CO_2 Capture Cost	$/t captured	14.55
CO_2 Capture Cost	$/t avoided in capture	17.21
Plant Life	Yr	20
Capital Charge Factor	%	15.0
Fuel Cost	$/MMkJ	1.18
Fuel Real Esc. Rate	%/yr	0.00
Fuel Levelization Factor		1.00
TPC	$/kW	1,642
Fixed O&M	$/kW-yr	32.98
Variable O&M	$/MWh	3.90
Heat Rate, HHV	kJ/kWh	9,727
Capital	$/MWh	35.04
O&M	$/MWh	8.61
Fuel	$/MWh	11.44
Levelized Cost of Electricity (LCOE)	$/MWh	55.08

ii. Carbon Capture: It was estimated that adding 90% carbon capture to an IGCC power plant would cost from $12.40 to $18.70 per megawatt hour of electricity production for projects using bituminous coals.[8] These estimates are for plants using Chevron-Texaco (now GE) and E-Gas (now Conoco-Phillips) gasifiers.

iii. Geologic Sequestration: Sequestration costs were estimated based on the base case deep saline aquifer storage option cost of $2.93 per metric ton of CO2 emissions avoided in MIT's "*The Economics of CO2 Storage"* (a detailed explanation of this scenario is found at pages 67 to 89). This figure was then converted to $10.75/metric ton of carbon (3.67*2.93) and further converted to $2.36/MWh based on the Table 8 standard plant characteristics:

[8] These estimates are documented in the Northbridge report which in turn cites a recent summary of EPRI studies - Neville Holt, "IGCC Technology Status, Economics and Needs", presentation at the International Energy Agency (IEA) Zero Emission Technologies (ZET) Technical Workshop, February 17, 2004, Gold Coast, Queensland, Australia, at slide 20.

- 6246MT CO2 avoided / 3.67 = 1702 MT C avoided
- 403.5MW *24hr/day*0.8CF = 7747 MWh net output
- 1702 MTC / 7747 MWh = 0.220 MTC/MWh
- 0.220 MTC/MWh * $10.75/MTC = $2.36/MWh

iv. Combined Costs: This then produces total CCS costs for the 90% capture case of $14.76/MWh to $21.06/MWh.

- These figures were adjusted for a $20/metric ton of carbon allowance price assumed in an initial carbon management program as follows (see footnote #4):

  i. The figure of 0.220 metric tons of carbon avoided per MWh was established in the calculation above. Combined with a $20/metric ton carbon value leads to a credit figure of $4.40/MWh

  ii. Subtracting this credit from the gross CCS costs results in a net cost of *$10.36 to $16.66/MWh* for 90% carbon capture.

- These 90% carbon capture case costs of $10.36 to $16.66/MWh were adjusted by a factor of 0.56 to derive net CCS costs for 50% carbon capture of about $5.80 to $9.33/MWh.

- These figures were applied to the annual output of 2,827,728 MWh per year from the IGCC plants, based on the standard plant data in Table 8 (403.5 MW net capacity*0.80 capacity factor* 8760 hours per year = 2,827,728 MWh/yr), resulting in total annual costs for each plant type as follows:

  i. 90% capture - $29.3 to $47.1 million/year
  ii. 50% capture - $16.4 to $26.4 million/year

- Total costs: two plants at 50 percent and two plants at 90 percent capture would work out to roughly **$100 to $150 million per year**

Broader CCS demonstration

- In addition, it would be necessary to conduct several additional projects in geologic settings and/or with other key characteristics not addressed by the four IGCC with geologic sequestration demonstration projects – which will require IGCC project developers willing to add the necessary equipment (and accept the associated plant de-rating), which may limit the ability to steer such projects to optimally desired geologic settings. If a roughly equivalent amount of funding support were allocated to non-IGCC projects, ideally including projects using carbon already captured in an industrial process and currently vented, substantial additional experience could be gained and this funding could be limited to the desired geologic settings.

Combined Program Cost

Together this would constitute a program of about $200 to $300 million per year (not including monitoring costs) – or up to $3 billion over ten years – probably starting up no earlier than about 2008, given the substantial lead time necessary to identify, plan and permit such projects. This program would need to run for at least a decade (and up to several) to allow time for project development and to gain the operating and monitoring experience to prove out this concept.

In summary, the Commission recommends up to $3.0 billion over ten years for an extensive national carbon capture and sequestration effort to account for phasing in of carbon requirements and their associated financial credit for carbon emissions avoided at the IGCC plants and to address the potentially large variations in actual carbon geologic storage costs[9] across a wide range of geologic settings as well as the need for a detailed GCS demonstration "road map"

[9] See Figure 4 at page 11 of the MIT study.

Energy at the State Level

Prepared by:

The Business Council for Sustainable Energy

April 2004

The Business Council for Sustainable Energy

Formed in 1992 following the Rio Earth Summit, the Business Council for Sustainable Energy is dedicated to promoting market-based approaches to reduce pollution and promote a diverse, secure mix of energy resources. The BCSE is comprised of companies and industry trade associations in the energy efficiency, natural gas, renewable energy, independent power and electric utility industries. Our membership includes companies on the cutting edge of efficient and environmentally sound fuels and technologies, such as natural gas, wind, solar and geothermal power, combined heat and power, insulation and fuel cells. The BCSE advocates the implementation of cost-effective programs and policies that recognize the environmental attributes of various energy sources and reduce reliance on imported fuels. Sister organizations have been formed in the European Union, United Kingdom and Australia.

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Executive Summary

The objective of this report is to provide a better understanding of energy policies that are being enacted at the state level and how these policies may affect federal policymaking. The paper provides a general outline of major energy policies some states have adopted, identifies differences in policy implementation and offers some insight into the interaction between and among policymakers at the local, state and national levels.

The policies profiled in this paper include renewable energy portfolio standards, net metering, financial incentives (production and investment tax credits, rebate programs and sales and property tax incentives), appliance and equipment standards, building codes, systems benefit charges and greenhouse gas reduction programs.

The common drivers to enact any type of energy legislation are economic growth, reduced energy costs, energy security (reduced energy dependence) and environmental protection. Several major trends emerged in evaluating policies implemented at the state level.

First, RPS showed to be the most popular and visible renewable energy development policy. Given the unique attributes of many clean energy technologies (such as intermittency, no fuel costs, higher upfront capital costs), the RPS uses least-cost bidding to ensure ratepayers receive the most cost-effective energy available (within the defined eligible technologies). It can have a significant effect on near-term competitive, utility-scale technologies but is ineffective on higher cost renewable energy technologies unless they are specifically addressed through technology set-asides.

Second, states and municipalities are using a wide variety of financial incentives, including equipment rebates, property tax exemptions and income tax deductions, to encourage the use of certain energy technologies. An increasing number of municipalities and utilities are providing rebates and incentives to promote the greater use of renewable and energy efficiency technologies.

Third, states are also increasing (and even requiring) the use of high efficiency equipment in their own facilities. By using such products, states are able to lead by example along with achieving financial savings and increased energy efficiency.

Fourth, over 20 states are utilizing an SBC to provide financial assistance for low income residents to pay utility bills and make energy efficiency improvements. Many states also are now using these resources to fund clean energy research, development and demonstration projects.

Fifth, states and municipalities are actively involved in efforts to reduce greenhouse gas emissions by joining organizations, creating greenhouse gas registries and enacting emissions caps. They appear to have taken the lead in advancing climate change mitigation policies in the absence of a more comprehensive federal response.

Though states are moving forward on energy policies that are usually considered under the purview of the federal government, there are a number of examples where the federal government, primarily the Department of Energy, Environmental Protection Agency and Department of Transportation, are interfacing with state agencies.

The key mechanism for federal and state interaction is the State Energy Program under DOE. SEP provides funding to states to design and carry out their own energy efficiency and renewable energy programs. Most SEP projects are cost-shared with the states.

Most of the federal-state coordination and interaction on energy policies centers on financial and technical assistance to the states that help achieve a variety of objectives. Some of these goals include reducing greenhouse gas emissions, increasing efficiency, training state employees and educating consumers.

Though some of the state and federal interaction is a response to circumstances of jurisdiction, others are dictated by a desire to streamline and reduce duplication. However, at least two factors emerged as key components to help facilitate more productive interaction. These include flexible implementation of programs and a commitment to long-range federal funding.

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Energy Policy at the State Level

The National Commission on Energy Policy (NCEP) is a bipartisan group of 18 energy experts who have joined together to develop long-term energy policies that enhance national security, strengthen the US economy and protect the global environment and public health.

This report provides an overview and analysis of select state energy policies. The NCEP believes that the synergies between federal and state actions will greatly advance our overall energy future.

This report will contribute to the Commission's final recommendations due to be released in December 2004.

The authors of this report hope that the information presented will help the members of the National Commission on Energy Policy to untangle the complex, interrelated world of energy and environmental policies and regulations, and to identify recommendations on the appropriate role of local, state and the federal governments.

Introduction

Energy policy has largely been within the purview of the federal government in the United States. With the notable exception of investor-owned utility regulation, the states have historically deferred to Washington to address broad energy policies and most of the subsequent, associated environmental issues.

But the political landscape is changing.

Many state policymakers, frustrated at the real or perceived lack of attention in Washington to a comprehensive national energy strategy, are taking matters into their own hands, enacting far-reaching legislation that tackles issues rarely focused on at the state level, such as climate change mitigation and new energy technology research, development and deployment.

What are the impacts of this paradigm shift? Is the increase in state activity serving to impel Congress and the Administration toward greater resolve in addressing energy policy at the national level? Or does the fact that states are intensifying their engagement reduce the urgency of action in Washington since states are addressing their own issues of greatest concern?

The objective of this report is to provide a better understanding of some policies that are being enacted at the state level and how this affects federal interaction. The paper provides a general outline of major energy policies that some states have adopted, identifies differences in policy implementation and offers some insight into the interaction between and among policymakers at the local, state and national levels.

The policies profiled in this paper include renewable energy portfolio standards, net metering, financial incentives (production and investment tax credits, rebate programs and sales and property tax incentives), appliance and equipment standards, building codes, systems benefit charges and greenhouse gas reduction programs.

1. Renewable Energy

Two programs that policymakers are employing to increase renewable energy technologies use are the renewable energy portfolio standard and net metering.

1.1 *Renewable Energy Portfolio Standard*

A renewable energy portfolio standard (RPS) requires a minimum percentage of electricity to be generated from renewable energy. State laws and regulations determine if the generator or the retail seller is responsible for meeting the requirements. Either through legislation or regulations, states define which renewable energy technologies are eligible under the RPS and the minimum amount of electricity to be generated (usually measured in percentage of total sales, generation or customer use). As of late 2003, 13 states had passed an RPS: Arizona, Nevada, California, New Jersey, New Mexico, Texas, Iowa, Wisconsin, Pennsylvania, Maine, Massachusetts, Connecticut and Minnesota. [1]

Renewable Portfolio Standard at the State Level

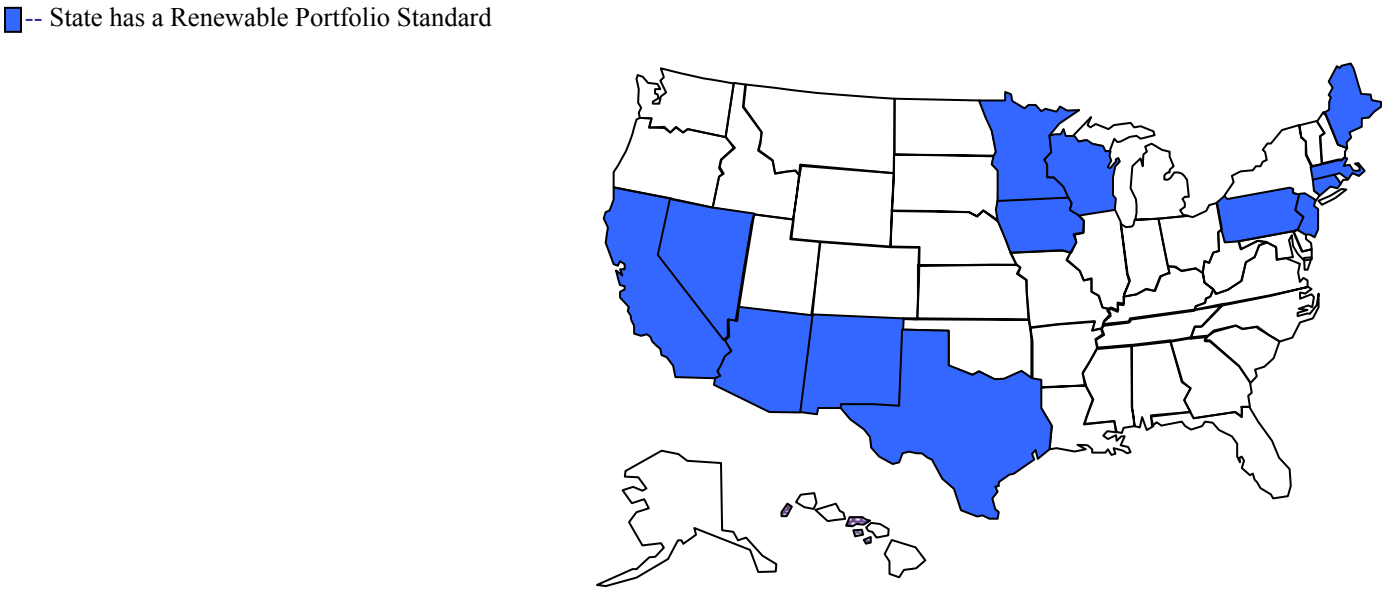

Table 1

[1] Database of State Incentive for Renewable Energy, February 2004, http://www.dsireusa.org.

Some energy experts believe that a portfolio standard is the most cost-effective method to bring near-term competitive renewable energy technologies into the marketplace, since renewable projects compete against one another to bring the lowest cost energy to market.[2] However, an RPS has little or no impact on technologies that are further from being cost-competitive or are not focused on large-scale utility generation, such as photovoltaics.

Arizona, a state with tremendous solar potential, recognized this problem and identified technology "bands" that specifically stated that solar technologies must fulfill a certain percentage of electricity generated. Arizona's RPS requires the state's regulated utilities to generate a minimum of 0.2 percent of their total retail energy sales from renewable sources in 2001, increasing to 1.1 percent by 2007. Solar energy technologies must be used to meet half of the requirement through 2003 and 60 percent in 2007. [3]

The primary drivers for RPS laws vary from state to state, though the common denominators are environmental protection and economic development. New Mexico's RPS (as well as others) mandates that the renewable energy must be generated from within the state. For other states, such as Texas and Iowa, state energy independence is an important consideration. The Iowa law was driven by the recognition that Iowa ratepayer dollars were essentially being "shipped out" of the state through the purchase of fossil fuels, while Texas—considered by many to be the energy capital of the US—became a net *importer* of energy in the 1990s, stirring the concern of policymakers and citizens of the Lone Star State.

Examples of State RPS Programs

- In 1991, Iowa was one of the first states to enact an RPS. Its legislation required the two investor-owned utilities in the state, Mid-American and Interstate Power and Light, to purchase a combined total of 105 megawatts of generation from renewable sources, providing two percent of Iowa's electricity. Both utilities are fulfilling this requirement mainly through wind power and biomass resources.[4]

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[2] PV Consumer Project, Interstate Renewable Energy Council, 2002.
[3] Renewable Energy Portfolio Standards, Arizona Section, New Rules Project, February 2004.
[4] Generating Solutions, How States are Putting Renewable Energy into Action, US PIRG, February 2002, Page 38.

- New Mexico's RPS was established by the New Mexico Public Utility Commission (PUC) and mandates that at least five percent of the energy sold by retail electric suppliers derives from qualified renewable sources. This energy must come from within the state, and eligible technologies include wind, solar, geothermal, biomass, hydropower and fuel cells. To offer flexibility for retailers, there is a provision that provides for a reduction below five percent if there is not enough renewable energy power available. The New Mexico PUC still needs to determine how to verify compliance and assess penalties.[5]

- California's RPS requires retail electricity sellers to increase their use of renewable energy by at least net one percent per year to a level of 20 percent by 2017.[6] In 2000, California generated ten percent of its electricity from renewable sources.[7] One of the unique provisions of California's RPS is that it is linked with the state's systems benefit charge (see "SBC" section). This linkage allows supplemental energy payments from the SBC to cover either a part of or the entire price difference[8] between the long-term market price and the price paid by the utilities to meet their RPS requirement.[9]

- In 1999, the Texas legislature passed (and then-Governor George W. Bush signed) the Renewable Energy Mandate Rule that established the state's RPS and a renewable energy credit trading program. This standard calls for 2,000 megawatts of new renewable energy to be installed in the state by 2009, excluding the 880 megawatts already installed when the legislation passed. Solar, wind, geothermal, hydroelectric, wave or tidal energy and biomass-waste products (including landfill gas) are eligible.[10]

  Through Texas' RPS, over $1 billion of new wind development has spurred the economy of rural west Texas and increased manufacturing jobs around the state. In 2001, Texas installed 913 megawatts of wind energy, while the rest of the US installed a total of 775 megawatts. In fact, for that year, only two countries (Germany and Spain) in the world surpassed Texas in the amount of wind energy installed. The state is approximately five years ahead of its schedule to meet its 2,000 megawatts goal.[11]

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[5] Alternative Energy Law, Iowa, Database of State Incentives for Renewable Energy, August 2003, http://www.dsireusa.org/library.
[6] Renewable Energy Standards at Work in the States Fact Sheet, Union of Concerned Scientists, February 2003, Page 1.
[7] Renewable Energy Portfolio Standards Proceeding – Docket #03-RPS-1078, CEC, 2002, Page 1.
[8] The amount paid is decided by the CEC through reviewing fund levels, market prices and other factors.
[9] PV Consumer Project, Interstate Renewable Energy Council, 2002, Page 1.
[10] Generating Solutions, How States are Putting Renewable Energy into Action, US PIRG, February 2002, Page 49.
[11] What Renewable Energy Means to Texas, Public Citizen Texas, 2002, Page 2, http://www.citizen.org/texas.

1.2 *Net Metering*

Net metering allows customers with small generating facilities to use a single meter to measure the difference between the total generation and consumption of electricity by allowing the meter to turn both forward and backward. Customers effectively receive retail prices for the excess electricity they generate. Without net metering, a second meter would be installed to measure the electricity that flowed back to the host utility, with the utility purchasing the power at a rate much lower than the retail price.[12] This policy enables customers to use their own generation to offset their consumption over a billing period without having to match consumption and production times, a benefit especially valuable to intermittent technologies such as wind and solar.

The primary beneficiaries of net metering are solar PVs, small-scale wind and geothermal heat pumps. A number of states, including Colorado, New Jersey and Nevada, limit the technologies to wind and solar, and in some cases, PV is the only solar technology that is eligible.

Except for Connecticut and Georgia, most net metering legislation does not include fuel cell technology because they are relatively new. Also, fuel cells are not always considered a full member of the renewable energy family because current technology sometimes relies on fossil fuel as the primary hydrogen source.[13]

Some net metering programs are mandated by the state PUC or legislature and others are offered voluntarily by individual utilities. Some states, such as Idaho, Iowa and Indiana, only require investor-owned utilities to offer net metering; others, including California and Texas, require all utilities (including rural electric cooperatives) to participate.

There is variation in the size of the generator's capacity, but the maximum size generally ranges from ten to 100 kilowatts. Some states restrict monthly generation such as Indiana, which limits each customer to 1,000 kilowatt-hours per month.[14]

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[12] Net Metering Policies, The Green Power Network, Department of Energy, June 2003, Pages 1.
[13] Net Metering Policies, The Green Power Network, Department of Energy, June 2003, Pages 5-6.
[14] Net Metering Programs, National Renewable Energy Laboratory, 1996, Page 2.

Examples of Specific State Net Metering Program

- Net metering has been in effect in Minnesota since 1983. It applies to all utilities in the state including cooperative electric associations and municipal utilities. Facilities with a capacity of 40 kilowatts or less are eligible. Minnesota's net metering law requires utilities to buy back excess generation at average retail rates, and there is no restriction on the total amount sold by the consumer. In 1999, there were approximately 110 qualifying facilities using net metering in the state.[15]

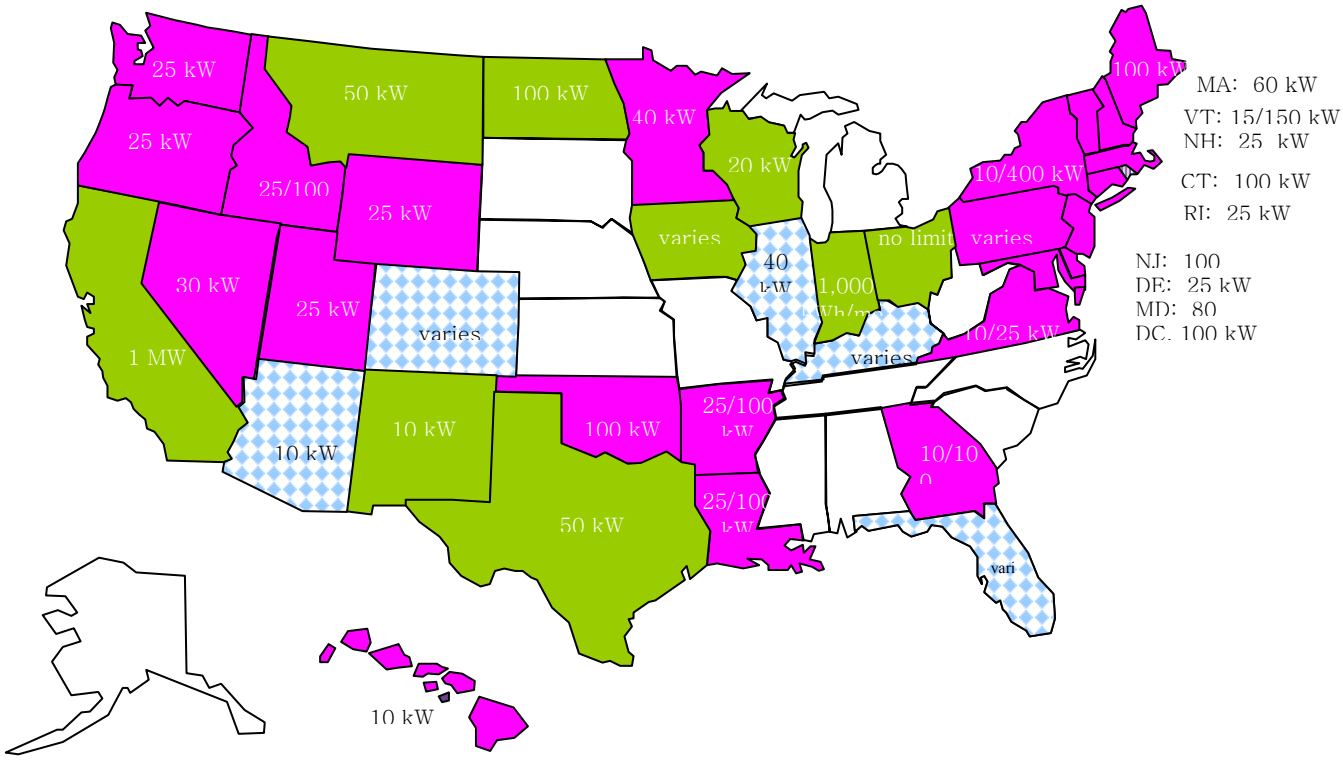
- In Colorado, net metering is not required but several utilities offer it as an option to customers. Public Service Company of Colorado, a subsidiary of Xcel, has offered net metering for facilities of ten kilowatts or less since 1994. Any excess generation during a normal billing cycle is used by the utility without compensation. Holy Cross Electric Association, also of Colorado, provides customers a similar option.[16]

- The Idaho PUC established a net metering program available only to residential and small commercial customers. The generating capacity can be no more than 100 kilowatts and any type of generation technology can be used. Customers who participate in Idaho's net metering program pay a small monthly charge to the utility for administrative costs and must carry $1 million liability insurance. The order applies to investor-owned utilities.[17]

[15] Net Metering Policies, The Green Power Network. Department of Energy, June 2003, Pages 12-13.
[16] Net Metering Policies. The Green Power Network. Department of Energy, June 2003, Pages 4-5.
[17] Net Metering Policies, The Green Power Network, Department of Energy, June 2003, Page 7.

State Net Metering Programs[18]

Table 2



kW indicates limits on system size (in some cases, the limits vary by customer type)

State-wide net metering rules for all utilities

State-wide metering rules only for certain utility types like independent operating utilities in these cases, other utilities--municipal utilities and cooperatives--may have different rules.

Net metering offered by one or more individual utilities

[18] Database of State Incentives for Renewable Energy, February 2004, http://dsireusea.org.

2. Financial Incentives

To encourage greater use of different energy technologies, many states provide financial incentives to consumers and manufacturers. These credits can be in the form of production and investment incentives, personal tax credits, rebate programs, sales tax incentives or property tax relief.

2.1 *Tax Credits*

A production tax credit (PTC) provides a tax credit per kilowatt-hour for electricity generated from qualifying projects, while an investment tax credit (ITC) applies to investments. These tax incentives are important factors in making renewable energy projects more competitive by helping offset the often higher upfront capital costs either directly (in the form of the investment credit) or indirectly (through the use of guaranteed per kilowatt-hour incentives with the production credit).

Financial incentives for using more traditional types of fuels such as oil, natural gas and coal tend to be aimed at promoting local fuel sources or at keeping state dollars in-state. For example, in Maryland, electricity suppliers can claim a tax credit of three dollars per ton of coal they buy from Maryland mining companies.[19]

State-level drivers to enact tax credits include development of local resources, protection of current jobs (or promotion of future jobs) and local investment in energy. In Illinois, the General Assembly approved $3.5 billion in subsidies to the coal industry to encourage the construction of new coal-fired power plants. This was done to lure power producers to the state, encourage the use of coal mined in Illinois and help reduce the threat of an energy crisis such as the one that struck California in 2001.[20] Louisiana also enacted tax breaks to entice more energy generators into the state, including property tax credits to power plants that sell power on the open market.[21]

2.2 *Rebate Programs*

Rebate programs are offered at the state, local and utility levels to promote the installation of certain clean energy equipment and energy efficiency technologies. A number of rebate programs available from state agencies and municipally-owned utilities mainly support solar water heating and photovoltaic systems.

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[19] Maryland's Fossil Fuel Subsidy Story, Chesapeake Climate Action Network, January 2004, http://www.chesapeakeclimate.org.
[20] Tax Analysis, State Tax Notes, June 11, 2003, Page 2016.
[21] Tax Analysis, State Tax Notes, November 5, 2001, Page 419.

Eligible sectors usually include residents and businesses, although some programs are available to industry, institutions and government agencies as well. In some instances, rebate programs are combined with low- or no-interest loans.

Examples of State and Local Tax Credits and Rebate Programs

- Montana offers financial incentives to advance the development and installation of renewable technologies. There is a 35 percent investment credit for an individual, corporation or company that invests at least $5,000 in a renewable energy facility. The state offers an income tax credit of $1,500 for the installation of a geothermal energy system. Montana also has an alternative energy revolving loan account that provides low-cost loans to individuals and small businesses to help purchase clean energy systems.[22]

- In Texas, the Solar and Wind-powered Energy Systems Exemption provides a property tax exemption on any value added by solar or wind equipment. The City of Austin, through Austin Energy, offers its customers a rebate on solar water heaters and equipment such as high efficient heat pumps, water heaters and air conditioners.[23]

- California and several of its cities offer consumer incentives to encourage energy efficiency and promote the use of clean energy technologies. Programs range from local utilities providing rebates for the installation of solar water heaters to personal income tax deductions on the interest of a consumer loan used to purchase energy efficient products or equipment.

  The Renewable Energy Trust Fund was created by California to increase the use of clean energy technologies. The $540 million fund, paid for by electricity ratepayers, was so successful that the legislature extended the funding – at the same annual levels – until 2012, thus creating $1.35 billion for ten years. The California Energy Commission manages the fund through four accounts: Existing Technologies supports the continued development and maintenance of existing renewable energy projects; New Technologies supports new clean energy generation projects; Emerging Technologies provides rebates for specified

[22] Database of State Incentives for Renewable Energy, 2002, www.ies.ncsu.edu/dsire/index.htm.
[23] Database of State Incentives for Renewable Energy, 2002, www.ies.ncsu.edu/dsire/index.htm.

technologies up to ten kilowatts; and Consumer Side provides rebates to consumers who buy green power from eligible power marketers.[24]

- One of the newest local consumer incentive programs was passed by the San Francisco Board of Supervisors. The San Francisco Peak Energy Pilot Program was created in conjunction with the local utility, Pacific Gas and Electric, and the city's environmental department in September 2003. The goal of the $16.5 million project is to reduce electric demand during peak hours and increase energy efficiency.

  This program provides incentives for both residents and businesses. For businesses, they include cash rebates for replacing old equipment with new energy efficient technologies and performance-based contracts that offer financial incentives to businesses for verified energy savings. Residential incentives include rebates for the installation of energy efficient equipment in apartments and the residential direct install program that identifies and provides a variety of energy efficient products and services to low-income residents.

  This program is being funded by California utility customers and is managed by the California Public Utilities Commission. [25]

- Some county and municipal governments also provide tax incentives to increase the use of cleaner and more efficient energy technologies. Gainesville (Fla.) Regional Utilities began a solar rebate program as part of its demand-side management initiatives. This program provides rebates to residential customers who replace their electric water heaters with solar water heaters.

As might be predicted, states that have SBC, RPS and net metering policies in place tend to have more significant incentive programs for consumers and manufacturers.

[24] Database of State Incentives for Renewable Energy, 2002, www.ies.ncsu.edu/dsire/index.htm.
[25] San Francisco OK's $16 Million Energy-Efficiency Program for Commercial, Residential Building, Green Biz, September 2, 2003, http://greenbiz.com./news/printer.

3. Energy Efficiency Policies

State governments set energy efficiency standards to reduce energy use, lower consumer energy bills and protect the environment. The major policy vehicles used to achieve these objectives include appliance standards, building codes, building product standards, state purchasing requirements and voluntary programs that support funding for energy efficiency programs.

3.1 *Appliance Standards*

Appliance and equipment standards are used to set the minimum efficiency requirements for newly manufactured appliances and other energy-consuming products. These standards accelerate the removal of inefficient products from the market by providing a new generation of efficient appliances to choose from. Consumers can receive immediate benefits through lower utility bills. For example, a residential refrigerator built in 2001 uses one-fourth of the energy used by a model from the 1970s. Similar efficiencies can be found in other appliances and white goods. [26]

The federal government sets minimum efficiency standards for some appliances and other equipment. The most visible energy efficiency appliance program is Energy Star, a federal voluntary program created to encourage greater use of highly efficient appliances. [27] If manufacturers meet the strict energy efficiency guidelines set by the Environmental Protection Agency and the Department of Energy, they are allowed to use the Energy Star label to promote their appliances.

Some states have implemented measures that go beyond the federal guidelines. California was the first state to adopt efficiency standards in 1974.[28] Most state efficiency measures are legislated but there has been an increase in proposals for more stringent rules by state PUCs.

In early 2004, Maryland's General Assembly passed the Maryland Energy Efficiency Standards Act that would set energy efficiency requirements for nine appliances. Governor Robert Ehrlich vetoed the bill, stating that it is the federal government's job to set appliance standards, but the veto was overridden by the State Senate and General Assembly. The state energy administration is writing the proposed regulations under the new law.[29]

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[26] Energy Efficiency's Next Generation, Appliance and Equipment Standards, ACEEE, November 2003, Pages 1-2.
[27] Energy Star Program, Department of Energy, 2003, www.energystar.doe.gov.
[28] Energy Efficiency's Next Generation, Appliance and Equipment Standard, ACEEE, November 2003, Page 2.

3.2 *State-Owned Facilities Increase Energy Efficient Equipment Use*

Another way that states are increasing the use of energy efficient equipment is through mandates for state-owned facilities to decrease energy use. This "lead by example" approach is seen in state elementary and secondary schools, hospitals, colleges and universities.[30] This policy appears to be the least controversial efficiency policy for states to enact and can serve multiple objectives including reduced pollution, financial savings and improved public image.

Examples of State-Owned Facility Mandates

- In Arizona, state facilities are required to reduce energy use by initiating efficiency measures – which will be achieved partly through the use of outside contracting[31] – and by purchasing energy efficient equipment for state buildings.

- Iowa has two programs that state facilities can use to improve energy efficiency: the Iowa Energy Bank and the State Facilities Program. The Iowa Energy Bank, funded by private donations and minimal state and federal funds, uses energy cost savings to help repay efficiency improvements made by private schools and local governments, among others.[32] The State Facilities Program is part of the State of Iowa Facilities Improvement Corporation; a nonprofit organization that helps state agencies put efficiency improvements into operation. The funding for the Corporation comes from energy conservation bonds that were sold in 1986 and raised over $12 million.[33] Both programs assess energy use in facilities, and then offer suggestions for improving efficiency.

Other states that have enacted efficiency standards for their facilities include California, Hawaii, Illinois, Massachusetts, Minnesota, New York, Oregon, Pennsylvania and Texas.

3.3 *Building Codes*

In the US, buildings account for more than a third of total energy use and carbon emissions.[34] The design and construction phases are ideal times to incorporate energy efficiency into new buildings as any type of

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[29] MEA to Work Quickly on Energy Efficiency Standards Act, Maryland Energy Administration, Press Release, January 2004.
[30] Energy Efficiency's Next Generation, Energy Efficiency in State Facilities, ACEEE, November 2003, Page 21.
[31] Energy Efficiency's Next Generation, Energy Efficiency in State Facilities, ACEEE, November 2003, Page 22.
[32] Energy Efficiency's Next Generation, Energy Efficiency in State Facilities, ACEEE, November 2003, Page 24.
[33] Energy Efficiency's Next Generation, Energy Efficiency in State Facilities, ACEEE, November 2003, Page 24.
[34] Energy Efficiency's Next Generation, Building Energy Codes, ACEEE, November 2003, Page 5.

improvements or changes require additional financial and time resources. However, there are several market barriers that hinder maximizing efficiencies in new construction.

The first is that the building industry is fragmented geographically, politically and physically. Second, builders bear the higher upfront costs and may not directly benefit from the additional upfront expenses of high efficiency energy equipment. Occupants reap the benefits of lower energy bills but the issue of energy savings does not seem to factor highly into new home buyers' purchase requirements. Regardless of the barriers, federal voluntary programs such as the EPA's Energy Star Homes and the Department of Energy's Building America programs have shown significant energy savings by providing guidelines for more efficient homes.

Examples of State Activities

Most states use the International Energy Conservation Code (IECC) as a base for building energy codes. The IECC was first published in 1998 and updated in 2000. The IECC deals with basic thermal performance ratings for windows, ceilings, wall and basement insulation and heating and cooling equipment. Some states have created their own, stricter codes, including California, Florida, New York, Minnesota, Oregon and Washington, while others do not have a state policy (meaning that all building codes are regulated at the local and county levels).

Enforcement of building codes is difficult due to a lack of resources. For example, a study about Massachusetts' code implementation, a state known for promoting clean energy and efficiency, showed that over one-half of the new homes were not in compliance with the state's energy codes.[35]

- In Florida, builders use a state-approved computer software program to calculate compliance requirements. The state also offers training, technical assistance and guidance to builders and others. Florida has received US DOE's State Energy Program (SEP) grants to provide training on the state's building energy code compliance and to conduct other training activities. [36]

[35] Energy Efficiency's Next Generation, Building Energy Codes, ACEEE, November 2003, Page 7.
[36] DOE's Status of State Energy Codes, Florida Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Page 1, www.energycodes.gov.

- Vermont passed its Resident Building Energy Standards (RBES) in 1997 and has aggressively pursued implementation. Builders comply with the RBES through online self-certification, and there are workshops, technical training and information available to learn how to comply with the regulations. Homeowners can seek damages within six years of occupancy from the builder if the home fails the RBES.[37] Vermont has received grants from SEP to encourage efficiency at the state level over the last five years. Projects include continuing its Energy Code Assistance Center, a state program that provides commercial code support materials, and revising the RBES Handbook.[38]

- In Oklahoma, the state adopted the 1998 IECC standard but allows local jurisdictions to adopt other nationally recognized model codes. The state tracks the compliance of building codes for state-owned buildings, and local authorities are responsible for enforcing any locally adopted codes.[39]

- In 2002, Idaho approved its first statewide codes for residential and commercial buildings, requiring all new building permits meet 2000 IECC standards. The state codes are at minimum standards, and local authorities can implement more strict regulations. Building contractors comply with the codes through self-certification.[40] Idaho has received SEP grants annually since 1996 to train local jurisdictions on 2000 IECC standards, provide on and off-site technical assistance and hire energy specialists to implement codes.[41]

- Texas adopted the IECC standards in 2001. This is significant for southern states as the IECC contains a solar heat gain standard for windows that can provide energy savings for cooling homes and reduce electricity demand at peak times.[42] The energy saved by complying with the IECC standard resulted in significant NO_x emissions reductions, which is important because Texas has several non-attainment areas.[43]

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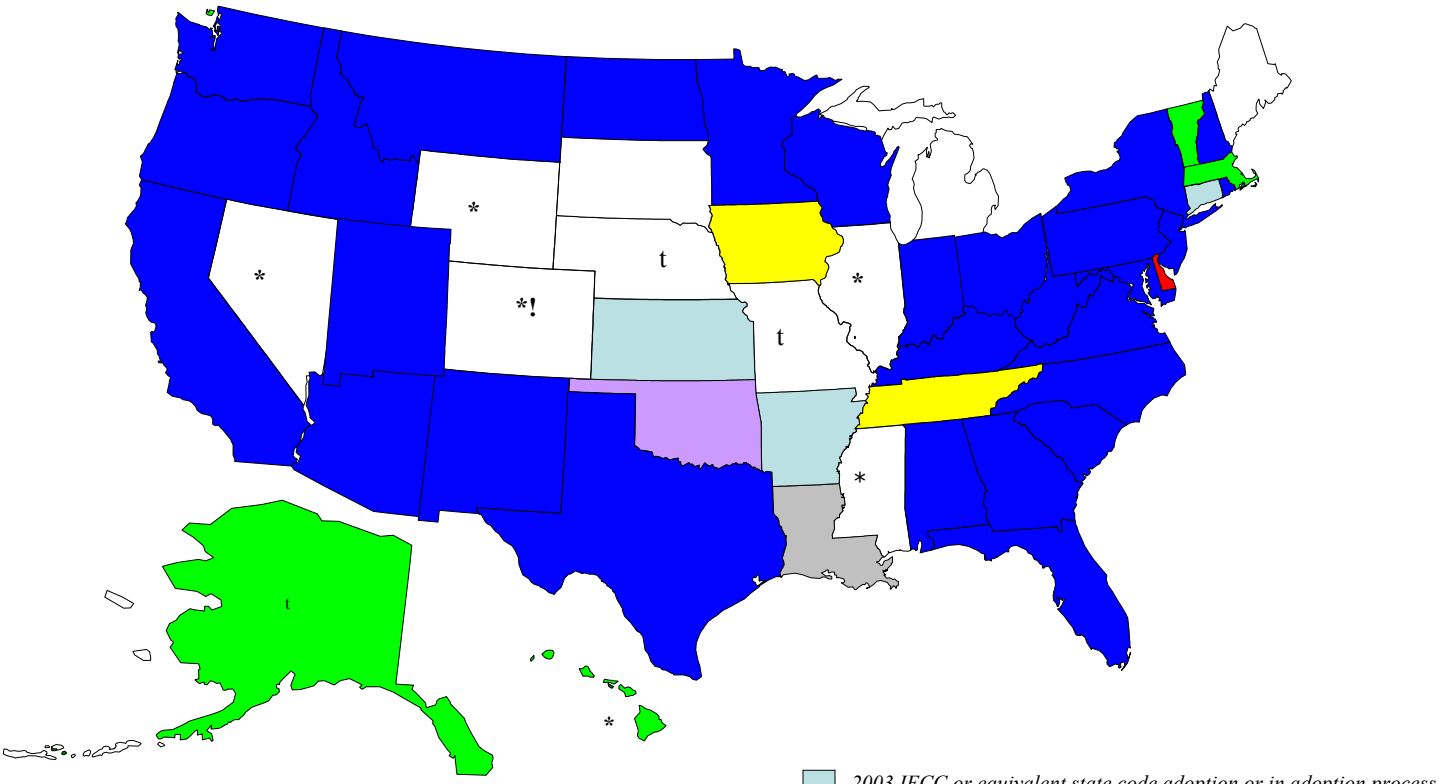
[37] DOE's Status of State Energy Codes, Vermont Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Page 6, www.energycodes.gov.
[38] DOE's Status of State Energy Codes, Vermont Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Page 7, www.energycodes.gov.
[39] DOE's Status of State Energy Codes, Oklahoma Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Pages 2-3, www.energycodes.gov.
[40] DOE's Status of State Energy Codes, Idaho Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Pages 2-3, www.energycodes.gov.
[41] DOE's Status of State Energy Codes, Idaho Section, Office of Building Technology, State and Community Program, Department of Energy, 2004, Page 8, www.energycodes.gov.
[42] Energy Efficiency's Next Generation, Building Energy Codes, ACEEE, November 2003, Pages 11-12.
[43] Texas was told to reduce its emissions to achieve national air quality standards and building codes was one method that was used.

