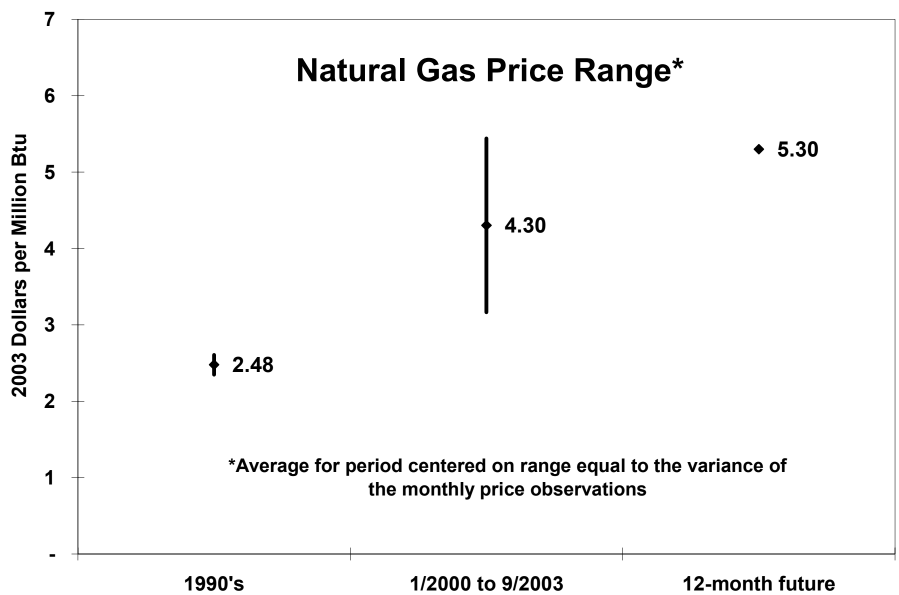
North American Natural Gas

Are we running out?

A White Paper

Abstract

Deregulation of North American natural gas markets in the late 1980's led to over a decade of low, stable prices and a corresponding growth in use. Since the end of the 1990's natural gas prices have been much higher and more volatile (see chart). Combinations of policies that encourage gas use and discourage gas production have contributed to this situation. The price of gas for the twelve months forward from November 2003 is approximately 114 percent higher than the price in the 1990's.



We expect prices to remain high (relative to historic prices) and volatile until one or more of the following occur: 1) the U.S. Federal government removes restrictions on oil and gas production in areas with abundant reserves; 2) significant investment is made in liquefied natural gas (LNG) infrastructure; 3) producers of unconventional and deepwater natural gas increase capacity significantly; 4) nuclear and coal power production are expanded; 5) demand-side market adjustments (such as more building insulation, setting thermostats lower, or population shifts to warmer climates) to higher prices are made. As can be seen little can be done short term, but much progress is already occurring on several of these. We expect these actions to reduce volatility to the level of the 1990's within about three years.

No, we are not running out of natural gas in the world. There is plenty of gas but its production and delivery to end users in North America is increasingly more expensive. North American producers are depleting the easy to produce gas in areas without significant access restrictions. Investors who would otherwise be willing to produce the more difficult gas reserves fear the U.S. Federal government will liberalize access to the low-cost reserves and strand their investments. Thus, the gap between production capacity and demand has shrunk to almost zero over the past several years, causing the high volatility.

As the world's oil and gas companies are already investing heavily in LNG infrastructure and natural gas is getting much attention in Washington D.C., we expect the gas market with help from U.S. Federal policy adjustments will bring prices back down to around $4 (in 2003 dollars) by 2007. Though lower than current prices, this forecast is still 60 percent above the average price in the 1990's.

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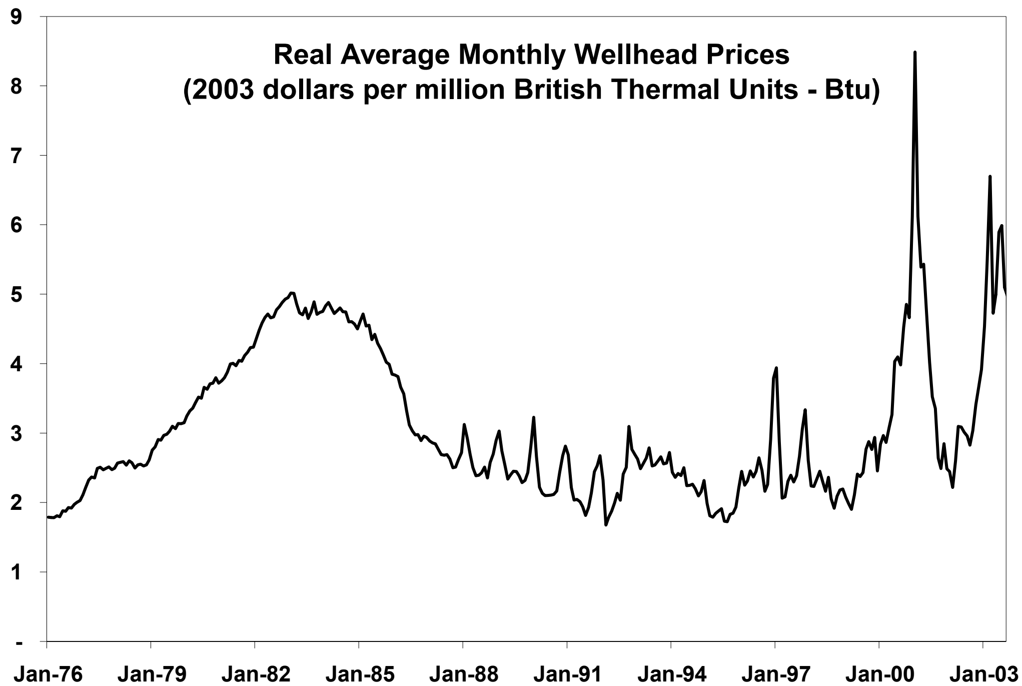
Introduction

Alan Greenspan shined the spotlight on the natural gas market in June of 2003 when he told Congress that there was a problem. "Today's tight natural gas markets have been a long time in coming, and distant futures prices suggest that we are not apt to return to earlier periods of relative abundance and low prices anytime soon," Chairman Greenspan commented following months of historically high natural gas prices in the United States. He suggested policies to remedy long-term market constraints but warned that the only remedy for the near term were high prices. We wondered what was happening to the market for a commodity whose total U.S. consumption represents approximately one percent of GDP and approximately 24 percent of all energy consumed. American Energy Solutions and Foster Bryan have joined forces to shed light on the natural gas market on behalf of our clients, commercial and industrial energy users and institutional investors respectively, and this paper is the product of that effort.



The graph above plots the real price history of natural gas as reported by the Energy Information Administration (EIA) which is the statistical and analytical arm of the U.S. Department of Energy (DOE). Dr. Greenspan's concerns are represented not just by the twin price spikes since 2000 but also the underlying fundamentals for this market. This paper will address those fundamentals and seek to lend evidence to the following questions:

1. Are natural gas supplies sufficient in North America and worldwide to support new technologies dependent on plentiful natural gas?
2. What has caused the high natural gas prices of the past three years in North America? Are natural gas prices going to return to the levels of the 1980's and 1990's ($3 per Mcf average in 2003 dollars) or have they experienced a fundamental upward shift?
3. Is worldwide natural gas production in danger of peaking while demand is growing? Would such a peak have devastating implications for the worldwide economy?

4. Where do the various views of the state of natural gas in North America diverge? On what is there consensus?

Natural gas market fundamentals are complicated and simple analyses are always flawed. For example, in 1985 the United States had natural gas proved reserves equal to twelve (12) times annual production of gas. That was more than 12 years ago, and the Unites States is still producing gas and still reports proved reserves of approximately eleven (11) times annual production. Hence reserve statistics, while intuitively appealing, must be understood for what they are, *estimates* of known gas deposits that can be recovered at current prices using current technologies. Characterizations of reserves as static inventories are deceptive and further analysis is required to assess the supply side of the market.

Sound bite explanations of the complex natural gas market are misleading almost by definition so it is unlikely that the popular press will do justice when covering this subject. Therefore our goal is to remedy the deficit of understanding by presenting a simple, straightforward, and objective analysis of this market. Because of its length this paper cannot present a full appreciation of natural gas market fundamentals but a thorough reading of it will help you decide if Chairman Greenspan is prophesizing catastrophic scarcity or merely encouraging investment and policies to smooth over a local market adjustment.

Definition of Common Terms

Production	When natural gas is extracted from the earth it is said to be 'produced.'
Reserves	Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty (90% probability that this amount or more will be produced) to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. Probable and Possible reserves carry 50% and 10% probabilities, respectively, of producing greater quantities.
Resources	Generally 'resources' refers to the entirety of a given fuel existing on Earth. However, the more meaningful term *Technical Resources*, refers to those resources for which the technology exists to produce them, regardless of the cost. Often *resources* and *technical resources* are used interchangeably. Resources are inclusive of reserves.
Units	Natural gas is commonly measured in heat units or British Thermal Units (Btu) and volume units or cubic feet (cf). A Btu is approximately the amount of heat contained in one match tip.[1] One million Btus (abbreviated MMBtu) is enough heat to keep a large house in the Northeast warm for about a day in the winter. The heat content of natural gas varies depending on the composition of the gas but generally there are about 1,050 Btus per cubic foot of gas. Therefore one million Btus is roughly equivalent to one thousand cubic feet (commonly abbreviated Mcf). For purposes of this paper we assume there are exactly one thousand Btus in a cubic foot of gas so that the terms Mcf and MMBtu are interchangeable.

Background

Humans have outpaced other species' ability to harness energy since we figured out how to light fires about 750,000 years ago and we have improved upon our fuel sources ever since. We burned wood then added coal then oil and then gas. Never did we give up the predecessor fuel, but very little wood is burned today in industrialized societies. All fossil fuels contain molecules of hydrogen and carbon (hence the name hydrocarbons), and the cleaner ones contain lower proportions of carbon. We have moved away from the carbon-rich fuels in favor of lighter fuels due to their efficiency rather than exhaustion of the heavier ones. Commercially burning pure hydrogen is the goal of many scientists, environmentalists, engineers, and investors. This paper looks at the market for one of the favored lighter fuels, methane (CH_4), or more commonly, natural gas.[2]

Natural gas is a hydrocarbon conventionally produced from discrete underground reservoirs. It burns cleanly relative to other hydrocarbons and has therefore found favor in industrialized countries that can afford to put it to widespread use. Natural gas is produced much like crude oil is; wells are drilled and the gas extracted. However, because of its gaseous state, efficient transport over short distances is most economic through pipelines. Natural gas can also be liquefied, transported in discrete vessels and re-gasified on arrival near its use. Because of the high cost of these processes, LNG has not been a significant supply source in regions with abundant natural gas, giving U.S. producers an economic barrier to entry. Thus U.S. natural gas trade with non-contiguous countries has been negligible.[3]

Physically, natural gas is one of many useful hydrocarbon formations including tar, crude oil, natural gas liquids (NGLs) and coal that form beneath the earth's surface when heat and pressure are applied to organic material. All of these hydrocarbons can substitute for each other in one way or another[4] and are produced, transported and refined with varying degrees of difficulty. Crude oil requires an extensive refining process before it becomes one of many liquid fuel types; gasoline and jet fuel are but two examples. Conversely, NGLs can be taken directly from the ground[5] and put in the tank of a car (though this is dangerous and illegal). Also, a suitably modified automobile can run on natural gas. Thus, over time, there is some degree of substitutability between different forms of hydrocarbons. As such, it is misleading to look at one form exclusive of the others.

