Gas and the Attractions of Project Finance

By Rod Morrison

Some $65 billion of project finance debt has been raised to develop LNG into the global business it is today. This article will look at how the project finance markets have followed the development of the LNG business and profile the use of project finance elsewhere in the gas industry.

Project finance is a specialised form of debt finance. It involves lending to a project company set up for the sole purpose of developing an individual development. The banks have limited recourse back to the corporate sponsors of the project. The debt is simply repaid from the cash flows generated by the project itself and from nowhere else.

This form of finance is not popular with the international oil companies (IOCs). It is time consuming and fairly legalistic. As the project company is the only source of cashflow, all the contracts surrounding the project need to be analysed in some depth and the banks need to take security over the assets of the project company. In addition, project finance debt is usually more expensive than standard debt backed by corporate balance sheets.

So why then has project finance been so popular in the LNG arena? The main reason is that LNG schemes tend to be developed on a joint venture basis by a national oil company (NOC) and IOC partners. The NOCs are not as cash rich as the IOCs and rather than spending money from national budgets on a new LNG plant, it is far more efficient to raise as much debt as possible, backed by the future project revenues.

The prime example of this approach is Qatar, which has raised roughly two-thirds of global LNG project finance via its NOC, Qatar Petroleum (QP). The QP business model is to fund a scheme with 30% equity and 70% debt. It takes 70% of the equity in the project company with the IOC partner taking the other 30%. QP then raises project finance debt at very competitive terms. In addition, the IOC partner is usually required to put in its own billion-dollar-plus shareholders loans as part of the financing package.

While the Qataris have called a moratorium on new gas-related projects until 2012, previously approved projects mean that they have dominated the LNG development market recently, raising $10 billion on new upstream plants.

The Qatari capital Doha – Qatar's economy is growing strongly and it has raised two-thirds of global LNG project finance.

There are plenty of other gas-rich countries interested in raising LNG debt such as Yemen, where Yemen LNG's plant at Balhaf is due to start up in December with the first delivery shortly thereafter.

There are plenty of other gas-rich countries interested in raising LNG debt. Two new LNG producers will require significant project finance very soon – Yemen LNG is seeking $1.7 billion and Sakhalin II in Russia is seeking $6 billion. And Australia and Papua New Guinea will shortly need significant sums to fund their LNG industrial development.

Downstream, the LNG regas terminals in the receiving countries often require project finance. The biggest market has been the US where small niche developers, again lacking big balance sheets, have raised project finance. This market has, however, slowed down in the past year as US gas prices have cooled and focus in the LNG market has once again shifted to Asia.

The other part of the LNG project finance market is shipping. Significant sums have been raised to pay for building ships, using a financing technique which is a hybrid between traditional shipping charter-based finance and traditional project finance.

Key players

The full first review of the global LNG project finance debt market was published in the *Project Finance International* 'LNG Finance' management report in mid-2005. This report stated that $44.1 billion had been raised for the LNG industry, with $135 billion still needed for further build-outs. Since then, *PFI* calculates that the figure raised has increased to $65.6 billion. And the sums still needed in the future remain very high. But timing of new projects is, of course, an issue. The development of the Iranian LNG industry has been very slow, for a number of reasons, while Russia has made limited progress too. These are the world's two largest gas producers and have the potential to be major LNG producers.

Sakhalin II, now majority owned by Gazprom, will be an important milestone for the project finance market. Another huge potential producer is Nigeria. But it has seen its recent project developments stalled – hit by local politics and rising global construction prices.

The $65.6 billion figure is split three ways. The LNG upstream terminals accounted for $42.7 billion – up from $28 billion in mid-2005. Within this figure bank debt provided $29.8 billion for terminals, bonds $5.7 billion and sponsor loans to projects, $7.2 billion. Given the importance of LNG to Japan, it is not surprising that four of the top five lenders to the LNG upstream sector are Japanese: Mizuho followed by French bank Calyon and then Bank of Tokyo-Mitsubishi, state export bank JBIC and SMBC. Royal Bank of Scotland, Citigroup, Gulf International Bank, Bank of Taiwan and Apicorp make up the rest of the top 10.

Goldman Sachs leads the bond underwriters followed by Lehman Brothers and Credit Suisse. ExxonMobil heads the sponsor loan providers by some way, $4 billion to ConocoPhillips' and Shell's $1.2 billion, with Itochu and Nissho Iwai providing $432 million each. Royal Bank of Scotland and Citigroup lead the financial advisor tables on these deals with four each, followed by Société Générale (SG) and Mizuho with three each. By country Qatar has raised $28.5 billion with Oman next on $5.4 billion.

In the regas terminal sector $8.9 billion of project finance has now been raised, up from $5.8 billion in mid-2005. Credit Suisse leads the fund providers in this table thanks to its $2 billion Sabine Pass financing from late 2006 in the US. Royal Bank of Scotland, BBVA, Citigroup and Caixa Galicia are the other top five lenders. Nearly half the debt has been raised in the US, $4 billion, with Spain next – as can be guessed from the inclusion of two Spanish banks in the top five lenders. Canada, China, India, Portugal and the UK have been the other markets for regas terminal project finance.

In the shipping sector, $14 billion has been raised, up from $6.8 billion in mid-2005. Royal Bank of Scotland leads the lenders followed by South Korean state export bank Kexim, given South Korea's involvement in building LNG ships, then Calyon, SG and SMBC. Qatar has raised $8.1 billion for its new LNG shipping fleet and Nigeria has raised $1.5 billion, followed by deals originated in South Korea and the UK.

These are the stark fund raising numbers but they tell only a small part of the story. Since the mid-1990s the LNG industry and the project finance market have changed together. Back then three-quarters of LNG sales went to Japan and South Korea. Project financings of LNG schemes were backed by solid sales contracts from credit-worthy Far Eastern utility buyers. Each scheme had two or three sales contracts to provide the project finance banks with the comfort they needed to lend to the project. But into the new century, the need for solid offtakes became less as the industry grew globally; Japan and South Korea are still the top customers but now account for just over half of sales. Bankers are prepared to accept less firm offtake commitments and allow project sponsors to pick their own destinations for LNG cargoes.