Residential Building Energy Codes[44]



* Code implementation depends upon voluntary adoption by local jurisdictions.

t 90.1 Mandatory for state-owned residential buildings three stories or less in height.

! 75 percent of jurisdictions in Colorado have adopted or are in the process of adopting the IECC 2000 or some adaptation of the 2000 IECC.

Table 3

[44] Building Codes Assistance Project, Residential Map, September 2002, http://www.bcap-energy.org.

3.4 *Systems Benefit Charge*

To help increase energy efficiency (especially among its low-income residents), many states have created a Systems Benefit Charge (SBC). An SBC is usually a distribution fee imposed on the customer with utilities being responsible for collection. SBCs are generally designed to fund benefit programs such as low-income customer assistance, renewable energy research, development and deployment and energy efficiency projects.

About 20 states have enacted an SBC or something similar. Most states set their SBC on a per kilowatt-hour basis, although a few states set a flat monthly fee.[45]

States also differ in how they manage the systems benefit programs. About one-half of the states allow utilities to administer their own energy efficiency programs. One-quarter of the states use their government agencies to manage energy efficiency programs, while others use a combination to oversee efforts. California is an example of such a fusion where the utilities are running programs but with state regulatory supervision.[46]

Examples of State SBC Programs

- The New York State Public Service Commission restructured the state's SBC by increasing the amount collected annually from $78 million to $150 million and extending it for five years. This fund is administered by New York State Energy Research and Development Authority. The resources are divided among research and development (includes renewable energy), energy efficiency and low-income energy assistance.[47]

  Another SBC was created by the Long Island Power Authority (LIPA) totaling $32 million over a five-period beginning in 1999. It is specifically for energy efficiency, clean distributed energy and renewable energy technologies. It is administered by LIPA; to date, it has only funded a rebate program for small PV systems and installed free PV systems in 30 homes.[48]

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[45] Comparing State Portfolio Standards and System-Benefit Charges Under Restructuring, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, October 2000, Table 2.
[46] Summary of Public Benefits Programs, ACEEE, May 2003, Page 1.
[47] Summary of Public Benefits Programs, ACEEE, May 2003, Page 3.
[48] Comparing State Portfolio Standards and System-Benefit Charges Under Restructuring, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, October 2000, Table 3.

- Illinois has three funds: a statewide, utility-specific energy trust and an SBC for the City of Chicago. The statewide SBC raises $83 million through a non-bypassable monthly fee on customer bills. It pays for energy efficiency ($3 million), renewable energy ($5 million) and low-income ($75 million) programs.[49]

  The one-time clean energy trust was established by Commonwealth Edison. It provides $225 million and was approved by the Illinois State Legislature in May 1999 as part of a statewide utility restructuring initiative. This fund is being administered by the Illinois Clean Energy Community Foundation and provides venture capital support as well as grants and loans to encourage the development of clean energy technologies.[50] Eligible technologies include solar, wind, biomass and energy efficiency. Chicago's SBC was created as part of a resolution to a franchise dispute with Commonwealth Edison and provides $100 million over a four-year period for renewable energy technologies and low-income assistance.

- In November 1997, the Massachusetts legislature enacted an SBC for energy efficiency, renewable energy and low-income assistance. The SBC was extended in 2003 for another five years. Of the approximately $147 million raised annually, $117 million goes to energy efficiency projects (including at least 25 percent for low-income assistance for energy efficiency improvements) and $30 million goes to renewable energy projects. The energy efficiency dollars are administered by the local utilities, and the Massachusetts Technology Collaborative oversees the renewable energy funds.[51]

- Oregon's SBC was created by a 1999 electricity restructuring law. The SBC is funded at $15 million each year to underwrite a revolving loan fund. The legislation also contains a "Universal Service Rider" for low-income bill assistance and efficiency upgrading. Historically, this rider receives approximately $100 million annually. In addition to the $15 million in energy efficiency funding, there are additional funds generated by agreements with individual utilities. A nonprofit organization was created to run the program and administer the funds.

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[49] Comparing State Portfolio Standards and System-Benefit Charges Under Restructuring, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, October 2000, Table 3.
[50] Comparing State Portfolio Standards and System-Benefit Charges Under Restructuring, Lawrence Berkeley National Laboratory and National Renewable Energy Laboratory, October 2000, Table 3.
[51] Summary of Public Benefit Programs, ACEEE, May 2003, Page 2.

SBCs provide states a dedicated funding mechanism to promote energy efficiency, renewable project development and assistance to low-income residents.

4. Climate Change

The climate change issue provides a view of state and federal interplay that is more contentious. Some states believe that climate change is a significant issue that needs to be addressed more concretely and in a shorter time horizon than does the federal government. They are beginning to take proactive action, with the development of state inventories and registries, emission reduction plans and, in some cases, mandatory emission reduction targets and emission trading programs. Some states are also joining partnerships with their neighboring states and even provinces of Canada.

To their proponents, these actions are filling the policy vacuum left by the federal government. Further, as demonstrated in other environmental policy areas, efforts to tackle climate change help achieve other priorities, including greater energy efficiency and increased renewable energy generation. Additionally, climate change programs complement pollution and air quality programs in non-attainment areas. Another reason for state action can be public pressure and municipal action.

There are several municipal climate change programs and, while less frequent, there are municipal or county carbon caps. For example, Suffolk County in New York adopted a multipollutant program that would fine any power plant in the county that generates over 1,800 pounds of CO_2 per megawatt per hour two dollars for every ton above the limit. An additional one dollar per excess ton would be charged in each consecutive year. The law, which was passed in July 2001 and went into effect March 2002, offers alternatives to paying fines including buying emission credits through nationally recognized CO_2 trading markets, investing in clean energy resources or energy efficiency or donating penalties to community environmental groups. [52]

4.1 *Registries and Market-Based Programs*

At least 39 states have enacted greenhouse gas inventories in an attempt to better understand their greenhouse gas emission levels. In many cases, an outgrowth of the inventory has been the creation of a voluntary greenhouse gas registry that encourages companies and other sources to record their emissions levels and reduction efforts over time. California, New Jersey and Wisconsin provide model greenhouse gas registries.

[52] Suffolk County Executive's Office, Suffolk County, New York, July 2001, Page 1.

While modestly different in structure, there is increased coordination among states to develop consistency among registry programs and reporting procedures.[53]

Market-based programs are also receiving increased attention at the state and regional levels to allow energy companies to purchase greenhouse gas allowances or off sets from other entities to meet CO_2 targets. In states such as New Hampshire, off sets that are generated in-state are preferred, but not mandated. Oregon created the Oregon Climate Trust. New generators can meet their carbon obligation by paying a mitigation fee to the Trust, which the Trust then invests in emission reduction projects.[54] Like New Hampshire, locally generated offsets that meet other social and environmental objectives are the goal.

In Maine, Governor John Baldacci signed legislation – at a public event staged as part of Maine's efforts to highlight climate change issues – that outlined specific state goals and a timeline to reduce CO_2, although the law does not stipulate how these targets are to be achieved. While other Northeast states, such as Vermont and Massachusetts, have developed action plans, Maine was the first to begin action through legislation.[55]

4.2 *Regional Action*

States are also using regional initiatives to address climate change, such as the West Coast Alliance and the alliance among governors of the Northeast. These states look to build coalitions to beget change in their regions. The alliances can also be used to push for federal action. From an economic, scientific and political perspective, a collaborative effort to reduce emissions is the best use of resources since greenhouse gas emissions do not respect political boundaries. The initiators of these regional alliances tend to have certain voluntary or mandatory emission controls enacted in their state. New York Governor George Pataki, who is the driving force in gathering the governors in the Northeast to participate in efforts to reduce climate change, has enacted emissions reduction policies in the state.[56]

Through either regional or their own programs, some states are noted for their comprehensive climate change policies. Massachusetts' program, for example, incorporates regional voluntary trading, a climate registry and

[53] State and Local Climate Change, Trexler and Associates, 2003, Page 4.
[54] State and Local Climate Change, Trexler and Associates, 2003, Page 4.
[55] Energy Efficiency's Next Generation, Appendix: Climate Change Initiatives at the State Level, ACEEE, November 2003, Pages 59-60.
[56] Energy Efficiency's Next Generation, Appendix: Climate Change Initiatives at the State Level, ACEEE, Nov. 2003, Page 60.

a strict limit on greenhouse gas emissions. California addresses climate change not only through the electricity sector but also includes the transportation and agricultural industries. It integrates greenhouse gas accounting and reporting, renewable energy development, regulation of motor vehicle emissions and innovative energy efficiency programs into a plan to reduce emissions and address climate change.[57]

Examples of State Climate Change Policies

- Massachusetts was one of the first states in the nation to formally establish limits on greenhouse gas emissions. Six large-scale power plants generate about 40 percent of total electricity but emit 90 percent of all greenhouse gases released by all in-state power plants. [58] Under an electricity restructuring initiative passed in 2001, the state requires each plant to reduce CO_2 by ten percent by the middle of this decade (from 1997 to 1999 average CO_2 levels). The law does not mandate a method for achieving these reductions. Plants are allowed to secure credits through verifiable off-site reductions, including renewable energy generation.

- In 1998, New Jersey's Department of Environmental Protection issued an administrative order that established a goal to reduce the state's total greenhouse gas emissions 3.5 percent below 1990 levels by 2005. This proposal was supported by a broad coalition of industry leaders and environmental groups.[59] The New Jersey plan to decrease greenhouse gas emissions is a comprehensive process with a mixture of approaches. One of the key programs is the "covenants," a voluntary pledge signed by organizations and companies to reduce emissions within the state's goal. Many of the state corporations, governmental departments and universities have signed the pledge. To complement this effort, New Jersey has an RPS,[60] an SBC and an environmental characteristics (the fuel makeup and emissions levels) disclosure to increase consumer awareness of greenhouse gas emissions. Through these efforts, New Jersey is set to surpass its 2005 greenhouse gas emission reduction goal by at least one percent and as much as four percent.[61]

- In early March 2004, the Washington State Legislature passed legislation limiting CO_2 that is similar in structure to Oregon's Climate Trust. The bill was signed by Governor Gary Locke on March 31, 2004.

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[57] Energy Efficiency's Next Generation, Appendix: Climate Change Initiatives at the State Level, ACEEE, Nov. 2003, Page 61.
[58] Greenhouse and Statehouse, The Evolving State Government Role in Climate Change, The Pew Center, 2002, Page 16.
[59] Greenhouse and Statehouse, The Evolving State Government Role in Climate Change, The Pew Center, 2002, Page 16.
[60] As of press time, New Jersey was in the process of adopting new rules that require electricity suppliers use renewable energy for four percent of the electricity they sell by 2008. The new rule doubles the amount of renewable energy that was originally required in the state's RPS set in 1999.
[61] Greenhouse and Statehouse, The Evolving State Government Role in Climate Change, The Pew Center, 2002, Page 17.

Previous to the above-mentioned bill, the Washington Energy Facility Site Evaluation Council had been directed by the Governor to establish CO_2 mitigation requirements for new fossil-fueled thermal power plants built on or after July 1, 2004 that generate more 350 megawatts. Offsets have priority within the county or immediately surrounding counties where the facility is located and the total CO_2 emissions are based on a two-year average. A similar rule for power plants smaller than 350 megawatts is being developed by the state's Department of Ecology.[62]

4.3 Coordinated Climate Change Activities at the Regional Level

Implementation of coordinated policies on a regional scale takes more time than does action in one state. The leading examples of regional cooperation on climate change are the New England Governors/Eastern Canadian Premiers and the West Coast Alliance.

- In August 2001, the Conference of New England Governors and Eastern Canadian Premiers adopted a resolution directing its environment and energy committees to form a task force of energy, environmental and other appropriate officials from state and provincial agencies to develop specific strategies and oversee and coordinate the implementation of a regional Climate Change Action Plan.[63] The plan includes Connecticut, Rhode Island, Vermont, Maine, New Hampshire and Massachusetts. The goals of this plan are to reduce greenhouse gas emissions from the electricity sector 20 percent by 2025, to promote increased vehicle fuel efficiency and to develop a regional emissions registry that would be the foundation for banking and trading of credits in the region. It also plans to increase awareness of the social, economic and environmental impacts of climate change.

  Other proposals that are being considered within the action plan include partnerships with universities and colleges to reduce emissions by ten percent below 1990 levels by 2021, the purchase of energy efficient office equipment for governments and the use of highly efficient vehicles in government fleets.[64] The Northeast Climate Action Plan Coalition, comprised of 150 representatives from the private sector, government and non governmental organizations in New England, was formalized in August 2002 to help implement the Plan.

[62] State and Local Climate Change, Trexler and Associates, 2003, Page 5.
[63] Greenhouse and Statehouse, The Evolving State Government Role in Climate Change, The Pew Center, 2002, Pages 16-17.
[64] Energy Efficiency's Next Generation, Appendix: Climate Change Initiatives at the State Level, ACEEE, November 2003, Page 61.

- In September 2003, the governors of California, Washington and Oregon announced an alliance to combat global warming. It is a public-private partnership that is seeking to mitigate climate change, but the specific details of the plan have not been finalized. The plan includes encouraging the use of more renewable energy and energy efficient appliances and increasing each state's purchase of efficient vehicles.[65] With the change in governorship in California, it is unclear whether the alliance will proceed as initially planned.

- In the same month, the governors of eleven Northeastern states agreed to develop a regional greenhouse gas trading program to address climate change. This proposal was initiated by New York Governor George Pataki and includes Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, Pennsylvania, Rhode Island, Maryland and Vermont. The group is calling for the creation of a regional, market-based cap-and-trade program for CO_2 emissions from electric power plants. The program is in its infancy, and the states need to agree on some key points including a CO_2 cap level, a credit trading infrastructure, an allocation methodology and the role of carbon sequestration.[66] One of the group's first projects is developing a greenhouse gas registry that would serve as the foundation for the carbon credit trading program. The project's details are being finalized and funding is being secured for this registry, possibly through the philanthropic sector.[67] The governors hope to have an agreement on a final plan by April 2005.

As seen by the proliferation of state and regional efforts, states are taking a proactive role in climate change management and offering a vibrant testing ground for policymakers at state, regional and federal levels. In the absence of strong federal action, the number of state and municipal policies will likely increase.

5. Federal and State Interaction

Though states are moving forward on energy policies that are historically considered under the purview of the federal government, there are a number of examples where the federal government, primarily through the Department of Energy, Environmental Protection Agency and Department of Transportation, are coordinating activities with state agencies.

[65] Governors of 3 West Coast States Join to Combat Global Warming, Jeffrey Ball, Wall Street Journal, September 22, 2003.
[66] Greenhouse and Statehouse, The Evolving State Government Role in Climate Change, The Pew Center, 2002, Pages 18-19.
[67] Energy Efficiency's Next Generation, Appendix: Climate Change Initiatives at the State Level, ACEEE, November 2003, Page 63.

5.1 *State Energy Program*

The key mechanism for federal and state interaction is the Department of Energy's State Energy Program (SEP), which was briefly discussed in the building codes section. SEP provides funding to states to design and implement their own energy efficiency and renewable energy programs and policies. Most SEP projects are cost-shared with the states. According to an Oak Ridge National Laboratory study in 2002, each SEP dollar attracts $3.54 in funding from state sources.[68]

There are two types of grants available under the SEP program: formula and special projects. The formula grants are distributed according to a formula that encompasses the state's size and population. These grants can be used by states to meet needs in specific end-use energy sectors that emphasize development and deployment of clean energy technologies. In Ohio, SEP resources were used to research and develop an SBC for the state. The state also utilized federal technical assistance in developing its SBC program.

Special projects grants are awarded on a competitive basis. States submit proposals on how specific technologies, policies and programs can be implemented in their state or region. For example, Vermont was awarded a grant to implement state and local climate change actions plans together with specific strategies and policies needed to achieve emissions reductions and targets. [69] Utah was awarded a special project grant to make its officials aware of opportunities to use energy efficiency and renewable energy measures in order to meet EPA's regional haze requirements.[70]

5.2 *Department of Energy*

In addition to SEP, DOE also provides seed money and technical assistance to states on issues such as technical advice on interconnection standards.

A more obscure but important example of joint interaction is DOE's national laboratories, which have developed feedback communication loops. These loops provide the states and the business community opportunities to interface on ways to accelerate deployment of energy technologies. The national laboratories also work with national energy organizations, such as the National Association of Regulatory Utility

[68] Oak Ridge National Laboratory, 2002, http://www.ornl.org.
[69] State Energy Program, Vermont, Department of Energy, 2001, http://www.eere.energy.gov .
[70] State Energy Program, Utah, Department of Energy, 2001, http://www.eere.energy.gov.

Commissioners, individual state utility commissions and regional DOE offices to develop innovations in energy policy such as green markets and tradeable emissions credits.

DOE, through different programs, provides grants to states that are aimed at increasing the use of certain technologies. Under the Million Solar Roofs Initiative, DOE provides funds to states that are interested in deploying more solar panels and identifying barriers to PV market penetration. Funds are used to remove barriers and help provide an effective aftermarket (for repair and technical services after the technology has been installed), among other things.

Working with state agencies, the Department of Energy provides low-income residents opportunities to reduce their energy use through its Weatherization Assistance Program.[71] This program is administered at the state and local levels.

DOE also funds efforts to encourage state public utility commissions and state environmental regulators to interact on common issues. For example, the Connecticut PUC, energy department and department of environmental protection are collaborating to address electrical reliability. In Utah, the Western Governor's Association and the DOE are funding the Western Regional Air Partnership, a program on techniques to integrate renewable energy and energy efficiency into the western states' air quality programs. The partnerships are between the state energy and air quality offices.

5.3 *Environmental Protection Agency*

The EPA collaborates with states on a variety issues affecting air quality. EPA and its regional offices work with individual states to find innovative ways to reduce pollution and increase air quality. States and municipalities that need to achieve a certain level of air quality through State Implementation Plans (SIPs) work with EPA to reduce their NO_x emissions. The federal agencies provide uniformity in rules and regulations; implementation is managed at the local level.

[71] Weatherization and Intergovernmental Program, US DOE –Energy Efficiency and Renewable Energy, October 2002, http://www.eere.energy.gov.

5.4 *Other Points of State and Federal Interaction*

The Federal Energy Regulatory Commission works with state regulatory agencies to coordinate electricity regulation, including transmission. This is an example of working together by necessity, given that the boundaries of jurisdiction overlap (the federal government controls wholesale electricity markets and the states oversee retail electricity markets).

The Department of Housing and Urban Development provides financial assistance to low-income residents to help pay their utility bills. HUD works with state and local agencies to distribute the funds. Both the HUD and DOE low-income energy assistance programs are in addition to any state SBC funds designated for low-income assistance.

The Department of Transportation also provides funding (usually in conjunction with DOE and EPA) for projects that bring together state transportation agencies with environmental and energy offices to integrate state environmental and energy policies.

In the building sector, DOE provides SEP grants for technical advice. It also funds other entities, such as the Pacific Northwest National Laboratory, to offer states educational resources on residential and commercial codes. Technical staff coordinates with states to gather feedback to provide better professional and technical advice for updating of building codes. States may use building codes to achieve other federally mandated policies (such as Texas did in addressing ozone non-attainment issues).

Since the oil crises of the 1970's, state energy offices are required to have in place an energy emergency preparedness program. To coordinate all the state offices, DOE's Office of Energy Assurance created an extensive communications network linking the state and regional programs. This office is the lead agency for energy issues for the Department of Homeland Security.

The National Association of State Energy Officials, the Association of State Energy Research and Technology Transfer Institutions and the US Department of Energy signed an agreement on November 14, 2002, establishing the State Technologies Advancement Collaborative (STAC). This accord allows states and the federal government to better collaborate on energy research, development, demonstration and deployment projects. State projects fall under several categories: Building Technologies, Industrial Technologies,

Transportation Technologies and Distributed Energy Resources. There are organizations from 25 states that are directly participating in this collaborative.[72]

These examples of cooperation illustrate that the federal and state governments have complementary roles to address local energy issues.

Conclusion

Major Trends

States have become increasingly active in passing energy policies to address energy and environmental objectives, and several major trends are emerging. In general, the common drivers to enact any type of energy legislation are economic growth, reduced energy costs, energy security (reduced energy dependence) and environmental protection.

Renewable Portfolio Standard

The RPS is the most popular and visible renewable energy development policy at the state level. It can significantly grow markets for near-term competitive, utility-scale technologies, but is largely ineffective on higher cost renewable energy technologies (unless specifically addressed such as Arizona did for solar energy). The availability of specific renewable energy resources within a state can impact the crafting of an RPS.

Financial Incentives

States and municipalities use a variety of financial incentives, including equipment rebates, property tax exemptions and income tax deductions, to encourage the use of certain energy technologies. Common drivers include development of local resources, protection of jobs and local investment in energy projects. Keeping and increasing in-state dollars appeared to be a universal driver among states. An increasing number of municipalities and utilities are providing rebates and incentives to encourage the greater use of renewable and energy efficiency technologies.

[72] State Technologies Advancement Collaborative, National Association of State Energy Officials, November 2002, http://naseo.org/stat.

Energy Efficiency

To date, only a handful of states have mandated minimum appliance standards, but more are considering this option. States are also increasing (and even requiring) the use of high efficiency equipment in their facilities. This provides financial savings, increased energy efficiency and allows the states to "lead by example."

Systems Benefit Charge

A number of states utilize an SBC to provide low income residents financial assistance for utility bills and energy efficiency improvements. States also use these funds to fund clean energy research and development as well as demonstration projects. SBCs have proven to be a stable source of energy funding as the amount of energy consumed does not vary greatly from year to year.

Climate Change

States and municipalities are becoming more involved in efforts to reduce greenhouse gas emissions. They are joining organizations (such as the Cities for Climate Protection Campaign), creating greenhouse gas registries and enacting emissions caps. States appear to be accelerating their climate change mitigation policies in the absence of a more comprehensive federal response.

Factors that Facilitate Healthy Federal-State Interaction

Though some of the state and federal interaction is a response to circumstances such as coordinating electricity regulation, others are dictated by a desire to streamline and reduce duplication. Several factors emerged as key components to facilitate more productive federal and state interaction.

Flexible Implementation

Given the impact that energy policy has on the broader economy and environment, successful implementation of policies is critical. Programs need clear guidelines to ensure policy objectives are met, but state officials must be allowed ample room for customizing policies to the unique facts and circumstances in their states. Federal agencies should provide uniformity on rules and regulations but implementation occurs at the local level.

Federal Funding

A comprehensive approach toward energy policy requires efforts to improve and advance the efficiencies of technologies while at the same time stimulating demand through a range of market conditioning activities. Addressing such a wide range of activities at so many levels of government and industry requires consistency and transparency. This is especially true with programs that require federal government support. Efforts to provide reasonable certainty of program funding levels can help program managers plan a long-term strategy with greater confidence.

The trends of the last decade indicate growing involvement by states in enacting energy and environmental policy. In order to avoid a patchwork of policies and regulations that hinders efficiency, cost-effectiveness and environmental protection, coordination between federal and state governments is essential.

As this trend continues, obvious questions of jurisdiction, duplication and ultimate program and policy control will persist. Federal agencies must provide clear, concise, but flexible policy guidelines. The federal government needs to increase its leadership in areas where there is no compelling state interest, such as climate change and other environmental questions that are regional, national or global in nature.

Those looking for a simple answer of how best to integrate activities that involve both federal and state officials will likely be disappointed. One thing is undeniable: a lack of transparency and clearly outlined jurisdictional authority will produce inefficiencies that will be detrimental to policymakers, ratepayers and the energy industry as a whole.

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Toward Polygeneration of Fluid Fuels and Electricity via Gasification of Coal and Biomass

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Abstract

The major challenges posed by transportation fuels are oil supply insecurity, the prospect of sustained high oil prices, health effects of air pollution, and the climate change risks posed by the buildup in the atmosphere of CO_2 from fossil fuel burning. The oil issues are the most pressing, and the climate challenge is the most daunting. The problems cannot be solved without radical changes in our transportation energy system—and getting started as soon as possible. A strategy for dealing effectively with these challenges in this quarter century is described. The elements of the strategy are: (*i*) bringing about a shift to energy-efficient hybrid-electric vehicles, (*ii*) the production of ultra-clean "designer" synthetic fuel from coal and biomass via gasification, and (*iii*) capture and underground storage of the CO_2 byproduct of synthetic fuel manufacture. This strategy makes it feasible to provide substantial quantities of clean liquid fuels for transportation without using oil, with ultra-low greenhouse gas emissions, without having to shift to a hydrogen economy, and with far less land than is required with fluid fuels produced from biomass only.

Introduction

An earlier paper (Williams, 2004a) argued that gasification is the key enabling technology for providing coal electricity with CO_2 capture and storage (CCS) at the least cost via use of the commercially-ready coal gasification combined cycle (Figure 1, left).

Gasification also opens up a huge potential for making, at attractive costs and in climate-friendly ways, clean "designer" synthetic fluid fuels from coal and biomass that can be used more efficiently than conventional crude oil-derived fuels. Exploiting these opportunities is highly desirable in light of: (*i*) intense concerns about security issues associated with dependence on Middle East oil, (*ii*) the prospect (with uncertain timing) that world oil production might peak in this quarter century with consequent sustained high oil prices, (*iii*) consideration that if a societal decision is made to stabilize atmospheric CO_2 at a level no more than double the pre-industrial CO_2 level, deep reductions in CO_2 emissions will be needed not just for electricity [as discussed in Williams (2004a)] but also for *fuels used directly*—i.e., fuels used for purposes other than for making electricity.

Energy supply security concerns

US domestic oil production peaked in 1970 at 11.2 million barrels/day (MMB/D) and has since fallen 30% to 7.8 MMB/D, while imports grew from 4.5 MMB/D to 12.3 MMB/D in this same period as the response to rising demand. The concern is growing global dependence on oil from the politically volatile Middle East, which accounts for 63% of the world's proved reserves. For example, political disruption of the flow of oil from Saudi Arabia, the world's largest oil producer, holding 263 billion barrels of reserves (23% of the world total), would have an especially devastating impact on the global economy. The cost of US military activity aimed at preventing disruption is high even in peacetime (Ogden et al., 2004).

Peaking of world oil production

It is highly probable that global oil production rate will peak in one or two or three decades. The timing of the peak is quite uncertain, but even if the peak is a quarter of a century off, the peak issue should be a major focus of policy planning today. Peaking will signal, not the running out of oil, which will continue to be a major primary energy resource throughout this century, but rather the end of the era of cheap ($15-$25 per barrel) oil.

This topical but controversial issue is discussed here not with the aim of judging who is right in estimating the timing of the peak [e.g., Deffeyes (2001); Campbell and Laherrere (1998); Hakes, 2000] but rather to point out that: (*i*) the timing of a peak will probably be influenced by public policy, (*ii*) a late peak is probably not more desirable than an early peak and might pose far much greater adjustment challenges to the global economy, (*iii*) the most discussed unconventional oil sources (gas to liquids, Canadian tar sands, and Venezuelan heavy oil) will each be able to delay the peak for only a few years so that backstop technologies (such as coal liquefaction) that will not be resource-constrained in this century warrant focused attention—even in the near term.

There are four questions underpinning the debates about the oil production peak: (*i*) How much conventional oil is in the ground? (*ii*) How much of this oil will eventually be recovered? (*iii*) When will the production peak occur? (*iv*) By how much will various unconventional oil sources be able to delay the peak?

There is surprising agreement regarding the answer to the first question. Both the technological pessimists [e.g., Campbell and Laherre (1998)] and the technological optimists (US Geological Survey World Energy Assessment Team (2000) agree that for conventional oil the amount of original oil in place (OOIP) is about 6000 billion barrels. Regarding the second question there is much disagreement. The pessimists believe that about 30% of the OOIP (1800 billion barrels) will eventually be recovered, whereas the technological optimists are betting that 50% will eventually be recoverable (3000 billion barrels).

But even for a given estimated ultimately recoverable oil resource estimates can vary widely as to when the production peak will occur. The model of M. King Hubbert envisions a bell-shaped curve for resource recovery, with a peaking of production occurring when cumulative production reaches about half the ultimate level (Deffeyes, 2001). The peaking dates listed in Table 1 are in line with this model for alternative estimates of the amount of oil that will ultimately be produced. This model indicates, for example, that for the 3000 billion barrels of ultimately recoverable conventional crude oil case, the peak will occur in 2021 if oil demand continues to grow until the peak at the 2%/y historical rate. Figure 2 presents alternative models for the same resource estimate that indicate peaking in 2037 (sharp peak) and 2030 (rounded peak). The appeal of these late peaking models is that they probably represent quite well the propensity of policymakers to increase incentives to oil producers who can be expected to plead for "tax relief" as it becomes more and more difficult to increase oil productive capacity. But delaying the peak with incentives could turn out to make much more difficult the post-peak adjustment of the global economy. For the sharp peak case in Figure 2 world conventional oil production falls to half the peak level in only 9 years—by 2046. Of course, oil from unconventional sources would be provided to help fill the demand/supply gap, but the cost of adjustment to a late peak could prove to be very high. Suppose that after the peak, demand growth slows to 1%/y as a response to the higher post-peak oil price. For the sharp peak case, the average rate of providing make-up

supplies from unconventional oil sources would have increase at a rate of an additional 3.5 MMB/D during each of those 9 years—which would be extremely difficult to accomplish. Even for the rounded peak case presented in Figure 2 the makeup rate would have to increase by an additional 1.6 MMB/D during each of the 16 years leading up to 2046—a daunting challenges for unconventional oil producers. To see this, consider, as an example, the alternative projections shown in Figure 3 for Canadian tar sands, an unconventional oil supply that is already providing 1 MMB/D—about 1.4% of global crude oil production. The most optimistic scenario shown in Figure 3 involves production growing 9.6%/y (a very rapid rate) over the 14-year period 2003-2017, from 1.0 to 3.8 MMB/D. But because production starts at such a low rate, the ramp-up rate is a modest 0.2 MMB/D increment per year on average in this period. Of course, in the real economy, prices will rise to close the demand/supply gap but the extraordinarily high oil prices that are likely to characterize late peak scenarios would have much more painful economic impacts than early peaks that pose less daunting challenges for unconventional oil producers.

The three most-often-discussed unconventional oil resources are gas to liquids (GTL), Canadian tar sands, and Venezuelan heavy oil. Each of these huge unconventional resources adds, in essence, another "Saudi Arabia" to resources—amounting in each case to 270 to 360 billion additional barrels. But, since the world appetite for oil is 30 billion barrels per year and growing, each of these extra "Saudi Arabias" pushes into the future the peaking date only 4-5 years, as indicated in Table 1..

For all the cases presented in Table 1 peaking for conventional and the considered unconventional sources occurs no later than 2033 and in most cases much earlier. For a given resource estimate, the peak could occur earlier than indicated if political or other considerations inhibit investment in new productive capacity—e.g., in the Middle East, where most remaining low-cost potential reserves are located.

Health impacts of air pollution

Although tightening regulations and improved control technologies have dramatically reduced air-pollutant emissions from motor vehicles, there are growing concerns about health impacts (mostly chronic mortality) associated with small particles in the air that are either emitted directly in fossil fuel combustion or are formed by reactions in the atmosphere from gaseous precursor emissions of SO_2 and NO_x (Pope et al., 1995). Quantification of health damages arising from automotive air-pollutant emissions, based largely on studies carried out under the European Commission's ExternE Programme, suggests costs that are comparable to direct expenditures on automotive fuels (Spadaro et al., 1998, Spadaro and Rabl, 1998; Rabl and Spadaro, 2000; Williams et al., 2000, Ogden et al., 2004), although such valuations are highly uncertain. The health damage costs are especially high for Diesel engine cars (Spadaro et al., 1998, Spadaro and Rabl, 1998; Williams et al., 2000), offsetting the advantages these cars offer via their greater efficiency than gasoline engine cars in addressing oil supply and climate concerns.

Climate challenge for fuels used directly

If society decides to stabilize atmospheric CO_2 at a level less than or equal to a doubling of the pre-industrial level of 275 ppmv, sharp reductions of CO_2 emissions from fossil fuel combustion would be required (Figure 2), not just for electricity (which accounts for about 1/3 of total CO_2 emissions—see Table 2) but also for fuels used directly. Even though electricity use tends to

grow faster than total energy, most global energy projections envision that the share of emissions contributed by fuels used directly will stay about the same, increase, or decline only modestly over the next half-century (Table 2)—so that decarbonizing fuels used directly will continue to be important.

Consider that a societal decision to stabilize atmospheric CO_2 at less than a doubling (500 ppmv) implies keeping emissions more or less constant at about the current emission rate of 7 GtC/y for the first half century, followed by a decline in the emission rate during the second half of the century (Pacala and Socolow, 2004; Socolow, Pacala, and Greenblatt, 2004)—a daunting challenge in light of the likelihood that under business-as-usual conditions emissions may well double by mid-century (Figure 2).

In what follows, the prospects for stabilizing emissions from liquid fuels during the first half century are explored.

Toward more energy-efficient end-use technologies

A promising strategy for dealing with all of the above challenges is to improve energy end-use efficiency. In this regard, an especially important development in automotive technology is the recent introduction of internal combustion engine/hybrid electric cars that are more fuel-efficient than today's typical new cars. Diesel hybrids would be more efficient than gasoline hybrids. Combining Diesel hybridization with weight reduction, aerodynamic drag reduction, and reduced rolling resistant tires should make it feasible to increase the fuel economy of today's 30 mpg car to 80 mpg_{ge} (mpg of gasoline equivalent) without loss of automotive performance in the 2020 time frame—see Table 3. Because a large fraction of the light-duty-vehicle fleet is represented by SUVs, the typical fuel economy achievable via such measures[1] is probably ~ 50-55 mpg_{ge}—still a marked improvement over the 20 mpg current average fuel economy for light-duty vehicles.

The health damages caused by Diesel vehicles stand in the way of fully exploiting these opportunities. However, implementing the tough new US regulations on Diesel emissions (formally promulgated by the EPA in 2002) would greatly alleviate these concerns, and there is growing confidence in the automotive industry that these new standards for Diesel cars can be met with new pollution-control technologies.

Furthermore, superclean "designer" synthetic fuels such as Fischer-Tropsch (F-T) Diesel and dimethyl ether (DME) can facilitate a shift to such cars. Both fuels perform extraordinarily well in compression ignition (Diesel-type) engines and can meet the new standards with less pollutant-control equipment than what is required with conventional Diesel fuel (markedly less equipment in the DME case). Both have essentially zero sulfur content. Because it has no carbon-carbon bonds, DME combustion generates essentially no soot; as a result, in the DME case there are no tradeoffs between NO_x and particulate (PM) control efforts—so that low emissions of both NO_x and PM are feasible with controls that are much simpler and much less costly than what is required with Diesel fuel. A significant drawback of DME is that its introduction would require a major refueling infrastructure change: it is a gas at atmospheric

[1] It is reasonable to expect that the average fuel economy of light-duty vehicles could be increased from the 2002 average of 19.7 mpg to (80/30)*19.7 = 52.5 mpg_{ge}.

pressure and must be stored in mildly pressurized canisters like propane. In contrast, F-T Diesel can be provided with existing refueling infrastructures.

Synthetic Fuel Supply Options

The main synthetic fuel options discussed here are biofuels, fluid fuels from coal without and with CCS, and fluid fuels from coal plus biomass with CCS. The focus is on synthetic fuels that are derived from syngas. When building a synthetic fuel out of the two small molecules CO and H_2 that are the main constituents of syngas, one has flexibility to identify and make synfuels that are inherently superior with regard to performance and emissions than hydrocarbon fuels derived from crude oil (TFEST, 2003). This point was noted above in the discussion about F-T Diesel and DME. Engineers have much less flexibility in improving via refining the qualities of crude oil, which, in essence, is a "soup" extracted from the ground that is made up of many large and complex molecules and containing many noxious ingredients.

Biofuels

Producing fluid transport fuels (liquids or gases) from biomass is one way to deal with oil supply security and price concerns. The production of biofuels would provide a new livelihood for farmers and open up the possibility of phasing out agricultural subsidies (Williams, 1994). Also, if the biomass is grown on a sustainable basis, the fuels produced from biomass would be carbon-neutral [except for the modest amounts of fossil fuels used in their production (Hall et al., 1993)] and thus effective in addressing the climate challenge.

However, the overall efficiency of converting solar energy into biomass is low—about 0.25% for energy crops grown in the US with current technology, and processing losses associated with converting biomass to a fluid fuel would reduce the efficiency further to about 0.15%. This implies that land-use constraints either from competition with food production or from concerns about biodiversity loss associated with monoculture energy crops will ultimately limit the role of biomass. But biomass can nevertheless make significant contributions despite eventual constraints. The World Energy Assessment concluded that during the 21st century biomass could provide between 100 and 300 EJ (1 EJ = 1.055 Quads) of primary energy without encountering conflicts with other land-use functions and the preservation of nature (Turkenburg et al., 2000). Since the manufacture of fluid fuels from biomass is typically 60% efficient, this implies the production of 60 to 180 EJ/y of fluid fuels. These are not tiny quantities—considering, for example, that total world oil use in 2000 was 155 EJ. However, in light of the very high levels of fluid fuel demand expected by 2050 under business-as-usual conditions[2] [see, for example, the projections in Table 4 of fluid fuel demand made in representative global energy scenarios developed by the Intergovernmental Panel on Climate Change in its Special Report on Energy Scenarios (SRES)].

It is clear that biomass alone cannot solve the fuels used directly challenges posed by conventional fluid fuels.

[2] I.e., in the absence of a climate policy constraint on energy.

