U.S. RELIANCE ON INTERNATIONAL LIQUEFIED NATURAL GAS SUPPLY

A POLICY PAPER PREPARED FOR THE

NATIONAL COMMISSION ON ENERGY POLICY

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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.

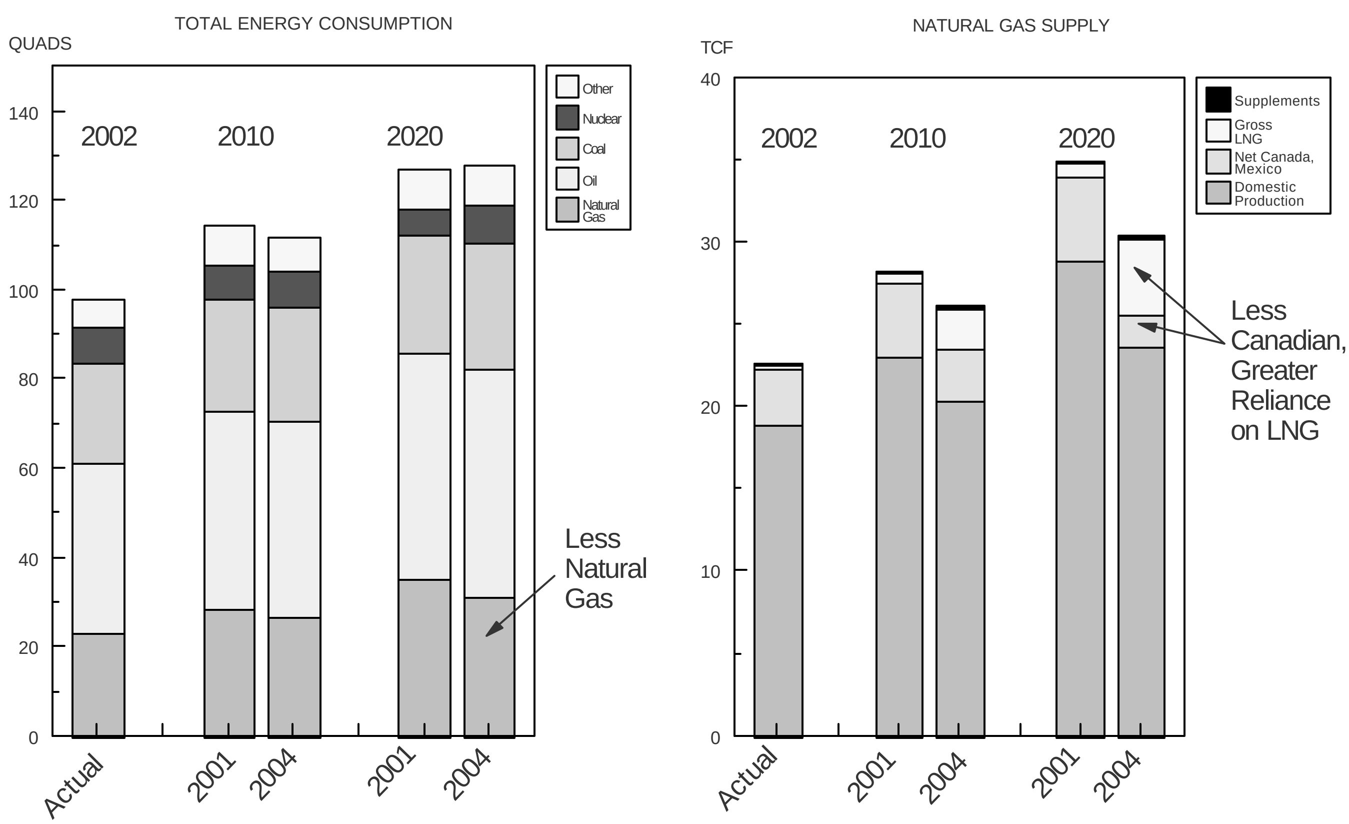
Most U.S. analyses of the likely growth of LNG imports are highly introspective, focusing on future North American gas prices and the likely construction of import terminal capacity. There is a widespread tendency to assume that if the terminal siting controversy can be resolved, LNG will flow into the 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:

o 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?

- o 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?
- o What are the economic implications of U.S. competition with Europe and Asia for LNG?
- o 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 260^{o}F) 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.

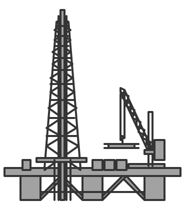
Initially, the technology developed in the Atlantic Basin and Algeria became the principal supplier. While the first deliveries from Algeria were comparatively short hauls to Europe, the U.S. entered the market first in 1972 when deliveries began for a small Distrigas (Cabot) project at Everett, MA. 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.

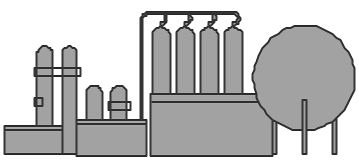
The period from 1972, when Distrigas started up, and 1982, when Trunkline started, was a period of almost unprecedented change in world energy markets. It included the first "oil price shock" with its sharp changes in world oil price levels. And for the U.S., it included the appearance of the regulation-induced 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.

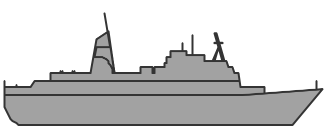
Figure 2-1

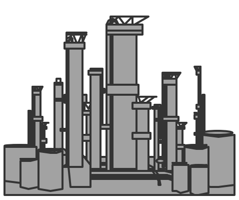
ELEMENTS OF AN LNG DELIVERY SYSTEM

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



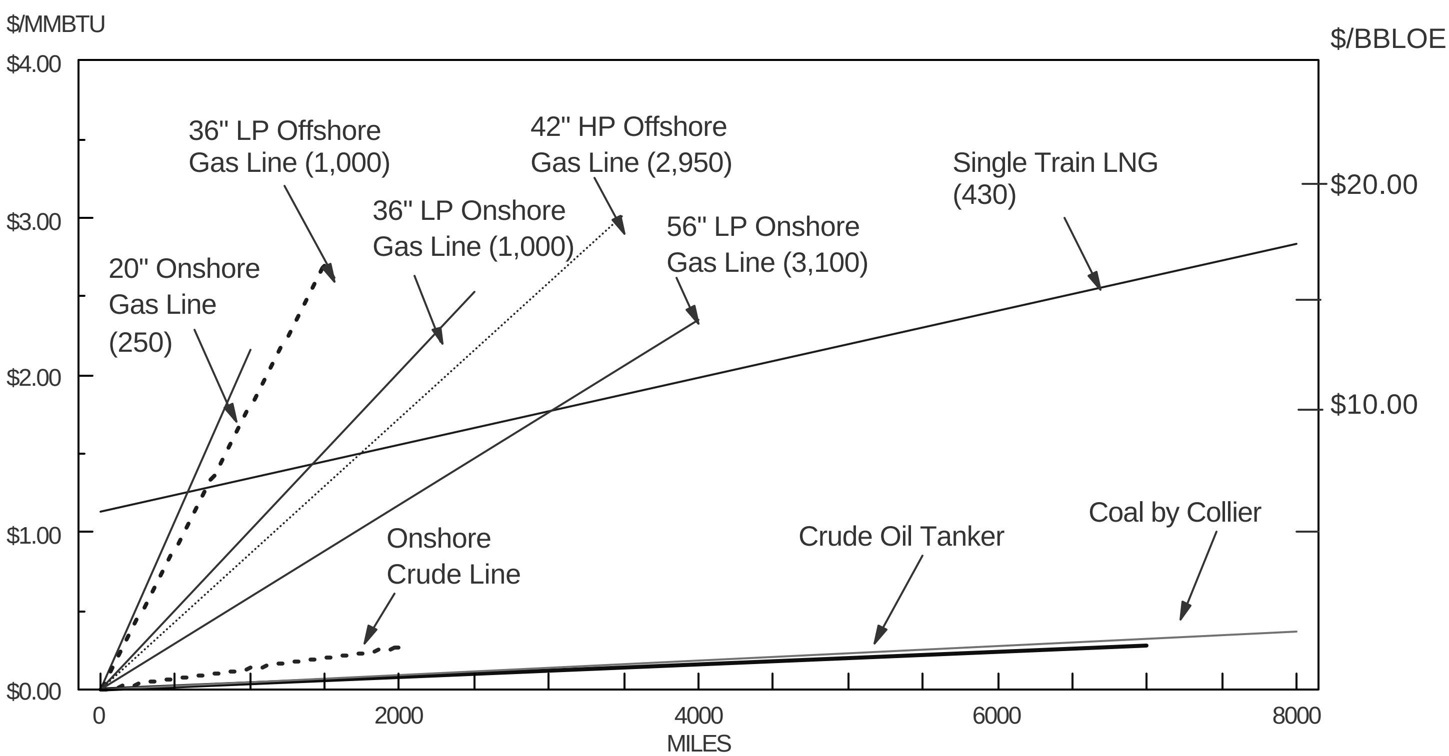






	CAPEX	MARGIN
Field Development (Varies)	$1.3 Bn	$0.80
Liquefaction	$1.6 Bn	$1.22
Tankers (10 @$180 Mn)	$1.6 Bn	$0.98
Regasification (Varies)	$0.5 Bn	$0..39
Total	$5.0 Bn	$3.39

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)



Jensen

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

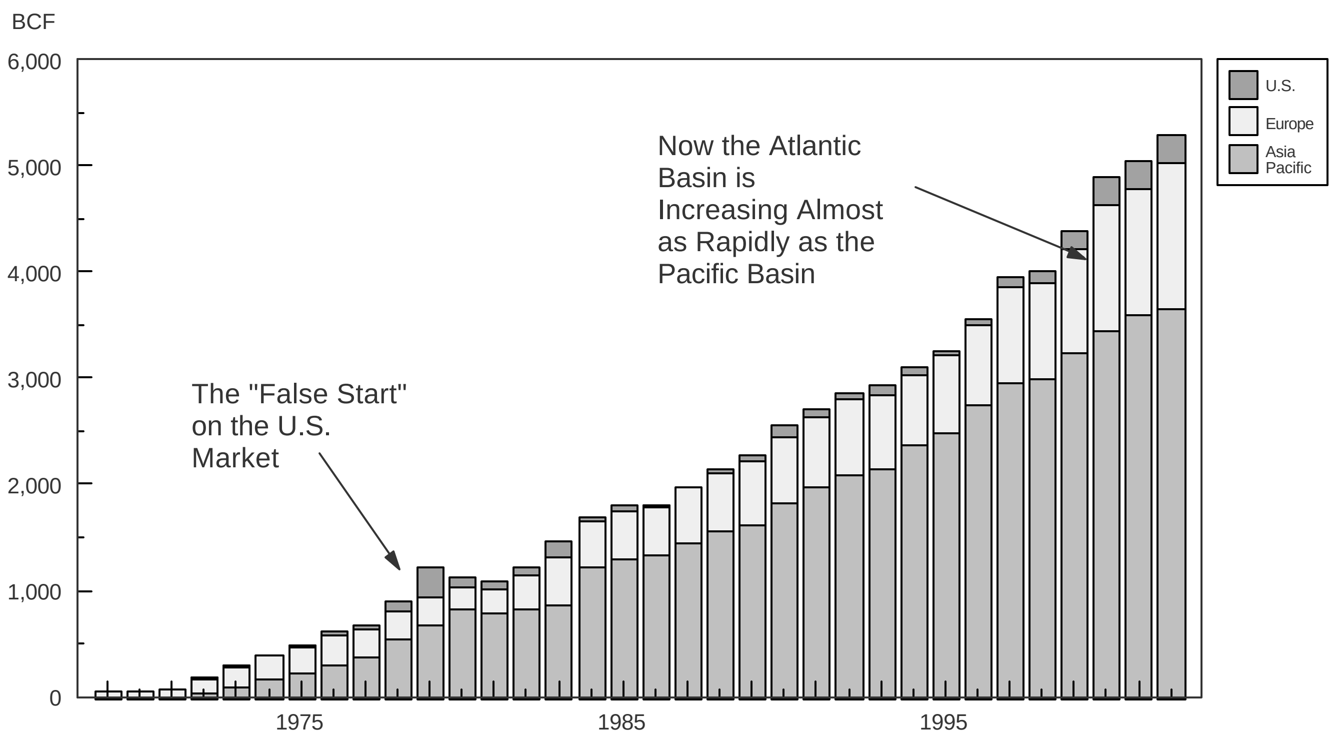


Figure 2-4

GROWTH OF LNG EXPORTS BY REGION

BCF

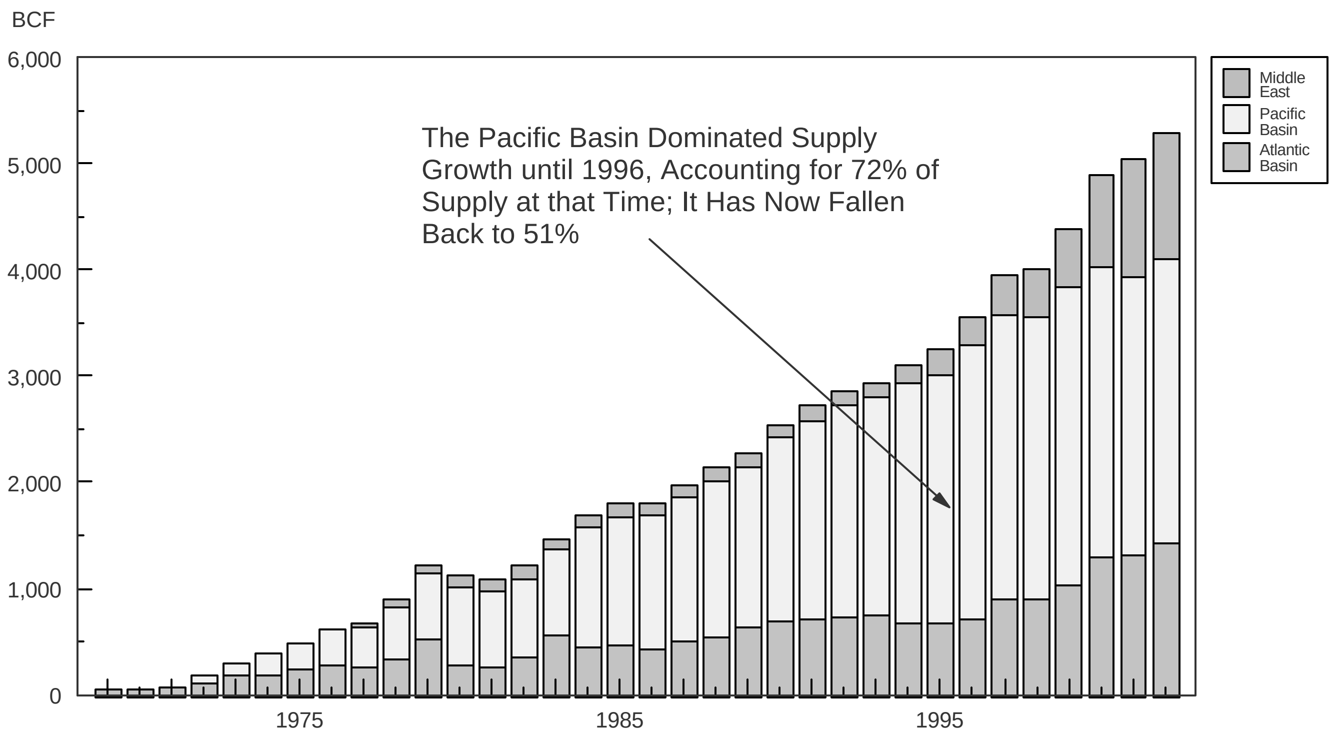


Table 2-2 provides similar information about the exporting countries.

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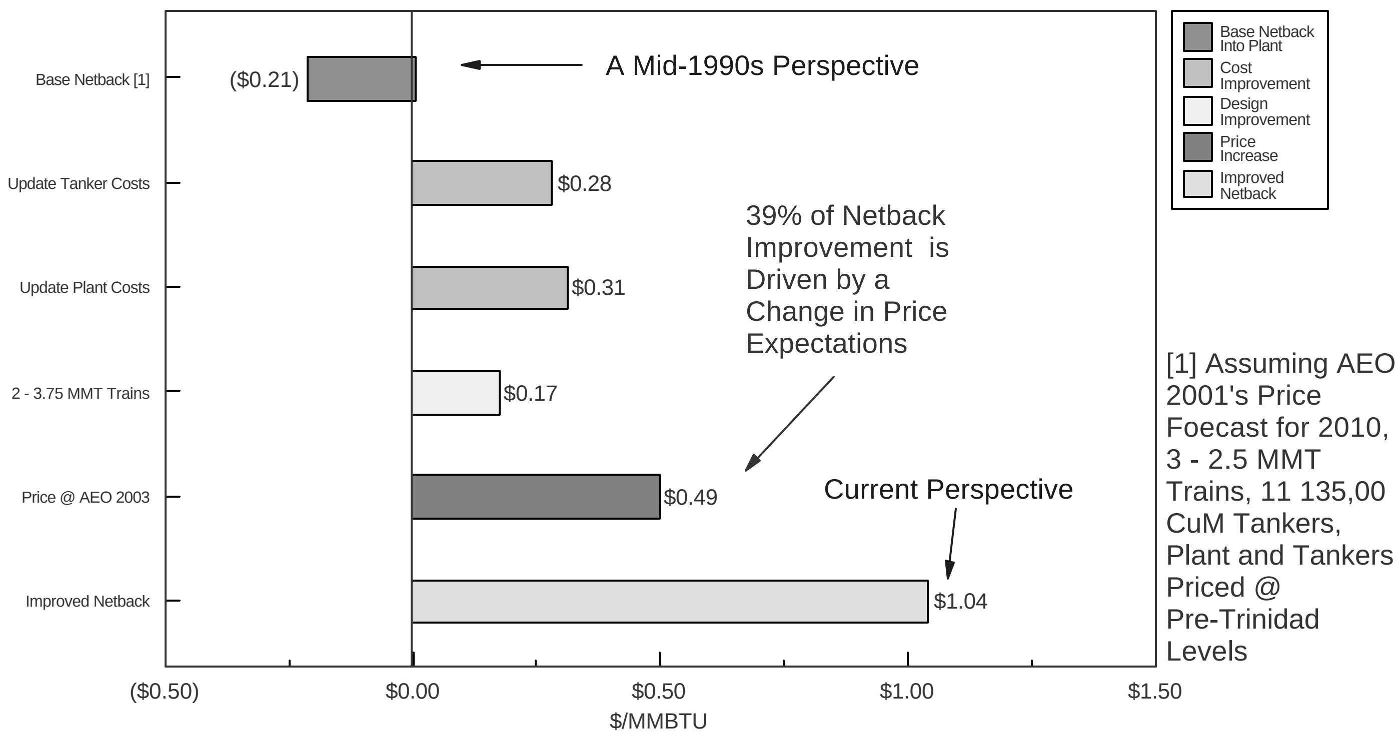
[3] "Netback" refers to the calculation commonly made in determining the economics of developing gas fields. It refers to the remaining value of the gas after deducting all downstream costs from the price that the gas would command in the marketplace.

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



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

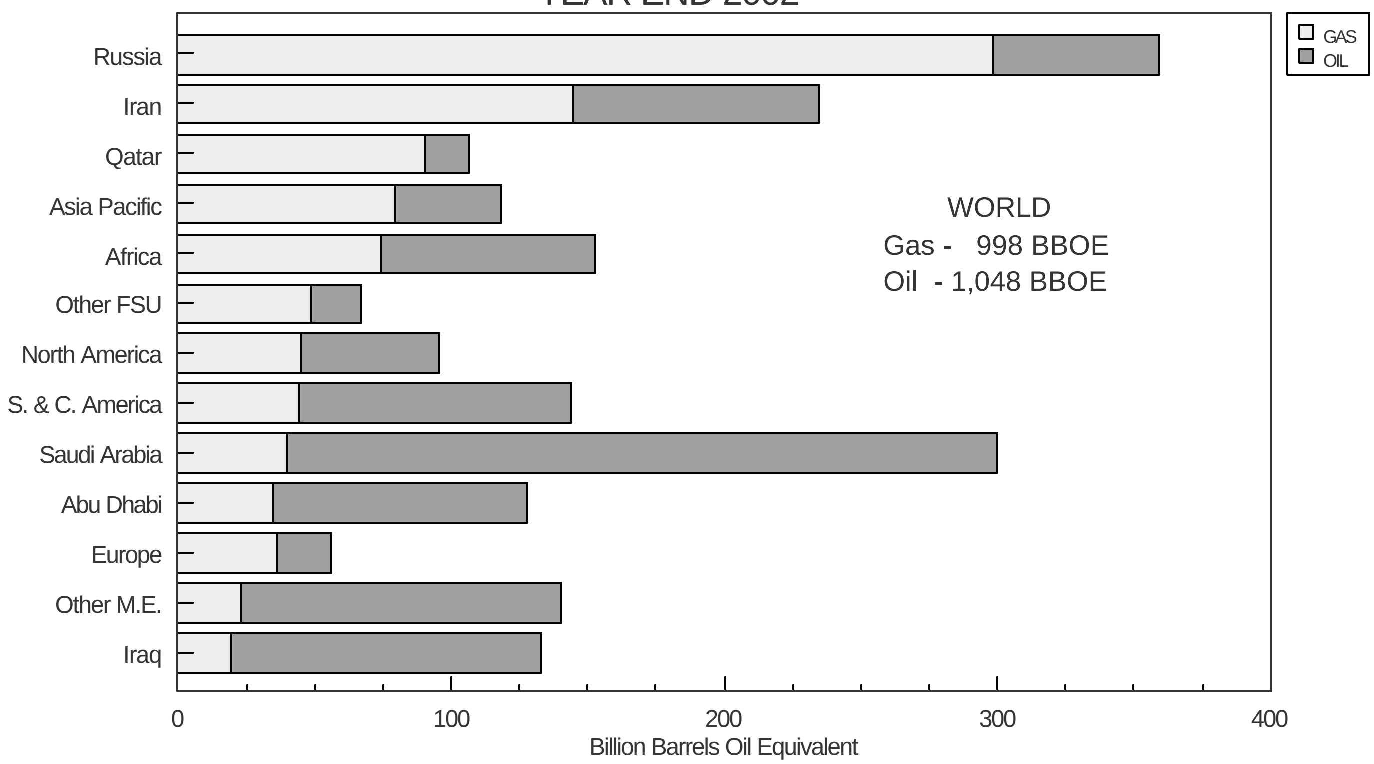
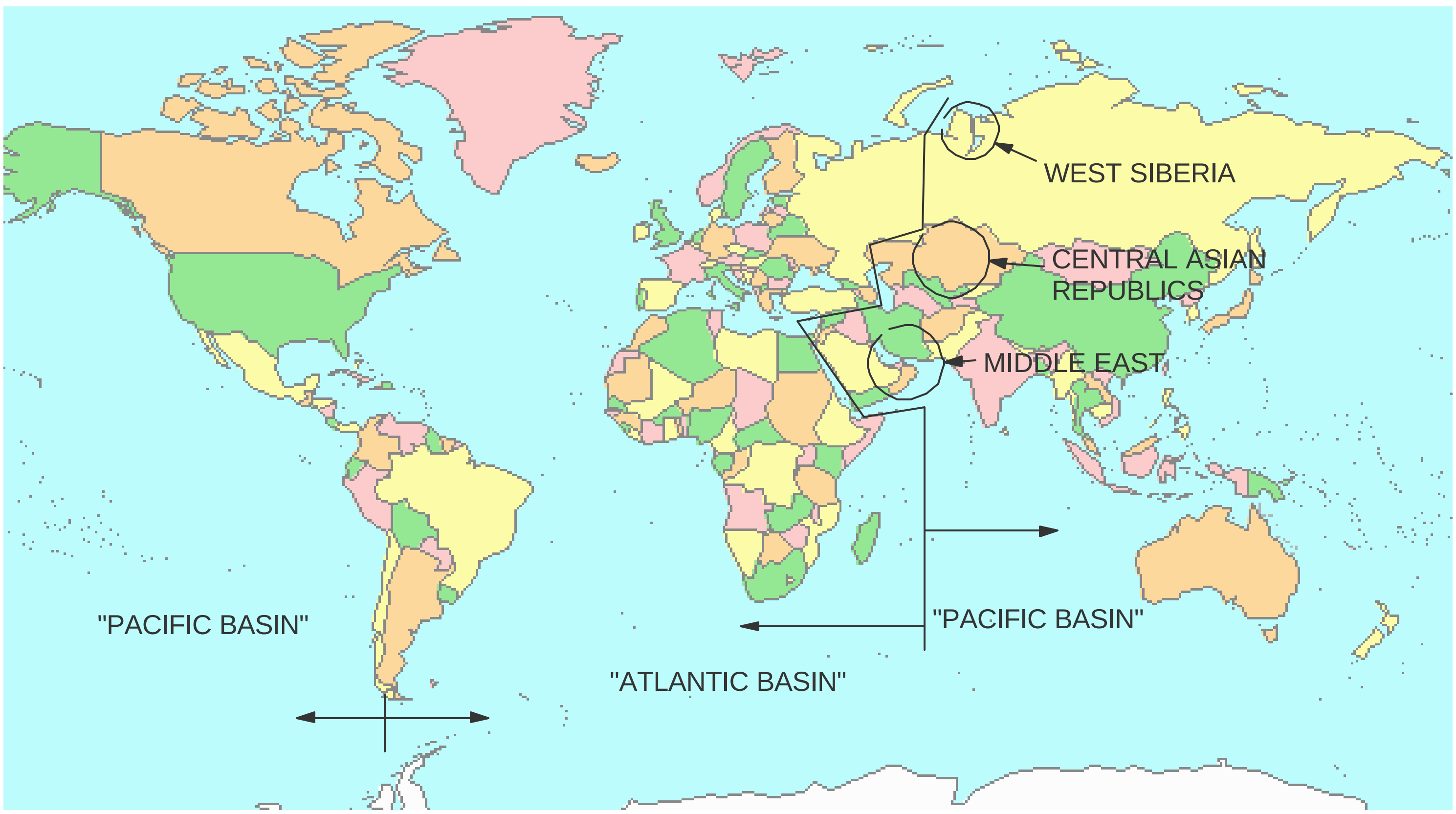


Figure 3-2

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.