The best way to illustrate the changing nature of LNG finance is to review the most recent deals in the market. Nearly all the illustrations show that the lending terms for the LNG industry have relaxed. Banks now require fewer covenants on deals in the sector, and lending margins have substantially reduced. But it should be noted the relaxation of banking terms have come, not only as the LNG industry has grown, but during the global credit boom over the last few years. That boom has now ended and the global credit crunch which began last summer is having an impact on the LNG sector. But this will not turn the clock back on the financial innovations.

RasGas and Qatargas

The first scheme to review is Ras Laffan 2 & 3, the largest of the LNG upstream deals. It took the idea of funding an LNG business, rather than an LNG project, to its logical limit. The QP/Exxon joint venture has put in place a $13.5 billion financing programme to fund three new trains – 5, 6 and 7. Cashflow from trains 3 and 4 was used to help

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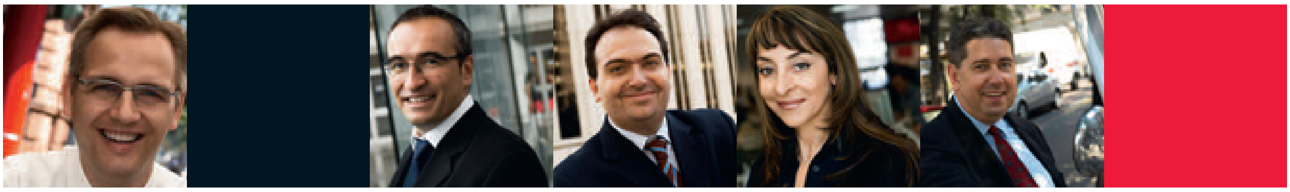
Peru PERU LNG Peru LNG **USD 2.25 Billion** LNG Export Facility **Financial Advisor**	**Qatar** QATARGAS 3 Qatargas 3 **USD 4.04 Billion** LNG Export Facility **Financial Advisor, Mandated Lead Arranger & Bookrunner**	**Indonesia** TANGGUH LNG Tangguh LNG **USD 3.5 Billion** LNG Export Facility **Financial Advisor**
Egypt Liquefied Natural Gas Egyptian LNG Egyptian LNG **Train 1 USD 950 Million** **Train 2 USD 880 Million** LNG Export Facility **Financial Advisor & Mandated Lead Arranger**	**United States** CHENIERE Sabine Pass **USD 1.5 Billion** LNG Import Terminal + Expansion Project **Joint Lead Arranger**	**UK** قطر للبترول Qatar Petroleum ExxonMobil South Hook LNG Terminal Co **GBP 420 Million** LNG Import Terminal **Mandated Lead Arranger & Bookrunner**



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Work is underway on the Qatargas 3 & 4 projects, whose financing closed in 2006 and 2007 respectively.

service the debt, thus making the cost of finance cheaper.

The financing is not banked on specific offtake contracts but instead on a suite of contracts to the US, Europe and India. The project company will retain the right to sell elsewhere as well. The project will need to sell a lot of LNG – trains 6 and 7 will each produce 7.8 mtpa. But annual revenues, according to the rating agency notes accompanying the financing, will hit $8.6 billion in 2010. Standard & Poor's, which gave the deal a high A+ rating, said the breakeven cost of the project was just $2.61 per million Btu. The debt service cover ratio (DSCR), which shows how much cash can cover the interest payments, is a high 5.17x.

The first part of the programme was put together in late 2005. It was made up of $970 million raised in the bank market, at a low 0.45% to 0.65% margin over libor on the 15-year loan, and $2.25 billion from the bond market – priced at 1.3% and 0.97% over treasuries for 15- and 22-year bond issues. ExxonMobil put a $1.4 billion shareholder loan into the deal. Then in 2006 a further $2.2 billion was raised in the programme – $1.55 billion from the bond market and $650 million from Exxon. However the bond pricing was slightly higher at 1.13% and 1.48% over treasuries. And now the state of the global bond market means further bond issuance in the programme will be unlikely, although the bank market is very much still open for business. The benefit of the bond route is that it provides a long tenor on the debt and has fewer covenants within the financing structure but the market can be more volatile than the bank market.

Qatar has also transacted two large traditional project financings for Qatargas 3 and 4, which will each have one train with a capacity of 7.8 mtpa.

Qatargas 3 raised $1.5 billion from the bank market in 2006 at the very low margin of 0.45% rising to 0.7% over the life of the 16-year loan. Japan's JBIC put $1 billion into the deal, US Exim $300 million and project co-sponsor ConocoPhillips $1.2 billion. Plans for a bond issue on the development have been dropped, however. Conoco will buy the gas under a 25-year offtake contract from

Commissioning of the Sakhalin II LNG plant is underway and exports are due to start later in the year.

the scheme and be able to send it into the Atlantic Basin – either into the US via its own Freeport terminal or into Europe. The banks take the price risk on the gas.

Qatargas 4 followed and reached financial close in 2007. It raised $2.8 billion from the bank market via a 16-year loan priced at 0.3% rising to 0.6%. Co-sponsor Shell is providing $1.2 billion. Plans for a bond have been dropped. Again the scheme is aimed at the Atlantic Basin market with Shell buying the gas under long-term contract and then selling it into the best market. Most of the gas has been earmarked for the US but could divert. DSCR is fairly high at 2.9x.

● Yemen and Sakhalin

Now Qatari development activity is slowing, the next two deals into the market will be Yemen LNG and Sakhalin II. These have been long-running sagas but that is the nature of the large project development business.

The Yemen LNG terminal is actually nearly built by the sponsor group led by Total, Yemen Gas Company and Hunt Oil. The 15-year $1.7 billon debt package will, however, refinance shareholder financing and improve project returns. This deal will have a slightly more old-fashioned feel. Half the bank loan will be backed by export credit agencies, which provide political and commercial cover to the banks, and the other half will be uncovered. The scheme's financing has been delayed by disputes over the ownership of the gas field supplying the project. These have now been resolved.

The Sakhalin II financing in Russia has been delayed by rising construction costs and the well publicised entrance of a new majority shareholder into the scheme – Gazprom. Again the actual project is almost built. The $20 billion development will be raising $6 billion of debt with $1.5 billion coming from the commercial banks and the rest from the various multilateral agencies led by JBIC.