Coal synfuels without CCS

Making fluid fuels from coal would not be resource-constrained for a long time to come. World-wide reserves (supplies recoverable with current technology at today's prices) are adequate for 225 years at the present rate of use, whereas estimated ultimately recoverable resources (which include besides reserves additional supplies estimated to be recoverable with some combination of better technology and higher prices) would last more than 2000 years at the present rate of use (Rogner et al., 2000). Coal is also abundantly available in many parts of the world that do not pose energy-supply-security challenges (e.g., United States, Canada, Australia, Russia, China, and Colombia) and is cheap, and its price tends to be stable.

The largest challenge posed by fluid fuels derived from coal is the buildup of greenhouse gases associated with the manufacture and use of coal-derived synfuels. For a typical coal synfuel, the fuel-cycle-wide GHG emissions per GJ of product would be about 80% higher than for crude-oil-derived hydrocarbon fuels (Larson and Ren, 2003; Celik et al., 2004).

To illustrate how troubling this option would be from a climate-change perspective, consider a world in which the only two liquid fuel options are conventional crude oil with an ultimately recoverable resource of 3000 billion barrels and coal-derived liquid fuel that is produced with CO_2 vented. Suppose further that liquid fuel demand grows 2%/y (the historical rate) until the conventional crude oil production peak is reached in 2021, after which demand grows 1%/y; under these conditions, demand for liquid fuels would nearly double, 2000-2050 (Table 6). Suppose also that after the peak, crude oil production would be proportional to crude oil left in the ground, so that by 2050 crude oil production would have fallen to less than ¾ of the 2000 level (Table 6). If all the remaining liquid fuel demand in 2050 is met by coal liquids with CO_2 vented, the GHG emission rate for liquid fuels in 2050 would be 6.3 GtC/y more than in 2000. Stabilizing the atmosphere at 500 ppmv requires finding ways to reduce this increment to near zero (Figure 2).

Hydrogen from coal with CCS

The climate challenge posed by coal synfuels can be addressed by making hydrogen (H_2) with CCS. The produced H_2 could be used in energy-efficient fuel cell or hybrid-electric internal combustion engine vehicles (Ogden et al., 2004). Pure H_2 with near-zero fuel cycle CO_2 emissions can be made from coal with only a slight modification of coal gasification combined cycle technology with CCS technology (Figure 1, right)—at much lower cost than for H_2 derived from renewable or nuclear primary energy sources with hoped-for future energy conversion technologies (Williams, 2003; NRC, 2004).

What is constraining evolution to a H_2 economy is not appropriate H_2 production technology but rather cost-competitive H_2 end-use technologies and a H_2 refueling infrastructure. Although most of the world's major automakers are putting major efforts into commercializing H_2 fuel-cell cars (Burns et al., 2002), even under optimistic conditions such vehicles cannot make significant contributions in reducing oil dependency in transportation or in mitigating climate change at least until some time in the second quarter of this century.

Liquid fuels from coal with CCS

Making H_2 is not the only way to provide fluid fuels from coal for transportation with CCS. Carbon-containing fluid fuels can also be made with CCS.

The most cost-competitive configurations are often plants that produce electricity [and sometimes other high-value products (e.g., chemicals, process steam)] as well as synthetic fuel (Figure 5)—modeled after polygeneration systems based on gasification of petroleum residuals (Figure 3) that are already well established in chemical process and petroleum refining industries (Williams, 2004a). With CCS (Figure 6), such systems based on current technology can provide transport fuels characterized by 3 to 25% lower fuel cycle-wide GHGs (depending on the system configuration) than crude-oil-derived products. When derived from low-cost coal at minemouth plants, such fuels would be competitive with crude oil-derived products at world oil prices of $31 to $35 per barrel (again depending on system configuration) when CO_2 emissions are valued at the minimum price ($67 per tonne of C) needed to make CCS profitable (Celik et al., 2004).

Such plants widely deployed during this quarter century could easily be modified later to produce a mixture of pure H_2 and decarbonized electricity (instead of only decarbonized electricity) as coproducts of the liquid fuel (Figure 7).

Meeting the climate challenge posed by fuels used directly can be addressed only partially by making coal synfuels with CCS—by an amount that is inadequate to meet the climate challenge of stabilizing atmospheric CO_2 at less than a doubling of the pre-industrial level. To see why this is so, consider a scenario identical to the one described above for coal synfuels produced with CO_2 vented—with the only modification being that the CO_2 coproduct is captured and stored. For this scenario, the fuel-cycle-wide emissions in 2050 from crude-oil-derived hydrocarbon fuels plus coal synfuels would be about almost 3 GtC/y more than from crude-oil-derived hydrocarbon fuels in 2000 (Table 6), with 60% of total liquid fuel-related emissions coming from the coal-derived synfuels.

Liquid fuels from coal and biomass with CCS

If biomass and coal are co-processed to make synthetic fuel for transportation, fuel cycle GHG emissions can be reduced much further than when only coal is used as a feedstock.

Synthetic fluid fuels typically have H/C ratios of 2 to 4, which is much higher than the 0.8 ratio typical of coal. The usual way to make up for the hydrogen deficit is to react some CO in the syngas exiting the coal gasifier with steam to produce CO_2 and H_2 (via the so-called water gas shift reaction: $CO + H_2O \rightarrow H_2 + CO_2$) and remove the CO_2 so produced (Figure 6).

An alternative approach is to gasify some biomass to make H_2 and mix this biomass-derived H_2 with the H_2–deficient coal-derived syngas before sending the mixture to the synthesis reactor. In order to reduce the GHG emissions for this alternative process, the CO_2 co-product of making H_2 from biomass is stored underground along with CO_2 recovered from processing coal (Figure 8). Because this biomass-derived CO_2 was originally extracted from the atmosphere during photosynthesis, storing it underground amounts to generating "negative" CO_2 emissions (Williams, 1998)—which offset some of the CO_2 emissions when the synfuel is burned.

Figures 9-10 and Table 5 present the results for this strategy when the liquid fuel produced is DME. Similar results are likely to be achievable for F-T liquids that would be derived from coal and biomass with CCS.

In the DME case, the net effect of adding biomass-derived H_2 to the coal DME system with CCS is to is to reduce by more than 4/5 the CO_2 emissions generated in manufacturing and burning a unit of fuel, relative to the case in which the fuel is made from coal with CCS (Figure 9). These findings are extended to include fuel-cycle-wide GHG emissions for these two cases and several others in Figure 10. Notably, for DME made from coal and biomass with CCS, the fuel-cycle-wide GHG emission rate is almost ¾ less than for either gasoline or Diesel derived from crude oil.

Figure 10 shows that for DME made from coal and biomass with CCS the fuel-cycle-wide GHG emission rate is not much more than for DME derived from biomass only. Moreover, because coal (in the amount 1.52 times the DME energy content) as well as biomass (in the amount 0.76 times the DME energy content) is used to make DME (Table 5), this strategy makes it possible to produce 1.69/0.76 = 2.2 times as much low-emitting DME per hectare per year via the coal/biomass strategy compared to the biomass-only option, which requires biomass in the amount 1.69 times the DME energy content for DME manufacture (Klintbom et al., 2003)—thereby greatly easing the land availability constraints that will eventually limit the potential for synfuels produced from biomass only.

Figure 10 also shows that for DME made from coal and biomass with CCS the fuel-cycle-wide GHG emission rate is not much more than for H_2 derived from coal with CCS [which is likely to be the least costly option for making H_2 with low GHG emissions in many circumstances (NRC, 2004; Williams, 2003)], suggesting strongly that low GHG emission rates can be realized without shifting to a H_2 economy for transportation.

The last line of Table 6 suggests that, if CO_2 storage proves to be viable at gigascale, the coal/biomass DME with CCS option offers the potential for stabilizing global emissions for liquid fuels in this half century. Consider a global liquid fuels scenario similar to the two already described above and summarized in Table 6 but with all the DME provided from coprocessing coal and biomass with CCS. For this scenario, the fuel-cycle-wide emissions in 2050 from crude-oil-derived hydrocarbon fuels plus coal/biomass-derived synfuel would be about the same as for crude oil-derived hydrocarbon fuels in 2000. The biomass required in 2050, some 120 EJ/y is at the low end of World Energy Assessment estimates as to the potential global biomass energy production in this period (Turkenburg, 2000). Moreover, the required biomass production rate in 2050 is not too different from the average rate of biomass energy production in the four SRES Marker Scenarios of the Intergovernmental Panel on Climate Change—some 112 EJy (Table 4).

With current switchgrass production technology the delivered cost of switchgrass at conversion facilities would be about $3/MBTU—about 2.3 X the average coal price for electric generators in the US. However, valuing the negative emissions of CO_2 associated with this biomass at $75/tC (which would make CCS profitable for a coal-based DME/electricity system) would reduce the net switchgrass cost to essentially the current coal price (see Table 5)—suggesting that, with current technology, coal and biomass are comparably competitive in addressing the climate challenge.

There are other ways to exploit the potential for negative emissions from biomass besides the scheme presented here. No attempt has yet been made to identify the optimum configuration for DME manufacture. Moreover, F-T liquids production from coal and biomass has not yet been investigated—an option that might lead to different configurations in light of the higher H_2/CO ratio needed for sythesis (~ 2 instead of ~ 1).

Negative emission exploitation opportunities also exist for stand-alone biomass energy systems, but there are constraints on these options. The production of H_2 as an energy carrier from biomass in stand-alone facilities is technically feasible—but it will be decades before H_2 is established as a major energy carrier. The recovered H_2 might instead be piped to a distant coal synfuels plant to be used as described earlier, but the high cost of H_2 pipeline transport makes this option prospectively uninteresting. The H_2 so produced might also be consumed onsite in a combined cycle power plant (as for the coal gasification combined cycle option shown on the LHS of Figure 1), but for typical biomass power plants of 50 – 200 MW_e scales and associated modest CO_2 flow rates compared to coal conversion plants, CO_2 transport would be costly ($ per tonne of CO_2 basis), typically rendering CCS unattractive if CO_2 must be piped appreciable distances to suitable storage sites. This scale issue would be an even worse constraint for dedicated plants that make DME or an alternative liquid fuel from biomass with CCS, because the amount of CO_2 recovered per unit of biomass consumed would be much less than when H_2 is made from biomass.

An attraction of the proposed biomass/coal coprocessing option is that the biomass feedstock benefits enormously from scale economies throughout the system—not the least of which is associated with CO_2 storage [note, for polygeneration system described here, the total CO_2 storage rate is four times the storage rate for biomass-derived CO_2 (Table 5)]. Of course transporting biomass long distances to such coal conversion plants drives up its cost, but as discussed above, the effective cost of delivered biomass (with valuation of the negative emissions benefit the biomass offers) can often be quite attractive despite such transport cost penalties.

Finally, it is worth noting that the negative emissions synergism described here for coal/biomass coprocessing does not exist for natural gas and biomass. In contrast to the situation for coal-derived syngas, which is deficient in H_2, natural gas-derived syngas has more H_2 than is needed for making liquid fuels.

Biomass supply options

Where might the biomass supplies come from? It is likely that initially waste biomass resources will be exploited (forest product industry and agricultural residues and urban refuse); recoverable wastes might amount to as much as 6 EJ/year in the US (Williams, 1994). In Sweden, one strategy being investigated involves making DME from forest product wastes in conjunction with pulp and paper making (Landalv, 2004)—a strategy that might also be relevant for the United States.

For developing countries a promising option is to make liquid fuels plus electricity from coal and sugar cane residues, which are copiously produced at present in many countries and currently used very inefficiently (Williams, 2004b).

Dedicated energy crops are also options. One possibility is switchgrass—a fast-growing grass that was ubiquitous in the Great Plains before this region was plowed and cultivated.

Thought experiment for making synfuels from coal and switchgrass

Table 7 presents a thought experiment illustrating what might be achieved in the US via production of 3.8 Quads/y of DME and 540 TWh/y of electricity from coal and switchgrass on 17 million hectares using current switchgrass production technology. The 2.8 Quads/y of switchgrass produced in this thought experiment is an amount of production estimated to be cost-competitive to producers if the average farmgate price of swichgrass is $44 per dry tonne or $2.4/MBTU (McGlaughlin et al., 2002). As noted earlier, the delivered price at the conversion facility would be about $3.0/MBTU, but the effective price there, net of the negative emissions benefit would be about the same as the average US price of coal for electric generators.

The amount of land involved in is relatively modest. It is just 35% higher than the total amount of land idled by the Conservation Reserve and other programs (12.5 million ha) in 2000. For comparison, the total amounts of land planted in crops and in farms in 2000 were 139 and 381 million hectares, respectively.

The DME produced would be adequate to support 131 million light duty vehicles (almost 2/3 of the LDV fleet in 2002), reduce oil imports by 5.6 million barrels per day (more than ½ of total US imports in 2002), and reduce GHG emissions for the DME cars by more than 90%—if 20 mpg gasoline-fueled LDVs (the current US average fuel economy) were replaced by 53 mpg_{ge} HE/CIE vehicles of equivalent performance. The coproduct electricity generated (from 77 GW_e of installed capacity) would be equivalent to 29% of US coal power generation in 2002, and the GHG emission rate per kWh allocated to electricity at these plants would be less than 10% of that for the coal steam-electric plants displaced. The required CO_2 storage rate amounts to nearly a billion tonnes of CO_2 per year.

The way forward

The overall strategy outlined here for addressing the challenges posed by fuels used directly requires several initiatives: (*i*) measures aimed at making a transition from coal combustion to coal gasification and polygeneration; (*ii*) measures to encourage biofuels production via gasification and coprocessing of biomass and coal; (*iii*) measures to promote a shift to fuel-efficient motor vehicles; (*iv*) the conduct of many "megascale" CO_2 storage demonstration projects (involving CO_2 storage rates ~ a million tonnes per year or more) to ascertain whether geological storage of CO_2 will be viable at gigascale; and (*v*) enactment of a climate mitigation policy that would make it profitable for the private sector to pursue cost-effective CCS activities.

Conclusion

The coprocessing of coal and biomass to make super-clean synthetic liquid fuels with CCS makes it possible to address effectively and simultaneously climate and energy-supply challenges posed by crude oil-derived hydrocarbon fuels without having to abandon liquid fuels. The strategy might obviate the need to evolve to a H_2 economy for transportation, although the strategy is fully consistent with and supportive of evolution to a H_2 economy.

Gasification also makes it possible to produce designer liquid fuels that are inherently superior to crude-oil-derived hydrocarbon fuels—thereby facilitating a transition to more energy-efficient end-use technologies such as compression-ignition-engine hybrid-electric vehicles.

The strategy makes it feasible to exploit the huge domestic energy potential of coal in a manner consistent with local, regional, and global environmental constraints. It also makes it feasible to ease substantially the land-use constraint on biomass energy (reducing by half the land required to make liquid fuels without increasing the fuel-cycle-wide GHG emissions per unit of fuel produced) by making it practically feasible to exploit the large negative CO_2 emissions potential associated with making H_2 from biomass with CCS—long before a H_2 economy can be put into place. It also frees the biomass industry of obligations for synfuel processing downstream of gasification (for which responsibility would likely be assumed by the fossil energy partner involved) and synfuel marketing—and probably offers a route for exploiting the biomass potential in providing liquid fuels that can be realized much more quickly than via a pure biofuels route.

The biggest technical uncertainty regarding this strategy is the gigascale viability of CCS. The biggest institutional challenge is finding ways to get the bioenergy, fossil energy, and energy efficiency communities to work collaboratively in addressing climate and oil-supply challenges—each of whom should recognize the strategic benefits it would gain from this collaborative activity.

Acknowledgments

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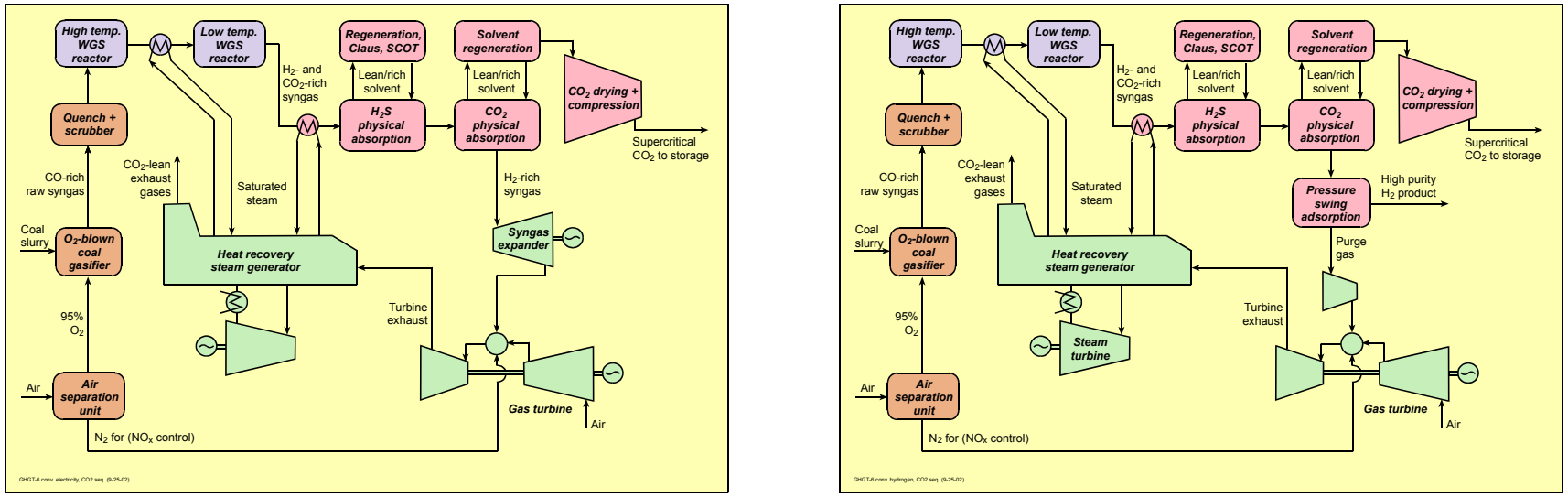


Figure 1: Coal Gasification with CO_2 Capture and Storage for Combined Cycle Power Generation (*left*) **and H_2 Production** (*right*)

The least costly CO_2 capture and storage (CCS) option for coal power generation is based on pre-combustion CO_2 capture using coal gasification combined cycle (CGCC) technology (*left*) in which: (*i*) coal is first gasified at high pressure (up to 70 atmospheres) in O_2 (from an air separation unit) and steam to produce mainly CO and H_2; (*ii*) the CO is converted to H_2 and CO_2 by reacting it with steam via the so-called water gas shift (WGS) reaction ($CO + H_2O \rightarrow CO_2 + H_2$); (*iii*) the CO_2 is removed (along with H_2S) from the shifted syngas using an appropriate solvent, dried, and compressed for pipeline delivery to an appropriate geological storage site; (*iv*) the H_2–rich, CO_2-depleted syngas is expanded to produce a modest amount of electricity; and finally, (*v*) the less-pressurized H_2-rich syngas is burned to make a large amount of electricity in a gas turbine/steam turbine combined cycle power plant. With current technology, coal electricity so produced costs 35-50% more per kWh than for a new coal steam-electric plant with CO_2 vented. In contrast, the cost of electricity with CCS for a coal steam-electric plant[3] is up to double the cost with CO_2 vented; the cost penalty is much lower with CGCC technology because the CO_2 is recovered at a much higher partial pressure (up to 25 to 30 atmospheres pre-combustion vs 0.15 atmospheres post-combustion).

The least costly approach for making H_2 with near-zero CO_2 emissions will often also be based on coal gasification with CCS (*right*). The required technology is nearly identical to that for CGCC with CCS, except that: (*i*) after CO_2 removal, the shifted, pressurized H_2-rich syngas is purified in a pressure swing adsorption (PSA) unit (instead of expanded in a syngas expander); (*ii*) the purified (up to 99.999% pure), pressurized H_2 is transported by pipeline to distributed end users, and (*iii*) the low-pressure purge gases from the PSA unit (the remaining impure H_2 along with small amounts of CO and other gases) are compressed and burned to make a small amount of coproduct electricity in a combined cycle power plant (Chiesa et al., 2004; Kreutz et al., 2004). With current technology H_2 with CCS can be produced for a cost of \$1.0 to \$1.2 per gallon of gasoline-equivalent energy (less than half the cost of H_2 derived via hoped-for future renewable energy technologies). The cost penalty for a CCS system is only 20% compared to a system with CO_2 vented—much less than the cost penalty for the electricity case, because the costs for water gas shift and CO_2 separation are required for H_2 manufacture even if the CO_2 is vented (Kreutz et al., 2004).

[3] For a coal steam-electric plant, decarbonization is carried out via post-combustion CO_2 capture from flue gases.

R.H. Williams, *Toward Polygeneration of Fluid Fuels and Electricity via Gasification of Coal and Biomass*, November 2004.

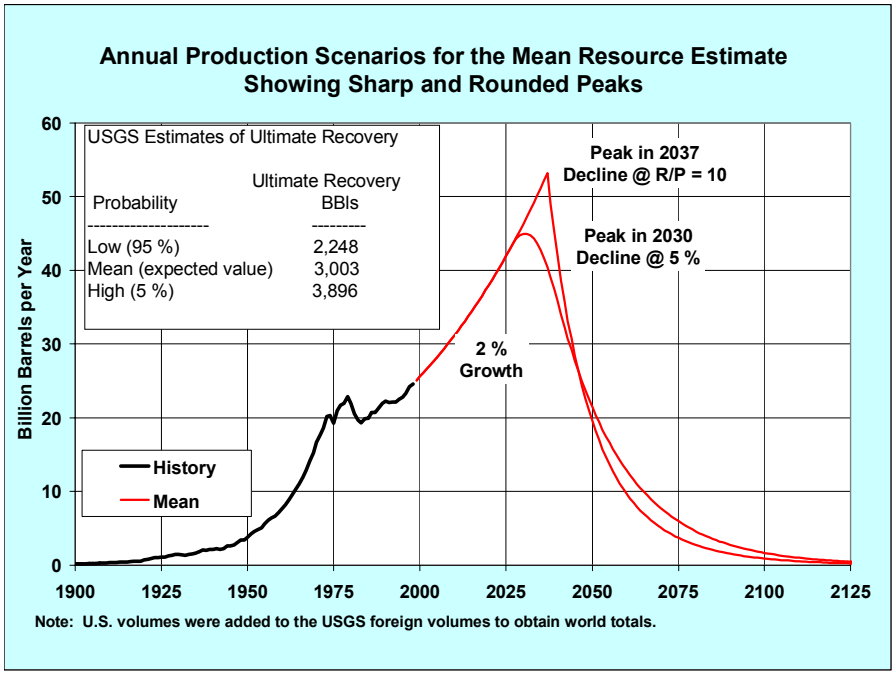


Figure 2: Energy Information Administraton Projections of Global Production of Conventional Crude Oil

Shown here are two alternative world production trajectories for oil based on the US Geological Survey's estimate that 3000 billion barrels of conventional crude oil will eventually be recovered. The estimated ultimately recoverable resource (the area under each curve) is the same in both cases.

Source: Hakes (2002).

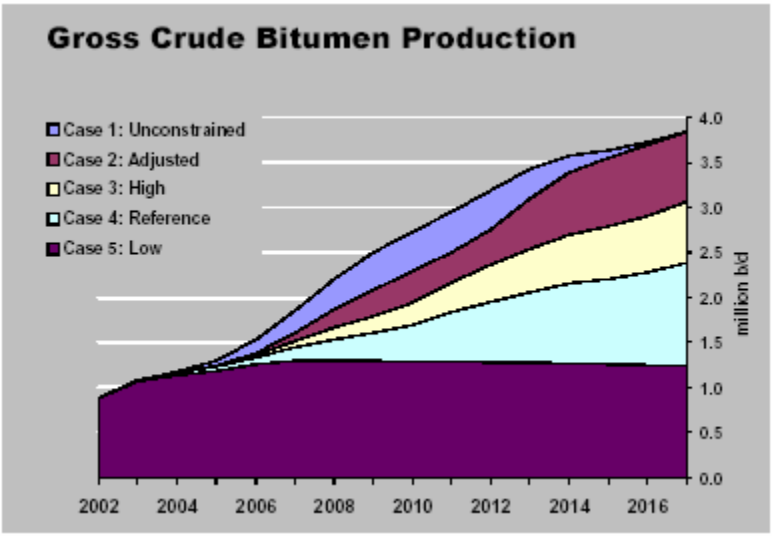


Figure 3: Alternative Production Trajectories for Oil Production from Canadian Tar Sands

These alternative scenarios for oil production from Canadian tar sands were generated by the Canadian Energy Research Institute.

Source: Dunbar (2004).

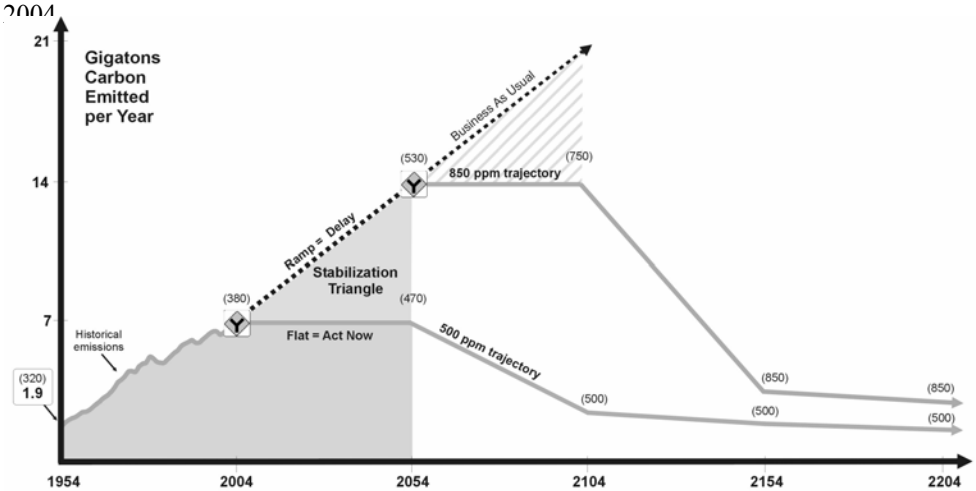


Figure 4: Stabilization Trajectories for Global CO_2 Emissions

If society chooses to delay action to stabilize atmospheric CO_2 for ~ half a century until "advanced technology" becomes available to deal with the problem more effectively than is feasible with today's technology, it would probably not be feasible to stabilize the atmosphere at a CO_2 concentration much lower than about 850 ppmv—which is triple the pre-industrial level (see Ramp = Delay trajectory—a business-as-usual scenario for the next half century). But early action aimed at stabilizing emissions using current and near-commercial technologies during the next half century (as indicated by the Flat = Act Now trajectory) followed by declining emissions via use of advanced technologies during the following half century would make it feasible to stabilize CO_2 at a level of 500 ppmv, which is less than a doubling of the pre-industrial level. Pursuing the Flat = Act Now trajectory is a daunting challenge—requiring by mid-century an emissions reduction rate equal to the total emissions rate today (~ 7 GtC/y). Although there is no single "silver bullet" that would make it feasible to achieve the targeted emissions reduction rate by 2054, there are many promising options capable of delivering ~ 1 GtC/y each.

Source: Socolow, Pacala, and Greenblatt (2004).

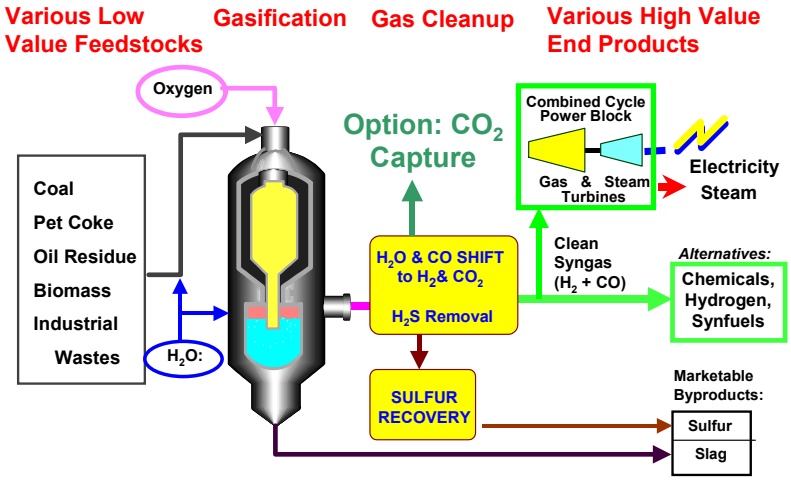


Figure 5: Carbon Refinery for the Polygeneration of Multiple High-Value Products from Low-Cost Carbonaceous Feedstocks

Gasification can be used to convert any low-quality, low-cost, carbon-rich feedstock into high-value products—chemicals and synthetic carbon-based fuels as well as decarbonized electricity and H_2. It will often be less costly (more profitable) to manufacture multiple high-value products in a single facility—by exploiting economies of scale and scope and opportunities for increased operating flexibility—and, sometimes, to gasify more than one feedstock at such a carbon refinery. The CO_2 coproduct of making decarbonized electricity and hydrogen-rich products at a carbon refinery can be transported via pipeline to and stored in appropriate geological media.

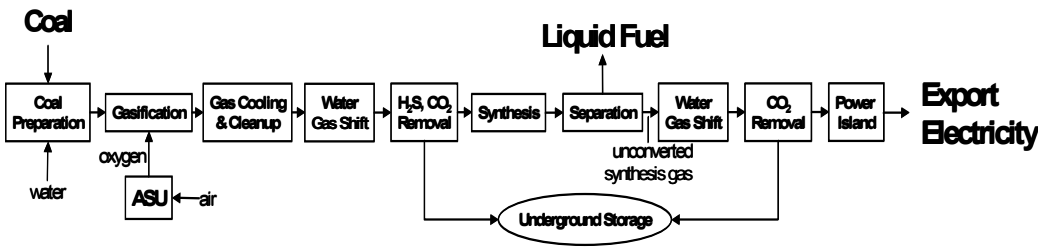


Figure 6: Co-Production of Liquid Fuels and Electricity via Coal Gasification with CO_2 Capture and Storage

Super-clean "designer" liquid fuels co-produced from coal with CCS would have fuel-cycle-wide GHG emission that are often less than for crude-oil derived products (Celik et al., 2004). In such plants shift reactors would be introduced both upstream and downstream of the synthesis reactor where the synfuel is made. The upstream shift reactor is needed to increase the ratio of H_2 to CO in the syngas from the 0.6 level in the syngas exiting the coal gasifier to the value needed for synthesis (1.0 to more than 2.0, depending on the synfuel). Downstream of this shift reactor but upstream of the synthesis reactor both CO_2 and H_2S must be removed from the shifted syngas—the CO_2 to maximize synfuel conversion and the H_2S to avoid poisoning the synthesis catalysts. It is sometimes less costly even when the carbon price is zero to remove the acid gases H_2S and CO_2 together and store them underground than to remove them separately, vent the CO_2, and reduce the H_2S to elemental sulfur; the amount of CO_2 removed under this "acid gas management strategy" can account for up to 30% of the carbon in the coal (Larson and Ren, 2003; Celik et al., 2004). The downstream shift reactor and subsequent CO_2 removal would be introduced only under a climate constraint that dictates decarbonization of the electricity coproduct (Celik et al., 2004).

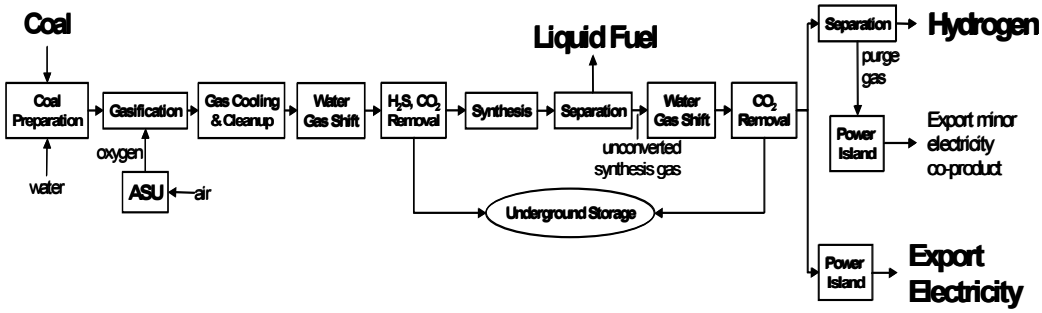


Figure 7: Polygeneration of Liquid Fuels, Hydrogen, and Electricity via Coal Gasification with CO_2 Capture and Storage

By the time H_2 is launched in the market as an energy carrier, pure H_2 can very easily be added as a co-product to the system that earlier produced liquid fuel plus electricity (as indicated in Figure 6), by adding a pressure swing adsorption unit (see RHS of Figure 1) to purify some of the H_2–rich syngas produced downstream of the synthesis reactor. Because the overall system thermodynamics and profitability are invariant over a wide range of H_2/electricity output ratios (Chisea et al., 2004; Kreutz et al., 2004), the actual H_2/electricity output ratio would typically be determined mainly by relative market demands for these two products.

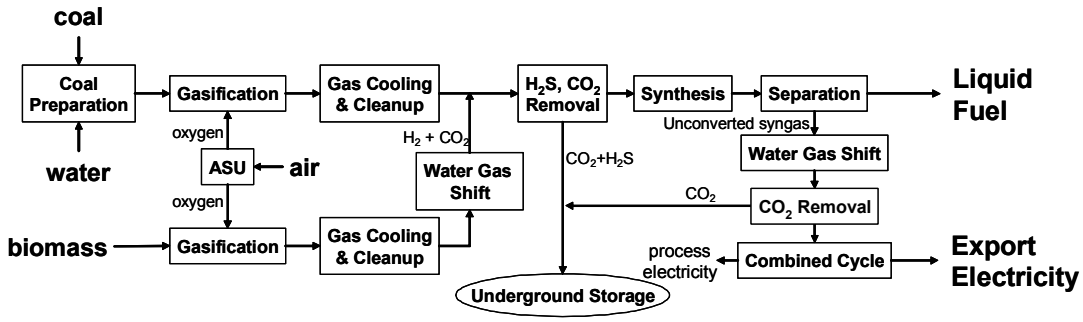


Figure 8: Co-Processing Biomass and Coal to Make Liquid Fuel plus Electricity with CO_2 Capture and Storage

An alternative to shifting the coal-derived syngas to increase the H_2/CO ratio to the value required for synfuel production (as in Figure 6) is to gasify some biomass to make the needed H_2 and store the CO_2 coproduct of this biomass-derived H_2 underground. Because this CO_2 was originally extracted from the atmosphere during photosynthesis, storing it underground amounts to "negative" CO_2 emissions for the biomass input to the system—which can offset much of the CO_2 emitted to the atmosphere when the synfuel is eventually burned (see Figure 9).

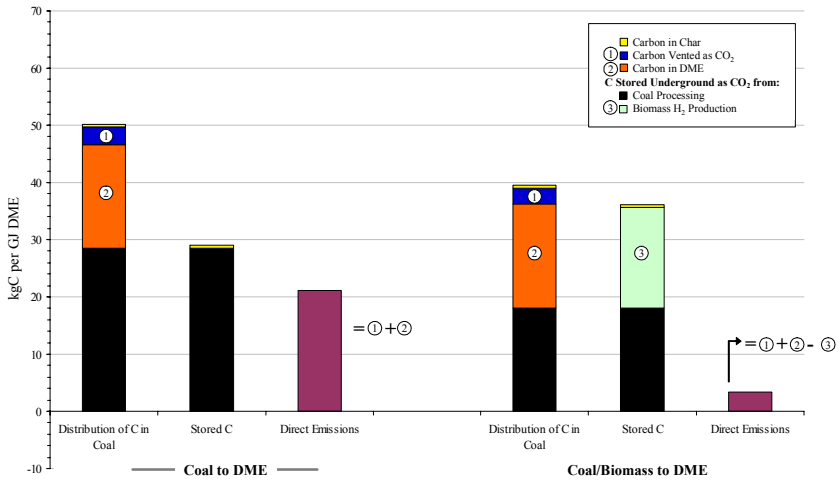
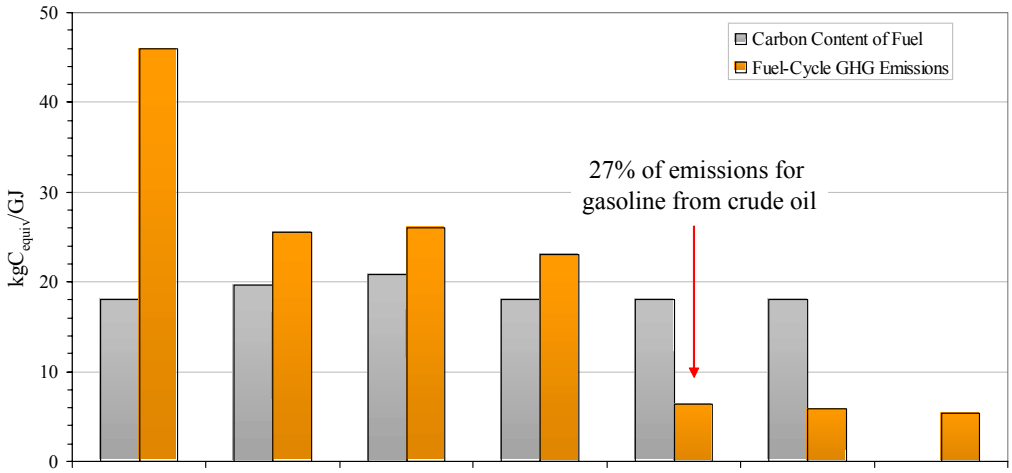


Figure 9: Carbon Balances in Making DME via Alternative Systems with CO_2 Capture and Storage

Carbon balances (in kgC per GJ of DME, lower heating value) for DME made with CO_2 capture and storage (CCS) via polygeneration. Balances are shown for a system using coal only [three bars on the left—the $DCAP_{89}$ option described in Celik et al. (2004), which involves capture as CO_2 of 89% of the carbon in the syngas exiting the synthesis reactor (Figure 6)] and for a system using coal plus biomass (three bars on the right). For coal, only the input energy, CO_2 emissions, and CO_2 storage rates allocated to DME production are shown; the coal input energy, CO_2 emissions, and CO_2 storage rates allocated to the electricity coproduct (not shown) are assumed to be the same as for a stand-alone coal gasification combined cycle plant with CCS that produces the same amount of electricity—as described in Celik et al. (2004) and in Table 5. Some of the carbon in the coal ends up in the DME product, some is vented at the production plant, and a small amount is discharged in the slag recovered from the gasifier. For the system represented by the three bars on the right, all biomass is used to make H_2 that is added to the coal syngas to increase the H_2/CO ratio in coal-derived syngas from 0.6 (the value at the coal gasifier exit) to 1.0 (the value needed for DME synthesis). Storing the CO_2 coproduct of making H_2 from biomass (accounting for 85% of the C in the biomass) represents negative emissions that reduce the net CO_2 emissions allocated to DME to less than 1/5 of the rate for the plant that uses only coal as a feedstock.



Energy Carrier	DME	Gasoline	Diesel	DME	DME	DME	Hydrogen
Primary Energy Source	Coal	Crude Oil	Crude Oil	Coal	Coal/Biomass	Biomass	Coal
CO_2 Capture and Storage?	No	No	No	Yes	Yes	No	Yes

Figure 10: Fuel Carbon Content and Fuel-Cycle-Wide GHG Emissions for Alternative Energy Carriers/Primary Energy Sources

Fuel cycle-wide emissions (in kgC per GJ of DME, lower heating value) are made up of emissions at the conversion plant plus emissions from burning the fuel plus emissions from other parts of the fuel cycle.

