Oxford ENERGY FORUM

A QUARTERLY JOURNAL FOR DEBATING ENERGY ISSUES AND POLICIES

Issue 58 August 2004

For your summer reading the first of our debates deals with the rather esoteric subject of GTL. Suddenly, it seems, the press is full of GTL projects and Qatar – but why? They cost billions of dollars and produce what appears to be rather limited quantities of diesel, even if it is environmentally pure. So, we have gone to Qatar itself, and to some of those who are involved with the projects, to find out more about the subject.

The first article comes from Howard Bevan, who gives us the view from Qatar. He puts GTL into the perspective of Qatar's long-term economy and shows how it will cut in with the necessary new income stream in the second decade of the century. He points out that GTLs are a logical extension of gas utilisation beyond LNG for a country such as Qatar which has, to all intents and purposes, limitless gas reserves. With its environmental attractions, GTL should be able to claim a preferential price in world markets. As Bevan shows, Qatar's GTL developments are the result of an internal strategic planning process, not at all the result of external investment pressures.

The first GTL project in Qatar is the ORYX project of Qatar Petroleum and Sasol, and Johann Van Rheede gives us some Sasol background to this. He describes the increasing attractions of diesel in transport and how GTL fits into this scheme. He tells us about the technical progress of Sasol in this area, starting from their use of the Fischer-Tropsch technology back in the 1950s. He continues with a survey of the ORYX project and looks at the future of Sasol's involvement in GTL development based on their joint venture with ChevronTexaco. He concludes with a reminder of the environmental and other advantages of GTL diesel and its other products.

Bipin Patel gives us a view of GTL from the technical and economic angle, and concludes that Qatar has every right to describe itself as the GTL capital of the world. He provides us with an economic overview of GTL versus LNG, both of which have high capital cost and are highly dependent on crude oil price. He shows how capital costs have fallen over the years and the importance of economies of scale in GTL plants. He also makes the

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point that GTL should not be considered as a standalone business but as an integrated gas-monetisation opportunity. All our contributors are agreed that Qatar, with its huge gas reserves, is the ideal location from which to launch what looks like being a GTL age.

Our second debate covers the somewhat arcane subject of oil reserves, which have recently produced (surely for the first time in their life) many headlines. What precisely is their significance for a company's long-term, or short-term, value and how can they affect the assessment by investors of the share price? Since much is written about the SEC definitions, we thought it would be beneficial to transcribe them here, and you will find them, therefore, as the first section of this debate.

Peter Nicol deals with reserve accounting from the point of view of the shareholder, and points out that reserve disclosure helps to fill an important information gap. He describes the various definitions that are used, but suspects that even a move to International Accounting Standards is unlikely in practice to counteract the importance of SEC standards and definitions. He debates the various arguments that swirl around this subject, but points out that, even if a move to P50 reserves disclosure from P90 were to take place, investors will have to recognise that there will still be volatility in disclosure from one time to another.

Brian Rhodes and Andy Crouch consider the valuation of reserves. Both SEC and SPE definitions, although different in particulars, work on the 'reasonable certainty' principle concerning reserve recovery. A problem, however, is that this seems to vary between companies; and, anyway, a company is not necessarily going to invest in development simply on the basis of reserve disclosure. They point out that analysts use many other measures in determining the relative value of companies. They conclude that in an ideal world analysts would be reducing, or at least quantifying, uncertainty, but, on the other hand, the rest of us may have a sneaking feeling that a bit of uncertainty provides spice in life.

The other main article in this issue by Paul Horsnell studies the fascinating subject of the recent oil price increase. He analyses the long-term value of crude over the past years and concludes that the step-increase that we have now seen reflects structural rather than cyclical issues. In the process he explodes the theories that this increase is due to speculators in the hedge funds, or to a so-called 'fear' premium.

Personal Commentary is by Peter Odell who, as you will see, challenges last year's Energy White Paper for its failure to take any proper account of the UK's most important energy source, the North Sea. He underlines its vital economic role in the past and suggests it should be properly incorporated into any future energy scenario. This is not something that can simply be left to the companies and their interpretation of market signals.

As always, if readers don't like the conclusions that are reached by our contributors, they are encouraged to write and tell us.