Many have argued that conflicting policies encouraging use and discouraging production of natural gas have led to the increased price volatility in recent years.[6] Such policies restrict petroleum exploration and production (E&P) on federal lands and coastal waters, encourage clean combustion over dirtier heavier hydrocarbons (such as oil or coal) and have contributed to a perception of gas scarcity in North America. Some have argued that domestic depletion of accessible reserves and a looming production peak present an imminent problem, which will have disastrous effects on the world economy. Others contend that such an abrupt supply shock is unlikely or will not have devastating implications as the eventual production peak will be anticipated by the market giving price signals for conservation, fuel switching, production technology research and development and renewable energy collection improvements. Moreover, these 'gradualists' think a production peak due to geologic constraints is far in the future rather than within a decade.

As even a gradual approach to the peak production of natural gas without viable substitutes can induce real economic consequences to those investments dependent on natural gas abundance, evaluating if and when natural gas production will peak and if it will matter (as the Stone Age did not end because they ran out of stone) is the goal of this paper.

North American Natural Gas Supply – Resources

Supply is broken into three sections in this paper. How much gas exists (resources); how fast we can get it (production); and our ability to move it to the end user (delivery). As noted earlier, explanations of any one of these components alone can give a misleading indication of natural gas supply.

North American natural gas proved *reserves* represent less than eleven (11) years of supply at current consumption and prices. The National Petroleum Council (NPC), a cooperative effort between government and industry working under guidance from the Department of Energy, recently estimated North American natural gas *resources* at over 2,200 trillion cubic feet (Tcf) or almost 80 years of supply.[7] As the gas industry distinguishes between reserves and resources these estimates are not contradictory, however, their methods and uses have led to intense debates.

Table 1 – World Natural Gas Resources

	Production Growth (1992-2001 CAGR)	2001 Production (Tcf)	2001 Proved Reserves (Tcf)	Total Resources (Tcf)
United States	0.9%	19.8	183	1,575
Canada	4.3%	6.7	92	542
Mexico	3.9%	1.4	30	100
Total North America	1.7%	27.9	305	2,217
Rest of World (NA import potential)	2.6%	65.6	5,196	17,918
Total World	2.2%	93.5	5,501	20,135

Sources: NPC, EIA and IHS Energy; note 'resources' includes proved reserves

Table 1 shows estimates of North American and World supply of natural gas as measured by reserves and resources as well as recent production growth (compounded annual growth rate – CAGR). The final column of this table is resources which includes proved reserves. By these estimates worldwide natural gas resources may last for another 215 years. In addition, there are vast, but speculative, gas resources found in formations for which we do not yet have the technology to produce (to be discussed later). Ken Shaw of IHS Energy, a Swiss energy consultancy known for its comprehensive database of worldwide oil and gas resources, has estimated what portion of these resources will be recovered. Including Shaw's estimates of recoverable speculative resources, natural gas resources could last over 466 years at the current rate of consumption.

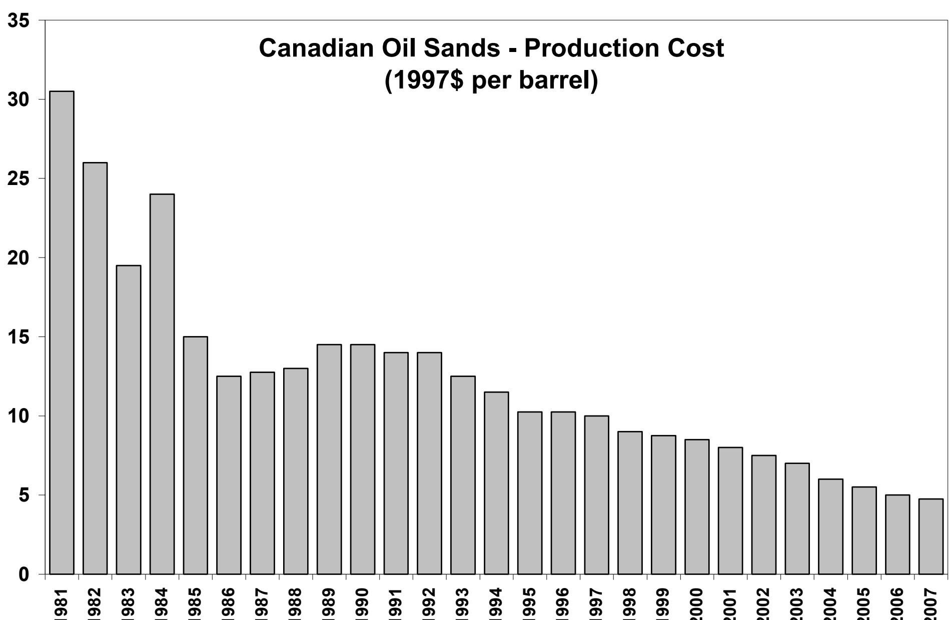
Proved reserves are defined as those resources "…that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e. prices and costs as of the date the estimate is made."[8] This definition seems to leave much room for interpretation but past reserve appreciation from existing fields suggests the proved reserves metric is associated with a very high degree of certainty and can almost be thought of as an inventory measure. Virtually everyone believes that reserves estimates will be realized, however resource estimates are another matter.

Interpreting natural gas 'resource' estimates is more art than science. Geologists Thomas Ahlbrandt and Peter McCabe of the U.S. Geological Survey (USGS) note that "appending the word 'resource'" to oil or natural gas "…creates a term that crosses the boundary between science and social science and includes economics. Many geologists begin to feel uncomfortable in this area between science and social science."[9] Resource assessments for North America or the world consider that there is gas yet to be discovered and attempt to estimate the amount. These assessments also estimate the amount of gas in existing fields that we cannot economically recover at today's prices, with existing technology and under current policy regimes. As production technology improves, prices rise, access policies liberalize or discoveries are made resources are converted into reserves. The oil sands in Alberta, Canada provide a good example of this dynamic for oil resources.

Alberta Oil Sands Example

Natural gas reserve estimates (or any other hydrocarbon reserve estimate) are dynamic as the definition above and the reporting history have proven. Technology, policies and costs are integral to the estimates. The example of the Canadian oil sands of Alberta is instructive. In Alberta, Canada there is a vast resource of heavy crude oil mixed with sand. These sands are much more difficult to produce, transport and refine than traditional, liquid crude oil. It has been technically possible for many years to produce this hydrocarbon resource; however it has not been cost effective. The cost of producing and processing the oil has been falling for years and in 2002 *Oil & Gas Journal*, in their annual survey,[10] decided that the Alberta oil sands should be included in the country's proved reserves of crude oil. The impact was astonishing. Canadian crude reserves increased from 4.9 billion barrels (Bbbl) to 180 Bbbl, an increase of 175 Bbbl.[11]

Those 175 Bbbl are a small part of the entire oil sand resource. The oil sands contain an estimated 2.5 trillion barrels of oil, 315 Bbbl of which are technically recoverable and 175 Bbbl that are economically recoverable today, and hence were added to Canada's proved reserves by *Oil & Gas Journal*.[12] The entire oil sands *resource* represents more oil than twice the proved crude *reserves* of the entire world, but only 7 percent of it is cost effective to produce with today's technologies (proved reserves). And in 2001 none of it was deemed economic to produce. The chart below shows the downward progression of oil sands operating costs as estimated by a major developer of the oil sands.

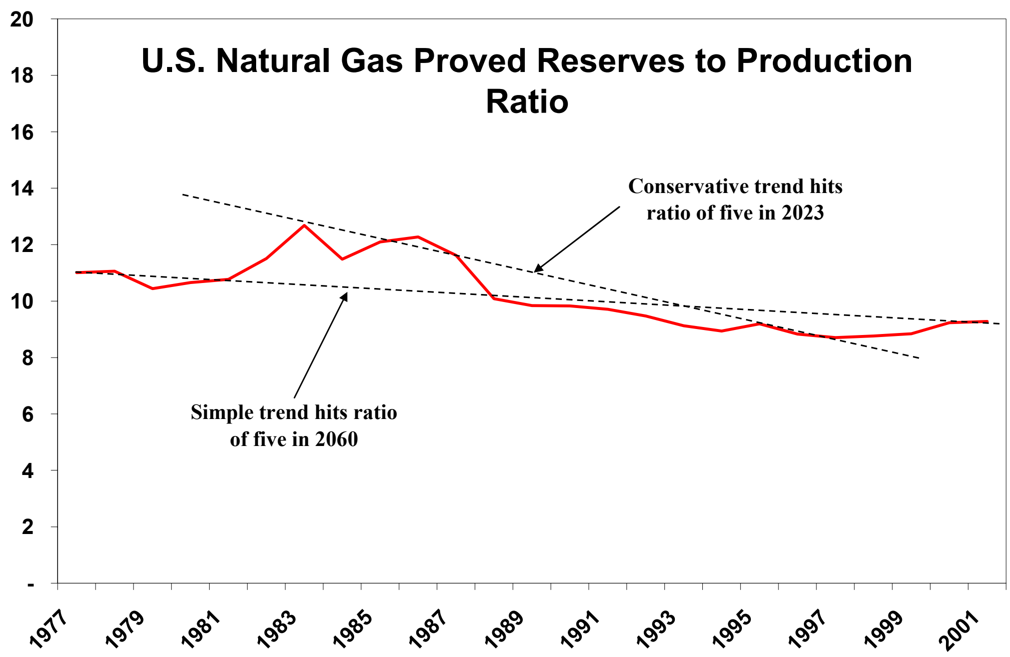


The decision by *Oil & Gas Journal* to re-classify part of the oil sands as 'proved' reserves in 2002 may seem arbitrary but it implies that the technology to produce the world's largest crude resource has converged (at least temporarily) with the world price of crude. Syncrude Canada Ltd., a major developer of the oil sands, expects its second half 2003 production costs to be $10.71 per barrel.[13] If an 8 percent return on assets is necessary to encourage more investment in this resource, a sustained crude price expectation of over $16.63 per barrel[14] accomplishes this goal. Further, as investment shrinks per unit costs (capital and operating), more of the resource will move to the proved reserves category. However, investment in production capacity is based on price expectations and given OPEC's influence on world oil prices (ability to reduce them quickly) investors may require much more than an 8 percent return.

Reserve to Production Ratio

As noted above the North American proved reserves to production ratio (R/P) implies approximately 11 years of natural gas supply left assuming current consumption, policies, prices and technology. But as the Albertan tar sands example shows for oil, proved reserves grow with prices, technology advances and policy support. A look at the history of the U.S. proved reserves to production (R/P) ratio is instructive. We see that this ratio falls over time though less steeply than a static inventory measure would (i.e. going from 10 to zero in 10 years).

The trend of the R/P ratio appears to be declining over time, though lately has been rising slightly. Extrapolating the simple trend in the graph, the slope between the two end points, we will not reach an R/P ratio of five until the year 2060. If we extend a more conservative trend on this ratio from the peak to the trough (1982 to 1996) we do not reach an R/P ratio of five until 2023. The process of 'reserve appreciation' seems to maintain the R/P ratio far above a static course.