For crude oil-derived gasoline and Diesel, the emission rates are from the Argonne National Laboratory's GREET model.

The DME from coal cases shown are the VENT case (left-most pair of bars) and the $DCAP_{89}$ case (4th pair of bars), described in the caption for Figure 9, developed in Celik et al. (2004). The VENT case involves venting as CO_2 at the conversion plant all carbon not contained in the DME product or the gasifier slag. The $DCAP_{89}$ case involves capturing and storing underground CO_2 plus H_2S upstream of the synthesis reactor as well as CO_2 equivalent to 89% of the carbon in the syngas exiting the synthesis reactor. For the coal cases only the CO_2 emissions allocated to DME production are shown; the CO_2 emissions allocated to the electricity coproduct (not shown) are assumed to be the same as for a stand-alone coal gasifier combined cycle plant that produces the same amount of electricity—with CO_2 vented in the VENT case and with CCS in the the $DCAP_{89}$ case. For all cases involving coal, fuel cycle GHG emissions in excess of the emissions arising from the carbon in the coal are estimated to be 1 kg C_{equiv} per GJ of coal—the average for US coal, as estimated in the GREET model; fuel cycle emissions associated with transporting DME from the conversion plant to the final user, assumed to be very small, are neglected.

The net fuel-cycle-wide emissions for making DME from biomass are from Klintbom et al. (2003).

Net fuel-cycle-wide GHG emissions associated with biomass production and transport to the conversion plant for the coal/biomass DME case are made up of CO_2 emissions [1.74 kgC_{equiv} per GJ of biomass—from Williams et al. (1995)] plus emissions of other GHGs [0.17 kgC_{equiv} per GJ of biomass—from Klintbom et al. (2003)]. This case takes into account the "negative CO_2 emissions" associated with CCS for the CO_2 coproduct of making H_2 from biomass, as described in Figure 9.

The fuel-cycle-wide emissions associated with making H_2 from coal with CCS are from Ogden et al. (2003).

Table 1: World Oil Production Peak For Alternative Estimates of Ultimately Recoverable Oil			
Estimated ultimately recoverable conventional oil (*including historical production*), 10^9 barrels[a]	1800	2400	3000
	Year of peak[b]		
Peak with no unconventional oil	2001	2012	2021
Peak if GTL is the only unconventional oil (360 x 10^9 barrels from 2000 TCF of natural gas)[c]	2008	2018	2026
Peak if Canadian tar sands are also included [assuming technically recoverable potential (300 x 10^9 barrels out of 1700 x 10^9 barrels of OOIP)[d]	2013	2022	2029
Peak if Venezuelan heavy oil is also included [assuming technically recoverable potential (272 x 10^9 barrels out of 1200 x 10^9 barrels of OOIP)[d]	2017	2025	2033

[a] The estimates of ultimately recoverable conventional oil range from pessimistic [1800 billion barrels (Campbell and Laherrere (1998)] to optimistic [3000 billion barrels (US Geological Survey World Energy Assessment Team (2000)].

[b] It is assumed that the peak occurs when ½ of the ultimately recoverable oil is produced and that oil demand grows 2% per year (historical rate) until the peak is reached. Global crude oil production in 2003 was 25.3 billion barrels, and cumulative crude oil production through that year was 960.8 billion barrels. The peak would occur earlier than the indicated values if, because of security concerns, there were no significant new investments made to expand productive capacity in the Middle East, where remaining low-cost oil is concentrated.

[c] This estimate was made by Pat Davis, Executive Director of Sasol, a South African company that is heavily involved in GTL (gas to liquids) technology—based on his estimate that stranded assets of conventional natural gas assets worldwide amount to 2000 trillion cubic feet (TCF). (Liquid fuels derived from non-stranded gas assets would be very expensive.) For comparison, the US Geological Survey's mean estimate of ultimately recoverable conventional natural gas remaining as of 1 January 2003 is 12,000 TCF (US Geological Survey World Energy Assessment Team (2000).

[d] Source: Holditch (2003). OOIP ≡ original oil in place. The percentage of OOIP estimated as ultimately recoverable is much less than the 50% that the USGS estimates will be the ultimately recoverable percentage of OOIP for conventional oil [the assumption underlying their estimated ultimately recovery oil resource of 3000 billion barrels because of the much more difficult conditions associated with higher recovery rates for unconventional oil resources. In the case of Canadian tar sands, for example, the Alberta Energy and Utilities Board (AEUB) estimates that about 175 billion barrels are proved reserves [oil recoverable with current technology and economic conditions], which is equivalent to 7 years of global crude oil production at the current rate. Most of this resource lies within 75 meters of the surface. With current technology oil sands are mined with "truck and shovel," and a water-based extraction process is used to separate from sand the bitumen, which is then mixed with a light hydrocarbon liquid and piped to refineries for further processing. The AEUB estimates that extracting the rest of the 300 billion barrels of estimated ultimately recoverable resources will require in-situ processing that would bring bitumen to the surface through wells (CERI, 2004).

Table 2: Distribution of Global CO_2 Emissions from Fossil Fuel Combustion (%)			
Year	2000	2020	2050
Electricity generation	36	25-38	22-43
Industry	32	28-32	24-37
Transportation	21	21-25	18-33
Residential/commercial	12	12-20	11-19

Source: International Energy Agency data for 2000. Projections are for the A1B-AIM, AIT-Message, A2-Image, B1-Image, B2-Message scenarios of the IPCC (IPCC, 2000).

Table 3: Outlook for Improving Automotive Fuel Economy[a]			
	Current technology	Advanced hybrid-electric cars (~ 2020)	
	Spark ignition engine	Spark ignition engine	Compression ignition engine
Power/weight (kW/t)	75	75	75
Fuel economy (mpg, gasoline equivalent)	30	69	80
Weight, including 136 kg payload) (t)	1.46	1.16	1.19
Drag coefficient	0.33	0.22	0.22
Frontal area (m^2)	2.0	1.8	1.8
Rolling resistance	0.009	0.006	0.006
Auxiliary power (kW)	0.7	1.0	1.0

[a] Source: Weiss et al. (2003).

Table 4: Fluid Fuel Use and Biomass Production in the IPCC's SRES Marker Scenarios								
SRES Marker Scenario	Global final fluid fuel use and biomass primary energy use (EJ)							Average growth rate for fluid fuels, 1990-2050 (%/y)
	1990			2050				
	Liquid fuels	Gaseous fuels	Total fluid fuels	Liquid fuelds	Gaseous fuels	Total fluid fuels	Biomass primary energy	
A1	110.9	50.5	161.4	301.8	295.1	596.9	192.8	2.2
A2	123.1	51.1	174.2	333.5	186.1	519.6	71.5	1.8
B1	96.8	45.1	141.9	149.2	123.7	272.9	76.3	1.1
B2	110.9	40.9	151.8	267.9	104.9	372.8	107.2	1.5

[a] Source: IPCC (2000).

Table 5: Energy and Carbon Balances for Plant Producing DME and Electricity from Coal and Switchgrass[a]				
Switchgrass yield (*dry t/hectare/year*)	9.4[b]			
Land harvested for switchgrass (km^2)	868			
Feedstock	Coal		Biomass	
Energy and carbon flows	Energy (MW)	Carbon (t C/d)	Energy (MW)	Carbon (t C/d)
Primary inputs	2203	4793	564	1320
Allocated to power generation[c]	1077	2346	-	-
Allocated to DME production	1126	2446	564	-
Distribution of carbon outputs				
CO_2 emissions from plant				
Allocated to power[c]	-	119	-	-
Allocated to DME	-	222	-	198[d]
Stored Carbon				
In DME product	-	1158	-	-
As CO_2 stored underground:				
Allocated to power[c]	-	2227	-	-
Allocated to DME	-	1019	-	1122
As char in gasifier slag	-	48	-	-
Net system outputs				
Power	394 MW_e			
DME	740 MW (11,300 *b/d Diesel equivalent*)			
CO_2 stored underground (10^6 *t* CO_2*/year*)	4.68			
From processing coal	3.48		-	
From making H_2 from biomass	-		1.20	
Switchgrass cost[e]				
Delivered to conversion plant	\$54/dry tonne (\$3.0/MBTU)			
Effective cost with C credit @ \$75/tC	\$23/dry tonne (\$1.3/MBTU)			

[a] These energy and carbon balances as well as those presented in Figures 9 and 10 represent preliminary results of an ongoing study assessing DME and electricity co-production from coal and biomass with CO_2 capture and storage (CCS) via the process shown in Figure 8. This analysis builds on the findings of an earlier study (Celik et al., 2004) assessing the co-production of DME and electricity from coal with CCS using the Texaco (now GE) gasifier [the $DCAP_{89}$ option described in that study, which involves capture as CO_2 of 89% of the C in syngas exiting the synthesis reactor (see Figure 6)]. But in contrast to the earlier study in which the H_2 deficit in coal-derived syngas (with $H_2/CO = 0.6$, less than the 1.0 value needed for DME synthesis) is provided by shifting this syngas, it is assumed here that the needed H_2 is provided by gasifiying biomass using the Institute of Gas Technology (IGT) gasifier, as assessed in Williams et al. (1995) and that the CO_2 coproduct of this process (accounting for 85% of the C in the biomass feedstock) is stored underground, along with CO_2 recovered from the coal syngas both upstream and downstream of the synthesis reactor (82% of the CO_2 recovered in coal processing is recovered downstream of sythesis).

[b] This is the productivity of switchgrass with current technology averaged over 17 million hectares for the switchgrass production scenario described in McGlaughlin et al. (2002).

[c] It is assumed that the coal input, CO_2 emissions, and underground CO_2 storage rates for the electric output are the same as for a stand-alone coal gasifier combined cycle plant with CCS, as described in Celik et al. (2004).

[d] The CO_2 emissions from biomass are exactly offset by CO_2 recovered from the atmosphere during photosynthesis.

[e] According to McGlaughlin et al.(2002) the average farm-gate price of switchgrass with current technology is \$44/dry tonne (dt). Assuming the switchgrass is transported 25 km to the conversion plant (the average distance for a facility at the center of a circular region, 20% in switchgrass), the delivered cost would be \$54/dt (\$2.98/MBTU). The effective cost of biomass [\$23/dt (\$1.29/MBTU)] takes credit of the negative emissions associated with storing underground the CO_2 coproduct of making H_2 from biomass (see Figure 8)—assuming a carbon price of \$75/tC (which would make CCS profitable in making DME from coal). For comparison the average price of coal for electric generators in the US was \$1.27/MBTU in 2003.

Table 6: Alternative Global Liquid Fuel Production Scenarios for 2050

	Refined liquids produced[a] (EJ/y)	Refined liquids from crude[a] (EJ/y)	DME[b] (EJ/y)	Coal for liquids (EJ/y)	Biomass for liquids (EJ/y)	GHG emissions (GtC/y)	CO_2 storage (GtC/y)
Actual 2000	129	129	0	0	0	3.3	0
Scenarios with alternative feedstocks for 2050							
Conv. crude + coal w/CV	250	93	157	278[c]	0	9.6[c]	0
Conv. crude + coal w/CCS	250	93	157	316[c]	0	6.1[c,e]	4.5[c,e]
Conv. crude + coal/biomass w/CCS	250	93	157	239[d,e]	120[d,e]	3.5[d,e]	5.3[d,e]

[a] Crude oil production = 24.9 billion barrels in 2000; 10% refinery losses assumed in making refined products. Liquid product demand assumed to grow 2%/y until conventional crude production peak is reached in 2021 (3000 billion barrels case, Table 1), after which demand grows 1%/y; after the peak, crude production assumed to be proportional to estimated ultimately recoverable oil left in the ground, so that production declines 2.4%/y.

[b] Assuming that all liquid fuel except that from conventional crude is provided by DME from coal or coal/biomass.

[c] Coal w/CV = VENT case (all CO_2 at conversion plant vented) and coal w/CCS = $DCAP_{89}$ case (89% of CO_2 not in DME is captured) in Celik et al. (2004).

[d] The case depicted in Table 5 for generic biomass—8400 plants of the type described there.

[f] Includes only the coal energy, GHG emissions, and CO_2 storage rates allocated to DME manufacture. For the electricity coproduct, it is assumed that the coal energy, GHG emissions, and CO_2 storage rates are those for stand-alone coal IGCC plants (with CO_2 vented in the VENT case and with CO_2 stored underground in the $DCAP_{89}$ case).

Table 7: Thought Experiment for Making DME for Cars Plus Electricity from Coal and Switchgrass[a] in the US

Total outputs of 196 plants like those described in Table 5 consuming switchgrass produced on 17 million hectares	
DME	3.8 Quads/y
Electricity	540 TWh/y[b]
Light-duty vehicles (LDVs) supportable by DME (for 52.5 mpg_{ge} CIE/HE cars @ 12,300 miles/y)[c]	131 x 10^{6}[b]
Crude oil displaced if alternative = 19.7 mpg gasoline LDVs @ 12,300 miles/y[c]	5.6 MMB/D[b]
GHG emission rates (10^6 tC/y)	
For 131 x 10^6 52.5 mpg_{ge} CIE/HE cars fueled with coal/switchgrass-derived DME w/CCS	26
For 131 x 10^6 displaced 19.7 mpg cars fueled with gasoline from crude oil	249
For 540 TWh/y of decarbonized coal power	11
For 540 TWh/y of displaced coal steam-electric power	152
Total GHG emission reduction rate for this strategy (10^6 tC/y)	364
Inputs (Quads/year):	
Switchgrass (@ 9.4 tonnes/ha/y on 17 x 10^6 hectares)	2.8
Total coal input (Quads/y)	10.8[b]
Allocated to DME production	5.5
Allocated to electricity generation	5.3
CO_2 storage rate	916 x 10^6 t CO_2/y

[a] Switchgrass production parameters are from McGlaughlin et al. (2002). Land in switchgrass is made up of 9.4, 5.2, 0.9, and 1.4 million hectares in croplands, CRP lands, idle lands, and pasture, respectively.

[b] For comparison, for the US in 2002: coal electricity generation = 1875 TWh, accounting for 20 Quads of coal; oil imports = 10.5 MMB/D; there were 204 million LDVs for which the average fuel economy and driving rate were 19.7 mpg and 12,300 miles/year, respectively.

[c] It is assumed that by shifting to energy-efficient CIE/HE vehicles the fuel economy could increase by a factor of 80/30 = 2.67 to 52.5 mpg_{ge} without loss of performance (see Table 3).

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HYDROGEN AND FUEL CELLS: A TECHNOLOGY AND POLICY OVERVIEW

Prepared for the National Commission on Energy Policy by
The Center for Energy and Climate Solutions
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EXECUTIVE SUMMARY

The possibility that hydrogen could solve many of the nation's energy and environmental problems has received growing attention in recent years, culminating in President Bush's 2003 State of the Union announcement of a $1.2 billion hydrogen initiative. Widespread use of stationary fuel cells running on natural gas seems likely post-2010, particularly if high-temperature fuel cells achieve their cost and performance targets. The transition to a transportation system based on a hydrogen economy will, however, be much slower and more difficult than widely realized.

It is unlikely that hydrogen vehicles will achieve significant (>5%) market penetration before 2030. A variety of major technology breakthroughs and government incentives will be required for them to achieve significant commercial success by the middle of this century. Continued R&D in hydrogen and transportation fuel cell technologies remains important because of their potential to provide a zero-carbon transportation fuel in the second half of the century. But neither government policy nor business investment should be based on the assumption that these technologies will have a significant impact in the near- or medium-term.[1]

INTRODUCTION

In 1993, the Department of Energy's hydrogen R&D effort did not yet have its own separate budget line and was funded at under $2 million-a-year. Yet, only ten years later, all of the major car companies had hydrogen vehicle programs, the major oil companies had hydrogen-production programs, dozens of new companies had been formed to develop hydrogen-related technologies, and in January 2003 President Bush launched a massive R&D effort "so that the first car driven by a child born today could be powered by hydrogen, and pollution-free."

What caused this sea change in 10 short years? There are two main reasons. The first is growing concern about a variety of energy and environmental problems, especially oil imports and global warming. Energy consumption and greenhouse gas emissions have grown faster in the transportation sector than in any other sector the economy. Options for displacing imported oil with a domestic low-carbon fuel are limited. Hydrogen is one of the few technical options (other options include cellulosic ethanol and electric batteries).

The second reason is a series of technological advances crucial to the hydrogen economy. A hydrogen economy—which is typically used to describe a time when the economy's primary energy carrier is hydrogen made from sources of energy that have no net emissions of greenhouse gases—rests on two pillars: a pollution-free source for the hydrogen itself and a device for converting it into useful energy without generating pollution. Let's start with the device, the fuel cell.

FUEL CELLS

Fuel cells are small, modular, electrochemical devices, similar to batteries, but which can be continuously fueled. For most purposes, you can think of a fuel cell as a "black box" that takes in hydrogen and oxygen and puts out only water plus electricity and heat. Today hydrogen is most easily and cheaply generated or "reformed" from natural gas. The reforming process can be performed *internally* for fuel cells that operate at very high temperatures—that is, these fuel cells can run directly on natural gas. But the low-temperature fuel cells ideal for transportation require an *external* reformer that delivers hydrogen of very high purity.

The fuel cell has a positively-charged electrode (anode) and a negatively-charged electrode (cathode) separated by an electrolyte. The material used for the electrolyte determines many of the fuel cell's properties, including its operating temperature, and thus is used to distinguish the different types of fuel cells. High-temperature fuel cells are more suitable for stationary applications because of their high efficiency, but they take too long to warm up to be viable as automobile engines.

Proton Exchange Membrane (PEM) fuel cells, have a plastic electrolyte. PEM fuel cells were developed in the early 1960s by General Electric for the Gemini space program. Fuel cells require catalysts to speed up the electrochemical reaction, and PEM fuel cells require platinum, so for many years they were far too expensive to be practical for commercial applications.

By the early 1990s, Los Alamos National Laboratory (and others) succeeded in cutting the amount of platinum by almost a factor of ten. This reinvigorated interest in hydrogen-vehicles because PEMs were exactly the kind of low-temperature fuel cell (operating at 150 ^{o}F) that could be used in a car. A future fuel cell vehicle might be twice as fuel efficient as current internal combustion engine vehicles, though perhaps only 25% more efficient than future gasoline hybrids and roughly the same efficiency as a future diesel hybrid.[2]

As of 2003, commercial PEM products with significant U.S. sales did not exist. The cost goal for PEM fuel cells is $50/kW or lower (an internal combustion engine costs the equivalent of $25 to $30/kW). Current PEM costs are 30 to 100 times greater. As of 2003, fuel-cell vehicles cost about $1 million each or more. In December 2002, Yozo Kami, Honda's engineer in charge of fuel cells, said it would take at least 10 years to bring the sticker price of a fuel-cell vehicle down to $100,000.[3] A major 2002 analysis for DOE concluded, "factory costs of future FCVs would likely be 40-60% higher than conventional vehicles."[4] Even this conclusion relies on relatively optimistic assumptions about technology breakthroughs, as well as mass production—hundreds of thousands of units per year. Many technologists we spoke to consider the DOE goal unattainable and question whether PEMs can ever be practical as a vehicle engine.

In stationary applications running on natural gas or other fossil fuels, PEMs require an external reformer, a separate device to extract hydrogen from the fuel. This limits overall electrical efficiency of a PEM system running on natural gas to 35% to 40%, similar to current internal combustion systems. Currently, their heat can be used only for water and space heating, which limits their cogeneration application. PEMs may have only limited application for stationary power, especially if high-temperature fuel cell costs continue to decline.

Phosphoric Acid Fuel Cells (PAFCs) use phosphoric acid as the electrolyte. They are the most mature fuel cell technology. More than two hundred 200-kW units have been placed in service. They operate at temperatures of about 300 to 400 degrees Fahrenheit and require an external reformer. The electrical efficiency of a PAFC is in the range of 30-35%.

Each unit also supplies a considerable amount of heat and can achieve an overall efficiency of 80% through cogeneration. Nevertheless, PAFCs have had little commercial success because they are much more costly than other onsite generation technologies, which deliver similar amounts of electricity and heat with similar efficiency, but for under $1000 per kilowatt. PAFCs have a total installed cost exceeding $4500 per kilowatt. UTC Fuel Cells is phasing out this product in favor of work on PEMs.

Molten Carbonate Fuel Cells (MCFCs) use liquid carbonate as the electrolyte. They are in the early stages of commercialization by Fuel Cell Energy. Because they operate at high temperatures (1200 degree F), they can produce hydrogen internally from a variety of fuels directly. MCFCs have electrical efficiencies of 47% to 50% or more. They operate with a much less expensive catalyst than PEMs and are more tolerant of carbon monoxide, which can "poison" PEMs.

On the other hand, MCFCs take a considerable amount of time to reach their operating temperature, and so are unsuitable for powering a car. They are also very bulky: The 250-kW units are the size of a railroad car and weigh about 40 tons. In 2003 demonstration projects, MCFCs have installed costs exceeding $4500/KW.

Solid Oxide Fuel Cells (SOFC) use ceramic as the electrolyte. They run at temperatures up to 1,800 degrees F, and can operate with air and natural gas (or other fuels) as direct inputs. Improvements in ceramics and manufacturing processes have reignited interest in SOFCs. In 2001, DOE launched a 10-year, $300-million-dollar effort to fund industry teams to develop an SOFC that costs $400 per kilowatt, one-tenth of current costs for other fuel cells.

A number of experts we spoke to believe SOFCs will be the stationary fuel cell winner. Ultimately, to succeed in the marketplace, stationary fuel cells will need to overcome the many well-documented barriers that have slowed the penetration of distributed energy and cogeneration.[5] These include the high price of natural gas, the general risk-averse nature of companies for investing in new technology, the desire of companies for rapid payback on capital-intensive energy investments, and various regulatory and financial barriers to self-generation created by utilities and governments. Some niches touted as good market entry points, including high-reliability power and residential generation, are difficult to break in to. To be successful products, stationary fuel cells will probably need to achieve an unsubsidized cost of $1000/kW or better, which is probably at least a decade away.

HYDROGEN PRODUCTION

Hydrogen production is a large, mature industry.[6] Hydrogen production in the U.S. is currently about 8 billion kg or the energy equivalent of 8 billion gallons, and growing at more than 10% per year In 2000, Americans consumed nearly 180 billion gallons of gasoline, diesel, and other transportation fuels for on-road travel.[7] A kg of hydrogen contains about the same usable energy as a gallon of gasoline. Thus, the scale of U.S. hydrogen production will have to be vastly greater to replace a large fraction of U.S. petroleum use, which is projected to rise more than 50% by 2025.[8]

Hydrogen is not a readily accessible energy source like coal or wind. It is bound up tightly in molecules like water and natural gas, so that it is expensive and energy-intensive to extract and purify. Then it becomes an energy carrier, like electricity. Onboard reforming of gasoline into hydrogen is no longer viewed as a viable option by most experts, and few companies are pursuing it. Methanol (CH_3OH) is also being pursued by a few companies as a hydrogen carrier, but faces the problem of stranded investment (see below), as most observers believe hydrogen will ultimately need

to be generated from zero-carbon sources. Hydrogen for fueling vehicles can be produced a variety of ways.

Natural gas (methane or CH_4) is by far the most common source of hydrogen.[9] Steam methane reforming (SMR) generates some 90% of U.S. hydrogen, representing some 5% of U.S. gas consumption. The overall energy efficiency of SMR (the ratio of the energy in the hydrogen output to the natural gas fuel input) is about 70%.

According to a July 2002 analysis for the National Renewable Energy Laboratory (NREL), the cost of producing and delivering hydrogen from an SMR, or producing hydrogen on-site at a local filling station, is $4 to $5 per kilogram, comparable to a price of gasoline of $4-$5 a gallon.[10] Considerable R&D is being focused on efforts to reduce the cost of producing hydrogen from natural gas, but fueling a significant fraction of U.S. cars with hydrogen made from natural gas makes little sense, either economically or environmentally, as discussed below.

Water can be electrolyzed into hydrogen and oxygen. This process is extremely energy-intensive. Typical commercial electrolysis units require about 50 kWh per kilogram, an energy efficiency of 70%. Since most electricity comes from fossil fuels, and the average fossil fuel plant is about 30% efficient, the overall system efficiency is close to 20%.

The cost today of producing and delivering hydrogen from a central electrolysis plant is estimated at $7 to $9 per kg. The cost of on-site production at a local filling station is estimated at $12 per kg. High cost is probably the main reason electrolysis is not a major source of the world's current hydrogen production. Replacing one half of U.S. ground transportation fuels in 2025 (mostly gasoline) with hydrogen from electrolysis would require about as much electricity as is sold in the U.S. today.[11]

From the perspective of global warming, electrolysis using the U.S. electric grid makes little sense for the foreseeable future. Burning a gallon of gasoline releases about 20 pounds of carbon dioxide. Producing 1 kg of hydrogen by electrolysis would generate, on average, 70 pounds of carbon dioxide. Hydrogen could be generated from renewable electricity, but that would be even more expensive and renewable electricity has better uses for the next few decades (see below).

Other low-carbon means of producing hydrogen are being pursued. In February 2003, the DOE announced the FutureGen project to design, build, and construct a 275-megawatt prototype plant that would cogenerate electricity and hydrogen and sequester 90% of the carbon dioxide.[12] The goal is to validate the viability of the system by 2020. DOE is pursuing thermochemical hydrogen production systems using nuclear power with the goal of demonstrating commercial scale production by 2015.

Biomass can be gasified and converted into hydrogen in a process similar to coal gasification. Simbeck and Chang estimate the cost of delivered hydrogen from biomass gasification at $5 to $6.30 per kg, depending primarily on the means of delivery. Other studies by NREL suggest a lower cost, especially for pyrolysis, should we achieve significant technological improvements and successful commercialization of biomass and hydrogen infrastructure technologies.[13]

Stranded investment is one of the greatest risks faced by near-term hydrogen production technologies. For instance, if over the next two decades we built a hydrogen infrastructure around small steam methane reformers (or methanol reformers) in local fueling stations, and then decided that greenhouse gas emissions must be dramatically reduced, we would have to replace that infrastructure almost entirely. John Heywood, director of the Sloan Automotive Lab at the Massachusetts Institute of Technology, argues, “If the hydrogen does not come from renewable

sources, then it is simply not worth doing, environmentally or economically."[14] At this time, no set of commercial technologies appears able to deliver hydrogen to vehicles at a price much below about three times the current price of gasoline (untaxed) on an equivalent energy basis. Hydrogen generated from zero-carbon energy sources would be even more expensive.

HYDROGEN STORAGE

Running a car on pure hydrogen, the option now being pursued by the vast majority of automobile and fuel cell companies, means the car must be able to safely, compactly, and cost-effectively store hydrogen onboard. This is a major technical challenge. Under most conditions, hydrogen has a far lower energy-to-volume ratio than other fuels such as methane or gasoline. At room temperature and pressure, hydrogen takes up approximately 3,000 times more space than gasoline containing an equivalent amount of energy. The DOE's 2003 *Fuel Cell Report to Congress* notes:

> Hydrogen storage systems need to enable a vehicle to travel 300 to 400 miles and fit in an envelope that does not compromise either passenger space or storage space. Current energy storage technologies are insufficient to gain market acceptance because they do not meet these criteria.[15]

The near-term storage options being most vigorously pursued are physical storage (liquefied hydrogen and compressed hydrogen gas) and chemical storage in metal hydrides.

Compressed hydrogen has been used in demonstration vehicles for many years, and nearly all prototype hydrogen vehicles today use this means of storage. It is potentially low-cost, compared to liquefaction or emerging technologies. Hydrogen is compressed up to pressures of 5,000 pounds per square inch (psi) or even 10,000 psi. For comparison, atmospheric pressure is about 15 psi. Even at these high pressures, hydrogen has a much lower energy per unit volume than gasoline does. Compression to 5,000 psi or 10,000 psi is a multistage process that could require energy input equal to 10% to 15% of the fuel's usable energy content.[16]

The main technical challenges facing compressed hydrogen are the weight of the storage tank and the volume required (safety issues are addressed below). A 5000-psi tank, which until recently was considered at the upper limits for storage of gaseous fuel, could still take up more than 10 times the volume of a gasoline tank with the same energy content. While this is acceptable for demonstration vehicles, it would not be practical for commercial vehicles. Even a 10,000-psi tank would take up 7 to 8 times the volume of an equivalent-energy gasoline tank or perhaps four times the volume for a comparable range.[17] Such tanks are being demonstrated, though working at such high pressures adds overall system complexity and requires materials and components that are more sophisticated and costly. Many experts we talked to, including DOE program staff, question whether a hydrogen economy can be built around a car with a 10,000-psi tank because of the energy penalty and safety concerns.

Liquid hydrogen is widely used today for storing and transporting hydrogen. Liquids enjoy considerable advantages over gases from a storage and fueling perspective: They have high energy density, are easier to transport, and are typically easier to handle. Hydrogen, however, is not typical. Hydrogen becomes a liquid only at -253 °C, just a few degrees above absolute zero (at atmospheric pressure). It can be stored only in a super-insulated cryogenic tank.

Liquid hydrogen is unlikely to form the basis of a hydrogen economy because of the cost and logistical problems in handling liquid hydrogen and because liquefaction is so energy intensive. Some 40% of the energy of the hydrogen is currently required to liquefy it for storage: 12.5 to 15

kWh per kg of hydrogen liquefied.[18] Since that electricity would come from the U.S. electric grid, liquefying 1 kg of hydrogen would by itself release some 18 to 21 pounds of carbon dioxide into the atmosphere, roughly equal to the carbon dioxide emitted by burning one gallon of gasoline.

Metal hydrides include several classes of hydrogen-containing compounds. Hydrogen is chemically bonded to one or more metals and is released through a catalyzed reaction or through heating. Hydrides can be stored in solid form or in a water-based solution. After a hydride has released its hydrogen, a byproduct remains in the fuel tank to either be replenished or disposed.

The major advantage of metal hydrides is the ability to contain a large amount of hydrogen in a small volume. A typical metal hydride tank could carry 5 kg of hydrogen in one third the volume of a 5000-psi tank. Hydrides are, however, heavy. The effective storage capacity may be under 2% by weight—each 1 kg carried may require 50 kg of tank or more so a tank carrying 6kg of hydrogen might weigh more than 300 kg, some eight times the weight of a full gasoline tank.[19] This weight reduces fuel efficiency, which is one of the main points of having a hydrogen vehicle in the first place

Researchers continue to struggle with sub-optimal hydrogen release (releasing only a portion of stored hydrogen) and refueling issues. Many current hydrides would take much more than five minutes to refuel. The chemical processes underlying many hydrides are also quite energy intensive.[20] Hydrides remain a major focus of research.

HYDROGEN SAFETY

Hydrogen has some safety advantages over liquid fuels like gasoline. When a gasoline tank leaks or bursts, the gasoline can pool, creating a risk that any spark would start a fire, or it can splatter, posing a great risk of spreading an existing fire. Hydrogen, however, will escape quickly into the atmosphere as a very diffuse gas. Also, hydrogen gas is non-toxic.

Yet, hydrogen has its own major safety issues. It is a flammable over a wide range of concentrations and its ignition energy is 20 times smaller than that of natural gas or gasoline. It can be ignited by cell phones and "electrical storms several miles away."[21] Hence, leaks pose a significant fire hazard. At the same time, it is one of the most leak-prone of gases. Odorants like sulfur are impractical, in part because they poison fuel cells. [22] Hydrogen burns nearly invisibly, and people have unwittingly stepped into hydrogen flames.[23] Hydrogen can cause many metals, including the carbon steel widely used in gas pipelines, to become brittle, raising the risk of "potentially catastrophic failure of pipelines."[24]

For these reasons, hydrogen is subject to strict and cumbersome codes and standards, especially when used in an enclosed space where a leak might create a growing gas bubble. Dale Simbeck, an expert on hydrogen infrastructure, notes: "Current codes for H2 storage and utilization are onerous. For example, in the United States, the current National Fire Protection Association (NFPA) code 50 A&B for H2 does not allow underground storage, requires large clearances from all combustible materials, and requires massive ventilation to avoid very expensive explosion-proof equipment."[25] Work is ongoing to develop less onerous codes and standards.

Some 22% or more of hydrogen accidents are caused by undetected hydrogen leaks.[26] This "despite the special training, standard operating procedures, protective clothing, electronic flame gas detectors provided to the limited number of hydrogen workers," as Russell Moy, former group leader for energy storage programs at Ford Motors has written. Moy concludes "with this track record, it is difficult to imagine how hydrogen risks can be managed acceptably by the general public when wide-

scale deployment of the safety precautions would be costly and public compliance impossible to ensure."[27] Thus, the critical path for a hydrogen economy must include major innovations in safety.

INFRASTRUCTURE and DELIVERY

A 2002 analysis by Argonne National Laboratory found that "the hydrogen delivery infrastructure to serve 40% of the light duty fleet is likely to cost over $500 billion."[28] We have talked with the Argonne researchers, and believe this study to be more realistic, more inclusive of all costs, than other studies. Argonne achieves its high cost projections even though the study assumes considerable cost and performance gains in a relatively mature technologies, such as a 50% cost reduction in hydrogen compressors.

Some, including General Motors, have proposed that the infrastructure cost could be considerably less, perhaps tens of billions of dollars. These analyses do not seem to be based on any genuine cost modeling, and certainly would require major technological breakthroughs in both hydrogen production and delivery. Many of the fuel providers have been far more cautious in their statements. Bernard Bulkin, Chief Scientist for British Petroleum, has said, "One thing that we know is that if hydrogen is going to make it in the mass market as a transport fuel, it has to be available in 30 to 50% of the retail network from the day the first mass manufactured cars hit the showrooms."[29] That would mean 50,000 to 90,000 newly fitted service stations. And unless hydrogen is generated on-site at those fueling stations, which we believe is impractical (see below), we will also need a massive infrastructure for delivering that hydrogen from wherever it is generated.

Jeroen van der Veer, Royal Dutch/Shell's Vice Chair, said in April 2003, "We estimate that the initial investment required in the US alone to supply just 2% of cars with hydrogen by 2020 is around $20 billion."[30] This suggests that the scenario of serving 30% to 50% of cars would be very costly. And indeed, Shell Hydrogen CEO Donald P.H. Huberts told the House Science Committee in March 2003, "further build-up of the hydrogen infrastructure [beyond 2%] will require hundreds of billions of US dollars."[31]

This raises the chicken-and-egg problem: Who will spend the hundreds of billions of dollars on a wholly new nationwide infrastructure to provide ready access to hydrogen for consumers with fuel-cell vehicles until millions of hydrogen vehicles are on the road? Yet who will manufacture and market such vehicles until the infrastructure is in place to fuel those vehicles? And will car companies and fuel providers be willing to take this chance before knowing whether the public will embrace these cars?

Centralized production of hydrogen is the ultimate goal. A pure hydrogen economy requires that hydrogen be generated from carbon-dioxide-free sources, which would almost certainly require centralized hydrogen production closer to giant wind-farms or at coal/biomass gasification power plants where carbon dioxide is extracted for ultimate sequestration. That will require some way of delivering hydrogen to tens of thousands of local fueling stations.

Tanker trucks carrying liquefied hydrogen are commonly used to deliver hydrogen today. This approach is widely viewed as undesirable for large-scale use because of liquefaction's high energy cost. Also, few automakers are pursuing onboard storage with liquid hydrogen. So after delivery, the fueling station would still have to use an energy-intensive pressurization system. This might mean that storage and transport alone would require some 50% of the energy in the hydrogen delivered, negating any potential energy and environmental benefits from hydrogen.

Pipelines are also used for delivering hydrogen. They may be the least expensive option for delivery of large quantities of hydrogen. Because hydrogen is very diffuse, prone to leaks, and highly reactive (it can embrittle steel), interstate pipelines are estimated to cost $1 million per mile or more. Yet, we have very little idea today what hydrogen-generation processes will win in the marketplace over the next few decades—or whether hydrogen will be able to successfully compete with future high-efficiency vehicles, perhaps running on other low-carbon fuels. This uncertainty makes it unlikely anyone would commit to spending tens of billions of dollars on hydrogen pipelines before there are very high hydrogen flow rates transported by other means, and before the winners and losers in both the production end and the vehicle end of the marketplace have been determined. In short, pipelines are unlikely to be the main hydrogen transport means until the post-2030 period.

Trailers carrying compressed hydrogen canisters are a flexible means of delivery, but they are relatively expensive because hydrogen has such a low energy density. Current tube or canister trailers deliver less than 300 kg of hydrogen to a customer, perhaps enough to fully fill 50 fuel cell cars.[32] One 2003 study by ABB researchers of hydrogen delivery in 5000-psi canisters found that a 40-metric-ton truck would deliver only about 400 kg of hydrogen into onsite high-pressure storage.[33] For a delivery distance of 300 miles, the delivery energy approaches 40% of the usable energy in the hydrogen delivered. Without dramatic improvement in high-pressure storage systems, this approach seems impractical for large-scale hydrogen delivery.

Producing hydrogen on-site at local fueling stations is the strategy advocated by those who want to deploy hydrogen vehicles quickly. The hydrogen would most likely be generated from small methane reformers (since on-site electrolysis would be more expensive and less efficient while generating high amounts of greenhouse gases). This seems viable for limited demonstrations and pilots, but is both impractical and unwise for large scale application for several reasons.

First, the upfront cost is higher. In this scenario, a fueling station would need an SMR system, a hydrogen purification unit, a multi-stage hydrogen compressor, a system to fuel cars, a significant amount of on-site high-pressure storage, and various control equipment. The Argonne study assumed significant advances in small SMRs and compressors over current technology and still found that infrastructure costs for fueling 40% of the vehicles on the road would exceed $700 billion. Studies that find dramatically lower costs all rely on technology not commercial as of 2003 and use cost projections that are very optimistic.

Second, the cost of the delivered hydrogen itself in this option is also higher than for centralized production. Not only are the small SMRs and compressors typically more expensive and less efficient than larger units, but they will likely pay a much higher price for the electricity and gas to run them. One analysis for NREL put the cost $4.40 per kg.

Third, "the risk of stranded investment is significant, since much of an initial compressed hydrogen station infrastructure could not be converted later if either a non-compression hydrogen storage method or liquid fuels such as a gasoline-ethanol combination proved superior for FCVs [fuel-cell vehicles]," as noted by a major 2001 study for the California Fuel-Cell Partnership (CaFCP).[34] Most of the investment would also likely be stranded once the ultimate transition to a pure hydrogen economy was made, since that would almost certainly rely on centralized production and would not make use of small steam methane reformers. Moreover, it's possible the entire investment would be stranded in the scenario where FCVs simply never achieve the combination of popularity, cost, and performance to triumph in the marketplace.