After these two schemes attention will then shift to western Australia and Papua New Guinea, where four mega-projects are chasing buyers. Various banks have been appointed to advise on financing options on each scheme.

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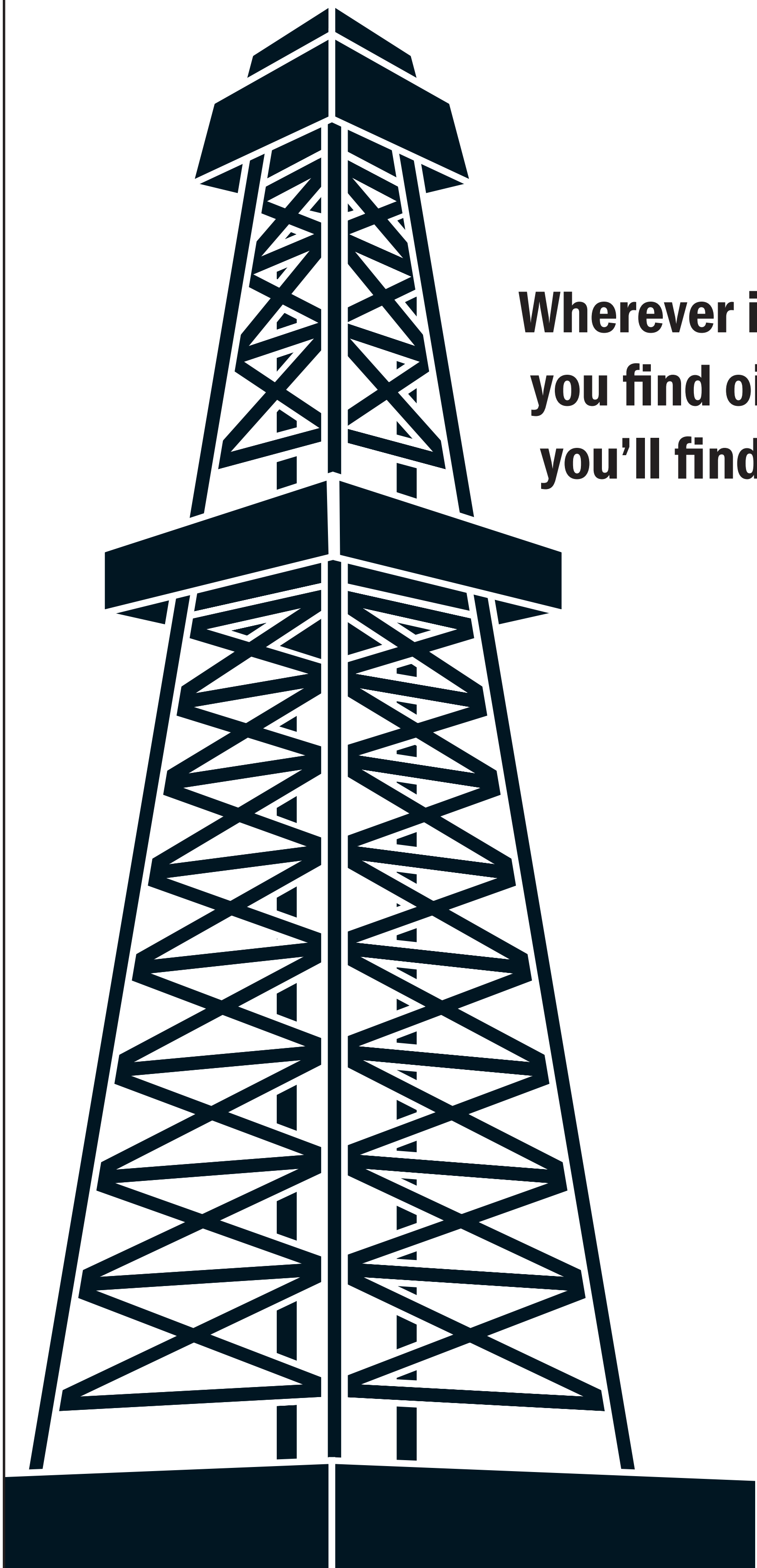

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Regas and shipping projects

At the receiving end of the LNG chain, the regas terminal financing market remains active, particularly in Europe. Until recently, however, the US market was the focus. Twenty-nine regas schemes had received approval in the US and a dozen more were on the cusp. But the boom has cooled. One New York banker was recently quoted in *PFI* as saying US terminal developers needed long-term intake contracts but these are becoming harder to obtain as LNG suppliers can find better prices in Asia.

The height of the North American regas terminal financing boom can be illustrated by two deals done in 2006. Niche developer Cheniere Energy raised a $2 billion high-yield bond for its Sabine Pass scheme in Louisiana. The company has gradually been increasing the size of its debt and the deal refinanced a loan taken out only four months before. As a high-yield bond, rated below investment grade at BB, the credit did not have to be as strong as investment grade deals. There was no fixed-price EPC on the second phase of the project and Cheniere Energy will be a significant intaker of the gas, alongside Total and Chevron. The deal priced at an attractive 7.25% and 7.5%. However, since it was done, the US high-yield bond market has collapsed so this could not be repeated.

Repsol and Irving Oil put together a more traditional utility type $675 million bank financing for its Canaport LNG deal. The deal was arranged and syndicated to traditional European project finance banks and had a long-term tenor and cheap pricing.

In Europe, regas terminal financings are akin to Canaport's utility model. The €400 million Reganosa scheme in Spain, developed by Endesa and Union Fenosa, had a low equity component, 10% in the financing package, a 1.7x DSCR and a 0.5% to 0.7% margin. The financing is backed by a nationally set regulated tariff structure and hence the project risks are lower and the financing package can be tighter. Many other European

Cheniere Energy raised a $2 billion high-yield bond for its Sabine Pass LNG receiving terminal, seen here nearing completion.

Yemen LNG Company Ltd.

Yemen LNG Company is currently constructing a natural gas liquefaction plant on the coast of Balhaf, Shabwah, and a 320-kilometre pipeline which will connect the gas processing facilities in Marib Block 18 to the liquefaction facilities, located at around 400 kilometre East of Aden. As of the start of 2008, construction of the Yemen LNG project involved over 8,000 people in Balhaf and almost another 700 along the pipeline.

