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Energy Security Insights

CONTENTS

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Natural gas: the fuel of the 21st century?

As India's energy mix comes to reflect a greater engagement with natural gas, it will increasingly have to contend with the geopolitical challenges surrounding natural gas development, production, and distribution at the international level, and with the need for attention to the development of markets, infrastructure, and regulation at the domestic level. In this issue of *Energy Security Insights*, we look at some of the emerging global trends, the opportunities gas markets are creating, the futuristic possibilities of unconventional sources of gas with a view to providing the global context to understand India's room to manoeuvre. We also provide a flavour of pipeline politics—both 'near' and 'far' and, perhaps, the shape of things to come. The global gas scenario seems to indicate that resources are not in short supply, especially not if unconventional sources of gas are taken into account. What is required is a consolidated effort and collaboration in the search for resources, establishing the reserves, and developing the technology and market for their use.

The key to seeing the emergence of gas as the fuel for the 21st century, given that it is relatively more clean and efficient as a fuel, and abundant as a resource, is to ensure that international, interdependent gas markets are developed, which requires investor confidence, reciprocal access, financial capital, and government backing in projects that involve geopolitically risky areas. The key to the smooth flow of investments and capital into the development, production, and supply of international gas sources is trust and cooperation. Absence of trust and existence of sanctions, embargoes, and threats tend to result in under-investments in resource development through reduced capital flows and, therefore, reduced energy developments. The economic impacts of such political choices are then felt keenly through reduced availability of energy supplies.

The energy crossroads that we face present an excellent opportunity for putting in place different ways of doing business in energy. The world is currently witnessing a renewed resource nationalism as countries seek to respond to the current high energy prices, either in terms of acquiring oil and gas reserves when these are not available domestically, or using them to flex geopolitical muscles when they are. But there is an urgent need to understand the interdependence of energy systems and the complementary interests of energy producers and consumers, and the need for stability in markets and supplies. Just as importers of natural gas seek to assure themselves of supply stability and consequently, to diversify sources of supply and even energy sources, exporters look to greater price and demand stability to ensure worthwhile investments in exploration and development and steady income flows. While energy security has hitherto been discussed from the perspective of importers, increasingly the debate is getting enlarged to include the exporters, as it is becoming evident that long-term security lies in recognizing and deepening the interdependence. Treating the issues faced by importers and exporters as separate, and even as conflicting, is leading to a deepening of fault lines, and every action on one side is seen as a way of raising the stakes and increasing the pressure on an already overheated system. Achieving global energy security will then be increasingly more difficult.

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Fostering international trade in natural gas: the geopolitical challenge of regional complexities

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The world has a wealth of historical analysis on the evolution of the oil industry over a century and more. Authors have received Pulitzer Prizes and other awards for chronicling the geopolitics of oil and narrating the entire saga involving the so-called 'Seven Sisters' and their exploits for gaining control of oil reserves and supply sources all over the world. The IEA (International Energy Agency) came into existence in the wake of the first oil price shock of 1973/74 as the collective response of the major oil-consuming nations to the Arab oil boycott and growing power of OPEC (Organization of the Petroleum Exporting Countries). At the time, the major consumers of oil were solely the OECD (Organization for Economic Cooperation and Development) nations. It is another matter that the IEA has over time broadened its agenda and evolved into a very different organization from what it was born as. Yet, its core strength still lies in its geopolitical and technical knowledge of oil developments worldwide and its major concern still relates to the collective OECD view of actions to ensure security of oil supply for promoting economic growth in the member nations of the IEA.

While acquisition of new knowledge on natural gas issues is part of the IEA's current efforts to understand global energy developments, it still lacks an understanding of the complex geopolitics of natural gas, which has an overwhelming local and regional character. The complexities of international trade in natural gas assume a very different dimension from that of trading for oil in the global market because of the fungible character of the latter.

On the other hand, natural gas trade is based largely on bilateral agreements between importing and supplying nations, or at best a limited number of nations involved in very specific agreements. Consequently, countries which negotiate trading in natural gas hardly have the benefit of precedence or a given script to work with. This is also a large commitment of investments that specific trading parties have to make upfront for infrastructure related to pipelines or LNG (liquefied natural gas) facilities. A new dimension also has been added to concerns on the reliability and long-term stability of gas trading arrangements with the recent differences between Russia and Ukraine, which saw political factors being introduced in an arrangement that most nations would like treated as purely an established commercial issue.

Several projections have been made about the role of natural gas in the future energy scenario of the world. The most recent of these involves the estimates of future demand and supply developed by the EIA (Energy Information Administration) of the US DoE (Department of Energy). The latest *International Energy Outlook* published by this organization in June 2006 projects natural gas consumption worldwide increasing at an average rate of 2.4% per year for the period 2003–30 as compared with 2.5% per year for coal and 1.4% per year for oil (EIA 2006). The report also emphasizes the fact that natural gas remains a more environmentally attractive energy source and certainly burns more efficiently than coal. However, coal is still expected to be the fuel choice in many regions of the world. As a result, the natural gas share in total world energy consumption on a heat equivalent measure would grow from 24% in 2003 to 26% in 2030. The important point to note is that most projections of the role of natural gas are based essentially on a business-as-usual scenario. In other words, the growth of infrastructure and particularly that required for international trade in natural gas is assumed to grow on a very conservative basis. In 2003, the industrial sector accounted for 44% and the electric power sector 31% of the world's total natural gas consumption. In future projections, natural gas use is expected to grow in keeping with existing trends by 2.8% per year in the industrial sector and 2.9% per year in the electric power sector. Against the background of these business-as-usual projections, a basic hypothesis needs to be put forward in relation to the role of natural gas in the world's energy future. The five points that essentially define such a hypothesis can be listed as follows.

1 The geopolitics of natural gas production, trade, and consumption is a complex subject and, in most parts of the world, is hardly understood at all, particularly on account of very location-based characteristics.
2 Most natural gas international trade decisions and forward thinking to create matching infrastructure are based on a lack of socio-political expertise, appropriate analysis, and pragmatism. Often, the sole emphasis is on the engineering and financial aspects. In general, some of the political dimensions of natural gas trade are not properly understood, particularly since this subject is largely dealt with by foreign ministries or by petroleum trading or production entities in countries that are involved in such decisions. The level of multi-disciplinary expertise required in these ministries or companies has not yet been developed to the requisite extent.
3 As a result of these factors, the global situation with regard to supply and international trade in natural gas is essentially one of under achievement and sub-optimal utilization of this resource. In other words, economic rationale suggests a much larger consumption of natural gas in different parts of the world, particularly where gas reserves exist in adequate quantity for matching demand and international trade possibilities involving markets in proximity.
4 If natural gas has to grow above or even within the business-as-usual scenario presented by several agencies such as the EIA of the US DoE, major expansion of natural gas infrastructure would have to take place at an early date and with a certain level of foresight and vision on the part of those countries that have the potential to supply natural gas and those which have large demand projected in the future. It would be noteworthy to mention that in the early 1980s, the Chiyoda Corporation of Japan actually foresaw the role of natural gas on the Eurasian landmass and carried out a detailed study of a network of pipelines that would ensure much greater supply of natural gas across international borders. Unfortunately, this vision and the elaborate exercise carried out by Chiyoda did not get sustained attention from political leaders in Asia and Europe and as a result the exercise remained confined to academic activity.
5 South Asia presents a unique example of the basic constraints and problems listed above. It would, therefore, be useful to study the situation in South Asia and to come to grips with what is really coming in the way of optimal exploitation of natural gas reserves in the neighbourhood and commensurate expansion of international trade across borders between countries in the region.

While projecting the global scenario, the EIA estimates that natural gas consumption would grow from 95 TCF (trillion cubic feet) in 2003 to 182 TCF in 2030. This essentially involves a doubling of natural gas production and consumption within a period of 27 years and as mentioned earlier represents an average annual growth rate of 2.4% per year. The relative increase in different regions of the world implied in these projections is shown in Figure 1, which

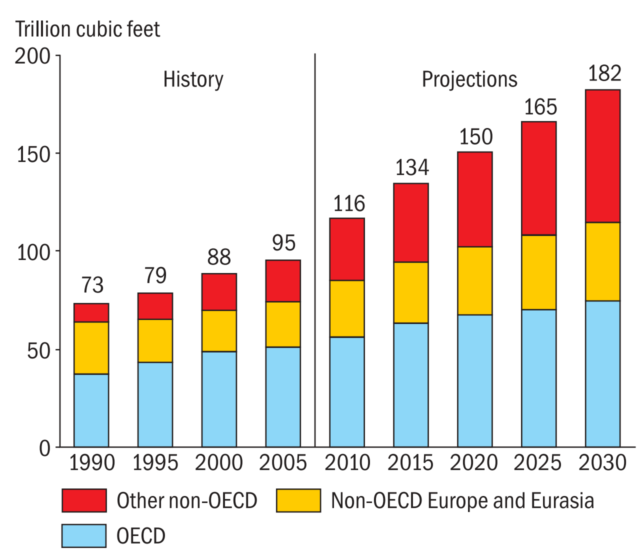

Figure 1 World natural gas consumption by region, 1990–2030
Source EIA (2006)

indicates a substantial increase in consumption in other non-OECD countries. This increase is also indicated in terms of the sectors that use natural gas in Figure 2, which shows consumption between the industrial sector and power generation separately and other sectors lumped together. As against these consumption levels, the availability of natural gas and the geographical distribution of known reserves is shown in Figure 3. This clearly indicates that the largest shares of reserves exist in the Middle East followed closely by Eurasia, essentially dominated by the reserves that exist in Russia. Other regions of the world have substantially

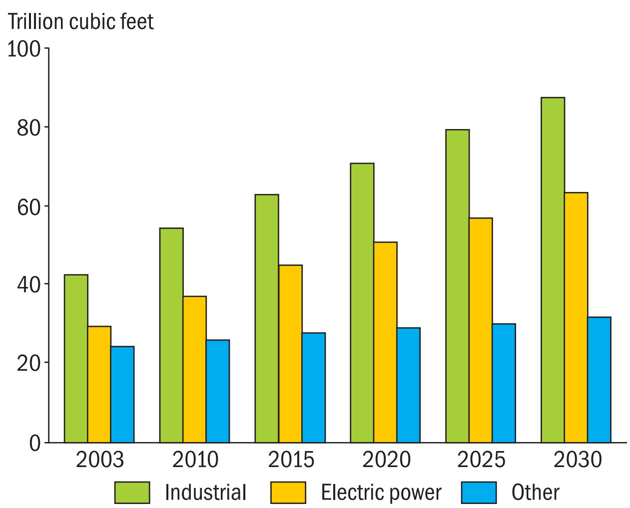

Figure 2 World natural gas consumption by end-use sector, 2003–30
Source EIA (2006)

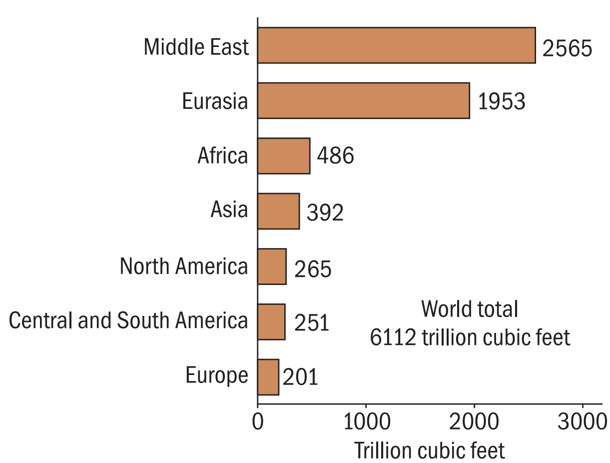

Figure 3 World natural gas reserves by geographic region as of 1 January 2006
Source EIA (2006)

lower reserves and, therefore, a conclusion can be drawn that South Asia being located in the Eurasia landmass and in close proximity with the Middle East is uniquely placed to exploit larger quantities of natural gas use in the future.

In the Middle East itself, the largest revision upwards in estimated reserves has taken place in Iran where between 2005 and 2006, these have increased from 940 TCF to 971 TCF, which represents an increase of three per cent. The EIA projections also indicate that natural gas consumption in non-OECD regions of the world would grow much faster than in the OECD countries with a growth rate of 3.3% in the case of the former and 1.5% in the case of the latter during the period 2003–30. As a result, the non-OECD component of increase would account for 73% of the world total increment in consumption up to 2030. Major increases in consumption are foreseen in China and India and these are shown in Figure 4 for both countries. China would, undoubtedly, increase its natural gas consumption on a substantial scale but the increase in India is also quite significant in relation to existing levels.

This set of projections implies that to achieve even the business-as-usual levels of energy consumption in India and in other countries of South Asia, greater vision would need to be exercised for ensuring that imports of gas on a much higher and secure basis and consumption take place in the future.

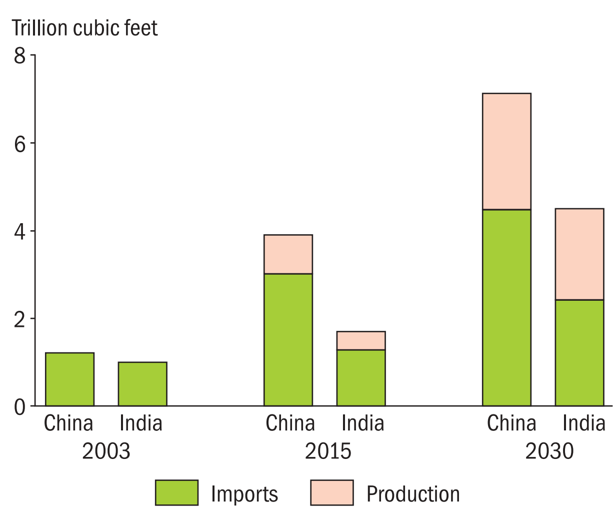

Figure 4 Natural gas supply in China and India by source, 2003, 2015, and 2030
Source EIA (2006)

It was in 1989 that Dr Ali Shams Ardekani of Iran and I came up with the conceptual framework for supply of natural gas from Iran by pipeline through Pakistan to India. Dr Ardekani was then requested to present the details of this project at the annual international conference of the International Association for Energy Economics in Delhi in 1990. The essential features of the proposal were based on a pipeline with a capacity of 100 MMSCMD (million metric standard cubic metres per day) of natural gas starting from Bandar Abbass and crossing Iran eastward, with a consumption uptake of around 10 MMSCMD the pipeline was to cross into Pakistan which would take around 20–25 MMSCMD for its own consumption. It was envisaged that this pipeline would enter India through the western border and go right up to Calcutta (now called Kolkata) supplying gas to the northern and eastern parts of the country. Components of the project included a gas gathering system and a gas processing system to remove hydrogen sulphide and natural gas liquids. The collected gas was to be compressed, dehydrated, and treated and fed into a liquid recovery plant where the heavier hydrocarbons were to be recovered and pipeline grade gas obtained for transportation.