In the CaFCP analysis, it takes 10 years for investment in infrastructure to achieve a positive cash flow, and to achieve this result requires a variety of technology advances in both components and

manufacturing. Also, even a small excise tax on hydrogen (to make up the revenue lost from gasoline taxes) appears to delay positive cash flow indefinitely.[35] The high-risk and long-payback nature of this investment would seem far too great for the vast majority of investors, especially given AFV history. A 2002 analysis of the difficulties faced in commercializing natural gas vehicles (NGVs) concluded: "The largest problem the NGV industry faced in Canada was a stalling in investment in public refueling facilities, which in turn retard [vehicle] conversion sales. Investment in new refueling facilities stalled because existing stations did not build up sufficient load to make them profitable."[36]

Fourth, natural gas is the wrong fuel on which to base a hydrogen-based transportation system:

- The U.S. consumes nearly 23 trillion cubic feet of natural gas today and is projected to consume more than 30 tcf in 2025. Replacing 40% of ground transportation fuels with hydrogen in 2025 would require an *additional* 10 tcf of gas (and 300 billion kWh of electricity—10% of current power usage).[37] Politically, given the firestorm over recent natural gas supply constraints and price spikes, it seems very unlikely the U.S. government and industry would commit to natural gas as a substitute for even a modest fraction of U.S. transportation energy.
- Much if not most incremental U.S. natural gas consumption for transportation would likely come from imported liquefied natural gas (LNG). This raises issues of safety, security, and import dependence, problems which alternative fuels are meant to address.
- Natural gas has too much economic and environmental value to the electric utility, industrial, and buildings sectors to justify diverting significant quantities to the transportation sector. Using natural gas to generate significant quantities of hydrogen for transportation would, for the foreseeable future, undermine efforts to combat global warming (see below).

These points do not mean that we cannot start generating hydrogen from natural gas—most U.S. hydrogen currently comes from natural gas. They do suggest that it would be especially unwise to build hundreds, let alone thousands, of local refueling stations based on steam methane reforming (or, we believe, based on any technology not easily adaptable to delivery of zero-carbon hydrogen).

ALTERNATIVE FUEL VEHICLES

The US government has relevant experience in the area of alternative fuel vehicles (AFVs). The 1992 Energy Policy Act established the goal of having alternative fuels replace at least 10% of petroleum fuels in 2000, and at least 30% in 2010. By 1999, some one million AFVs were on the road, only about 0.4% of all vehicles. In 1998, alternate fuels consumed in AFVs substituted for about 0.3% of that year's total consumption of gasoline. A GAO report explained the reasons for the lack of success:

> The goals in the act for fuel replacement are not being met principally because alternative fuel vehicles have significant economic disadvantages compared to conventional gasoline vehicles. Fundamental economic impediments—such as *the relatively low price of gasoline, the lack of refueling stations for alternative fuels, and the additional cost to purchase these vehicles*—explain much of why both mandated fleets and the general public are disinclined to acquire alternative fuel vehicles and use alternative fuels.[38]

It seems likely that all three of these problems will hinder FCVs. Compared to other alternative fuels (such as ethanol and natural gas), the best analysis today suggests hydrogen will have a much higher price for the fuel, the fueling stations, and the vehicles.

Can we address the high cost of fuel-cell vehicles by somehow finding extra economic value in those vehicles when they are not being used, thereby reducing their initial cost and accelerating market

introduction? Many analysts have proposed plugging parked fuel cell cars into the grid to generate power, so the transportation fuel-cell would do double duty as a stationary fuel-cell.

Yet, generating electricity with a car's low-temperature fuel cell using that reformed gas would cost $0.19 per kWh, according to a 2001 study.[39] The process also produces 50% more carbon dioxide emissions than the best natural gas conversion technology in use today.[40] For the relatively small amounts of hydrogen that a fuel-cell car would need, delivering hydrogen is likely to be prohibitively expensive per kilogram. Yet, it would probably be even more expensive to generate hydrogen onsite (for instance, at home).

Finally, transportation fuel cells are typically being designed for about 4000 hours of use, a factor of 10 less than typical power plants. Meeting the cost and performance targets for PEM cars will probably prove so difficult that we can't expect the same hardware being able to meet the performance characteristics of a power plant. General Motors itself said in October that it does not see PEM cars as a source of continuous power.[41] In general, we don't think that home electricity generation with either a stationary or mobile fuel-cell will provide synergistic cost savings that can jumpstart commercialization.

ENVIRONMENTAL, RESOURCE, and COMPETITIVE ISSUES

Alternative fuels and vehicles are typically proposed to address two issues: Air pollution and oil import dependency. Analysis suggests that fuel-cell vehicles (FCVs) will provide costlier solutions to these problems than competing strategies and technologies.

Air pollution is a major national and global problem**.** Consider greenhouse gases (GHGs). For near-term deployment, hydrogen would be produced from natural gas at local fueling stations. This has three GHG impacts. First, the fuel delivery chain entails small leaks of methane, a potent GHG. Second, the reforming process produces carbon dioxide. Third, compressing hydrogen, the likely near-term approach for onboard storage, requires significant electricity, again generating significant GHGs. An analysis by MIT in 2003 concluded that a diesel hybrid in 2020 would have GHGs that were more than 10% *below* those of a 2020 FCV running on gas-derived hydrogen; the technology advances required for diesels will be able to meet air quality requirements in 2020 are considerably less daunting than the multiple breakthroughs required to enable practical hydrogen cars in that timeframe Also, such a future FCV running on gas-derived hydrogen would offer little life-cycle GHG advantage over the new Prius.[42]

Further, FCVs are likely to be much more expensive than other vehicles, and their fuel is likely to be more expensive (and the initial hydrogen infrastructure could cost $5000 per car).[43] While hybrids and clean diesels may cost more than current vehicles, at least when first introduced, their greater efficiency means that, unlike FCVs, they may pay for most if not all of that extra upfront cost over the lifetime of the vehicle. A June 2003 analysis in *Science* magazine put the cost of carbon dioxide avoided by fuel cells running on zero-carbon hydrogen at more than $250 per ton even with fuel-cell costs at the optimistic price of $60 per kW.[44] An advanced internal combustion engine could reduce GHGs for far less and possibly for a net savings because of the reduced fuel bill.

Also, any natural gas used to make hydrogen must be diverted from other uses. The life-cycle or "well-to-wheels" efficiency of a FCV running on gas-derived hydrogen is likely to be 25% to 35%.[45] The efficiency of gas-fired power plants is already 55% (and likely to be 60% or more in 2020). Cogeneration is over 80% efficient. For this reason, natural gas is far more cost-effectively used to reduce GHGs in electric generation than it is in transportation.

Similar analysis has been done for renewable energy. A November 2002 study calculated that a megawatt-hour of electricity from renewables, if used to manufacture hydrogen for use in a fuel-cell vehicle, would save slightly under 500 pounds of carbon dioxide.[46] That is less than the savings from displacing a future combined cycle gas plant, and far less than the savings from displacing coal power. In other words, until we have an excess of renewable energy on the grid, renewables are far more efficiently and cost-effectively used to directly displace fossil fuel power plants than to make hydrogen for cars to displace oil consumption, from the perspective of reducing GHGs. As the 2003 *Science* analysis concluded: "Until CO_2 emissions from electricity generation are virtually eliminated, it will be far more cost-effective to use new CO_2-neutral electricity (such as wind) to reduce emissions by substituting for fossil-electric generation than to use the new electricity to make hydrogen."[47] It seems unlikely our electric grid will be close to carbon free before 2050.

As for urban air pollution, the 2003 analysis by Keith and Farrell estimates that FCVs would reduce oxides of nitrogen at a cost 100 to 500 times greater than current strategies.[48] New vehicles and fuels being introduced this decade as a result of state and federal environmental regulations will be exceedingly clean. The PZEVs (partial zero emission vehicles) that are being introduced into the California market will, when coupled with low-sulfur gasoline, have emissions cleaner than L.A. air with a projected incremental cost of a few hundred dollars per vehicle.[49] Assuming PZEVs and low-sulfur gasoline become widespread nationally, the incremental benefit to urban air pollution emission reductions from future FCVs are unlikely to be cost-effective compared to other strategies such as scrapping or fixing old, dirty cars or cleaning up power plants and large off-road vehicles.

Dependence on imported oil is an issue that has stimulated significant political concern in the past two decades but little concrete action. Again, hydrogen FCVs are not an attractive near- or medium-term option for reducing oil imports because other advanced vehicles using existing liquid fuels can achieve reductions in oil consumption far more cost-effectively. In the long-term, hydrogen will have to compete with biofuels and electricity as replacements for oil. It is impossible to judge today what alternative fuel will be most cost-effective post-2030, so all should be vigorously pursued.

The notion that hydrogen FCVs represent some sort of a pure techno-fix that can deliver national benefits (such as reduced oil imports) without the kind of government intervention that now appears politically unattractive (such as CAFE) is mistaken. FCVs may well have few private benefits compared to other advanced vehicles and instead have many disadvantages (higher first cost, higher fueling cost, limited range, limited refueling options, safety concerns). Thus we would expect that greater government regulatory intervention would be required to accelerate their penetration into the marketplace compared to other advanced vehicles and fuels with fewer disadvantages.

HYDROGEN PARTNERSHIPS AND PILOTS

Because any transition to a hydrogen economy would be very complex and involve multiple stakeholders, a number of partnerships have been created to launch hydrogen pilots around the world. Two of the most important are in Iceland and California.

Iceland is the country poised to become the world's first hydrogen economy.[50] Iceland may be better suited to a near-term hydrogen transition than any other country because it has excess renewable energy, deriving virtually all of its electricity and space heating from hydropower and geothermal energy. Also, Iceland is practically a city-state with about 62% of the population living in or around the capital city of Reykjavik. A hydrogen infrastructure can be established at relatively low cost—a few fueling stations in Reykjavik and on the roads around the island could easily serve most of the

needs of the population of 280,000. In 1999, a group of stakeholders formed what is now Icelandic New Energy Ltd. Iceland's partners include Shell, DaimlerChrysler, and Norsk Hydro.

This consortium has begun to pioneer a multi-stage hydrogen transition in Iceland. A hydrogen fueling station was opened in April 2003, and three fuel cell buses, 4% of the city's bus fleet, are being introduced into Reykjavik. The goal is ultimately to replace the fishing fleet with fuel-cell vessels and the private transportation fleet with FCVs by 2040 if feasible.

California has the leading U.S. pilot program for hydrogen.[51] At the center is the California Fuel Cell Partnership, whose Its 30 members include most major automakers, a number of energy companies (BP, ChevronTexaco, ExxonMobil, and Shell), and several key government agencies. It was formed in 1999 to foster coordinated development and real-world testing of fuel-cell vehicles.

By mid-2003, partnership members had helped put three dozen fuel cell vehicles on the road in California and dozens more were scheduled to be added in subsequent months. To begin servicing them, eight hydrogen fueling stations dotted the state from Los Angeles to Sacramento. In July 2003, Dr. Woody Clark, an advisor to the California Governor's Office, announced a plan to establish a "Hydrogen Freeway" that would provide hydrogen refueling stations up and down the state.

CONCLUSION AND RECOMMENDATIONS

Stationary fuel cells could well become a major marketplace success post-2010, particularly if solid oxide fuel cells achieve their cost and performance goals. Hydrogen and fuel-cell vehicles should be viewed as post-2030 technologies. Hydrogen vehicles are probably a post-2050 greenhouse gas mitigation strategy, barring a dramatic acceleration in U.S. adoption of zero-carbon electric generation. Given these conclusions, we have a number of recommendations:

Begin a major national effort to encourage combined heat and power (CHP). To enable a hydrogen economy, we will first need a stationary fuel-cell economy. The biggest potential market for stationary fuel cells is on-site cogeneration or CHP, which also represents one of the lowest cost strategies for reducing GHG emissions. Unfortunately, the barriers to rapid growth in CHP remain high. A number of studies have proposed policies to reduce those barriers, such as the July 2000 NREL report, *Making connections*, and they should be aggressively pursued.[52] At that point, fuel cells will still have to compete with the myriad other CHP technologies, such as gas turbines, which will require meeting aggressive cost and performance targets.

Take a long-term, conservative perspective on hydrogen. Over-hyping the potential of hydrogen vehicles will not bring them to the market sooner. More likely it will create a backlash that will slow their ultimate market success. Hydrogen analysis should be conservative in nature, stating clearly what is technologically and commercially possible today, and, when discussing the future, be equally clear that projections are speculative and will require both technology breakthroughs and major government intervention in the marketplace. Analysis should treat the likely competition fairly: If major advances in cost reduction and performance are projected for hydrogen technologies, similar advances should be projected for hybrids, biofuels, and the like. If hydrogen is presented as a solution to problems such as global warming, projected costs should be compared to the likely competition.

Continue R&D into hydrogen and fuel-cell vehicles. While hydrogen vehicles are clearly a long-term solution, the limited options available for reducing oil consumption in the transportation sector necessitate pursuing all potentially viable options. This is especially true given estimates by groups like Britain's Royal Commission on Environmental Pollution that found that the world will need to

reduce GHGs by more than 50% in the second half of this century.[53] We do need pilot projects to gain practical experience with hydrogen-powered vehicles, but pilots should be focused less on trying to speed early deployment of large numbers of fuel-cell vehicles and more on trying to answer key questions about storage, infrastructure, safety, and the like.

[1]Writing about the future prospects of hydrogen is necessarily speculative, since it involves a variety of different technologies that are not a commercial today and may never become commercial. Our conclusions are based on discussions with some one hundred experts and a review of dozens of major recent studies.
[2]Significantly, fuel cells typically have higher efficiencies at lower power, so hybridizing a fuel-cell vehicle (by adding a battery) does not improve its efficiency as much as hybridizing an internal combustion engine. General Motors has said it does not see hybridizing a fuel-cell vehicle as a strategy worth pursuing, but Toyota does.
[3]Chester Dawson, "Fuel Cells: Japan's Carmakers Are Flooring It," *Business Week*, December 23, 2002, p. 50.
[4]Arthur D. Little (ADL), *Guidance for Transportation Technologies: Fuel Choice for Fuel-cell Vehicles, Final Report*, Phase II Final Deliverable to DOE, 35340-00, Cambridge, MA, February, 2002, Appendix, p. 107, p. 31.
[5]R. Brent Alderfer et al., *Making connections: Case studies of interconnection barriers and their impact on distributed power projects*, National Renewable Energy Laboratory (NREL), Golden, CO, July 2000.
[6]The hydrogen facts in this section are from DOE, *Proceedings National Hydrogen Energy Roadmap Workshop Washington, DC, April 2-3, 2002*; "Frequently Asked Questions" provided by DOE's hydrogen program (www.eere.energy.gov); and "Hydrogen Production Processes," DOE's Office of Fossil Energy web site (www.fe.doe.gov).
[7]Stacy Davis and Susan Diegel, *Transportation Energy Data Book*, Edition 22, ORNL, Oak Ridge, TN, 2002, p. B-1. Hereafter ORNL, *TEDB*.
[8]Energy Information Administration (EIA), *Annual Energy Outlook 2003*, January 2003, Washington DC.
[9]Natural gas isn't pure methane, but rather a naturally occurring mixture of gases, primarily (about 95%) methane, but also including a variety of other gases that vary by region.
[10]Dale Simbeck and Elaine Chang, "Hydrogen Supply: Cost Estimate for Hydrogen Pathways – Scoping Analysis," developed for the National Renewable Energy Laboratory (NREL) by SFA Pacific, Inc., July 2002. Simbeck and Chang, use a natural gas price of $3.50/million Btu for centralized production, and $6/million Btu for onsite production at a fueling station.
Many analyses assume that the total delivered cost for hydrogen need be reduced only to a level at which it is twice that of gasoline (for an equivalent amount of energy delivered). They argue that hydrogen fuel cells will be over twice as efficient as gasoline internal combustion engines, so the fuel can be twice as expensive and consumers will still end up paying the same total fuel bill. But that is comparing a future technology with a current technology—and not even the best current technology. The best hybrids *today* are twice as efficient as traditional internal combustion engine vehicles and perhaps only 25% to 35% less efficient than *projected* fuel cell vehicles (assuming fuel cells achieve their performance targets). A hybrid diesel-electric vehicle would have about the same overall efficiency as a fuel cell vehicle. DOE's stated program goal is for hydrogen to compete with untaxed gasoline, which we believe is an appropriate goal from a marketplace perspective, though many experts we spoke to believe it is unattainable.
[11]This is true even assuming fuel-cell vehicles are twice as efficient as internal combustion engine vehicles.
[12]FutureGen Fact Sheet, U.S. Department of Energy, Office of Fossil Energy, February 2003.
[13]Spath et al, "Update of Hydrogen from Biomass," NREL, Golden, CO, April 2000, revised July 2001.
[14]Barry C. Lynn, "Hydrogen's Dirty Secret," *Mother Jones*, May/June 2003.
[15]*Fuel Cell Report to Congress* (ESECS EE-1973), DOE, February 2003, Washington, DC.
[16]Ulf Bossel and Baldur Eliasson, "Energy and the Hydrogen Economy," ABB Switzerland, January 2003, and personal communications with Raymond Drnevich.
[17]George Thomas and Jay Keller, "Hydrogen Storage—Overview," presentation to H2 Delivery and Infrastructure Workshop, Washington, DC, May 2003.
Fuel cell vehicle may be twice as fuel efficient as internal combustion engine vehicles, so they have twice the range for fuel with an equivalent amount of energy. To the extent that the competition in 2020 and beyond is hybrid gasoline or hybrid diesels, though, fuel-cell vehicles will have a serious range disadvantage. The 2004 Prius has a range of 500 to 600 miles, roughly double that of comparable midsize cars today.
[18]JoAnn Milliken, "Hydrogen Storage Activities Under the Freedom Car & Fuel Initiative," U.S. DOE, Presentation to the National Hydrogen Association Meeting, March 5, 2003, and Raymond Drnevich,

"Hydrogen Delivery: Liquefaction & Compression," presentation to H2 Delivery and Infrastructure Workshop, Washington, DC, May 2003. A technology breakthrough could lower the liquefaction energy penalty, but it seems exceedingly unlikely to us that liquefaction will ever be a viable wide-scale approach.
[19]Michael Valenti, "Fill'er up—with hydrogen," *Mechanical Engineering*, February 2002. See also Thomas and Keller, who describes a metal hydride system carrying 3.2 kg of hydrogen and weighing 320 kg.
[20]James J. Eberhardt, "Fuels of the Future for Cars and Trucks," presentation to 2002 Diesel Engine Emissions, Reduction (DEER) Workshop, San Diego, CA, August, 2002.
[21]James Hansel, "Safety Considerations for Handling Hydrogen," a seminar for presentation to Ford Motor Company, Air Products and Chemicals, Inc., Allentown, PA, June 12, 1998,
[22]Jim Campbell, "Hydrogen Delivery Technologies and Systems: Pipeline Transmission of Hydrogen," presentation to H2 Delivery and Infrastructure Workshop, Washington, DC, May. Moreover, even if practical odorants could be found, they would be highly unlikely to leak and diffuse in tandem with hydrogen, the tiniest and lightest of all molecules.
[23]"Hydrogen Material Safety Data Sheet," in Hansel.
[24]Campbell, "Hydrogen Delivery Technologies."
[25]Dale Simbeck, "CO2 Capture and Storage—The Essential Bridge to the Hydrogen Economy," presented at the 6th International Conference on Greenhouse Gas Control Technologies (GHGT-6), October 1-4, 2002, Kyoto, Japan, SFA Pacific, Inc., Mountain View, CA.
[26]The 22% figure comes from Russell Moy, "Tort Law Considerations for the Hydrogen Economy," *Energy Law Journal*, November 2003. Hansel, "Safety Considerations," uses a 40% figure.
[27]Moy, "Tort Law." See also Russell Moy, "Liability and the Hydrogen Economy," *Science*, Vol. 31, July 4 2003, p. 47.
[28]Marianne Mintz et al., "Cost of Some Hydrogen Fuel Infrastructure Options," Presentation to the Transportation Research Board, January 16, 2002 by Argonne National Laboratory.
[29] Bernard Bulkin, speech to National Hydrogen Association annual conference, Washington, DC, March 2003.
[30]Jeroen van der Veer, "Hydrogen—fuel of the future," Remarks at Iceland Hydrogen Economy Conference, 24 April, 2003.
[31]Donald Huberts, "The Path to a Hydrogen Economy," testimony to the House Science Committee, March 5, 2003.
[32]Drnevich, "Hydrogen Delivery."
[33]Bossel and Eliasson, 2003. The same size truck carrying gasoline delivers some 26 metric tons of fuel (10,000 gallons), enough to fill perhaps 800 cars.
[34]California Fuel-cell Partnership (CaFCP), *Bringing Fuel-Cell Vehicles To Market: Scenarios And Challenges With Fuel Alternatives*, prepared by Bevilacua Knight, Inc., 2001 (hereafter CaFCP 2001), p. 4-23
[35]CaFCP 2001, p. 4-24.
[36]Peter Flynn, "Commercializing an Alternate Vehicle Fuel: Lessons Learned From Natural Gas For Vehicles, *Energy Policy*, Vol. 30, 2002, pp. 613–619.
[37]EIA, AEO 2003. This assumes double efficiency for FCVs, 70% of efficiency of SMRs, and high-pressure on-board storage.
[38]US General Accounting Office, *Energy Policy Act of 1992: Limited Progress in Acquiring Alternative Fuel Vehicles and Reaching Fuel Goals,* GAO/RCED-00-59, Washington DC, February 2000.
[39]Willett Kempton et al., "Vehicle-to-Grid Power: Battery, Hybrid, and Fuel Cell Vehicles as Resources for Distributed Electric Power in California," prepared for: California Air Resources Board, California Environmental Protection Agency, and Los Angeles Department of Water and Power, June 2001.
[40]While most homes could probably find productive use for the heat from a one-kilowatt fuel cell, a car will probably have a 60- to 80-kilowatt fuel cell. This means that the overall system efficiency might be 35%. Also, some way of disposing of the waste heat will need to be found (and if that requires air conditioning, as some recent fuel cell demonstrations have, system efficiency will be further lowered).
[41]Keith Cole (director, Legislative and Regulatory Affairs, GM), "GM: Sustainable Mobility," Presentation to Fuel-cell Policy Roundtable, Dirksen Senate Office Building, Washington, DC, October 1, 2003,.
[42]Malcolm Weiss et al, "Comparative Assessment of Fuel-cell Cars," Massachusetts Institute of Technology (MIT), Cambridge, MA, 2003 (http://lfee.mit.edu/publications/PDF/LFEE_2003-001_RP.pdf). The conclusion about the Prius is based on analysis by CECS.

[43]Consider Shell's numbers from Jeroen van der Veer, "Hydrogen—fuel of the future," Remarks at Iceland Hydrogen Economy Conference, 24 April, 2003: "We estimate that the initial investment required in the US alone to supply just 2% of cars with hydrogen by 2020 is around $20 billion." That means infrastructure for some 4 million cars and light trucks (ORNL, *TEDB*) will cost $20 billion, yielding $5000 per car.
[44]David Keith and Alexander Farrell, "Rethinking Hydrogen Cars," *Science*, Vol. 301, July 18, 2003, pp. 315-316.
[45]Gas from LNG has a further energy penalty of about 15%. *Strategic Study of Household Energy and Greenhouse Issues*, Prepared by Sustainable Solutions Pty Ltd for the Australian Greenhouse Office, June 1998.
[46]Nick Eyre et al., "Fuelling Road Transport," Report by the Energy Saving Trust (London), the Institute for European Environmental Policy (London), and National Society for Clean Air and Environmental Protection (Brighton), November 2002, pp. 35-38.
[47]Keith and Farrell, "Rethinking Hydrogen Cars."
[48]Keith and Farrell. A related issue is that if the hydrogen delivery process requires any significant amount of power from the U.S. electric grid, such as for hydrogen compression, then certain emissions, such as particulates, could actually increase with FCVs compared to gasoline engines.
[49]James Healey, "One of these cars is an environmentalist's dream," *USA Today*, September 16, 2003.
[50]The Iceland discussion is based on Jon Skúlason and Helgi Bjarnason, "Hydrogen Developments: Case of Iceland," presentation to IEA/OECD, March 2003; *Iceland's Third National Communication under the United Nations Framework Convention on Climate Change*, Icelandic Ministry for the Environment, April 2003; *Transition to a Hydrogen Economy— a strategy for sustainable development in Iceland,* World Wildlife Fund (WWF) International and Iceland Nature Conservation Association, April 2001; and *Welfare for the Future: Iceland's National Strategy for Sustainable Development 2002-2020,* Icelandic Ministry for the Environment
[51]The California discussion is based on Alan Lloyd, "The Path to a Hydrogen Economy," Testimony submitted to The Committee on Science Of the U.S. House of Representatives, Washington, DC., March 5, 2003 (www.house.gov/science/hearings/full03/mar05/lloyd.htm); Poul Erik Bak, "California to Establish 'Hydrogen Freeway," *h2cars.biz*, July 29, 2003 (www.h2cars.biz/artman/publish/article_208.shtml); and information available at the California Fuel Cell Partnership website (www.cafcp.org).
[52]Alderfer et al., *Making connections*.
[53]Royal Commission on Environmental Pollution, *Energy – The Changing Climate*, Report to Parliament, June 2000.

CELLULOSIC ETHANOL FACT SHEET

National Commission on Energy Policy Forum:
The Future of Biomass and Transportation Fuels

June 13, 2003
Washington, DC

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I. RAW MATERIALS (FEEDSTOCKS)

Biomass. Plant matter of recent (non geologic) origin or materials derived therefrom.

Cellulosic biomass. Biomass composed primarily of plant fibers that are inedible by humans and have cellulose as a prominent component. These fibers may be hydrolyzed to yield a variety of sugars that can be fermented by microorganisms. Examples of cellulosic biomass include grass, wood, and cellulose-rich residues resulting from agriculture or the forest products industry. At a representative price of $40/dry ton, cellulosic biomass costs the same per BTU asoil at $13/barrel.

Cellulosic biomass may be available as either:

Residues - biomass resulting from activities or processes undertaken for some purpose other than ethanol production. Examples of such residues include corn stalks and other non-edible parts of plants used to produce food, municipal solid waste, and pulp and paper industry wastes.

Dedicated crops – crops grown for the primary purpose of energy production. Examples of potential dedicated crops for producing cellulosic biomass include grass and short rotation trees.

Comparison of ethanol production from corn and cellulosic biomass. Corn* is easier, and currently less expensive, to process into ethanol than is cellulosic biomass. However, cellulosic biomass is less expensive to produce than corn by a factor of roughly 2 on a per ton basis, and the amount of ethanol that can be produced per acre of land of a given quality is

* The discussion of "corn" here concerns corn kernels, which are currently used for ethanol production and represent about half the above-ground dry matter of a corn plant at harvest time.

higher for cellulosic biomass than for to corn. Relative to corn, production of a perennial cellulosic biomass crop such as switchgrass requires lower inputs of energy, fertilizer, pesticide, and herbicide, and is accompanied by less erosion and improved soil fertility. Finally, cellulosic biomass differs from corn kernels in that it contains substantial amounts of non-fermentable, energy-rich components that can be used to provide energy for the conversion process as well as to produce electricity (see discussion of energy balance below). Process energy for corn ethanol production is typically provided by coal or natural gas, although it would be possible for process energy to be provided by biomass in the future.

The chemical composition of ethanol produced from corn and lignocellulose is identical. However, ethanol production and utilization cycles are different when cellulosic biomass is used as the raw material as a direct result of the features mentioned in the preceding paragraph. Key aggregate characteristics impacted by these features in addition to feedstock cost include process energy balance and greenhouse gas emissions. For ethanol production from corn based on current practice, fossil energy inputs into the production cycle represent about 2/3 of the energy content of the ethanol produced, and greenhouse gas emissions on a per mile basis are about 2/3 of a gasoline base case, representing an approximately 33% reduction. For ethanol produced from cellulosic biomass, the energy balance and greenhouse gas emissions are more favorable, as considered below (Section III).

II. PRODUCTS & PROCESSES

Ethanol and fuel utility. Ethanol is a two-carbon alcohol (C_2H_6O), which is a high performance fuel for use in spark-ignited internal combustions engines. The warrantees of all new cars sold in the United States cover use of 10% ethanol/90% gasoline blends. In addition, the capability to utilize ethanol and gasoline in any ratio up to 85% ethanol is established in over 2 million "fuel-flexible vehicles" on the road today at no incremental cost to consumers. Since a gallon of ethanol contains about 2/3 the energy of a gallon of gasoline, a larger fuel tank is required to achieve a given travel radius when using ethanol-rich fuels. Ethanol can be reformed to hydrogen, either at the point of fuel delivery or on-board the vehicle, which can subsequently be used in a fuel cell. Both reformers and fuel cells are not now commercially available.

Current commercial status and cost of production. About 2.1 billion gallons of ethanol are produced annually from corn in the United States today. This may be compared to current yearly gasoline consumption of 131 billion gallons, which is equivalent to 164 to 196 billion gallons of ethanol (depending on how it used). Consumption of liquid fuels for heavy duty vehicles is about a third of gasoline consumption with air travel accounting for a smaller additional fraction. Fuel ethanol sells in the United States for about $1.20/gallon ($1.50 to $1.80 on a gasoline-equivalent basis), which may be compared to wholesale gasoline prices of about $0.75/gallon.

About half of current ethanol production capacity is associated with wet mills, which are integrated facilities producing a range of products in addition to ethanol such as sweeteners, corn gluten meal, gluten feed, starch, and, increasingly, additional biologically-produced products such as feed supplements. The remainder of production capacity, and most of

recently-added capacity, is in dry mills. Dry mills are typically smaller than wet mills, and produce ethanol and a single animal feed coproduct (distiller's dried grains).

There are no commercial plants producing ethanol from cellulosic biomass in the world, although celllulosic ethanol has been produced during war time by processes featuring acid hydrolysis. Several commercial ventures have been proposed involving selling ethanol produced from cellulosic biomass into existing chemical or fuels markets, suggesting that cost-competitive production of ethanol from cellulosic biomass in these markets, although not bulk fuel markets, is within reach today. Funding for such ventures has however not been secured to date.

Conversion technology. Steps involved in producing ethanol from cellulosic biomass involve an activation step, biological conversion, product recovery (typically via distillation), and residue processing and utilities. Activation involves converting recalcitrant cellulosic biomass into reactive intermediates, and may be accomplished via either pretreatment & enzymatic hydrolysis, acid hydrolysis, or gasification. Of these alternatives, the lowest future costs have been projected pretreatment and enzymatic hydrolysis. Process design studies consistently indicate that steps associated with overcoming the recalcitrance of cellulosic biomass are the most costly, involve the greatest technical risk, and have the largest potential for R&D-driven cost reduction. A considerable literature exists in which specific R&D advances are analyzed with respect to potential for cost reductions and probability of success.

III. EVALUATION & IMPLICATIONS

Energy balance considerations. The ratio of energy output to fossil energy input is favorable (> 4) for production of cellulosic ethanol, and can be expected to improve further as the technology matures. Fossil energy inputs for production and delivery of cellulosic energy crops are modest, e.g. estimated at about 5% of the energy content of the feedstock for switchgrass production, and inputs for waste cellulosic feedstocks are potentially lower still. The energy content of unfermentable process residues is greater than the energy than required for conversion to ethanol in the current designs, with the excess representing an attractive source of electrical power. The combined energy yield of ethanol and power is over 50% of the energy content of cellulosic biomass for current designs.

Greenhouse gas emissions. The photosynthetic production of biomass removes from the atmosphere the same amount of CO_2 that is returned upon conversion and utilization. The extent to which the ideal of a sustainable carbon cycle (zero net greenhouse gas emissions) is approached depends on the fossil energy inputs required used in the feedstock production/conversion/utilization cycle. Since such inputs are very low in the case of cellulosic ethanol (above), net greenhouse gas emissions are also very low. Several detailed life cycle studies have concluded that greenhouse gas emissions accompanying use of cellulosic ethanol are less than 10% accompanying use of gasoline, and zero or negative net greenhouse gas emissions have been estimated for some scenarios.

Additional environmental implications. Agricultural production of cellulosic biomass is widely thought to entail decreased environmental impacts and some significant environmental benefits as compared to production of row crops. Rates of erosion are exceedingly low for perennial grasses, and field data and models indicate that soil organic matter and fertility increase over time under grass cultivation even with regular harvest. Nutrient capture rates are very high due to the extensive root system of perennial grasses, with loss of nutrients to water sources corresponding low. Anticipated rates of pesticide and herbicide application are much lower for energy crops than for row crops. Elements removed from the soil as part of harvesting biomass must be replenished by additives to the soil, but there is potential to recycle such elements from the processing facility back to the field. Several studies associate conversion of cropland from row crops to perennial grasses with improved water quality, fertility, and wildlife habitat. Effluents from biomass processing facilities are amenable to conventional treatment technologies and are not expected to present a significant burden on the environment if managed responsibly.

Land availability. There are 1.9 billion acres of land in the contiguous United States, of which about 450 million acres is categorized as cropland and an additional 580 million acres is categorized as range or pasture. These categories exclude forestland used for commercial forestry or parks/nature preserves. Most agricultural, pasture, and range land is in use today for food production today, with about 90% of agricultural output going to feed animals and 10% going to feed humans directly. About 30 million acres of cropland has been placed into the Conservation Reserve Program, primarily motivated by a desire to prevent erosion due to row crop production on sensitive sites. Most of the land in the CRP is planted in perennial grasses. Widely-divergent estimates have been made as to the potential availability of biomass on a scale sufficient to provide for large-scale energy needs.

IV. GOVERNMENTAL SUPPORT & INCENTIVES

Current support for research and development. Federal funding for bioenergy (fuels and power) has been estimated at $150 million annually. Of this, about $48 million is spent on biomass-based fuels, including but not restricted to ethanol, with the largest expenditures by the DOE followed by the USDA. The annual renewable energy appropriation is among the most heavily earmarked of all appropriation bills, with net DOE funding after earmarks for biomass-derived fuels and power having decreased annually since 2000. In the area of bioenergy and biobased industrial products, which includes a variety of raw materials not limited to cellulosic feedstocks and a variety of products not limited to fuels, the combined DOE and USDA funding request for FY04 is 36% smaller than the FY03 appropriation.

Tax incentives and other legislation. The effective price of ethanol for use in low-level gasoline blends is lowered by 54 cents per gallon by federal tax incentives, with additional state incentives available in some locations. The Senate recently voted to incorporate a Renewable Fuels Standard (RFS) into the Senate Energy Bill (S.14). Among other provisions, the RFS would require renewable fuel production at the level of 5 billion gallons by 2012. Amendments to S.14 that would provide extra credit for production of ethanol produced from cellulosic materials have been proposed.

The Role of Biomass in America's Energy Future*
December 2004

Project led by Dartmouth College and the Natural Resources Defense Council, with sponsorship by the U.S. Department of Energy, the Energy Foundation, and the National Commission on Energy Policy.

* Report available on National Commission on Energy Policy website: www.energycommission.org

November 8, 2004

Memorandum

From: Charles Mann
To: National Commission on Energy Policy
Subject: Ethanol from Biomass

The following memorandum was prepared at the request of the National Commission on Energy Policy (NCEP). Its purpose is to provide a non-technical background and explanation in support of Section IV.F (Non-petroleum Transportation Fuels) of the NCEP report. This paper draws heavily upon the work of an NCEP-sponsored research effort called "The Role of Biomass in America's Energy Future," with reference to additional sources but was developed independently and differs in a few respects from that report.

1.0 Introduction

Ethanol (ordinary alcohol) is one of the most promising forms of domestically produced liquid fuel and of renewable energy. Despite an extensive subsidy program, described below, little progress is being made toward producing ethanol sufficiently cheaply and in quantities that could displace a meaningful portion of imported oil. This paper describes what might be done to achieve economical production in the US of fuel ethanol from inexpensive plant 'biomass' (not corn) as a large-scale substitute for gasoline derived from imported oil[1].

This paper considers the feasibility of producing ethanol from plant materials at a cost that would be similar to gasoline and in quantities large enough to replace a significant portion of gasoline over time. The paper recommends policies that would be necessary to achieve this goal. This paper deals only with the question of producing ethanol from the cellulose in bulk plant material – 'cellulosic ethanol'. Fortunately, the technology is already known for the transportation, storage, distribution and use of ethanol in large quantities in conventional automobile engines[2].

One of the largest renewable energy programs sponsored by the US government is the subsidized production of ethanol from corn. This ethanol is blended into gasoline and helps to reduce the pollution from automobiles. Currently, in addition to the requirement that some ethanol be blended into gasoline, a subsidy of approximately $0.51 per gallon is offered to producers of ethanol[3]. Last year about 3 billion gallons of ethanol was produced (equivalent to about 2% of current US gasoline consumption)[4]. Based on this production level, the Federal government paid around $1.5B in subsidies for this ethanol and has paid similar amounts over the last several years.

While the cost of producing ethanol from corn has been reduced over the last decade, there is no realistic prospect that corn-based ethanol could ever be cost competitive with gasoline or produced in quantities large enough to make a real difference in oil imports.

At present it costs about $1.40 gal to produce ethanol (on an equivalent gallon basis)[5] compared to gasoline which had an average wholesale price of $ 0.60 gal over the decade ending in 2001, and is projected by the US Energy Information Agency to be in the range of $0.71-$0.96 per gallon[6].

The ethanol subsidy program has been beneficial to farmers (about 7% of US corn production is used to produce ethanol) and ethanol producers but is of very little value to address broader energy policy concerns.

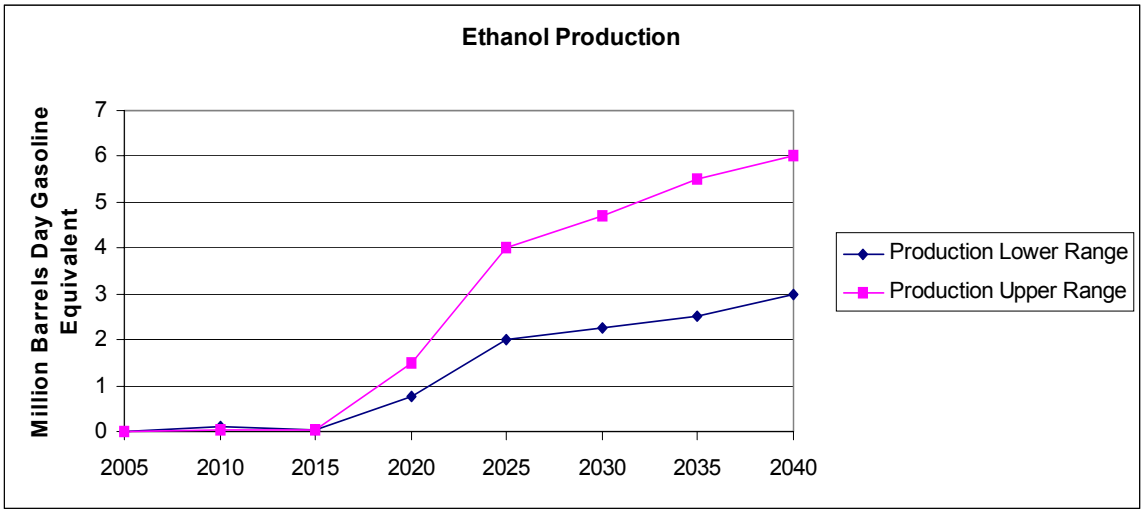
Cellulosic ethanol is an attractive energy alternative because its use improves oil security and reduces the risks of global climate change. Ethanol can be produced on American farms and directly replace gasoline within the existing gasoline distribution-auto technology system. Cellulosic -based ethanol could be produced and used with approximately zero net emissions of CO2[7]. The question is: how much can be made and how cheaply?

There is substantial skepticism about the feasibility of a large-scale program for cellulosic-based ethanol. It arises from two sources. First, Federal energy researchers and some private companies that have tried to produce commercial cellulosic -based ethanol have made promises of early success – and failed to produce. Second, there is doubt about the availability of sufficient land to grow enough 'energy crops' to make a difference, without disturbing current farm and forest production. The political result is that a small and scattered Federally-funded research effort continues. Perhaps partly as a result of the lack of confidence in the ultimate results, this research program has been exceptionally subject to shifts in direction and to congressional 'earmarks' that divert a large fraction of a small pool of money[8].