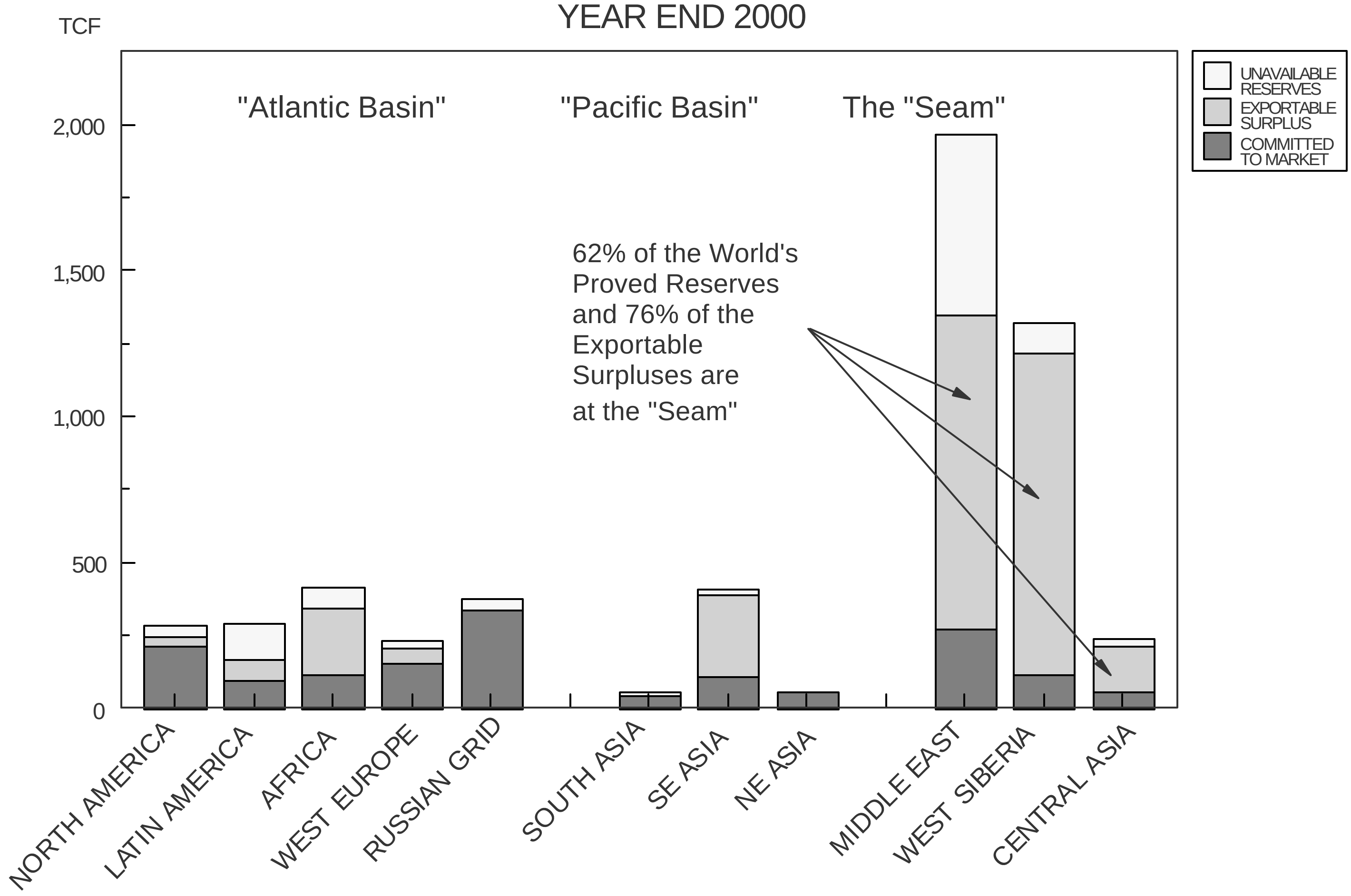
The only LNG facility originally designed to operate on associated/dissolved gas was the small Libyan plant. Nigeria flares more gas than any other country and the early pressures on the companies to reduce flaring led to the interest in LNG. However, the early feedstock to the Bonny, Nigeria liquefaction 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

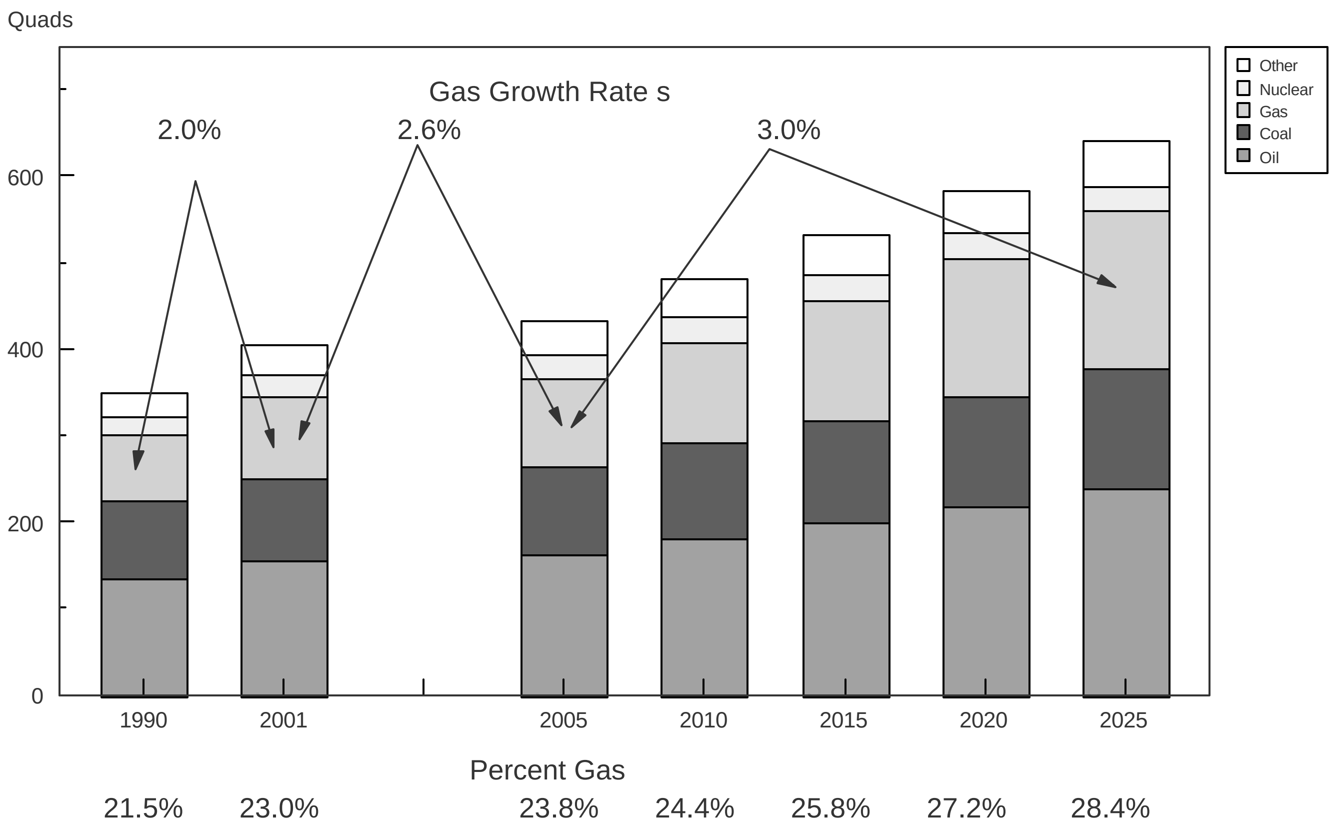


Figure 4-2

PROJECTED GROWTH IN WORLD GAS DEMAND TO 2025 BY REGION

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS

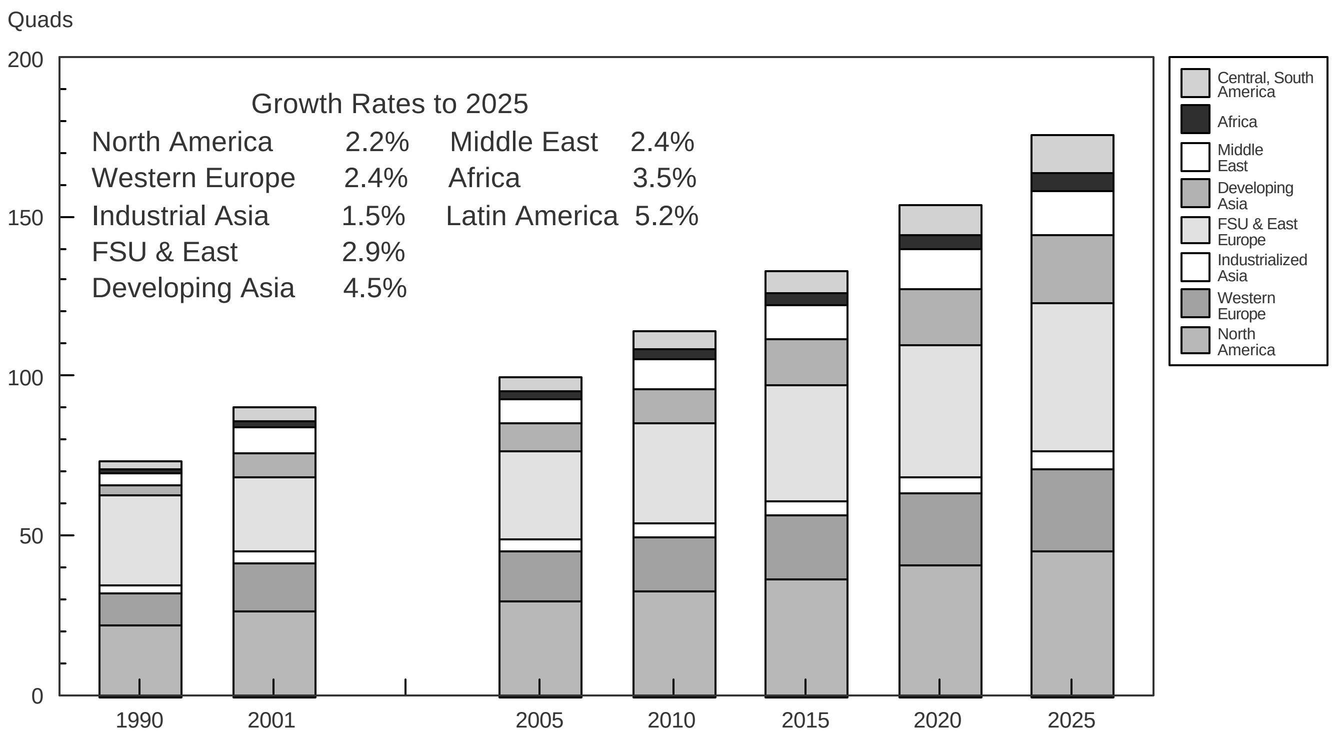


Figure 4-3

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

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS

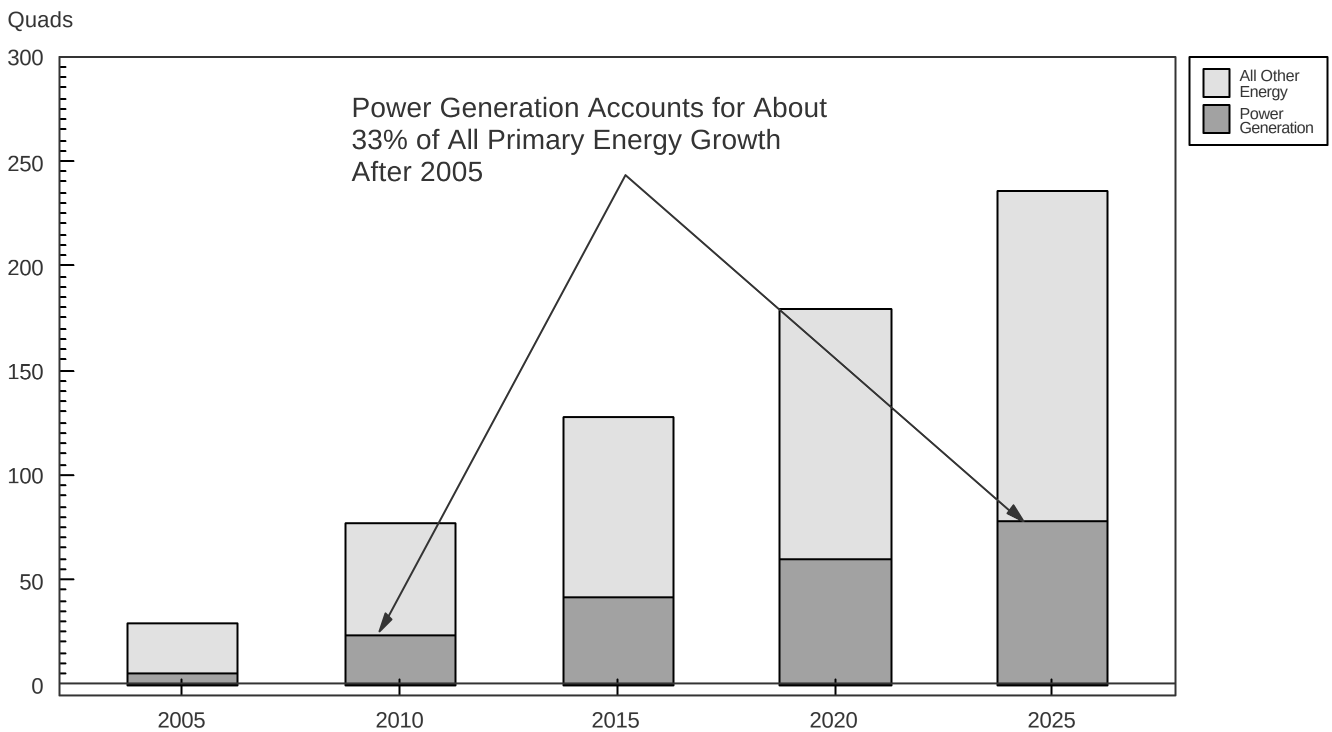
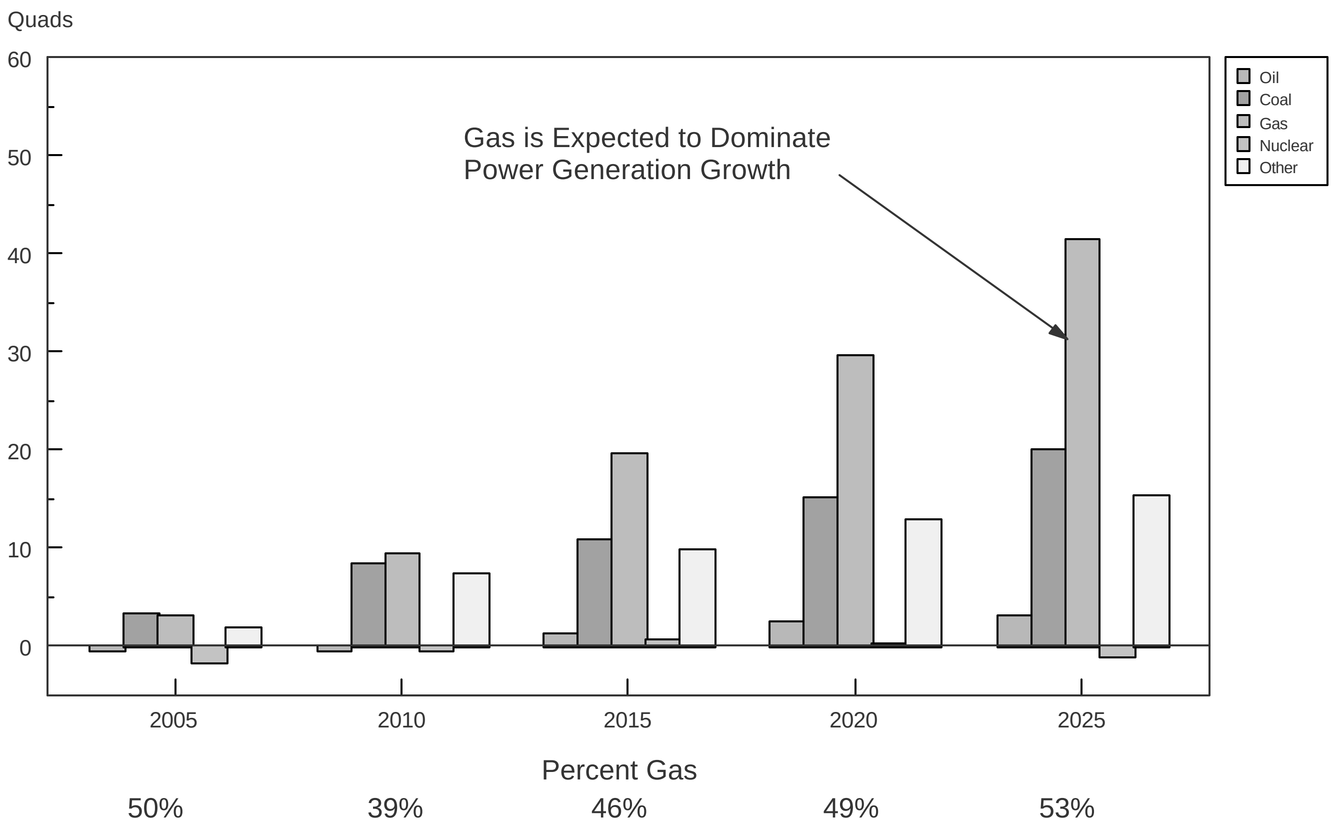


Figure 4-4

INCREMENTAL PRIMARY ENERGY UTILIZATION FOR ELECTRICITY GENERATION FROM A 2001 BASE

(EIA INTERNATIONAL ENERGY OUTLOOK 2003)

QUADS



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

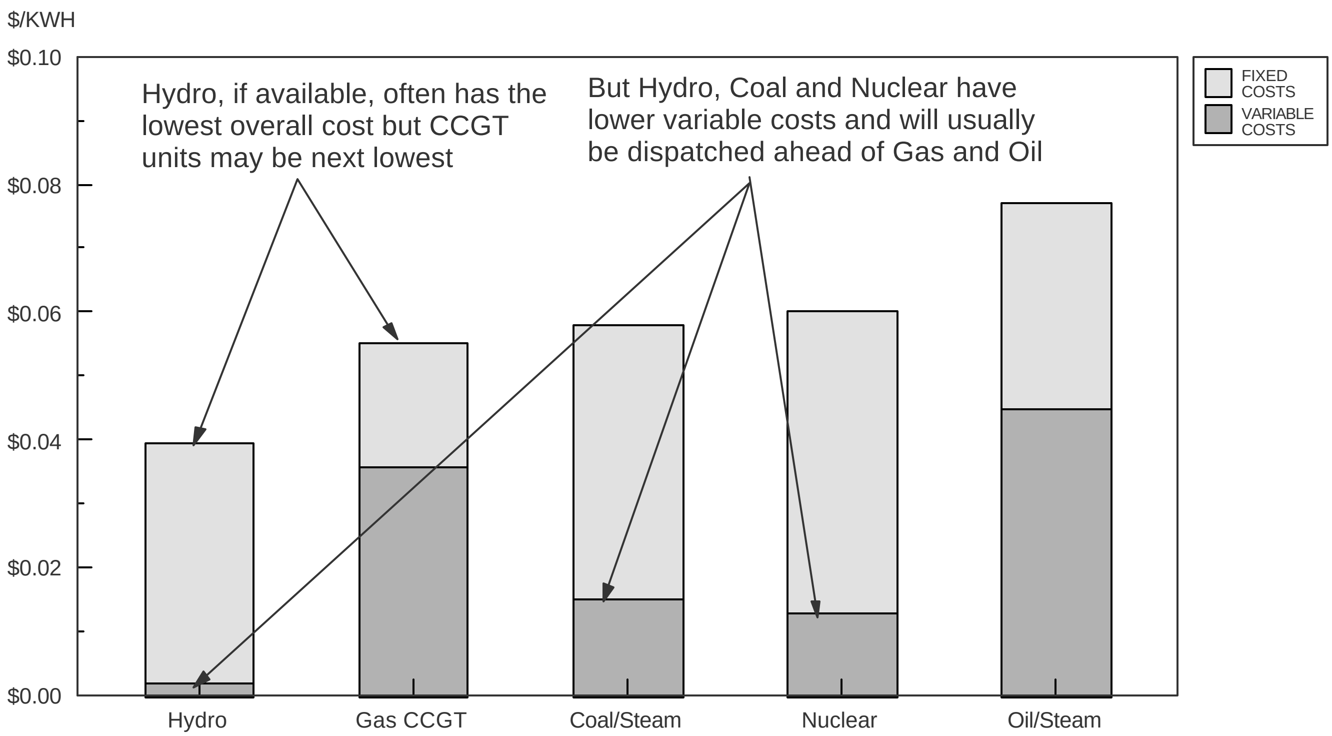


Figure 4-6

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

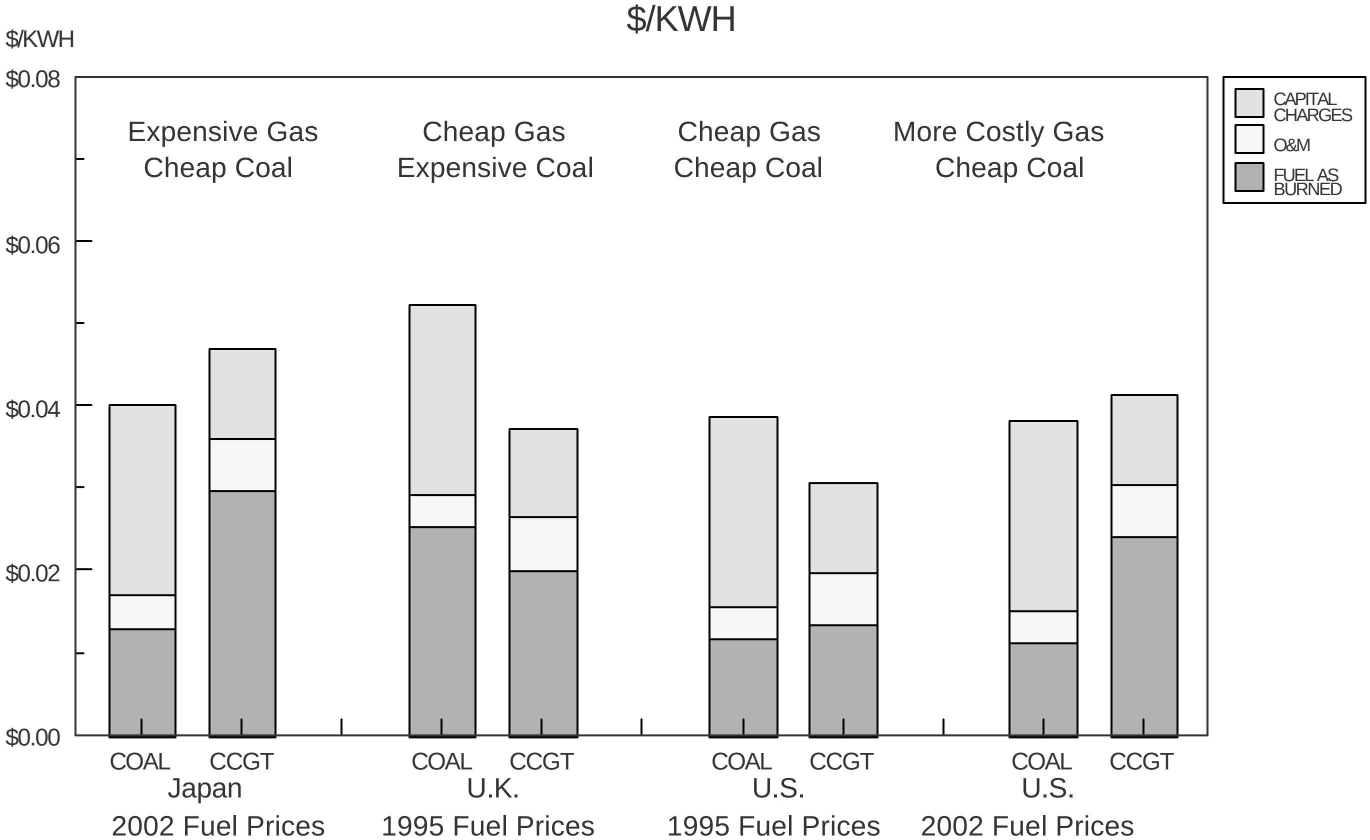


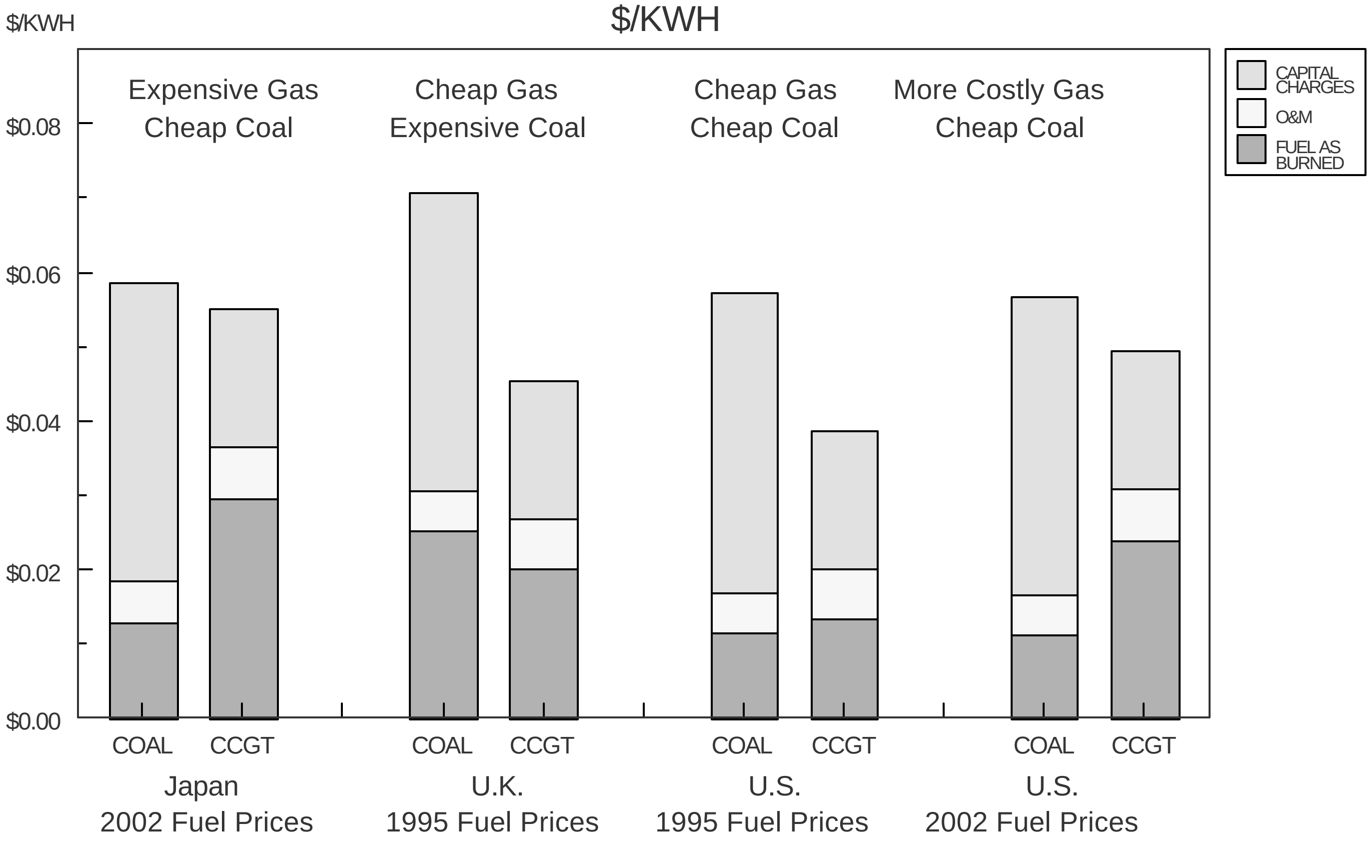
Figure 4-7

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

$/KWH



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,

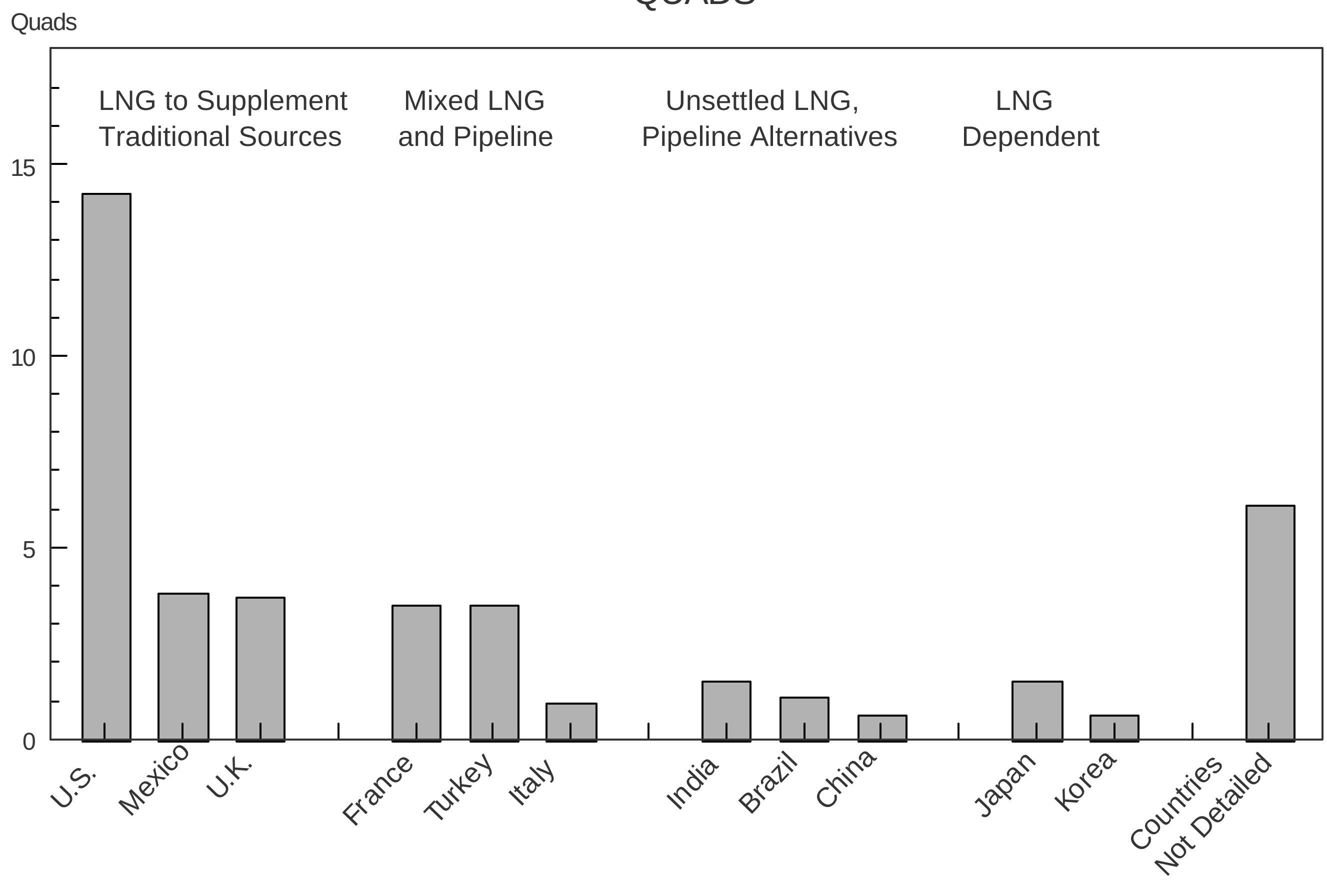
[5] Page 244, World Energy Investment Outlook, 2003 Insights, International Energy Agency, Paris