Restrictions on access to gas resources artificially contribute to market volatility. The recently released NPC study estimates that 209 Tcf of undiscovered technically recoverable resources are contained in areas with U.S. Federal government restrictions on exploration and production. Drilling is not allowed off either coast of the United States as well as the gulf coast of Florida. There are also significant restrictions on drilling in the Rocky Mountains. The NPC evaluated the effect of removing these restrictions and found that it would add 3 Bcf per day to production by 2020 and this would reduce gas prices by $0.60 per MMBtu.

As mentioned earlier, all hydrocarbons can substitute for each other over time. In the near term coal power plants can be run at higher utilization rates and gas plants at lower rates. Longer term we can build more coal plants and fewer gas plants. There are also technologies to convert natural gas-to-liquid (GTL) fuels traditionally produced from crude oil. For example Conoco Gas Solutions is building a pilot plant in Oklahoma that will be able to produce up to 100,000 barrels per day of diesel fuel (or other liquid petroleum products) from natural gas.[15] Similarly, the DOE is funding research on technologies to break down coal into gases that could substitute for natural gas. Therefore the influence of the markets for other hydrocarbons on the natural gas market is growing.

Table 2 – U.S. Proved Reserves to Production for Hydrocarbons

Hydrocarbon	Quadrillion Btu		
	Reserves	Production	R/P
Natural Gas	183	20	9
Oil	130	11	12
Natural Gas Liquids	30	3	9
Coal	6,709	27	248
COMBINED	7,053	61	115

As an indication of the supplies of those other forms of hydrocarbons in the United States, Table 2 shows the proved reserves to production ratios for four of them. Some believe that reserve measures are gamed by oil and gas companies to maintain a steady appreciation in order to replace their depleting resource, and, therefore, maintain a stable balance sheet. They contend that reservoirs are intentionally under estimated when initially discovered and then systematically revised upward as reservoirs are depleted. They do not dispute that the reserves in any given year are legitimate but that reserve estimates from existing fields become less reliable over time. This, they contend, combined with fewer new discoveries spells eventual (and some say imminent) disaster for the world economy, but more on that later.

Unconventional Resources

Conventional natural gas is found in discrete reservoirs making for relatively simple production. Unconventional accumulations of natural gas are referred to as continuous sources as they permeate large mineral deposits of coal, sandstone, shale or chalk. Similarly, there are unconventional accumulations of oil such as the Albertan oil sands mentioned above. These unconventional resources are more expensive to exploit, but their costs have fallen over time. Unconventional production represented approximately 20 percent of total non-arctic U.S. and Canadian production in 2002 according to the NPC. That share of total production is expected to climb to 40 percent by 2025.

In their 1995 assessment of resources the USGS estimated unconventional hydrocarbon resources in the United States. Table 3 shows the results of this assessment for natural gas. The mean estimate (50 percent probability of this level of resource or more) for natural gas totaled 358 Tcf or enough to satisfy 16 years of U.S. consumption. However, given that these are technical resources, they are not necessarily obtainable at ‘current prices.’

Table 3 – U.S. Technical Resource of Unconventional Gas

Natural Gas Resource	Mean Technical Resources (Tcf)
Sandstone, shale and chalk	308
Coal-bed methane (CBM)	50
Total unconventional gas	358

The USGS assessment estimated the level of effort that would be required to produce this resource and shed some light on its production costs. The USGS notes:

> Significant extraction effort will be required to obtain this gas. Based on existing technology, the assessment indicates that approximately 960,000 productive wells will be required to recover potential reserve additions of 300 Tcf….Furthermore extrapolation of present day success ratios implies that roughly 570,000 "dry" holes would have to be drilled along with the productive wells. By way of perspective, the most oil and gas wells of all kinds ever drilled in the Unites States in one year is about 92,000.

Thus, this rather large resource will be produced over many years from many wells. Coal bed methane (CBM) technologies have found recent success in reducing production costs. Since 1989 production of CBM in the United States has grown from 0.1 Tcf to 1.6 Tcf in 2001. It seems to be the most promising domestic unconventional resource and both the House and Senate energy bills debated in 2002 called for the restoration of tax credits for CBM production.

Natural gas hydrates is a resource whose raw potential is enormous, however, whose production prospects are speculative. They occur abundantly in nature in both the arctic regions and in marine sediments in an ice-like formation. To give some perspective on the size of this resource Dr. William Dillon of the USGS notes, "the worldwide amounts of carbon bound in gas hydrates is conservatively estimated to total twice the amount of carbon to be found in all known fossil fuels on earth."

This resource represents tremendous potential but very little near term energy. Production of gas hydrates present several problems. These problems range from environmental issues to safety concerns. In Siberia they have been producing a form of land based hydrates for many years but extension of that process to other deposits does not appear economic at this time. Research efforts are being funded around the globe to unlock this potential, but at this time it would be foolish to assign any significant probability to their economic production in the next couple of decades. Still, Dr. Ken Chew, of IHS Energy forecasts that over 12,000 Tcf of this resource is ultimately recoverable.[16] This represents just two percent of what Dr. Chew says is the consensus estimate of hydrate gas in place worldwide and about 0.2 percent of high estimates of the resource.

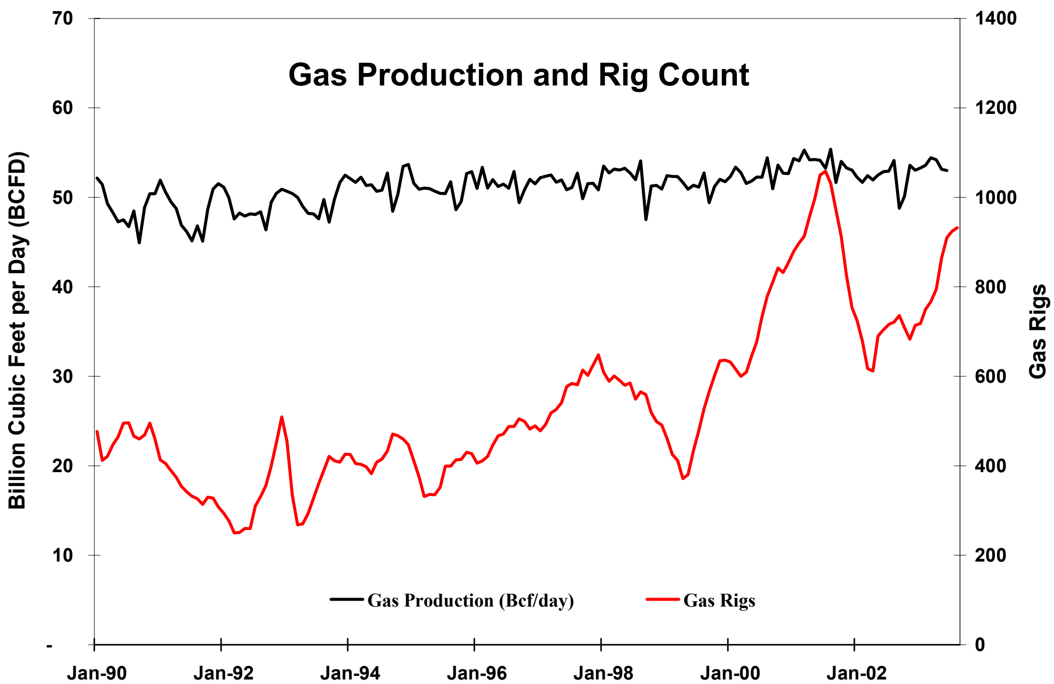
Another speculative resource that must experience significant research and development successes before it can become a large contributor to world markets is 'anomalously-pressured basin-center gas.' This is gas dissolved in higher or lower than normal pressured low permeability aquifers in the central deeper parts of basins. Such depths increase exploration costs as each well is far more costly than those at traditional depths. Dr. Chew estimates that approximately 11,000 Tcf of this resource will be recoverable by future generations. This represents between one and thirteen percent of various estimates of the total resource in place worldwide.

Today's unconventional resources are becoming more commonplace as the technologies to produce them improve. Tax credits for coal bed methane production have encouraged the improvements in production technology necessary to establish it as a future conventional resource. Similarly, as the Albertan oil sands example demonstrates, unconventional resources are sometimes vast and show great promise. Production is costly, but improving. More importantly, these unconventional resources are more uniformly distributed across the globe and not controlled by politically "unfriendly" regimes.

North American Natural Gas Supply – Production

A better supply metric than resources is the rate of production. Even a mythical unlimited quantity of natural gas tells us little about the market if it takes progressively more investment to extract it from the ground. For example, if one field can produce 100 MMcf per day through 100 wells and another can produce 100 MMcf per day through 200 wells, the amortization of the capital costs in the second field are double those in the first. If we assume a competitive market where producers are price takers, they cannot merely pass on these capital costs. Therefore firms are hesitant to invest in high cost production until they are convinced market prices will support it.

The nearby chart compares U.S. production to the count of rotary rigs engaged in natural gas exploration and production. We can see that the number of rigs, though volatile, has been generally rising since the mid 1990's but production has stayed effectively flat. Thus we are witnessing the depletion of the "low-hanging fruit." The more difficult to produce gas will only be produced if market prices will support the additional drilling.

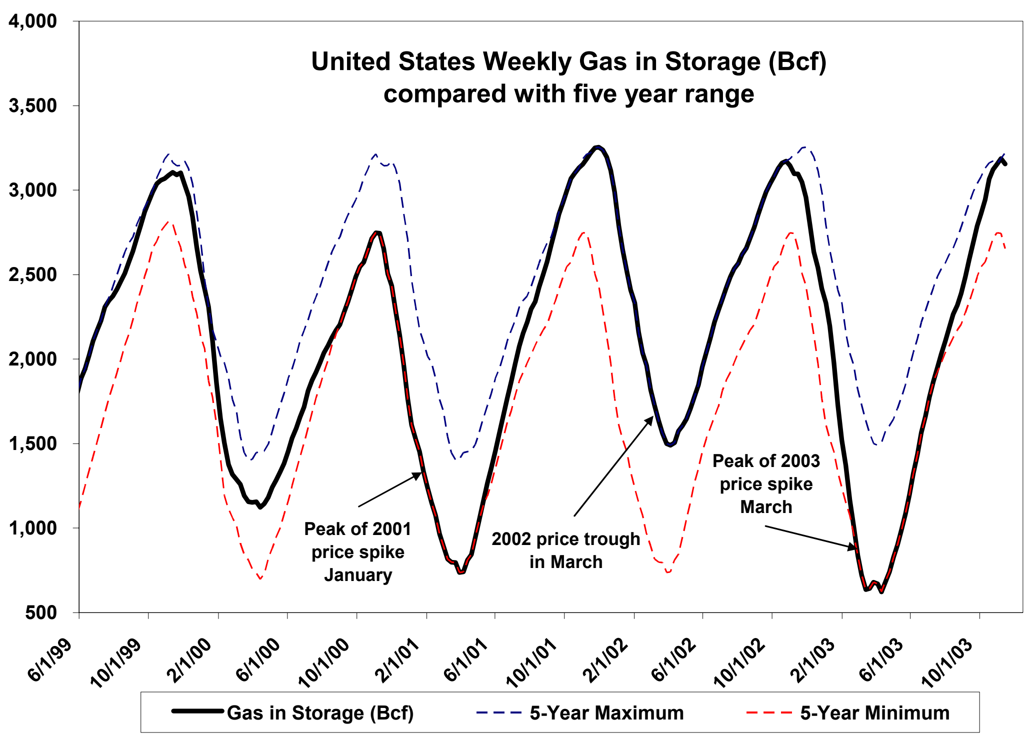


This increase in effort required to produce gas will create upward pressure on gas prices as new investment in production equipment will follow sustained higher prices. Constraining such investment is the potential for the federal government to open up previously restricted lands for drilling. Investors are understandably reluctant to invest in expensive production when relaxation of restrictions on inexpensive production would doom their high-cost investment. As such, productive responses to high prices are slow, creating a very inelastic short run supply and adding to price volatility.