The National Commission on Energy Policy has co-sponsored and participated in a substantial technical and policy review of the feasibility of producing large quantities of cellulosic -based ethanol at costs competitive with gasoline. Based on this research and other sources one may conclude that:

- There is a high probability that the costs of producing ethanol could be reduced to a level similar to the price of gasoline[9].
- There is sufficient crop land, and some waste raw materials, available to produce a large quantity of ethanol, possibly as much as the equivalent of 50% of current US gasoline consumption. This contrasts with the limited potential production of corn-based ethanol.
- National ethanol production from energy crops and wastes could achieve production in the range of the equivalent of 2-4 million barrels per day of gasoline by 2025, as illustrated in Table 1. The lower range of production would result from a combination of higher production costs and limited land availability wherein only the best-situated producers could compete. The higher range of production would be determined by land availability and assumes that many facilities would be able to attain the combination of feedstock costs, scale, and processing efficiency necessary to compete with gasoline.

Figure 1
Projected Range of Potential Cellulosic Ethanol Production
Resulting from Proposed Program



- Ethanol production in the range of 2 million barrels per day of oil equivalent would reduce oil imports by 20% compared to today's level and produce approximately one half million farming, manufacturing and related jobs[10].
- Achieving economical ethanol production on this scale would have very significant benefits for the economy and security of the US, including reduced oil imports (and prices), increases in US employment, and reduced pollution, especially including reduced emissions of the 'greenhouse gas' CO_2. For example, displacing 20% of gasoline with cellulosic ethanol would reduce US CO_2 emissions by 8%[11].
- The technology of producing ethanol from cellulose could also be adopted on a large scale in other countries, which would have world-wide benefits including reduced risk of climate change, considerably lower prices of oil in the world market, and more diverse supplies of liquid fuel in the world market.
- To achieve the necessary improvements in the technology of ethanol production from ordinary plant material will take a long but not very expensive research and development effort, since most of the problems to be solved can be attacked in the laboratories of America's universities and corporations.
- The current US government programs directed toward reducing the cost of ethanol production are too scattered, small and poorly targeted to achieve this goal. The current subsidies to corn-based ethanol apply to ethanol from cellulose but are not sufficient to encourage private producers to conduct the long-term research necessary to commercialize this technology.
- The development of this technology will have world-wide benefits. Other oil-importing countries could purchase this technology from US ethanol producers

and use it to displace their own imports. The results will be downward pressure on the world price of oil and world-wide reductions in CO_2 emissions.

This paper outlines the steps necessary to bring the first commercial or near-commercial scale cellulosic ethanol plants into operation, through a combination of research spending and direct production subsidies. The research program will take a decade. The deployment program will support the construction of approximately 5 plants, each producing roughly 30 million gallons of ethanol annually. As these plants help to mature the technology before first self-supporting plants can come into operation, so that by 2015 production can reach or exceed 1 billion gallons per year.

Patience is key. 2025 sounds like a very long way off. One should remember that the first "oil crisis' the Arab Oil Embargo of 1973 occurred more than 30 years ago. Since that time sustained efforts on energy research have yielded some real successes, especially in energy conservation. It is such a sustained effort that is called for here.

2. Understanding the Problem

There are large challenges to be overcome to reduce the cost of ethanol to the point where it is competitive with gasoline. The basic technology examined is this report is the production of ethanol from plant materials including both agricultural wastes (e.g. cornstalks) and specialized crops that could be grown as a feedstock for producing ethanol. The fundamental feedstock for this technology is the cellulose contained in plants, hence the name "cellulosic ethanol." At present, production of cellulosic ethanol is more expensive than ethanol from corn and there is no commercial production of cellulosic ethanol. However, since the feedstocks would be much cheaper than corn, cellulosic ethanol could ultimately be cost-competitive with gasoline.

The second challenge is to produce sufficient cellulose-containing plant material to make a major contribution to displacing gasoline without disrupting current production of food and forest products. Some cellulosic ethanol could be made from currently-available waste materials such as corn stalks; some could be produced from energy crops grown on idle land. However, to produce billions of gallons of cellulosic ethanol will require both improved high-yield energy crops and some integration of ethanol production into existing farming activities, where land that is currently used for crops or forest products is used to produce these in combination with ethanol.

Processing Technology & Costs

Ethanol is made by yeasts that consume sugar and produce the ethanol as a metabolic waste product – the process we call fermentation. It is currently produced mainly from corn. The starch found in corn kernels is readily converted to sugars which are then consumed by yeasts.

The primary constituent of most plants is cellulose. Cellulose is built by plants from various types of sugars made by the plant. For the plant, the cellulose provides structural

strength and it is resistant to attack by bacteria and funguses. Unfortunately that resistance makes it hard to break the cellulose back down into the sugars from which it is built. Of course, bacteria and funguses do break down cellulose and consume the sugars, but they do so very slowly; think of a log rotting on the forest floor. That is the first, and greatest challenge at hand. It is already possible to make cellulosic ethanol but the costs are still too high. What makes this technology very promising is the potential to use quite inexpensive feedstocks, such that if the processing costs can be reduced the product cost could be attractive. The basic technology is still fermentation, a low temperature, low pressure process not very different from brewing beer.

The critical difference between starting with corn compared to other plant materials is the cost per energy unit of the raw material.

Table 1
Comparison of cost per unit energy of cellulose to alternatives

	Tons per acre	Dollars per ton	Dollars per unit energy (million Btu)
Corn	4	90[12]	5.75
Switchgrass	5-10[13]	20-40[14]	1.25-2.5
Gasoline (wholesale)	Not applicable	Not applicable	5-9[15]

Table 1 shows that cellulosic feedstocks are already cost-competitive with oil on an energy basis (with current wholesale gasoline prices well over $1.00 per gallon) and is much cheaper than corn[16].

First, consider the potential for improvements in processing technology. No great leap in technology is required. To make ethanol at costs competitive with gasoline can be done with an evolution of established technologies, including the further application of genetic engineering that is already showing positive results. Total failure is unlikely, though how low and how fast production costs can be reduced is uncertain.

As discussed below, the problem is getting the cellulose to break down into sugars that can be fermented. The total cost will be a function of yield (higher yield reduces the cost of the required amount of raw material) plus processing costs. Table 2 provides a summary comparison of these two major cost components for ethanol from corn and switchgrass compared to gasoline. A long period of development has brought the increased the yield of gasoline and other products from crude oil and reduced processing costs, to the point where raw material cost dominates. As cellulosic ethanol moves down the same path, costs will fall.

Table 2
Comparison of current cost of production of ethanol and gasoline

	Feedstock Cost $ / MMBtu	Yield %	Processing Cost $ / MMBtu	Total Cost $ / MMBtu
Corn	7.5	80	3.5	12[17]
Switchgrass	2.5	36	10	18[18]
Gasoline	19	88[20]		5.20

The basic concept of cellulosic ethanol is simple: convert the cellulose to sugar then yeasts do the rest. Any unconverted cellulose and other byproducts are used as the energy source for production of electric power and perhaps, eventually, for the production of other chemical products. The starting materials can be any type of plant material including agricultural and forest wastes that contain cellulose. However, for economical production each processing plant will be built to use a particular feedstock and will require growing large quantities within a reasonable distance of the 'bio-refinery'.

The raw plant material is a mixture of cellulose, the closely related sugar-containing material hemicellulose, lignin (a tough and indigestible material that provides strength to the growing plants), protein, and some fats or oils.

The process involves the following steps, some of which might be combined into the metabolism of a single organism:

- Harvesting and transporting the raw material
- Pre-treatment by both physical and chemical means to make the cellulose easier to break down. This is a critical step. The hemicellulose is relatively easily broken down into sugars[21]. The cellulose fibers (with current technology) cannot be directly broken down into sugars but the cellulose can be made more accessible for further processing.
- Conversion of the cellulose to sugars either 1) via the action of enzymes mixed with the cellulose and water or 2) by the action of bacteria or funguses on the cellulose. The enzymes are chemicals produced by bacteria that promote the breakdown of the cellulose. In the first case the enzymes are produced by the bacteria, collected, and used as a chemical treatment. In the second case, the bacteria produce the enzymes and use them internally as they digest the cellulose.
- Fermentation of the sugars to ethanol by yeast (or modified bacteria).
- Purification and concentration of the dilute 'beer' into fuel-grade ethanol.
- Burning the lignin to provide energy for the process[22], and surplus electric power is sold (displacing some power otherwise produced from fossil fuels[23]).

Whether the cellulose if broken down by enzymes or by bacteria (where the enzymes are inside the growing bacteria) the process is based on natural biological tools developed by bacteria and funguses over millions of years.

Processing plant material handling, chemical processing, energy systems, water management and so on for a 'bio-refinery' are all modest adaptations or extrapolations from current commercial agricultural product and chemical industry processes

The primary weakness of the current technology for cellulosic ethanol is that the breakdown of cellulose to sugars is very slow, requiring a large processing facility. Secondly, the cost of acid and equipment for pre-treatment of biomass is high. Other problems are that the processing itself consumes a substantial portion of the energy available in the cellulose (for example, some of the cellulose is used to feed bacteria to produce enzymes for use in the process) and undesirable byproducts are produced. As a result of these factors, the energy yield of ethanol from cellulose with current technology is about 36%, while it is expected that this could be increased to around 70%[24]. Research to date has already resulted in an improvement in the portion of cellulose that is converted into ethanol, the 'conversion efficiency'. Conversion efficiency can be improved in three ways: through improved pre-treatment that makes more of the cellulose accessible to the bacterial enzymes; improved bacteria that both attack the cellulose faster, so that with the same processing time more ethanol is recovered; and finally, the bacteria can be engineered to use less of the sugars for their own metabolism, making more available in the form of ethanol.

The limitations of current processes can in turn be traced to two areas where research efforts have been somewhat limited: development of improved bacterial strains, which given current technology must be somewhat a trial-and-error process, and gaining a better understanding at a fundamental level of the structure of cellulose in plants and how it responds to various treatments.

As an indication of the kind of solutions to be developed, one might consider the ideal approach as described by Professor Lynd[25]. He suggests the possibility of developing a single organism (a bacteria, almost certainly) that can break down the cellulose into sugars, ferment the sugars to ethanol and excrete the ethanol, while producing few byproducts. This concept is referred to as 'consolidated bio-processing' (CBP). The microbe(s) would almost certainly be 'engineered' starting with a bacterium that naturally performs some of these functions, but modifying it using recombinant DNA technology. For example, a bacterium that lives in oxygen-free conditions might be given genes from bacteria or yeasts that live in oxygen-rich environments, since they use the sugars more efficiently[26].

Table 3 from the draft report "Biofuels: A Path to the Fuel of the Future", indicates the range of production costs that might be attained assuming feedstock costs based on current feedstock productivity (corresponding to $40 / dry ton of feedstock). These production costs would make cellulosic ethanol competitive with gasoline at a wholesale gasoline price of about $1.00 / gallon. Potentially feedstock costs could be reduced from $0.38 / gallon of ethanol in this example by to as little as half as much[27]. The estimate is based on a detailed "bottom up" engineering cost model assuming financing and return on investment such as a manufacturing company might ordinarily expect.

Table 3
Illustrative Cellulosic Ethanol Projected Production Cost[28]

Ethanol/Rankine Power Cost Summary

All Values in 2003$

Minimum Ethanol Selling Price **$0.6678**

Feedstock Rate (dry ton/day)	5,000	
Ethanol Production (MM Gal. / Year)	184.3	Ethanol at 68°F
Ethanol Yield (Gal / Dry US Ton Feedstock)	105.3	
Feedstock Cost $/Dry US Ton	$40	Switchgrass
Internal Rate of Return (After-Tax)	10%	
Equity Percent of Total Investment	100%	

Capital Costs		%of total
Feed Handling	$7,600,000	4.5%
Pretreatment	$24,300,000	14.3%
Biological conversion	$8,500,000	5.0%
Distillation and Solids Recovery	$28,900,000	17.0%
Wastewater Treatment	$19,000,000	11.2%
Storage	$2,300,000	1.4%
Residue Processing	$72,600,000	42.8%
Utilities	$6,500,000	3.8%
Total Installed Equipment Cost	$169,700,000	
Added Costs	$120,600,000	
(% of TPI)	42%	
Total Project Investment	$290,300,000	
Loan Rate	N/A	
Term (years)	N/A	
Capital Charge Factor	0.1771	
Denatured Fuel Prod. (MMgal / yr)		
Denatured Fuel Min. Sales Price		
Denaturant Cost ($/gal denaturant)		
Maximum Yields (100% of Theoretical)		

Operating Costs (cents/gal ethanol)	
Feedstock	38.0
Other Raw Materials	4.7
Waste Disposal	0.0
Electricity	-9.9
Fixed Costs	6.2
Capital Depreciation	7.9
Average Income Tax	6.1
Average Return on Investment	13.9

Operating Costs ($/yr)	
Feedstock	$70,000,000
Other Raw Matl. Costs	$8,600,000
Waste Disposal	$0
Electricity	-$18,300,000
Fixed Costs	$11,400,000
Capital Depreciation	$14,500,000
Average Income Tax	$11,200,000
Average Return on Investment	$25,700,000

Product Value	$71,395,261
Feedstock Cost	$70,000,169
P/F	1.02

This technology is within reach. Organisms and enzymes have been identified or developed that can break down (hydrolyze) cellulose and hemicellulose, albeit at modest yields and rates. There has been enormous progress in the broad field of genetic engineering that can be applied to the development of cellulosic ethanol. In the last decade progress has been made in the following elements of the technology:

- Use of dilute acid pre-treatment to break down the hemicellulose
- Development of bacteria that efficiently ferment the sugars that result from the digestion of hemicellulose[29]
- Development of first-generation bacteria that combine cellulase production and fermentation.

The work to be done consists of laboratory-scale and perhaps pilot-scale testing, to be followed by a program to commercialize the resulting improved basic technology[30]. Elements of such a program are discussed in the policy recommendations section, later in this paper.

Raw Materials

An important secondary question is how much land is available to grow energy crops. This will depend on the development of technology to use diverse plants for cellulose production and the improvement of yields (tons of plant material per acre per year) so that fewer acres are required. Another, but more speculative possibility is that if the protein in the plant feedstocks can be recovered, the energy crop could also be an animal feed crop, substituting to some extent for widely-grown crops such as soybeans. Later in this paper, estimates are provided of the extent of ethanol production that would be possible with varying levels of land use and implementation of these technologies Almost any plant material could be used as a feedstock to produce ethanol, though it may turn out that 'customizing' the plants in ways other than maximum tons per acre may be valuable. The following have all been investigated as ethanol raw materials:

- Agricultural wastes. These include wastes that are harvested and discarded in processing (of which bagasse from sugar cane processing is most significant) and crop materials left in the field (corn stalks). These wastes will be important for the first phases of commercialization of cellulosic ethanol, but can support production of only around 20 billion gallons per year[31].
- Switchgrass. A native perennial prairie grass that can be grown widely and at good yields.
- Fast-growing trees including hybrid poplars[32] and willows.

Table 4 shows the land available for these energy crops, given current land use patterns and the yields given current crop productivity[33]. The areas where each could be grown are shown are illustrated by the biomass supply scenario developed in a USDA Study, as shown in Figure 2[34].

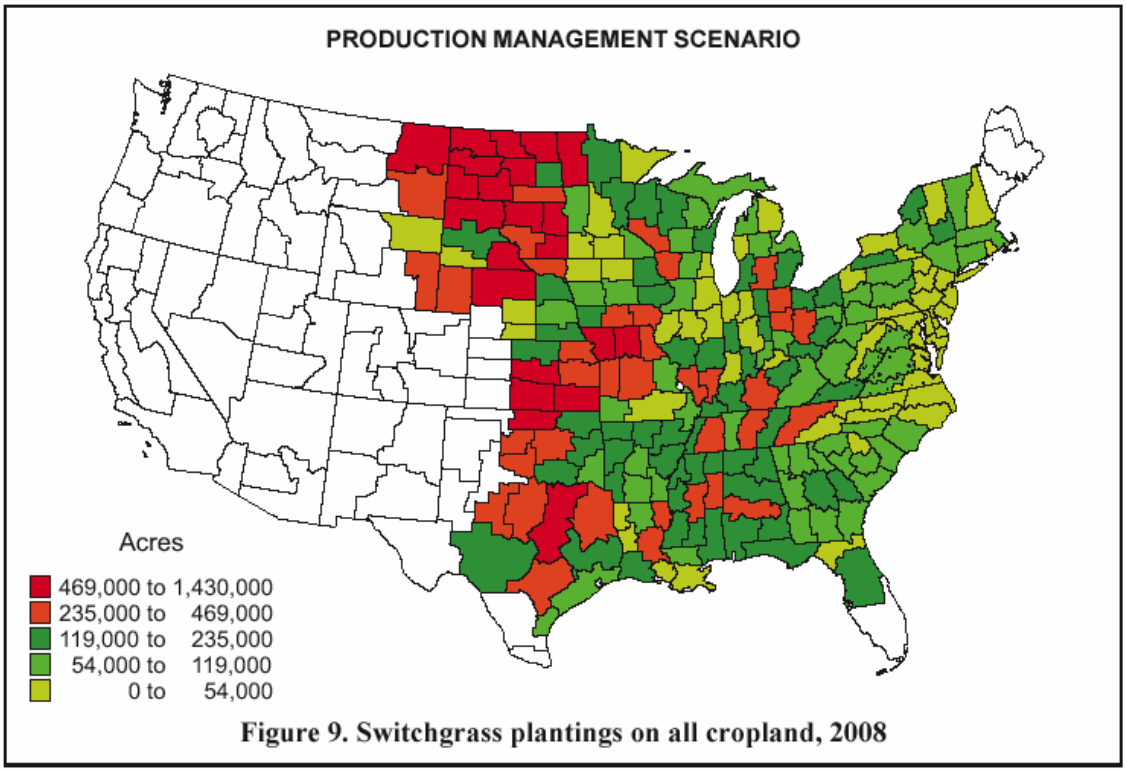


Figure 9. Switchgrass plantings on all cropland, 2008

Table 4

Land Use and Production of Cellulosic Ethanol in 2025

		Biomass Production		Ethanol Production	
	Acres MM	Base Productivity MM tons /y	Enhanced Productivity MM tons /y	Base Productivity B Gal / y	Enhanced Productivity B Gal / y
Crop Lands	42	189	420	20.8	59.1
Forest Lands	20	80	120	8.8	13.2
Waste Materials		200	200	22.0	22.0
Total	62	469	740	51.6	94.3
Gasoline equivalent in MM BBl /day				2.2	4.1

Land is limited: there is a modest amount of land in the US that is set aside from cultivation under US Department of Agriculture programs[35]. There is land, usually in smaller and more scattered parcels that are either idle or used for some grazing. If land is used for energy crops that is currently used for row crops, grazing or forestry, the supply of those products will decrease. That could be in the financial interest of farmers, could reduce expenditures for Federal crop support payments, and might overall be in the national economic interest, in that the value of the energy crop – private and national - could exceed the value of the current uses[36]. Substantial production of cellulosic ethanol could occur with diversion of lands currently used for agriculture and forestry. These factors were analyzed in the USDA study mentioned above, in which energy crop production is considered to compete with conventional crops for use of farmland. The study did not consider the effect of co-production of energy crops and food or fiber might increase the amount of land available to produce raw material for cellulosic ethanol. Table 4 assumes that a portion of the land that is now forested is converted to

energy crops (including poplars or willows) or used for forest co-production (forest co-product means producing pulp or lumber from the most desirable portions of trees, and ethanol from the rest). Table 4 assumes that about 10% of the timberland not in reserved areas (e.g. national parks) is used for energy crop production or co-production. Table 4 also includes estimated production of cellulosic ethanol from agricultural wastes, such as corn stover[37].

A direct attack on land as a limitation is to increase the productivity of energy crops, that is to get more tons from the same acreage. This has already been demonstrated with the development of hybrid poplars . With switchgrass the effort to improve yields is at an early stage. Currently, in a typical setting in the southeastern US, about 5 dry tons of switchgrass can be harvested each year. This is similar to the biomass productivity of corn (about 6 dry tons per year per acre for the total above-ground corn plant). Corn has, of course, been systematically bred over the last century to maximize the yield of kernels – not total biomass. During the last 60 years corn yields have been increased 5-6 fold, or about 3-4% each year on average. Corn is an annual plant that must develop a root system from scratch after planting. Switchgrass is perennial grass that over several years after planting develops an extensive and deep root system that is efficient at absorbing water and nutrients. Considering the history of improvement in corn as model, and recent improvements in switchgrass yield, it is reasonable to expect a doubling in productivity over 20 years to reach 10 dry tons per acre / year. This improvement is assumed in the 'enhanced' case summarized in Table 4.

Three levels of feedstock availability and ethanol production can be envisioned:

- Production from currently available wastes and unused or lightly used land.
- Production with enhanced yield, based on historical experience with improvement of other crops.
- Production with some substitution of combined energy/protein crops for current crops such as soybeans[38]. This would most likely occur after 2025 and is not included in the estimates in Table 4.

Finally, one should note the ecological implications of the growth of these energy crops on a large scale. Compared to row crops they appear to be considerably better in the following respects: lower requirements for fertilizer, insecticides and herbicides, lower soil erosion and richer habitat for animals and birds. No negative effects have been identified, other than some fallow lands now used for hunting or other recreation might be converted to energy crop land (and thereafter might be less accessible).

Recommendations

The technology for cellulosic ethanol produced at prices competitive with gasoline is at least a decade away and it will take another decade for large-scale commercialization of the technology, including building plants and growing feedstock in large quantities. After

that the technology can continue to evolve on its own, very possibly around a world-wide base of production and research. The recommendations presented below build on this premise by funding commercialization (and technology development related to commercialization) at a time when the technology is ready.

The second critical finding and premise for recommendations is that biologically-based production of cellulosic ethanol is likely to succeed and the alternative pathways, such as biomass gasification or thermochemical (acid) treatment, should be abandoned. The argument for abandoning gasification is threefold. First, the most urgent national need is for liquid fuels that can displace imported oil. Gasification can be used either for production of electric power (for which little oil is used) or as a very indirect means of producing liquid fuel via gasification and reforming the gasses to liquids, with resulting reduction in yield. Second, gasification is inherently challenging in that it demands high temperatures and pressures compared to a low-temperature simple 'brewing' technology. Thirdly, gasification technology will continue to be advanced independent of programs related to biomass energy because of the interest in other applications, such as coal gasification. In fact gasification is a relatively mature technology compared to cellulosic ethanol and existing techniques could be adapted to biomass should a rationale for doing so emerge. Thermal (acid) processing of biomass has already been extensively investigated and it is clear that there is very little chance of improving it to the point that it is an attractive pathway to competitive ethanol production costs[39].
The third and final premise is that the technology barrier is too high for the private sector to leap under the current ethanol subsidy program. Only publicly-funded research will bring us across that barrier.

Since 1980, research and development has brought down the costs of bioenergy by nearly a factor of three, and advances that could bring the cost of fuel produced from cellulosic biomass to the point that it is competitive with current gasoline prices on an energy basis are readily foreseeable. For instance, it is anticipated that advanced pretreatment and consolidated bioprocessing of cellulosic biomass by themselves would bring the plant gate price of cellulosic ethanol from a farmed energy crop to less than $0.50 cents per gallon.[40]

Therefore the fundamental recommendation is for a highly structured multi-year research program, to be followed in tandem with a fresh approach to commercialization, as described below. The proposed total expenditure is $750 MM for research between 2006 and 2015 and $750 MM for deployment between 2008 and 2017 (with payments under projects initiated on or before 2017 to continue thereafter, as described below).

The objectives of the research program are two:

- The development of a consolidated bioprocessing (CPB) technology for conversion of cellulose and hemicellulose to ethanol in a single process step.
- The development of improved feedstocks with a yield (in typical growing conditions) of at least 10 dry tons per acre per year, within 15 years.

The development of the CPB technology should probably follow the two-track approach advocated by Lee Lynd and others[41] using both recombinant and 'engineered' natural organisms[42]. This research is in large part applied in nature and can and should be a highly parallel effort with multiple candidate organisms and research teams.

At the same time several more fundamental research programs should be pursued. These would include:

- Systematic 'empirical' testing of cellulose pre-treatment technologies[43]
- Basic investigation to improve the understanding of cellulose structure in various potential feedstocks and it relation to cellulase activity.
- Research on better tools, such a means of measuring enzyme activity.

In parallel, existing programs on feedstock development should continue and increase in scale, including development of both grass and tree feedstocks, so that energy crops can be grown in many setting across the US.

The cellulosic ethanol research program will consist primarily of laboratory research and field demonstration projects (for feedstock development). It would be appropriate and cost-effective that it be conducted entirely through competitive, peer-reviewed solicitations, with requirements for publication of the results.

While there is time for the development of an effective approach to commercialization, this paper suggests the following structure be used, based on experience with "reverse auctions' in California and procurement of power generation resources in other state:

- The US Government will enter into a series of long term contracts to pay subsidies for specific quantities of cellulosic ethanol.
- Producers will bid a proposed amount of subsidy per gallon.
- Proposals will be evaluated primarily on price with consideration given to technical and financial credibility. Use of a specific technology will not be a selection criterion. Producers will have to provide commercial guarantees of performance. Producers may employ and retain proprietary technology.
- Auctions will be held regular intervals, say every two years.
- The quantity purchased under each contract will be large enough, and the term long enough to support private-sector financing of a commercial-scale plant.

This model has been used successfully in the power sector (competitive bids under RFP's run by utilities). It lets the market pick the technology and the price is also market-determined. The term can be long enough, say 10-15 years to allow reasonable debt repayment and for the facility to implement a couple of cycles of process improvement.

In the very long term, if this program is successful on a large scale it will have a paradoxical result: demand for oil could fall so substantially that the cost 'goal posts' shift out of reach again. In that case, government policies may be needed (and be cost effective) for the indefinite future to continue to drive adoption of cellulosic ethanol. At

the point the program is 'free' compared to what consumers would otherwise have had to pay for gasoline.

The timing of the funding of demonstration projects will relate to the evolution of technology through the research program, which could begin to produce results in 2008 and continue for at least a decade. It is likely that the technology necessary to make cellulosic ethanol fully competitive with gasoline, including basing production on high-yield energy crops will take a least a decade to develop, with many substantial improvements becoming available as the research progresses. Assuming prompt action on the NCEP recommendations, the DOE could begin an expanded and re-directed research program before the end of 2005, with initial research grants in 2006. The research programs will vary in their character and duration, but some elements, such as expanded investigation of techniques for feedstock pre-treatment should produce valuable results by 2008. The broader research program, including the development of organisms and supporting systems for 'consolidated bio-processing" (the single-step conversion of cellulose to ethanol) will probably take a decade to reach the efficiency level required to produce ethanol that is commercially competitive with gasoline. A reasonable target period for that critical milestone is 2015-2020.

The technology deployment program will consist of 5 projects, beginning in about 2008 and spaced approximately every other year. This schedule will permit each project to test a meaningful improvement in technology from the research programs and over previous pioneer efforts. As described above, the bidder will propose the amount of subsidy per gallon that they will receive. Successful bidders will receive payments for ten years from the start of production of each project. The annual payment each project will be capped at $15 MM per year (totaling $750 MM for the entire program). It is expected that each bidder will optimize the project size to give the lowest per-gallon cost within the cap amount. Probably, as the cost of production falls with improved technology over time, the project sizes will increase. Given the size of the cap on annual payments, it is expected that projects will be in the range of from 20 to as much as 50 million gallons per year (from one thousand to several thousand tons of feedstock per day).

The first projects are likely to use 'free' agricultural wastes as feedstocks, since there are locations at which moderate of amounts of such materials are already available at an agricultural processing plants, for example sugar cane wastes ("bagasse")[44]. The total estimated available agricultural wastes suitable for ethanol production are estimated to be sufficient to produce as much as two billion gallons of ethanol annually[45] [add footnote]. By the later stages of the demonstration projects, around 2015, the first large-scale commercial waste-based ethanol projects are expected to begin operation (without subsidies beyond those similar to current support for ethanol production). At this point production from subsidized projects is expected to be in the range of 150 MM gallons of ethanol annually. Commercial waste-based production starting around 2015 or a little earlier will quickly take total cellulosic ethanol production to over one billion gallons annually during this period (equal to about a third of current corn-based production). In some cases existing corn-based plants may be expanded to produce ethanol from the currently-unused portions of the corn plant (the "stover").

Figure 3

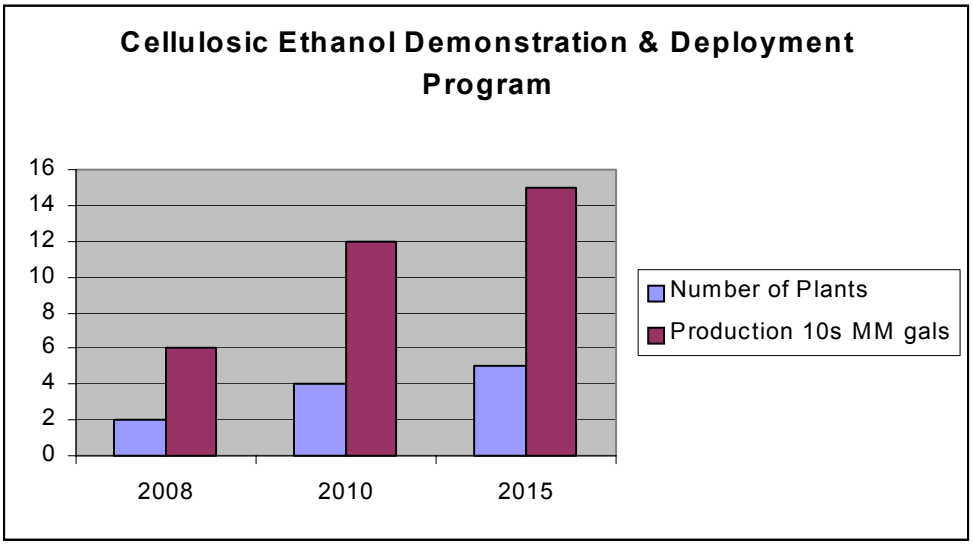
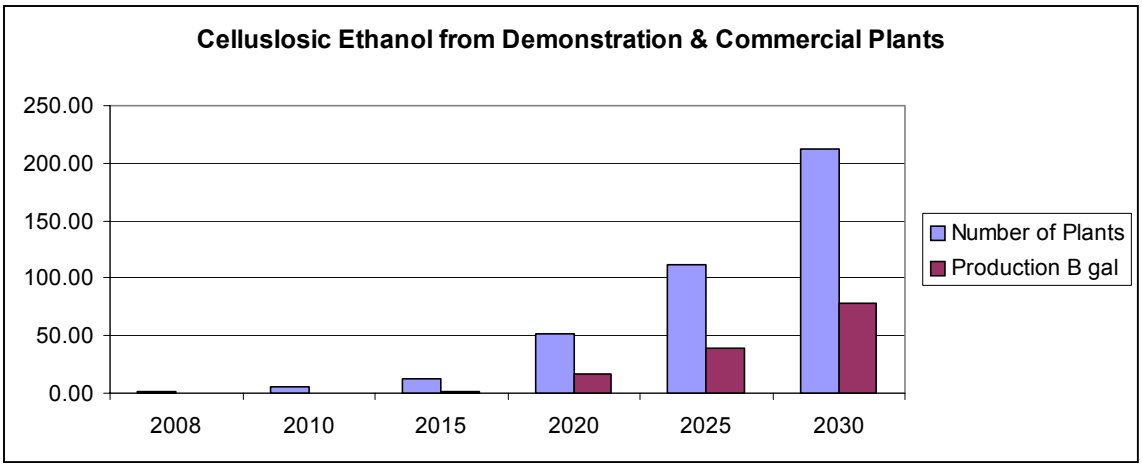


Figure 3 illustrates the production timing for the demonstration projects.

As the technology for producing and processing large-scale energy crops such as switchgrass advances, these are expected to be the preferred feedstock for later and larger projects that are nearing gasoline-competitive price levels. Adjustments in the program over time may be necessary, such as conducting one or more bid solicitations that are targeted to a particular feedstock. Large-scale production of ethanol from energy crops will therefore begin after 2015, starting in the areas where feedstock costs are lowest[46] Around 2015 the cellulosic ethanol industry could begin the transition to a fully commercial enterprise in which substantial private, proprietary research efforts begin. Once cellulosic ethanol can be produced in some locations for costs competitive with gasoline, the industry growth will depend on the development of energy crop production and continued optimization of the process. As indicated in the discussion of feedstocks, production could reach levels of 40-80 billion gallons per year by 2025 (equivalent to 2.5-5 million barrels of gasoline per day). The timing of production from both the demonstration and initial commercialization of the industry is illustrated in Figure 4.

Figure 4



[1] Note on sources: This report is based primarily on the study ""The Role of Biomass in America's Energy Future " of which the NCEP is a co-sponsor but was not prepared by that group. Other sources of material are identified in the notes below. While largely consistent with this report it differs in certain aspects of the recommended policy.

[2] Ethanol can be mixed with gasoline up to 10% with no modifications to existing engines, to about 20% with minor modifications and up to 85% with some specialization of the engine. Ethanol has a favorable "octane number" and if the engine is designed for a high-ethanol blend it can designed to be 7-10% more efficient than a conventional gasoline engine.

[3] The major subsidy specifically for ethanol is an excise tax exemption for gasoline that is blended with between 5.7 and 10 percent ethanol. The value of the exemption has fluctuated overtime, but the 1998 Transportation Equity Act set it at $0.052 per gallon of blended gasoline with 10 percent ethanol from 2003 to 2004 and $0.051 for years 2005 through 2007 when the act expires.3 For 10 percent blends, this translates into $0.52 and $0.51 per gallon of pure ethanol. In addition to this partial excise tax exemption, blenders, users of pure ethanol, and small producers are all also allowed to reduce their taxable incomes by the same amount per gallon of ethanol. The total value of these subsidies over the last two decades is estimated at over $13 billion dollars.3

[4] Renewable Fuels Association Press Release July 26, 2004 http//www.ethanolrfa.org/pr040727.html

[5] McAloon et al Determining the Cost of Producing Ethanol from Corn Starch and Lignocellusic Feedstocks, NREL) October 2000.

[6] New York, NY Gasoline Conventional Regular Spot Price FOB (C/gal) 1991-2001 DOE /EIA data

[7] Using ethanol for fuel produces near-zero net CO_2. Ethanol produced from US-grown crops is "renewable energy". The growing plants take up CO_2 from the atmosphere, which is released when the ethanol is burned. Production does not take large amounts of fossil fuel (e.g. to operate the farm. In addition, the initial establishment of some of the 'energy crops' to produce ethanol will result in substantial permanent sequestration of CO_2. For example, if perennial switchgrass is grown on lands that are currently in row crops a large below-ground biomass of roots will be established and, current evidence suggests that carbon will be added to the soil (in the form of humus) for a substantial period before equilibrium is reached. See The Role of Biomass in America's Energy Future .

[8] In total dollars, the budget history for biomass energy research has been a roller coaster ride, starting with the peak in spending in 1979 of $134 million, followed by huge reductions in the 1980s and a return to 50 percent of 1979 funding during the early 1990s. Throughout the 1980s, biomass research was a potpourri of programs including energy from waste, ethanol research, thermochemical fuels, and biomass feedstock research. In the 1990s, DOE brought more discipline to the research program by focusing primarily on power production from biomass—because of its immediate ability to address climate change issues—and on ethanol—because of its growing industrial success in the fuel blend market. But, layered on top of this

improved focus was a shift in focus from applied R&D to industrial partnership and technology transfer. This shift directed a significant amount of available funds to expensive partner-led deployment efforts. Since 2000, biomass energy R&D has returned to its original focus on improving national security by reducing U.S. dependence on foreign oil. As a result, research on power production has been phased out, in favor of reintroducing research on thermochemical fuels for transportation. Ethanol research has shifted away from a strict focus on ethanol production to a focus on the use of biomass sugars as an intermediate material for making higher value products as well as fuels—the so-called "biorefinery" approach. Finally, the deleterious effects of two decades of constantly shifting priorities are now exacerbated by the intrusion of congressional earmarks in the R&D management process. In 2004, 45 percent of DOE's biomass R&D funding was tied up in a collection of unaligned and often redundant projects that Congress has directed DOE to include, which serves only to dilute the ability of this research program to focus its limited resources on the long-term goal of developing biomass as a sustainable energy source.

[9] The report "The Role of Biomass in America's Energy Future" notes: "The only other cost evaluation that looked at mature technologies concluded that cellulosic ethanol could reach a wholesale price of about $0.50 per gallon ($0.75 per gallon gasoline equivalent). This range is further corroborated by taking a top-down approach comparing cellulosic fuel refining to other commodity refining processes that have reached maturity. As a result, the RBAEF team is optimistic that the analysis will result in similarly attractive prices for cellulosic ethanol."

[10] Assuming a production cost of $055 / gallon, generating primary economic activity of $23 B (displacing imports) and assuming payroll and benefits of $45,000 per employee.

[11] Based on EIA estimates (Annual Energy Outlook 2001) that oil accounts for 42% of US CO2 emissions, as a usage level of approximately 20 MM BBL/ day.

[12] Assuming $2.50 per bushel – a representative recent price

[13] "Biofuels a Path to the Future" Table 2 Switchgrass yields [p21]

[14] For example, Ugarte, Daniel et. al "The Economic Impacts of Bioenergy Crop Production on US Agriculture" USDA, February 2003 notes field-gate prices of switchgrass ranging from $17 / dry ton to over $30 / dry ton, depending on the region and quantity (assuming current crop productivities).

[15] Equivalent to $0.60 - $1.00 per gallon. DOE Annual Energy Outlook 2004 projects a 'base case' year 2025 price of gasoline oof $0.86 / gal in 2004 dollars.

[16] Assumes gasoline in the range of $0.60 to $1.00 / gallon wholesale. Corn at approximately $2.50 per bushel. Assumes a typical energy content for both corn and switchgrass of 15.6 MMBtu / ton. See also similar estimates in Lynd, Lee et. Al. Biocommodity Engineering, Biotechnology Progress 1999, p 777-793 Table 3.

[17] McAloon, Andrew e.a.l "Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks" National Renewable Energy Laboratory, October 2000.

[18] Various estimate of current production costs of cellulosic ethanol are in the range of $1.20-$1.40 / gal. See for example: Wyman, Charles, "Biomass Ethanol: Technical Progress, Opportunities and Commercial Challenges.

[19] Direct comparison of crude oil prices per energy unit (which were about $4.00 / million Btu for the 1991-2001 period) to gasoline is not meaningful because the refinery products include high-value gasoline and diesel fuel and low-value residual fuel oil and petroleum coke, as well as a variety of secondary chemical by products. The conversion efficiency figure shown represents the total energy content of all refinery products compared to the energy content of the crude oil.

[20] Represents the total energy efficiency of oil refining. Cited in Interim Results from Research Project: The Role of Biomass in America's Energy Future, briefing for NCEP May 17, 2004.

[21] The current technology for hemicellulose is to treat the raw feedstock with hot dilute sulfuric acid. Genetically engineered bacteria are then used to ferment the resulting sugars to alcohol. Some undesirable by products are produced, but even with current technology a large fraction of the hemicellulose can be fermented.

[22] Alternatively, it might become cost effective to gasify the lignin to a liquid that could substitute for diesel fuel or a natural gas substitute.