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

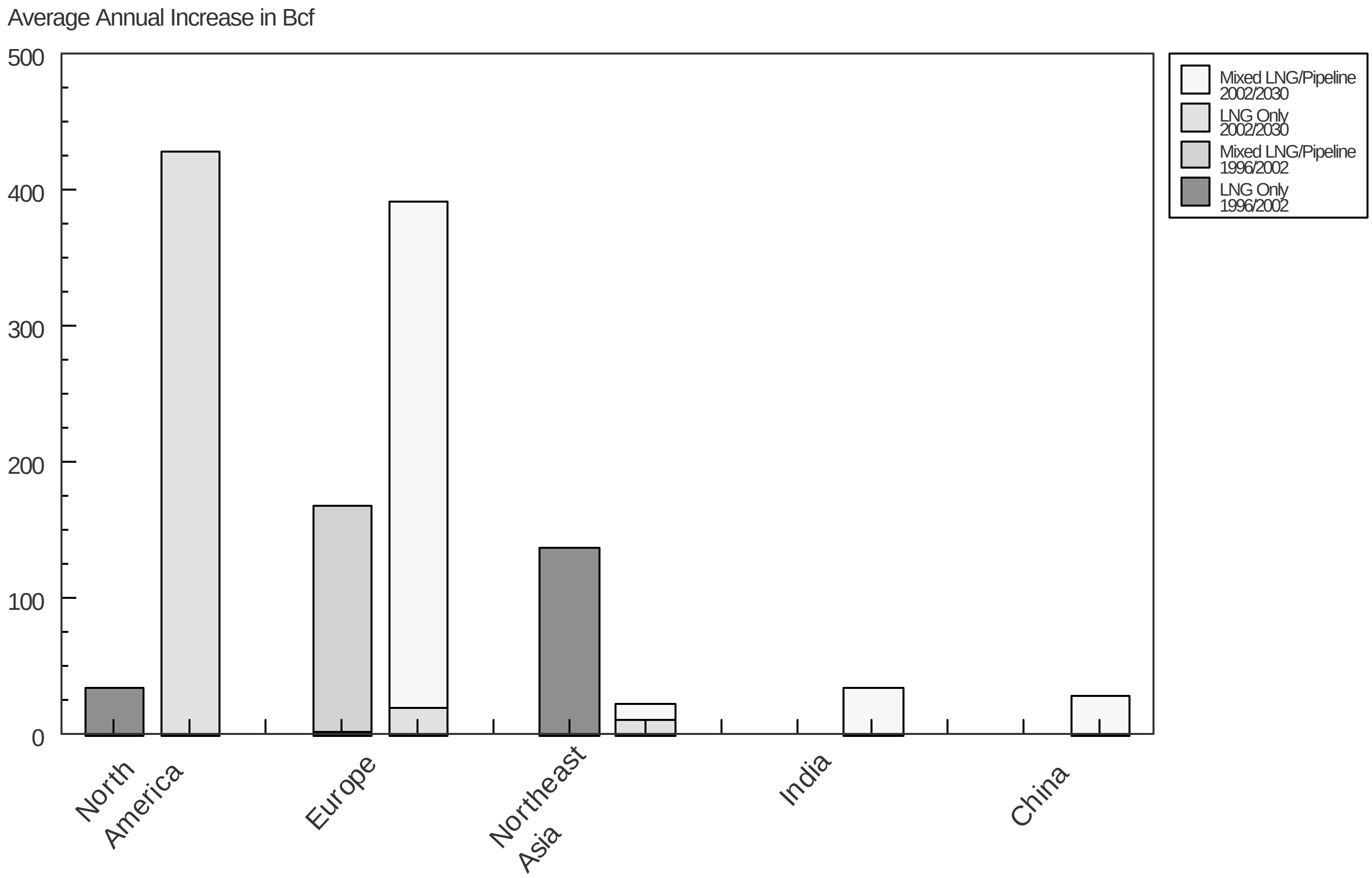


Figure 4-10

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

LNG OR MIXED PIPELINE/LNG EXPORT TRADES ONLY

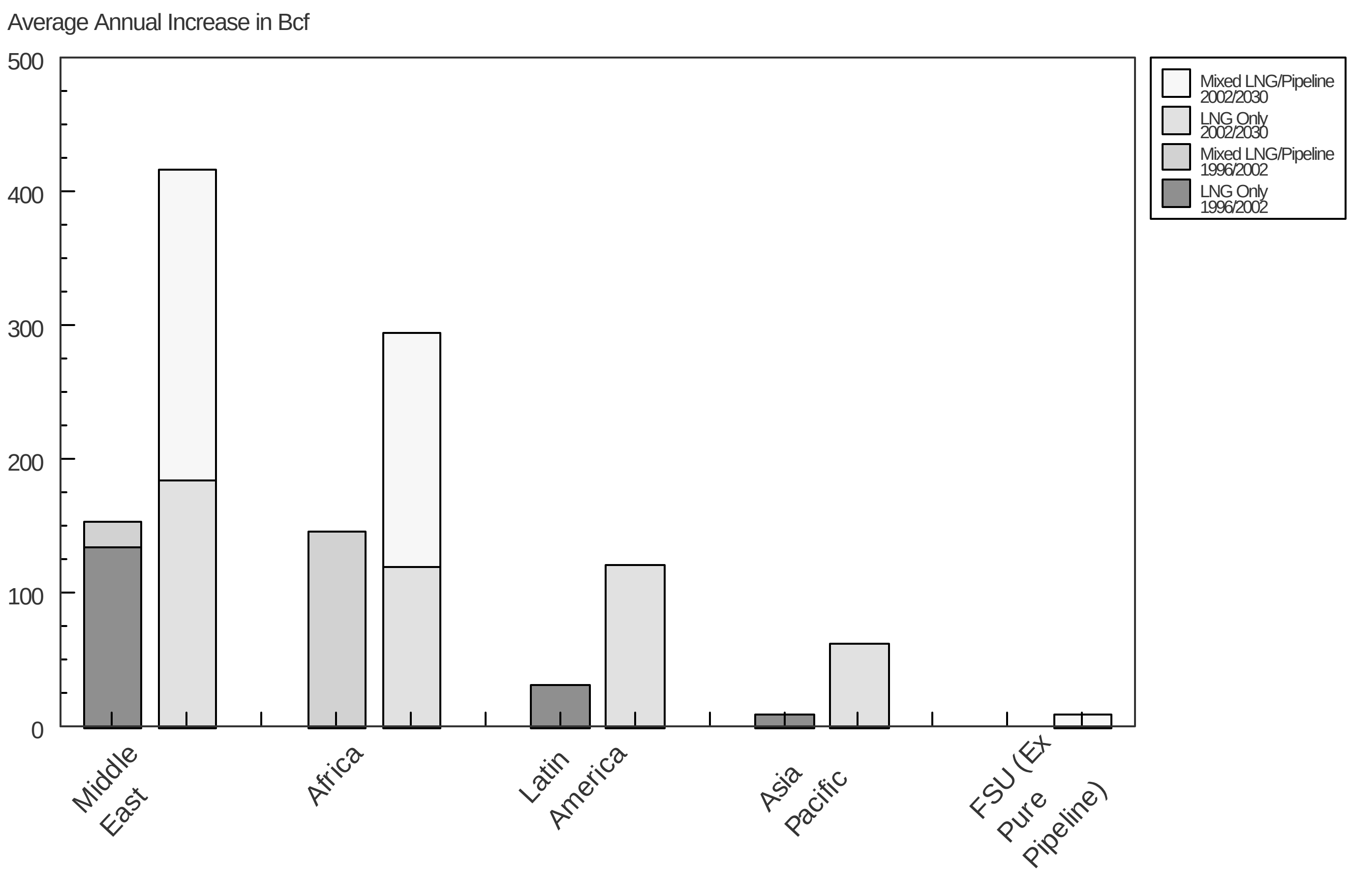
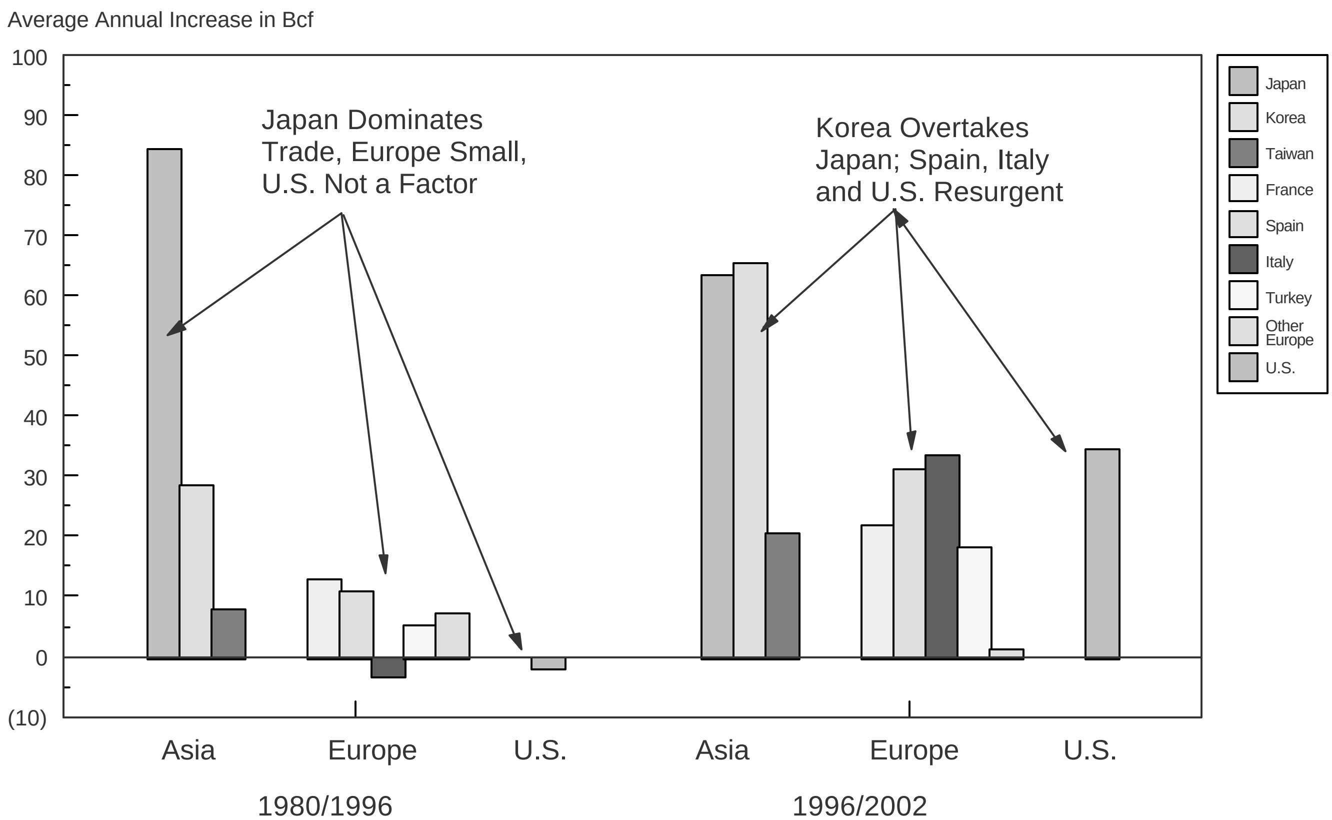


Figure 4-11

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 260° 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

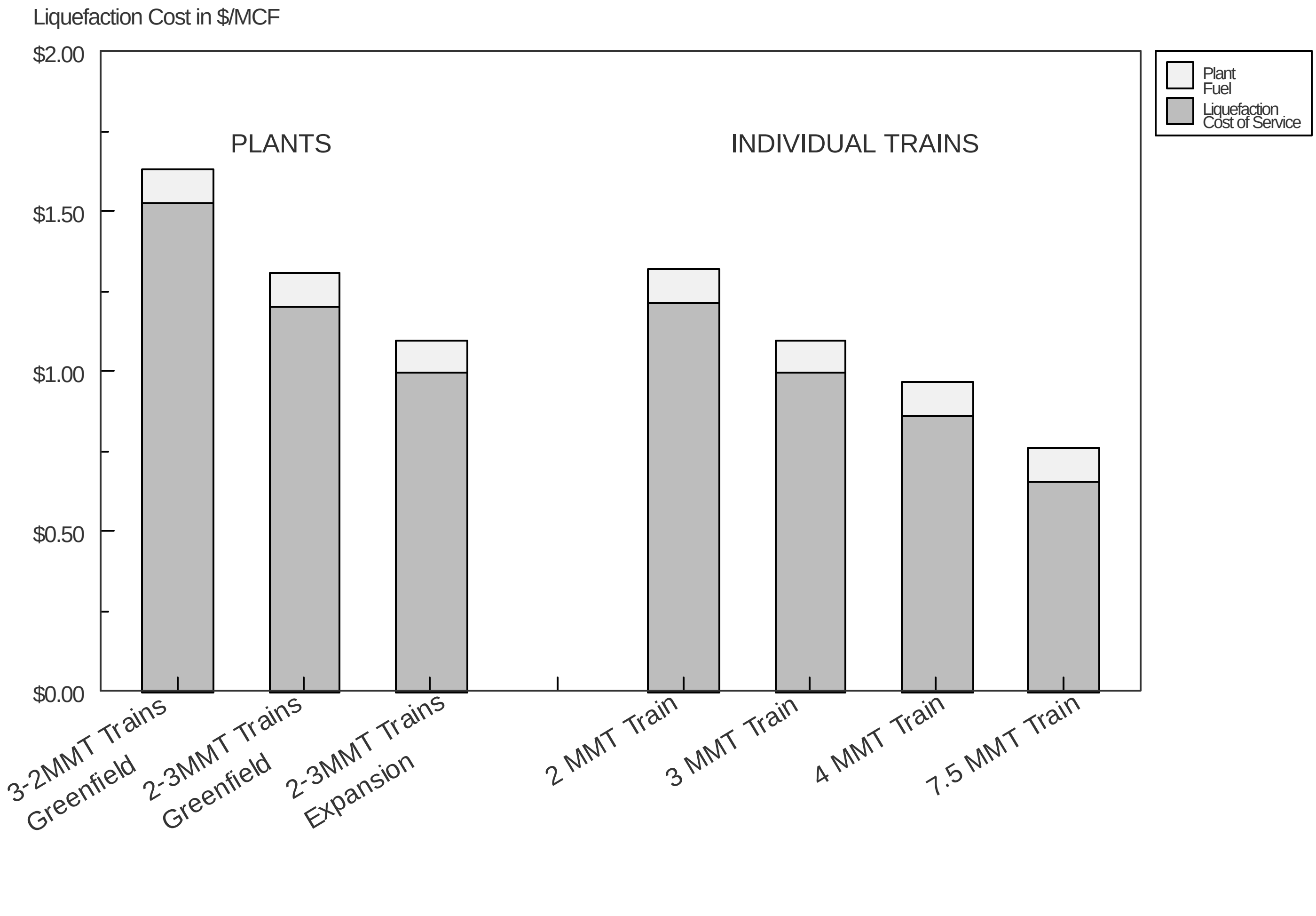


Figure 5-2

LNG EXPORTS COMPARED WITH LIQUEFACTION CAPACITY

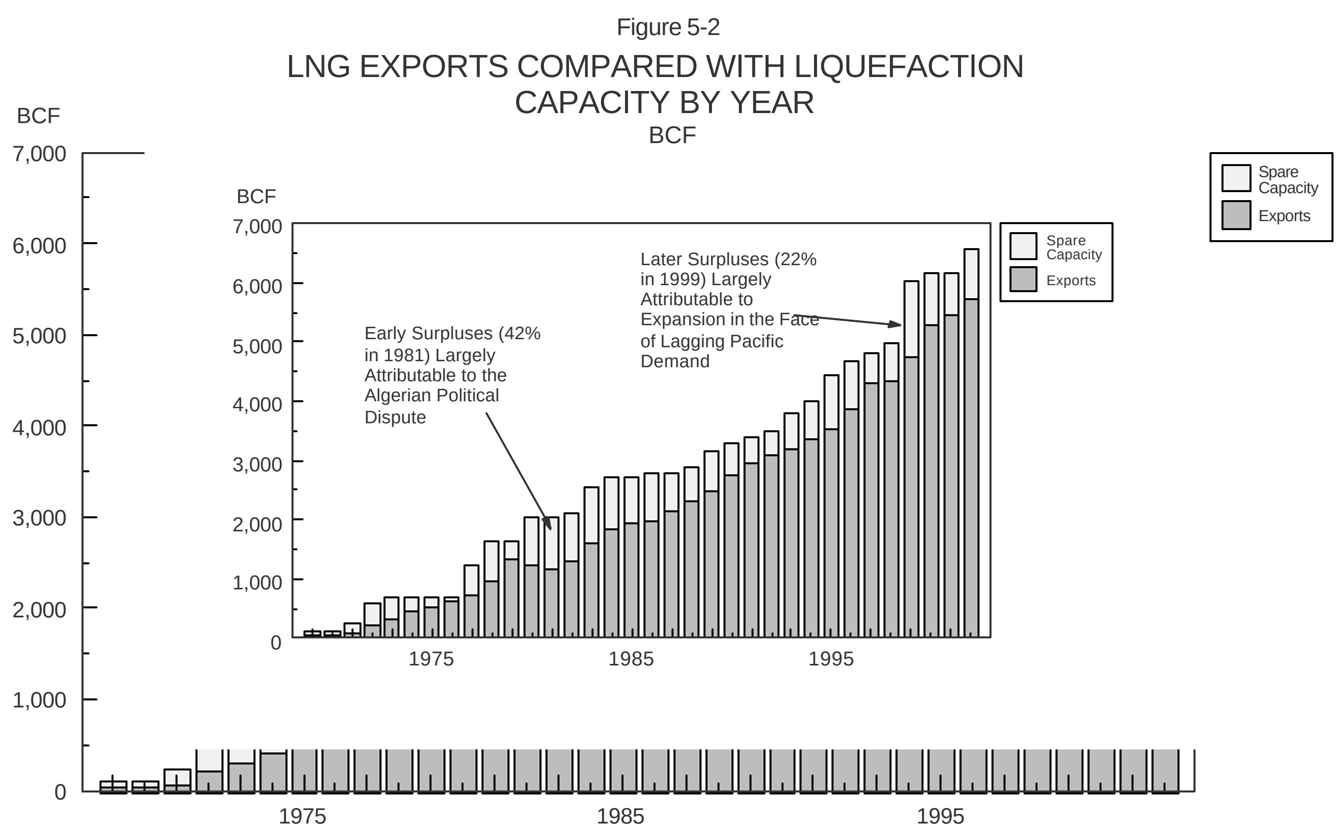


Figure 5-3

EXCESS LIQUEFACTION CAPACITY BY KEY EXPORTING REGIONS

BCF

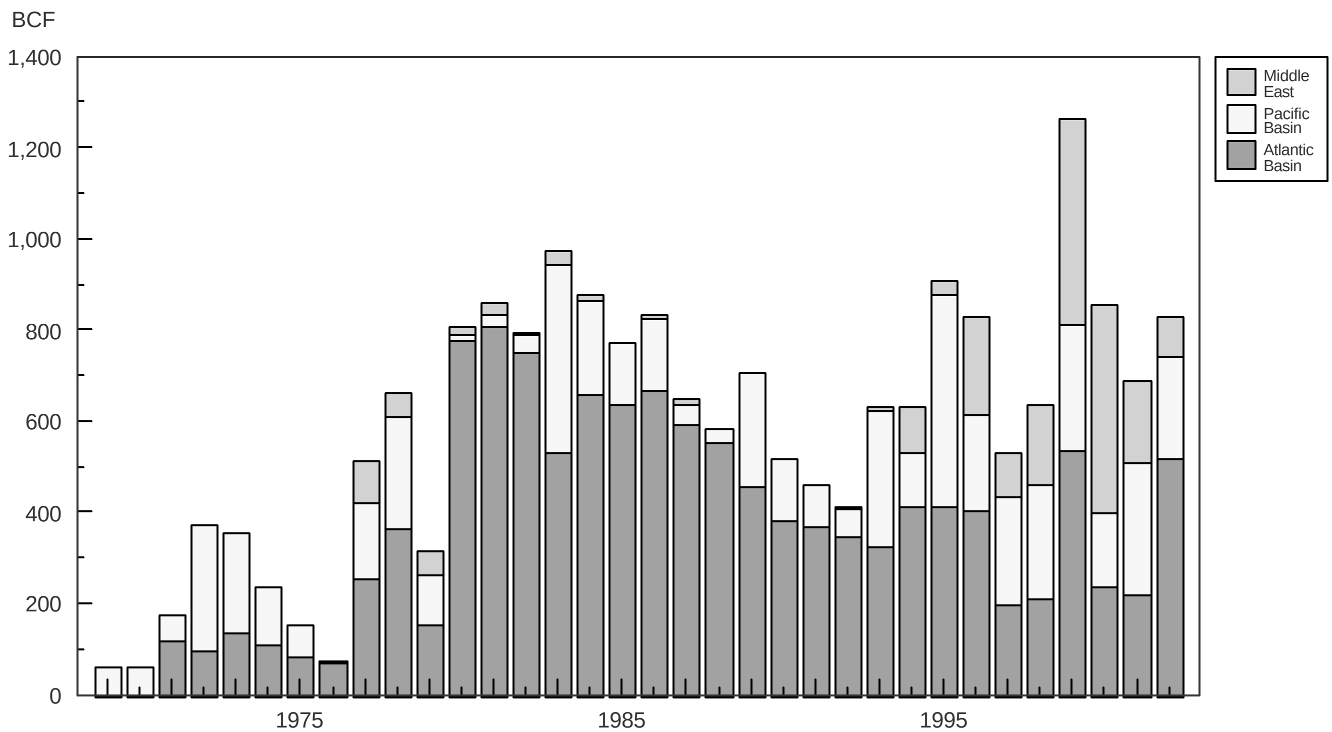
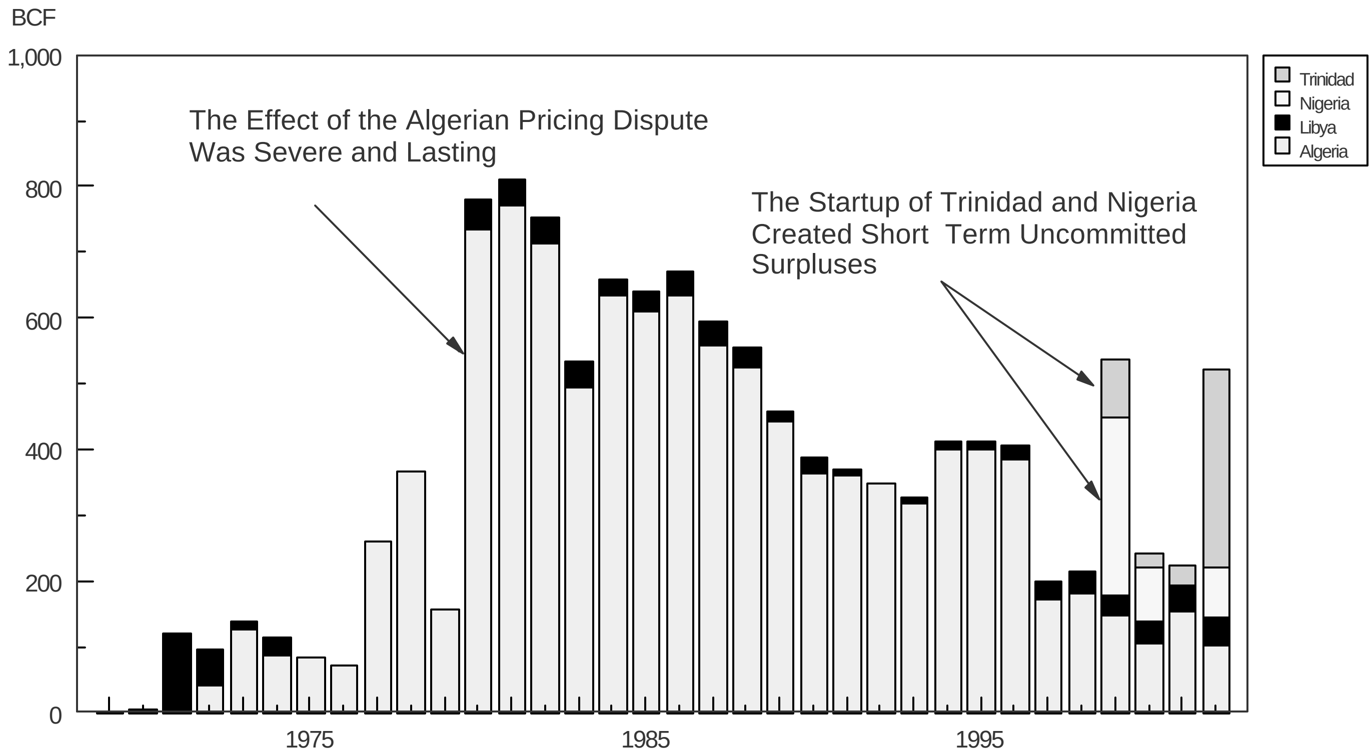