Those who forecast much higher gas prices point to this continued increase in effort required to produce at effectively the same rate for the past decade. This evidence of rising production costs appears to be a harbinger of higher natural gas prices as production in North America from accessible areas has become more difficult as the 'low-hanging fruit' is depleted. However, as noted in the resources section, there remains much potentially low-cost gas that is not accessible due to government restrictions.

North American Natural Gas Supply – Delivery

According to the EIA the average residential price of gas in the 1990's was $6.80 per MMBtu. Only $1.91 of that cost is the price of the gas at the wellhead leaving the lion's share of residential gas cost to transport the gas to the burner tip in the furnace, water heater or stove. Moving gas from producing fields to end users is accomplished by a transmission pipeline network of some 278,000 miles in the U.S. In addition, local distribution companies (LDC's) provide delivery services through another 700,000 miles of pipes. Constraints on this transmission system are reflected in pricing differentials between various regions. Large discoveries of gas in one part of the country have little impact on price in another part of the country if pipeline capacity into that region is constrained.



Just as pipes move gas physically, underground storage transfers summer production to winter consumption. Large underground storage reservoirs allow the serving of peak loads behind network constraints. In the United States gas demand peaks in the winter due to heating loads. Since production, relative to demand, is constant year-round, gas storage is the answer to meeting the peaks. The nearby graph shows the seasonality of gas demand as well as the rolling five-year maximum to minimum range.

The winter heating season ends each March and the industry fills storage through the summer until November when heating begins again. The 3,000 Bcf storage threshold is targeted by industry watchers as one allowing adequate supply for a moderately cold winter. Years not hitting that mark have been associated with price spikes as the 2000/2001 winter witnessed.

We did not plot price on this graph to reduce clutter, but we have noted certain peaks and troughs in the price series. The gas market price peaks occur at times when storage is setting a five-year low and the price dipped in 2002 when storage was setting a five year high. This shows that the price spikes may be related to lack of gas in storage (or perceptions of such as storage reservoirs never fully deplete) to flatten demand on the well over the year.

Some firms are contemplating using salt caverns near LNG terminals and retrofitting them for LNG storage. Such expansions to storage capacity may reduce its price, but storage capacity is not necessarily constrained. Withdrawal capacity on the coldest day of the year is limited and spiking prices will ration gas on days when that limit is reached. The aggregate gas deliverability from U.S. storage is 79.5 Bcf per day and all new storage built is impacting deliverability far more than aggregate storage. Ziff Energy, a gas market consultancy in Canada, anecdotally points out that since 1990 storage capacity in Western Canada has grown twofold while withdrawal rates fourfold. The storage market places a premium on newer facilities that are high-deliverability-multicycle (HDMC) versus the older single cycle (inject in the warm months, withdraw in the cold months) facilities. Such facilities can handle power generation peaks during summer heat spells as well as the traditional cold spells in the winter with the ability to cycle the working gas several times a year.

As some predict demand for gas will shift from stable industrial demand to seasonal power generation and residential/commercial heating loads, this will shift the aggregate gas load to a more weather dependent and inherently more volatile state. Such a shift would require increased investment in gas delivery and storage infrastructure to offset the increasing seasonality and weather dependence. The NPC recently estimated that over $8 billion per year must be invested in gas delivery infrastructure in the North America through 2025. This investment will be spread over all segments: interstate transmission, local distribution, storage and arctic pipelines to bring vast supplies from Alaska and Northern Canada.

Peak Oil (and Natural Gas)

There is a heated debate regarding the rate of production of fossil fuels. This debate is often described as one between optimists and pessimists. The pessimists are proponents of an imminent ‘peak’ theory. This theory holds that production of gas or oil will peak, and decline steeply long before the resource depletes. ‘Peak oil’ proponents say that reductions in world production of fossil fuels during times of increasing ‘demand’ will lead to catastrophic economic consequences and that the world is nearing such a peak for oil, and natural gas will not be far behind. This ‘imminent peak’ school is led by adherents to geologist King Hubbert’s theories of production peaks.[17] Hubbert famously forecasted in 1956 that US Lower 48 oil production would peak in 1970 and it did. Many have disputed the ‘peak’ theories and maintain faith in the price system to produce enough oil and gas from the world’s vast resource. Such people maintain that the eventual production peak will not be due to geologic constraints but demand changes. These folks are often referred to as oil and gas 'optimists.' We will briefly outline the arguments of the two sides; optimists and pessimists, and then present our analysis of the debate.

Pessimists[18]

Existing oil and natural gas fields have exhibited a steep rise in production in the early years after discovery as well as a steep decline from peak production as the reservoir depletes. This alone would not concern anyone as new fields can be found and exploited to maintain the production rate. However, the oil and natural gas pessimists point out that newly discovered fields have been much smaller than the old ones and it is requiring many more wells to replace the production of older depleting wells.[19]

Pessimists argue that geologic constraints dictate the shape of the production curve. They give little credit to prices, investment and technology in determining field production rates. Pessimists extended Hubbert's theory to imply that there was little that could be done to stem the declining production of oil and gas fields.

Geologist Ken Deffeyes worked with Hubbert and is an enthusiastic proponent of the peak oil theory. In his recent book on the topic, *Hubbert's Peak*, he debunks the four (4) possible solutions to the peak production problem, which he estimates to occur between 2004 and 2008 for oil: new technology; drill deeper; drill someplace new; and speed up exploration.[20] Deffeyes has little faith in these as solutions to the impending production peak.

1. New technology – according to Deffeyes the oil industry invested heavily in research and development in the 1980's. With much of that R&D being successful "…that makes it difficult to ask today for new technology. Most of those wheels have already been invented."

2. Drill deeper – The rule of thumb in the industry is that oil forms between 7,500 and 15,000 feet deep, the 'oil window.' Below 15,000 feet natural gas is formed and above 7,500 feet nothing occurs to organic rich sediments. While drilling deeper may not help find more oil; it may help with natural gas discovery.

3. Drill someplace new – According to Deffeyes, the only promising petroleum province that remains unexplored is a part of the South China Sea (due to competing ownership claims). This area is unlikely to be another Middle East. Thus, almost all of the Earth had been geologically surveyed.

4. Speed up exploration – Even if large fields were located it would be many years before production were ramped up to significant levels. Deffeyes says there is little chance of ever finding fields capable of replacing the Middle East.

Energy investment banker Matthew Simmons is an oil pessimist who performed an analysis which "…used neither the data nor the Hubbert methodology."[21] Simmons demonstrates that the world's major oilfields are getting old. Of the 60 oilfields worldwide producing more than 100,000 barrels per day, only two have been discovered in the last 25 years. For domestic natural gas he points to the well-productivity data to make the point that the new reservoir discoveries are small. Gas well completions[22] are expanding dramatically while production is only staying flat. The level of gas discovery, he contends, is not keeping up with demand and prices will adjust to compensate. Such price adjustments will be dramatic according to many pessimists.

Optimists

Seeing a far rosier future for fossil fuel production are the optimists consisting of energy economists and several geologists. Optimists point out that most resource assessments show ample gas and that technology has led to far greater resource extraction from existing fields than was expected. Further the optimists believe that all forms of energy make up the relevant market and not just particular forms of hydrocarbons. That is with coal so abundant in North America, they feel there is little chance gas or oil prices can remain inflated because ultimately coal can be used as a replacement. Also, they point out that price increases will affect demand behavior and disguise a reduction in quantity demanded as a production peak. The optimists dispute the pessimists' methods and their disregard of prices in motivating investment to increase production or conservation to decrease consumption.

Michael Lynch is an energy economist who has debated this issue with several of the pessimists. Recently he summarized the flaws of the pessimists' analysis in *Oil and Gas Journal.*[23] Lynch defines several areas where the pessimists' arguments fall short. The most significant mistake pessimists make is their assertion of causation where they find correlation. An example is their claim that the global drop in discoveries proves scarcity of a resource without any acknowledgement of the fact that investing in exploration in light of huge existing reserves makes little economic sense.

Lynch also highlights several bad predictions of two prominent pessimists and their tendency to revise peak dates out and ultimate recovery estimates up. Such revisions give evidence to the optimists' claims, he says.[24] Their lack of rigor leads them to draw conclusions where none is warranted. Some pessimists even acknowledge the methodological flaws and lack of statistically significant support for their theories[25] but argue that the implications of their being correct are too dangerous to be haggling over scientific process.

Lynch describes a test of the imminent peak theory:

> The controversy will no doubt continue, but for upstream companies, there is a clear choice inherent in the two schools of thought. If the Hubbert modelers and their colleagues are correct, then the appropriate strategy would be to assume much higher oil prices soon, hire geologists and engineers, sign long-term rig contracts, and invest in high cost production, including gas-to-liquids and even oil shale. Borrow against future elevated revenue and buy reserves whenever possible.
>
> If, however, the arguments here and elsewhere that there is no peak visible for non-OPEC oil production (absent a price collapse), let alone global production, and volatility will remain high, then keep a low debt level, focus on low cost projects, and maintain flexible inputs (personnel and equipment) so as not to be caught with high expenses when the occasional price collapse comes. That most companies are following such a path suggests that they have already judged the issue.

The optimists contend that either this debate is well known and energy companies choose to believe the optimists or markets are terribly inefficient and the pessimists' arguments are not well known among senior management.[26] That is, if they believed that prices were on the verge of skyrocketing, they might behave as Lynch describes.

Lynch concludes "…that the current school of Hubbert modelers have not discovered new, earth-shaking results but rather have joined the large crowd of those who have found that large bodies of data often yield particular shapes, from which they attempt to divine physical laws."[27]

Analysis of Debate

The accuracy of Hubbert's U.S. Lower 48 oil production peak forecast lent his theory much credibility and led many to extend it to other non-renewable commodities and to world supplies of oil. However, the real price of oil fell 26 percent between 1957 and 1970[28] and large supertanker technology had just been introduced in the late 1960's making the inexpensive Middle Eastern oil fungible worldwide. Thus, domestic producers saw little incentive to invest in production. Hubbert himself extended his theory to natural gas and predicted a 1975 peak for U.S. production at 14 Tcf per year while actually in 2001 it was almost 20 Tcf. So, this appears to demonstrate that Hubbert's initial prediction, though accurate, may have been lucky.

Conversely, the pessimists have only claimed that the end of "cheap" oil (and natural gas) was near, not the end of oil or natural gas. Some of the optimists own assessments imply that prices will have to rise in the future (not near future though) to maintain production, thus lending credence to the pessimists' claims. When all the $2 per barrel (production cost) oil in the Middle East is used up, it may make sense to ramp up exploration worldwide, possibly raising the cost of the marginal barrel (or Mcf) and therefore the market price. Though with so much inexpensive gas and oil restricted from production (OPEC quotas and U.S. government drilling moratoria) producers are understandably hesitant to invest in higher cost production.