[23] Approximately 5% of the energy content of the feedstock could be available for sale in the form of electric power, displacing substantial amounts of fossil fuel. For example the 5,000 ton per day plant summarized in Table ___ would produce electric power sufficient to displace the equivalent of about 225,000 tons of coal burned in a conventional power plant.

[24] See: Biofuels a Path to the Fuels of the Future" Chapter 2 cites current yield at 50 gallons per ton of feedstock and advanced technology yield of 105 gallons per ton. Lynd, Lee et al. Likely Features and Costs of Mature Biomass Ethanol Technology in Applied Biochemistry & Biotechnology Vol 57/58 19666 notes current yield of 50.3% and 'best parameter case" of 69.3%.
[25] Lynd, Lee et.al Microbial Cellulose Utilization: Fundamentals and Biotechnology, Microbiology and Molecular Biology Reviews, September 2002 p.506-577
[26] Ibid. p. 542.
[27] See: Biofuels a Path to the Fuels of the Future" Chapter 1.
[28] The production cost indicated in this table includes an allowance for the return on invested capital that is representative of that required by and industrial firm engaged in commercial production of cellulosic ethanol.
[29] Hemicellulose consists in large part of 5-carbon sugars that are not fermented by the usual strains of yeast, which metabolize the 6-carbon sugars found in barley malt, sugar cane or are prepared from cornstarch. Progress in processing is documented in: Wyman, Charles E., Biomass Ethanol: Technical Progress, Opportunities and Commercial Challenges Annual Review Energy Environment 1999.
[30] "Biofuels: A Path to Fuels of the Future" notes the following: "Key advanced technology operations included in the RBAEF project's mature biomass-to-ethanol process design include: pretreatment via ammonia fiber explosion (AFEX), which results in complete recovery of cellulose and hemicellulose sugars without degradation; consolidated bioprocessing, in which cellulase production, cellulose hydrolysis, hexose fermentation, and pentose fermentation are combined in a single process step; thermally efficient ethanol distillation employing intermediate heat pumps and optimal sidestream return (IHOSR); fully integrated coproduction of process steam, electricity, and/or thermochemical fuels from process residues; and extensive water recycle and onsite wastewater treatment featuring anaerobic digestion."
[31] The primary sources of waste fuels will the agricultural wastes that are currently left in the field, including corn stover, wheat and rice straw, and bagasse (which is currently harvested). In most cases where waste products are available in bulk at a processing plant (having been trucked from the fields along with the crop) they are already used for some purpose. Therefore, in most cases the costs of harvesting and transporting these waste materials must be incurred.
[32] Hybrid poplars of various species have been developed for use for production of pulpwood. These species are commercially available including types suitable for various climate zones. As an energy crop they would be grown in "short rotation intensive cultivation" with harvest about 12 years after planting. Current yields are estimated to be in the range of 3-6 dry tons per acre per year.
[33] Assumes that 1 gallon of ethanol is functionally equivalent to .655 gallon of gasoline. Assumes production of 110 gallons of ethanol / dry ton of feedstock. .
[34] Ugarte, Daniel et. al "The Economic Impacts of Bioenergy Crop Production on US Agriculture" USDA, February 2003
[35] The "Conservation Reserve Program, under which almost 30 million acres are set aside in a program under which the land owners receive payments for holding the land aside from farming. Substantial portions of these lands are not suitable for growing energy crops. See Ugarte, Daniel et. al "The Economic Impacts of Bioenergy Crop Production on US Agriculture" USDA, February 2003
[36] McLaughlin, S. B. et. al. "High-Value Renewable Energy from Prairie Grasses" Environmental Science & Technology Vol 36, No. 10, 2002
[37] The estimate used here is adjusted downward from material provided by Oak Ridge National Laboratory. The source information is summarized below. The quantities are expressed in millions of tons per year. For this paper, it is assumed that only a fraction of the forest thinning and urban wood wastes are available. Lester Lave of Carnegie Mellon University presented a similar estimate of waste availability (presentation to NCEP, June 13, 2003).

Estimated Availability of Waste Biomass Materials for Production of Ethanol

Forest residues		Agricultural crop residues			Urban wood wastes
Logging & other removal residue	Forest Thinning	Corn stover	Wheat straw	Other crop residues	All sources
41	96	68	12	29	42
Residues generated from commercial logging operations, silvicultural operations, and forest land clearings.	Biomass identified to reduce fire hazards (Healthy Forest initiative). Excludes treatment biomass suitable for higher valued merchantable forest products.	Availability is based on current mix of tillage practices and takes into account amounts of biomass needing to stay in the field for soil erosion and nutrient replacement purposes. Estimates are much higher if tillage practices changed (no-till fraction) and crop yields increased. Wheat straw includes winter and spring wheat		Includes sorghum, barley residue, oats residue, rye residue, rice straw, bagasse (sugarcane), cotton gin and field trash, and orchard prunings.	Urban wood wastes include the following sources -- yard and tree trimmings, packaging waste and durable from municipal sources, construction and remodeling wastes, and demolition debris.

Source: Bob Perlack, Environmental Sciences Division Oak Ridge National Laboratory

[38] Among the technologies that the RBAEF project is assessing are methods to separate the protein faction from biomass without destroying the cellulosic sugars necessary to make ethanol. Currently the United States devotes 74 million acres to growing soybeans primarily as a protein supplement for animal feed. Switchgrass, a cellulose-rich energy crop, actually can produce more protein per year than soybeans. If the protein separation process can be successfully integrated with the fuel production process, then a significant fraction of the land currently devoted to soy beans could be converted to energy crops. Furthermore, this would add another valuable coproduct to the biorefinery process making fuels that much more cost-competitive.

Crop	Biomass Productivity (tons/acre/year)	Protein Fraction	Protein Productivity (tons/acre/year)
Switchgrass	5.0-10.0	8%-12% (early cut)	0.4-1.2
Soybeans	1.1-1.3	36% (bean only)	0.4-0.45

[39] Thermal processing as a pre-treatment step before biological processing of cellulose is and will remain important.

[40] Lynd, L, "Overview and Evaluation of Fuel Ethanol from Cellulosic Biomass: Technology, Economics, the Environment, and Policy." *Annual Review of Energy and the Environment* 21. p. 433.

[41] See Microbial Cellulose Utilization: Fundamentals and Biotechnology

[42] Recombinant technology is the transfer of genes between unrelated species. Engineered organisms are hybridized and/or selectively bred using modern version of the techniques by which traditional crops were developed and improved.

[43] Lynd, Lee et. al. op. cit. 1999 p784.

[44] Lynd, Lee Overview and Evaluation of Fuel Ethanol from Cellulosic Biomass: Technology, Economics, the Environment and Policy in Annu. Rev. Energy Environ. 1966 p 403-65 Table 2.

[45] Estimates provided by Oak Ridge National Laboratory to NCEP. These make allowance for current uses of many wastes, such as the already-high utilization of many forestry wastes.

[46] As noted in Ugarte et al. op cit. some switchgrass could be produced as cheaply as $17 / dry ton (farm gate) at current yield. Increased yields would further reduce these costs.

THE CAR AND FUEL OF THE FUTURE: A TECHNOLOGY AND POLICY OVERVIEW

Prepared for the National Commission on Energy Policy by
The Center for Energy and Climate Solutions
JUNE 2004

EXECUTIVE SUMMARY

Transportation is the major source of U.S. dependence on imported oil and the sector that has had the fastest growth in greenhouse gas emissions over the past two decades. Yet the efficiency of our light duty vehicle fleet is at a 20-year low and efforts to promote alternative fuel vehicles in the marketplace have largely failed. Nonetheless, the urgent need to reverse the business-as-usual growth path in greenhouse gas emissions in the next two decades to avoid serious if not catastrophic climate change necessitates action to make our vehicles cleaner.

The pathways most widely discussed for reducing or replacing oil while significantly reducing transportation greenhouse gas emissions are efficiency (such as hybrid vehicles), hydrogen, grid-connectable or plug-in hybrid-gasoline vehicles, ethanol from cellulosic biomass, and synthetic diesel fuel (with carbon sequestration). Most alternative fuel vehicle (AFV) pathways, however, are unlikely to be cost-effective strategies for reducing gasoline consumption and emissions for the foreseeable future, according to most studies.

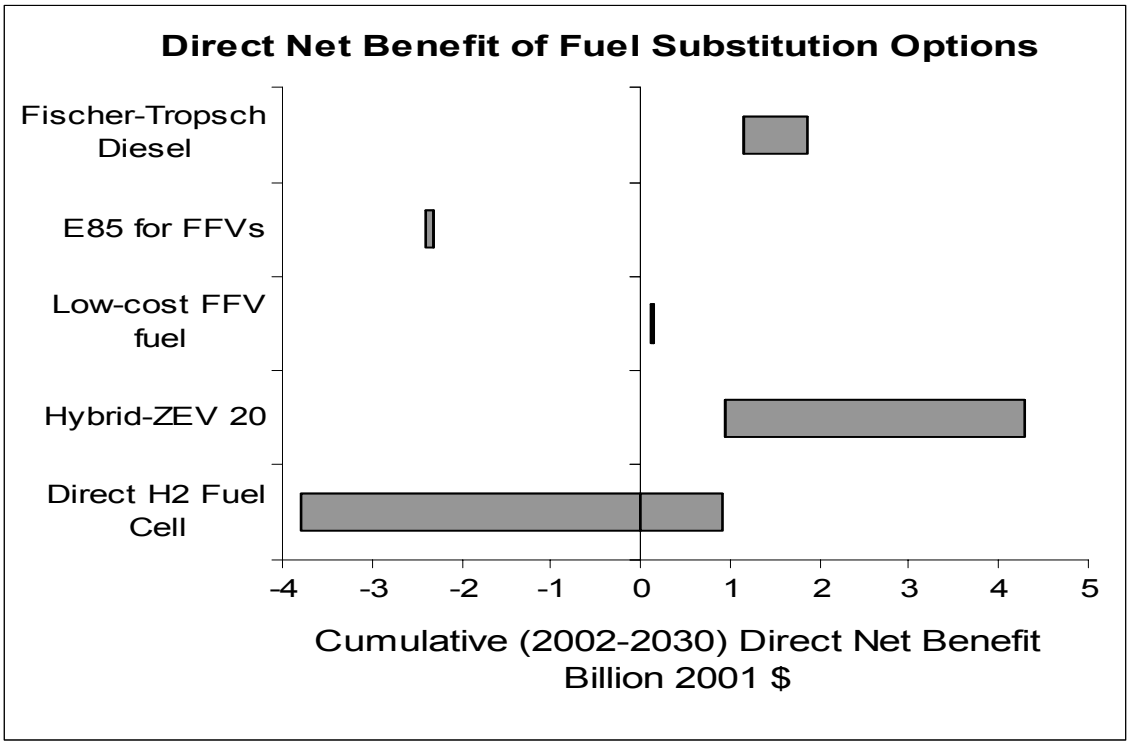
In the near- and medium-term, by far the most cost-effective strategy for reducing emissions and fuel use is efficiency. Hybrid vehicles in particular offer the possibility of breaking the political logjam on higher fuel efficiency standards because they can reduce gasoline consumption and greenhouse gas emissions 40% to 50% with no change in vehicle class and hence no loss of jobs or compromise on safety or performance. If we are to achieve significant fleet-wide efficiency gains by 2025, some form of marketplace intervention by the federal government is virtually inevitable.

All of the AFV pathways will require technology advances and strong government action to succeed.[1] Hydrogen is the most challenging of all alternative fuels, particularly because of the enormous challenge required to change our existing gasoline infrastructure. It is the least likely to be a cost-effective solution to climate change by 2035. Cellulosic ethanol has significantly less infrastructure challenges since it can be blended into gasoline. It is a very promising strategy if costs can be reduced and productivity increased. If carbon sequestration on a large scale proves practical, synthetic diesel fuel from coal and biomass gasification (such as Fischer-Tropsch or dimethyl ether) may also become a viable strategy.

Plug-in or grid-connectable hybrids may be the most promising AFV pathway. These hybrids can be plugged into the electric grid and run in an all-electric mode for a limited range between recharging. Plug-in hybrids will likely travel three to four times as far on a kilowatt-hour of renewable electricity as fuel cell vehicles. Unlike most AFVs, plug-ins hold the potential of being cost-competitive at current gasoline prices. They deserve at least as much attention from policymakers and car companies as hydrogen fuel cell vehicles have received. *We believe that the most plausible vehicle of the future is a plug-in hybrid running on a combination of low-carbon electricity and a low-carbon biomass-derived fuel.*

One of the few recent studies to compare different alternative fuels including plug-in hybrids is the August 2003 joint report of the California Energy commission and the California Air Resources Board, *Reducing California's Petroleum Dependence*.[2] The two agencies looked at the direct economic benefit of various AFVs and alternative fuels, including Fischer-Tropsch diesel made from natural gas, a mixture of 85% Ethanol and 15% gasoline (E85) for flexible fuel vehicles (FFVs), a future low-cost FFV fuel, a hybrid zero emission vehicle with a 20-mile all electric range (Hybrid-ZEV 0), and a direct hydrogen fuel cell. The results can be seen in the following figure.

FIGURE ONE



The results are very dependent on the assumptions. Gasoline prices were assumed to be from $1.47 a gallon to $1.81 a gallon, for instance, and they are currently higher than that and could be even higher in the future. No environmental benefits were calculated, although they could be significant in some cases. No economic value was assigned for the possibility of using the plug-in hybrids to provide grid services (such as spinning reserve) when the vehicles were not being driven, even though this is a plausible scenario. The incremental cost of fuel cell vehicles ranged from $1800 to $5000 although current incremental costs are several hundred thousand dollars.

Nonetheless, the results show that in a detailed apples-to-apples analysis comparing a wide variety of alternative fuel vehicles, plug-in hybrids hold the potential for significant direct net economic benefits. They also make clear that alternative fuels can be attractive when they approach the price of gasoline and underscore the need for some way to value the environmental benefits of alternative fuels. The same study also showed that most of the pure fuel-efficiency options, including hybrids, had a positive direct net benefit.

INTRODUCTION

Any U.S. energy and environmental policy effort must come to grips with transportation. Some two-thirds of U.S. oil consumption is in the transportation sector, the only sector of the U.S. economy wholly reliant on oil. The energy price shocks of the 1970s helped spur growth in natural gas use for home heating, and drove the electric utility sector and the industrial sector to reduce their dependence on petroleum. But roughly 97% of all energy consumed by our cars, sport utility vehicles, vans, trucks, and airplanes is still petroleum-based.

The transportation sector remains one of the largest sources of urban air pollution, especially the oxides of nitrogen that are a precursor to ozone smog and particulates that do so much damage to our hearts and lungs. Vehicle emissions of such pollutants, however, have been declining steadily, and by 2010, federal and state standards will make new U.S. cars exceedingly clean.

Yet, even as new internal combustion engine vehicles dramatically cut the emissions of noxious urban air pollutants by automobiles, their contribution to global warming has begun to rise. In the 1990s, the transportation sector saw the fastest growth in carbon dioxide emissions of any major sector of the U.S. economy. And the transportation sector is projected to generate nearly half of the 40% rise in U.S. carbon dioxide emissions forecast for 2025.[3]

Internationally, the situation is equally problematic. As Claude Mandil, Executive Director of the International Energy Agency (IEA), said in May 2004, "In the absence of strong government policies, we project that the worldwide use of oil in transport will nearly double between 2000 and 2030, leading to a similar increase in greenhouse gas emissions."[4] If by 2050 the per capita energy consumption of China and India were to approach that of South Korea, and if the Chinese and Indian populations increase at currently projected rates, those two supergiant countries *by themselves* would consume more oil than the entire world used in 2003.[5]

Since oil is a finite, non-renewable resource, analysts have attempted to predict when production will peak and start declining. Some believe this will occur by 2010. In his 2001 book, *Hubbert's Peak: The Impending World Oil Shortage*, Princeton geophysicist Kenneth Deffeyes, writes "There is nothing plausible that could postpone the peak until 2009. Get used to it."[6] Royal Dutch/Shell, a company itself downgrading reserve estimates, adds only a few years to this forecast. According to Shell, "A scarcity of oil supplies—including unconventional sources and natural gas liquids—is very unlikely before 2025. This could be extended to 2040 by adopting known measures to increase vehicle efficiency and focusing oil demand on this sector."[7]

Whether we will adopt these known measures or not remains to be seen. The purpose of this paper is to discuss and compare the various measures.

Shell's other hedge, "including unconventional sources and natural gas liquids," is environmentally problematic. Making liquid fuels out of unconventional sources of oil (such as Canadian oil sands) is relatively energy-intensive, and relying on these sources will significantly increase greenhouse gas emissions. Indeed, Canada's increasing use of natural gas to extract its heavy oils is one reason that its exports of natural gas to United States are projected to shrink in coming years. Both the U. S. Energy Information Administration (EIA) and the National Petroleum Council (NPC) project a sharp decline in net imports of Canadian natural gas by 2025.[8] Making conventional liquid fuels out of natural gas is also a questionable use of natural gas from an environmental perspective.

In particular, for those who are concerned about global warming, it is critical that whatever strategy the United States adopts to reduce greenhouse gas emissions in the vehicle sector does not undermine

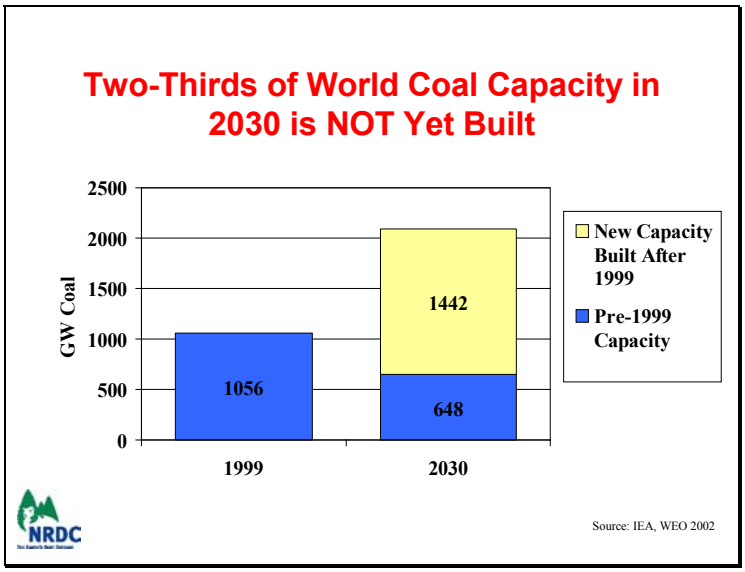
our efforts to reduce greenhouse gas emissions in the electricity sector. The nation has been sprinting to build new natural gas power plants. As of 2003, the U.S. had more than 800 gigawatts (GW) of central station electric power generation. "Of the 144 gigawatts added between 1999 and 2002, 138 gigawatts is natural-gas-fired," as EIA noted in 2002.[9]

Rising demand coupled with supply constraints has led to soaring natural gas prices. Remarkably, in its most recent *Annual Energy Outlook 2004*, EIA concludes that in the electricity sector, "the share from coal is projected to increase from 50 percent in 2002 to 52 percent in 2025 as rising in natural gas prices improved the cost competitiveness of coal-fired technologies. *AEO2004* projects that 112 gigawatts of new goal-fired generating capacity will be constructed between 2003 in 2025." At the same time, utilization of existing coal plants is projected to rise, so that by 2025, *coal consumption by electric generators will be 50% higher than today*.[10]

EIA projections are made assuming no change in U.S. policies, such as a cap on carbon emissions, and as such are often wrong. Yet, they underscore the critical need for a different energy policy and for using any incremental natural gas production/imports or renewable energy for displacing new coal fired generation, rather than for making alternative fuels for at least the next two decades.

Both the EIA and NPC project that far more of this country's growing demand for natural gas will be met from imported liquefied natural gas (LNG) than from increases in production. Thus, we should start thinking of the natural gas resource base as a global one when we contemplate using natural gas for purposes other than displacing increased coal generation. That's especially true because projected growth in global coal consumption is an even bigger greenhouse gas problem than projected US growth in coal consumption.

By 1999, the world had just over 1000 gigawatts of coal-fired electric generating capacity, of which about one third was in United States. Between 2000 and 2030, over 1400 GW of new coal capacity will be built according to the International Energy Agency, of which 400 GW will replace old plants (see Figure).



These plants would commit the planet to total carbon dioxide emissions of some 500 billion metric tons over their lifetime, unless "they are backfit with carbon capture equipment at some time during their life," as David Hawkins, Director of Natural Resources Defense Council's Climate Center told

the U.S. House Committee on Energy and Commerce in June 2003.[11] Hawkins continued: "To put this number in context, it amounts to half the estimated total cumulative carbon emissions from all fossil fuel use globally over the past 250 years!"

So again, it is critical that whatever strategy the world adopts to reduce greenhouse gas emissions in the vehicle sector does not undermine our efforts to reduce greenhouse gas emissions in the electricity sector. With this caveat in mind, we will explore the five pathways most widely discussed for reducing or replacing oil while significantly reducing transportation greenhouse gas emissions: efficiency, electricity (particularly plug-in hybrid-gasoline vehicles); ethanol from cellulosic biomass; synthetic diesel fuel; and hydrogen. To achieve greenhouse gas reductions, one or more of these pathways may require permanently sequestering carbon dioxide underground.

EFFICIENCY

Efficiency is typically the most cost-effective strategy for addressing major energy issues because the savings achieved from the reduction in energy consumption can offset some or all of the increase in cost of the efficient technology. Energy efficiency strategies often have a positive net present value or short payback. Alternative fuels typically have high costs—for the fuel, the vehicle, and the infrastructure—which undermines their cost effectiveness and practicality.

The fuel efficiency approach is the one this country used so successfully from the mid-1970s to mid - 1980s, when we doubled the fuel efficiency of our fleet while making our cars safer, mandating that new cars have a fuel efficiency of 27.5 miles per gallon (mpg). In a 2002 report to President Bush, the National Academy of Sciences concluded that automobile fuel economy could be further increased by 12 percent for small cars and up to 42 percent for large SUVs with technologies that would pay for themselves in fuel savings.[12] That study did not even consider the greater use of diesels and hybrids. Studies by the national laboratories for DOE, by the Massachusetts Institute of Technology, and by the Pew Center on Global Climate Change have concluded that even greater savings could be cost-effective while maintaining or improving passenger safety.[13] The Europeans have a voluntary agreement with automakers that will reduce carbon dioxide emitted per mile by 25% between 1995 and 2008-2009 for the average light-duty vehicle, which equates to a vehicle fuel efficiency of almost 40 mpg. Japan has a mandatory target with similar goals.[14]

Efforts to raise fuel economy standards have been stuck in political limbo for years. Because of this inaction, the fuel economy of the average vehicle on American roads is at its lowest level in two decades.[15] The fuel economy laws have a loop-hole allowing sport utility vehicles (SUVs) and light trucks to average 20.7 mpg, 25% lower than the new car standard. This has allowed overall vehicle efficiency to drop as the SUV share of new vehicle sales has grown. Ford, for instance, has backed off a voluntary commitment to increase SUV fuel efficiency, and, in fact, its 2003 model year SUVs were less fuel-efficient than the previous year.[16]

The two most potent arguments against raising fuel economy standards have centered around safety and jobs. The argument has been that fuel economy standards will inevitably push people into smaller and lighter vehicles. Such vehicles are supposedly less safe—a claim with little analytical support but tremendous political potency. The matching argument has been that Detroit makes most of its profit on bigger vehicles, and a move to smaller vehicles would inevitably come at the expense of profit and hence the jobs of autoworkers.

HYBRIDS

Hybrid gasoline-electric vehicles are a game changer for both of those arguments. The best hybrids, like the Toyota Prius, allow a 60% to 100% fuel economy gain with no reduction in weight or size. The onboard energy storage device, usually a battery, increases efficiency in several ways. It allows "regenerative braking"—recapturing energy that is normally lost when the car is braking. It also allows the internal combustion engine to be shut down when the car is idling or decelerating. It allows key components, such as the air-conditioning unit, to be run off the battery. Finally, because gasoline internal combustion engines have lower efficiencies at lower power, the battery allows the main engine to be run at higher power and thus more efficiently more of the time, especially in city driving.

Electrifying the car also has numerous safety and performance benefits. The Prius has an electronic brake-by-wire system that is arguably safer than traditional brakes, and hybrid electronics hold the promise of far more controllability, instant response, and safety. Ultimately we may see electric motor on every wheel for increased control. Also, most manufacturers are using some of the efficiency gain from the hybrids to increase acceleration, yet another performance gain.

Since hybrids actually cost a little more, they represent a source of increased income and jobs for Detroit and for the country as a whole. This creates the possibility of replacing imported oil with hardware manufactured by Americans. Temporary tax credits can help consumers with the price cost for initial models. But once hybrids are in mass commercialization in a variety of models from several automakers, their incremental costs will likely be less than three years of their gasoline savings—a good payback for all consumers and businesses.[17] Also one can't simply ascribe a pure cost to hybrids since they deliver performance, safety, engine-downsizing and other benefits beyond their energy savings.

General Motors has, until recently, been very dismissive of hybrids, especially hybrid cars. Indeed, as recently as January 2004, *CNN/Money* reported: "General Motors Corp. has no plans to try to answer the success of the Toyota Prius, the critically-acclaimed gas/electric hybrid car, said Robert Lutz, GM's vice chairman of product development. It just doesn't make environmental or economic sense to try to put an expensive dual-powertrain system into less expensive cars which already get good mileage, Lutz said at the North American International Auto Show."[18]

Yet by March, GM was taking out full-page ads in major newspapers and magazines, with a paragraph that begins: "HYBRIDS. Powered partly by engines, partly by batteries, hybrids deliver improved fuel economy with uncompromising performance…. Cars, trucks, SUVS and buses you already know and trust, with an extra boost at the fuel pump." So GM can no longer argue that fuel economy is incompatible with "uncompromising performance." And Ford Motor took out its own two-page ad in late March touting their new hybrid: "As the first and only gas/electric SUV, the Escape Hybrid compromises nothing."

GM's and Ford's ads highlight that hybrids are now likely winners in the marketplace, delivering improved performance with higher fuel economy. Probably the biggest danger for U.S. from a jobs and competitiveness perspective is if car companies fail to embrace them quickly enough.

Moreover, hybrids are almost certainly the platform from which all future clean vehicles will evolve. For instance, if we achieve two major scientific breakthroughs—in fuel cell membranes and hydrogen storage—then fuel cells may well be inserted into hybrids. If battery technology continues to improve, then plug-in hybrids are likely to become an attractive option. Biofuels require highly

efficient vehicles to reduce the land and infrastructure impact of a major switch away from gasoline. All of these issues are discussed further below.

So from a policy perspective, a top priority for any clean transportation technology is to promote the use of hybrids. Indeed, policy should promote hybrids that are also partial zero-emission vehicle (PZEV). These vehicles running on low-sulfur gasoline have very low tailpipe emissions, for instance, only 0.02 grams of NOx (nitrogen oxides) per mile. Both the Toyota Prius and the Ford Escape hybrid SUV are hybrid PZEVs. These vehicles qualify for special consideration under California air regulations as Advanced Technology Partial Zero Emission Vehicles (AT-PZEVs). Accelerating the market penetration of AT-PZEVs would go a very long way to addressing the impacts cars have on air quality, gasoline consumption, and greenhouse gas emissions while creating the conditions for the next generation of alternative fuels.

DIESELS

Diesel engines are the workhorses for big trucks and construction equipment because of their efficiency, durability, and high torque (the force that produces wheel rotation and hauling power) at low speed. Modern diesel engines are quite different from the smoky and noisy engines of the 1970s and 1980s, with advances such as "electronic controls, high-pressure fuel injection, variable injection timing, improved combustion chamber design, and turbo-charging."[19] Although they represent less than 1% of car and light truck sales in United States, diesels are becoming the car of choice in Europe, where gasoline prices are much higher, where fuel taxes favor diesel use, and where tailpipe emissions standards are less stringent.

Gasoline taxes in Europe and Japan are several times that of United States, and overall, their gasoline prices are two to three times that of ours. Gasoline in Japan, France, United Kingdom, and Germany costs between $3.60 and $4.60 per gallon.[20] In France and Germany, diesel fuel costs about $1 per gallon less than gasoline. Diesels have some 40% of the market for cars in Europe, and by 2001 represented the majority of new cars sold in a great many European countries. They are 20% to 30% more fuel-efficient than gasoline.[21]

While diesels currently have higher emissions of particulates and oxides of nitrogen, they are steadily reducing their emissions. Many believe that with the large amounts of R&D funding currently aimed at diesels, they will be able to meet the same standards as gasoline engines in the near future, but probably at a price premium.

A new global warming concern about diesel emissions involves their high level of emissions of black carbon (BC) or small some particles smaller than one micron (PM1.0). Recent work by NASA's James Hansen and others suggest that black carbon is a potent greenhouse gas.[22] One estimate even suggests that the black carbon emission from diesel engines may wipe out their global warming benefit compared to gasoline engines. As Princeton professor Bob Williams wrote in 2004, "Thus, ironically, the ongoing shift in Europe to diesel cars might lead to increased global warming even though it would help Europe meet its Kyoto obligations—because BC is not a greenhouse gas and is thus not covered by the Kyoto protocol or the Framework Convention on Climate Change."[23]

Under Federal Tier I emissions standards, diesel cars may have no greenhouse gas benefit versus gasoline engines. Under the stricter Tier II emissions standards now being phased-in, the black carbon problem is largely solved for diesel cars, and their greenhouse gas benefit returns, but, as Williams notes, "this would be accomplished at a significant extra first cost," which could be $500 to $750—and this is on top of the significant price increment one must pay for diesels versus gasoline-powered cars. Today's diesels already cost "between one and nearly six thousand dollars more than

their gasoline counterparts."[24] There is also be very legitimate concern that in the real world, emissions can be higher than mandated because cars and pollution control equipment often is operated differently than in tests and because some fraction of pollution-control equipment malfunctions.

The key to the success of diesels as a long-term greenhouse gas reduction strategy will be fuels with far lower net carbon dioxide emissions than current diesel fuels (possibly coupled with advanced particulate controls). This could include bio-diesels or, as will be discussed below, a synthetic diesel fuel made using a process that includes sequestration of carbon dioxide.

OTHER STRATEGIES

Some argue that radically new vehicle design strategies could have a huge impact on vehicle efficiency. One of the best-known proponents, Amory Lovins of Rocky Mountain Institute, recently argued that "designing and making cars differently—emphasizing ultralight weight, ultralow drag, an integrated design—can reduce required propulsive power by about two-thirds." He further argues that "new manufacturing and design methods can also make these radically more efficient vehicles cost-competitive and uncompromised."[25]

Such claims so far exist mainly at the "concept car" level. By way of comparison, "GM introduced the first fuel cell-powered concept vehicle nearly 40 years ago," as the company stated in a recent advertisement.[26] Radically different car designs not only require taking head-on the huge incumbent advantage of the sunk cost in the existing vehicle manufacturing infrastructure—which is especially problematic since early models of new vehicles typically have not achieved economies of scale and thus have a large cost disadvantage. At the same time, radically new vehicles must overcome obstacles related to public acceptance and concerns about safety

It may be that ultralight weight cars can be built as safe as existing cars, but the overwhelming public perception is that heavier cars are safer. There is little evidence at least in United States that people are ready to embrace ultralight weight cars. While small city cars that are commonly found in foreign capitals are not exactly the same as an ultralight, their complete absence from US roads suggests that the introduction of vehicles that weigh the same as city cars, even if they are larger, will be a difficult sell—unless there is a fundamental change in the car-buying public. Until we see ultralight weight vehicles from multiple car companies succeed in the US market, it would be unwise to basic government policy on the hope of their success.[27]

Currently, there is scattered anecdotal information that oil at $40 a barrel and gasoline at $2 a gallon is slowing sales of large SUVs (such as GM's Hummer) and spurring buyer interest in hybrids.[28] The fuel bill for the average American car is only about $100 a month, so even significant increases in the price of gasoline have small impacts on the budgets of consumers or the total annual operating costs of a vehicle. That is perhaps a key reason why for many years fuel economy has ranked relatively low on the list of desired attributes for a car. It is also a reason why gasoline taxes are not a potent policy tool.

Much higher oil prices could certainly influence consumer behavior to choose a different mix of vehicles. However, the rule of thumb is that a $1 a barrel price increase translates into a price increase of about 2.4 cents per gallon of gasoline.[29] So oil prices would have to approach $80 a barrel before the United States even saw gasoline prices near European levels. It seems unlikely such prices will be seen anytime soon for sustained period of time, especially since many forms of unconventional oil are already becoming economical at current prices, and technology continues to

improve to lower their cost.[30] Rather than an oil peak, we may well see an oil plateau, where carbon-intensive unconventional oil hold off the inevitable decline in conventional oil.

We believe that it is far more likely that global warming will be the catalyst for behavior change. Certainly there is little if any evidence today that global warming influences the car purchases of U.S. consumers. And given how slowly the climate changes, it could well be two decades (or more) before climate change becomes so painfully obvious as to change the way people think about their major energy-consuming purchases. If we are going to avoid serious climate change, the government needs to act now, rather than waiting and hoping for a major, permanent change in the public's vehicle tastes.

If their were a carbon cap or tax resulting in a price for carbon of $50 per metric ton, that would add 1.3 cents per kilowatt-hour for coal power plants with 34% efficiency, 0.5 cents per kilowatt-hour for natural gas power plants with 53% efficiency, and only 12.5 cents per gallon to gasoline.[31] So again it would probably take a prohibitively high price for carbon to drive gasoline prices just to European levels. A cap and trade system phased in predictably over an extended period of time that led to a moderate price for carbon, $50 to $100 a ton, is probably a critical strategy for driving fuel switching in the electricity and industrial sector, but its effect on the price of gasoline (and electricity for that matter) would be too small to encourage much efficiency. Thus achieving significant greenhouse gas reductions in the transportation sector in the medium-term will almost certainly require government mandates or regulations aimed at raising the average fuel economy of the fleet.

ALTERNATIVE FUELS and ALTERNATIVE FUEL VEHICLES

Alternative fuel vehicles (AFVs) and their fuels face two central problems. First, they typically suffer from several marketplace disadvantages compared to conventional vehicles running on conventional fuels. Hence, they inevitably require government incentives or mandates to succeed. Second, they typically do not provide cost-effective solutions to major energy and environmental problems, which undermines the policy case for having the government intervened in the marketplace to support them.

On the second point, in September 2003, the US Department of Transportation Center for Climate Change and Environmental Forecasting released its analysis, *Fuel Option for Reducing Greenhouse Gas Emissions from Motor Vehicles.* The report assesses the potential for gasoline substitutes to reduce greenhouse gas emissions over the next 25 years. It concludes that "the reduction in GHG emissions from most gasoline substitutes would be modest" and that "promoting alternative fuels would be a costly strategy for reducing emissions."

The U.S government and others (such as of California and Canada) have tried to promote AFVs for a long time. The 1992 Energy Policy Act established the goal of having alternative fuels replace at least 10% of petroleum fuels in 2000, and at least 30% in 2010. Currently, alternate fuels consumed in AFVs substituted for under 1% of total consumption of gasoline. A significant literature has emerged explaining this failure.[32] Besides the question of whether AFVs deliver cost-effective emissions reductions, there have historically been six major barriers to AFV success:

1. High first cost for vehicle
2. On-board fuel storage issues (i.e. limited range)
3. Safety and liability concerns
4. High fueling cost (compared to gasoline)
5. Limited fuel stations: Chicken & egg problem
6. Improvements in the competition (better, cleaner gasoline vehicles).

All AFVs that have so far been promoted with limited success—electric vehicles, natural gas vehicles, methanol vehicles, and ethanol vehicles—have each suffered from several of these barriers. Any one of these barriers can be a showstopper for an AFV or an alternative fuel, even where other clear benefits are delivered. MTBE, for instance, has had its biggest difficulty with the safety and liability issue, even though it has minimal problems in the other areas because it can be blended directly with gasoline. Electric vehicles deliver the clear benefit of zero tailpipe emissions, and can even have lower per mile costs than gasoline cars, but range, refueling, and first cost issues have limited their success and caused most major auto companies to withdraw their electric vehicles from the marketplace.

The chicken & egg problem—who will build and buy the AFVs if a fueling infrastructure is not in place and who will build the fueling infrastructure before the AFVs are built—remains the most intractable barrier. Consider that there are millions of flexible fuel vehicles already on the road capable of running on E85 (85% ethanol, 15% gasoline), 100% gasoline, or just about any blend, for about the same price as gasoline powered vehicles, and yet the vast majority of them run on gasoline and there are have been very few E85 stations built.

In the case of natural gas vehicles, the environmental benefits were oversold, as were the early cost estimates for both the vehicles and the refueling stations: "Early promoters often believe that 'prices just have to drop' and cited what turned out to be unachievable price levels." One study concluded, "Exaggerated claims have damaged the credibility of alternate transportation fuels, and have retarded acceptance, especially by large commercial purchasers."[33]

All AFVs face the increasing "competition" from improved gasoline-power vehicles. Indeed, two decades ago when tailpipe emissions standards were being developed requiring 0.02 grams/mile of NOx, few suspected that this could be achieved by internal combustion engine vehicles running on we formulated gasoline.

The new generation of hybrid PZEVs such as the Toyota Prius and Ford Escape hybrid have substantially raised the bar for future AFVs. These vehicles have no chicken and egg problem (since they can be fueled everywhere), no different safety concerns than other gasoline cars, a substantially *lower* annual fuel bill, *greater* range, a 40% to 50% reduction in greenhouse gas emissions, and a 90% reduction in tailpipe emissions. The vehicles do cost a little more, but that is more than offset by the current government incentive and the large reduction in gasoline costs, even ignoring the performance benefits. Compare that to many AFVs, whose environmental benefits, if any, typically come at the expense not merely of a higher first cost for the vehicle, but a much higher annual fuel bill, a reduced range, and other undesirable attributes from the consumer's perspective.

HYDROGEN

In an October 2003 paper for the Commission, we examined the difficulties facing hydrogen as an AFV. We will not repeat that analysis here, but will briefly report on some of the key analyses published subsequently, which tend to reinforce our main conclusions

The central challenge for any AFV seeking government support beyond R&D is that the deployment of the AFVs in the infrastructure to support them must cost effectively address some energy or environmental problems facing the nation. Yet in the spring issue of *Issues and Science and Technology*, two hydrogen advocates, Dan Sperling and Joan Ogden of U.C. Davis, wrote, "Hydrogen is neither the easiest nor the cheapest way to gain large near- and medium-term air pollution, greenhouse gas, or oil reduction benefits."[34] A 2004 analysis by Jae Edmonds et al. of Pacific

Northwest National Laboratory concluded in that even "in the advanced technology case with a carbon constraint … hydrogen doesn't penetrate the transportation sector in a major way until *after 2035*." A push to constrain carbon dioxide emissions actually delays the introduction of hydrogen cars because sources of zero-carbon hydrogen such as renewable power can achieve emissions reductions far more cost-effectively simply replacing planned or existing coal plants. As noted above, our efforts to reduce greenhouse gas emissions in the vehicle sector must not come at the expense of our efforts to reduce greenhouse gas emissions in the electric utility sector.