Figure 5- 4

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

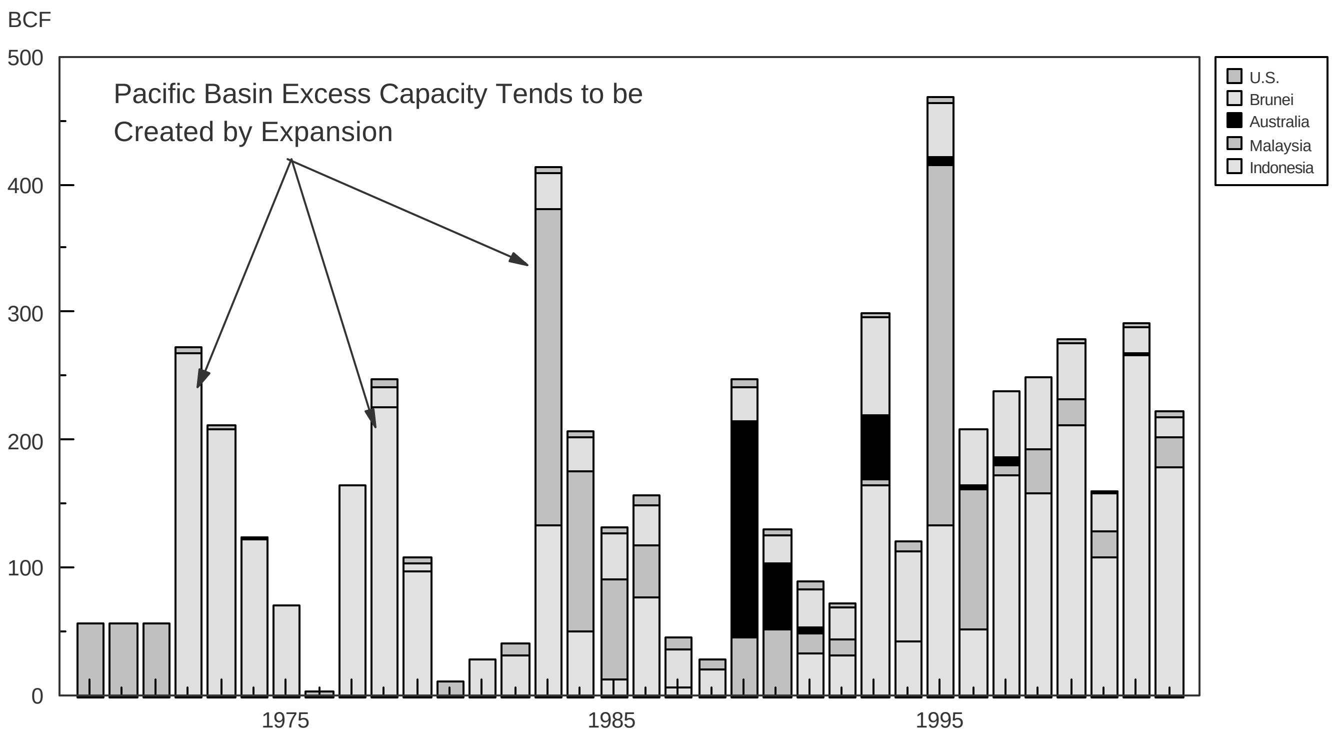
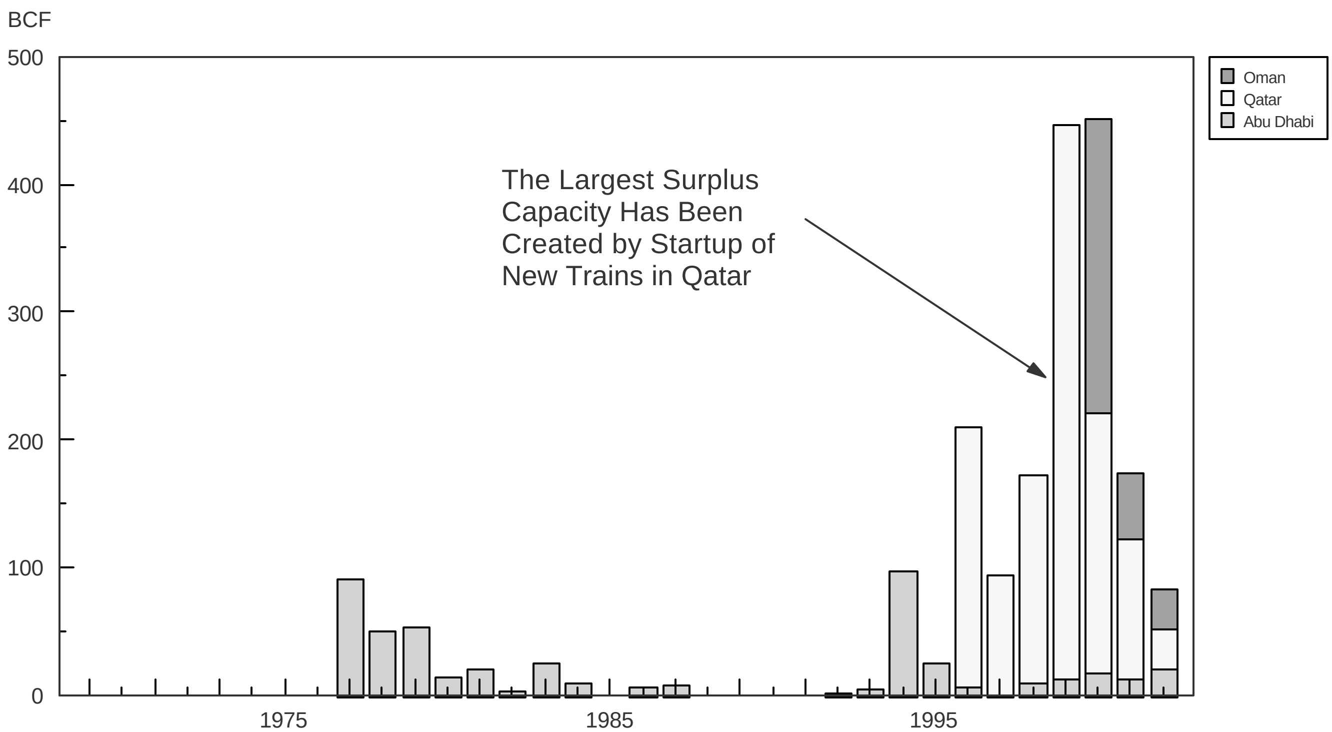


Figure 5- 6

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.

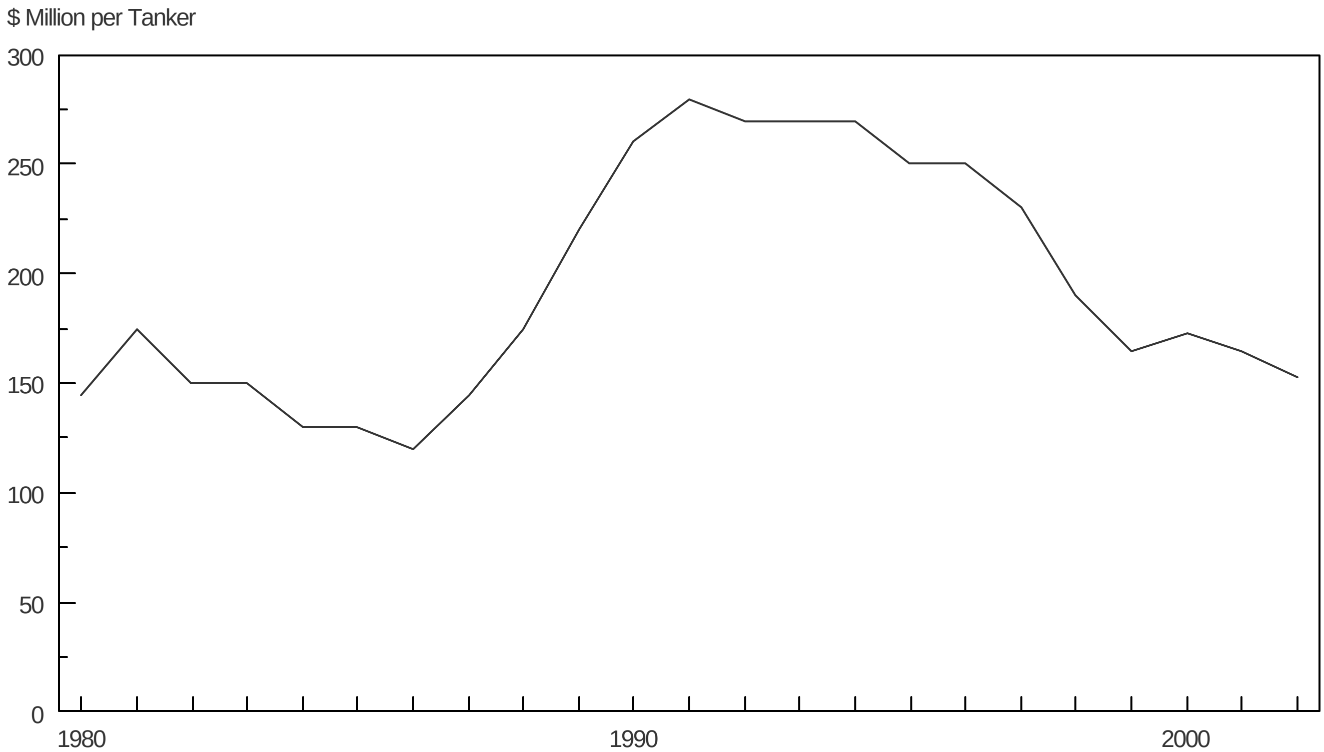
The History of the LNG Trade and Its Effect on Tanker Availability

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

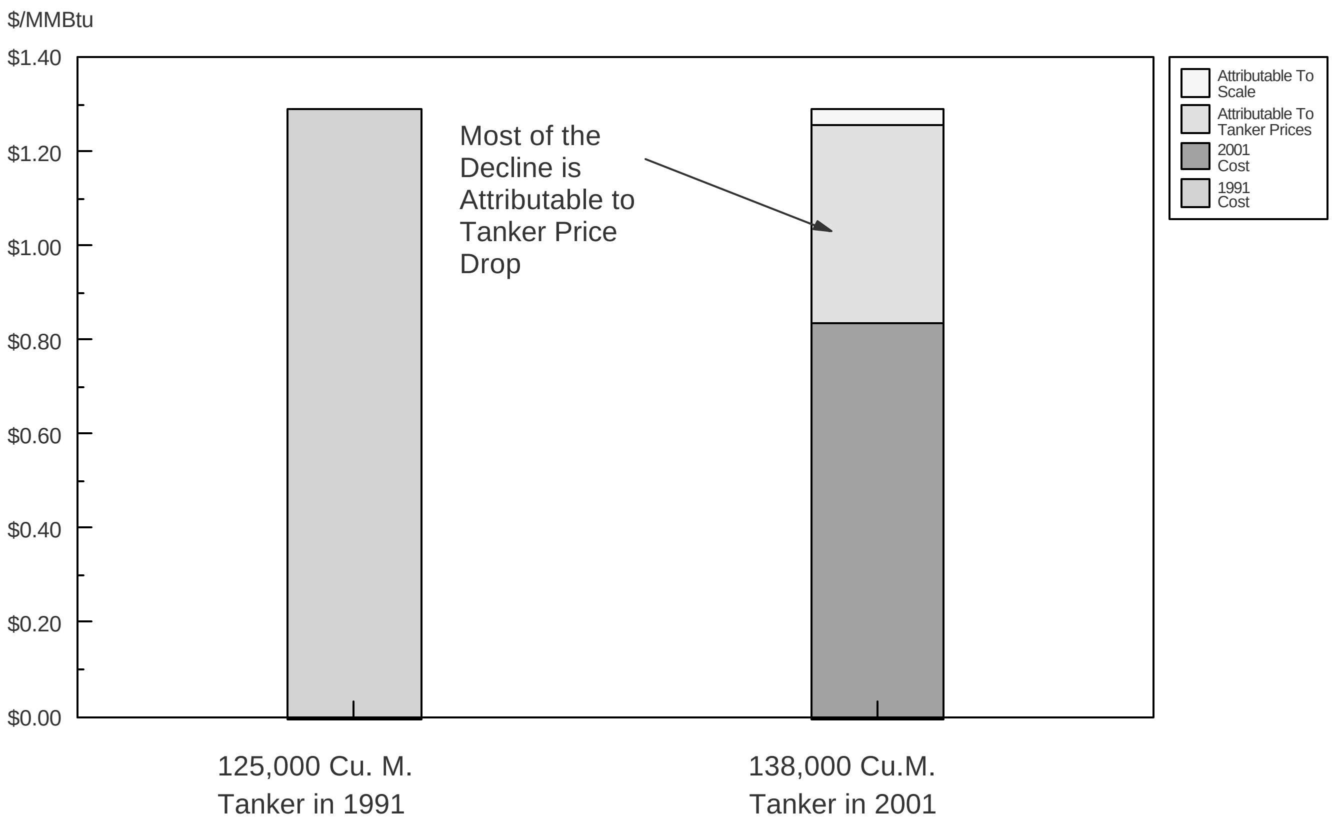


Figure 6-3

EVOLUTION OF LNG TANKER SIZES

TANKER CAPACITY - AVERAGE AND LARGEST IN SERVICE

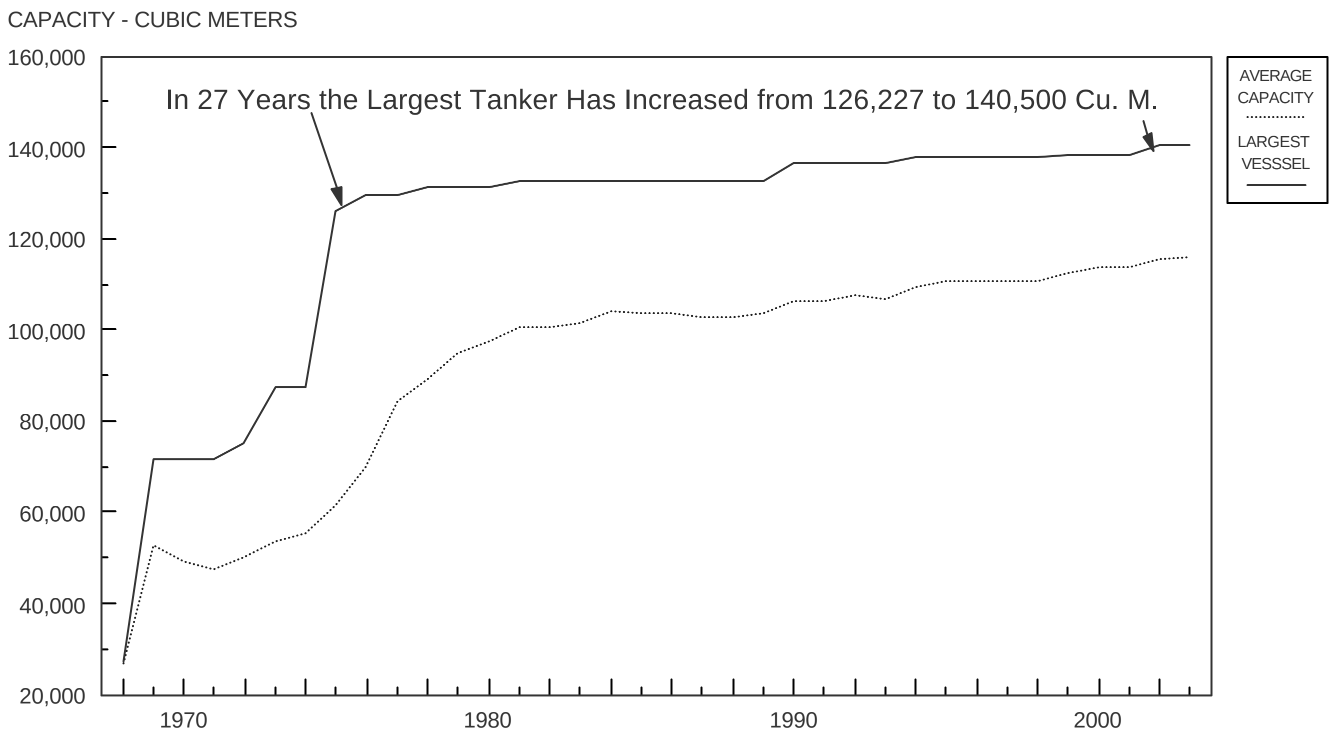
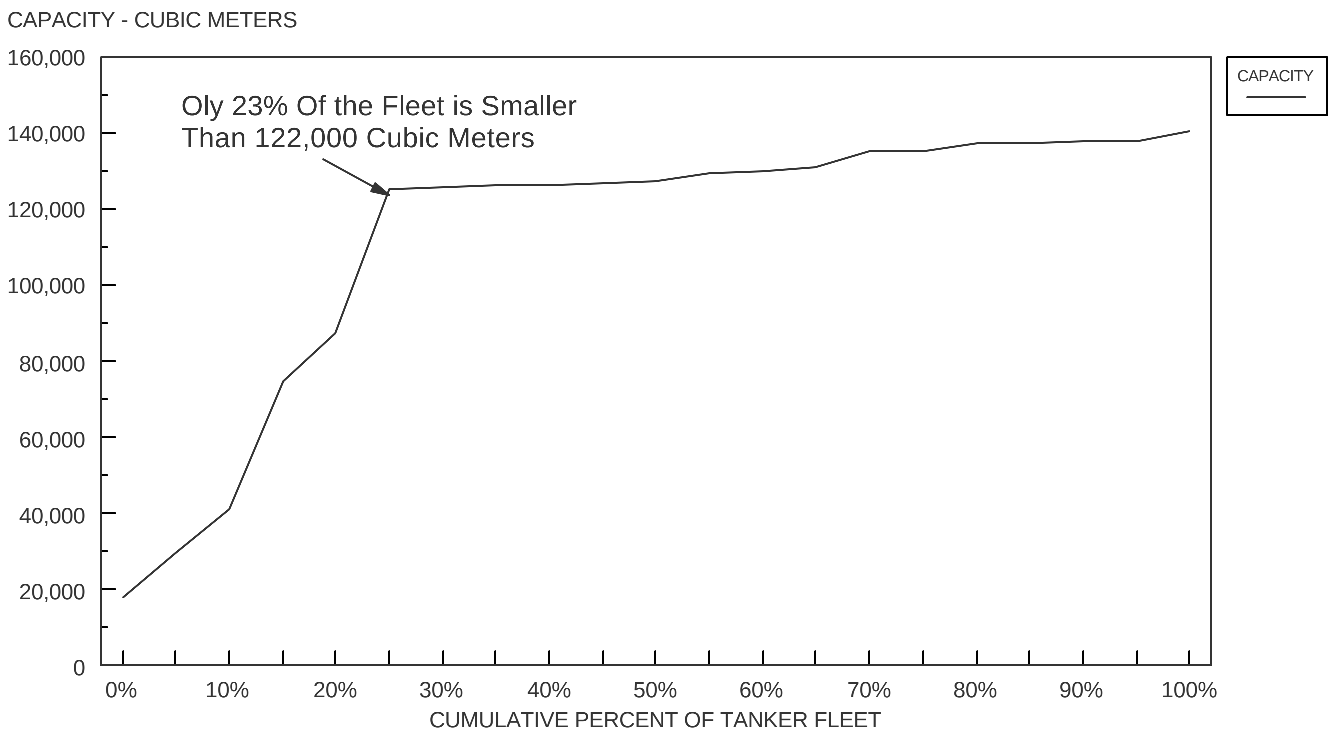


Figure 6-4

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

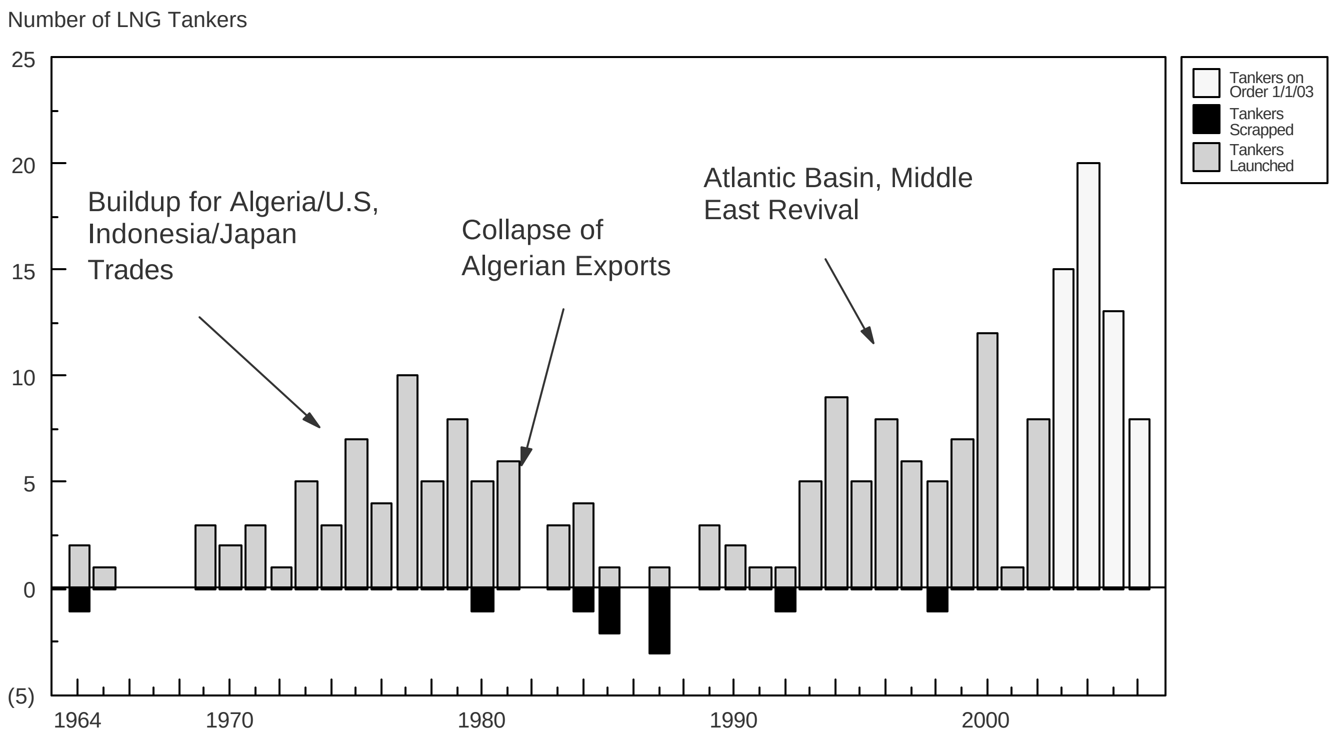
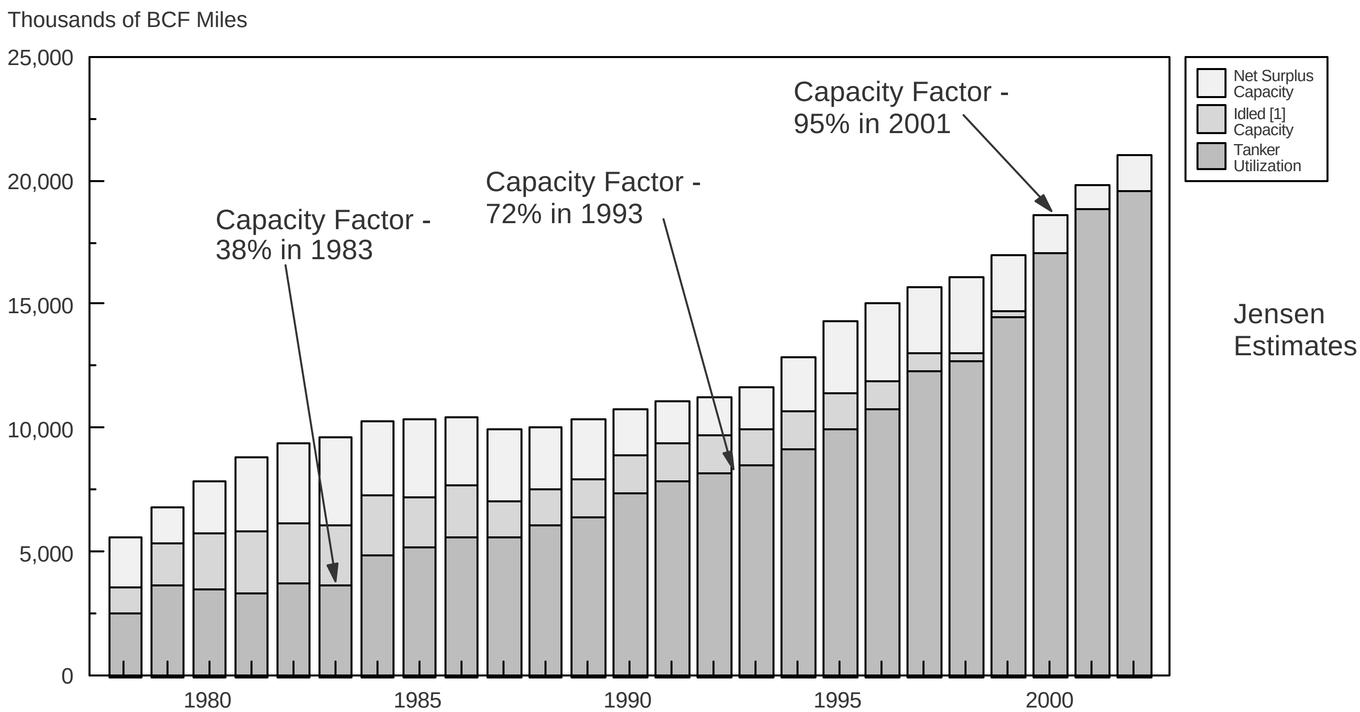


Figure 6- 6

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?