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Gas to Liquids

Howard Bevan provides a perspective from Qatar

Gas to Liquids (GTL) technology has been much publicised during 2003. Qatar is avowed to be the 'GTL capital of the world'. The decision to promote projects which are based on very expensive plants and mostly uncommercial processes, might on the surface be an unusual one. This article seeks to set out the reasons behind this decision and to show how GTL plants fit into a coherent national strategy.

This analysis starts with the crude oil reserves position (Table 1) and some economic fundamentals.

At this stage it is convenient to make a few 'heroic assumptions' and to pick a planning horizon, which for convenience I will pick as 2012. National expenditure is of course difficult to predict and is based on many imponderables. This is especially true of small Gulf States with high indigenous birth rates and a large expatriate population. Again assume that the long-term oil price is $20/barrel and government expenditure is at current rates – say QR18.2 billion ($5 billion) for Current Expenditure and QR4.3 ($1.2 billion) for Capital Expenditure.

If oil production is 700,000 b/d then this will provide $4.8 billion. Other non-oil revenues can be considered small. Of course not all revenues accrue to the state. Much of the offshore production is developed under Sales and Purchase Agreements (SPAs) but by 2012 most of this revenue will come to the state. Qatar current strategy is therefore based on minimising non-hydrocarbon capital expenditure and making such expenditure only when oil is above $20/b. Budgets have historically been balanced by deferring capital expenditure. The figures are somewhat imprecise here but do illustrate the current and future situation.

By 2012 oil production may have sunk to 500,000 b/d and provide an income of only $3.4 billion so there is a shortfall in real terms of about $1.4 billion – with a very big 'ceteris paribus'. Further declines are expected after 2012. Of course more reserves may become 'proven' and come on stream. Recovery rates in some fields are low and some technical progress on these rates is to be expected. However a National Income Policy needs more certainty than that!

With Qatar's national income being almost entirely dependent on oil revenue, it is logical to exploit the country's great national asset, namely the North Field. This gas field is the world's largest non-associated gas field. Qatar's national strategy is to exploit this asset in order to supplement and eventually replace oil revenues. This is necessary in order to maintain national income and hence the well-being of its citizens.

The North Field gas reserves are currently stated as being 'in excess of 900 tcf'.

It is assumed below that LNG production may reach 70 million tonnes per year and that gas for GTL projects may reach 8 billion cubic feet per day (cf/d). Under these assumptions consumption of gas from the North Field will reach between 6–7 trillion cubic feet (tcf) per year or say 120–140 tcf for a typical 20-year life span project. So gas reserves are ample.

Table 1: Qatar Crude Oil Production and Reserves

	1980	1990	2000
Reserves – crude oil (billion barrels)	3.6	4.5	4.5
Production – thousand b/d	476	434	796
Crude Oil R/P Ratio (Years)	22	30	17

The first question to ask is, 'how much income will be needed and when?' This can then closely be followed by the question, 'how long will it take to develop the new sources of income based on monetising the gas resources of the North Field?'

Well, Qatar Petroleum (QP) has a strategy for monetising the North Field. It recognises that there are four principle ways of using and monetising the gas, namely:

1) Liquefied Natural Gas
2) Pipeline Gas
3) Methane and Ethane based Petrochemicals and Fertilisers plants
4) GTL Plants

QP, acting on behalf of the State of Qatar, is pursuing all four legs of its strategy in terms of revenue generating projects. In LNG, Qatar has successfully established its Qatargas and RasGas LNG Plants and in pipelines the Dolphin Project is now underway (pipeline gas to the United Arab Emirates). Qatar already has some petrochemical plants operational (and has had for some time). Companies such as QAFCO (Fertilisers), QAPCO (Plastics), QCHEM (Plastics), QAFAC (MBTE) and QVC (vinyl monomers) are all in operation. Expansions and new plants are planned.

Actual short and medium cash flows are of course subject to commercial confidentiality. However some rough estimates can be made with published data.

First let us simplify matters by assuming that petrochemical profits are small and cyclical – just the icing on the cake and not something to base national income on.