The anticipated cost of the project was around 11.75 billion dollars. The initial response of decision-makers in India and Pakistan in particular to the project as a whole was generally negative and skeptical. Undoubtedly, given the political complexity involving discussion among the three countries, there was a logical basis for skepticism, but senior officials in the Ministry of Petroleum and Natural Gas, Government of India, saw the merit of an established supply of natural gas and moved in a determined manner with other departments of the Government of India to pursue this possibility. The project is now very much part of the agenda of political and commercial relations among the three countries, but in the meantime the equations which existed earlier have altered considerably, and with an increase in international oil prices, the initial price of gas on offer is now being revised upwards, also adding to existing complications in the negotiations.

Iran is not the only source from which India can import natural gas through pipeline. There is now increasing interest in the TAPI option which would source gas in Turkmenistan (T), which holds the fourth largest reserves of gas in the world, transporting it through Afghanistan (A) and Pakistan (P) into India (I). During the period of the Taliban regime in Afghanistan, this was an obvious non-starter, symbolized by the fact that Unocal, which was very active in pushing the pipeline at least up to Pakistan, pulled out in desperation. However, with a semblance of democracy and stability returning to Afghanistan, the TAPI option becomes a serious possibility. On the eastern flank, both Bangladesh and Myanmar have been possible suppliers of gas, but here again on account of inertia on various fronts and lack of understanding between some governments, no headway has been made to convert these possibilities into reality. In the case of Myanmar, the hesitation has perhaps been greater on the Indian side, on account of what was perceived as an undesirable arrangement because of what the world considers as an unacceptable human rights record in that country. However, not only has an American company Unocal constructed the pipeline for supply of gas from Myanmar to Thailand, but it also needs to be remembered that the gas pipeline from the former Soviet Union to western Europe was agreed on at the peak of the cold war when the communist regime in that state was seen as a major violator of human rights.

The one conclusion that can be drawn from recent problems with so-called pipeline politics is that private companies as well as governments have not really come to grips with the geopolitical aspects of international trade in natural gas by pipeline. In fact, even in the case of LNG, supply arrangements and agreements do not get implemented in a smooth manner. Both China and India have had difficulty in sourcing LNG for the two terminals in Guangdong and Fujian in China and Dahej in India, respectively, essentially because agreements were signed at very favourable terms several years ago, but global prices have in the meantime gone up to bring these agreements into question. International relations and diplomatic initiatives are not being driven adequately by opportunities that exist for greater international trade in natural gas using pipeline transportation. Nowhere is this fact more apparent than in China and South Asia, particularly since both these regions are in the neighbourhood of the largest gas reserves in the world.

The extent of trade that could take place on the strength of the large natural gas reserves is only a fraction of what is possible. A recent publication entitled *Natural Gas and Geopolitics from 1970 to 2040*, edited by David G Victor *et al*. and published recently by Cambridge University Press, explores some of the complexities of natural gas geopolitics. What is baffling is the fact that very few think tanks in this part of the world consider this subject worthy of scholarship and hence do not explore it with adequate seriousness. What is even more baffling and discouraging is the fact that even the think tanks that do work on these issues are seldom heard by the policy-making community. As a result, diplomatic initiatives and bilateral relations with some of the countries that could help promote large-scale imports of gas remain frozen in time. A good example can be seen in the fact that despite dramatically improved relations between India and the US, hardly any effort has been made by the Indian establishment to act as honest broker behind the scenes to bring the US and Iran together. Perhaps these efforts would not have succeeded beyond a certain degree, but it can be summarized that India's leverage with Iran could have been improved substantially for pushing the natural gas pipeline deal through several years ago rather than remain in the current state of uncertainty, even after 17 years have gone by since the project was proposed and presented.

Energy security globally and in this region would depend, at least over the next quarter century, significantly on the supply of natural gas on a stable and secure basis. This, however, will not happen unless the geopolitics of natural gas pipelines is properly and fully understood and some major initiatives taken in hand to bring about implementation of projects that have been on the table for long. International relations and diplomatic, commercial, and political linkages will need to be structured in future on the basis of energy choices and possibilities existing on the horizon. Natural gas would be a crucial part of energy solutions for South Asia and China, a fact which China seems to have realized far better than other parts of the world including South Asia. Understanding the geopolitics of natural gas trade by pipeline is an essential part and pre-requisite of steps to be taken. Organizations both within and outside the government must show greater commitment to analysing the challenges and opportunities ahead for enhancing energy security through optimal levels of natural gas trade across political boundaries.

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Natural gas markets: a global perspective

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Until a few years ago, growth in global gas trade was impeded by mobility constraints. However, LNG (liquefied natural gas) and, more recently, GTL (gas-to-liquid technology) are fast bridging the gap and connecting what were previously regional gas markets. Moreover, with growing competition for natural gas, consumers and producers are responding by opting for diversification of their trade partners. These developments have started to create a truly global gas market—expanding the range and nature of energy needs, which can be met by natural gas.

In this paper, an overview of the global gas market is presented. The sections below discuss the supply and demand outlook for natural gas, how gas is being traded globally, and conclude with a discussion on the challenges that the global gas industry faces.

Supply outlook

Over the last two decades, as a result of innovations in exploration and extraction techniques, proven reserves of natural gas have increased steadily from 84 TCM (trillion cubic metres) in 1980 to 180 TCM in 2004, at an average annual growth rate of 3.2%. The world's ratio of proven natural gas reserves to production at current levels of production is about 66 years. Potential reserves are much greater than proven reserves. Global ultimate recoverable reserves are estimated at 450–530 TCM (IEA 2004).

The Russian Federation has the largest share (26.7%) of world's proven gas reserves, followed by Iran (15.3%) and Qatar (14.4%). Almost three-quarters of the world's natural gas reserves are located in the Middle East (40%) and transitional economies of the Former Soviet Union (32%). Reserves in the rest of the world are fairly evenly distributed on a regional basis with Africa holding about 7.8% reserves, Asia Pacific having 7.9% reserves and North, Central and South America together holding about 8.1% of the world's total reserves. India and China have 0.5% and 1.2%, respectively (BP 2005).

Global gas production has almost doubled from 1457 BCM (billion cubic metres) in 1980 to 2691 BCM in 2004. Russia and USA are the main natural gas-producing countries of the world, accounting for approximately 22% and 20% of the total production, respectively (BP 2005). Other major producing countries are Canada, United Kingdom, Iran, Algeria, Norway, Indonesia, Netherlands, Saudi Arabia, Uzbekistan, Turkmenistan, and Malaysia.

Natural gas production is expected to grow very strongly in regions of Former Soviet Union, Middle East,[1] Caspian region, Latin America, and Africa, where gas has not been fully monetized. On the other hand, the more mature fields in Europe and North America are experiencing a stagnancy and decline in production. However, on an overall basis, world natural gas production is expected to grow in the future as a result of exploration, greenfield and expansion projects, in anticipation of growing demand (Figure 1).

Demand outlook

The world demand for natural gas has grown from 991 to 2433 BCM between 1971 and 2002 at a rate faster than that of both oil and coal (2.9% per year *vis-à-vis* 1.4% and 1.7%, respectively). As a result, its share in TPES (total primary energy supply) has risen from 16% in 1971 to 21% in 2002 (IEA 2004a). The main gas-consuming countries in the world are the US, accounting for 24% of total consumption in 2004, and the Russian Federation, with 15% of total consumption. Other important consumers are UK, Canada, Iran, Germany, Italy, Japan, Ukraine, and Saudi Arabia. Together, North America, Europe, and Eurasia consumed about 70% of the total natural gas in 2004.

As per future projections by various agencies, natural gas consumption is likely to grow at much more rapid pace as compared to oil and coal (Figure 2). Under certain scenarios of growth, gas could overtake oil as the fuel of choice by 2030 (Brinded 2004).

This growth in demand will be driven by the competitive edge that gas has over other fuels. It is attributable to a number of factors including the ones listed below.

- More stable gas prices *vis-à-vis* oil (higher prevalence of long-term contracts in gas markets insulates prices from fluctuations)
- Better distribution of gas as compared to highly skewed distribution of oil
- Environmental advantages[2] over other fossil fuels, especially when used for power generation. Over the life cycle – from wellhead to electricity generation – carbon dioxide emissions from gas-fired power generations are approximately one-half of those from coal-generated electricity.

[1] As of now, the world's top 15 gas fields are located in these two regions.

[2] Dry natural gas contains 99.5% of methane, which has a low carbon content and results in lower emissions of noxious gases.

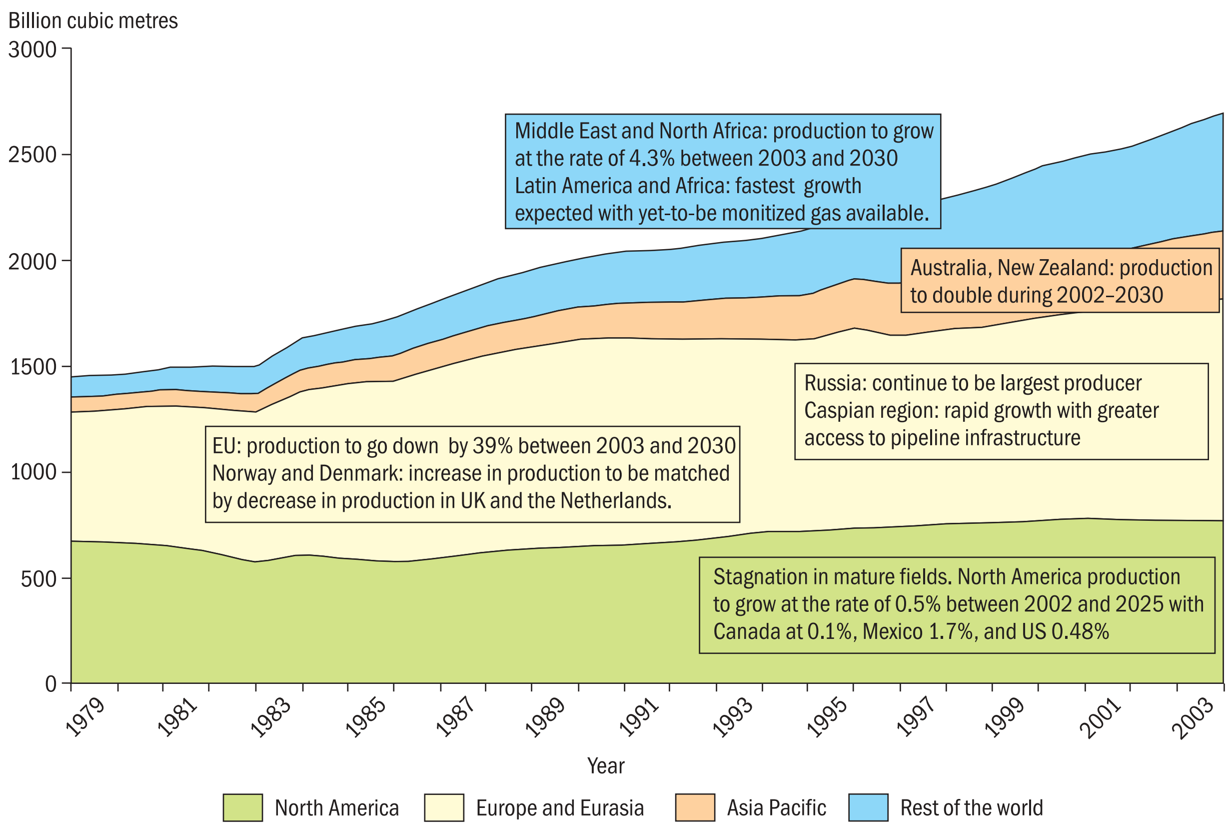


Figure 1 Natural gas production by area: present and future prospects

Note Gas fields in the main producing basins (in Canada, US, UK, Netherlands, etc.) are approaching exhaustion, development costs are rising and production-decline rates per well are accelerating. US production has been fluctuating between 561 and 583 BCM since 1990s. Canadian production has dropped from 188 to 183 BCM between 2002 and 2004. UK production has declined from 108 to 96 BCM.
Sources BP (2005), IEA (2005), IEA (2005a), EIA (2006), Quinlan (2006)

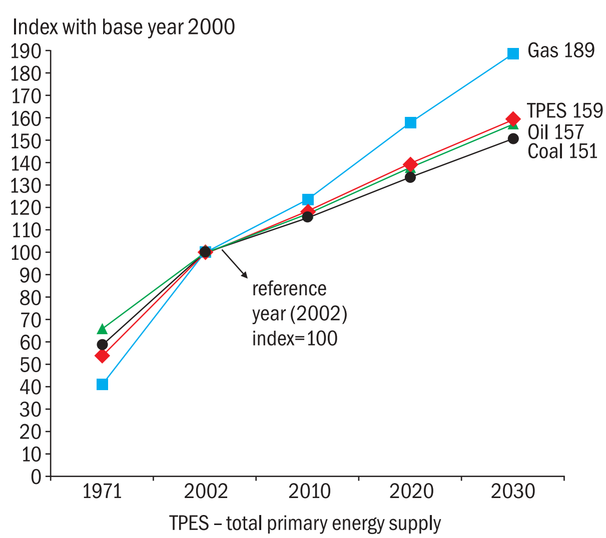


Figure 2 Gas consumption projections till 2030
Source IEA (2004a)

P Higher efficiency in use, especially in power sector, as compared to coal.

Power generation is expected to account for 59% of the incremental gas demand raising its share in world gas market from 36% in 2002 to 47% in 2030. In Europe, adherence to Kyoto is likely to increase gas demand appreciably by 2012. China has introduced new penalties on emissions, which will improve the competitive position of combined cycle gas turbine plants.

North America, Europe and Asia Pacific are expected to account for 60% of the growth in natural gas demand in the coming two decades. The most robust growth in demand of natural gas has been projected for developing countries in Asia, Africa, and Latin America, with primary demand in Brazil. Demand in China and India is likely to grow by more than 5% per year between 2002 and 2030. Gas consumption in Japan and Korea is projected to double and more than double in the Middle East over the same period. Russia and other transition economies as a whole are expected to remain the world's second largest gas market, with primary demand growing at an average annual rate of 1.6% during 2002–30 (IEA 2004a).