Our own view is that the pessimists are correct in that production of the *inexpensive and accessible* North American gas may be near a peak. Similarly, we agree that there may be an approaching peak of traditional sources of crude oil; that is, inexpensively *produced* crude oil.

However, we disagree with the pessimists as they give too little credit to the ability of prices to adjust both sides of the market: demand and supply. They claim that we are too close to the peak to develop new technologies to replace fossil fuels, as if replacement (a supply side response) is the only option. Thus, their forecasts are for conventional resources only,[29] that is, inexpensively *produced* resources. If the market price of oil is $30 and it takes $25 per barrel to produce tar sands in Canada and $2 per barrel to produce oil in Saudi Arabia, and the Saudi oil dries up, what are the implications? A $28 per barrel margin is taken away from the Saudi royal family and distributed to Canadian workers and capital providers *without changing the market price of oil*.

Even if production does peak, the implications of that peak are that prices rise and markets adjust through substitution and conservation. The pessimists see drastic implications of a production peak: "…war, starvation, economic recession, possibly even the extinction of homo sapiens," (Campbell).[30] We find such scenarios either silly or improbable but without opening up federal lands to oil and natural gas production we find the abundant gas scenario with continued low energy prices (below $3 per Mcf[31]) overly optimistic.

Following Lynch's test of the pessimists' theories by observation of oil company behavior, we have devised a few additional questions to ask those who predict an impending world peak in oil and natural gas production.

1. Can the 1970 peak of U.S. Lower 48 oil production be attributed to the declining real price of oil and the recent invention of super tanker technology that greatly reduced the cost of transporting inexpensive Middle East oil production?
2. Has any effort to extend Hubbert's theory to other fuels or regions ever proved successful?
3. Why have none of the analyses resulting in the impending doomsday forecasts been published in a respected peer-reviewed publication?
4. How is the data upon which the oil and natural gas pessimists' forecasts are based more reliable than the data available to the NPC, the USGS or other government and industry groups? Do oil companies have access to such data and if so why have they apparently chosen to agree with the more optimistic conclusions?

We suspect pessimists will have trouble answering these questions. We agree with several of their assumptions and conclusions but their forecasted consequences lack coherency. If the price of gas triples next year we will see an incremental two percent inflation. Further, it can stay at that price the following year with no impact on inflation. Coal plants will run at higher capacity and gas plants at lower ones; longer term, gas plants will not be built and coal ones will. People will set thermostats for cooler in the winter and warmer in the summer. Industries dependent on gas feedstocks (such as fertilizers) will move out of North America. Meanwhile, conservation technology research and development will grow, inefficient capital assets will be retired and replaced, and the economy will respond to the signal.

Exploration and Production Technology

The advance of technology has allowed the production of far more resources than previously thought possible from existing fields. Collectively such technologies are referred to as Improved Oil Recovery (IOR) and the same technologies often apply to both oil and gas. These technologies are a major source of the reserves growth phenomenon (described above) according to Norman Smith and George Robinson, two industry observers with over half a century of experience together.[32] They note that Norwegian reserve growth from North Sea fields is weighted 2 to 1 in favor of improved recovery from existing fields rather than discoveries of new fields.

Exploration technology has improved dramatically since the invention of 3-Dimensional Seismic imaging in the early 1960's. This tool helped create far more accurate images of the subsurface and has improved the well success rate from approximately 10 percent in the 1970's to almost 50 percent today according to ExxonMobil. Onshore wells typically cost about $500,000 to drill and offshore about $8 million. Such improvements in success rates can significantly reduce production costs by reducing the dry well cost amortized over successful production. Also, much of the world has not been mapped by 3-D seismic imaging yet holding out promise for greater recovery from older fields. 4-Dimensional seismic imaging adds time as another dimension to see how fields change during production and how it is likely to change in the future. These processes are data intensive and improve with the increase in computational speed, thus reinventing seemingly old technologies.

Whereas 3-D and 4-D seismic imaging can greatly enhance our ability to locate good prospective well sites prior to drilling, Direct Hydrocarbon Detection (DHD) significantly increases drilling success rates by adding surface geochemical data to reveal the presence of gas seepage to the surface. Keith Phipps of W.L. Gore & Associates (famous for the brand Gore-Tex) notes that actual results from drilling hundreds of wells over the past five years shows a 93 percent success rate in predicting dry holes and an 88 percent success rate in predicting the presence of hydrocarbon-bearing zones at depth.[33] Such technologies if they are perfected will lower exploration risk and hence costs.

Production technology advances have resulted in the rapid expansion of unconventional gas production as well. Resources such as coal bed methane, tight gas sands and gas shale have benefited initially from production tax credits but have flourished since their expiration suggesting the credits succeeded in jumpstarting the technologies needed to produce these resources.

These examples of technology improvements support the notion that reserve growth is real and not wholly dependent on discoveries of new fields. Reductions in production costs and higher field recovery rates bring previous 'technical resources' over to the 'proved reserves' category

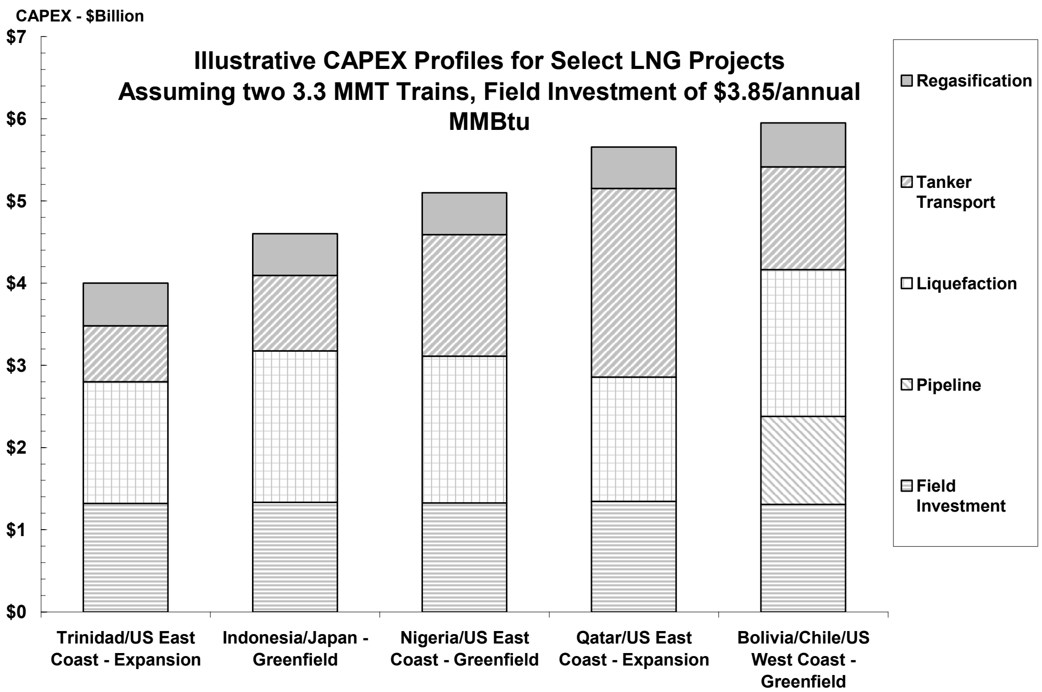
Liquefied Natural Gas

There are several decades of natural gas supply worldwide, but reserves and consumption are not uniformly distributed around the globe. Just as the invention of the supertanker in the late 1960's brought about the era of international oil trade, recent technological advances in the liquefaction, transportation and regasification of natural gas may introduce another chapter of international energy trade.

Natural gas liquefies and reduces its volume by approximately 600 times when it is chilled to 256 degrees Fahrenheit below zero. Such cryogenic transport is complicated and requires massive capital investment over and above the cost of exploration and production. After the natural gas is produced, it must be piped to a liquefaction facility and loaded onto tankers. The tankers themselves are specially made to maintain temperature and pressure during transport. In the consumption region, the cargo must be unloaded and re-gasified and sent into the pipeline distribution network (or stored for peak-shaving applications).

The existing infrastructure for LNG trade in the United States is small. There are four (4) gasification plants[34] all of which are undergoing expansions, which will increase aggregate send-out capacity to 3.9 Bcf per day or 1.14 Tcf per year at an 80 percent load factor. That is about 5 percent of 2001 U.S. consumption and would occupy about 20 percent of the worldwide LNG tanker fleet of 199 ships[35] (assuming average round trip of 25 days per cargo sized at 2 Bcf).

James Jensen has testified before congress on LNG and written extensively on the economics of LNG trade for more than 20 years. The chart below summarizes his extensive research on the LNG cost structure. His estimates of investment required for LNG production and delivery between various worldwide markets ranges between $4 and $6 billion.[36] We can see that the capital expenditure budget for the receiving country ranges from 9 percent to 13 percent of the entire budget while the producing country ranges from 51 percent to 70 percent of the capital. Such international capital content adds complexity to potential business models that look to exploit LNG trade.



As the average capital investment for establishing one of these trade routes is approximately $5 billion, a diversified portfolio of three of these routes would require $15 billion. The combined annual exploration and production (E&P or upstream) capital expenditures of ExxonMobil, ChevronTexaco, Royal Dutch/Shell, and Conoco Phillips was $35.2 Billion in 2002. Thus, if it were to take four years to construct such capacity these combined companies would have to dedicate 11 percent of their upstream capital budgets for that four-year period. This investment would add capacity of (assuming a 90 percent utilization) 0.91 Tcf per year or about 3.9 percent of 2002 consumption. If LNG infrastructure were to continue at this rate of development it would take over 20 years to construct capacity for importing 20 percent of U.S. consumption.

Extending his capital cost estimates, Jensen projected the per-unit cost of LNG trade over various routes. He compared these estimates to the EIA's oil price estimate for 2010. Specifically, he speculated that gas prices would be 90 percent of the cost of a barrel of oil on a comparable Btu value, or $3.62 per MMBtu.[37] Jensen defines the 'netback' as the residual profit accruing to the producing region at the stipulated market price at the Henry Hub (the natural gas pricing point on which the NYMEX gas contract is based) after all other value chain costs are covered.

Jensen calculates that an expectation of prices supporting a netback of $0.80 per MMBtu would encourage upstream production of stranded reserves (gas reserves not near enough to demand to make pipeline transportation economic). This calculation is based on a 15 percent return on investment to production assets. Most all the trading routes Jensen studied showed that they could support LNG trade at the $3.62 per MMBtu price. Thus, a sustained market expectation of near $4 natural gas should encourage profitable LNG trade between the United States and several potential producing regions.

This optimistic scenario is contrasted with the EIA's forecast for natural gas in 2010. That forecast is at $2.85 per Mcf and would doom several of these routes. Such low-cost natural gas scenarios would discourage the massive capital investment necessary for implementing these trade routes.

However, the more optimistic LNG scenario is expected by many observers. Particularly, Cambridge Energy Research Associates LNG Director, Michael Stoppard notes that, "the natural gas business is on the brink of profound change. It is set to become global and to adopt a more flexible market model."[38] Additionally, Raymond James & Associates last month noted, "…the minimal economic hurdle rate for LNG to hit our hubs suggests a 'global' gas price that ultimately will be tied to global oil prices."[39] As such Jensen's optimistic scenario appears to be gaining credibility.