Qatar is committed to build about 70 million tonnes of LNG capacity by 2012. Again, actual terms are confidential, however we can use the alternative fuel cost price of income to the state of $0.50 cents/million Btu (the rationale for this minimum price is explained below). This will provide an income to the state of about $1.8

billion per year. On a similar basis the Dolphin pipeline project may eventually provide sales of 2.5 billion cf/d of gas and a revenue of say $0.5 billion a year.

We see therefore that the financial situation is 'comfortable' without GTL projects – at least until steeper crude oil production declines set in. Qatar plans to replace its lost revenue from declining crude oil production with revenue from LNG, pipeline gas and petrochemical sales.

So this still begs the question of why GTLs?

> "We can see therefore that capital costs will have to be below $17.00/b for a GTL project to be viable and that sustainable long-term oil prices be above $20/b"

Readers will presumably be aware of the early GTL history and the role of Fischer Tropsch catalysts in sustaining German oil product production during the Second World War. More recently South Africa sustained similar production throughout an oil embargo. However these are special cases. GTL technology has been bedevilled by high capital costs that have prevented this technology from attaining broad commercial viability. Just how the economics stack up can be judged from some simple calculations. Start with the assumption that the long-term oil price might be $20/b, then gas could be priced at a minimum of marginal fuel cost which must be roughly equivalent to the cost of production of a low to medium priced crude oil, say about $0.50 cents/million Btu, equivalent to $3.00/ b. We can see therefore that capital costs will have to be below $17.00/b for a GTL project to be viable and that sustainable long-term oil prices be above $20/b. Obviously, lower capital costs and higher oil prices will strengthen a GTL project. Similarly the higher gas prices associated with alternative gas projects will weaken a project. It is only recently that capital costs have come down to this level.

However this only occurs under certain circumstances. These are:

- Plants have to be 'large' to achieve economies of scale;
- A proven infrastructure (ports, jetties and tankage) for producing gas and liquids and exporting products has to be in place;
- Individual plants are large consumers of gas. To achieve synergies of production it is desirable to have more than one GTL plant on a site.

Consequently a large gas field with low production costs is needed to make GTL projects viable. To illustrate this point, two large GTL plants, consuming say 3000 million cf/d, require a reserve base of 20 trillion cubic feet.

On top of these criteria, there has to be a commercial, financial and political stability present that will allow banks and foreign and national oil companies to invest about $5 to $6 billion in such projects. Perhaps it is understandable that Qatar is considered a prime location for this. Given that the overall economics and business climate may be favourable does not mean GTL projects will flourish. There has to be a strong commercial, and in Qatar's case national, reason to undertake such projects.

We now come to the second question, which is, how long does it take to develop new projects? It is true to say that Qatar Petroleum and its foreign partners have taken a long time to develop some projects – ten years is an often recognised timescale from inception to production. However, much learning has taken place and timescales have come down. Nevertheless, under SPAs, significant cash to the state will not occur for the first few years. So it is obvious that now is the time to plan for post-2012. Projects are considered to be developed in 'waves'. First we have the petrochemical plants, then LNG plants and pipeline projects. Then will come the GTL plants. Already on the horizon is the next wave of projects, perhaps for implementation after 2015!

However we have already said that petrochemical revenue is cyclical. LNG markets are limited and, at least until other less prolific gas fields decline, appear to be well supplied, although new technologies and economies of scale will allow Qatar to expand its markets. There are limits to the number of pipelines that can be built. So all the arms of the strategy have some limitations. Market size and market opportunity are also important issues. World demand for LNG may be between 300 and 400 million tonnes in 2012 with Qatar providing 17 to 25 per cent of that volume. World oil demand may be 90 mb/d with Qatar GTL providing 750,000 barrels (less than 1 per cent). GTLs therefore help provide more diversification in Qatar's portfolio of revenue producers and, as a consequence, risks of a 'market shock' are somewhat reduced.