Trade in gas

International trade in gas has witnessed a tremendous growth since 1973, increasing nearly nine times to reach 692 BCM in 2003, with an annual growth rate of 7.5% (IEA 2005a). The mismatch between supply and demand drives this growth. On the one hand, there is North America and Europe, which currently accounts for about 50% of demand and holds 9% of world's reserves, on the other hand, there is Middle East and Russia with two-thirds of the world's reserves, accounting for one-third of consumption. However, only about 28% of gas consumption was met by imported gas in 2004 (IEA 2005).[3] International trade in natural gas has been constrained by high transportation costs, inadequate infrastructure, and geopolitics.

Two features characterize the international gas trade between these countries and continents: the first is that it is largely dominated by pipeline gas and the second, driven by the first, is that the gas markets are mainly regional. In 2004, about 77% of natural gas was transported by pipeline and rest 23% as LNG (IEA 2005). The main countries exporting by pipeline are the Russian Federation, Canada, Norway, Netherlands, Algeria, and Turkmenistan while countries importing by pipeline are the US, Germany, Italy, Ukraine, and France.

With major reductions in LNG supply costs[4] in the past decade or so, LNG has come to play a key role in connecting the regional gas markets and delivering greater volumes across borders. The flexibility of LNG, which is transported by ship rather than pipeline, allows a single source to supply multiple markets. This facilitates seasonal flexibility and makes it ideal for reaching new markets. The longer the distance, the more cost-competitive LNG becomes, compared to pipeline gas. At present, there are 12 LNG-exporting nations and 15 LNG-importing nations. The Pacific Basin is the largest LNG-producing region in the world, supplying nearly 49% of all global exports in 2004.[5] Middle East has recently emerged as an important LNG-exporting region, with plants now operating in Abu Dhabi, Oman, and Qatar.[6] Countries in the Atlantic Basin, led by Algeria, exported about 28.3% in the same year. Other important exporters of the region are Nigeria, Trinidad and Tobago, Libya, and Egypt. Russia and Norway are in the process of building their first liquefaction terminals. Other potential new exporters, such as Iran, Yemen, Equatorial Guinea, Angola, Venezuela, and Bolivia are looking at LNG exports as a way of monetizing their natural gas resources.

Japan, South Korea, and Taiwan are the leading LNG importers, and accounted for about 65% of global LNG imports in 2004. Seven European countries – Spain, France, Italy, Turkey, Belgium, Portugal, and Greece – received about 21% of global imports, while the US imported about 10% of the global LNG imports (BP 2005).

LNG trade is growing at a very fast pace, due to worries over pipeline supplies and the need to ensure long-term supply contracts. Producers are envisaging more expansions and greenfield

[3] As per BP statistics, about 25% of natural gas is internationally traded.

[4] Reduction in LNG costs have come largely from increases in train size, improved fuel efficiency in liquefaction and regasification, improved equipment design, the elimination of gold-plating, better utilization of available capacity, and more use of competitive bidding procedures. Between 1990 and 2000, liquefaction costs have fallen typically by 25%–35%, and shipping costs by 20%–30%.

[5] Most LNG trade takes place in Asia-Pacific, with three of the five top LNG exporters – Indonesia, Malaysia, and Australia – in the region. Indonesia is the world's largest LNG producer, exporting about 19% of the world's total volume in 2004.

[6] In 2004, the three countries accounted for about 18.3% of world's LNG trade.

plants (10 export plants are under construction, 19 are proposed, and 13 are speculative[7]) while more and more consumer countries are either in the planning stages or process of building regasification terminals (20 import plants are under construction, 33 are proposed, and 41 are speculative) (The Petroleum Economist Ltd 2006). Inter-regional trade in natural gas is projected to more than triple to about 1265 BCM between 2002 and 2030. By 2030, more than 50% of all inter-regional gas trade is expected to be in the form of LNG (*vis-à-vis* 27% in 2004) (IEA 2004a) (Figure 3).

But despite all these projections for LNG, supply is still the key issue today in the growth of these projects, due to growing resource-nationalism in gas-rich countries, geopolitical problems, and a global squeeze on contractors and materials (Catan 2006).

Regional markets: blurring boundaries

The global gas market can be broadly classified into three regional markets—Asia Pacific, Europe, and North America. With the reduction of LNG supply costs and opening up of gas markets, the regional nature of these markets is fast changing. LNG has provided access to European, US, and Asian markets to regions like Middle East where capacities and volumes were underutilized. Also many of the importing countries are looking at LNG as a means of diversifying their energy supplies.

North America

North America constitutes a very integrated and mature market for natural gas. The region has the world's most developed pipeline infrastructure. Most of the trade in the region is from Canada to the US (importing almost 95% of its total gas imports from Canada) through numerous gas pipeline connections (Map 1).[8] Pipeline infrastructure between the US and Mexico is comparatively less developed with about 11 BCM of natural gas exported to Mexico by the US.[9]

Currently, North American natural gas market is almost self-sufficient with less than one per cent of the region's gas demand being met by LNG imports from outside regions. However, the region's natural gas consumption is expected to grow at an average annual rate of 1.5% (*vis-à-vis* 0.5% for production) during 2002–25, implying an increased dependence on imports, mainly in the form of LNG. The net LNG imports of the US as a share of total natural gas consumption is expected to increase sharply from 1% in 2002 to 15% in 2015 and 21% in 2025 (EIA 2005).

In view of the growing demand, the region (particularly the US) is rapidly expanding its LNG capacity.[10] If all the proposed facilities are constructed, they could add more than

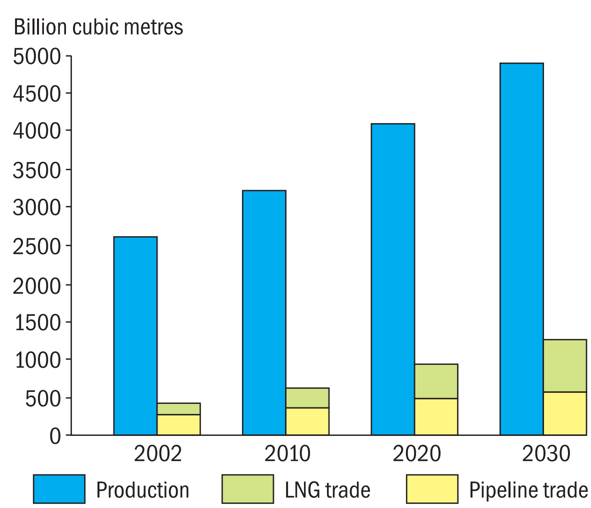


Figure 3 Net inter-regional trade and production, 2002–30
Source IEA (2004a)

[7] Speculative LNG plants are those that are being considered but there are no concrete plans as yet.

[8] The pipelines include Alliance Pipeline, the Northern Border Pipeline, the Maritimes and Northeast pipeline, the Trans Canada Pipeline system, and West coast energy pipelines.

[9] The US supplies small quantities of LNG to Asia from Cook Inlet (Alaska) amounting to 1.68 BCM in 2004.

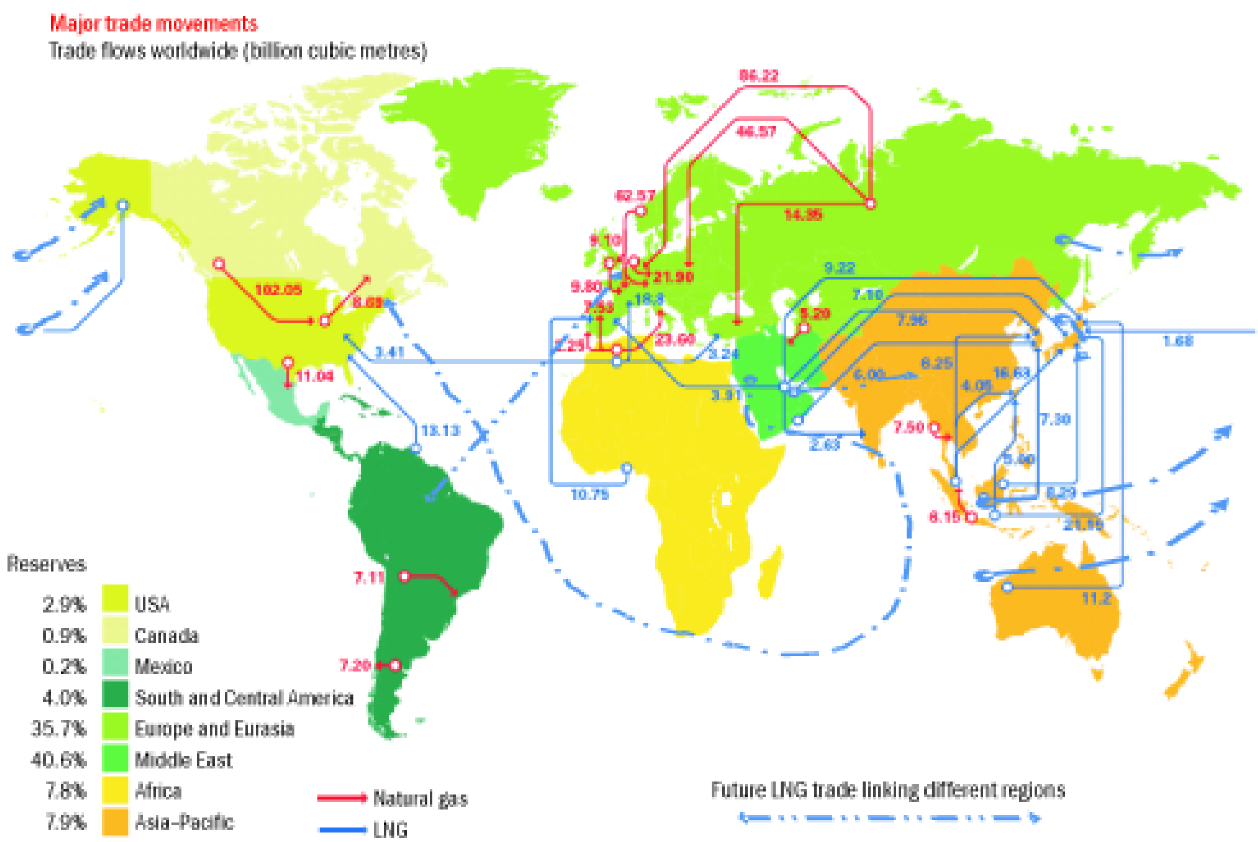
[10] About 6 LNG terminals are under construction in the region to source imports from Nigeria, Algeria, Oman, Qatar, Trinidad and Tobago starting by the year 2008. Twenty-four new LNG regasification plants are planned for the region during 2006–10 facilitating imports from existing LNG exporters and new regions like Russian Federation, Australia, Malaysia, and Indonesia. More than 25 regasification projects are speculative (2006–10) in three countries – US, Mexico, and Canada – of which 21 are located in the US (The Petroleum Economist Ltd 2006).

566 BCM to the region's import capacity, equivalent to almost 75% of the natural gas consumed in North America in 2002 (EIA 2005). Latin America is expected to emerge as the largest exporter to the region by 2030 while imports from the Middle East and Africa are likely to increase substantially (a 52- and 20-fold increase, respectively from the present miniscule level) (Map 1).

European markets

The largest gas markets in the region are UK, Germany, Italy, the Netherlands, and France. The net gas exporters within Europe are the Netherlands, Norway, Denmark, and UK.[11] Europe's reliance on external suppliers has increased to nearly 37% of its gas needs in 2004 as compared to 17% in 1980. Russia is the largest supplier to Europe providing more than 60% of total region's imports from external sources in 2004—entirely by pipeline[12] (Map 1). Germany is the largest importer, followed by Italy, Turkey, and France. New importers are emerging, in particular the UK market. Algeria is the next biggest exporter of gas to OECD (Organization for Economic Cooperation and Development) Europe, both via pipeline and as LNG. Europe has also been importing LNG from Nigeria, Trinidad and Tobago, Libya, and spot cargoes from the Middle East in recent years.

With stagnant production and limited reserves, import dependency of Europe is expected to increase up to 70% by 2030. Russia



Map 1 Major trade flows during 2004 and likely future trade
Adapted from BP (2005)

[11] Norway exports most of its volume of gas to the continent and small volumes to the UK. The Netherlands exports half of its gas production to other European countries. Denmark is a small exporter to Germany and Sweden.

[12] Two important pipelines, which bring Russian gas to Europe, are Blue stream and Yamal-Europe-I.

is expected to maintain its position of the largest exporter with gas exports of 189 BCM to the region in 2030 (Map 1). However, the high dependence of Europe on Russian imports has fuelled concerns about the security of future supplies. Further, Russia's reliability as a dependable gas supplier for Europe is increasingly being questioned. Russian gas exports to Western Europe transit either through Ukraine or through Belarus. A legacy of unclear contractual arrangements have troubled and weakened Russia's relationships with its two main transit countries. The recent gas dispute in January 2006 between Russia and Ukraine over price has increased the insecurity among European importers.[13]

These factors have renewed Europe's interest in exploring pipeline gas from the Caspian region with plans of Caspian gas entering Europe by 2010.[14] African exports to Europe are also expected to expand rapidly with new pipelines being constructed in addition to the existing two pipelines.[15] At the same time, LNG option is also being looked at to diversify from piped gas supply. Currently, there are 11 LNG regasification terminals operating in Europe and more than 15 new plants have been proposed, including the 7 that are under construction.[16] Large volumes of LNG imports from the Middle East (26 times greater inflows are expected), West Africa (three-fold increase in exports are likely), and Latin America (from zero imports in 2004 to 13 BCM in 2030) have been projected (IEA 2005).

The Asian market

The Asian market comprises Japan, South Korea, and Taiwan as the major LNG importers, and Indonesia, Australia, and Malaysia as the major exporters dominating the Pacific basin. China and India are emerging as new markets for natural gas. By 2030, India and China are expected to depend on imports for 40% and 27% of their gas needs, respectively. Russia is considering diversification to new markets of Asia (pipeline and LNG) as well as entering the Atlantic LNG business. By 2030, Middle East and Russia are likely to emerge as important suppliers of gas to the region.

New developments, needs, responses

Over the years, with deregulation and restructuring, natural monopolies, which dominated the natural gas industry in a number of countries, have given way to increased competition and new market models. Also, governments, which played a central role in creating markets and infrastructure for natural gas absorbing most of the risks, are increasingly moving away from this role to become more of facilitators and regulators of markets. Investment and risk-taking is being increasingly undertaken by the private sector. Lowered entry barriers and deregulated prices have allowed new participants to emerge. The opening of markets has, in turn, led to more efficient pricing and greater choice among natural gas contracts.