As part of the project commitment to maximise employment of Yemeni citizens, Yemen LNG is implementing a Technician Training Programme. 192 Yemeni technical trainees are currently following an intensive 18-24 month technician training programme at the Company's world-class Technical Training Centre in Sana'a. The programme includes hands-on assignments at industrial and LNG facilities abroad to prepare these trainees for Operations, Maintenance and Support roles at the LNG plant in Balhaf as it approaches completion by end 2008. Upon completion of the programme, these Yemeni professionals will be participating in the commissioning and start-up of the Balhaf LNG terminal and will have gained the knowledge and basic competencies which they will rely on throughout their careers.

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39.62% 16.73% 17.22% 9.55% 6.00% 5.88% 5.00%

Bonny Gas Transport raised $680 million for its portfolio programme covering 13 vessels including the *LNG Akwa Ibom*.

schemes will follow a similar route although the regulatory regime will vary between countries.

The LNG shipping market has been very active over the last couple of years. Given the boom in upstream terminal activity, all the schemes have required new ships to transport the cargo.

In financing terms the LNG shipping deals have one advantage over the upstream terminal or regas schemes. In the cashflow waterfall from a project, shipping is at the top as its repayments are taken out of the operational budgets. But this benefit can be offset by the fact that there are residual balloon payments at the end of term of the debt. These mean 50-60% of the principal still has to be repaid and the loans must be refinanced. The reason for this structure is that it is assumed the ships will have a life, and a value, beyond the debt.

Until recently LNG shipping deals were arranged on the basis of one financing per ship, so banks could keep security over each ship. So even if a financing had more than one ship included in the debt package, it was structured as an individual financing for each ship. That changed in late 2006 when two deals were transacted on a portfolio basis.

Bonny Gas Transport (BGT), the shipping company serving Nigeria LNG, raised $680 million for its portfolio programme covering 13 vessels. The deal had the normal shipping finance security package on each vessel but had an over-arching contractual structure, a common terms agreement. This sets the common terms on the existing debt and any extra debt which BGT can raise on the portfolio. The deal was transacted in the bank market, with the 12-year loan priced at a very low 0.75%, but with looser covenants more associated with a bond.

Nakilat LNG, the shipping company serving Qatar, raised $4.3 billion in its financing programme. Up until this deal it had been joint venturing with international shipping companies on procuring and operating its LNG ships. But it then decided to take complete control and, at the same time, fund 16 new ships all in one go. Its financing is split between a $1.15 billion bond, $1.95 billion of bank debt and $1.2 billon from Kexim. The bonds run for 22 and 27 years and were priced at 1.45% and 1.65%. The 16-year bank debt came in at 0.45% rising to 0.7%. Each ship has it own contracts but each ship's funds come from intercompany loans from its parent Nakilat. The financing was the first phase in an $8 billion programme. But the second phase has been delayed by the global bond market problems.

Other gas sectors

Away from LNG, storage and pipelines will be the main areas for gas project finance. There is one further area – gas-fired power stations, which are often funded via project finance when a specialist power station developer is involved. But in these schemes, while the gas supply contract is the key to the economics of a plant, the gas supplier is usually part of the development picture, not the developer itself.

Project finance in the gas storage sector tends to involve smaller companies. In the US, two deals were project financed in 2007, Bobcat and NorTex, both of which are near the Henry Hub. GE Energy Financial Services joined Bobcat as $65 million equity provider and Royal Bank of Scotland arranged $185 million of debt, initially priced at


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2.5% over libor but reduced back to 2.125% due to strong bank syndication demand. Barclays Capital and WestLB arranged $335 million of debt for Falcon Gas Storage's NorTex scheme with the 6.5-year loan coming in at 2.5% over libor.

In Europe, Deutsche Bank has been appointed to arrange €900 million of finance for Eurogas Corporation's scheme off the coast of Barcelona. And in Hungary banks are looking at a €700 million financing for a MOL scheme which will serve the country's strategic storage needs. ING is advising.

The gas pipeline sector is really driven by geopolitics. But once project approvals have been granted, project finance is an obvious funding option. The schemes have high upfront costs, steady tariff payments during their lifetimes and many sponsors in the project company – all ideal conditions for project finance.

Gazprom and its partners are pressing on with the €5 billion Nord Stream scheme which will take gas directly from Russia to Germany via the Baltic Sea. ABN Amro, Dresdner and SG are advising and the project company says the financing should be in the market later this year. In southern Europe the Nabucco Turkey-to-Austria project, which will not supply Russian gas, is said to be moving again and ABN Amro is advising. There is a competing Gazprom/Eni scheme, Southern European Pipeline, to take gas from Russia to Bulgaria. Royal Bank of Scotland is advising. Another scheme on the horizon is the Galsi pipeline to take Algerian gas to Sardinia and mainland Italy on which BNP Paribas is advising.

While LNG is likely to remain the focus of project finance in the gas industry, these examples show that it is taking root in the storage and pipeline sectors.

Rod Morrison is the Editor of Project Finance International *(www.pfie.com).*

Construction underway on the onshore section of the Nord Stream pipeline – the project financing should be in the market later this year.

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Fresh Impetus for Methane Hydrates

By Iain Esau

The hunt for economic ways to exploit the world's huge untapped methane hydrate reserves has received fresh impetus in the last year or so due to rocketing energy demand in expanding economies such as Brazil, China and India, which has helped drive oil and gas prices to record highs.

India and China, the soon-to-be economic superpowers who are desperate to wean themselves off expensive, conventional, imported hydrocarbons, have made major strides by discovering indicators of significant hydrate resources in their marine exclusive economic zones. Korea has also been prospecting offshore, while further work has been carried out at the Mallik test site onshore Canada.

Recent developments

India was always thought to host sizeable offshore hydrate resources which New Delhi's National Institute of Oceanography has estimated at some 1890 trillion cubic metres (tcm) based on data gathered in 2002 and 2003.

Some of this offshore potential was proven in 2006 when, as part of India's National Gas Hydrate Programme, a highly successful, \$36 million, 39-well drilling programme discovered the world's largest concentrated hydrate zone to date.