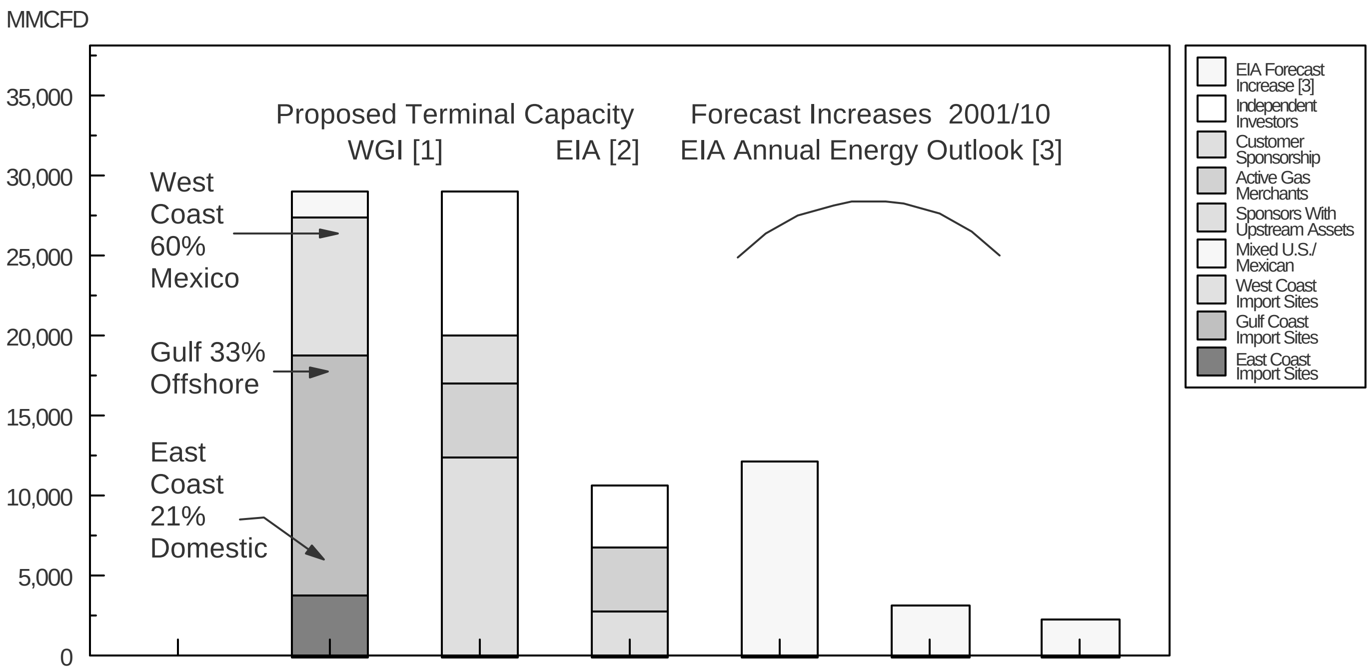
It is very difficult to answer that question explicitly, what is clear is that most of the terminals shown in the previous tables will *not* be built. The LNG business, both in liquefaction and in receipt terminals, has always been characterized by a great deal of "gaming" - that is a large number of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

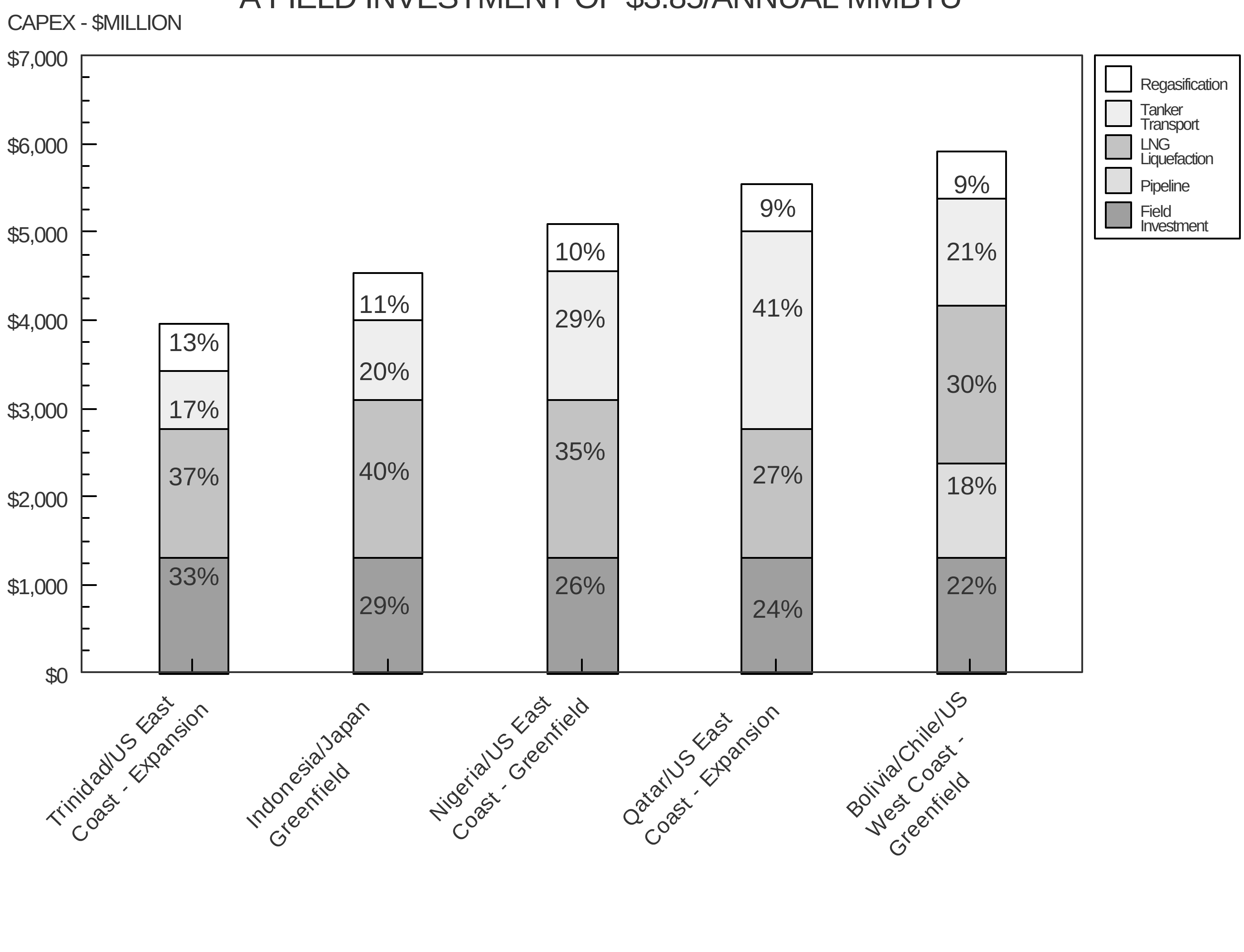
Most of the early purchasers were regulated utilities or government monopoly companies and thus were effectively able to lay off some of the market risk to their end use customers. Once a contract was approved by the regulators or government overseers, the price and volume terms became part of the regulated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

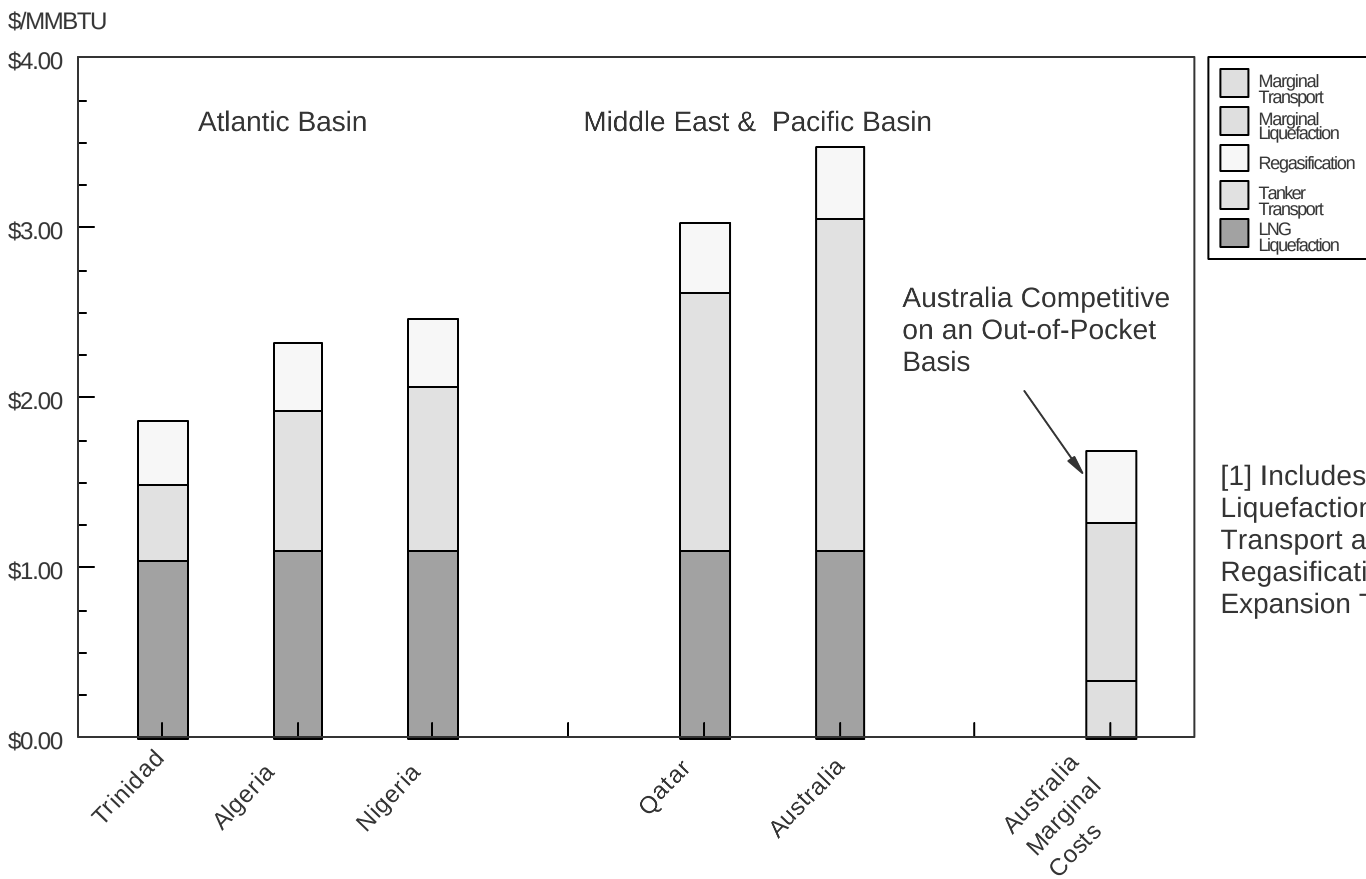
"Spheres of Influence" for Various Supply Sources

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

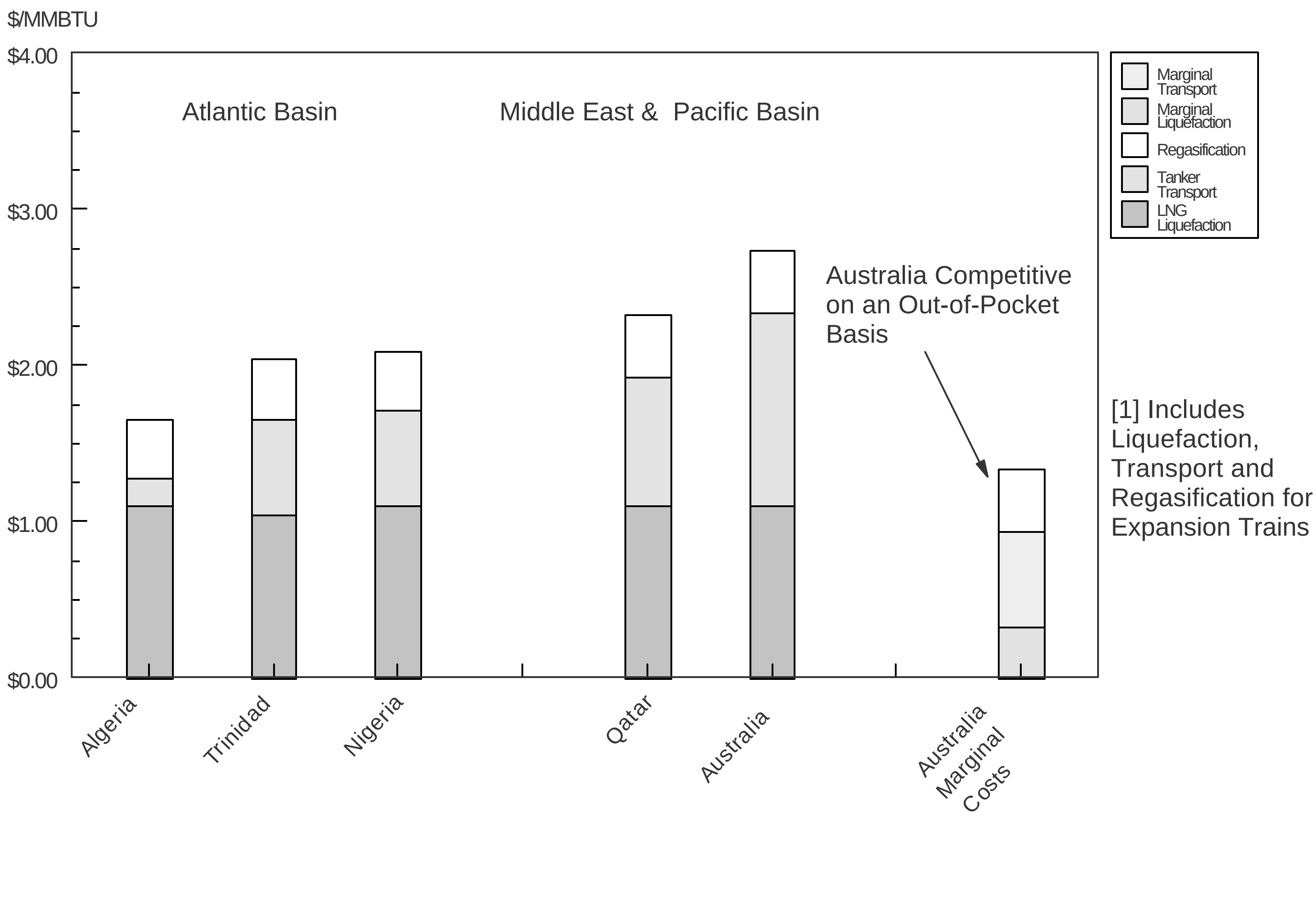


Figure 9-4

ILLUSTRATIVE TRANSPORTATION COSTS [1] FOR A JAPANESE TERMINAL

ASSUMING GREENFIELD OR EXPANSION WITH TWO 3.3 MMT TRAINS

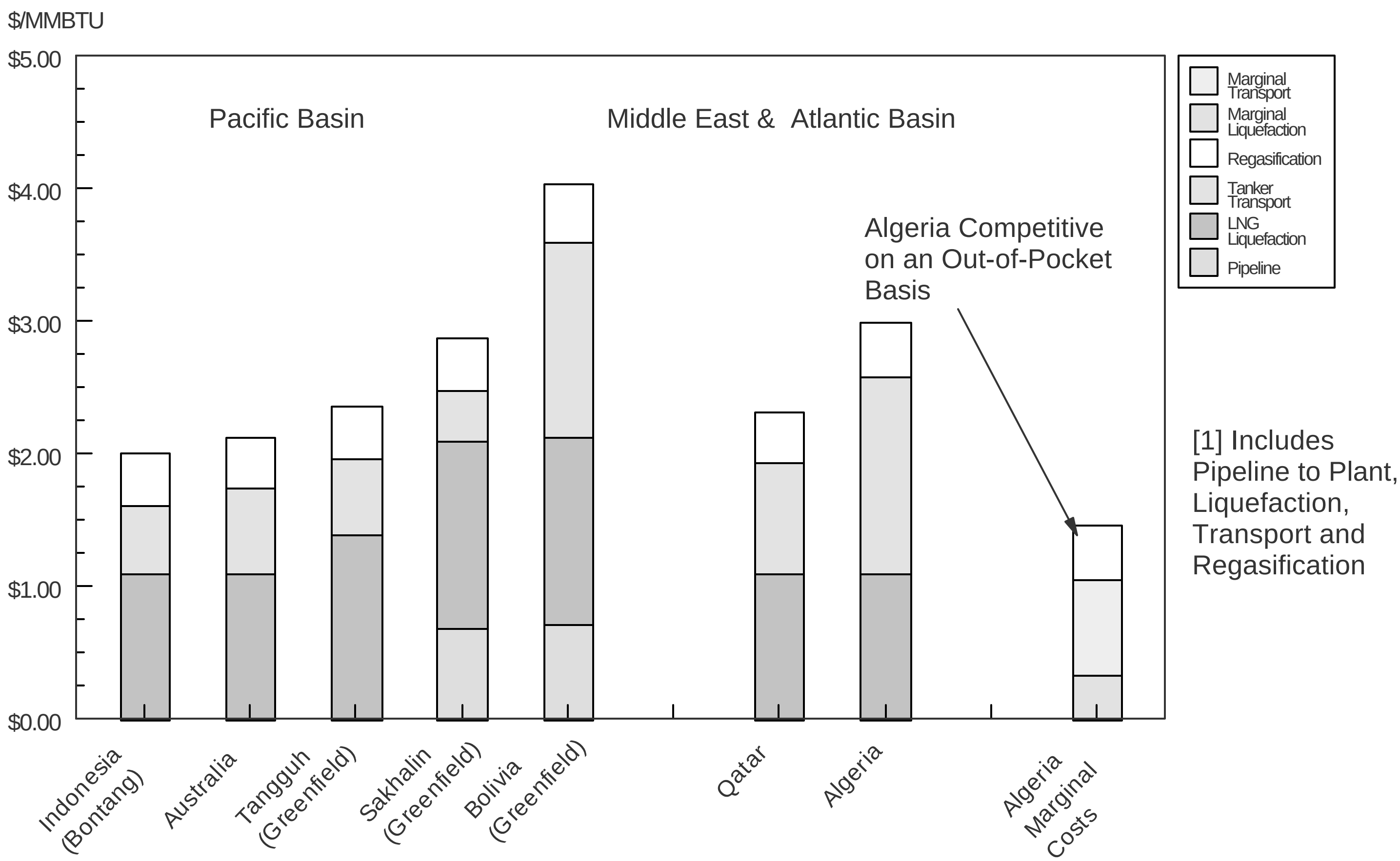


Figure 9-5

ILLUSTRATIVE TRANSPORTATION COSTS [1] FOR A BAJA CALIFORNIA TERMINAL

ASSUMING GREENFIELD OR EXPANSION WITH TWO 3.3 MMT TRAINS

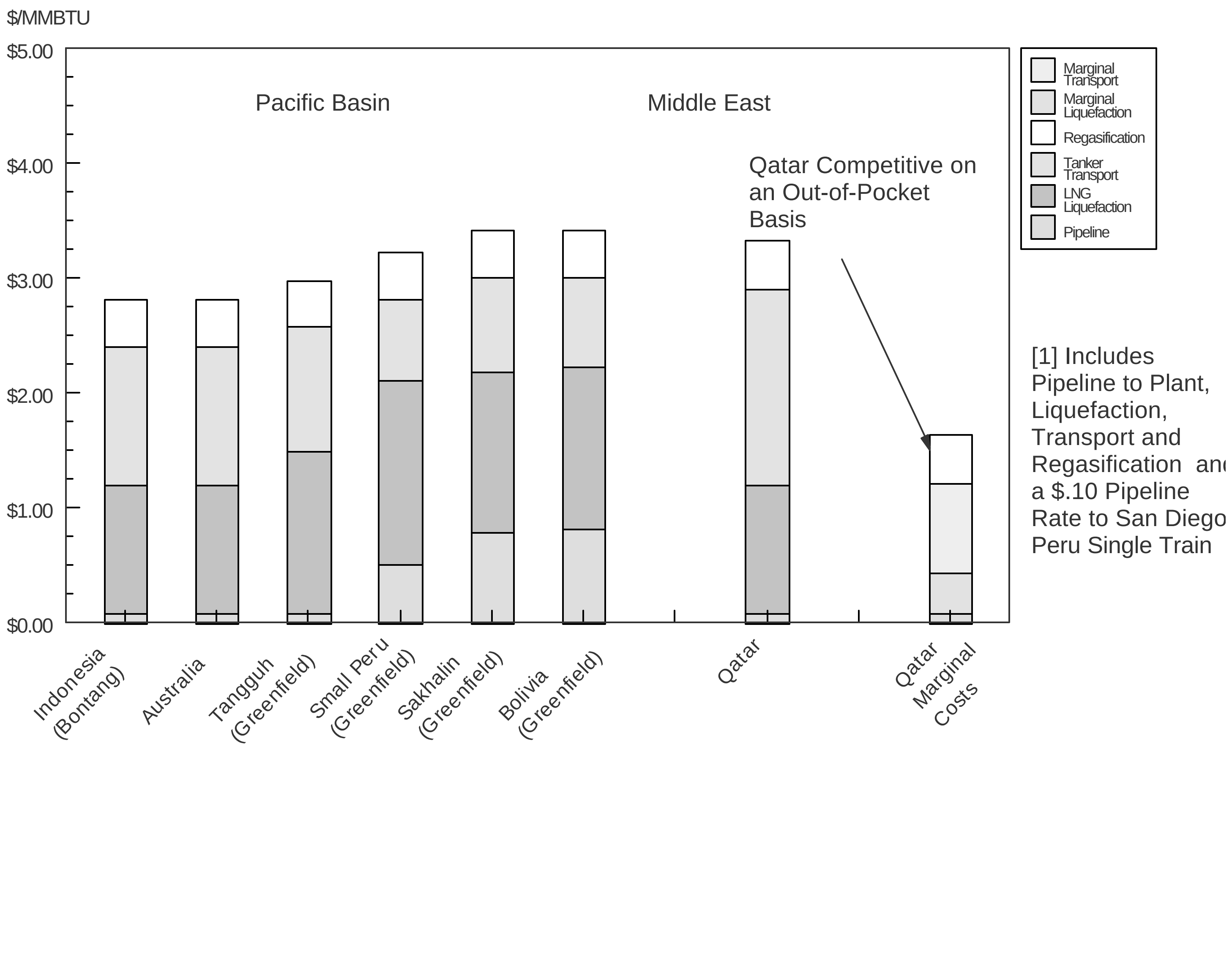
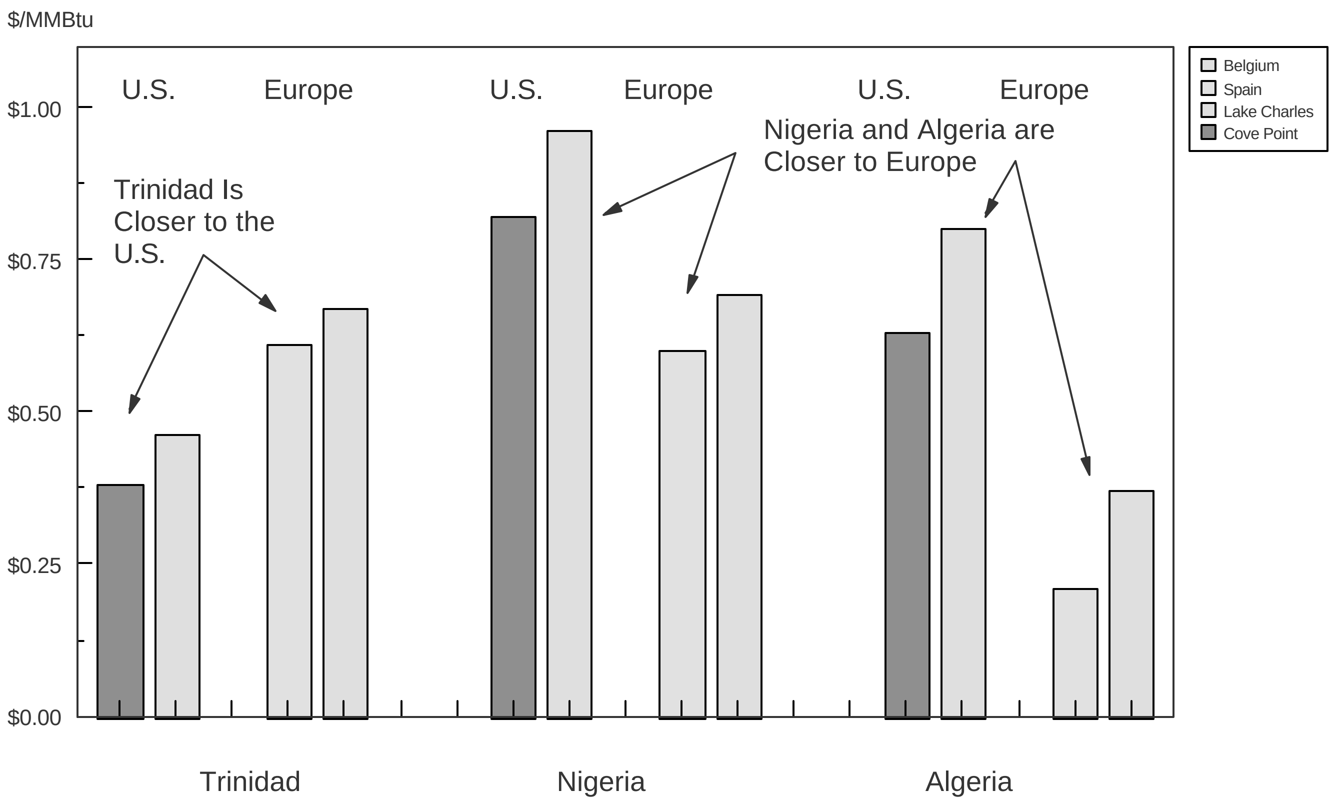


Figure 9-6

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.

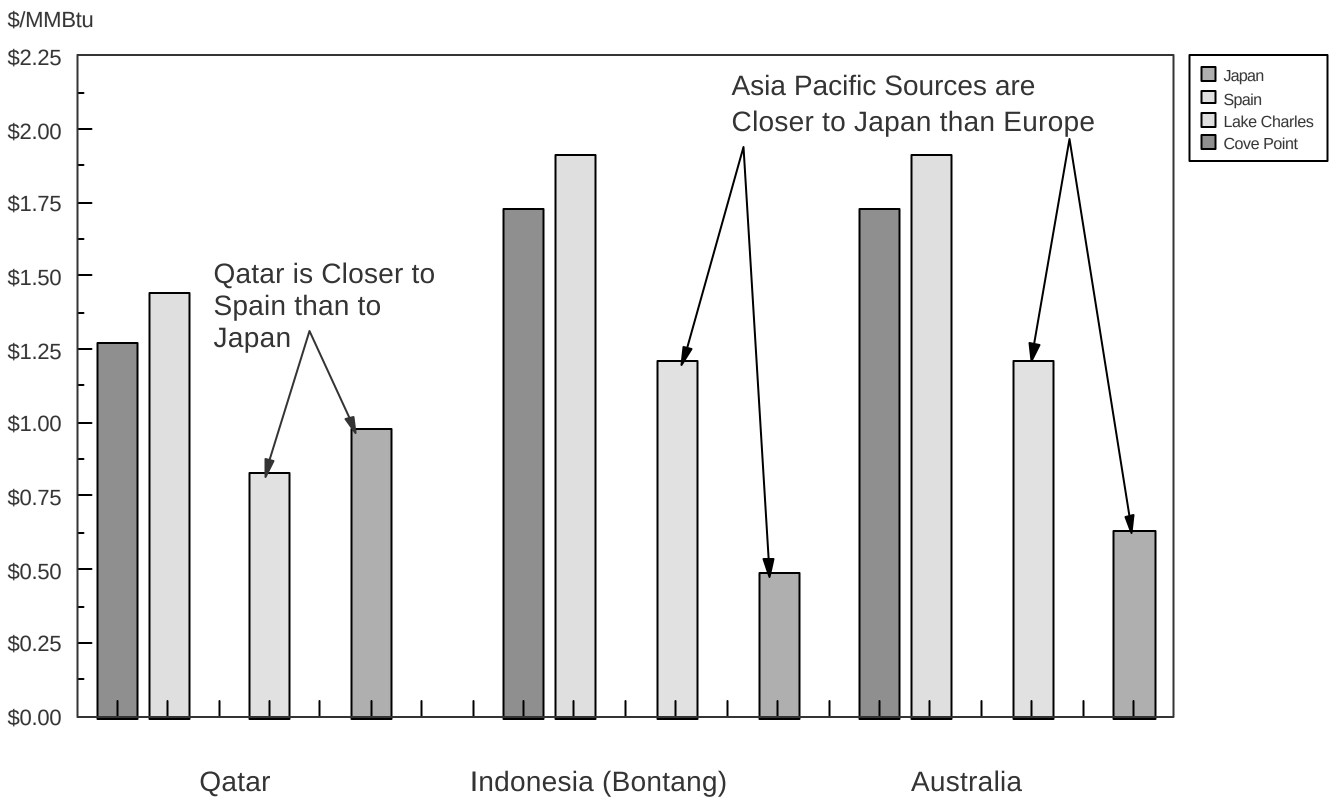
These rigid patterns began to break up in the 1990s as LNG surpluses in the Asia Pacific market and uncommitted receipt terminal capacity - especially in the U.S. - made short term transactions possible. While still small as a percentage of total international trade, these short term transactions began 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

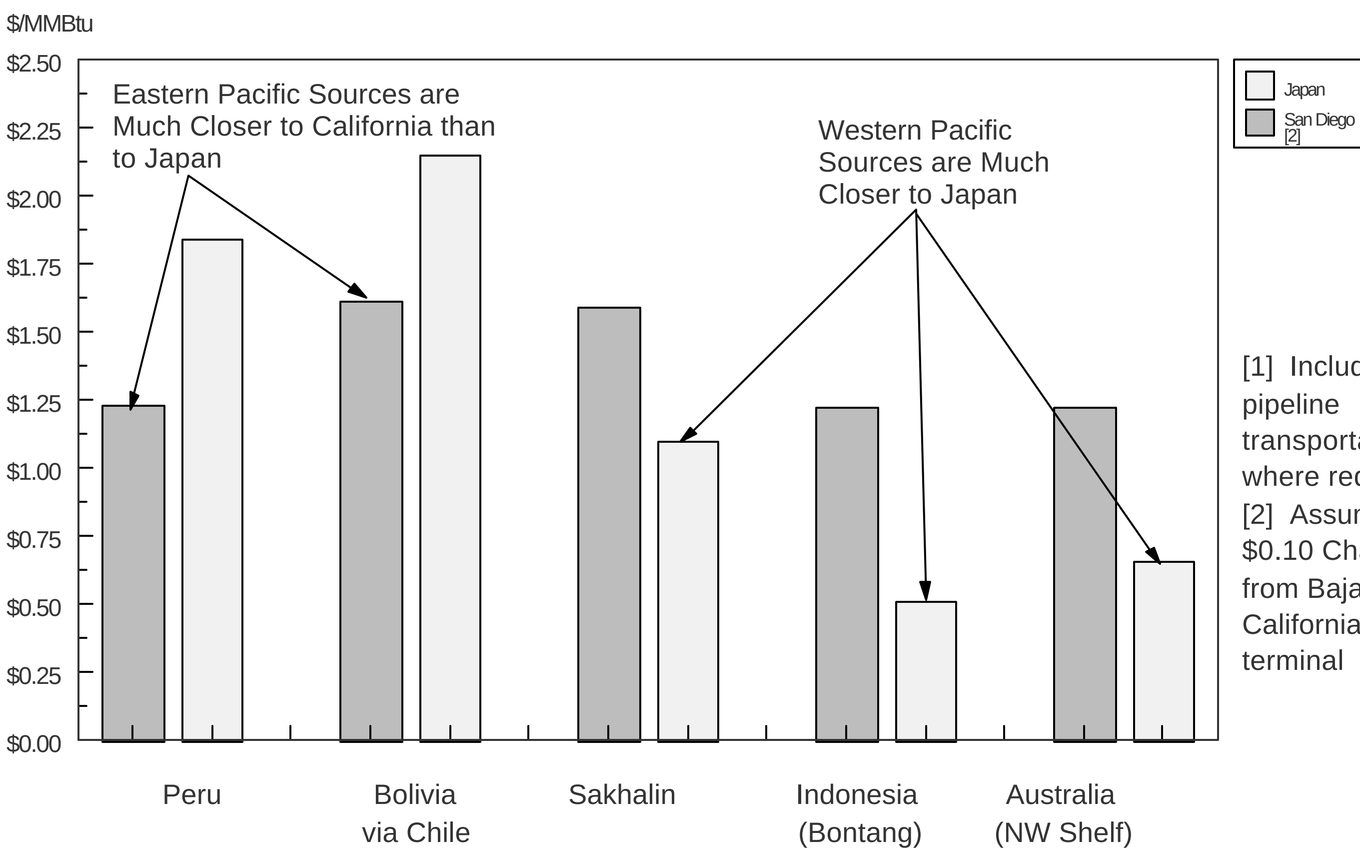


All Sources East of Suez are Closer to Europe and Japan than to the U.S.