The contractual frameworks in the natural gas industry have themselves evolved. The traditional LNG contracts were long-term (often 20–25 years) and rigid. Take-or-pay clauses shifted the volume risk to the buyer. Contracts also contained 'destination clauses' that prevented buyers from reselling the cargoes to third parties. Although even with liberalization, long-term LNG contracts are not likely to disappear, importing companies are seeking increased flexibility and better contractual terms. Increased flexibility in LNG shipping has

[13] See article by Chandrashekhar Dasgupta in this issue.

[14] via the 25-BCM/year Nabucco pipeline and 16-BCM/year South Caucasus pipeline (from Azerbaijan to Turkey) (Watson 2006 and EIU 2006). There are plans to build a Trans-Caspian pipeline from Turkmenistan to link up with the south Caucasus pipeline.

[15] Currently two pipelines connect Algeria to Europe: the Transmed pipeline to Italy; Maghreb-Europe pipeline to Spain. New pipelines to secure Algerian gas are under construction: Medgaz (to Spain) and Galsi (to Italy) with overall capacity of 18–20 BCM/year by 2010. Also, the Trans-Sahara pipeline is under construction, starting from Nigeria to Algeria and then joining to the European grid (Gupta 2005).

[16] Major suppliers of LNG to the region are Algeria, Libya, Nigeria, Oman, Qatar, and UAE. Imports from Nigeria and Trinidad and Tobago are expected to rise steadily. Egypt and Venezuela are likely to emerge as new bulk suppliers of LNG in the region.

led to new long-term contracts having a shorter duration (from 8 to 15 years in Europe[17] and 15 to 20 years in Asia), greater flexibility in contractual terms,[18] smaller volumes and new price indices[19] (IEA 2004).

Another very significant development is the emergence of gas 'hubs' involving both LNG and pipeline gas. 'A hub can be defined as the entry point to a transmission network. Hubs draw supply from a variety of sources and enable operators to market gas to end-users.'[20] These are emerging in the US and Europe (Belgium, Netherlands, Germany, and the UK),[21] providing opportunities for price arbitrage. In very liquid gas markets, spot and futures markets have formed. Spot markets usually start with over-the-counter trade (trade that occurs in some context other than a formal exchange) with gas deliveries ranging from a period of one day to one year. Deliveries in future, on the other hand, are handled through forward contracts in which there is a commitment to deliver or take a specific amount of gas at a defined time and price. In order to hedge against price risks, the first natural gas futures contract was launched in 1990. Gas futures are usually paper trades that happen in organized commodity exchanges with standardized terms (IEA 2004). The globalization of the natural gas market has also resulted in links emerging among inter-regional prices. Traditionally, LNG prices have been higher in the Pacific Basin as compared to the Atlantic Basin. However, with the emergence of Middle East as a prominent LNG supplier, there may be a convergence in the prices in the two regions (EIA 2003).

Yet another development in the natural gas industry is the emergence of a short-term LNG market. While long-term contracts are essential for securing long-term supply requiring large investments for financing large gas reserves projects, short-term or spot contracts provide for balancing demand and supply in the short-to-medium term. Spot markets have emerged essentially due to spare capacity in infrastructure (liquefaction, LNG tankers, and regasification) and presence of a large number of players in the LNG markets. This kind of trade allows gas to go to the highest value market. Spot/short-term trading has grown rapidly from one per cent of the LNG market in 1992 to eight per cent of the global LNG trade in 2002.[22] It is projected to grow up to 15%–20% of LNG imports by the next decade, especially in the Atlantic Basin (EIA 2005). One implication of the increasing short-term trading and physical arbitrage is that inter-regional pricing links are evolving.

Also now buyers and sellers are taking on new roles. Buyers are investing in the upstream, including liquefaction plants.[23] Traditional sellers, such as BP and Shell, have leased capacity at terminals and are extending their role into trading. New buyers have been emerging, including independent power producers.

Conclusion

Energy experts globally are of the view that natural gas is the fuel of choice in the 21st century. Like oil, a truly global and integrated market for natural gas is emerging. At the same time, natural gas like oil, is rapidly gaining geopolitical importance as evident in recent events. These geopolitical

[17] In Europe, several shorter-term contracts have recently been signed, mainly to supply the Spanish markets (IEA 2004).

[18] Producers are now willing to relax the rules governing the reselling of LNG to third parties. Nigeria LNG has already removed any destination clauses on its current and future contracts. Russian Gazprom agreed in July 2002 to drop the destination clause from all future contracts. Algeria has also indicated that it would not introduce limitations on future cross-border gas sales with European importers. Japan and South Korea have swapped LNG cargoes for the last three years.

[19] For instance, Qatar has pegged its LNG sales to crude oil in Japan, to Henry Hub spot prices in US, to NBP spot prices in the UK and to fuel oil prices in continental Europe (IEA 2004).

[20] <http://www.suez.com/metiers/english/energie/lexique_energie.php?f=1> as on 15 May 2006

[21] Henry Hub in the US, Zeebrugge in Belgium, Emden, Bunde (Germany/Netherlands), Title Transfer Facility in the Netherlands, National Balancing Point in UK, etc. (IEA 2004).

[22] The leading short-term exporters in 2002 were Algeria, Oman, Qatar, Trinidad and Tobago, and the UAE. Short-term imports were dominated by the US and Spain, followed by South Korea and France (EIA 2005).

[23] For instance, Tokyo Gas and the Tokyo Electric Power Company have both invested in the Darwin liquefaction plant in Australia.

developments will have significant implications on investments in the natural gas industry.

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The European Union, Russian gas, and energy security

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The first four days of 2006 witnessed a suspension of Russian gas sales to Ukraine, as well as a shortfall in deliveries to the EU (European Union) through the Ukraine pipeline. Though the blip lasted for only a few days, it triggered off a spate of allegations in the West concerning Russia's use of gas supplies as a political weapon, its questionable reliability as a supplier, and the implications for the EU's energy supply security.

The last day of 2005 saw the failure of extended negotiations between Russia and Ukraine on a phase-out of the preferential price previously offered to Ukraine. Ukraine refused to accept a Russian demand for an increase in the price of natural gas from 50 to 230 dollars per 1000 cubic metres—close to the price applicable to the EU. Thereupon, on New Year's Day, Russia discontinued gas sales to Ukraine. When EU countries started to complain about shortfalls in gas deliveries, Russia insisted that it had been supplying the full contracted quantities to these countries and charged Ukraine with siphoning off gas intended for Western Europe. (Since some 80% of Russian gas supplies to the EU are delivered through pipelines running through Ukraine, the latter is physically in a position to divert these supplies for its own use.) Ukraine rejected the charge but refused to allow inspections to verify the quantities of gas entering and issuing from its pipeline. However, under pressure from the EU, the Russia–Ukraine dispute was speedily resolved and, on 4 January 2006, a complex agreement was concluded, under which RoskUkrEnergo (a company owned jointly by Russia's Gazprom and an Austria-based shell company with unknown beneficiaries) will buy gas from Russia at a price of 230 dollars per 1000 cubic metres, as well as from Turkmenistan at a price of 60–65 dollars per 1000 cubic metres, and will then sell the mixed gas to Ukraine at 95 dollars per 1000 cubic metres. The blip in gas deliveries to the EU was over.

The blip was the first significant shortfall in Russian gas exports to Western Europe. It is notable that exports had continued without interruption through the Cold War years. When the West Siberian gas pipeline for connecting Russian gas fields to markets in West Europe was launched at the beginning of the 1980s, the Cold War was in full swing. The western alliance was deeply divided over the energy security aspects of the deal. The US was strongly opposed to the project. It warned that reliance on Russian gas supplies would not only make West Germany and France vulnerable to Soviet political pressures but would also provide the Soviet Union with the convertible foreign currency that it desperately required to pursue its global agenda. West Germany and France took a very different view, maintaining that a partial switch to gas would reduce their dependence on the vagaries of the oil market, and thus enhance their energy security. Moreover, Russia's pressing requirement for convertible currencies would ensure that it would respect its contractual commitments regarding gas exports.

Failing to dissuade its allies, Washington announced – ostensibly as a response to oppressive Soviet policies in Poland – an embargo on a list of dual technology items to the Soviet Union, including equipment required for the pipeline project. The embargo applied not only to US companies but also their overseas subsidiaries, and even to foreign companies manufacturing US components under license. The ban affected British, German, and Italian firms that had binding contracts for the pipeline construction project. The Europeans rejected this exercise in extraterritoriality. The crisis in the western alliance was finally resolved on the basis of a compromise. Existing contracts were exempted from the embargo. At the same time, there was an understanding among the allies that West European dependence on gas imports from Russia would not exceed 30% of consumption and, furthermore, that the Troll field in Norway would be developed as an alternative source located in NATO (North Atlantic Treaty Organization) territory (Yergin 1991 and Thatcher 1993).

As we have noted already, natural gas supplies from the Soviet Union (and later, Russia) flowed without any significant interruption for a quarter century, right up to January 2006. What, then, led to the Russo–Ukrainian dispute and the brief disruption of supply in the first few days of the current year? The answer lies partly in the economic realm, and partly in the political realm. The economic factor relates to the evolution of Russia's energy-pricing policy, while the political factor concerns the fault lines in Ukrainian politics and a new East–West struggle for influence in that country.

After the disintegration of the Soviet Union, Russia continued to supply gas at preferential prices to former Soviet republics, with which it hoped to maintain close political and economic ties. Thus, the price at which gas was exported to Ukraine was not increased since 1990, despite a three-fold rise in the price for Western Europe. In the context of its application for WTO (World Trade Organization) membership, however, Russia is required to follow a non-discriminatory pricing policy, and it was pressed by the West to conform to WTO norms. In early 2005, Russia announced that subsidized exports would be phased out and that importers would have to pay market-determined prices in future. However, the time frame for the phase-out of subsidies was to be decided separately on a case-by-case basis, through negotiations with each country.

This is where the political factor could make an appearance. A major political upheaval occurred in Ukraine in 2005. An 'Orange Revolution', encouraged by the West, resulted in the installation of a new president whose declared objective is to join the NATO alliance. A political fault-line runs through Ukraine. In the South-East, the population is predominantly Russian-speaking and has very close ethnic, historical, and cultural ties with Russia. By contrast, the North-West is mainly populated by Ukrainian-speakers, with historical and cultural ties with Central Europe. The country is thus divided on the question of NATO membership.

Russia, for its part, has very high stakes in Ukraine. Its Black Sea fleet is based in the Ukrainian port of Sevastopol. Sevastopol, whose population is predominantly Russian, was transferred to Ukraine in 1954 as a result of a redrawing of what were then internal boundaries of the Soviet Union. Ukraine's entry into NATO would obviously imperil the future of the Russian naval base. Moreover, the Russian and Ukrainian defence industries remain integrated even after the break-up of the Soviet Union. This, too, will have to change if Ukraine joins NATO. The pro-NATO position of Ukraine's President Yushchenko is obviously incompatible with maintenance of special defence ties with Russia. Against this background, Moscow's desire to speedily phase out gas subsidies for Ukraine should not have come as a surprise to anyone. Its earlier policy of selling gas to Ukraine at a preferential price could be justified only on political grounds. The justification for a subsidy, or even a delayed phase-out of the subsidy, ceased to be applicable after the 'Orange Revolution'. Political reasons explain the earlier subsidy, not the decision to demand a market price.

Allegations of Russia's unreliability as a supplier, thus, lack a factual basis. However, there are other – and more solid – grounds for EU concern about long-term security of gas supplies. In 2000, domestic production accounted for 46% of the EU's gas consumption. There was reasonable diversification of sources of supply—Russia accounted for only 25% of EU consumption (well within the original 30% limit), while Norway, a country with close political and economic ties with the EU, supplied 15%. The current position is, thus, relatively comfortable. However, domestic production is projected to fall by as much as 50% in the next 20 years. Import dependency is, thus, projected to increase sharply. Hence, as pointed out in the Green Paper prepared by the European Commission in 2006, the 'challenge is to ensure a continued high level of diversification of supply' (European Commission 2006). Though Russia has a good record in meeting contractual obligations, over-dependence on Russia is not in the long-term interests of the EU. The construction of new US-promoted pipelines to bring Caspian and Central Asian gas to Europe, without transiting Russian territory, is expected to make a major contribution to this end. Gas (and oil) pipelines from Azerbaijan, transiting through Georgia and Turkey, will start operation later this year. The US is also pushing for a new pipeline to bring gas from Kazakhstan to the EU, through Azerbaijan (Gorst 2006).

The Green Paper also makes a number of other recommendations. In addition to new pipelines, these include expansion of the LNG (liquefied natural gas) infrastructure, comprising terminals and storages. LNG imports are less constrained by considerations of proximity to source than is the case with natural gas. Therefore, they permit greater diversification of sources of supply. Moreover, they have greater spare capacity than pipelines. As the Green Paper points out, 'LNG terminals offer a particular contribution to security of supply, since they are not normally utilized 100% of the time. This offers additional flexibility in case of an emergency'. Together with underground storage, they help ensure 'competitive gas prices at all times through higher import flexibility' (European Commission 2006). The Green Paper goes on to make a strong case for a single EU market for electricity and gas and a Europe-wide grid, instead of fragmented national networks.

From Russia's perspective as a leading oil and gas exporter, an essential feature of energy security is greater price stability of these commodities at levels that would provide an incentive for further exploration and expansion of production. Just as the EU seeks to diversify sources of supply, Russia is diversifying its export markets. Japan and China, in particular, offer new opportunities for enhanced exports of natural gas to the Far East, while gas from the Barents Sea is expected to be shipped as LNG to the US. It is also building new pipelines to the EU in order to reduce dependence on any single transit country. Particularly significant, in this context, is the construction of a new pipeline under the Baltic Sea affording direct access to Germany.

Viktor Khristenko, Russia's industry and energy minister, recently called for 'equitable pricing', 'consistent supplies for all consumers' and action to 'stabilize global energy markets'. The goal, he said, should be to 'forge a long-term, reliable, and environmentally sustainable energy supply at prices affordable to consumers and to the exporting countries (Khristenko 2006). These issues will occupy centre stage at the forthcoming G-8 Summit in Moscow.

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Unconventional sources of gas: a short review

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As conventional sources of fossil fuel become more expensive, and reliable energy becomes as much a geopolitical issue as an economic or technological one, it is increasingly obvious that we need to exploit hitherto untapped resources to meet our needs.