The *JOIDES Resolution* scientific research vessel left Mumbai in April 2006 on a four-month drilling stint and its big achievement was to find what was described as a "remarkable" 128-metre thick gas hydrate layer in the Krishna-Godavari Basin off the

The *JOIDES Resolution* made some interesting discoveries during a four-month drilling stint in the Indian Ocean. (ABOVE) Murli Deora, India's Minister for Petroleum and Natural Gas (CENTRE IN THE PICTURE), visited the ship in Mumbai and (OPPOSITE) core studies underway onboard.

east coast, an area known for its huge conventional natural gas discoveries. Near the Andaman Islands, the research team also found one of the thickest and deepest gas hydrate occurrences yet known located in volcanic ash layers as deep as 600 metres below the seafloor. In addition, the expedition established the existence of a fully-developed gas hydrate system in the Mahanadi Basin of the Bay of Bengal.

In total, 21 of the wells hosted successful drill cores which were taken in water depths between 900 and 1600 metres. A final synthesis of the project's findings is expected to be published soon and there are tentative plans to carry out a production test, using an adapted vessel, perhaps as early as 2009.

China followed India in establishing itself as a deepwater hydrate province when drill cores were taken in mid-2007 from wells in the South China Sea. A big bonus for the energy-hungry Beijing government, however, was that the two samples recovered by the China Geological Survey were unusual because they contained 99.7% and 99.8% pure methane. China now plans to invest substantial funds into hydrate research over the next decade in an attempt to catch up with the USA, Japan and India.

Hard on the heels of China and later in 2007, South Korea found gas hydrates offshore with successful cores being taken off its south-east coast. Drillship *Tamhae 2* located hydrates 100 kilometres south of Ulleung Island and 135 kilometres north-east of the industrial city of Pohang in the East Sea at a water depth of over 2000 metres. Seoul has earmarked several hundreds of millions of dollars to be spent on hydrate research through to 2014 in an effort to fast-track its exploitation.

Meanwhile, in northern Canada, further work has taken place at the renowned Mallik methane hydrate field over the last two winters. Led by the Japan Oil, Gas and Metals National Corporation (JOGMEC) and Natural Resources Canada, the 2006-08 Mallik gas hydrate production research programme was conducted to evaluate the natural properties of gas hydrates, and for the first time to measure and monitor their long-term production behaviour.

Earlier research

The site became famous in 1998 when a research programme led by the Geological Survey of Canada (which is part of Natural Resources Canada) and what was then known as Japan National Oil Corporation (JNOC), proved that Mallik, originally discovered in the 1970s, was one of the most concentrated gas hydrate occurrences in the world. (The assets controlled by JNOC were sold off in 2004-2005 and its role as a state oil company was taken over by the newly-created JOGMEC.)

Four years later, a five-nation research team, again led by the Canadians and Japanese, began work at Mallik to prove that theories about how to exploit methane hydrates would work in practice.

The results were a major success with methane extracted from hydrates more than 1000 metres beneath the ground. Full-scale equipment tested the response of Mallik's hydrate reservoir to heat and depressurisation and in both cases the hydrates broke up or disassociated and released methane. This proved the technical feasibility of exploiting hydrates and the rush began to devise methods to

commercially extract the gas, particularly in offshore environments, and led by India and Japan.

In 2001, based on information gleaned from six wells drilled off Japan in 1999-2000, Tokyo's Ministry of Economy, Trade and Industry shot seismic in the deepwater Nankai Trough off southern Japan to look for what are usually, but not always, regarded as the tell-tale sign of the existence of hydrates, a bottom simulating reflector (BSR).

BSRs were interpreted from the data so, in 2004, Japex and Teikoku Oil drilled about 30 wells, with success, in the Nankai Trough. That drilling campaign was part of the government's ongoing Methane Hydrate Exploitation Programme, or MH21, which aims to test and develop new technologies for offshore hydrate drilling and production. Leading MH21's research efforts are the National Institute of Advanced Industrial Science and Technology, the Engineering Advancement Association of Japan, and JOGMEC.

The next stage for the MH21 consortium is carrying out production tests on the most promising

AN ABUNDANT YET CHALLENGING RESOURCE

Gas hydrates are essentially one methane molecule surrounded by a cage of six water molecules in the form of ice. Most of the world's hydrate resources lie under the oceans with the remainder locked in continental high-latitude areas of North America, Europe and Asia. They are generally found in waters deeper than 300 metres, where bottom water temperatures approach 0° Celsius, and up to 1100 metres below the seabed. In onshore polar regions, hydrates can be found between about 150 and 2000 metres sub-surface.

Gas hydrates can take the form of thick layers, thin veins or nodules, or may fill reservoir pores. Below hydrate layers, conventional gas can often be found.

Resource estimates vary wildly but the USA's Department of Energy (DoE), a traditionally reliable and conservative source of data, reckons that oceanic hydrates could yield well over 1 million tcm. This compares to conventional natural gas resources of only 360 tcm, half of which is deemed commercial, although rising demand for gas and technological advances are improving this proportion. In total, the world's hydrate reserves are thought to be double that of the combined resources of all known fossil fuels – oil, natural gas, coal and oil shale.

However, in addition to being a potential energy source, hydrates may also pose a risk of uncontrolled release of methane. Variations in

Orange chunks of methane hydrate lie exposed on the ocean floor. Methane ice worms are thought to feed off bacteria that grow on the hydrate.

sea level can cause pressure fluctuations in hydrate layers which may result in methane being released into the atmosphere, while earthquakes and submarine landslides can prompt the same response. Although it is unlikely that exploiting hydrates will accelerate any disassociation of methane induced by natural processes, where gas hydrates occur close to the seabed there are unique environmental issues such as sea floor settlement and possibly foundation stability problems that will have to be assessed.

Accordingly, people entrusted with creating a commercially viable way of extracting methane from hydrate crystals also have a duty to prove that this can be done in an environmentally friendly manner.

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Gas hydrate being flared during the winter of 2007 from the Mallik production research well in Canada's Mackenzie Delta. Research and development studies at this site were led by JOGMEC and Natural Resources Canada. Aurora College, part of the Government of the Northwest Territories, acted as the operator for the well programme.

hydrate structures in the Nankai Trough through to 2011. Japan estimates that its deepwater sediments harbour some 7.4 tcm of gas, sufficient to meet domestic demand for 100 years, and its aim is to begin commercial production of methane hydrates by 2016, and faster if possible.