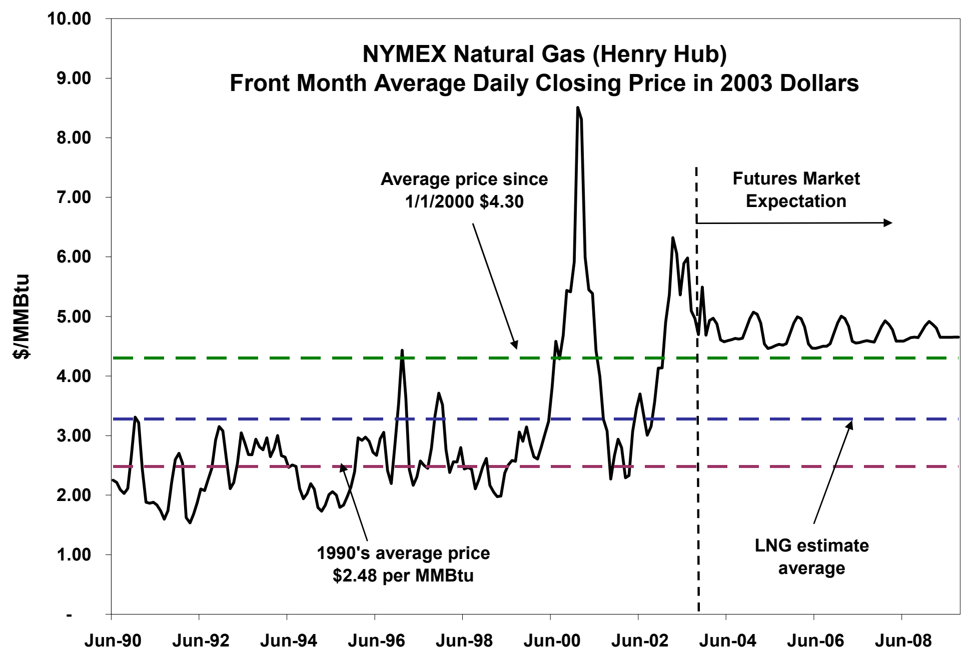
LNG Cost Estimates

Table 4 presents several ranges of LNG costs from production to regasification. The first is extrapolated from Jensen's estimates above presenting the minimum and maximum cost route assuming his $0.80 per MMBtu required 'netback' to the producing region (and excluding the uneconomic routes). The second is an estimated range from the Institute for Energy, Law & Enterprise, at the University of Houston and the third is an estimate from Drewry Shipping Consultants published in *Oil and Gas Journal*.[40] The next two ranges are the EIA estimates for trade utilizing both expansion of existing re-gasification plants and newly constructed plants. The final estimate is by the Alaska Natural Gas Authority for trade between Alaska and the U.S. west coast. We can see in Table 4 that the various LNG cost estimates center on about $3.30 per MMBtu. All of these analysts have noted the significant reduction in LNG costs over the past decade.

Table 4 – LNG Cost Estimates

Estimator	Low Price ($/MMBtu)	Middle ($/MMBtu)	High Price ($/MMBtu)
James Jensen	2.61	3.04	3.47
IELE	2.00	2.85	3.70
Drewry Shipping Consultants	2.80	3.10	3.40
EIA Expansion Facility	3.31	3.41	3.51
EIA New Facility	3.40	4.02	4.64
Alaska Natural Gas Authority	N/A	3.25	N/A
Mean	2.82	**3.28**	3.74

If we compare these costs to the history of the real domestic gas cost as measured by the New York Mercantile Exchange (NYMEX) front month contract (converted to 2003 dollars) for the Henry Hub we see that natural gas price expectations must be about $0.80 (or 32 percent) higher than the 1990's average of $2.48 in order to justify the large investments that LNG requires.



However, the average real price since January 1, 2000 was $4.30 per Mcf giving some justification for the required LNG infrastructure. Further, though liquidity is thin past a few months out, the futures market is signaling sustained costs well above that average. LNG investment is growing as massive production projects in Qatar and Australia, re-gas facility expansions in the U.S. and the order book for tankers show. The major risk for these sizable investments is the potential stranded asset risk posed by U.S. Federal relaxation of exploration and production restrictions on Federal lands. If the major LNG investments are successful in reducing price and volatility in the U.S. pressure to relax such restrictions will likely wane.

Import Potential

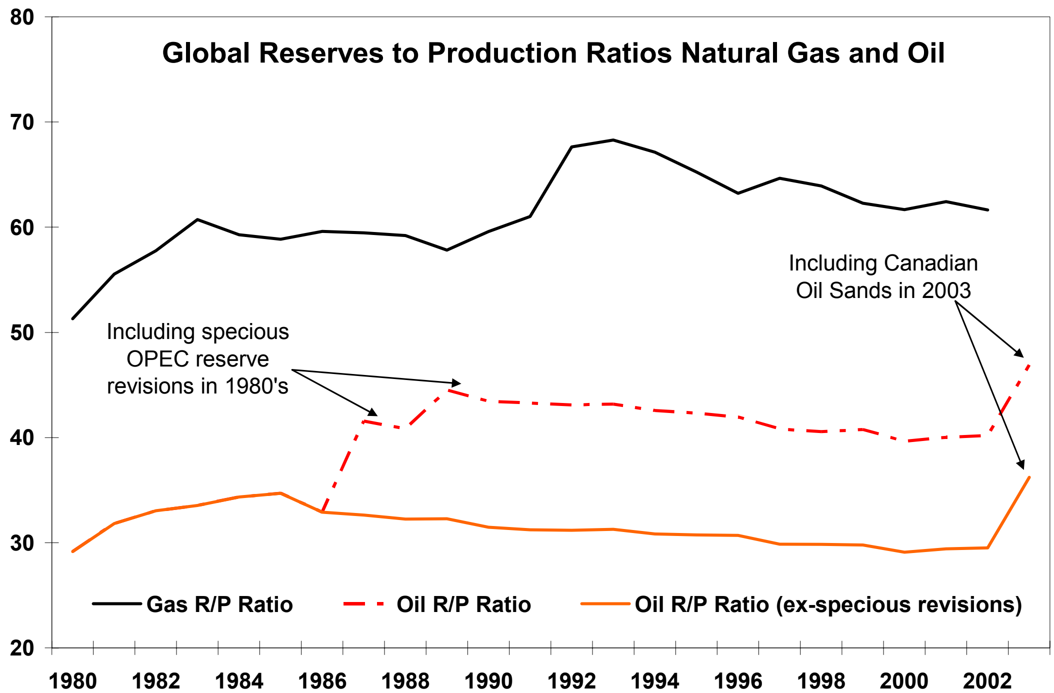
Ignoring the credibility of foreign reserve estimates (as many pessimists dispute) and actually using geologic factors, the EIA estimated worldwide reserves in their International Energy Outlook 2003. This estimate shows approximately 60 years of reserves based on 2002 consumption. Though the credibility of foreign reserves will always be an issue, gas has not carried the political baggage that oil has in the past as it has not been widely traded between nations and its international value has been a fraction of oil's. In Table 5 below we show the EIA report of the top 20 countries for natural gas reserves.

Global reserves to production ratios for natural gas and oil are shown over time in the graph below. The natural gas R/P ratio increases over time as new fields are discovered and older fields are extended due to better technologies. This contrasts with the United States ratio shown earlier which declines slightly over time as drilling and discoveries do not keep up with consumption. For oil the graph shows the R/P ratio both with and without some 'specious' reserve revisions in several OPEC countries. That is, we subtracted the magnitude of the upward revisions in 1987 and 1989 from select OPEC countries all years going forward as many argue that they were only increased because OPEC changed the quota allocation measure from production to reserves. The oil R/P ratio without the specious OPEC reserve revisions falls slightly until the 2003 inclusion of the Canadian oil sands. This inclusion of the oil sands demonstrates the impact of technology in hydrocarbon production and many believe that such innovations will keep gas and oil reserves expanding far beyond that necessary to meet expected demand.

Contrary to North American reserves, global reserves of gas alone (i.e. without reserve growth) signal almost six decades of gas supply at current prices. International trade of gas is in its infancy and must expand in order for these metrics to have any relevance to the North American market. This development will be discussed below.

Table 5 – Top 20 Countries Natural Gas Proved Reserves

Country	Reserves (Tcf)	Percent of World Total	Country	Reserves (Tcf)	Percent of World Total
1. Russia	1,680	30.5	12. Australia	90	1.6
2. Iran	812	14.8	13. Norway	77	1.4
3. Qatar	509	9.2	14. Malaysia	75	1.4
4. Saudi Arabia	224	4.1	15. Turkmenistan	71	1.3
5. U.A.E.	212	3.9	16. Uzbekistan	66	1.2
6. Unites States	183	3.3	17. Kazakhstan	65	1.2
7. Algeria	160	2.9	18. Netherlands	62	1.1
8. Venezuela	148	2.7	19. Canada	60	1.1
9. Nigeria	124	2.3	20. Egypt	59	1.1
10. Iraq	110	2.0	Rest of World	622	11.3
11. Indonesia	93	1.7	Total World	5,501	100.0



Worldwide natural gas resources (which are inclusive of reserves) have been assessed by many groups. Earlier we presented estimates of worldwide resources from various sources (NPC, EIA, and IHS Energy) and here show similar results for conventional gas resources estimated by the USGS in 2000 in their *World Petroleum 2000*. This survey estimated the quantities of petroleum resources that have the potential to be added to reserves over the 30-year timeframe between 1995 and 2025. The assessment considered "geologic characteristics to be the primary criteria for resource assessment."[41] That is, the USGS estimated worldwide undiscovered conventional resources and reserve growth from conventional fields by physical assessment (by documenting the geology of various regions and their provinces throughout the world but not actually drilling wells) rather than relying exclusively on reported data. Table 6 shows the results of the assessment.

Table 6 – USGS Estimates of Worldwide Conventional Gas Resources

Category	Total (Tcf)
Undiscovered conventional resources	5,196
Reserve growth in conventional fields	3,660
Measured (proved) reserves	4,793
Total	13,649

The USGS results are slightly lower than those shown earlier as they do not include unconventional resources. The USGS shows almost 147 years of world supply. However, as we have discussed, this metric ignores production rates, though even petroleum pessimists assume natural gas has a much brighter future than oil. Another glaring fact gleaned from this assessment is the distribution of natural gas resources relative to consumption. North American consumption (30 percent of world consumption) and estimated resources (8 percent of world resources) demonstrates why major energy companies are investing heavily to expand the international trade of natural gas through LNG.

Natural Gas Demand

Natural gas is used for everything from cooking and heating to manufacturing fertilizers and generating electricity. It is this latter use, power generation, which has contributed to the growth expectations in recent years. Because of its relatively benign emissions characteristics, inexpensive capital cost and short construction times, some 96 percent (138 of 144 GW) of new power generation built in the United States between 1999 and 2002 was natural gas fired.[42] The EIA expects natural gas generation to increase its share of U.S. generation to 29 percent from 17 percent from 2001 to 2025. This growth in natural gas generation contributes to the EIA expectation that natural gas consumption in the U.S. will grow 2.0 percent per year until 2012 versus the 0.1 percent growth rate between 1999 and 2002.