Over the last half century, our use of natural gas has grown steadily—driven by intrinsic advantages such as being a safe, clean, burning fuel. Today, natural gas provides a vitally important and growing proportion of the world's energy. Yet, even as we worry about the depletion of our oil reserves, many believe that similar concerns about gas are just around the corner. As countries grow ever more concerned about energy security and their dependence on expensive imports,[1] previously under-exploited sources of gas have become the targets of intense interest.

In this article, we discuss some of these 'unconventional' sources of gas: what these

[1] South Korea and Japan are examples of countries dependent on expensive LNG imports to meet their needs. For a discussion of India's natural gas requirements see the Planning Commission's 'Integrated Energy Policy' draft report.

resources are, how they are formed, the technological and economic challenges faced in exploiting them, and a brief overview of the current state of production or research. We have focused on six kinds of resources that are generally regarded as options for the future (though some such as CBM [coal-bed methane] have been commercialized and others such as shale gas have a long history).

1 CBM
2 Gas hydrates (or methane hydrates)
3 Deep natural gas
4 Shale gas
5 Tight natural gas
6 Geopressurized gas

Coal-bed methane

The process of coal formation from organic matter is accompanied by the release of methane gas. Under high pressures, this gas may be adsorbed on the surface of coal and is then referred to as CBM. Methane stored in this manner has traditionally been regarded as a mining hazard (and given evocative names such as 'The Miner's Curse'). Because of the large internal surface area of coal, a coal seam may store about six or seven times as much gas as a conventional reservoir of equal volume (US Department of the Interior 2000). Today, improvements in technology have made it feasible to commercially extract methane from coal beds.[2] CBM is commercially extracted in the US, China, Australia, and Canada, with the US being the world's largest producer (see Figure 1 for information on CBM reserves and production).

Production of coal-bed methane

CBM extraction requires the removal of water in order to depressurize the seam and release the gas. A variety of technology improvements such as pre-drilling before mining, long-hole horizontal drilling, the use of large-scale ventilation systems and technologies such as ECBMR (enhanced CBM recovery) have made

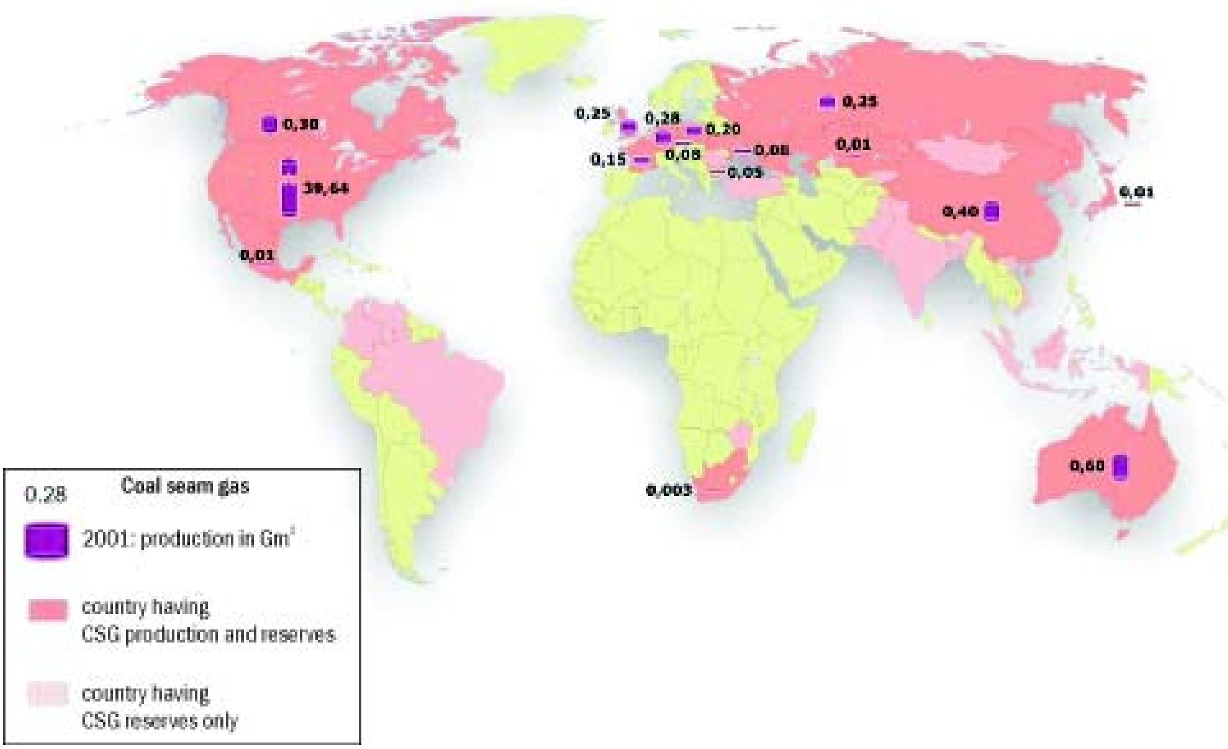

Figure 1 Global coal-bed methane resources
Source Gerling (2004)

[2] The technology to extract CBM was first developed in the US in the 1970s and 1980s. By 2003, 9% of total US dry gas production was from CBM (US Department of Energy figures).

it increasingly viable to extract CBM from coal mines.[3] ECBMR using carbon dioxide injection also has the potential to reduce overall carbon emissions. Unfortunately, there remain a number of severe challenges, which still need to be overcome.

The production of CBM on a large scale can require drilling tens of thousands of wells and constructing extensive support infrastructure, including pipelines and water treatment facilities (King 2001). While the extent of drilling and infrastructure depends on the amount of methane in the seam, there are certainly serious environmental challenges associated with activity on this scale. These include forest cover degradation, dust release, habitat changes, and noise and exhaust concerns (US Department of the Interior 2003). In addition, there are problems associated with the water removal that accompanies CBM production. This water is occasionally potable but is often contaminated or highly saline, and can cause environmental harm. In the long term, water table levels and irrigation water might also become concerns (Robinson and Bauder 2001).

Coal-bed methane in India

CBM resources are found in many parts of the world and have the potential to become an important source of gas in India as well (Figure 1). There are rich CBM deposits available along the Damodar river basin in West Bengal, in areas such as Moonidih, Amalbad, and Kalidaspur. Mines around Raniganj and Jharia as well as parts of the Godavari basin can also be exploited.

India formulated its CBM policy in 1997 and a pilot-scale demonstration project has begun in Jharia at an estimated cost of 768.5 million rupees (Dutta 2006). A total of 16 contracts have been signed for exploration and production of CBM in the country and commercial production is expected to begin in 2007/08.[4] The Jharia project is a collaboration among the coal ministry, the Global Environment Facility, and the UNDP (United Nations Development Programme). It is expected that CBM might find economical uses in power generation, as a transportation fuel for mine dump trucks (already implemented at Moonidah and Sudamdih mines), as a feedstock for fertilizer plants (gas from Jharia may be used at Sindri) and in industries such as cement plants, refractories, and steel plants.[5] Methane injection into coal-fired blast furnaces has also been found to increase iron production and reduce coal consumption (Kurunov, Kornev, Loginov, *et al.* 2002). Transportation costs are a significant part of the total cost of natural gas and, therefore, finding such uses close to the mines themselves makes a great deal of economic sense.

Economics of coal-bed methane exploitation

While commercial extraction of CBM has taken place in countries such as the US or Australia, the project sizing is crucial for operational and economic feasibility. Without careful simplification and optimized cost reductions in conventional drilling equipment, accompanied by economies of scale, it is hard to achieve commercial viability (Wendell 2003). In addition, some of the newest techniques such as ECBMR with carbon dioxide injection still need to be proved commercially feasible. An economic analysis of these technologies carried out for the US Department of Energy in 2004 found that nitrogen injection is more economical than carbon dioxide injection (Reeves, Darrell, and Oudinot 2004). This, of course, would reduce the environmental benefits. Local conditions such as the permeability of coal, or the nature of the project site (greenfield or brownfield) were also found to have an important effect on the cost of the extracted gas. That said, some ECBMR projects using carbon dioxide injection, such as the Wasson (Denver) field in the US have shown promise both technically and commercially.

[3] For a detailed discussion of CBM formation and production, as well as environmental issues, see ALL Consulting and Montano Board of Oil and Gas Conservation (2004).

[4] Press Information Bureau, Government of India, 27 June 2006.

[5] The Central Mine Planning and Design Institute website is a useful resource for information on CBM prospects and uses in India. See <http://www.cmpdi.co.in/cmpdi/CBM.htm>. (Accessed 28 May 2006)

In India, most projects are still in the exploration phase. A significant economic challenge is posed by the need to import expertise, technology, and equipment from outside India (the US, Australia, and Germany are possible options). In order to initiate this process, India and the US are in the process of setting up the Coal Bed Methane and Coal Mine Methane Information Centre.[6] It has been estimated that a total capital expenditure of 2.2 billion dollars might be required to develop CBM in India (Kansal 2003). The ONGC (Oil and Natural Gas Corporation) has approved an investment proposal worth 9.5 billion rupees for exploration and development activities in Jharkand and West Bengal, marking India's first commercial exploitation of CBM.

Natural gas hydrates

Methane hydrates are formed when a molecule of methane is trapped inside a cage made up of water molecules. This cage-like structure, where there is no direct chemical bond between methane and water, is an example of a class of molecules called clathrates. The formation of such a structure requires the presence of methane and water, low temperatures and high pressures (there is a phase boundary beyond which the molecule will not form), and the right geochemical conditions.[7] Hydrates are normally classified as

1 marine hydrates (such as the US Blake Ridge Site) and
2 permafrost hydrates (Mallik site in Canada).

Extraction and exploration of gas hydrates

Hydrates are potentially a huge energy resource with recent estimates suggesting that methane hydrates contain between 500 and 2500 gigatonnes of carbon, as compared to 230 gigatonnes of carbon from all other natural gas sources (Milkov 2004). Unfortunately, there are severe technical challenges involved in both exploration and extraction.

The oldest way to detect gas hydrates has been through the use of seismic reflection surveys. This technique is based on the fact that hydrates in high concentrations stiffen the sediments they are in and alter seismic velocity. Other newer methods include geochemical and heat-flow surveys, sonar scans, and the analysis of samples using piston coring.[8] Exploration on a large scale requires actual drilling as is carried out by ships such as the research vessel—The Joides Resolution. One major problem in assessing reservoir sizes is that hydrates are only stable in a particular temperature and pressure range, outside which the structure disintegrates.

Different methods of recovering gas from hydrates include the *in-situ* dissociation of hydrate molecules through heating the reservoir, decreasing pressure or injecting an inhibitor such as methanol or glycol into the reservoir. Of these, depressurization seems to be the most economically promising approach (Collett 1998). As of now, there exists no proven technology to commercially extract natural gas trapped in hydrates. However, the Mallik 2002 Production Research Program[9] showed the technical feasibility of gas production.[10] It has also been suggested that the natural gas obtained from the Western Siberian Messoyakhskoya oil well in Russia comes partly from gas hydrates. More recently though, this claim has been debated in the literature (Collett and Ginsburg 1997).

[6] See the Ministry of External Affairs factsheet (2 March 2006) on the Indo–US energy dialogue for a number of other initiatives of this kind. <http://meaindia.nic.in/treatiesagreement/2006/02ta0203200601.htm>

[7] For more information on the formation and structure of methane hydrates, see the National Methane Hydrates R&D Programme website at <http://www.netl.doe.gov/technologies/oil-gas/FutureSupply/MethaneHydrates/about-hydrates/conditions.htm>.

[8] For an overview of methane hydrates, including extraction and exploration methods, see Boswell (2005).

[9] An international research project involving seven partner countries (including India) of the International Continental Scientific Drilling Programme. See <http://www.icdp-online.org/sites/mallik/news/index.html> for details.

[10] Official press release at the 'International Gas Hydrate Symposium: From Mallik to the Future', December 2003, Chiba City, Japan. Last accessed online on 26 May 2006. <http://www.icdponline.org/sites/mallik/news/pressReleases/Mallik_Chiba_PressV3.pdf>

Gas hydrate research efforts

Research into natural gas hydrates has been given considerable importance by a number of countries including India. In India, the National Institute of Oceanography, the National Institute of Ocean Technology, the National Gas Hydrate Programme, and the Department of Ocean Development are all working in this area. The ONGC has been engaged in exploratory work and has identified prospective areas in the Krishna–Godavari Basin, offshore Andaman and the Laccadive ridge in the Arabian Sea. The Ocean Drilling Program's research drill-ship, the Joides Resolution, carries an international crew of scientists and engineers from 11 nations. The ship has collected high quality gas hydrate samples from the Krishna–Godavari Basin, underscoring the potential of hydrates in India.

Outside of India, countries such as the US, Japan, and Canada have national hydrate research programmes.[11] In addition, firms such as Chevron Texaco, Schlumberger, and Haliburton have been jointly conducting a multi-year join industry research project on hydrates in the Gulf of Mexico. An interesting use of the hydrate molecular structure that is being explored is as a means of transporting gas, possibly much more cheaply than LNG (Gudmundsson and Borrehaug 1996; Gudmundsson and Graff 2003). This requires the technology to form the hydrates, store them in stable state for a significant length of time, and develop methods to efficiently extract the gas from the hydrate slurry afterwards. Advances such as gas-to-solid technologies may also play a significant role in commercializing this technique (Fitzgerald 2002).

Economics of methane hydrate exploitation

Methane hydrates remain many years away from any commercial exploitation, though the potentially massive resources across the world and the depletion of conventional sources have made them the subject of intense research. The US National Petroleum Council in 1992 published one of the few initial economic assessments, comparing the cost of gas from hydrates in Alaska to conventional gas. A multi-year economic assessment project is currently being carried out in Alaska (Howe, Nanchary, Patil, *et al*. 2004) including computer simulations of reserve production. Some experts[12] have speculated that gas hydrates might become profitable at natural gas prices of about 5 dollars per thousand cubic feet, but at this stage it is hard to make concrete statements. Economics aside, there are also serious concerns about the role of hydrates in the global carbon cycle and the implications of extraction on climate change.[13]

Deep natural gas

Deep natural gas is a term that refers to gas deposits found in wells that are much further underground (beyond 4000 metres) than conventional wells. Such resources occur in either conventional trap formations, or unconventional 'basin-centre' accumulations with spatial dimensions exceeding conventional fields. The formation of deep gas is a process that depends on a variety of factors, including the thermal stability of methane, the kinetics of the formation reaction, the nature of the source rock, and the presence of water (Dyman, Wyman, Kuuskraa, *et al*. 2002).