Alaska

Alaska is also an important prospect because the North Slope's hydrate resources have been estimated at almost 17 tcm. If just some of this gas could be exploited it would represent a valuable addition to US resources.

An onshore hydrate research programme was carried out between 2003 and 2005, led by Anadarko Petroleum working with contractors Maurer Technology and Noble Corporation and supported by the US Department of Energy.

This project aimed to identify, quantify and predict production potential for hydrates located on the North Slope and spudded the first well, called Hot Ice-1, in early 2003. However, operations were suspended three months later due to an earlier-than-expected Arctic thaw.

Activity restarted the following year with a well drilled from Anadarko's innovative Arctic Platform, designed to reduce the environmental effects of such an operation. The platform, sited south of the Kuparuk oilfield, was a lightweight aluminium structure elevated above the tundra on steel legs and similar in design to offshore jackup drilling rigs. Unfortunately, no hydrates were encountered in this well and the project was wound down in early 2005.

BP is now leading another Alaskan study to determine the size and features of a hydrate reservoir complex in Prudhoe Bay, close to its eponymous multi-billion barrel oilfield, while further work is being done by the oil company at its Milne Point oilfield in Alaska.

In early 2005, the supermajor completed the first phase of a three-stage hydrate programme that delineated and characterised more than 12 discrete gas hydrate accumulations at Milne Point. A well was then drilled on the Mount Albert prospect, the results were positive and a long-term production test is planned for this year.

Petroleum companies carrying out traditional upstream activities in Alaska, including BP, are considering building a pipeline to take conventional gas to the continental US markets, a proposed piece of infrastructure that could provide an outlet for methane extracted from hydrates. It is expected that onshore hydrate production would probably take place in parallel with oil and gas production from a conventional hydrocarbon field because these types of deposits are usually found near one another in the Arctic.

This point has been proven in Russia where the Messoyakha gas field is believed to have been producing methane from a hydrate layer since the 1960s, a finding that four decades ago first triggered research into this challenging but staggeringly abundant resource.

Potential around the world

In Russia, the key hydrate plays are now thought to be western Siberia, Lena-Tunguska Province and the Timan-Pechora Basin, as well as several sedimentary basins in north-east Siberia and the Kamchatka Peninsula. But Moscow is putting little effort into exploiting this resource largely because of the abundance of its conventional gas reserves.

The first evidence that hydrates lay beneath the oceans came in the 1970s when they were discovered on the Blake Ridge off the USA's eastern seaboard. Further discoveries followed in the Black Sea, off Guatemala, Costa Rica, and in the Gulf of Mexico, where Chevron has tentative plans to drill test wells by the end of this decade. Other deposits have been identified off Chile, Indonesia, Nigeria, Norway and Canada's Pacific coast.

Hydrates have been found in inland waters such as the Caspian Sea and Lake Baikal and are thought to exist in the Sea of Okhotsk off eastern Russia, the Mediterranean Sea, off Bangladesh, Brunei, Malaysia, North Korea, Pakistan, the Philippines, Sri Lanka, Taiwan, Thailand and Vietnam.

Some hydrate specialists believe that commercial hydrate production will become a reality in the next five to 10 years, with most expecting that first production will be from an Arctic region of Alaska, Canada or Russia where concentrated hydrate deposits lie above deeper conventional oil and gas fields. However, offshore production, perhaps from Japan or India, could possibly come on stream faster.

As the Mallik programme proved, heating or depressurisation of hydrate reservoirs is likely to the best method to allow gas to flow to the surface and the expectation is that the highest production rates will probably be achieved by using the two techniques in parallel. Another possibility would be to inject methanol or ethylene glycol into a hydrate-rich pay zone to allow it to dissociate and release its valuable energy cargo.

In some cases, if a well is drilled to exploit the free gas underlying a hydrate zone, it could have the added benefit of reducing the pressure within the overlying gas hydrate layer which would then cause dissociation.

The added bonus, according to research, is that free gas associated with methane hydrate reservoirs is likely to contain between one-eighth and one-half of the methane contained in the hydrate, boosting the economics of any such development.

So the future for methane hydrates is promising. In fact, according to Houston-based consultancy Hydrate Energy International: "Production of gas from hydrates is technically feasible at present, with the primary remaining hurdles being pipelines to transport the produced gas to market and the willingness of operators to pursue the opportunity."

Iain Esau is the London correspondent of the international oil and gas newspaper Upstream *(www.upstreamonline.com).*

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IT in the Gas Industry: The Power behind the Energy

By Adrian Bridgwater

Information technology has played a vital part in the evolution of the modern gas industry. A huge amount of computing power now supports the gas chain from exploration and production to downstream areas such as pipeline monitoring, leak detection, transmission flow monitoring and customer relationship management (CRM).

Technology tiers

The use of IT in the gas industry can reasonably be divided into three tiers. Firstly, there are implementations that have improved performance, but could equally have been deployed in a non-gas industry environment. A tier one development could manifest itself as something as fundamental as a business process management system.

Tier two would be more bespoke developments such as computer-aided design (CAD) mapping systems specifically developed to act as deployments within the gas industry.

Finally, tier three technology developments are those that come about as refinements in the handling and treatment of gas, but that are driven by increased prowess in research and development as a result of having more computing power to hand.

Mission critical

Technology deployments in the gas industry are unquestionably widespread, but they are also more multifarious in their form and function than in general commerce.

"Technology has driven deeper inroads into the gas industry than in many other verticals. This penetration has been necessitated by an increasingly competitive global market and the potential for this natural resource to diminish or become more elusive to extract, which has driven efficiency and effectiveness in exploration to the fore," says Duncan Chapple, Managing Director of data specialist consultancy Lighthouse Analyst Relations. "The need for mission critical systems to be fully operational becomes a key differentiator in terms of whether firms prosper or ultimately fail," he adds.

As in many other industries with "live" working operations, reducing IT downtime is a perpetual challenge. Despite the advent of technology that helps companies to monitor IT services and circumvent hardware issues, efforts to attack the software source of downtime have been somewhat less successful. A common problem is the issue of inaccurate software configuration data, i.e. how the system was built with a view to future-proofing it and allowing it to be upgraded. So as upgrades fail, downtime becomes a reality and the company loses money.