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"

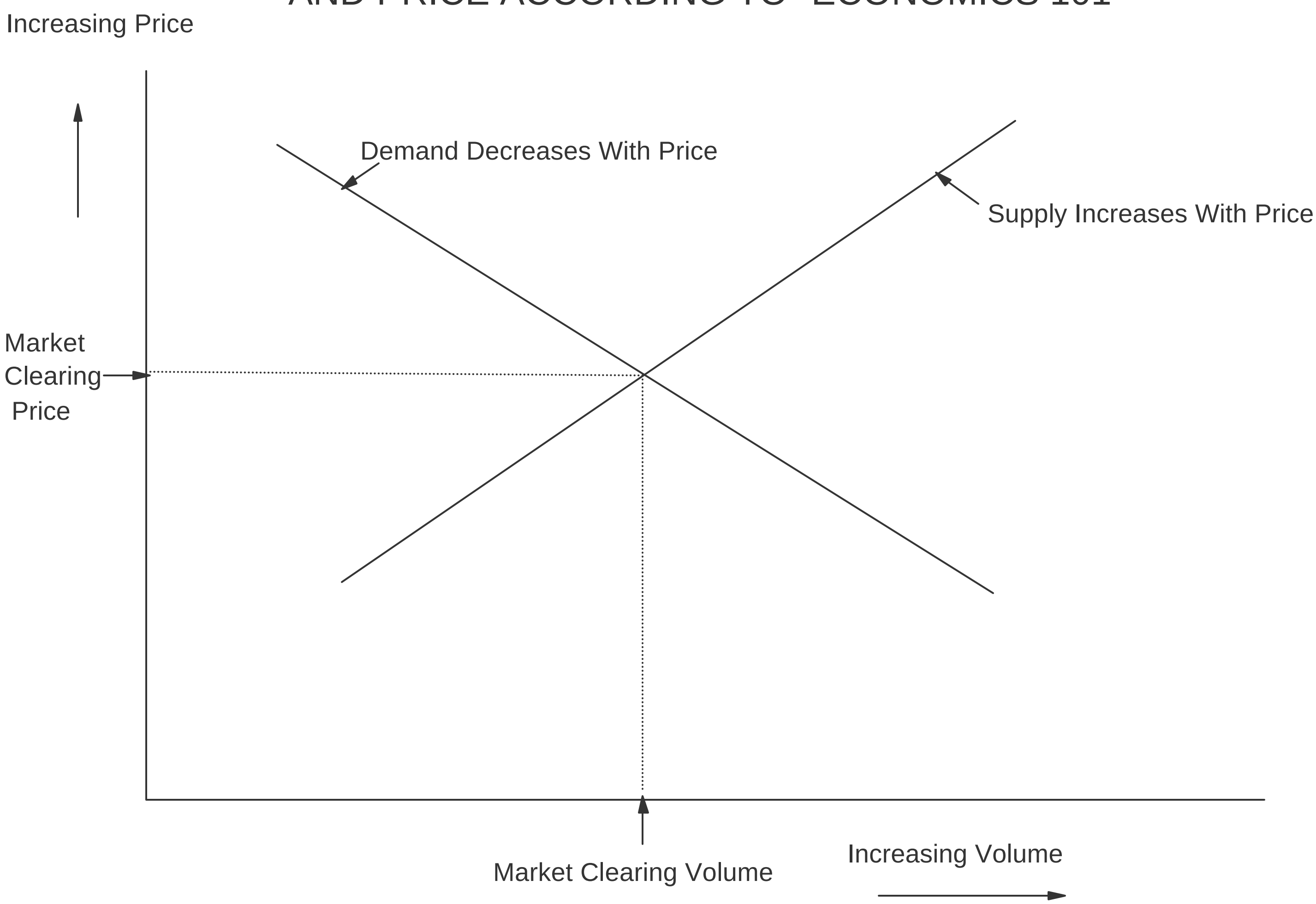


Figure 10-2

WHILE THE MARGINAL SELLER IN A CLEARED MARKET EARNS NO ECONOMIC RENT, NOTHING PREVENTS LOW COST SELLERS FROM DOING SO

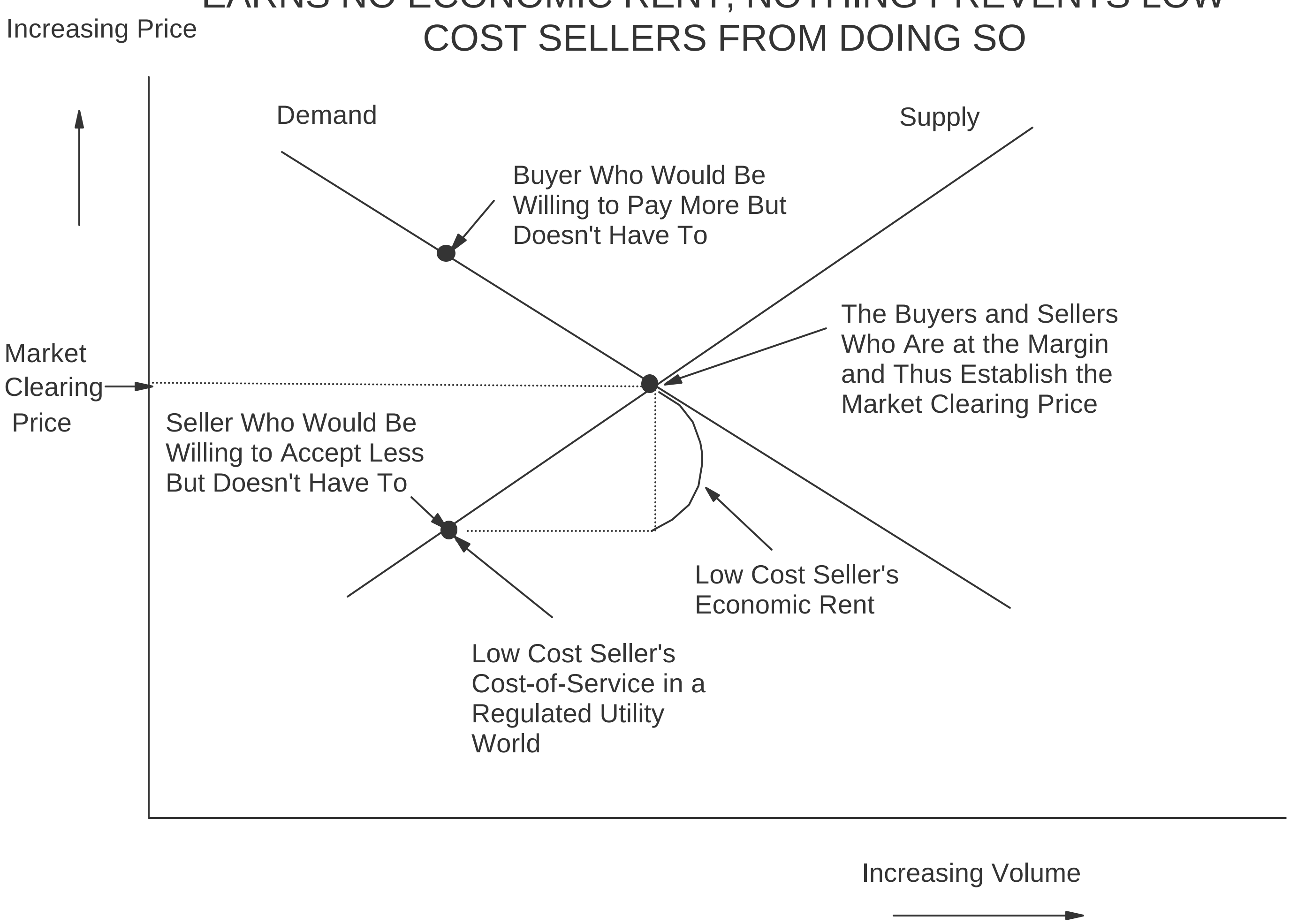
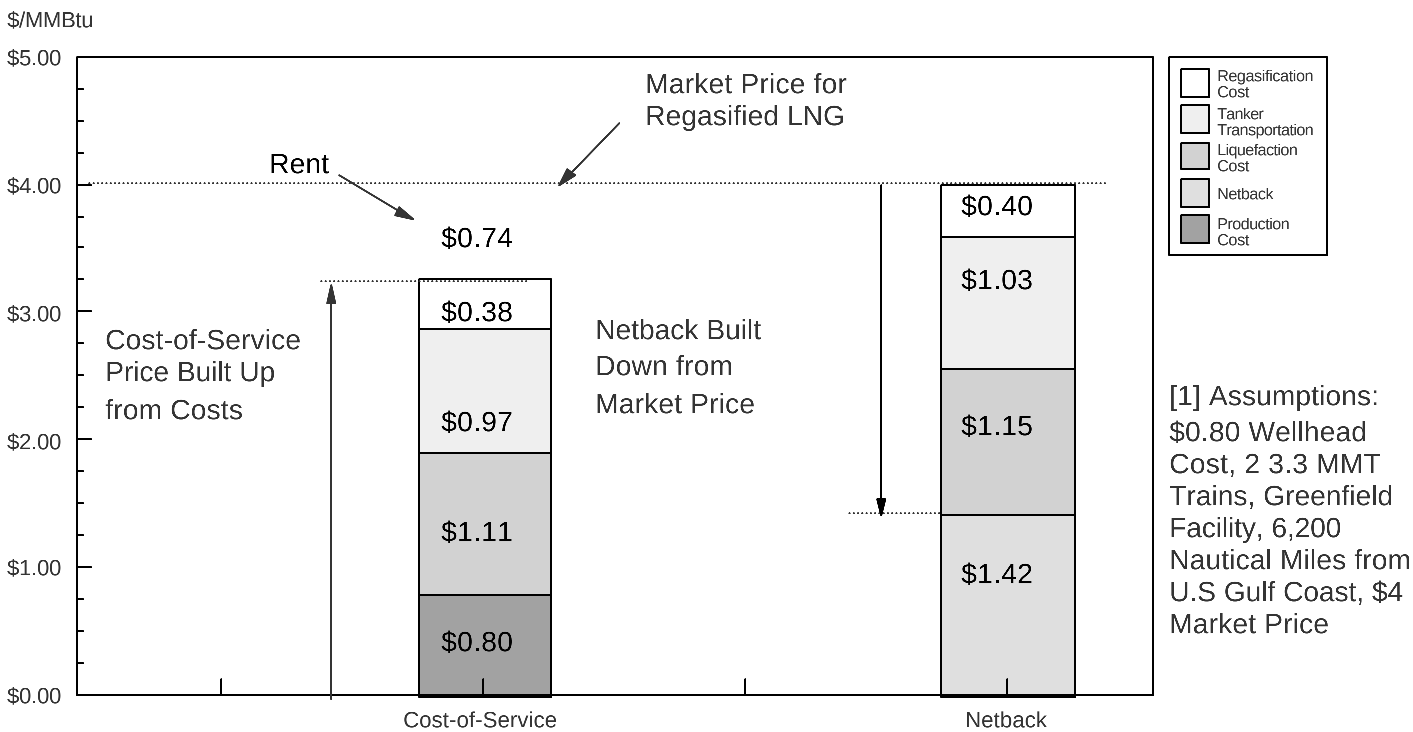


Figure 10-3

"COST-OF-SERVICE" LNG PRICING CONTRASTED WITH "NETBACK" PRICING - A HYPOTHETICAL [1] LNG TRADE INTO THE U.S.



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

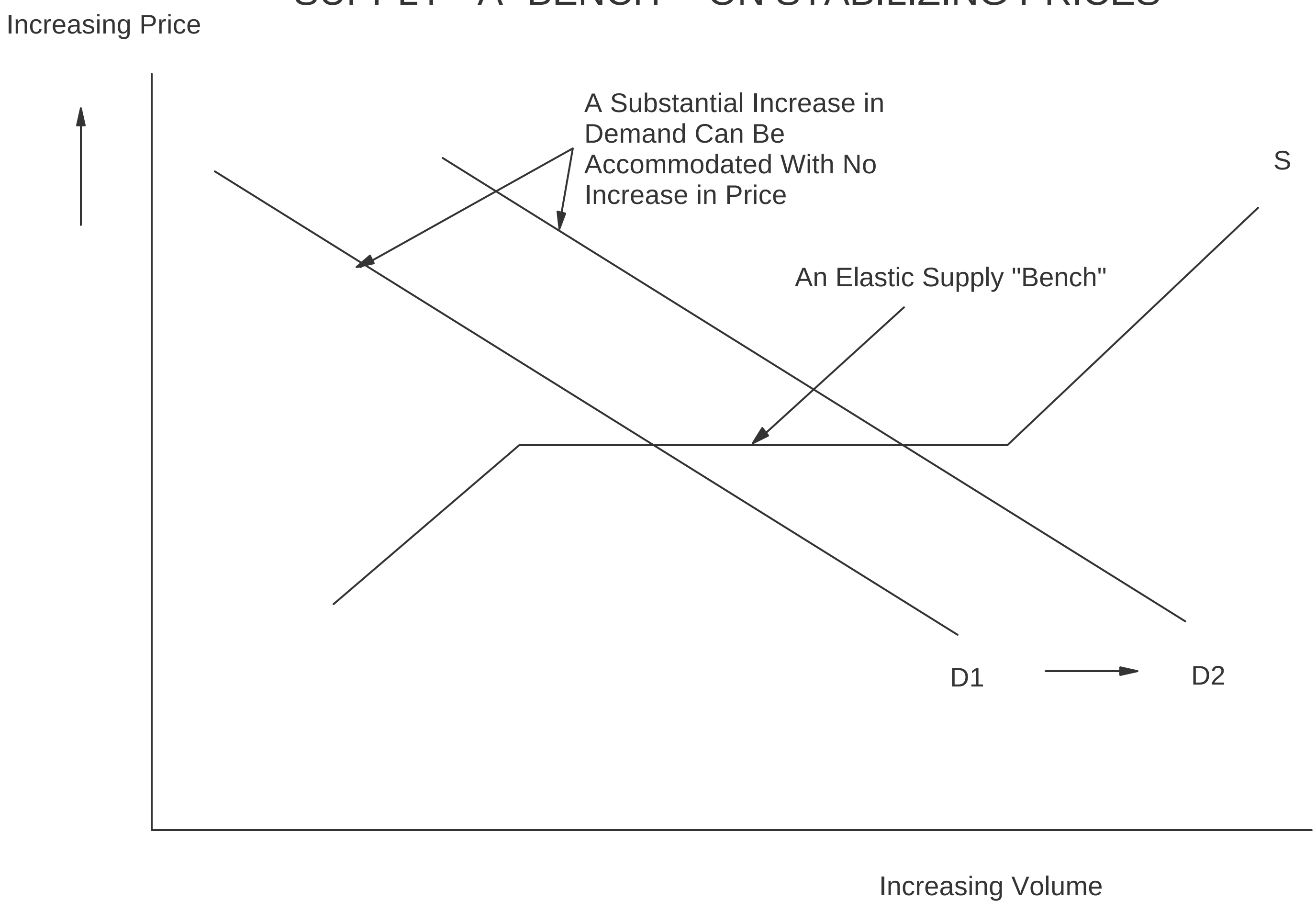
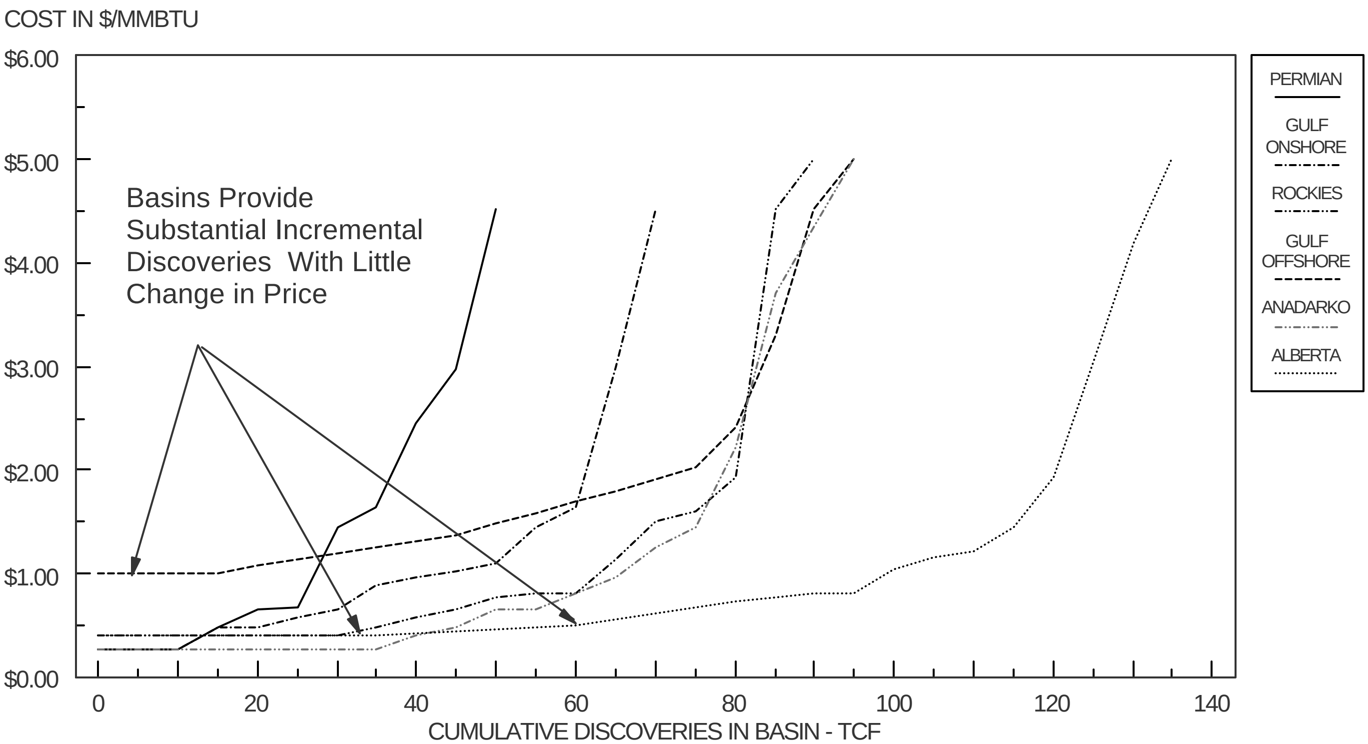


Figure 10-5

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.

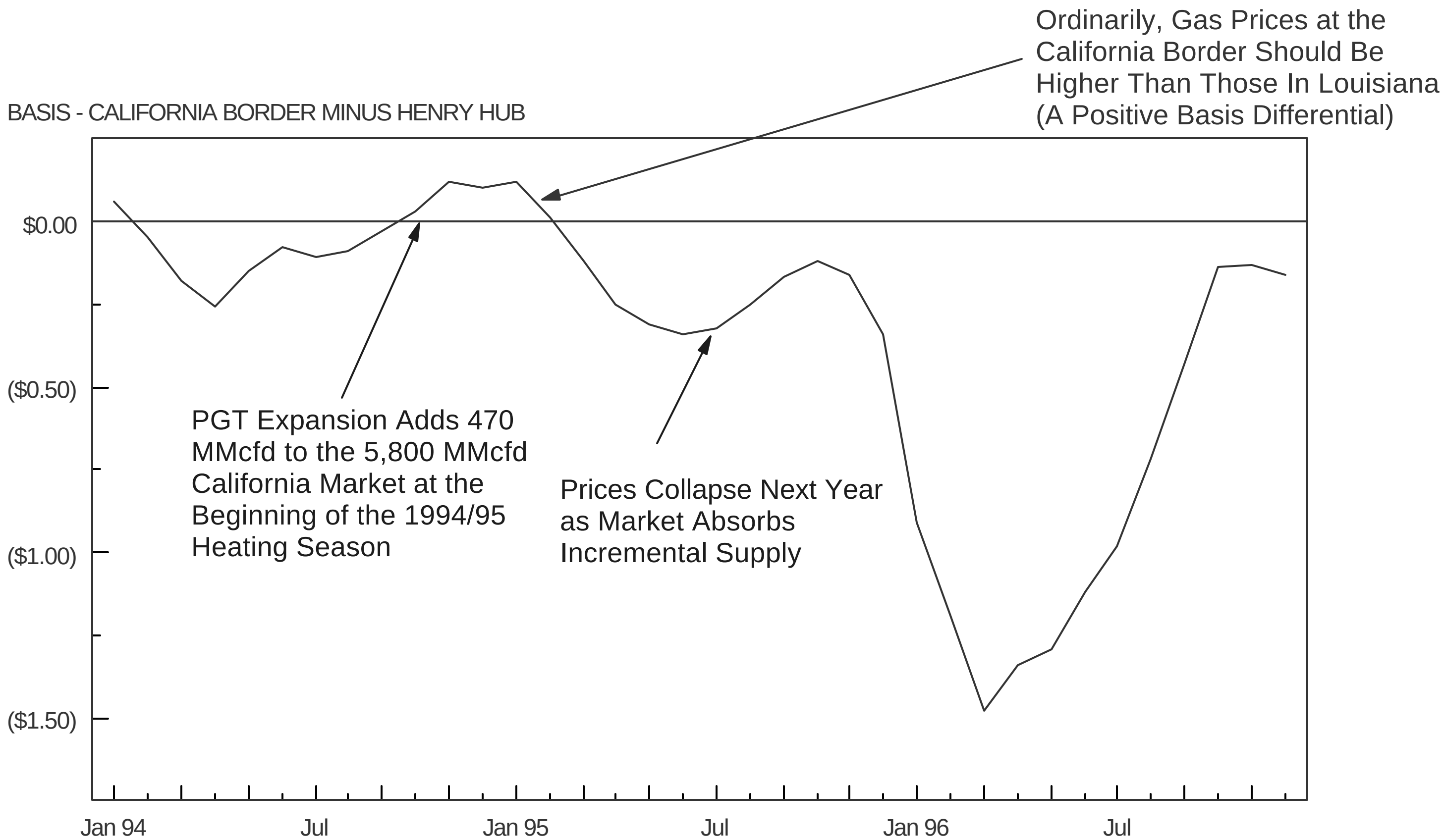
The fact that basis differentials for markets removed from the pricing reference point can themselves vary quite widely introduces a further element of “basis risk” into the pricing equation. For the U.S. market, for example, an LNG delivery to the Everett, MA or Cove Point, MD terminals would be expected 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.

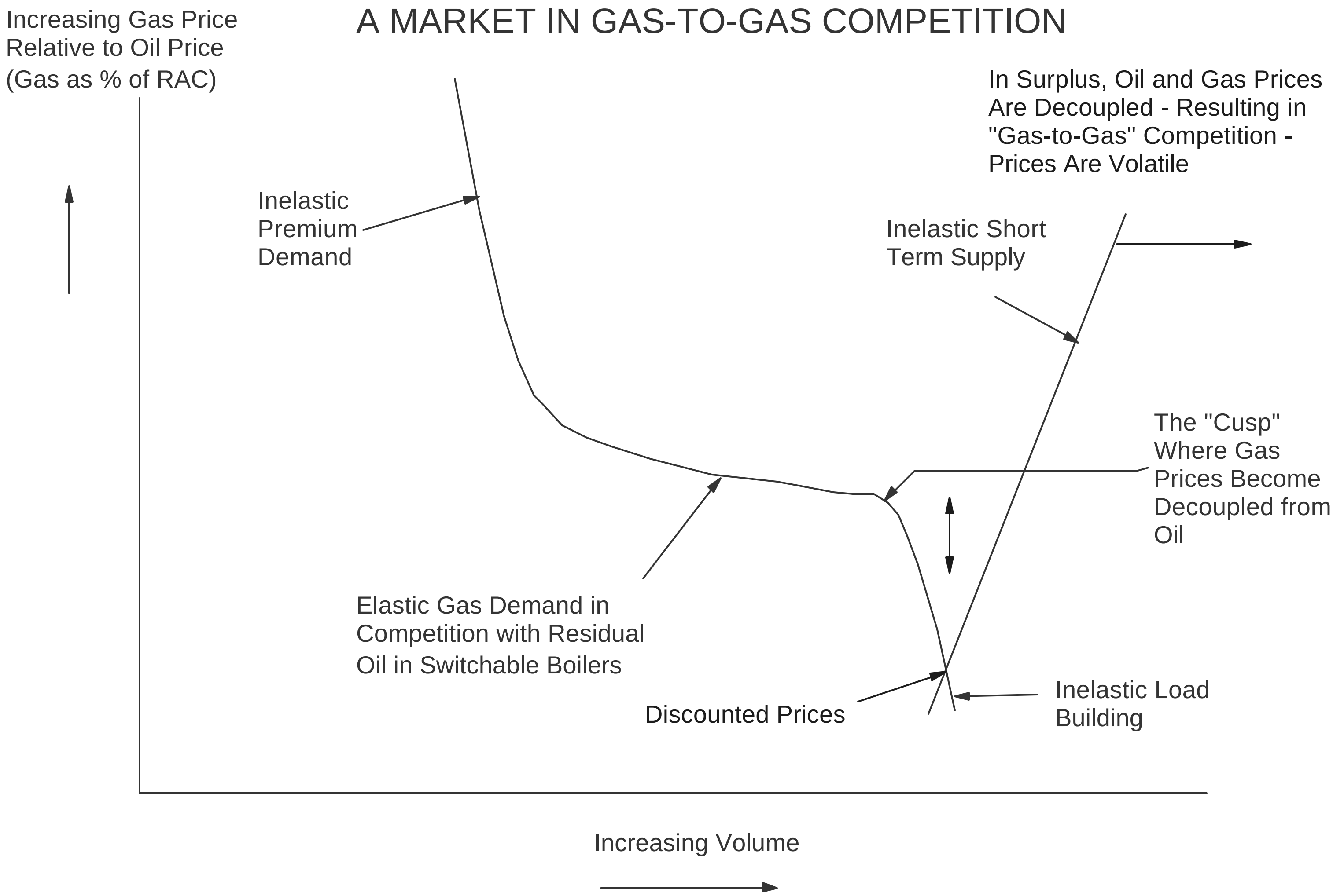
A more realistic way of viewing the gas demand curve is to show it in relationship to oil prices, rather than in the absolute level of gas prices themselves. Figure 10-7 provides such a relationship by using the ratio of gas prices to oil prices as the price determinant.