In fact, *Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context*, a January 2004 study by the European Commission Center for Joint Research, the European Council for Automotive R&D, and an association of European oil companies, concluded that using hydrogen as a transport fuel might well *increase* Europe's greenhouse gas emissions rather than reduce them. That is because many pathways for making hydrogen, such as grid electrolysis, can be quite carbon-intensive and because hydrogen fuel cells are so expensive that hydrogen internal combustion engine vehicles may be deployed instead (which is already happening in California). Using fuel cell vehicles and hydrogen from zero-carbon sources such as renewable power or nuclear energy has a cost of avoided carbon dioxide of more than $700 a metric ton, which is considerably higher than most other strategies being considered today.[35]

A number of major studies and articles have recently come out on the technological challenges facing hydrogen. A DOE study noted that transportation fuel cells currently cost about $5,000/kw, some 100 times greater than the cost of internal combustion engines.[36] A 2004 article for the Society of Automotive Engineers noted, "Even with the most optimistic assumptions, the fuel cell powered vehicle offers only a marginal efficiency improvement over the advanced [diesel]-hybrid and with no anticipation yet of future developments of IC engines. At $100/kW, the fuel cell does not offer a short term advantage even in a European market."[37]

A prestigious National Academy of Sciences panel concluded a major report in February with a variety of important technical conclusions.[38] For instance, the panel said, "The DOE should halt efforts on high-pressure tanks and cryogenic liquid storage…. They have little promise of long-term practicality for light-duty vehicles." A March study by the American Physical Society concluded that "a new material must be discovered" to solve the storage problem.[39] An analysis in the May 2004 issue of *Scientific American* stated, "Fuel-cell cars, in contrast [to hybrids], are expected on about the same schedule as NASA's manned trip to Mars and have about the same level of likelihood."[40]

Hydrogen fuel cell vehicles face major challenges to overcome each and every one of the barriers discussed above. Of all AFVs and alternative fuels, fuel cell vehicles running on hydrogen are probably the least likely to be a cost-effective solution to global warming, which is why the other pathways deserve at least equal policy attention and funding.

PLUG-IN HYBRIDS

A straightforward improvement to hybrids can allow them to be plugged into the electric grid and run in an all-electric mode for a limited range between recharging. Since most vehicle use is for relatively short trips, such as commuting, which are followed by an extended period of time during which the vehicle is not being driven and could be charged, even a relatively modest all-electric range of 20 or 30 miles could allow these vehicles to replace a substantial portion of gasoline consumption and tailpipe emissions. If the electricity were from CO_2-free sources, then these vehicles would also have dramatically reduced net greenhouse gas emissions.

Because they have a gasoline engine, plug-in hybrid electric vehicles (PHEVs) avoid two of the biggest problems of pure electric vehicles. First they are not limited in range by the total amount of battery charge. If the initial battery charge runs low, the car can run purely on gasoline and on whatever charging is possible from the regenerative breaking. Second, electric vehicles take many hours to charge, so that if for some reason owners were unable to allow the car to charge—either because they lacked the time between trips to charge or there was no local charging capability—then the pure-electric car could not be driven. In some respects, PHEVs combine the best of both hybrids and pure electric vehicles.

Battery improvement will lead to increased functionality for PHEVs. Improvements in specific energy (Wh/kg) and specific power (W/kg) will reduce weight. Reductions in cost and increases in cycle life (durability) will make PHEVs more affordable. Adequate safety is a requirement. Operating temperature is important, but batteries with unusual operating temperatures may be considered if other benefits are demonstrated. Convenience of recharging is crucial, but the definition of "convenience" varies by users. A full recharge overnight from an ordinary home outlet is generally considered to be sufficient for a personal PHEV. Larger vehicles might require higher charging voltages, or possibly undergo a battery cartridge replacement rather than recharging.

BATTERY CHARACTERISTICS: ENERGY AND POWER

Batteries with high *specific energy* can store large amounts of electricity for their weight. A gasoline tank has a specific energy of about 12 kWh/kg. This is roughly 100 times as great as the best batteries. Electric vehicles require batteries with high specific energy, and range is a function of energy capacity. Most batteries have a minimum charge threshold that should generally be maintained. This is often about 20% of full capacity. While the batteries can tolerate occasional discharges below this point, repeated deep discharges will damage the battery. The computer controls in a hybrid can automatically preserve this margin.

Batteries with a high *specific power* can discharge their electricity quickly in powerful bursts. The power of a gasoline vehicle is determined by the engine, not the fuel tank; a typical gasoline engine has a specific power of about 150-400 W/kg,[41] which is generally at the lower range of what batteries can achieve. Electric vehicles, by comparison, have their maximum power output determined by both the batteries and the motor. When the weight of the electric motor is taken into account, electric vehicles and gasoline vehicles are roughly comparable. Acceleration is largely a function of specific power, so specific power is important in hybrid vehicles.

Current hybrid-electric vehicles like the Toyota Prius are not designed for extended operation in pure electric mode, so they have typically optimize their batteries to provide high specific power. Because plug-in hybrids use the battery both for supplemental power for acceleration and for extended electric-only operation, they require high specific energy and high specific power. There is a tradeoff—for a given battery technology, higher specific power tends to increase cost per kWh of storage capacity.

There are many battery technologies under investigation for use in electric vehicles. The most widely used or most promising are discussed below.

LEAD ACID

Lead acid batteries are currently used in most automobiles for starting, lighting, and ignition applications. Some electric vehicles have been made with lead-acid batteries, including General Motors' EV I and the many electric vehicles in use at the beginning of the 20th century. Lead-

acid batteries are inexpensive, but have poor specific energy, specific power, and lifetime. Lead-acid batteries are not seen as a promising technology for EV, HEV, or PHEV vehicles.

NICKEL METAL HYDRIDE

Nickel metal hydride (NiMH) batteries are used in existing hybrid vehicles. These batteries offer a higher power density and longer deep-cycling lifetimes compared to lead-acid batteries. Toyota Prius uses NiMH batteries, covered under an 8-yr/100,000-mile warranty. NiMH batteries do suffer from self-discharge over time.[42]

A 2001 EPRI study projected NiMH batteries as the most plausible battery technology for PHEV vehicles, although life cycle requirements remained a concern. EPRI estimated that the lowest reasonable price for NiMH batteries in 2010 would be $250/kWh, leading to a system incremental cost of $5782 for a PHEV60 (of which $4844 is battery cost).[43]

Recent information from Cobasys (formerly Texas Ovonics) indicates that the 12V NiMH batteries alone can have a specific energy of 43 Wh/kg and a specific power of 1100 W/kg at 50% depth of discharge (DOD). When assembled into hybrid electric systems of higher voltage, specific energy is 27-33 Wh/kg and specific power is 667-824 W/kg (depending on size).

A report prepared for the California Energy Commision concluded that, with recent advances, the lifetime of NiMH batteries in pure EVs was over six years.[44] The report also noted that specific energy for EVs can be up to 65 Wh/kg, and that a 30-kWh pack was expected to cost $9,000 at production volume of hundreds of thousands per year. A 2001 presentation by Dr. John Heywood of MIT notes that NiMH batteries configured for use in EVs can have specific energy of 70 Wh/kg and specific power of 150 W/kg, whereas those configured for use in HEVs can have specific energy of 40 Wh/kg and specific power of 400 W/kg.[45] The Cobasys design features a substantial improvement in specific power over that cited by Heywood, but only a marginal improvement in specific energy.

LITHIUM-ION

Lithium-ion batteries demonstrate considerable potential for specific energy and specific power. Although currently expensive to manufacture, and posing some safety concerns, they are a primary focus of inquiry.

Sandia National Laboratory noted in 2000, "The lithium-ion battery has four times the energy density of lead-acid batteries and two to three times the energy density of nickel-cadmium and nickel-metal hydride batteries"[46] Argonne National Laboratory noted in 2001 that the best laboratory designs for lithium-ion batteries provide "specific power up to 1 kW/kg and a cycle life of more than 100,000 shadow-discharge (10%) cycles. The battery operates at ambient temperatures, although at 50°C (122°F) the calendar life of the cell is shortened significantly."[47]

Lithium-ion battery modules require protective control circuitry to prevent dangerous overcharging conditions. Deep-discharge cycle lifetime is uncertain. Manufacturers claim they will be able to produce at comparable cost to NiMH. More recently, lithium-ion batteries have been observed displacing NiMH as the battery of choice for cell phones.[48]

The following information is provided by GlobTek, a supplier of lithium-ion batteries:

Voltage (V)	3.6 / 3.7
Specific Energy (Wh/Kg)	100-160
Specific Energy (Wh/L)	250-360
Cycle Life (Times)	1000
Operation Performance at -20°C (Relative to Capacity at 25°C)	90%
Self-Discharge Rate (%/month)	6-9
Memory Effect	no

Lithium ion batteries are increasingly used in consumer electronics, but are not yet widely used in vehicles. An electric vehicle developer recently constructed a vehicle with a battery pack consisting of 6,800 conventional consumer-electronic lithium-ion batteries (battery designation 18650). The "tzero" vehicle has a range of 250 miles at 75-80 mph and can accelerate from 0-60 in 3.6 seconds. Because the 18650 battery is mass-produced in huge volumes, AC Propulsion found assembling a huge number to be a less expensive option that purchasing a lithium-ion battery pack designed for EV operation.[49] The battery weigh 43 g each for a total of 292 kg, but the designers estimate that a conventional EV would only use about half as many cells (AC Propulsion was interested in demonstrating extremely high performance).

Lithium ion polymer batteries attempt to improve on conventional lithium ion batteries. The primary advantage is geometry, as these can be shaped in a variety of forms. They are more expensive than conventional lithium-ion batteries and have lower energy density and cycle life. They are also somewhat safer (less risk of overcharge) and lighter. Sony and Sanyo are among the principal developers of lithium-ion polymer batteries. Recent batteries have achieved a specific energy of 95 Wh/kg and specific power of up to 2000 W/kg at full charge (down to 1300 W/kg at 80% depth of discharge).[50]

SODIUM NICKEL CHLORIDE

Sodium nickel chloride batteries include the "Zebra" batteries made by MES-DEA in Switzerland. They are currently used in the bus and commercial vehicle market.[51] There is also no self-discharge and no overcharge gassing reaction (as can happen with lithium batteries). Peak power is retained down to 80% depth of discharge, and the battery has a 90% useful depth of discharge.[52] Energy density is similar to that of lithium-ion batteries, at about 94 Wh/kg according to the company's documentation.[53] Cost is currently at $500/kWh but with a projected $220/kWh for volume production.[54]

One drawback to sodium nickel chloride batteries is the high-temperature operation. Batteries operate within an insulated box (300 °C). However, an NREL review found that the batteries were generally unlikely to present significant public safety hazards.[55] Specific power is also low, at 169 W/kg. For use in hybrids, the company seeks to increase specific power to at least 350 W/kg.[56]

These batteries are currently used in transit bus applications, at the 600V size. For such use, the manufacturer provides a one-year warranty. The manufacturer estimates a 75% chance of the battery lasting at least two years and 50% chance of lasting at least three years in transit bus application.[57]

Many other battery chemistries are being explored, and it is possible if not likely that future battery technologies will outperform the best current technologies.

BARRIERS

PHEVs avoid many of the barriers to AFVs discussed earlier. They do not have a limited range. They do not have major safety and liability issues—although great care would have to be taken in the design of any home-based system that charged PHEVs or allowed them to feed back into the grid. They do not have a high fueling cost compared to gasoline. In fact, the per mile cost of running on electricity is likely to be less than the per mile cost of running on gasoline. The chicken & egg problem is minimized because electricity is widely available and charging is relatively straightforward.

The vehicle will almost certainly have a higher first cost, but this is likely to be more than compensated by the economic benefit of a lower fuel bill, as the 2003 study by The California Energy Commission and Air Resources Board concluded. Also, that study did not consider a large potential revenue stream the vehicle owner may be able to extract from the utility by having what is essentially a portable electric generator.

The largest potential revenue stream that a PHEV owner might be able to extract is for so-called spinning reserves, which, as one analysis explains, "are contracts for generating capacity that is up and running, and is synchronized with the power line." When called upon, a spinning reserve "must ramp up to its full output within 10 minutes." Spinning reserves are valuable to a utility or power system because they contribute "to grid stability helping to arrest the decay of system frequency when there is a sudden loss of another resource on the system."[58] Value can also be extracted by generators that can provide faster response when grid voltage needs to be increased or decreased, so-called "regulation services." Since cars are designed to start rapidly, they could quickly add their power to the electric grid when needed. Utilities would pay for this service if there was a guarantee that the car could deliver juice when needed, which suggests that this is more practical for vehicle fleets or for a corporate sponsor.

The potential value of such services is significant: $700 to $3000 per year.[59] This value is so large that it might allow the monthly cost of purchasing or leasing a PHEV to be *lower* than a conventional car, and perhaps even cover the replacement cost for batteries if they prove not to have a 100,000+ mile lifetime typically expected of modern cars. It is critical that we fund some real-world demonstrations of PHEVs providing these services, to see if this value can be extracted. If it can, we might see major utilities helping to subsidize the cost and/or financing of PHEVs.

Environmentally, PHEVs offer two potentially significant benefits. First, since they are designed to run all electric for short trips such as commuting, they offer the possibility of being zero-emission vehicles (ZEVs) in cities. Since the decision to run the car all electric will reside with the driver, some method of verification will be required if these vehicles are to receive ZEV credit. Given that early adopters, such as electric utilities, will probably want to maximize all-electric use, some sort of remote verification (similar to smart-pass technology) seems viable. The best early uses of PHEVs may well be to replace dirty diesel engine vehicles used regularly in cities, such as buses, maintenance vehicles, and delivery trucks. If hydrogen fuel cell cars ultimately prove impractical, PHEVs may be the only viable option for urban zero emission vehicles.

The potential greenhouse gas benefits of PHEVs are even more significant, if a source of zero-carbon electricity can be utilized for recharging. PHEVs have an enormous advantage over hydrogen fuel cell vehicles in utilizing zero-carbon electricity. That is because of the inherent inefficiency of generating hydrogen from electricity, transporting hydrogen, storing it onboard the vehicle, and then running it through the fuel cell. The total well-to-wheels efficiency with which a hydrogen fuel cell vehicle might utilize renewable electricity is 20% to 25%. The well-to-wheels efficiency of charging

an onboard battery and then discharging it to run an electric motor in a PHEV, however, could exceed 80%.

As Alec Brooks, a leading designer of electric vehicles, has shown, "Fuel cell vehicles that operate on hydrogen made with electrolysis consume *four times as much* electricity per mile as similarly-sized battery electric vehicles."[60] Ulf Bossel, founder of the European Fuel Cell Forum, comes to a similar conclusion in a recent article, "The daily drive to work in a hydrogen fuel cell car will cost four times more than in an electric or hybrid vehicle."[61]

This relative inefficiency has enormous implications for achieving a sustainable energy future. To replace half of U.S. ground transport fuels (gasoline and diesel) in the year 2050 with hydrogen from wind power, for example, might require 1400 gigawatts of advanced wind turbines or more. To replace those fuels with electricity in PHEVs might require under 400 gigawatts of wind. That 1000 GW difference may represent an insurmountable obstacle for hydrogen as a greenhouse gas mitigation strategy—especially since the U.S. will need several hundreds of gigawatts of wind and other zero-carbon power sources in 2050 just to sharply reduce greenhouse gas emissions in the electricity sector. As Bossel writes, "the forced transition to a hydrogen economy may prevent the establishment of a sustainable energy economy based on intelligent use of precious renewable resources."

CELLULOSIC ETHANOL

Biomass can be used to make a zero-carbon transportation fuel, like ethanol, which is now used as a gasoline blend. Today, the major biofuel is ethanol made from corn, which yields only about 25% more energy than was consumed to grow the corn and make the ethanol, according to some estimates. Considerable R&D is going on into producing ethanol made from sources other than corn. This so-called cellulosic ethanol can be made from agricultural and forest waste as well as dedicated energy crops, such as switchgrass or fast-growing hybrid poplar trees, which can be grown and harvested with minimal energy consumption, so overall net emissions are near zero.[62]

All cars today can use a mixture of 10% ethanol and 90% gasoline, E10. Some 4 million flexible-fuel vehicles, which can run on either gasoline or a blend with 85% ethanol, E85, are on the road today, but few use E85 because of its high price. This suggests that we cannot solve the chicken-and-egg problem for an alternative fuel merely by delivering a cost-effective vehicle capable of running on that fuel.

The big advantage ethanol has over alternative fuels like hydrogen (and natural gas) is that it is a liquid fuel and thus much more compatible with our existing fueling system. Existing oil pipelines, however, are not compatible with ethanol, so significant infrastructure spending would still be required if ethanol were to become the major transportation fuel.[63] Ethanol production will require major technological advances before matching the price of gasoline on an equivalent energy basis. Lester Lave and two other Carnegie Mellon University researchers present the following calculation:

> Producing cellulosic ethanol costs about $1.20 per gallon (1.80 per gallon, gasoline equivalent, since ethanol has two-thirds of the energy of a gallon of gasoline). Assuming that the per-gallon distribution costs are the same for ethanol and holding total tax revenue constant, ethanol would sell for $1.80 per gallon at the pump. However, this is equivalent to $2.70 per gallon in order to get as much energy as in a gallon of gasoline.[64]

This calculation should viewed as a projection given that there are no commercial cellulosic ethanol plants anywhere in the world as of 2004. Nonetheless, it suggests two things. First, if oil prices in, say, 2020 are higher than they are today, then cellulosic ethanol will represent a potentially quite competitive alternative fuel. This is particularly true since a price for carbon is virtually inevitable by 2020, further improving the relative cost competitiveness of cellulosic ethanol to gasoline. The average price of gasoline United States has already hit $2.00 a gallon with oil at $40 a barrel. Given that our first strategy for reducing greenhouse gas emissions must be fuel efficiency, particularly hybrids, we will be unlikely to need substantial amounts of cellulosic ethanol until post-2020. At that time we will have a far clearer picture of future trends in climate change and in the production of both conventional and carbon-intensive unconventional oil. The key will be to ensure that we have taken aggressive measures long before then to bring down the cost of cellulosic ethanol through R&D as well as efforts to subsidize the first initial plants. The Commission, through its support of "The Role for Biomass in America's Future" project, is developing a variety of valuable recommendations in this area. It is possible that would still need technological progress and economies of scale in production plants, cellulosic ethanol could drop to under $2.00 per gallon of gasoline equivalent.

The second conclusion we might draw from cost projections for cellulosic ethanol is that if we can develop a substantial biomass resource for the purpose of creating a low-carbon fuel, it will almost certainly be more cost-effectively used to make cellulosic ethanol than hydrogen. As the National Academy of Sciences panel on the hydrogen economy concluded in February 2004, "hydrogen production from biomass is a thermodynamically inefficient and expensive process, in which approximately 0.2% to 0.4% of the total solar energy is converted to hydrogen at a price of currently about $7.05/kg H2 by gasification in a midsize plant. Even with major technology breakthroughs, "the committee estimates the possible future technology price for hydrogen from gasification of biomass to be $3.60/kg H2, which is noncompetitive relative to other hydrogen production technologies."[65]

For hydrogen production from biomass, perhaps the biggest problem is how expensive and energy-intensive it is to transport hydrogen over long distances. Unfortunately, large biomass resources tend to be quite distant from population centers where vehicle fuel is needed, and transporting solid biomass is also very expensive and energy intensive. Converting that biomass to a liquid fuel like cellulosic ethanol and then transporting that fuel is likely to be the most cost effective and least energy-intensive way of delivering a low-carbon bio-based fuel. A particularly significant benefit of using biomass to make cellulosic ethanol rather than hydrogen is that the switchover to ethanol can be done gradually, as more and more ethanol is blended with gasoline, whereas any switchover to hydrogen almost certainly requires a massive government subsidy for the infrastructure to attempt to solve the chicken-and-egg problem.[66]

BARRIERS

Probably the biggest barrier to biofuels, and to biomass energy in general, is that biomass is not very efficient at converting and storing solar energy, so large land areas are needed to provide enough energy crops if biofuels are to provide a significant share of transportation energy. One 2001 analysis by ethanol advocates concluded that to provide enough ethanol to replace the gasoline used in the light-duty fleet, "it would be necessary to process the biomass growing on 300 million to 500 million acres, which is in the neighborhood of one-fourth of the 1.8 billion acre land area of the lower 48 states" and is roughly equal to the amount of all U.S. cropland in production today.[67] That amount of displaced gasoline represents about 60% of all U.S. transportation-related carbon dioxide emissions today, but under 40% of what is projected for 2025 under a business-as-usual scenario. Given the acreage needed, using so much land for these purposes would obviously have dramatic environmental, political, and economic implications.

Thus, if ethanol is to represent a major transportation fuel in the coming decades, then U.S. vehicles will need to become much more fuel-efficient. Doubling the efficiency of the fleet by 2030 with hybrid engines and other advanced technology would substantially reduce the biomass acreage requirements. And putting cellulosic ethanol blends into plug-in hybrids with further reduce acreage requirements, especially since there are plausible strategy for cogeneration of biofuels and biomass electricity.

In the long-term, biomass-to-energy production could be exceedingly efficient with "bio-refineries" that produce multiple products. Lee Lynd, professor of engineering at Dartmouth, described one such future bio refinery where cellulosic ethanol undergoes a chemical pretreatment, then fermentation converts the carbohydrate content into ethanol, as carbon dioxide bubbles off.[68] The residue is mostly lignin (a polymer found in the cell walls of plants). Water is removed, and the biomass residue is then gasified to generate electricity or to produce a stream of hydrogen and carbon dioxide. The overall efficiency of converting the energy content of the original biomass into useful fuel and electricity would be 70%, even after accounting for the energy needed to grow and harvest the biomass. The carbon dioxide can be sequestered. Also, this process could be used to generate biodiesel. This is admittedly a futuristic scenario, but is the subject of intense research, and could make ethanol directly competitive with a gasoline, and biomass electricity competitive with other zero-carbon alternatives, especially when there is a price for avoiding carbon dioxide emissions. The syngas could also be used to make synthetic diesel fuel (see below).

SYNTHETIC DIESEL FUEL FROM COAL

Interest has renewed in coal-derived diesel fuels for several reasons. The surge in diesel vehicles has led to a desire to find a long-term low-carbon fuel for diesels. Several of the nations that will be key to any action on global warming have vast coal resources, including the United States, China, and India. And there has been growing policy interest in as well as R&D funding for carbon capture and storage, which may make it possible to utilize coal resources for making fuels (and electricity) without increasing greenhouse gas emissions.

America's coal resource base is vast. Recoverable coal reserves amount to about 270 billion tons, or 250 years at current production rates.[69] The demonstrated reserve base is almost 500 billion tons, and the total resource base may exceed 4 trillion tons.[70] Coal is also relatively inexpensive compared to other fossil fuels, a key reason it generates over 50% of U.S. electricity. Numerous considerations constrain the use of coal as an energy resource. Mining can have significant impacts on land and water. When burned, coal produces sulfur oxides (SO_x), nitrogen oxides (NO_x), mercury, and particulate matter (PM). Coal also produces more carbon dioxide per unit of energy produced than oil or natural gas.

Technological innovations can ameliorate many of the difficulties associated with the use of coal as an energy resource. By converting coal to liquid or gaseous fuels, it will be possible to use it for transportation, greatly reducing the risks of price shocks associated with increasing demand for oil outpacing supply. Gasification and liquefaction can remove nearly all of the sulfur and mercury from the coal, dramatically reducing pollutant emissions. If carbon sequestration is proven to be effective, coal-derived liquid fuels could have lower CO_2 emissions than conventional diesel or gasoline. Production of liquid fuels from coal offers a viable option for energy security for the U.S., China, and other coal-rich countries.

Synthetic fuels development was a focus of U.S. energy independence efforts in the 1970's. Efforts were largely abandoned, but then resumed in the 1990's. In 2001, the National Energy

Technology Laboratory held a series of "Clean Liquid Fuels" workshops. One coal-to-liquids facility is under development in Gilberton, PA.[71] The project was awarded a DOE grant for a feasibility study in 2000; the facility has since been funded for development through the Clean Coal Power Initiative.[72] The facility will seek to produce electricity and liquid fuels from waste coal; CO_2 sequestration is a possibility.

Coal can be converted to liquid or gaseous fuels through a number of processes. Some of these were pioneered in the Second World War to provide fuel for airplanes and tanks. Germany in particular employed a number of technologies, including lignite distillation, Fischer-Tropsch processes, and hydrogenation.[73]

Indirect coal liquefaction first combines the coal with oxygen and steam or water to produce synthesis gas (also known as syngas), which is most often a mix of carbon monoxide and hydrogen.[74] The syngas can then be processed into liquid or gaseous fuels such as Fischer-Tropsch liquids, dimethyl ether (DME), or methanol. Toxic metals can be removed from the syngas through a carbon filter. Direct coal liquefaction skips the syngas step, and includes technologies such as distillation and hydrogenation (adding hydrogen to a coal-water slurry). The addition of hydrogen improves the H/C ratio, bringing the resulting product closer to lighter hydrocarbons such as those found in gasoline or diesel fuel. It also removes sulfur, allowing for clean-burning fuel.[75] Direct liquefaction results in a crude oil, which is then be further refined.

For purposes of mitigating climate change, synthetic diesel fuels seem to present an appealing option. Diesel compression-ignition engine (CIE) cars are 20% to 30% more efficient than gasoline spark-ignition engine (SIE) cars, and hybrid technology offers the potential for further efficiency gain. As noted above, however, using conventional diesel fuel, black carbon (soot) can offset the greenhouse gas benefits—even if vehicle particulate matter standards are tightened by a factor of eight down to 0.01 grams per mile.[76] Although some assessments dispute this conclusion (because particulate matter also includes light-colored matter that produces some cooling effects), it is widely recognized that at the very least particulate matter has a number of harmful health effects. For any replacement fuel, low PM emissions are an advantage.

Producing liquid fuels from coal with no carbon sequestration would increase net CO_2 emissions relative to petroleum-derived fuels. Because much of the CO_2 generated in the coal-to-liquids process is a central waste stream, capture and storage may be a viable strategy, which would significantly reduce this impact and allow such coal-derived fuels to have the coal or lower net greenhouse gas emissions than regular diesel fuel. Further, blending in some biomass with the coal before it is gasified and the CO_2 is sequestered can sharply reduce net emissions, as the biomass pulled CO_2 out of the air while it was growing and the sequestration process then permanently stores it underground.

DIMETHYL ETHER (DME)

DME can be made from biomass, natural gas, or coal. If it is made from biomass, the life-cycle CO_2 emissions are 25% that of diesel. If it is made from natural gas, emissions are comparable to diesel. And, if made from coal, CO_2 emissions would be 90% higher than diesel if the CO_2 were vented, but could be reduced to 20% less than diesel with sequestration of CO_2 and H_2S.[77] By one calculation, carbon sequestration might add only 15% to the cost of DME.[78]

Used in a diesel engine, DME provides substantial reductions in particulate matter (PM) and nitrogen oxides (NOx). As noted by Dr. Bob Williams, "For DME used in a heavy duty CIE, uncontrolled emissions of NOx and PM have been measured to be 58% and 75% less than for conventional Diesel."[79] Black carbon soot is virtually eliminated due to the absence of carbon-

carbon bonds. However, DME is a gas at standard temperature and pressure. For use as a vehicle fuel, it would require moderate compression (similar to propane) to liquefy it for distribution. This would entail considerable infrastructure investments.

FISCHER-TROPSCH (F-T) LIQUIDS

The Fischer-Tropsch process can produce fuel out of syngas. It also offers a way to recover "stranded" natural gas (resources that would be uneconomical to transport in gaseous form). While diesel fuel is easily produced, the lighter components can be processed into gasoline with substantial refining. Fischer-Tropsch processes are widely used in South Africa to produce liquid fuels from coal.

Fischer-Tropsch liquids can be transported through the existing infrastructure and used in existing engines. They offer a substantial opportunity to reduce dependence on petroleum, and offer modest environmental benefits. In a 1998 study, emissions from trucks were measuring using California diesel and Fischer-Tropsch diesel. F-T emissions were lower by 12% for NOx, 24% for PM, CO by 18%, and hydrocarbons by 40%.[80] Fischer-Tropsch diesels are also very low in aromatics, a class of compounds that includes hazardous chemicals such as benzene.[81] However, life-cycle CO_2 emissions from Fischer-Tropsch liquids are higher than for petroleum-derived fuels unless sequestration is employed.[82]

Indirect coal liquefaction through the Fischer-Tropsch process provides a "safety valve" against oil price shocks or supply disruptions. Its emission characteristics are superior to conventional diesel, and its cost may be competitive. The National Academy of Sciences estimated an achievable cost of F-T diesel at $35/bbl, or $30/bbl with electricity co-production.[83] This cost is for commercialized technology, not pioneer plants. The Academy also notes that "experience with sustained R&D indicates that DOE's goal of $25/bbl (1991 dollars) for coal-based liquids may be attainable with continued research and systems studies."[84]

BARRIERS

The challenges to widespread use of coal-derived fuels are significant. As Bob Williams explains, "the major drawback of DME is that requires a new gaseous fuel infrastructure."[85] Thus it faces most of the same barriers that have proved intractable for other alternative fuels in the United States. DME may prove a more viable fuel in areas countries without in existing gasoline infrastructure, such as China.

Fischer-Tropsch diesel does not have the infrastructure problems. Price, however, remains a problem and, as with cellulosic ethanol, someone will have to take the risk with the first several pioneer plants. Also, particulate matter, while lower than conventional diesel, is still high enough to be a significant concern for both global warming (black carbon) and direct human health impact.

Finally, until sequestration is demonstrated to be politically, economically, and environmentally viable on a large-scale, neither F-T diesel nor DME will make sense from a global warming perspective.

SEQUESTRATION ISSUES

Costs for geological sequestration are currently quite high, more than $30 a ton of carbon dioxide, according to the DOE.[86] The technical challenges for reducing those costs are significant. A February 2003 workshop on carbon management by the National Academy of Sciences concluded, "At the present time, technology exists for the separation of carbon dioxide and hydrogen, but the capital and

operating costs are very high, particularly when existing technologies is considered for fossil fuel combustion or gasification streams."[87] Significant R&D is being invested to bring the costs down.

The key question is where to put the carbon dioxide. Recent attention has focused on pumping highly compressed liquid CO_2, so-called supercritical CO_2, into geological formations, such as deep underground aquifers. As the National Academy workshop noted, "Less dense than water, CO_2 will float under the top seal atop the water in an aquifer and could migrate upward if the top seal is not completely impermeable."

The problem here is that even very tiny leakage rates can undermine the environmental value of such sequestration. If we are trying to stabilize CO_2 concentrations at twice preindustrial levels, a 1% leakage rate could add $850 billion *per year* to overall costs by 2095, according to an analysis by Pacific Northwest National Laboratory. That study concluded, "Leakage of CO_2 from engineered CO_2 disposal practices on the order of 1% or less per year are likely intolerable as they represent an unacceptably costly financial burden that is moved from present generations to future generations."[88] If we cannot be certain that leakage rates are below 1%, "the private sector will find it increasingly difficult to convince regulators that CO_2 injected into geological formations should be accorded the same accounting as CO_2 that is avoided," avoided, that is, directly through technologies such as wind power. The authors note that, "there is no solid experimental evidence or theoretical framework," for determining likely leakage rates from different geological formations.

How long will it take before carbon capture and storage emerges as a major solution to global warming? That remains uncertain. As Princeton's Bob Williams wrote in 2003, "One cannot yet say with high confidence that the CO_2 storage option is viable."[89] The technology itself is very challenging, and just as commercializing fuel cells has taken much longer and has proven far more difficult than was expected, so, too, may building large commercial coal gasification combined cycle units.[90] Through its FutureGen program, DOE is aiming to design and build a prototype coal plant that would cogenerate electricity and hydrogen and sequester 90% of the carbon dioxide. The goal is to "validate the engineering, economic, and environmental viability" of a system by 2020.[91]

CONCLUSION AND RECOMMENDATIONS

We must change our transportation policy if we are to address rising dependence on imported oil and greenhouse gas emissions. Avoiding serious climate change will almost certainly require a significant reduction in projected U.S. transportation greenhouse gas emissions by 2025—and a dramatic reduction in absolute emissions by 2050. Moreover, whatever strategy we used to reduce transportation carbon dioxide emissions must not interfere with our equally urgent efforts to minimize any increase in coal emissions and then to reduce those emissions.

The only plausible strategy for achieving significant reductions in projected vehicle petroleum use and carbon dioxide emissions by 2025 is fuel efficiency. For achieving 2050 targets, we believe that the most plausible strategy is a plug-in hybrid (PHEV) running on a combination of low-carbon electricity and a low-carbon biomass-derived fuel. The hydrogen fuel cell is the AFV that has the most technical and infrastructure hurdles and is the least efficient pathway for utilizing renewable resources. Given these conclusions, we have a number of recommendations:

Phase in CO_2-related standards for cars and light trucks. We should aim for at least a 33% reduction in CO_2 emissions per mile for new vehicles by 2020 (which would still leave new U.S. vehicles less efficient than European vehicles will be by 2010). Absent such standards, emissions and imports will continue to grow sharply. There is no escape from a government mandated solution, whether in the form of CO2 emissions standards or a rebate for efficient vehicles and feebate for inefficient vehicle. Absent a standard, much of the efficiency gain of new technologies will likely go towards providing increased vehicle acceleration and weight, as it has for the past two decades. Ideally, the government would adopt measures that would accelerate the market penetration of hybrids, particularly hybrid partial ZEVs, since that is the best platform for the subsequent generation of vehicles needed to achieve absolute reductions in vehicle carbon dioxide emissions by 2050.

Aggressively pursue plug-in hybrids. If PHEVs were to prove practical, they are probably the ideal future platform for addressing all three major problems created by current vehicles: greenhouse gas emissions, tailpipe emissions, and oil consumption. PHEVs would likely utilize renewable electricity resources three to four times more efficiently than hydrogen fuel cell vehicles, and have a comparably lower per mile cost of operation. Federal and state governments should launch a major R&D effort to develop PHEVs and immediately begin pilot programs to see how they operate in real-world conditions. It is particularly important to learn if economic value can be derived from electric utility services, such as spinning reserves, provided by PHEVs when they are not being driven. If so, PHEVs might have no price penalty compared to conventional vehicles. Also worth exploring is how to capture the air quality benefits from PHEVs running all-electric during ozone-alert days.

Aggressively promote biomass-derived fuel. The most plausible biofuel for delivering significant reductions in U.S. greenhouse gas emissions and oil consumption in the medium- and long-term is cellulosic ethanol. We endorse the recommendations that the Commission has received through its support of "The Role for Biomass in America's Future" Project, including

- Driving the development of the first six pioneer cellulose-to-energy plants between 2008 and 2012 using production or investment incentives;
- Modifying agricultural subsidies to include energy crops without increasing total farm subsidies or decreasing farm income; and
- Increasing and/or redirecting R&D towards biofuels.

We agree with the Project that the biofuels "effort should be at least as large as that currently underway for hydrogen." Research and development into synthetic diesel fuel made from a mixture of gasified coal and biomass should be pursued, accompanied by R&D into capturing and storing the hydrogen from this process. Ultimately, a renewable (or low-carbon) fuels standard will be beneficial, especially in helping to ensure that alternative fuels like hydrogen or synthetic diesel actually reduce greenhouse gas emissions.

Take a long-term, conservative perspective on hydrogen. While hydrogen might ultimately prove to be a viable and environmentally desirable alternative fuel post-2035, it is currently getting funding and policy attention that is vastly disproportionate to both its probability of success and likely environmental benefits. Hydrogen should be viewed as a long-term, high-risk R&D effort, requiring at least three major scientific breakthroughs (fuel cell membranes, storage, and renewable hydrogen generation) before it is practical or desirable. It is worth continuing hydrogen R&D, but at least twenty years premature to be investing substantial funds in deploying vehicles or infrastructure. The only pilots that are justified are those that feed back directly into the R&D process. For hydrogen cars to be cost-effective in reducing greenhouse gas emissions, the government will *first* have to sharply shift our current energy policy to make renewable power the primary source of U.S. electricity. Also, hydrogen is no alternative to government regulations; indeed, for hydrogen and fuel

cell vehicles to become commercially successful, the federal government will have to intervene in the vehicle marketplace far more than it has ever done in the past.

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[1]Writing about the future prospects of hydrogen and other alternative fuels is necessarily speculative, since it involves making comparisons among a variety of different technologies that are not a commercial today and some of which may never become commercial. Our conclusions are based on discussions with dozens of experts and a review of dozens of major recent studies.

[2]*Reducing California's Petroleum Dependence*, Joint Agency Report, California Energy Commission and California Air Resources Board, Sacramento, August 2003

[3]Energy Information Administration (EIA), *Annual Energy Outlook 2003*, January 2003, Washington DC, Table A19.

[4]www.iea.org/Textbase/press/pressdetail.asp?PRESS_REL_ID=127

[5]Joseph Romm and Charles Curtis, "Mideast Oil Forever?" *Atlantic Monthly*, April 1996 (www.theatlantic.com/issues/96apr/oil/oil.htm).

[6]Kenneth Deffeyes, *Hubbert's Peak: The Impending Oil Shortage* (Princeton: Princeton University Press, 2001), p. 158.

[7]"Energy Needs, Choices and Possibilities: Scenarios to 2050," Global Business Environment, Shell International, London, 2001 (www.shell.com/static/media-en/downloads/51852.pdf), p. 18.

[8]Energy Information Administration (EIA), *Annual Energy Outlook 2004*, January 2004, Washington DC, p. 50.

[9]Energy Information Administration (EIA), *Annual Energy Outlook 2003*, January 2003, Washington DC, p. 67.

[10]*AEO2004*, pp. 6, 155

[11]David G. Hawkins, Testimony, U.S. House Committee on Energy and Commerce, Subcommittee on Energy and Air Quality, June 24, 2003 (www.nrdc.org/globalWarming/tdh0603.asp).

[12]National Research Council, Effectiveness and Impact of Corporate Average Fuel Economy (CAFE) Standards, National Academy Press, Washington, DC, 2002 (www.nap.edu/books/0309076013/html/).

[13]Interlaboratory Working Group 1997, p. 5.44-5.48; David Greene and Andreas Schafer, "Reducing Greenhouse Gas Emissions from U.S. Transportation," Pew Center on Global Climate Change, Arlington, VA, May 2003 (www.pewclimate.org), pp. 13-18; and Malcolm Weiss et al., "On The Road In 2020: A life-cycle analysis of new automobile technologies," MIT, Cambridge, MA, October 2000 (http://mit42v.mit.edu/public/In_the_News/el00-003.pdf), Tables 5.3 and 5.4.

An Oak Ridge National Laboratory study found that "based on a comparison of fatality data for SUVs to other vehicles, the registered-vehicle-fatality rate (defined as number of fatalities per number of registered vehicles) for SUVs is higher than the registered-vehicle-fatality rate for other vehicles." Stacy Davis and Lorena Truett, *An Analysis of the Impact of Sport Utility Vehicles in the United States*, ORNL, Oak Ridge, TN, August 2000, p.24 (www-cta.ornl.gov/cta/Publications/Final%20SUV%20report.pdf).

[14]Greene and Schafer, p. 48.

[15]Alliance to Save Energy, "Increasing Automobile Fuel Efficiency," Fact Sheet, Washington, DC, May 2003 (www.ase.org/policy/factsheets/TFS.htm).

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[16]"Ford Says New S.U.V.'s Less Fuel-Efficient Than Old Ones," *New York Times*, July 18, 2003 (www.nytimes.com/2003/07/18/business/18CND-FORD.html).

[17]Greene and Schafer, 14.

[18]Chris Isidore, "GM: Hybrid cars make no sense," *CNN/Money*, January 6, 2004, money.cnn.com/2004/01/06/pf/autos/detroit_gm_hybrids/.

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