The problem becomes acute for the gas industry as each operation has bespoke large-scale needs and is likely to have a mixture of tailor-made or home-grown software designed to service specific requirements alongside more off-the-shelf packages. Research from data analysis company Vanson Bourne has shown that it is often home-grown software that manages a company's most mission-critical systems and drives its competitive advantage – but at the same time, this software is the hardest to map and the most damaging to the business when it goes wrong.

"The energy industry as a whole has become increasingly reliant on technology and in particular, specialist software to manage business processes and IT services. The industry has come to realise that proprietary software applications, while often the very substance of a firm's competitive advantage, also present substantial management challenges, given the non-standard design of bespoke software," says Dr Jim White, a business technologist at business service management company Managed Objects.

"Gas firms and others often discover that the knowledge about this technology's inner workings is tacit and has departed with the original software developers, while at the same time, new developers have been adding or modifying functionality over time. In the absence of sophisticated technology to discover and map these applications, the end result is a piece of software that is critical to the business – yet no one really understands completely quite how it works; that's problematic if it breaks."

To address this predicament, vendors such as Managed Objects are quick to extol the virtues of adopting their methodology to control the total "suite" of software that a particular gas company builds and augments over time. These solutions work by correlating networks, systems, end users, software applications and even business metrics to the services that IT delivers. A more managed approach is a more controlled, more measurable and more accountable option.

● Data sharing and backup

The petroleum industry has constantly adapted to take advantage of the current state of information technology and deploy it in the field in its most efficient possible usage scenarios. The interpretation of 3D seismic data is a good example. First and second generations of this computer-driven process required extensive training and specialist knowledge, but as we have progressed toward a generation of "point-and-click" technologies, the number of potential professional users who have been able to benefit from using such systems has increased. This means that today, management can be afforded a macro-level view of what the specialists may be working on.

Another example is the design process, which often involves a wide range of people and departments. "Getting these people to collaborate in a seamless, secure and efficient manner can be a challenge," says Steve Partridge, Business Development Manager at Adobe Systems. "What we are seeing is a huge growth in adoption of Acrobat 3D, a package that allows designs from CAD applications, such as CATIA V4 and V5, UGS NX plus others, to form an interactive 3D PDF that can be securely shared, reviewed and marked up for cross-team inspection. The 3D PDF can also store product manufacturing information such as dimensions, tolerances, etc, that are all important to those reviewing the designs. Added to this, when you compare the file size of a 3D PDF to native CAD files, it is up to 150 times smaller, so easier to

A huge amount of computing power supports the gas chain. This control centre in Den Helder, for example, monitors the operations of 18 offshore platforms which Wintershall operates in the Dutch sector of the North Sea.

share over email – all important in today's age of remote working and virtual teams."

Underlying all IT applications is a bedrock of data storage, backup and server power. The quantity of geotechnical data and analysis data continues to explode and, consequently, many large petroleum companies will add multiple terabytes of storage capacity per day, all within a single deployment. Additionally, regulatory and legal requirements dictate that data should be protected and kept for longer periods of time. A third issue is that many companies use outdated backup and archive practices, making their day-to-day activities increasingly inefficient.

"Like all businesses, gas companies continue to struggle with backup, recovery and archive of critical information," declares Peter Hodge, Oil & Gas Marketing and Solutions Development Manager for EMC Corporation. "Simultaneously they are trying to reduce the primary data stores required to house massive data growth and lower storage costs and complexity. This enables the companies to further their geological and geophysical exploration to stay ahead of the competition."

According to Rick Nicholson, Vice President of Energy Insights at data analyst firm IDC: "Due to the mismatch between the storage architecture and the changing value of information throughout the life of exploration and production assets, current information management practices do not enable oil and gas companies to get the maximum value from their information at the lowest total cost at every point in the information life cycle."

Server and storage room technologies are often perceived as the least tangible and, very often, least interesting of the elements of the total technology "stack" that any organisation has in place. Despite this, they remain as important to the foundations of a solid technology backbone as the front-end user interfaces that complete the picture. Without storage and backup, what a gas company does today may just as well be lost tomorrow.

"Backup and archiving are very different processes," explains EMC's Hodge. "Backups are generally short-term, frequently overwritten copies of active production information that are used when a problem arises to get the business back up and running. Many organisations have difficulty completing a backup in time to start production and wrestle with the tradeoffs of degraded production performance or ending the backup job. Neither option is attractive."

Hodge continues: "Gas companies can dramatically improve IT performance by moving fixed content (information that is no longer actively changing) out of the production environment into an online active archive. The result is that primary production system capacity is reduced. Backup windows are shorter because they're based on smaller active data sets. Recoveries have less static content in them and are much faster and easier to manage. Information retrievals come from the searchable online archive, not out of a backup image. Application performance improves and is more consistent since there is less data in the system. Now that the backup image is smaller and more manageable, companies can also move to new, affordable disk-based backup and recovery to dramatically improve recovery time, manageability and reliability."

All of this progression towards so-called "intelligent" management of different data types means that modern gas companies can control a database that is something far more than a straightforward repository, however large. As such, we have seen the rise of the "relational database" model. It sounds simple, but if we fail to accept that database information is a collection of "relations" (or related data housed in fields and tables) that can be organised and forced to conform to a set of requirements, then we fail to realise the value of the sum of that information as it is aggregated and co-related. A more intelligently managed database has direct commercial benefits.

Customer interface

Operators of gas pipelines need to ensure they maximise the flow of gas and adhere to the contractual agreement with their clients. Operators need robust and secure billing systems so shippers of gas can change the nomination of gas as and when they require. If secure systems are not in place, operators will not meet their contractual obligations. Again, technology comes to the fore as the management tool of choice.

"Billing technology has progressed in leaps and bounds over the last decade; advances that have been driven primarily by customers who are more savvy about their options and more challenging in their needs. In terms of billing (and CRM), there are some interesting parallels between the requirements of the gas industry and our primary market, telecoms. Both must accommodate complex corporate account structures, 'prepaid' and 'postpaid' payment types, 24/7 operations, real-time service updates, cyclical billing, bill formatting, online bill presentment and so forth. Underpinning everything is the necessity to safeguard customers' personal and financial records," says Tony Wilson, Chief Operating Officer of Martin Dawes Systems.