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?

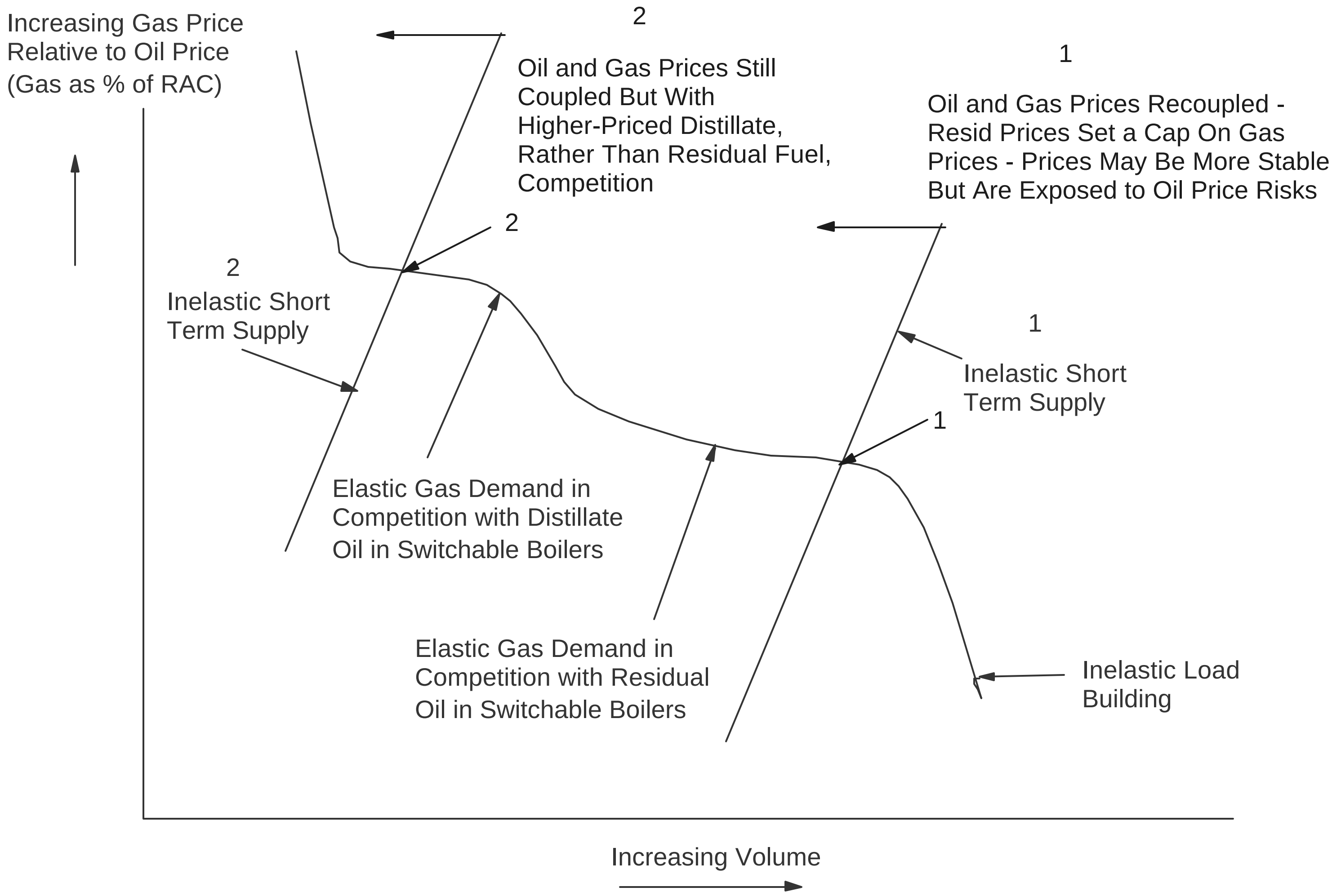
Before the gas trading companies got into their financial difficulties, many were promoting an ambitious concept of using financial derivatives for long term as well as short term risk management. Taken to its extreme, the seller no longer had to rely on long term contracts for his future cash flow but 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.

[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

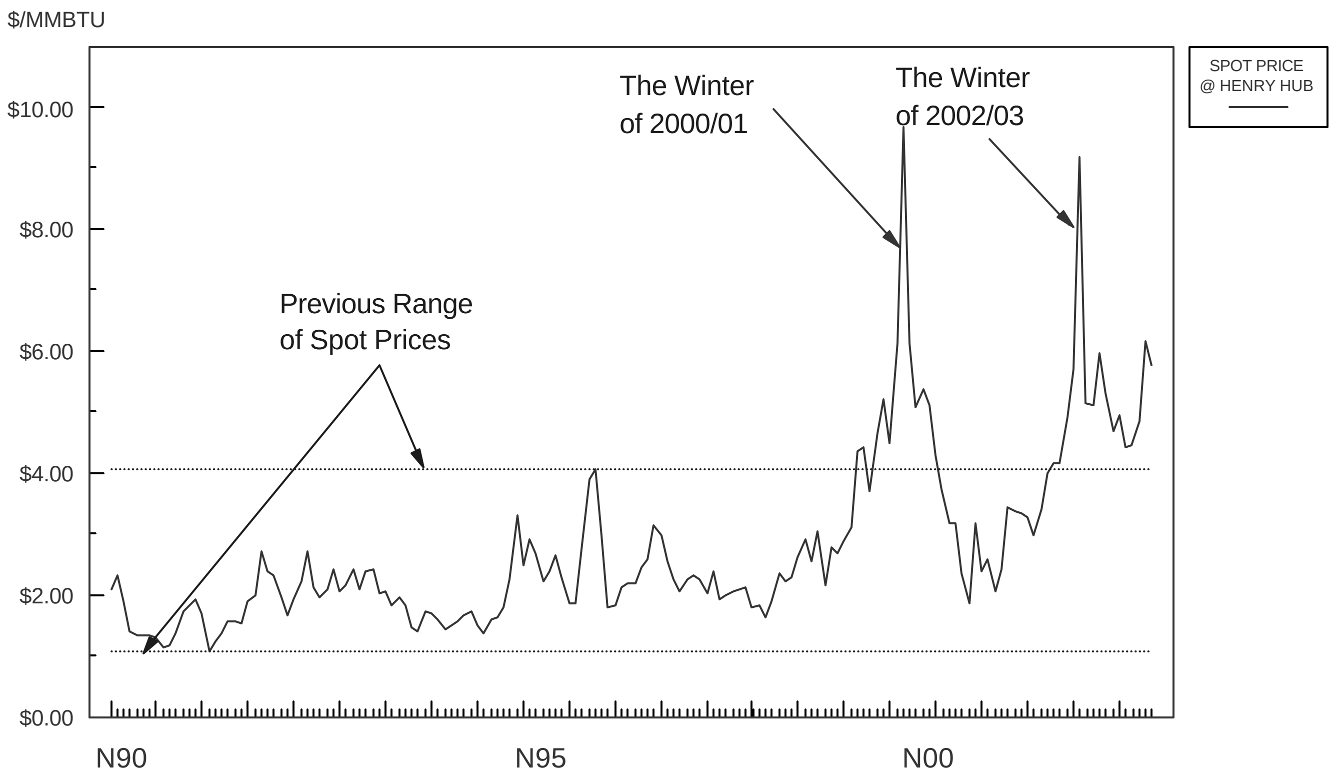


Figure 10-10 compares the estimated pre-tax cash flow as a percent of capital investment in a new independent Gulf Coast terminal, an estimated hurdle rate to justify the investment, and the return that the investment might have experienced in July/June 2000/01 and again the following year. The margins 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

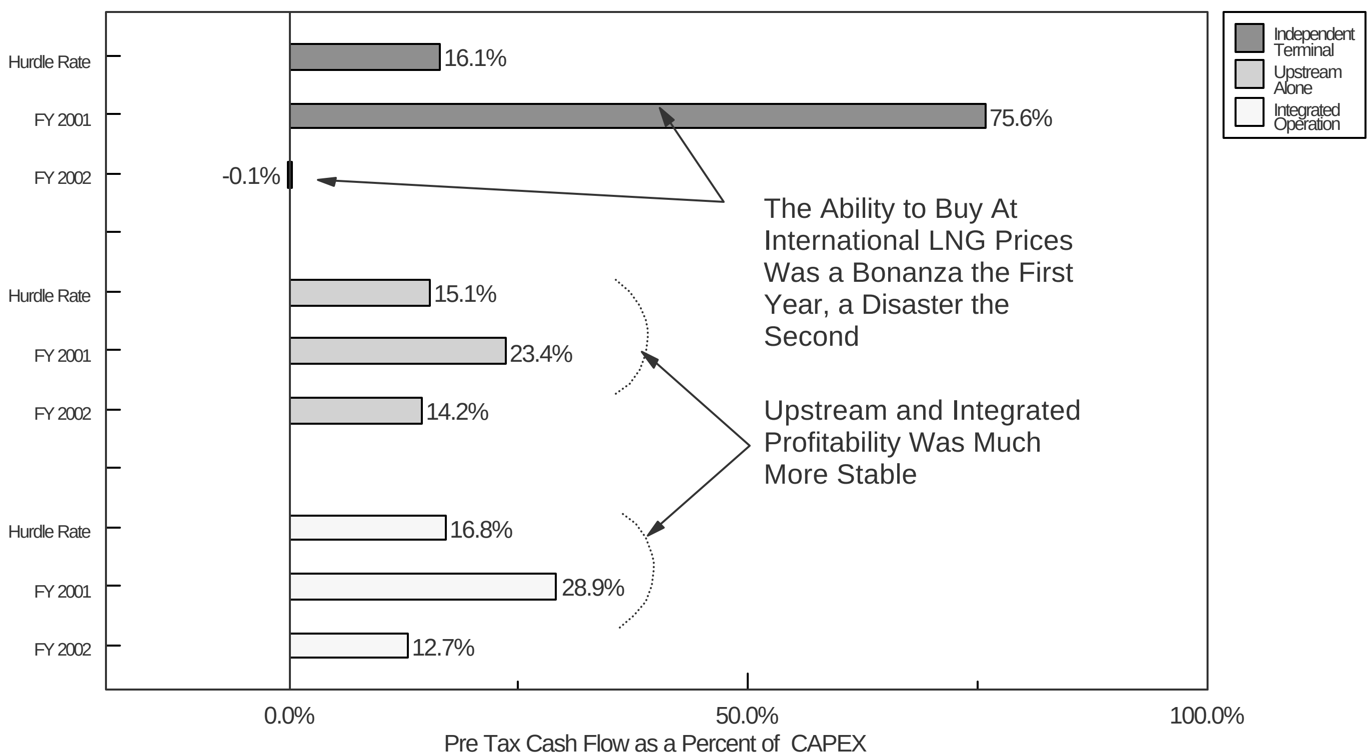


Figure 10-11

COMPARISON OF U.S. LNG TERMINAL IMPORTS WITH CAPACITY

MMCFD

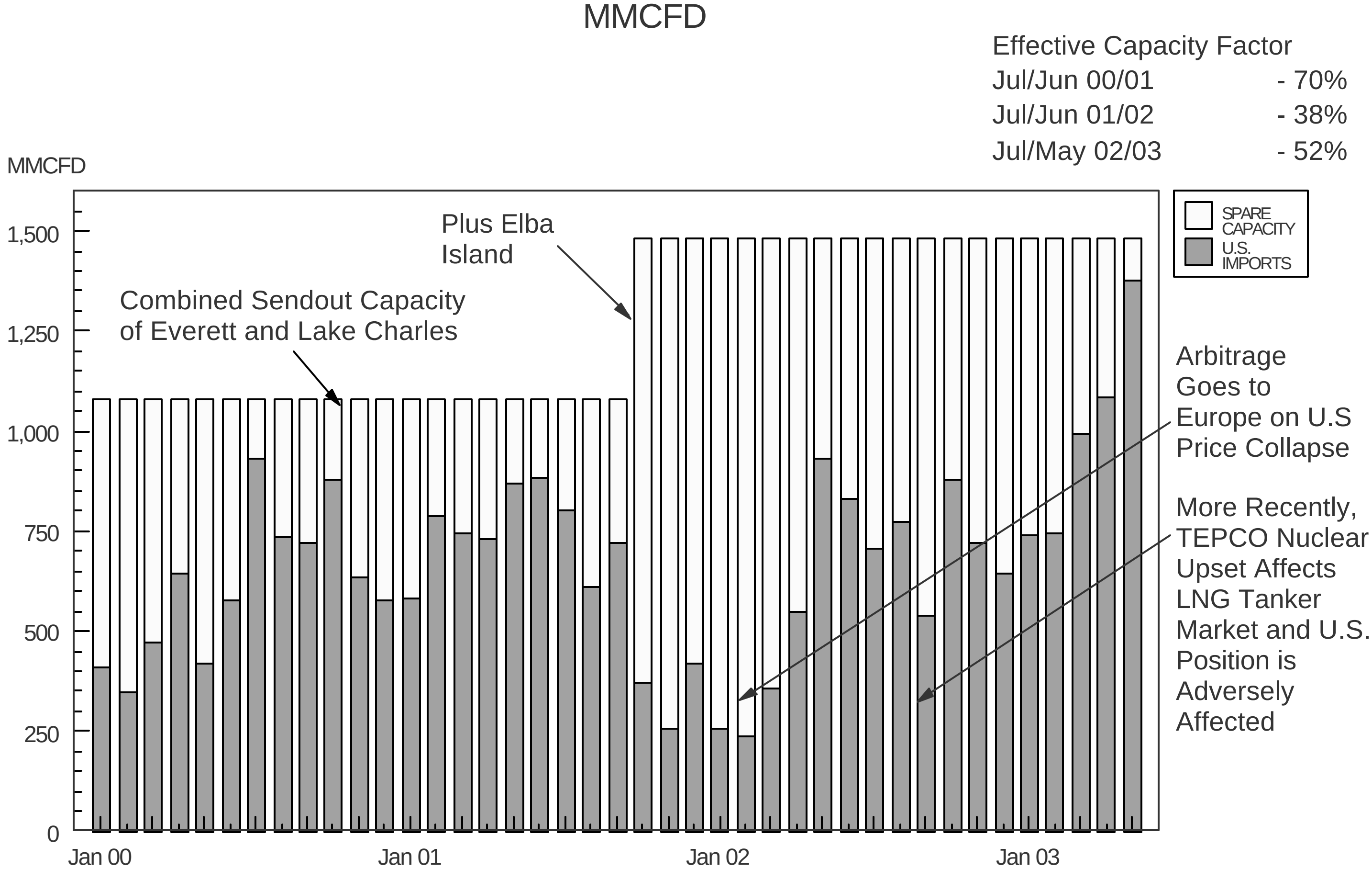


Figure 10-12

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

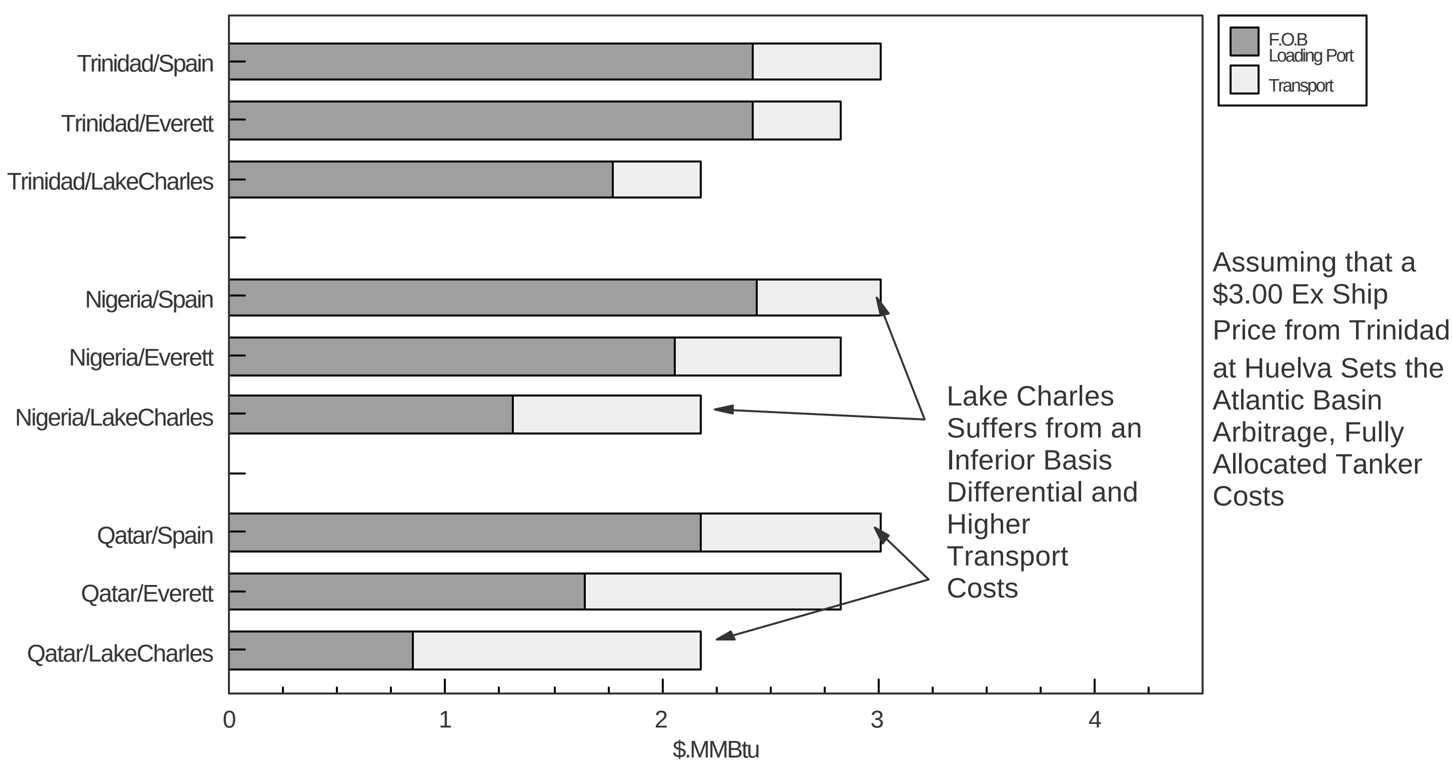


Figure 10-13

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

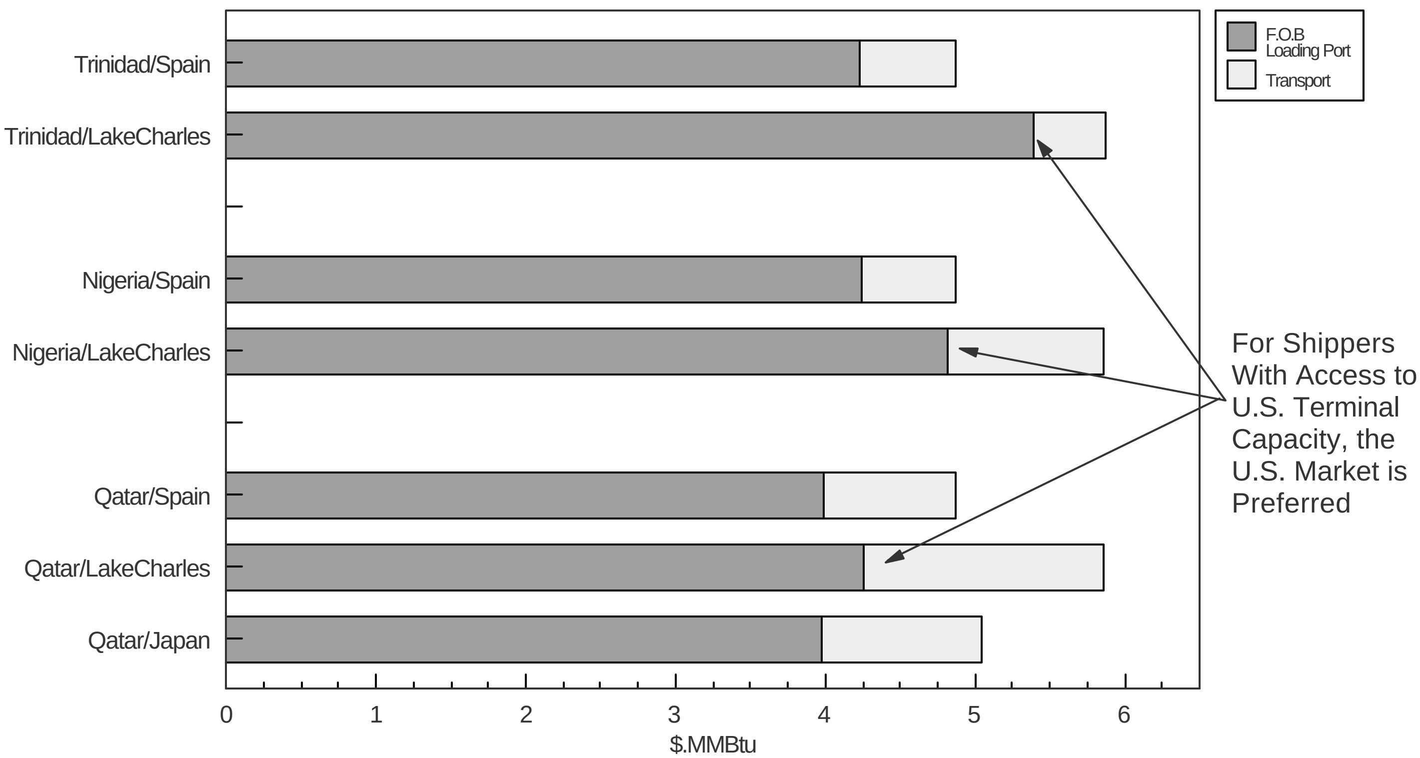


Figure 10-14

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

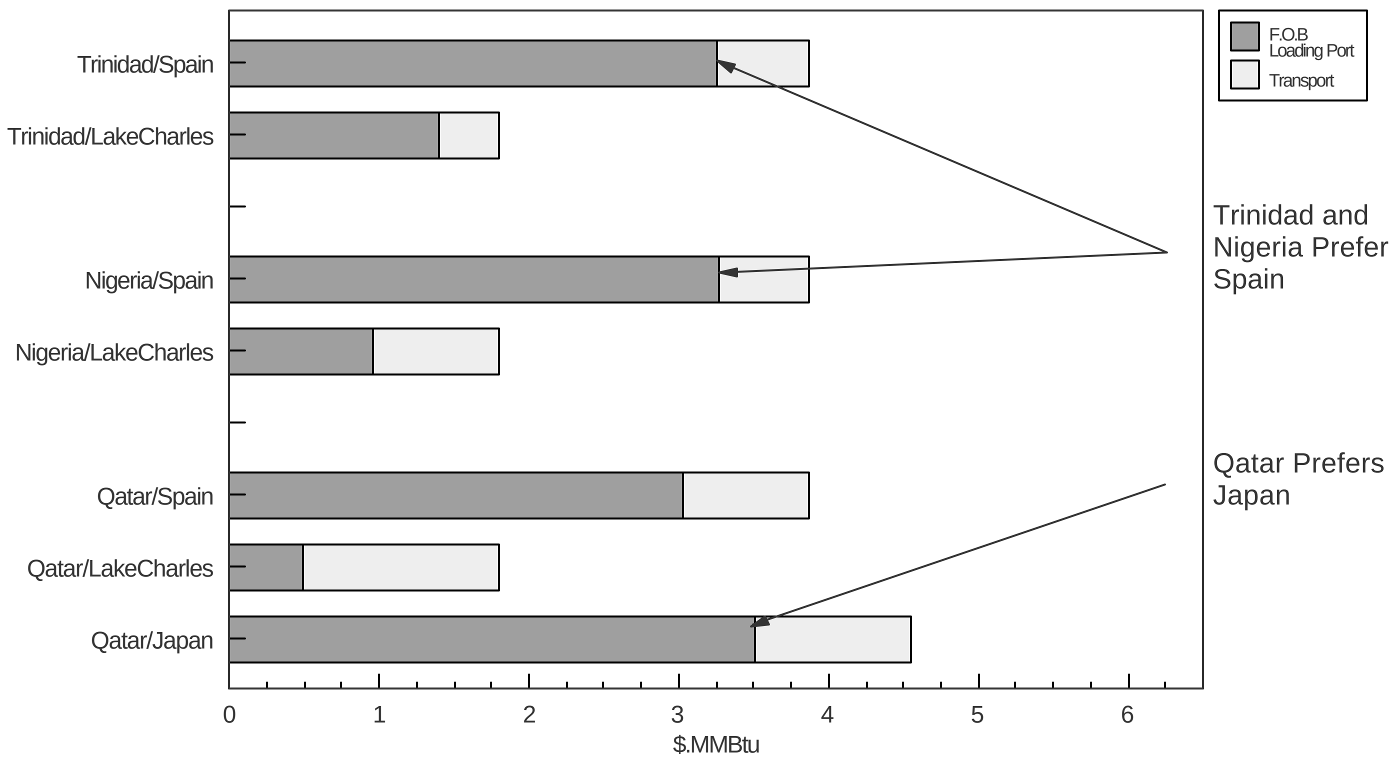
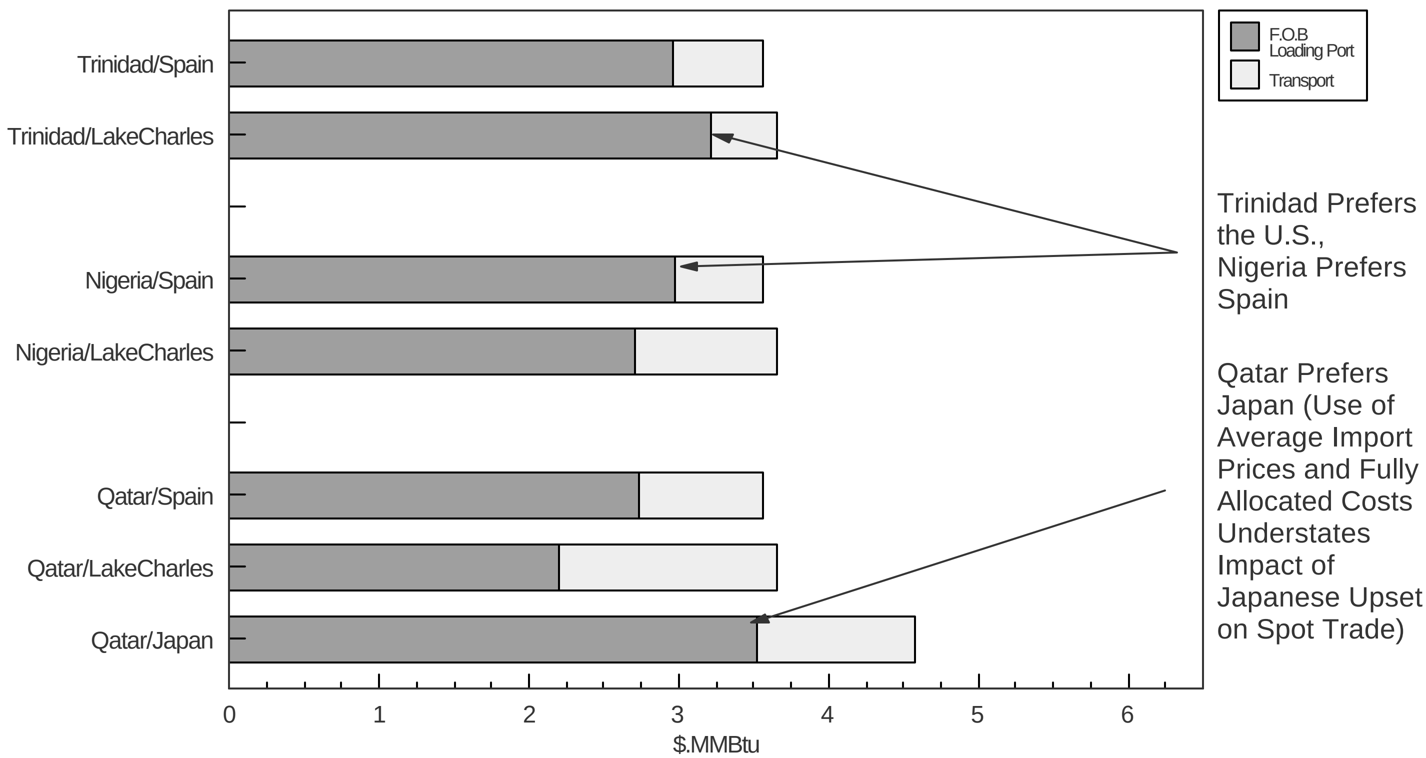


Figure 10-15

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.