Extraction technology and ongoing research

Deep gas resources require advanced drilling and exploration techniques and are significantly more expensive than conventional wells. Successfully completing a well requires overcoming some very hostile drilling environments, with high temperatures and pressures and the presence of acid gases such as carbon dioxide and hydrogen sulphide (Dyman, Wyman, Kuuskraa, *et al*. 2002). However, the

[11] See Collett (2004) for a discussion of international hydrate research.

[12] Arthur H Johnson, President Hydrate Energy International and Adj. Research Professor, Tulane University quoted in **The Ice Meth Cometh**, *Chemical and Engineering News*, 17 August 2005. (Accessible at <http://pubs.acs.org/cen/news/83/i34/8334ebus1.html>. Last accessed on 30 June 2006)

[13] For cataclysmic possibilities, see the theory of a 'Methane Burp'.

technology to commercially drill such wells does exist and the US Department of Energy estimates that approximately 300 onshore deep wells were drilled in 2004. The Deep Trek research programme (US Department of Energy) is one major research initiative in advanced deep- drilling technologies. China possesses deep gas resources in the Daqing oilfield (Xujiaweizi). The China National Petroleum Corporation has been developing the technology to exploit these wells. In India, Reliance Industries in partnership with the Canadian company Niko Resources have discovered deep sea gas in the Krishna–Godavari Basin. This region has the potential to be developed as a major source of gas for the Indian market.

Economics of deep natural gas exploitation

Deep gas is significantly more expensive to extract than natural gas at conventional depths. The American Petroleum Institute Joint Association Survey on Drillings in 1996 estimated the cost of drilling and equipping an 180-metre onshore gas well in Texas to be 0.46 million dollars as compared to 5.2 million dollars for a 5000-metre deep well. Even so, while a deep well can cost more than twelve times as much as a conventional onshore well, they also produce about 40 times more output (Snead 2005). In addition, the much larger upfront investment in drilling costs, and the greater gas production from deep wells generates a much larger economic impact on the state. Estimates suggest that a deep well produces approximately six times the productive economic impact of wells below 4000 metres (Snead 2005). The increasing need for natural gas and the rise in prices are likely to make deep wells ever more attractive and economically viable.

Devonian shale gas

Shale[14] is a soft sedimentary rock with fine grains and is very often organically rich. Shale gas is gas contained within shale sequences, sometimes trapped between two thicker layers of shale. This kind of gas is found in the same types of sedimentary rock formations as shale oil. The gas is stored in two ways.

1 As adsorbed gas on kerogen (the source for shale oil), a waxy, organic, long-chain organic polymer found in the rock. This is a similar phenomenon to the way CBM is found.

2 Methane may also be present as free gas in the rock matrix and in fractures. While the form of the gas is similar to a conventional reservoir, here the shale is both the source and the reservoir rock. Organic matter within shale may be broken down into gas by either biological or thermogenic processes.[15]

Extraction technology and ongoing research

Shale gas is hard to extract for a number of reasons. Extensive fracturing is needed to sustain commercial production rates and typically, recovery and production rates are low. Because of this, a fairly high density of wells becomes necessary. There are also other serious environmental concerns including low efficiencies, greenhouse emissions, and extensive water use. That said, some of the impact of wide-scale drilling could be mitigated through measures such as intelligent field design and directional drilling from a single pad.[16] Much of the research into shale gas is concentrated in North America, by the Gas Technology Institute in Canada, the US Department of Energy, as well as private players such as Schlumberger Corporation.

Global shale gas potential

Shale gas has a long production history and potential as backstop energy source for conventional gas. As far back as 1926, gas was commercially extracted from the Devonian Shale of the Appalachian basin in the US.[17] Well costs in the Albany shale region of the US have ranged between a hundred and a hundred and fifty thousand dollars.[18] In 2002, shale gas made up

[14] Devonian shale was formed about 350 million years ago.

[15] The Canadian Society of Unconventional Gas provides an introductory discussion of shale gas among other unconventional forms on their website. See <http://www.csug.ca/faqs.html#Sa>

[16] Ibid

[17] On the other hand a lot of people believe that 'shale is the energy of the future and always will be!'

[18] Kathy Shirley. *Shale Gas Exciting Again*. Explorer (American Association of Petroleum Geologists), March 2001. Accessible at <http://www.aapg.org/explorer/2001/03mar/gas_shales.cfm>

only four per cent of US production (Faraj, *et al.* 2002). India has large shale deposits in Assam and Arunachal Pradesh that are typically near the surface, resulting in lower drilling costs. However, until date, the various difficulties involved in extracting oil or gas from shale have meant that these resources have remained unexploited. Large shale oil and gas deposits are also present in many other parts of the world, such as China, Inner Mongolia, the Barnett and Lewis shale fields in the US, and the Western Canada Sedimentary Basin region of North America.

Tight gas

Tight gas is natural gas trapped within very low permeability sandstone, hard rock or non-porous limestone. This gas may be under very high pressure if the rate of gas generation exceeds the rate at which gas escapes to the surface (Naik undated).

Extraction technology and ongoing research

Tight gas was first produced in the 1970s in the Western US's San Juan Basin. Currently, 19% of the US production comes from tight gas sands (Haines 2005). Production of tight gas is expensive as it requires advanced drilling techniques (such as directional and under balanced drilling), fracture stimulation (which has been done using nuclear and hydraulic energy), and the fact that well bores need to be very close to the gas in order to sustain reasonable gas recovery.[19] This forces the need for many thousands of wells and advanced technology in order for this resource to be made economically viable on a large scale. Improvements in extraction technologies include reservoir evaluation models, the use of MR (magnetic resonance) imaging, advances in perforation and multizone fracturing, and better well design and techniques such as refracturing, which help enhance production.[20] Research efforts, as with many other natural gas sources, have a strong base in the US (Department of Energy and the US Geological Survey) and Canada (Gas Technology Institute). There are also private initiatives by many oil majors to push tight gas production (ExxonMobil and Schlumberger for example).

In India, tight gas potential exists in the Assam Arakan fold thrust system, the foothill regions of Assam foreland, the Krishna–Godavari Basin, Kaveri and Mahanadi river basins, and the Tapti–Daman block of Bombay offshore. Research is being carried out by ONGC (and its affiliated institutes). Figure 2 shows the global distribution of tight gas resources.

Economics of tight gas exploitation

Though expensive to produce, tight gas resources have a history of commercial exploitation, especially in the US. The production was, however, aided by tax credits and high demand in the seventies and eighties. A study of a typical tight gas sites in the US estimated total well costs at 2.8 million dollars (Perry, Cleary, and Curtis 1998). Using current technology, the well recovered a cumulative 2.4 BCF (billion cubic feet) of gas over 10 years. With wellhead gas prices held at 1.50 dollars per thousand cubic

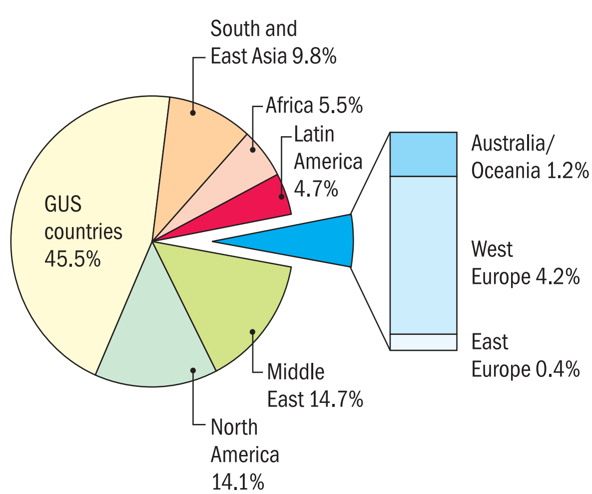

Figure 2 Distribution of global tight gas resources (modified from Gerling 2004)

[19] See Perry, Cleary, and Curtis (1998) for more information.

[20] The March 2005 issue of *The Oil and Gas Investor* has a special supplement on Tight Gas that is a good source of detailed information. (Accessible at <http://www.oilandgasinvestor.com/pdf/Tight%20Gas.pdf>. Last accessed on 29 May 2006.)

feet net to the well, this production proved insufficient to generate a positive return on investment. However, assuming the use of the most advanced technology, recovery was estimated to increase to 3 BCF and well costs reduced to 2.3 million dollars. At these amounts, the well provided a positive return on investment with a four-year payback period.

Tight gas resources could, therefore, come into play as a backstop energy source in the future. While a number of challenges need to be overcome, a combination of rising economic incentives and improving technologies makes the possibility of larger-scale global commercialization of tight gas resources more likely.

Geopressurized gas

Geopressurized gas is created in formations where compacted clay is present over a porous media such as sand or silt. Natural gas is squeezed out of the clay and enters the porous layer under very high pressure. These zones are typically at depths between 3000 and 8000 metres.[21] Very often, the reservoir exists in the form of hot brine aquifers saturated with methane (between 30 and 80 cubic feet of methane per barrel of fluid). It has been estimated that the total global resources of geopressurized brine gas could be as much as 110 times the world's current proved reserves (Smil 2003).

Extraction technology and ongoing research

Extracting gas from brine aquifers requires stripping methane from the pressurized aquifer and then re-injecting the degassed brine into the sand below the ground. Preliminary research has indicated that it is most economical to produce gas from brine aquifers of lower salinity and high volume (Griggs 2005). Geopressurized aquifers actually act as potential sources of hydraulic and thermal energy as well as chemical energy from natural gas. While proven commercial technology is still in a relatively nascent stage of development, small amounts of gas have been commercially produced in Italy, Japan, and the US. The Wells of Opportunity and Design Wells research programme in the US ran for almost a decade in the eighties and helped show the technical feasibility of extraction methods (Griggs 2005).

Conclusion

There is an increasing realization today that renewable energy alone cannot solve the world's problem of finding energy that is both environmentally sustainable and will meet our growing needs (Jaccard 2005). Natural gas being cleaner than coal and oil has some inherent advantages as a fuel source. In addition, our reliance on gas has begun to put conventional reserves under pressure. As technology improves, therefore, unconventional resources of gas are more and more likely to become ripe for exploitation, serving to increase our reserve base and allowing for greater usage of natural gas in many parts of the world.

However, not all the known sources of methane are likely to see commercial exploitation very soon. Resources of methane stored as hydrates or geopressurized aquifers, while extremely large, are still years away from commercialization. Currently these are exciting research prospects, but not options for the immediate future. Other unconventional sources, including tight gas resources, CBM and deep gas, are characterized by current production in some parts of the world and the existence of technology to make economic production feasible (in the presence of incentives such as high demand, energy security concerns or high gas prices). These kinds of gas resources might, therefore, come into play as backstop energy options.

From the point of view of India's energy security, the work we put into technology acquisition, research, and exploration over the next decade is crucial. CBM holds a great deal of promise, and is a resource that we are developing most actively. However, it is important to remember that CBM (with its associated environmental and implementation

[21] The web reference Naturalgas.org maintained by the Natural gas Supply Association is a good starting point for information on many unconventional sources of gas. Accessible at <http://www.naturalgas.org/overview/unconvent_ng_resource.asp>.

issues) is not quite a bed of roses and cannot be our only focus. Thus while India has been a part of global research into gas hydrates, more immediate options such as tight gas, deep gas, and shale gas also need to be explored thoroughly.

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Gas supply in India's diplomacy for energy security*

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Natural gas, being a 'clean' fuel, is increasingly seen as the fuel of the 21st century. Between 1980 and 2003, the share of natural gas in the world energy mix rose from 18% to 22%. The demand for gas is expected to increase at 2.3% per year till 2025, when it will constitute 25% of the world energy mix and consolidate its position as the number two fuel in the world's energy mix.

On the supply side, the prognosis relating to gas is quite comfortable—present resources can meet current demand for 60 years. With new discoveries, reserves could meet demand for 150 years at the present rate of consumption. Between 2002 and 2025, gas consumption will increase by nearly 70%. The electric power sector will account for almost one-half of the total incremental growth in worldwide natural gas demand over the forecast period.

Both pipelines and LNG (liquefied natural gas) have a role to play in transporting gas. Pipelines are best for shorter hauls and, thus, should dominate local and regional trade. Generally, LNG is cost-competitive with pipelines only over distances in excess of 4000 kilometres.

Today, out of the total global gas production of 2691 BCM (billion cubic metres), only 25% is internationally traded. 19% gas is being transported through trans-national pipelines, and 6% as LNG. Europe is the principal importer of gas by pipeline (320 BCM per year),

*The views expressed in this article are personal views of the author and do not reflect those of the organization.

followed by USA (102 BCM per year from Canada). Japan is the principal importer of LNG (77 BCM), followed by Europe (40 BCM), Republic of Korea (30 BCM) and USA (19 BCM). According to industry forecasts, international trade in natural gas is expected to increase significantly in coming years, accounting for one-third of the world output, by 2020. This increased trade will cover both LNG and piped gas. International trade in LNG is expected to grow by 7% per year till it becomes 38% of gas trade by 2020.

Trans-national gas pipelines

While oil pipelines have been in existence in different parts of the world since the early part of the 20th century, trans-national gas pipelines are of recent origin. The setting up of pipelines from the Former Soviet Union to Germany and later to other parts of Western Europe, in the 1970s and 1980s – at the height of the Cold War – was a political, financial, and commercial challenge. The increase in oil prices in the early 1970s encouraged Germany and other European countries to look for alternative forms of energy, particularly gas. In 1973, FRG (Federal Republic of Germany) received its first gas delivery from the Soviet Union. Over the years, German imports continued to increase, with supplies to FRG and GDR (German Democratic Republic) reaching 17.2 BCM in 1980. In the 1980s, Soviet gas supplies were extended to France and other major European countries.

These supplies from the Soviet Union took place amidst strong US opposition, which included extra-territorial sanctions on supply of equipment and technology. The US had concerns that the gas trade would not only provide the Soviet Union with additional hard currency but could also reduce European resolve to confront the 'evil empire' in the Cold War. However, the European countries remained firm in their resolve to import Soviet gas and, by 1989, the USSR met 30% of FRG gas demand. It is important to note that, throughout the Cold War when Soviet gas was reaching the FRG, as also West Berlin, never once were the supplies disrupted.