Gas companies that apply technology at all three of the "technology tiers" can bring economies of scale and efficiencies in production to almost every layer of their business model. Of course, simply buying in more IT is not a panacea for a more flexible commercial proposition. It has to be done prudently, with planning and with a view to the future. In an increasingly competitive environment, the goal is for companies to align themselves to be more efficient operators.

Adrian Bridgwater is a freelance journalist specialising in cross platform software application development as well as all related aspects of software engineering and project management.

THE RIGHT TOOL FOR THE JOB

As anyone who has worked on the front line for a gas exploration company will tell you, mobile computing devices come in a shape and "form-factor" all of their own. This is not the territory of laptops or mobile phones (although those may be used as well), rather this is where a new breed of rugged devices exists to perform in demanding environments.

To take one example, Intermec's durable construction of its CK32IS handheld computer (PICTURED) reflects the operational reality of these environments. Breakage in a hazardous location is more than a matter of downtime and inconvenience – it is potentially lethal. The CK32IS has achieved an IP67 sealing and 1.5-metre drop specification and is the only mobile computer to achieve Zone 0 certification, which designates "double fault" safety in environments in which flammable gases are present under normal operating conditions.


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Iran's Natural Gas Expansion Plans

By Hedayat Omidvar

Over the last decade Iran's gas production has nearly tripled and the country has moved from 10th to fourth position in the global ranking of producers. But with 28 tcm of proven reserves – the world's second largest after Russia – Iran has plenty of scope for further development on the gas front. IGU Charter Member the National Iranian Gas Company (NIGC) is working to supply growing domestic demand and to increase international trade.

Government policy is to encourage greater use of gas, which overtook oil as an energy source in 2002 and accounted for just over half of Iran's primary energy consumption in 2006. The target is to extend the transmission and distribution network to reach 80% of the population and increase the gas share of primary energy consumption to 69% in 2009. By this time NIGC expects to have 29,400 kilometres of gas transmission pipelines in place and a distribution network of 150,000 kilometres, and is forecasting annual domestic consumption of 156 bcm compared to 113 bcm in 2006.

Gas from the South Pars field is treated at this plant in Assalouyeh.

More than 60% of Iran's gas reserves are located in non-associated undeveloped or partially developed fields. The largest of these is the offshore South Pars gas field, which was first identified in 1988 and is being developed in 28 phases. South Pars was originally thought to contain just 3.6 tcm. Current estimates show it to contain at least 7.8 tcm (with some estimates going as high as 14 tcm) as well as over 17 billion barrels of condensate.

By 2015 condensate production from South Pars phases 1-14 is expected to reach 628,000 b/d, while the potential gas production is 400 mcm/d of which half is slated for export.

Gas exports via pipeline to Turkey started in December 2001 and, at presstime, exports to Armenia were due to start in exchange for electricity supplies under a 20-year deal. As well as exporting gas Iran also imports it, primarily to serve the north-east of the country. A pipeline connection with Turkmenistan was inaugurated in December 1997 and gas is supplied under a 25-year deal with imports of 6.3 bcm in 2006. There is also a swap deal with Azerbaijan whereby Iran supplies the Arzerbaijani enclave of Nakhichevan and receives a corresponding amount of gas from Azerbaijan. This started in 2005 and covered 0.26 bcm in 2006.

NIGC has an investment programme of $18 billion for the 2007-2009 period covering transmission pipelines, compressor stations, gas-processing plants, underground storage, distribution networks and maintenance.

Pipeline projects

The Iranian Gas Transmission (IGAT) system is being expanded with the completion of the IGAT IV pipeline and a number of other projects. IGAT IV links South Pars and the Parsian gas plants with the centre and north of the country. The project includes 1,030 kilometres of 56-inch pipe in two sections and has a capacity of 110 mcm/d. In 2004 the main part of the pipeline was connected with the Pol Kaleh compressor station in Isfahan, and a 351-kilometre section to Fars Province also became operational. The second stage of IGAT IV includes a 42-inch spur line to Kerman, a 24-inch line to serve a Fars petrochemical plant, a second 40-inch line to Yazd and a 40-inch Isfahan-Mobarakeh pipeline.

The 56-inch IGAT V trunkline is designed to carry 75 mcm/d of sour gas from South Pars Phases 6-8 to the Khoozestan oil fields for injection. It connects Assalouyeh and Agha Jari, a distance of 504 kilometres, and has five compressor stations.

Both the second stage of IGAT IV and IGAT V were due to be completed at presstime.

The IGAT VI pipeline will generally parallel IGAT V to serve the gas needs of Bushehr and Khoozestan provinces, including oil field injection. With a length of 492 kilometres and a diameter of 56 inches, it will have a capacity of 90 mcm/d. Two compressor stations are planned and completion is due by the end of 2008.

IGAT VII, 860 kilometres of 42 to 56-inch line, will carry gas produced in South Pars Phases 9 and 10 for use in Sistan and Baluchestan provinces in southern Iran. In the future it could connect to an export line to India, Pakistan and the UAE.

IGAT VIII, a 1,050-kilometre, 56-inch line, will carry South Pars gas to the Parsian gas plant and north to a line serving Tehran. It will have 10 compressor stations.

Both IGAT VII and IGAT VIII are due for completion in 2009.

To meet growth in gas demand in the northern and eastern provinces of Semnan, Khorasan, Golestan and Mazandaran, NIGC plans a second pipeline between Parchin and Sangbast, 790 kilometres long with a diameter of 48 inches, and a 110-kilometre, 40-inch segment between Miami and Jajarm. The system will have four compressor stations and will handle South Pars gas delivered through IGAT VIII.

To serve the western and northern provinces of Hamadan, Kordestan, Zanjan, as well as East and West Azerbaijan*, NIGC plans to lay 280 kilometres of 48-inch pipeline between a compressor station at Saveh and the city of Bijar, and 192

ABOVE AND BELOW
By 2009 NIGC expects to have 29,400 kilometres of gas transmission pipelines in place.

* This does not refer to the State of Azerbaijan; East and West Azerbaijan are two of Iran's 30 provinces.