Table 2 shows Qatar's potential GTL projects and their status. Several things are apparent from this table and I summarise them here:

1) Although there are plans for about

Table 2: Status of GTL Projects

Project	Capacity Barrels/day	On Stream Date	Progress
Oryx- SASOL	34,000	2006	Under Construction
Shell	140,000	2010–12	FEED* / Drilling
Conoco-Phillips	160,000	2010–12	Statement of Intent
Marathon	120,000	2010–12	Statement of Intent
ExxonMobil	102,000	2010–12	Pre-FEED Completed
Oryx Debottleneck	66,000	2009–10	Memorandum of Understanding Economic Appraisal
SASOL Chevron	130,000	2010	Statement of Intent

750,000 b/d of GTL capacity, much is still at the planning stage. Only the Oryx –Sasol plant is under construction and only the Shell Plant is under FEED although they are doing some development and appraisal drilling as well. As pre-FEED and FEED studies progress it is expected that actual capacities may change as design parameters are optimised.

2) One should note that the GTL production may well be greater than crude production by 2012. Furthermore, field condensate and LPG production have been ignored in this very simplified outlook of revenues.

3) The on stream dates look very congested. It is obvious that all the GTL projects cannot be built at once even if the phasing of construction is taken into account.

“there is an entrepreneurial spirit within Qatar and Qatar Petroleum”

The GTL projects will use about 8000 million cf/d and, using the same revenue to the state assumption, generate another $1.4 billion per year. Whilst it has been shown that the revenue is not strictly needed for some time, more revenue obtained from monetising the North Field is of course welcome.

So I return to the question, ‘Why GTL and why now?’ The second question is easier to answer than the first. It takes a long time to implement these projects; eventually more revenue will be needed.

However there is an entrepreneurial spirit within Qatar and Qatar Petroleum which gives the confidence to take on and implement big projects. There is a feeling that if anyone can bring in this new technology then Qatar and its partners can. Qatar is widely recognised as a good place to do business. Obviously in this case, agreements to implement GTL projects will have a considerable amount of risk mitigation built into them.

Let us now turn to the uses of products from GTL projects. Plants will obviously be ‘tuned’ to meet downstream marketing needs. A typical 150,000 b/d plant may produce 32,000 barrels of mixed LPGs, 39,000 barrels of naphthas, 57,000 of gasoils, 16,000 of lube base oils and 6000 of normal paraffins per day. Again, some interesting insights can be made from these simple figures.

In LPGs, as gas producers ramp up their gas production (from LNGs as well as GTLs) then they will become significant producers (and exporters) of LPGs (and incidentally of field condensate).

GTL naphthas are straight chained. They are therefore an ideal feedstock for steam crackers and are expected to fetch a premium over conventional naphthas.

With GTL gasoils, the initial interest was in the production of ‘green’ diesel as these gasoils are of extremely low sulphur content. There is now a realisation that diesel markets are controlled by specifications for diesel. Sulphur specifications can be met by a variety of blending options and processes. A sulphur premium for GTL gasoils will therefore be set by its blending value. However GTL gasoils (again being straight chained) have a very high cetane value so they again acquire a blending value from this property. It is envisaged, therefore, that GTL gasoils will, when available, take their place as a premium component in the gasoil blending pool. They may very well be useful in upgrading FCC bottoms for diesel uses rather than, for instance, allowing them to be down graded into bunker fuels.

Lube Base oils and N-paraffins are specialist uses for GTL gasoil cuts. Again they have unique properties. They represent good ways of making high value product – but this is really the subject for another article. They also represent good ways of increasing employment opportunities in Qatar.

We see therefore that Qatar has a unique opportunity to implement GTL projects. The view of their profitability and the need for the projects is very long term. They are something for the future. However the drive and enthusiasm for these projects is present now. This long-sighted view of planning the development of Qatar’s hydrocarbon resources coupled with a natural entrepreneurial spirit is a typical one today in Qatar as waves of projects follow each other.

Johann Van Rheede looks at GTL technology and the market for diesel fuels

Key political, economic, environmental and technical trends are converging around the world in favour of stimulating the growth of new-generation gas-to-liquids (GTL) conversion technology, arguably one of the most viable and promising solutions for the future of alternative and cleaner energy technologies.

In a nutshell, a GTL plant – such as ORYX GTL, currently being built at Ras Laffan in Qatar by Sasol in partnership with Qatar Petroleum – converts natural gas in three integrated production steps to produce an ultra-low-emissions form of diesel, as well as a premium-grade GTL naphtha and some liquefied petroleum gas (LPG).