Since the end of the Cold War, Russian supplies of gas by pipeline to Europe have increased, going further eastwards to the UK, Belgium, and the Netherlands, in the early of part of 21st century.

Asian gas demand

Today, while the world's gas map depicts numerous gas pipelines moving across thousands of kilometres from Russia, Central Asia, and the North Sea to Western Europe, there are hardly any pipelines in Asia that move eastwards and southwards. This is now set to change due to two important factors:

1 the increasing Asian demand for gas and
2 the ability of Asia to transport gas economically from producers to consuming centres.

Over the next 25 years, the energy requirements of Asia are expected to increase two-and-a-half times, an increase of an additional 2.5 BTOE (billion tonnes of oil equivalent). Gas will have a significant place in this scenario. At present, Asia has much less share in gas demand than the world average (6% versus 12%). Hence, to meet Asia's rapidly increasing energy requirements, consumption of gas will have to increase. The expectation is that it will do so from 210 MTOE (million tonnes of oil equivalent) in 1997, through 600 MTOE in 2020, to 800 to 900 MTOE in 2030.

The principal sources of global gas lie in Asia. The Asian area of Russia has 27% of the world's proven reserves, followed by Iran (15%) and Qatar (14%). In fact, North and Central Asia and the Gulf between them have over 70% of world reserves. As against this, the principal consumers of Asia – China, Japan, Republic of Korea and India – together have less than two per cent of global reserves, with Japan and Korea having no reserves at all. At the same time, in 2004, the latter two countries imported just over 100 BCM of gas as LNG out of a total global LNG trade of 178 BCM.

The Indian hydrocarbon scene

The *Hydrocarbon Vision 2025*, published by the Government of India in February 2000, set out in stark terms India's energy security predicament: its crude oil self-sufficiency declined from 63% in 1989/90 to 30% in 2000/01. In 2024/25, crude oil self-sufficiency is expected to be a mere 15%.

The situation relating to gas is equally grim. From 49 BCM in 2006/07, India's demand for gas is expected to rise to 125 BCM in 2024/25. As against this, production from existing fields and discoveries is 52 BCM, leaving a gap of 75 BCM to be filled through new domestic discoveries and from imports. The electric power sector is projected to account for 71% of the total incremental growth in India's natural gas demand from 2000 to 2025. India's installed power capacity at present is based on coal (59%), hydro-power (26%), gas (10%), and nuclear (2%).

In order to obtain gas for its energy requirements, India is pursuing three options in tandem.

1 Development of domestic resources
2 Pursuit of long-term LNG contracts
3 Participation in trans-national gas pipeline projects

All these efforts have met with some success. Both foreign and Indian companies have announced major gas discoveries in India, particularly in the Krishna–Godavari Basin, and there are indications that the Bay of Bengal and the Andaman area have considerable gas potential. According to Indian oil experts, 20 TCF (trillion cubic feet) of gas reserves has already been established along the east coast; this area has the potential to yield as much as 100 TCF of gas, providing, over the next 10–15 years, between 250 and 350 MMSCMD (million metric standard cubic metres per day). With regard to LNG, India has entered into 25-year supply contracts with Qatar and Iran. LNG from Qatar is being received from 2004, while supplies from Iran will commence in 2009.

However, it is India's participation in the trans-national gas pipeline projects on its western and eastern land frontiers that has seized the imagination of strategic affairs and energy security writers, with robust discussions on these novel proposals (for India) taking place in seminar halls and the columns of our newspapers. This is not surprising, since trans-national pipelines involving India, though discussed over several years, have till recently been moribund. The present position of these projects is set out in the following paragraphs.

Iran–Pakistan–India gas pipeline project

The project has a sound commercial base as Iran has the world's second largest gas reserves, particularly offshore in the South Pars and North Pars fields (which it shares with Qatar). A pipeline from the Iranian collection centre of Assaluyeh on the Gulf to the Indian border would be about 1900 km, which is well within the range of economical gas supply by pipeline *vis-à-vis* LNG. Pakistan is gas-dependent, with gas constituting 50% of its energy mix, while India's requirement of gas, presently 7% in the energy mix, is expected to increase very significantly, particularly to provide fuel for the power plant projects in northern, north-western, and central India.

This project was first suggested in 1989 by Dr R K Pachauri of TERI and the then Iranian Deputy Oil Minister, Dr Ali Shams Ardekani, who later became Iran's Deputy Foreign Minister. Initially conceived as a tripartite Government-to-Government project, the project could not make any headway on account of Indo-Pak differences through the 1990s and the early part of the 21st century. The Gordian knot was cut only in January 2005 when, on the sidelines of the Round Table of Asian Oil Ministers, in New Delhi, the Indian and Iranian petroleum ministers agreed to commence negotiations on the project on the basis of India buying Iranian gas at the Pakistan–India border.

Initial discussions between Iran and India at officials' level led to considerable clarity on both sides with regard to the technical, commercial, financial, and legal issues pertaining to the project, a good learning experience for the Indian side that was pursuing a trans-national pipeline project for the first time in its energy history. These early discussions culminated, in June 2005, in the visit of the Indian Petroleum Minister to Pakistan and Iran. During these visits, it was agreed by the three countries that the project would be 'a safe and secure world-class project', and discussions pertaining to the project would be pursued bilaterally by JWG (Joint Working Groups) at the Secretary/ Deputy Minister level.

During the bilateral JWG meetings in New Delhi, in December 2005, it was agreed that sufficient progress had been made in understanding the various issues pertaining to the project and that it was now necessary to move to a tripartite format at officials' level. Accordingly, the first tripartite meeting was held in Tehran, in March 2006, followed by another in Islamabad in May. These meetings have addressed two issues that are fundamental to the future of the project, i.e., the structure of the project and the price of the Iranian gas to be supplied to Pakistan and India.

Considerable flexibility based on international experience is available to structure the proposed project to meet the various interests and compulsions of the three parties. Thus, one possibility would be to divide the project between its construction and operational phases, and insist on an integrated corporate structure during the 25–30-year operational phase, while possibly accepting a looser model during the 5-year construction phase.

The issue of gas price has got seriously complicated on account of the significant increases in global oil prices over the last year, to which the price of LNG and even of piped gas is pegged. Given the expectation that oil prices well over 50 dollars per barrel are likely to prevail for the foreseeable future, it can be safely anticipated that world gas prices will be significantly higher than those with which we have been familiar in the regulated market in India. However, now that deregulation of gas price is already under way, even domestically produced gas will, in due course, come to follow global trends. The negotiations for the price of the piped gas in respect of the Iran project, as also other pipeline projects, will have to take into account these global trends, particularly since, over the coming years, there will be a sharp scramble for gas in the US, Europe, and East Asia, besides India and Pakistan.

Though important issues remain to be resolved, the positive aspects of the discussions over the last year or so are listed below.

- The Government of India and companies' officials have acquired considerable knowledge and expertise with regard to trans-national pipeline projects.
- Again, in different sections of Indian opinion, there is now a greater familiarity with such projects, along with an understanding of the place of gas in our energy security, and the role of trans-national pipeline projects in this regard.
- Dialogue between Indian and Pakistani officials has been held in a cordial and constructive atmosphere, with agreement on several issues of common interest.
- Tripartite discussions at technical and officials' levels have yielded consensus on the specifications of the project as also clarity regarding options pertaining to project structure and gas price.
- Above all, the leaders of the three countries have repeatedly conveyed their full political support to the project and their deep interest in its successful outcome on the basis of commercial considerations, i.e., the project has been effectively removed from the domain of extraneous bilateral, regional, and global issues, and is being pursued only on the basis of economic considerations as part of the larger energy security interests of the countries concerned.

Turkmenistan–Afghanistan–Pakistan pipeline project

This project was first conceived in the 1990s to transport gas from Turkmenistan to Pakistan, and possibly to India. It was envisaged that this route would provide a new and valuable outlet for Turkmen gas which has been almost totally monopolized by the Russian company, Gazprom, which had piped it westwards to Europe. The project could not make any headway till recently on account of continued disturbed conditions in Afghanistan as also the state of Indo-Pak relations.

Following the installation of the Karzai government in Kabul, the project was revived, with the ADB (Asian Development Bank) being the lead development manager and consultant for the project. The heads of state of the three countries signed a Framework Agreement, in May 2002, extending their political support to the project and agreeing to facilitate the successful construction and operation of the project.

The Framework Agreement set up a Steering Committee at the ministerial level to pursue different aspects of the project. Nine meetings of the Steering Committee have been held so far, the last one taking place in Ashgabad, in February 2006, which India attended for the first time as an observer.

Till recently, two issues had delayed consideration of the project

1 whether Turkmenistan had the gas reserves to justify the project; and,
2 whether it was legally in a position to export this gas in light of concerns that its gas was legally committed to Russia.

The ninth meeting of the Steering Committee took place on the basis of assurances by Turkmenistan on both issues. Turkmenistan, on the basis of international certification provided by an international surveyor, confirmed that it had sufficient reserves to justify the project, and that it was free to export this gas to Pakistan and India. The three ministers also decided to issue a formal invitation to India to join the project, which would then become TAPI (Turkmenistan– Afghanistan–Pakistan–India). In May 2006, the Indian cabinet approved India's participation in the project.

The project has considerable geopolitical significance in that, for the first time, South Asia would have access to gas from Central Asia. Once the pipeline is operational, it is possible that Turkmenistan could evolve from a single source of gas to the pipeline into a regional hub, with pipelines from neighbouring countries, such as Uzbekistan, Kazakhstan, Azerbaijan and even Russia, linking up with this pipeline to meet the increasing demands of South Asia. In due course, pipelines from the Caspian region could also go to LNG terminals on the Gulf to transport Central Asian LNG to South-East Asia and North-East Asia.

Myanmar–Bangladesh–India pipeline project

Myanmar has good reserves of gas in its offshore area in the north, with Indian companies having a 20% share in two blocks. Other offshore areas are also being explored and developed at present. Myanmar's reserves are, perhaps, not as substantial as those of Iran and Central Asia. However, the country's proximity to India and the fact that the pipeline will not only bring Myanmar gas to India, but would also enable us to monetize Tripura gas and promote power and industrial projects in our north-eastern and eastern regions, have made the proposal attractive. The proposed route of the pipeline crosses Bangladesh territory and then terminates in Kolkata.

The political basis to carry the project forward was worked out in January 2005 when the petroleum ministers of India, Myanmar, and Bangladesh met in Yangon and concluded a tripartite joint press statement. In terms of this document, a trilateral MoU (memorandum of understanding) would be concluded at the ministerial level, which would set up a Techno-Economic Joint Committee to pursue the various details of the project.

However, the finalization of this MoU got stalled as Bangladesh insisted on including references to three specific bilateral Indo-Bangladesh issues in a preambular paragraph of the MoU. India objected to the inclusion of these references on the ground that the bilateral issues did not pertain to the pipeline project as such, and that the issues were, in any case, being pursued separately at other bilateral and regional fora.

Due to lack of progress in respect of routing the pipeline across Bangladesh, India is now examining the possibility of transporting Myanmar gas through an overland pipeline through the north-east, skirting Bangladesh, as also the possibility of transporting gas as compressed natural gas to receiving points on the east coast.

Gas for India's energy security

All the pipeline proposals with which India is involved are fraught with political and security-related problems that would need to be satisfactorily addressed. For these projects to be realized, we must first accept that they are extremely important, indeed critical, for India's energy security interests. Once this is understood, international best practices can readily yield arrangements that would be put in place with regard to all aspects of the projects – technical, financial, commercial, and legal – that would serve to insulate the projects from the vagaries of day-to-day politics and provide the desired level of comfort to our policy-makers.

In order to understand the crucial role of these pipeline projects for India's energy security, we must have some understanding of their place in our energy mix.

The bulk of the gas required by India is destined to be used to fuel power projects in order to sustain a growth rate of 8% per year. To achieve this, as the Kirit Parikh report[1] has noted, by 2032, India's primary energy supply would have to increase three to four times, while electricity supply would have to increase five to seven times, i.e., power generation would have to increase from 120 000 MW to 778 000 MW by 2031/32.

To reach these targets, India would need to pursue all available fuel options and energy forms—conventional and non-conventional. However, the factual position in respect of specific energy resources has to be noted. Today, India's energy mix comprises coal 50%, oil and gas 45%, hydropower 2%, and nuclear 1.5%. In 2022, fossil fuels will continue to dominate India's energy mix to the extent of 75%, with hydropower providing 14%, and nuclear power 6.5%. Even robust votaries of nuclear power have noted that, most optimistically, nuclear energy will provide only 8.8% in India's energy mix in 2032, as against 76% for fossil fuels, and 12% for hydropower. In 2052, when nuclear energy is likely to be 16.4% of our energy mix, coal is expected to be 40%, hydrocarbons 35%, and hydropower 5.1%.

Coal will continue to be the principal fuel in our power projects. Today, 90% of coal used for power generation is from domestic sources. However, with coal mines depleting rapidly, together with concerns pertaining to pollution on account of the high ash content of domestic coal, India will have to increasingly look at other energy sources to meet its power requirements. According to TERI estimates, India's coal requirements will increase from the current level of 360 MT (million tonnes) to about 1650 MT by 2031/32. However, with consistent deterioration in coal quality and availability, just 650 MT is expected to be available by 2031. Thus, by 2031, India will be importing gas and coal for its power requirements.

Cost of imported coal has been rising in tandem with the international price of oil and gas. Besides this, significant increases in coal import would require augmentation of India's port-handling capabilities, as also upgradation of the domestic rail network, besides installation of anti-pollution measures in the power projects. Thus, India's increased power generation requirements will see a competition among domestic coal, imported coal, and imported gas, though industry assessments are that power generation using imported gas (piped gas and LNG) is commercially more attractive than imported coal.

Trans-national pipelines are difficult and complex ventures since

- they involve different countries with differing interests;
- being trans-national in character, and involving neighbouring countries, they frequently carry a substantial and complex political baggage of disharmony and discord; and,
- the projects are beset with serious technical and financial difficulties, requiring the mobilization of huge resources from domestic and international sources in an environment of mutual trust and confidence.

These problems are particularly daunting in an Asian environment, which has been the stage of considerable intra-continental discord and conflict, and has relatively few success stories with regard to regional and continental cooperation. It is also true that some of the issues that divide Asian countries, particularly neighbours, are fairly complex and are unlikely to be resolved in the near future.