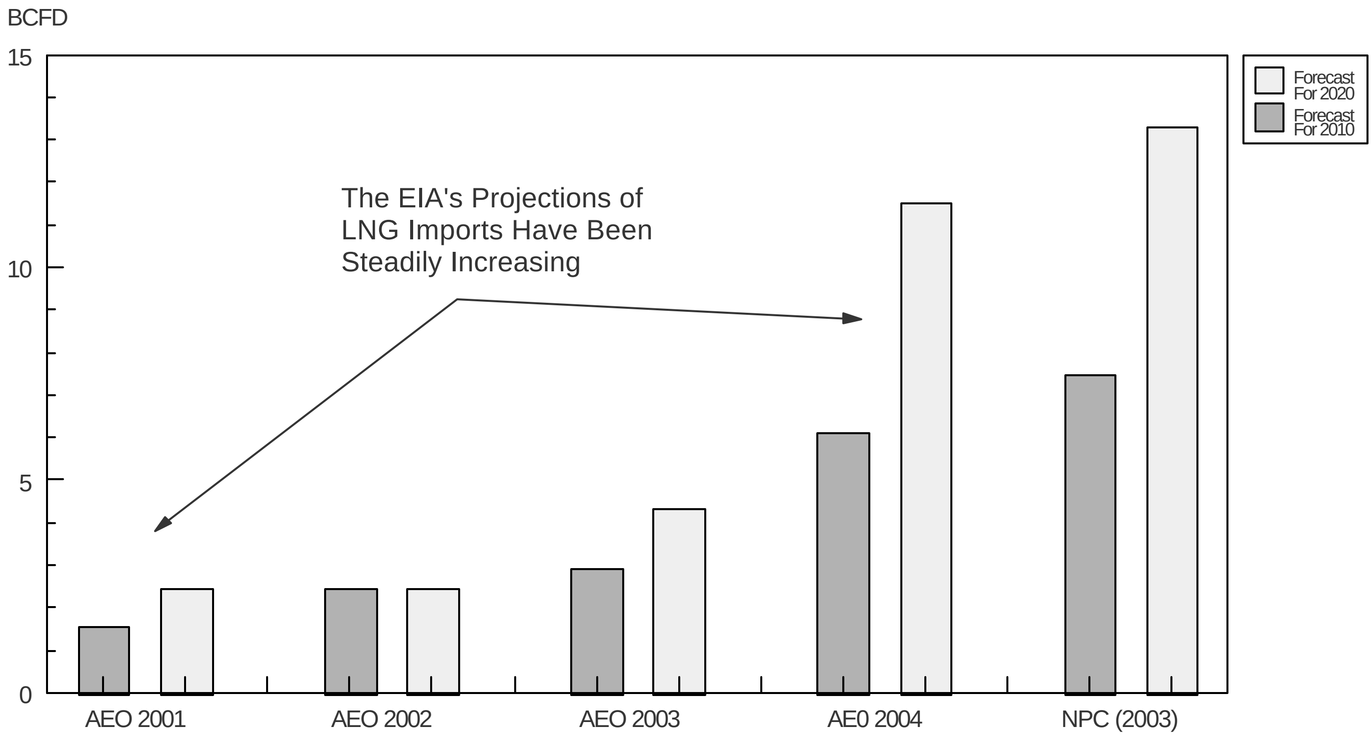
The somewhat sanguine U.S. view of international LNG supply is encouraged by trade press reports that commonly give the impression that potential LNG supply is virtually unlimited. But LNG observers have learned to be highly skeptical about such optimistic trade press reports, not only about whether 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.

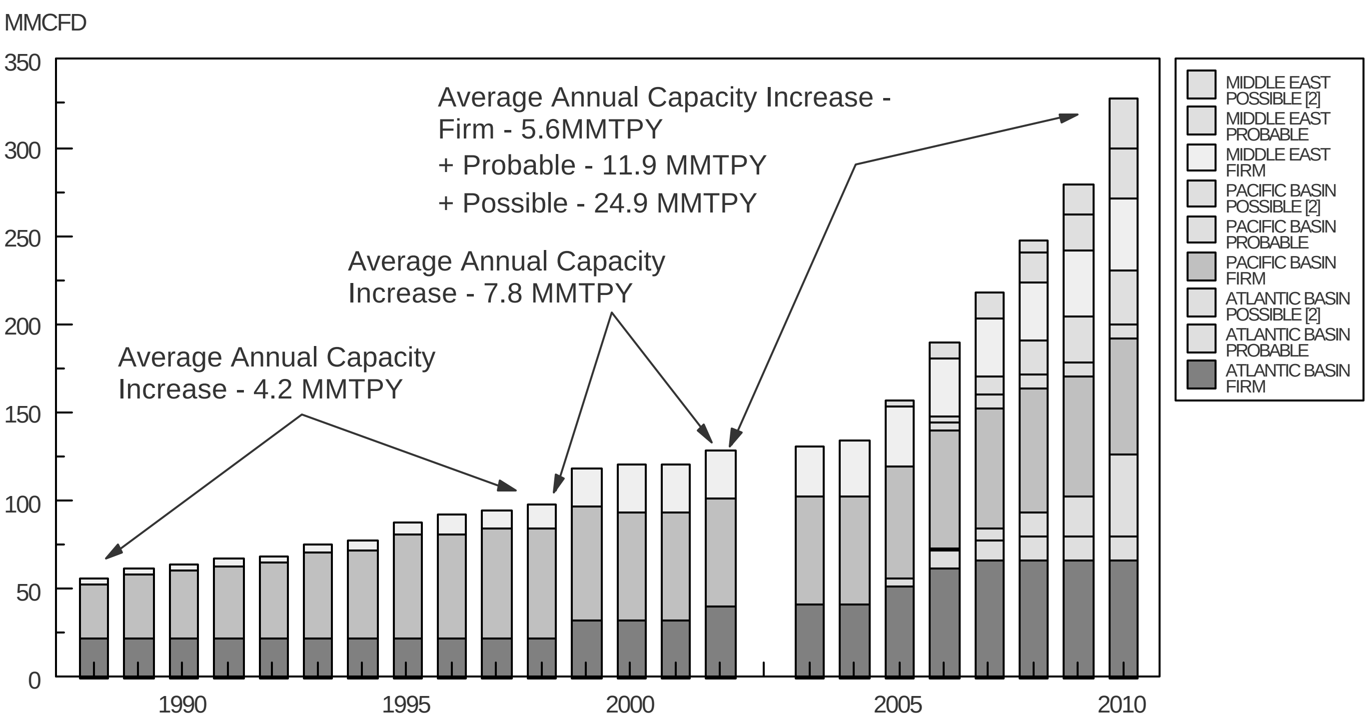
By monitoring contract commitments, it is possible to get some idea of how realistic it may be to satisfy some of the optimistic forecasts of LNG imports into the U.S. Figure 11-4 is such an estimate based on contract commitments in place as of the middle of 2003. Clearly, the contracted volumes, while 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

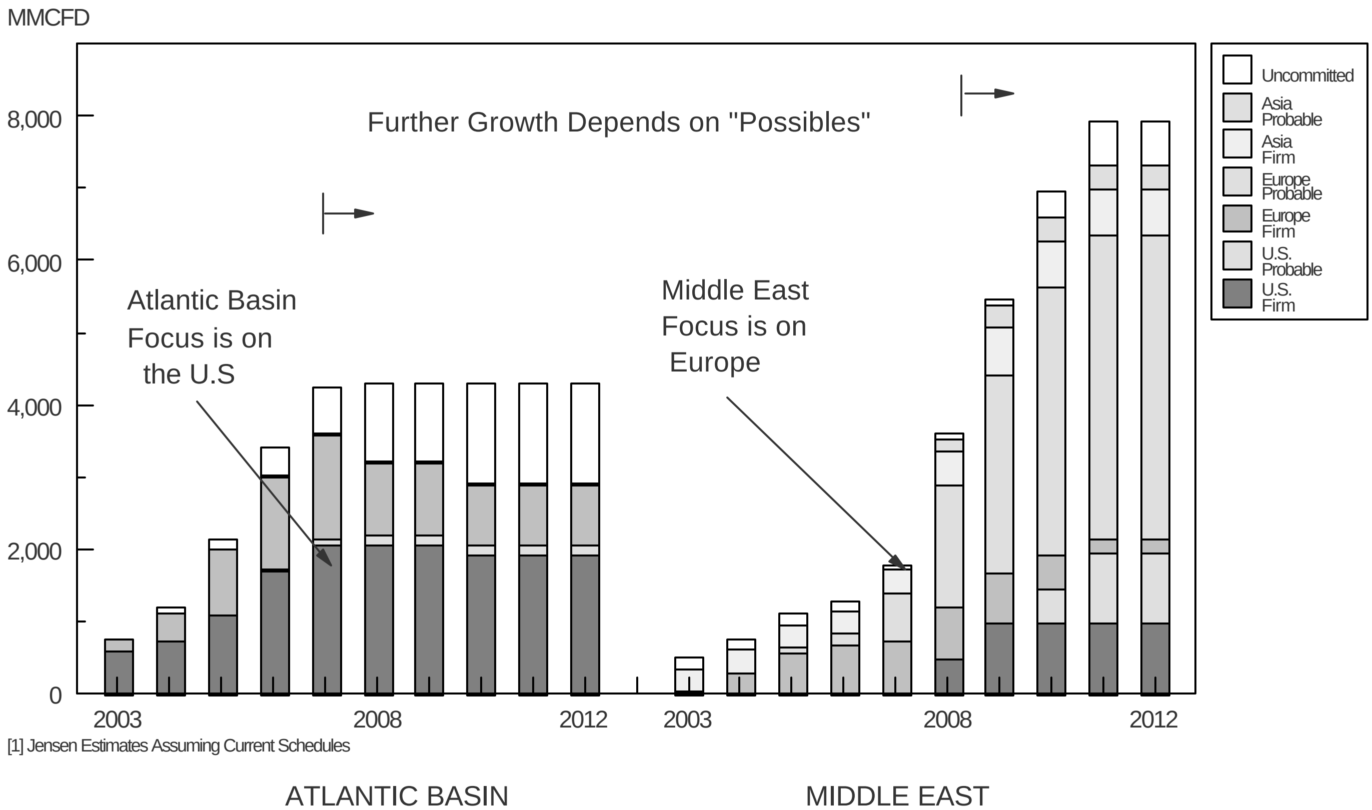
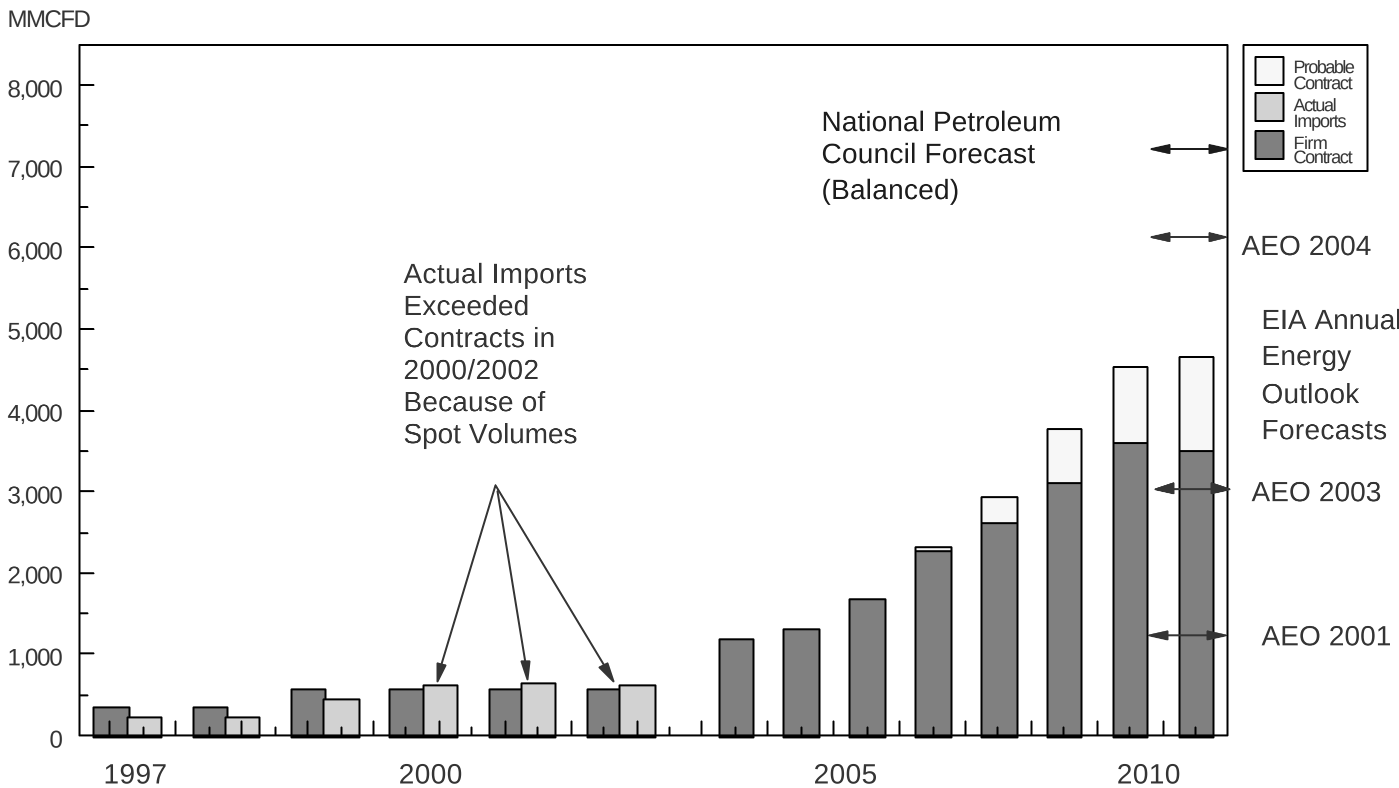


Figure 11-4

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.

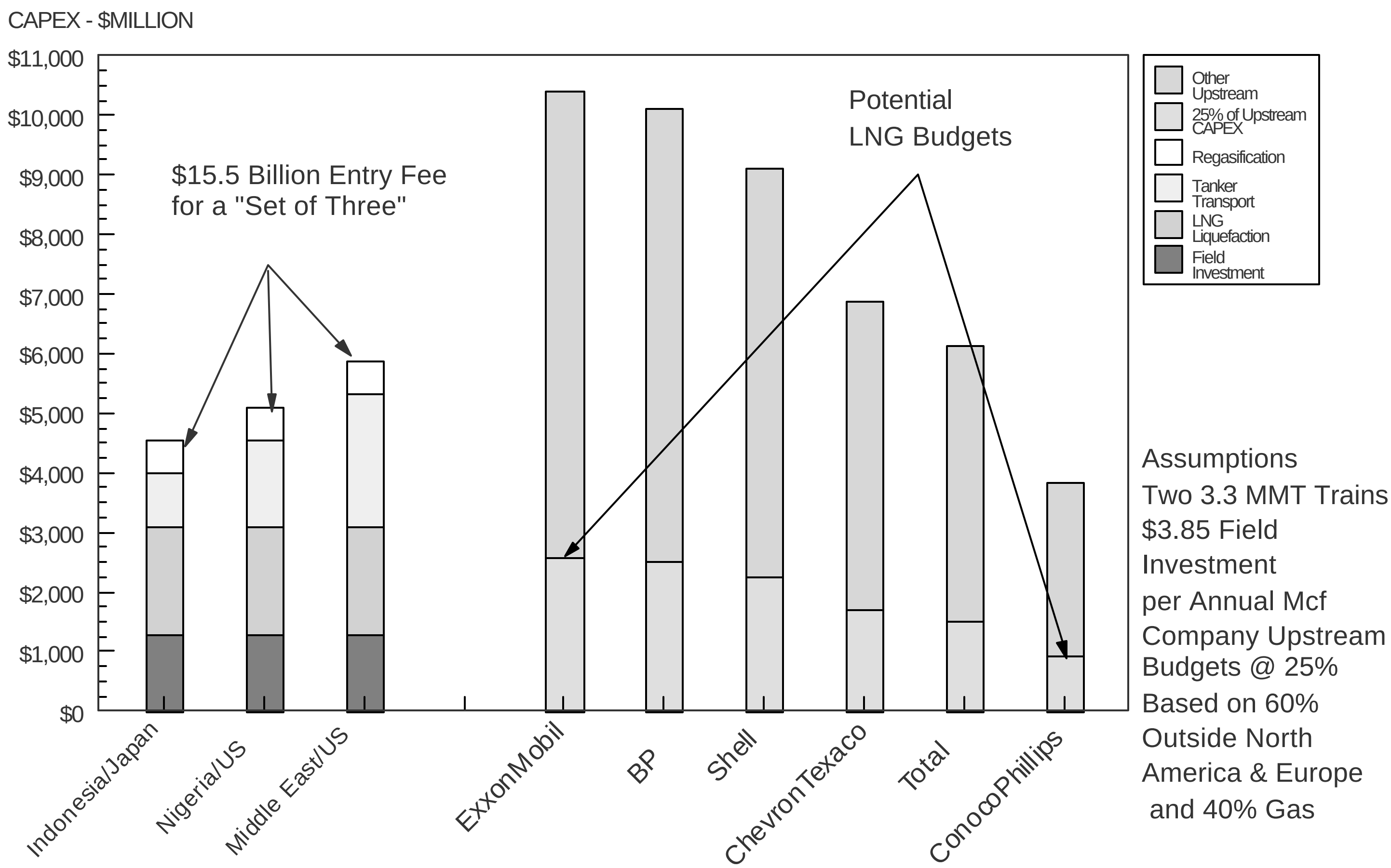
In the face of these market and political risks, integrating downstream and creating a diversified supply portfolio would seem to make good sense as an investment strategy for producers. The problem is that the price tag for the highest degree of diversity is so large that few companies can afford it.

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.

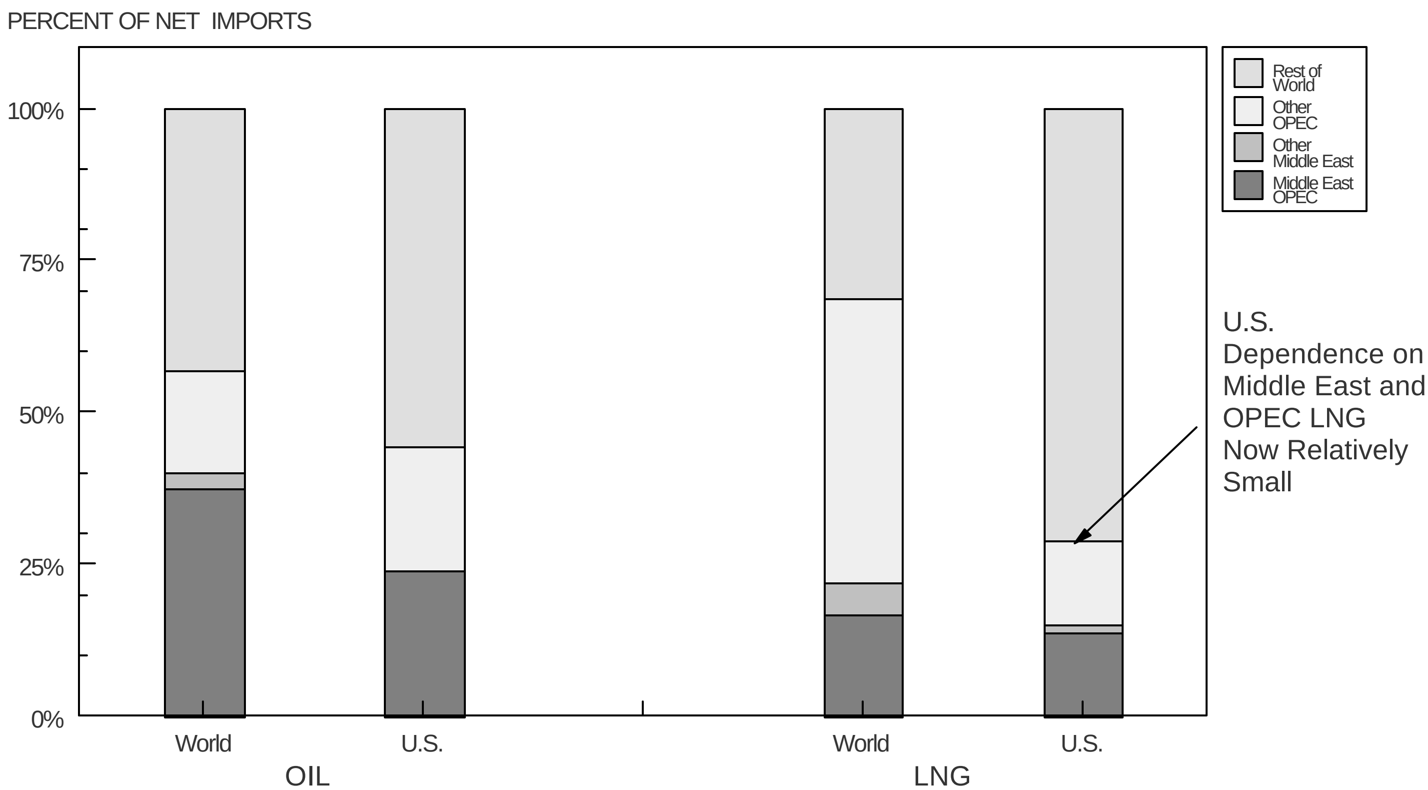
The U.S. has historically relied somewhat less than the rest of the world on oil imports from OPEC and from the Middle East. And because of the heavy reliance on Trinidad for LNG, it is much less dependent on either OPEC or the Middle East for LNG than are Europe and Northeast Asia. However, the new 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.

[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%.

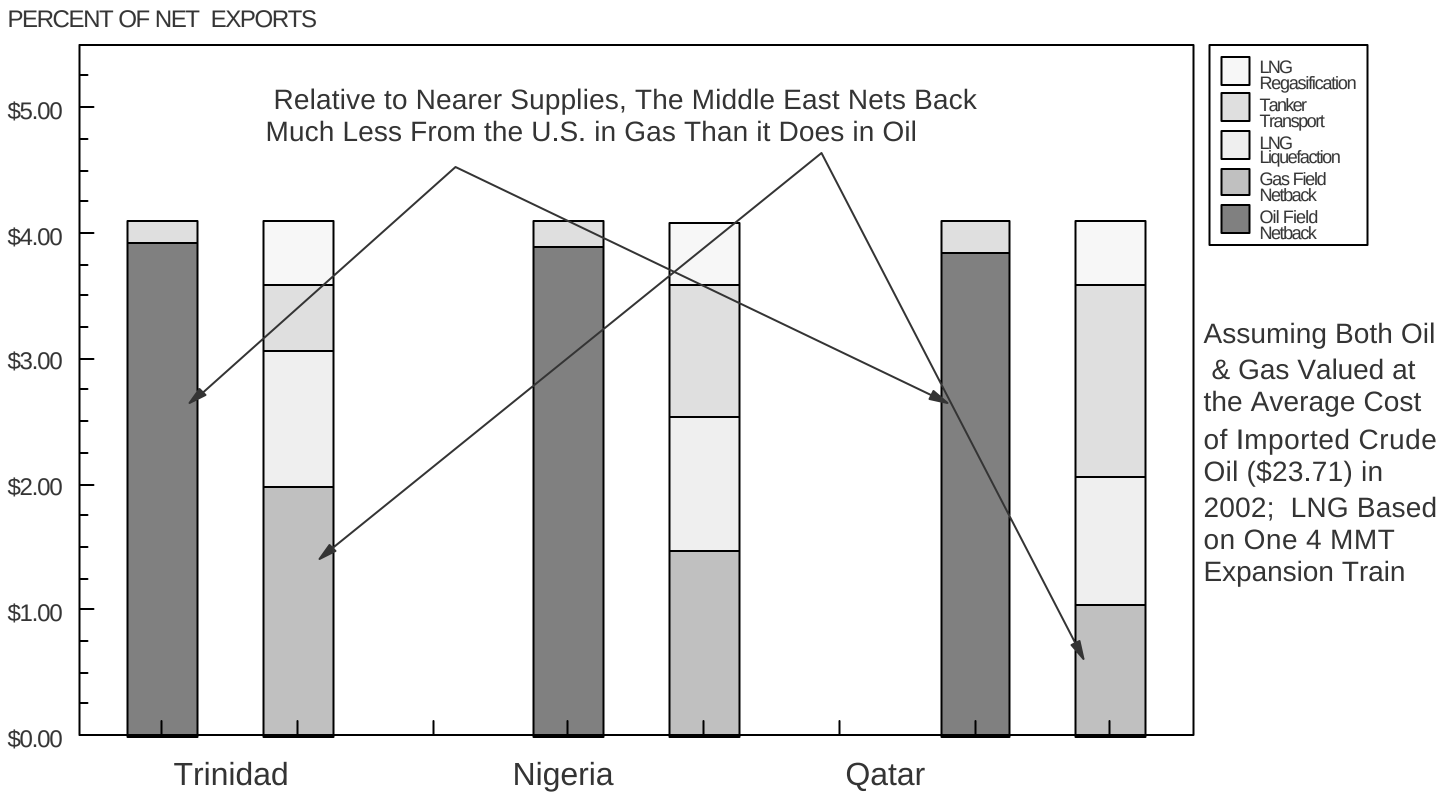
It is possible to lose sight of the fact that gas prices in both Europe and Asia also rose, so that the competitive impact of the price increase was somewhat moderated. Figure 13-1 compares the change in gas prices in the U.S. for the two periods with those of Germany (the largest gas importing country 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.