The following factors underpin these key trends:

- the vastness of the world’s natural gas reserves, many of which lie in remote regions not conducive for economic conversion into liquefied natural gas (LNG);
- diminishing reserves of crude oil;
- unusually high crude oil prices – and the threat of these recurring frequently;
- the growing focus by an increasing

number of countries on their strategic need to secure and diversify their future energy requirements, thereby lessening their dependence on traditional crude oil imports;
- ever-increasing pressures for further reductions in exhaust tailpipe emissions;
- the increasing swing towards dieselisation in regions such as Europe, Australia and South Africa because of the significant advances gained in recent years in developing high-performance, diesel-powered passenger cars, and the diesel engine's superior energy efficiency compared with gasoline and other alternative-fuelled engines; and
- the mounting global drive to reduce emissions of greenhouse gases, most notably carbon dioxide (CO_2).

Diesel Enjoys Higher Status

Until recently, diesel engines used in the passenger-car market were largely stigmatised in many of the world's more developed economies because motorists regarded this fuel as too dirty, odorous and inferior. Diesel-fuelled compression-ignition engines in passenger cars were also noisier and less potent than their petrol-fuelled, spark-ignition counterparts. The situation was exacerbated because of diesel's poor cold-start properties in the long, cold European and American winters.

Today's new-generation passenger car compression-ignition engines, offered by almost all leading European, Japanese and Korean vehicle manufacturers, are a far cry from those built twenty years ago. Now that diesel-powered cars are quieter, smoother, cleaner and zestier, a growing number of motorists are attracted to the diesel engine's superior fuel efficiency. A typical automotive manufacturer can today produce any model of car with the certainty that a diesel-fuelled version will travel up to 60 per cent further than its gasoline-fuelled counterpart with the same size fuel tank and driving under the same conditions.

Inspired by such encouraging factors and, in particular, the significant advantage that GTL diesel is demonstrating over its crude oil-derived counterpart regarding reduced exhaust emissions, the South African-based, integrated fuels and chemicals company, Sasol, decided to expand its international footprint by commercialising one of its latest breakthroughs in the field of Fischer-Tropsch process technology, the Sasol Slurry Phase Distillate (Sasol SPD) process.

Sasol has been successfully using commercial Fischer-Tropsch technology since 1955. Since the late-1980s, the company has developed two advanced variants of its unique Fischer-Tropsch process, both of which are applied commercially in South Africa:

- the high-temperature version using Sasol Advanced Synthol (SAS) reactors at Secunda; and
- the low-temperature Sasol SPD process using at its heart the low-temperature Fischer-Tropsch (LTFT) Slurry Phase reactor at Sasolburg.

Sasol developed and refined these versions during the 1980s and the early-1990s to convert synthesis gas (syngas) derived from coal gasification. Both processes, however, can be adapted with very little modification – and harnessed competitively – to process syngas derived from natural gas reforming.

Launching the Global GTL Industry

Sasol, together with Qatar Petroleum (QP), is pioneering the world's GTL industry at Ras Laffan in north-east Qatar on the Arabian Gulf. Here, close to Qatar's vast North Field gas reserves, QP and Sasol (through Sasol Synfuels International) are developing the US$950 million ORYX GTL plant through their 51:49 joint-venture company, ORYX (Q.S.C.). The European construction company, Technip, is currently building the plant through a US$675 million, lump-sum contract in an established Qatari industrial region with harbour facilities.

Site work for the construction of the ORYX GTL plant commenced in October 2003. All civil engineering work, including pipe laying, will be completed in mid-2005. Major pieces of equipment, including the LTFT Slurry Phase reactors being fabricated in Japan, Haldor Topsøe autothermal reformers, a ChevronTexaco Isocracking unit and all compressors – all on long-lead order – will arrive at Ras Laffan in phases during the latter half of 2004.

Once brought into beneficial operation during the first quarter of 2006, the ORYX GTL plant will have a design capacity of about 34,000 barrels a day (b/d). It will produce, on average each day, about 24,000 barrels of GTL diesel, 9000 barrels of GTL naphtha and 1000 of LPG. The ExxonMobil Enhanced Gas Utilisation project at Ras Laffan will clean and supply cost-competitive natural gas from Qatar's North Field. This field has about 900 trillion cubic feet (tcf) of proven gas reserves – an oil equivalent of more than 160 billion barrels.