Table 7 – U.S. Natural Gas Consumption by Segment (EIA)

Demand Segment	1999-2002 CAGR	2002 Consumption (Tcf)	2002-2012 CAGR
Plant & Pipe	-1.0%	1.68	2.2%
Residential	1.3%	4.91	1.3%
Commercial	-0.8%	3.11	1.5%
Industrial	-3.9%	7.19	1.4%
Power	4.7%	5.53	3.5%
TOTAL	0.1%	22.44	2.0%

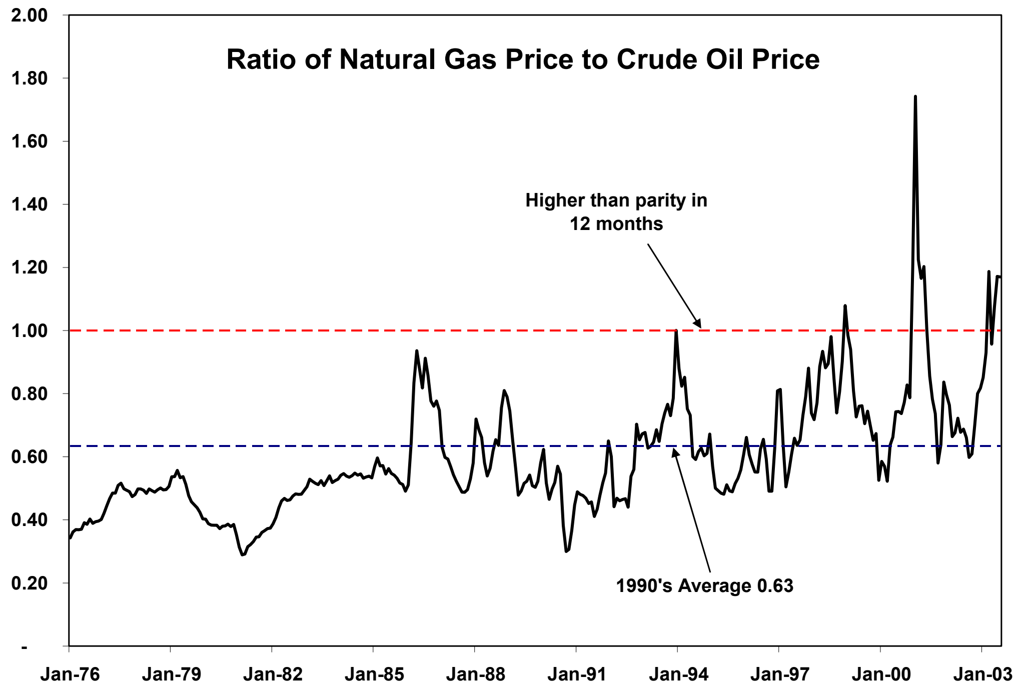
The United States consumed 22.4 Tcf of natural gas in 2002. The components of the consumption are represented in Table 7 along with compound annual growth rates (CAGR) by segment. The 'Plant & Pipe" segment is that natural gas consumed in the production of natural gas (drilling and extracting) as well as that consumed in the distribution of natural gas (compressor stations that enable pipeline systems).

Some end use consumption is more responsive to price than others. Given few opportunities to substitute away from natural gas if one's appliances require it, commercial and residential loads are not as responsive to price signals as other sectors. With time consumers can respond to price shocks much more readily than in the short term. As the oil price shocks of the 1970's and 1980's demonstrated we can change our habits much more significantly over time than we can immediately after a price shock.[43] Interestingly, between 1996 and 1999 the average size of a new home increased 22 percent (from 1,825 to 2,225 square feet) and 70 percent of the homes in 1999 were gas heated compared to only 47 percent in 1986.[44] The relatively low cost of gas during the 1990's probably influenced these trends.

Industrial demand has historically been the most elastic for two primary reasons. First, cheaper fuel stocks in foreign countries provide competition for U.S. manufacturers of natural gas intensive products. Second, manufacturers can often substitute fuel oil for natural gas when natural gas prices spike domestically. This industrial 'fuel switching' helps stem natural gas price spikes above the energy equivalent price of oil. However, the low gas prices of the 1990's led many firms to become complacent on fuel-switching capability. The NPC found that 26 percent of industrial demand in 1995 could switch to oil if necessary whereas today only 5 to 10 percent can.

Power generation offers another fuel switching opportunity that impacts the natural gas market. As stated above, the technology of choice in the power generation sector is natural gas fired turbines. Such new efficient capacity cannot switch between fuel oil and natural gas. These natural gas turbines are displacing older steam plants capable of burning oil or natural gas. The newer turbines are far more efficient with heat rates (number of Btu's required to produce a kilowatt-hour (kWh) of electricity) around 7,500 Btu per kWh versus 15,000 for the older oil boilers. The structural shift from dual-fuel capability generation to efficient gas-only generation may contribute an upward price pressure (or eliminate a downward pressure) on natural gas as the new turbines can tolerate a much higher natural gas price compared to the older boilers which would switch to oil when the price of natural gas rose above that of oil on a heat equivalent basis.

A study of the natural gas to oil price ratio can show how this pressure might work. The graph below shows the ratio of the wellhead natural gas price in dollars per MMBtu to the refiners' acquisition cost (RAC) of crude oil in dollars per MMBtu. There are approximately 5.8 million Btu's per barrel of oil. Prior to the widespread use of efficient gas-only power generation (starting in the mid-1990's) the old switchable boiler generation provided a nice cap on natural gas prices at the price of oil. However, since new natural gas generation capacity can produce a kilowatt-hour with half as much heat as the older boilers can, some argue that this disciplinary mechanism on the gas market is eroding. And that can be seen in the recent spikes of the gas to oil cost ratio above heat parity (100%) for 12 months since 1998.



In the 1990's the average ratio was 63 percent as oil was more valuable relative to gas. The ratio has reached above parity several times during the recent gas price run up. This is perhaps related to the expansion of high efficiency gas-only electric generation and reduction of industrial loads able to switch fuels. Natural gas is clean and popular and its use is projected to grow substantially. As the NPC noted in their recent study, "government policy encourages the use of natural gas but does not address the corresponding need for additional natural gas supplies."[45]

General Equilibrium

While most analysts of gas markets competently address supply and demand fundamentals few of them adequately address the equilibrium between them. More importantly, they often ignore close substitutes or the power of behavioral reaction to price movements. Price movements in the natural gas market can impact the markets for coal, oil, building materials such as insulation or energy efficient windows, housing in Florida and wool clothing. These other markets are all affected by the price of gas just as they affect the price of gas, albeit some in a very small way. While it is probably impossible to empirically demonstrate higher gas prices cause people to buy more wool clothing, there is little doubt that people will find ways to live consuming fewer gas molecules as the price rises. The process of many interdependent markets allocating resources efficiently is called general equilibrium. We believe that this process is at odds with all long-term forecasts of sustained gas prices over $4 per Mcf.

We reiterate three important market dynamics that seem to escape most analyses of the North American natural gas market:

1. Markets are driven by expectations. As such, an expectation of discoveries of inexpensive production will discourage investment in known expensive production for fear of stranding such

investment. North American investment in marginal resources or expansion of LNG capacity may be restrained by expectations of federal relaxation of production restrictions in protected areas. Or LNG expansion might discourage investments in local resources that may cost more than $4 per Mcf to produce. Analogously, expensive oil resources may not be produced for fear of OPEC ramping up production and lowering prices.

2. Production cost of the marginal resource drives market price in a competitive market. Pessimists argue that depletion of low-cost resources will have catastrophic effect. They fear that higher cost production will proportionately raise the market clearing price of gas. As the Alberta oil sands example shows (for oil, though gas is analogous), even with production cost about 5 times that of Saudi Arabia's, its impact on the worldwide market for oil is to put downward pressure on price when the market is above about $10 per barrel (the approximate marginal production cost of the tar sand).

3. Short term supply of natural gas is extremely inelastic as there are few ways to increase production quickly. Developing new fields is a slow process. Though the demand side of the market is much more responsive in the short term, growing demand over recent years and the inelastic supply contribute to sustained price volatility.

Market Adjustment Example

As a simple exercise we have speculated on a possible scenario to demonstrate the market interactions. Assume that the price of gas tripled from the past couple of decade's average of $3 to $9 per Mcf. What would be the response of the market both from the supply side and the demand side? First, worldwide LNG shipments would all be diverted to maximize North American re-gasification plants' capacity. Compared to 2002 LNG imports this would add an incremental 900 Bcf to the market or 4 percent of 2002 North American consumption. Second, rig count would rise to meet the sudden demand, but new wells would require several months before they had any impact on the market price. Third, industrial gas loads (one third of U.S. consumption) that have overseas competition would shut down or switch to oil-based fuels. Fourth, residential and commercial loads would find a way to turn down their furnaces in the winter (or see their winter heating tab rise about $120 per month). Fifth, peak power generation plants would reduce their output and be offset by electric utility load management programs. Sixth, political pressure to expand production in previously restricted areas would be great. If such prices were sustained one can list numerous structural changes that would occur including a demographic shift to warmer climates, renewal of nuclear power plant construction, and the rapid expansion of coal gasification technologies.

These changes are certainly disruptive, but hardly catastrophic to the vast majority of the population (though not the industrial sector). However, it is difficult to conceive of such an abrupt and sustained price rise. While this paper does not intend to advance policy prescriptions, we would advocate policies to avoid such a disruptive situation. However, it is clear that the vast coal deposits in North America and gas resources worldwide will never allow such sustained high prices.

Conclusion

We introduced this report with a series of questions to be addressed herein. We will conclude with a short summary of the evidence brought to bear on each.

1. Are natural gas supplies sufficient in the North America and worldwide to support new technologies dependent on plentiful natural gas?

Yes, gas supplies are sufficient but production is increasingly difficult in North America. While gas production may appear to be peaking in the U.S. (produced less in 1999 and 2000 than in 1998), there is much of this country that has not been explored or developed due to restrictions. It is likely that sustained high prices will bring political pressure to bear on access to these restricted areas. Also, the combination of high global gas reserves and falling LNG costs should open a new era of international gas trade for the U.S. As LNG cost estimates are in the low to mid \$3.00 per Mcf range, we can expect LNG to pressure prices down to this range when they are above it (as they are now). Significant downward natural gas price pressure, caused by the availability of LNG, may be several years off as the current infrastructure is small but expanding. As North America represents thirty percent of world gas consumption and contains less than six percent of world proved reserves, LNG trade will make sense long before gas exhaustion is a concern.

2. What has caused the high natural gas prices of the past three years in North America?
Are natural gas prices going to return to the levels of the 1980's and 1990's (average \$3 per Mcf in 2003 dollars) or have they experienced a fundamental upward shift?

There were several causes: first hydroelectric power production was 31 percent and 15 percent below the 1990's average in 2001 and 2002 respectively in the U.S. Natural gas powered generation capacity largely made up for this shortfall of Mother Nature. Second, the winter of 2000-2001 was 11 percent colder than the 1990's average as measured in heating degree days by the National Weather Service. These factors when combined with the production constraints described above led to the dramatic price spikes. While there are several forces that could hypothetically bring the prices back down near the \$2.35 per Mcf average of the 1990's (series of warm winters and cool summers, fewer production restrictions on federal land, rapid LNG importation, nuclear and coal power generation expansion), we believe that we are unlikely to see prices below \$3.50 in the foreseeable future. If the price does drop below \$3.50 it will be short lived as the more likely long term price marker for domestic gas is near \$4 per Mcf with periods well above that driven by storage and weather.