At the same time, it should be noted that the international community, over the last 35 years, during which thousands of kilometres of oil and gas pipelines have been laid across all our continents, has developed laws, rules, norms, and practices that ensure that pipelines can be

[1] Draft Report of the Expert Committee on Integrated Energy Policy

insulated to a considerable extent from the vagaries of day-to-day politics and made 'safe and secure' on the basis of international best practices. Not surprisingly, today 130 trans-continental pipeline projects, valued at 200 billion dollars, are at various stages of implementation in Europe, Africa, North and Latin America, and, above all, Asia.

While the challenges involved in the implementation of trans-national pipeline projects are serious, what gives them impetus is the common interest of oil and gas producers to have stable markets for their products and for consumers to have assured supplies to maintain their economic development programmes. Though Asia has relatively little experience of trans-national oil and gas pipelines, the availability of abundant hydrocarbons within the continent, as also the overwhelming demand for this resource, ensures that concerns of national security and energy security can and should coalesce.

Complementary interests in energy security of producers and consumers constitute the strongest factor in enabling policy-makers to replace contemporary political discord with energy-based cooperation.

Natural gas supply and pricing issues in India

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Given the oft-repeated pluses for natural gas becoming a preferred fuel source for India, various projections have been made for natural gas demand in India over the next five years. Based on these projections and taking into account future domestic gas production, it would be reasonable to assume an import requirement of 150 MMSCMD* (million metric standard cubic metres a day) by 2011/12. This includes the current import of 20 MMSCMD in the form of LNG (liquefied natural gas) by the Petronet LNG terminal at Dahej.

Based on the current landed price of LNG at Dahej at around 2.80 dollars per MMBtu (million metric British thermal unit) (a very conservative one given today's high prices), this import requirement translates to a foreign exchange outgoing of 5.5 billion dollars per year. In more realistic costing terms, this figure could easily double or triple. Given that long-term contracts of about 20 years generally govern gas supplies, the pricing of gas is critical to the successful outcome of negotiations. It is, therefore, important to understand how gas prices have evolved in India against an increasing range of supply sources and delivery systems and the outlook for the future.

Gas at administered prices

In 1997, the government decided to link, in stages, the domestic price of gas to the price of a basket of international fuel oil prices based on calorie equivalence and to achieve 100% parity in 2001/02. At that time, the only significant producer was ONGC (Oil and Natural Gas Corporation) and as fuel oil prices were low, consumers were happy. However, when crude oil prices started rising from 2002 onwards and with it fuel oil prices, government did not permit domestic gas prices to rise proportionately, mainly to give protection to the power and fertilizer sectors. Meanwhile, E&P (exploration and production) companies under the NELP (New Exploration and Licensing Policy) discovered gas and they were allowed to negotiate prices with consumers. Recently, taking into account ground realities, the government increased the domestic price of gas to the power and fertilizer sectors from 1.80 dollars per MMBtu to 2.12 dollars per MMBtu, while prices to other consumers were benchmarked at the LNG landed price. This has led to a range of natural gas prices in India.

* 4 MMSCMD is equivalent to 1 million tonne of LNG required to feed a 1000-MW modern power station for one year. Crude oil at 70 dollars per barrel is equivalent to 12 dollars per MMBtu in heat value

Liquefied natural gas imports

With the commissioning of Petronet LNG's regasification plant in Dahej, imported gas made its entry into India. Petronet LNG signed a very favourable contract with RasGas of Qatar for a fixed price of 2.53 dollars per MMBtu FOB (free on board) till 2009 (thereafter to be crude oil indexed). Adding a shipping charge of about 0.28 dollars per MMBtu and regasification charge of 0.50 dollars per MMBtu, the ex-plant price, excluding taxes works out to 3.31 dollars per MMBtu. More recently, gas prices across the world have escalated in tandem with crude oil prices which are hovering around 74 dollars per barrel (July 2006). The Shell terminal at Hazira with a capacity of 2.5 MMTPA (million metric tonnes per annum) was commissioned in April 2005 with no firm contract for supply and has had to make ad-hoc purchases at much higher prices compared to Petronet LNG. It has faced considerable difficulty in marketing its gas, which has been pitched below the naphtha price to attract power companies and other units using naphtha. Enron's Dabhol plant, which has been idle for the last few years, is now being revived by the new management, Ratnagiri Gas and Power Pvt. Ltd. Here also it has not been possible to tie up a long-term supply of LNG, due to limited availability internationally, as also the desire to secure the best possible price. Meanwhile, the plant has been started on naphtha, which had been acquired earlier.

Discussions with Iran on the supply of LNG have been on the table for quite sometime. In 2005, Iran had agreed to supply India 5 MMTPA of LNG at 3.215 dollars per MMBtu FOB, somewhat higher than that contracted with Qatar. However, when Iran's Deputy Oil Minister Mr Hosseinian visited India in May 2006, he said that the Supreme Economic Council of Iran wanted to renegotiate the deal as the price offered was too low and, more importantly, no firm contract existed, as it had not approved the deal. The Indian government insisted that a valid contract was in place. In view of the fact that international gas prices have increased substantially, it remains to be seen whether India accepts the new Iranian position and agrees to buy LNG at considerably higher prices. However, the whole issue may become an academic one, if Iran is not able to access technology for liquefying the gas, which is mainly with the Americans.

The uncertainty with regard to pipeline imports

A proposal to bring gas by pipeline from Iran through Pakistan was mooted as early as in 1989. Here again, though discussions on a number of issues relating to demand numbers (60 MMSCMD to Pakistan and 90 MMSCMD to India), pipeline costs, project structure, financing, and security have recently taken place, the basic issue of the price at which gas will be made available at the pipeline entry point is still to be clinched. A couple of years back, a price of about 1.2 dollars per MMBtu at the wellhead seemed reasonable. Adding pipeline transportation costs and transit fees to Pakistan, will take the delivered cost at India's border to about 2.50 dollars per MMBtu. In view of the increase in international prices, it is understood that India is prepared to pay up to 4.2 dollars per MMBtu. India has also asked for a transparent structure where wellhead price, pipeline transportation costs and transit fees are separately identified. As in the case of LNG, Iran is looking at a much higher price for piped gas, reportedly 7.2 dollars per MMBtu. In this particular case, no contract exists. Iran has now stepped up the ante by saying that India should clinch the deal by July 2006, as otherwise it would proceed on a bilateral basis with Pakistan. Dealing with Iran on purely commercial terms has not been without its hazards, as has been seen. However, nowhere in the world is there a potential source of plentiful gas supply located in such close proximity to a hungry market. Further, Iran has few other options to monetize its gas by way of exports. Therefore, though Iran has reneged on the contract for LNG, it should not deter us from keeping the window open for further discussions on the pipeline deal.

India has finally come on board the ADB-sponsored (Asian Development Bank-sponsored) proposal to extend the planned Turkmenistan– Afghanistan–Pakistan gas pipeline to India, which is not without its own security problems and doubts on total gas reserves in Turkmenistan. The planned pipeline from Myanmar will now bypass Bangladesh and loop over the north-eastern states before entering Bihar; a circuitous route necessitated by Bangladesh not agreeing to allow the pipeline to pass through its territory. In both cases, no serious discussions on pricing seem to have taken place—perplexing in view of the price differences with Iran.

Need to engage with the ECT

The ECT (Energy Charter Treaty) was signed in December 1994 and came into force in April 1998. The Treaty is a legally-binding multilateral agreement and the only one dealing specifically with inter-governmental cooperation in the energy sector. The focus currently is mainly on gas pipelines but its charter also covers grid power.

Fifty-one countries are signatories to the Treaty including the CIS (Commonwealth of Independent States) and almost all the countries of western Europe. Russia has signed the Treaty but is yet to ratify it. Pakistan and Iran are observers—the first step to becoming members. India is not yet an observer to the Treaty and has been mulling over the issue for more than a year.

The Treaty's provisions focus on five broad areas: investment, trade, transit, energy efficiency, and dispute resolution. The investment-related provisions are regarded as a cornerstone of the Treaty. The focus is on protection and promotion of foreign energy investments based on the extension of national treatment, or most-favoured nation treatment, whichever is more favourable. There is a back-up mechanism for both inter-state arbitration and investor-dispute settlement. Foreign investors can sue the host country for any alleged breach of an agreement in a domestic court of the host country or submit it to international arbitration, which is binding and final.

The second area is trade, where all charter member states, whether belonging to the WTO (World Trade Organization) or not, subscribe to WTO rules for energy trading. This applies equally to energy suppliers, transit and consumer countries.

The third and, perhaps, most important area from India's viewpoint is the issue of transit, as the pipeline from Iran would have to cross Pakistan. The Treaty's transit provisions require that members facilitate energy transit without distinction as to the origin, destination or ownership of energy, or discrimination as to pricing, and without imposing any unreasonable delays, restrictions or charges. A contracting party shall not interfere with the transit of energy in the event of a dispute and shall have to abide by the dispute resolution procedures of the Treaty. The Treaty also recognizes that it is very important that there are no disadvantages to the transit country. All costs and risks have to be addressed and covered, which must have some incentive in the form of fees and taxes to allow for transit facilities. In view of the importance of transit, it is proposed to establish a detailed transit protocol to make transparent the criteria for setting cost-based transit tariffs and to promote the effective settlement of transit disputes.

The fourth area is to promote energy efficiency amongst its members. This is not so much with regard to any hard legal obligations but more on implementation of measures to improve energy efficiency, thereby reducing the negative environmental impact of the energy cycle.

Finally, the Treaty has a dispute settlement mechanism, which makes an initial conciliation phase mandatory. If that fails, parties can start the international arbitration process. The final award would be enforceable against the defaulting country including its assets throughout the world, if it has ratified the New York Convention.

An important feature of the ECT is that should a country quit the Treaty, the transit and trade provisions will continue to apply for one year thereafter and the investment provisions for a period of 20 years. The aim is to protect foreign investors from political risks. However, expropriation/nationalization is permitted if it is for a public purpose and the investor is adequately compensated at fair market value.

Recent domestic natural gas finds

While production from mature gas fields are in decline and imports, not only from Iran but also from Myanmar and Turkmenistan are clouded in uncertainties, the saving grace has been the large discoveries by Reliance (14 TCF [trillion cubic feet]) and GSPC (Gujarat State Petroleum Corporation) (20 TCF) in offshore fields in the KG Basin (Krishna–Godavari Basin). The

ONGC is also awaiting certification before announcing its find.

The Mukesh Ambani-headed Reliance Industries Ltd hopes to bring the gas onshore and feed it initially to the NTPC's (National Thermal Power Corporation's) expansion plants in Gujarat and to Anil Ambani-headed Reliance Natural Resources' proposed 5600-MW power plant at Dadri in Uttar Pradesh. Though the delivered price of 3.27 dollars per MMBtu offered by Reliance to NTPC is a very attractive one under present circumstances, the deal has hit a roadblock, as Reliance Industries wants a cap on its liability to supply an alternative fuel in case of failure to supply gas. The NTPC has gone to court but is hopeful of resolving the issue through mutual discussions under the aegis of the Cabinet Secretary. The same price has been offered to the Reliance Natural Resources' Dadri project. The petroleum ministry has to approve the basis of the price. Reliance also has ambitious plans to supply gas to domestic and commercial consumers in cities that fall along the alignment of the pipeline.

The GSPC is still to develop its plans, of which not much is known, but based on its reserves is capable of supplying 57 MMSCMD. Therefore, one of the first issues that the shortly-to-be-appointed Regulator will have to tackle is providing clarity to the pipeline clauses in the Regulatory Board Bill on common and contract carriage, open access, etc.

The supply by Reliance Industries to NTPC and the Dadri Project will absorb about 32 MMSCMD of gas, as against Reliance's total supply projections of 40 MMSCMD. There are unconfirmed reports that Reliance's reserves are higher than stated and could supply as much as 80 MMSCMD, which, together with GSPC's 57 MMSCMD, totals 137 MMSCMD. This excludes whatever production ONGC may table in the future from the KG Basin once their reserves are fully established. In comparison, the availability to India from the Iran–Pakistan–India pipeline could reduce to only 57 MMSCMD, after taking into account Iran's recently tabled own requirement in the eastern part of the country and Pakistan's revised demand figure. Whether or not the Iran deal materializes, it is essential that a detailed price-sensitive demand analysis in various parts of the country is made, as the earlier figures under the *Hydrocarbon Vision* and the ADB study are out of date. A year-by-year plan on how this demand will be met from various sources including the infrastructure requirement, e.g. transmission and distribution pipelines and storage, needs to be quickly determined. The present basis of working only on broad numbers no longer serves the purpose.

Getting real

Despite the recent finds, and the general enthusiasm with natural gas as an important fuel for India's future, there is need for a good deal of work on three issues: (1) gas infrastructure, which is inadequate and insufficient to link the producer to the consumer; (2) natural gas pricing; and (3) greater pipeline diplomacy and commitment if pipeline imports are to become real. While administered pricing may continue for sometime and may see some gradual escalation, output from ONGC's and Oil India Ltd's ageing fields will decline. The Gas Linkage Committee has been disbanded as no additional APM (administered pricing mechanism) gas is available and new compressed natural gas markets will not get gas at APM prices. Consumers who are using more expensive fuels such as naphtha (currently priced at around 18 dollars per MMBtu) and those who are not getting the full requirement of APM gas have already started buying imported gas or from NELP producers in recognition that high gas prices are here to stay and other options are more expensive or not available. GAIL (India) Ltd has secured two LNG cargoes from Algeria (the biggest exporter of LNG to Europe) at around 9 dollars per MMBtu and is confident that, even after shipping and regasification charges, it will be able to market the entire quantity. Petronet LNG has done even better by contracting a cargo from Egypt at 7.6 dollars per MMBtu ex-ship. In the short term, spot purchases of LNG cargoes seem to be the only way of augmenting gas availability as gas from the KG Basin will not come onshore till 2009 and output from all present and proposed LNG export terminals in the region appears to be committed till 2010 under long-term contracts.

Centre for Research on Energy Security

CeRES (Centre for Research on Energy Security) was set up on 31 May 2005. The objective of the Centre is to conduct research and provide analysis, information, and direction on issues related to energy security in India. It aims to track global energy demands, supply, prices, and technological research/breakthroughs – both in the present and for the future – and analyse their implications for global as well as India's energy security, and in relation to the energy needs of the poor. Its mission is also to engage in international, regional, and national dialogues on energy security issues, form strategic partnerships with various countries, and take initiatives that would be in India's and the region's long-term energy interest. *Energy Security Insights* is a quarterly bulletin of CeRES that seeks to establish a multi-stakeholder dialogue on these issues.

Previous issues of this newsletter are available at **<http://www.teriin.org/div_inside.php?id=41&m=3>**.

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