"Until recently, diesel engines used in the passenger-car market were largely stigmatised … because motorists regarded this fuel as too dirty"

Most of the GTL diesel from the ORYX venture (about 8 million barrels a year) will be marketed to customers in Europe, where most of this ultra-low-sulphur diesel will most likely be used as blend stock for higher-sulphur diesel derived from conventional crude oil refining.

The need constantly to lower the capital and operating costs of GTL plants remains the biggest technological challenge faced by the industry. The focus is on reducing the per-barrel-a-day installation cost from an initial $30,000 to $20,000 and even less. Continuous research and technology improvement is the mainstay of Sasol's effort to continuously improve its process integration, catalyst efficiency and low temperature Sasol Slurry Phase FT reactor technology to this end. Costs are also subject to the remoteness of the operation, the scale of the project, feedstock costs, infrastructure and many other factors. We at Sasol believe that GTL can be economically sustainable at a crude oil price of $20/b or even less.

Sasol Chevron is a global joint venture (50/50) between Sasol and ChevronTexaco and is responsible for the development, implementation and management of GTL ventures based on the Sasol Slurry Phase Distillate process and the marketing of their products. The GTL project which became Oryx GTL in Qatar, a joint venture agreement between Qatar Petroleum (51 per cent) and Sasol (49 per cent), preceded the formation of Sasol Chevron.

GTL Diesel Reduces Tailpipe Emissions Significantly

Through the combined expertise of Sasol Synfuels International, Sasol Technology, Sasol Oil and Sasol Chevron, Sasol has worked closely with original equipment manufacturers (OEMs), government bodies, automotive industry associations and reputable research, testing and standards authorities in Europe, the United States, Japan and South Africa in evaluating and testing GTL diesel since the early 1990s.

GTL diesel produced through the Sasol SPD process has virtually no sulphur (less than five parts per million; 5ppm), a high cetane number (greater than 70) and a notably low aromatic content (less than 1 per cent). These properties enable significant reductions in tailpipe emissions generated by vehicles powered by compression-ignition engines. The benefits may include substantially reduced emissions of nitrous oxides, sulphur oxides, carbon monoxide, unburned hydrocarbons and particulates.

GTL diesel has a significant combustion performance advantage because its cetane value is much higher than that of conventional diesel fuels. The higher cetane number not only decreases tailpipe emissions, but also allows for easier engine starting in cold conditions. GTL diesel is also significantly more efficient when comparing its use in a compression-ignition car with that of gasoline in a spark-ignition counterpart.

Besides reduced tailpipe emissions the ultra-low sulphur content of GTL diesel also offers a number of commercial benefits over its crude oil-derived counterpart in that:

- better engine wear is achieved;
- lubricants have greater longevity;
- fewer deposits are formed inside the engine; and
- exhaust catalysts achieve greater performance and durability.

In addition:
- exhaust odour is reduced, particularly after start-up; and
- engine noise is reduced.

"Sasol GTL technology may become the energy technology of choice for many countries during the next few decades"

Like most other severely hydrotreated low-sulphur diesel fuels, GTL diesel lacks natural lubricity and requires the addition of a lubricity improver.

Given Sasol Chevron's forecasts that GTL diesel could account for about 5 per cent of the current global diesel market within the next 12 to 15 years – and considering the relative growth in diesel over gasoline – Sasol GTL technology may become the energy technology of choice for many countries during the next few decades. This is especially relevant for countries seeking greater diversity in their energy supply, while keeping abreast of new developments in diesel formulation and usage.

Looking ahead, GTL naphtha may well be suited as a fuel of choice for future use in reformers for the production of hydrogen for fuel cell applications because it is sulphur-free and, compared with crude oil-derived counterparts, has a notably high hydrogen/carbon ratio. Fuel cells are expected to become an increasingly important component of the world's future energy mix.