3. Is worldwide natural gas production in danger of peaking while demand is growing? Would such a peak have devastating implications for the worldwide economy?

There is plenty of gas worldwide to satisfy almost any demand scenario. However, transition to a new worldwide gas market will likely be fraught with price volatility as well as significantly higher prices than witnessed in the 1990's in North America. In order to access worldwide supplies massive investment in LNG is necessary. Such investment is slow and takes the right mix of market expectations and political will. The recent North American price spikes have already generated significant investment in LNG infrastructure worldwide and, if there are no market restrictions, this should continue and create downward pressure on natural gas prices when they rise above about \$4 per Mcf. Until LNG investment takes hold, North America will likely experience price spikes similar to 2003 or 2001 for approximately the next three to five years. No, these price spikes will not have devastating economic impacts either in North America or worldwide. Note that a doubling of gas prices from \$5 per Mcf to \$10 per Mcf would only increase inflation in the United States by about 1.1 percent. Though disruptive to certain industries it is hardly devastating to the entire economy.

4. Where do the various views of the state of natural gas in North America diverge? On what is there consensus?

Gas market analysts generally agree that there is plenty of gas in the world. They also agree that the easy to produce gas in North America (not restricted from production) is depleting rather rapidly. Opinions diverge on the economic impacts of shifting from low-cost production to high-cost production. Many fossil fuel pessimists fear that spiraling gas (and oil) prices will have devastating consequences to the North American economy. Conversely the optimists believe the market will work and higher prices will do their job in delivering more gas to North America and allocating it to the best use. Further, they believe that before prices reach catastrophic levels, alternatives will be developed.

In conclusion, natural gas like crude oil in the late 1960's is entering into a new commercial paradigm of international trade characterized by global fungibility. North American production capacity will remain very close to North American consumption for the near term keeping gas prices high and volatile until about 2007. Structural supply and demand side market changes will ultimately bring prices down to around \$4 per MMBtu in 2003 dollars. LNG, production access in the U.S., advanced production technology, demographic movements and efficiency adjustments will be among these structural changes occurring between now and 2007 to bring about the reduced volatility and average price. As such, the long term outlook for technologies dependent on abundant supplies of natural gas and that are economically justified at \$4 per Mcf is favorable.

Authors

The primary analyst and project director was Michael Motherway, Vice President of American Energy Solutions, Inc. James Throckmorton, Managing Director of Foster Bryan Ltd. was the principal contributor from Foster Bryan. Dr. Eugene Kim, Research Associate and Petroleum Economist at the Bureau of Economic Geology at The University of Texas at Austin reviewed a late draft and provided valuable input. Dr. Derek Tittle, Visiting Assistant Professor of Economics, Georgia Institute of Technology and Neil W. Lareau, Head, Technology Application Branch, Georgia Tech Research Institute also contributed substantial insights.

End Notes

[1] Specifically a Btu is the amount of energy required to raise the temperature of one pound of water one degree Fahrenheit (from 60 to 61 degree F) at constant pressure of one atmosphere.
[2] Natural gas is a more general term that encompasses more than pure methane (CH_4). Most natural gas contains well over 90% methane.
[3] In 2000 the United States imported 226 Bcf of LNG (0.94 percent of total consumption). That same year the U.S. exported 66.4 Bcf of LNG to Japan (66.0 Bcf) and Mexico (0.4 Bcf) from Alaska. Thus net imports were 159.6 Bcf in 2000 accounting for less than 0.7 percent of consumption. Source: Energy Information Administration/Natural Gas Monthly August 2001.

[4] For example coal can produce electricity that can power trains as substitutes for liquid fuel cars. Over the longer term (the term over which structural changes must take place) coal can produce electricity that can charge batteries in electric cars. The technology also exists to gasify coal and oil residues as well as producing liquid hydrocarbons from gas.

[5] NGLs are also extracted from natural gas before it is put into the pipeline as they are more valuable as feedstocks for producing ethylene (used in many products from plastics to insulation to carpet fibers), than their heat value if left in the natural gas stream. There are times when the price of gas runs so high that producers do not remove the liquids from the gas as their heat value is higher than their value as a feedstock for other products.

[6] The volatility as measured by the variance of the monthly average daily closing price of the front-month NYMEX contract for natural gas since January 1, 2000 was almost nine times the volatility of the 1990's.

[7] National Petroleum Council, "Balancing Natural Gas Policy – Fueling the Demands of a Growing Economy," taken from September 25, 2003 slideshow presenting results of study.

[8] ExxonMobil 2002 Annual Report – Reserve Summary

[9] Ahlbrandt, T.S., McCabe, P.J., "Global Petroleum Resources: A View to the Future," *Geotimes,* November 2002.

[10] According to Marilyn Radler, economics editor for the Oil and Gas Journal, in the March 2003 issue of *Geotimes.*

[11] Source: *Oil & Gas Journal,* Vol. 100, No. 52 (December 23, 2002), page 113.

[12] Source: the Canadian Association of Petroleum Producers (CAPP) web site – www.capp.ca

[13] Canadian Oil Sands Trust second quarter 2003 financial report. Syncrude Canada, Ltd. operates the Trust. Based on an exchange rate of 1.4 $CAD/$US. Note that $CAD 6.54 per barrel is purchased natural gas used to heat up the oil so that it can flow. Alternatively, part of the oil itself can be used in the production process.

[14] On June 30, 2003 Syncrude reported assets of $CAD 3.42 billion and 5.89 million barrels produced for the quarter (annualized to 23.6 million barrels). 8 percent of $CAD 3.42 billion is $8.28 per barrel.

[15] Conoco Gas Solutions has constructed a pilot plant in Oklahoma that will be able to produce up to 100,000 barrels per day of diesel fuel from natural gas. The process requires about 8.2 MMBtu per barrel of diesel fuel and they forecast a total production cost of approximately $23.10 per barrel of diesel.

[16] Dr. Ken Chew, "World Gas Resources – Past and Future," presentation delivered to the 2nd Annual Global GTL Summit in London, May 30, 2002.

[17] Other noteworthy adherents to this school are geologists Colin Campbell, Jean Laherrere, and Kenneth Deffeyes.

[18] The debate has centered on oil as it is thought to be more exploited and to peak sooner than natural gas. However, the pessimists have made similar predictions for natural gas with slightly later peak dates. The arguments on either side of the oil debate apply equally well to natural gas.

[19] Matthew Simmons points out that natural gas production stayed flat in the U.S. between 1999 and 2001 despite the fact that natural gas well completions went from 10,000 to over 22,000. Address to the International Workshop on Oil Depletion in Uppsala, Sweden on May 23, 2002

[20] Deffeyes, K. S. (2001), Hubbert's Peak, Princeton, N.J., Princeton University Press, p. 8-10

[21] Deffeyes, Kenneth, posting on his personal web site on February 26, 2003.

[22] A well is 'completed' when it has been drilled and prepared for production.

[23] Lynch, Michael C., "Petroleum Resources Pessimism Debunked in Hubbert Modelers' Assessment," *Oil and Gas Journal,* July 14, 2003.

[24] Matthew Simmons said in mid-2002 that "Most gas analysts and many industry executives think that gas supplies will fall by 2 percent to 4 percent this year, even though gas drilling fell by 45 percent. They are making the classic mistake of ... misunderstanding depletion, which caused the supply flatness in the first place, despite a drilling boom." Supply actually fell only 3.2 percent in 2002.

[25] Thomas Ahlbrandt quoted in Williams (2003): "The systematic rise and fall of oil production is not technically supportable, as Hubbert, Laherrere, and others have published, although generally not recognized by (Colin) Campbell, (Kenneth) Deffeyes, and others who have been making draconian end-of-civilization claims since 1989 and every year since. Why is there no accountability for these failed forecasts either by Hubbert or disciples such as Campbell, Laherrere, etc.?"

[26] Matthew Simmons says that he is "…amazed at the limited knowledge that exists, even in the U.S. or within our major oil and gas company's senior management about this topic and its dire consequences." Sweden address, 2002.

[27] Lynch (2003)

[28] Source: WTRG Economics, see www.wtrg.com

[29] Thomas Alhbrandt of the USGS colorfully makes this point: "When I talk to the Malthusians, Hubbertians, pessimists, depletionists, doomsters, or whatever term you like to use for them, they all become very uncomfortable with adding so-called unconventional oil resources to the picture. They prefer to argue individual nations are so absorbed that they would rather destroy the rest of the world rather than develop these unconventional resources." From Williams (7/14/2003).

[30] Ruppert, Michael C., “Colin Campbell on oil: perhaps the world’s foremost expert on oil and the oil business confirms the ever-more apparent reality of the post 9-11 world,” http://www.fromthewilderness.com/free/ww3/102302_campbell.html, October, 2002.
[31] This is the average of the two final decades of the 20th century (in 2003 dollars)
[32] Smith, Norman and Robinson, George, “Reserves Growth: Geology, Technology, Economics: Technology Pushes back Reserves ‘Crunch’ Date Back in Time,” *Oil & Gas Journal,* April 7, 1997.
[33] From press release of Gore Exploration Surveys dated March 6, 2003.
[34] The four facilities are (expanded send-out capacity in MMcf/day): Everett, MA (915); Cove Point, MD (1,000); Elba Island, GA (806); Lake Charles, LA (1,200).
[35] August 2003. Source: LNGOneWorld. There are currently 56 LNG tankers on order expanding the worldwide fleet to 199 ships by 2006.
[36] Jensen, James T., “The LNG Revolution,” *The Energy Journal of the International Association of Energy Economics,* Vol. 24, No. 2, 2003.
[37] That oil price forecast is $23.36 per barrel; 90 percent of which is $21.27 and since there are 5.8 million Btu’s in a barrel of oil, a natural gas price of $3.62 per MMBtu is used.
[38] As quoted in the *Oil & Gas Journal,* October 27, 2003.
[39]As quoted in the *Oil & Gas Journal,* October 27, 2003.
[40] Jensen, 2003; Institute for Energy, Law & Enterprise, “Introduction to LNG,” January 2003; Landia, Alexander, et al, “UK’s North Sea Gas Infrastructure Must Compete with LNG,” *Oil and Gas Journal,* August 25, 2003.
[41] U.S Geological Society World Assessment Team, *USGS World Petroleum Assessment 2000,* Introduction page 5.
[42] Source EIA
[43] Consider the American taste for imported cars in response to the oil shock of the early 1980’s. Given the much higher fuel taxes in Japan and Germany (the two largest auto importers); their auto industries had developed small, fuel efficient cars. In March of 1978 the foreign market share for cars in the United States was 15.7 percent and the price of gasoline was $1.01 (in 1984 dollars). Three years later the price of gasoline had risen 36 percent in real terms to $1.44 per gallon. During the same period the foreign share of the domestic auto market had risen to 25.6 percent, or a 63 percent rise in share (9.9 share points).
[44] Energy Information Administration, “U.S. Natural Gas Markets: Recent Trends and Prospects for the Future,” May, 2001.
[45] NPC (2003), page 7.