GTL naphtha also contains a high proportion of paraffinic material, making it ideal for use as a cracker feedstock, or as feedstock for manufacturing solvents. It is therefore likely to become a preferred feedstock for chemical crackers because it has the right combination of chemical properties to increase the yields of ethylene and propylene, the two most important monomers for the high-growth international polyolefins industry.

GTL is Backed by Vast Gas Reserves

The world's vast natural gas reserves are currently estimated to be at least 146 trillion cubic metres or more than 5150 trillion cubic feet (tcf), an oil equivalent of at least 960 billion barrels. The larger reserves are found in and around the North Sea, the USA, Canada, Russia, Ukraine, Kazakhstan, Turkmenistan, Qatar, Iran, Iraq and other parts of the Middle East, as well as Algeria, Malaysia, Indonesia and Australia. The former Soviet Union (FSU) and the Middle East each hold an estimated one-third of these reserves.

About 50 per cent of gas reserves are in remote regions, far from established infrastructure. This factor makes remote natural gas largely uneconomic to develop through conventional monetisation methods because of high, if not prohibitive, transport costs.

In addition, large volumes of natural gas are being flared as associated gas in many commercial oilfields, as is the case in Nigeria, which flares more than 700 billion cubic feet (bcf) of natural gas annually. This amount of gas could produce about 180,000 b/d of GTL diesel.

Up until now, the preferred way to commercialise remote natural gas has been to produce LNG and transport it in specialised and expensive ships to selected markets. Through the Sasol SPD process, however, natural gas can now be converted, in situ, into high-quality GTL diesel suitable for the most advanced compression-ignition engines, as well as other higher-value hydrocarbon products, most notably GTL naphtha.

Upbeat Future of GTL

From the perspective of Sasol, working through Sasol Synfuels International and Sasol Chevron, the global GTL era has dawned. With ORYX GTL, the GTL industry has proved its commercial viability to the international money markets.

In addition, GTL diesel has a strong advantage on the environmental and strategic supply fronts, and that is why a growing number of gas-rich countries are thinking in terms of GTL technology as a potential way in which to monetise some of their gas reserves.

Bipin Patel looks at the economics of gas to liquids

Introduction

Over the last decade the GTL industry has made great strides towards becoming a global commercial enterprise. GTL in the form of LNG has grown from an industry of 80 million tonnes per annum (tpa) in 1993 to 130 million tpa today and is set to double this in the next 5–6 years. GTL technology, which primarily uses the low temperature Fischer Tropsch (FT) process, is poised to become a viable technical and commercial option to bring remote gas resources to markets. The FT technology provides an important and strategic option, complementing existing capabilities in the pipeline and LNG gas-technology for monetising gas resources.

The primary products from a GTL-FT process are high quality diesel for use in transportation fuels industry and naphtha as feedstock for the petrochemical industry. The transportation fuels market is estimated at 20 million b/d, which provides an unconstrained market for GTL products.

GTL therefore can demonstrate a significant role in the monetisation of gas reserves, at the same time providing a superior product in the market place.

Discussion

Does it make sense for Qatar to declare itself as capital of the GTL world?

The following factors tend to support this proposition:

- Qatar North Field Gas reserve is enormous and estimated to be more than 500 trillion cubic feet (tcf).
- Monetisation to date was only possible via LNG projects, and the limited regional pipeline (UAE)
- Further diversification is critical for Qatar and GTL provides this option
- Qatar's oil reserves are forecast to last for approximately twenty years. Large-scale monetisation of natural gas is vital for the country's future.

  In addition to the above Qatar, with its current political stability and favourable fiscal regime, can claim priority in the implementation of GTL facilities.

What is the value of GTL to Qatar?

- Monetisation of the resource, which is in practice remote from consumers.
- Future economic security and stability through diversification
- Value added products rather than direct sale of resources
- Maintenance of internal economic balance which reflects the world's highest resource income per capita
- LNG is faced with the competitive challenge of long-term contracts and price pressures
- GTL competes with crude-oil based products in an essentially unlimited market.
- Higher value for the gas is derived via GTL than via LNG when crude oil prices remain around the $25 range.
- Prestigious position in the Middle East and the world

What is the value of GTL to the companies?

- Overall economics i.e. reserves as assets, value of the associated liquids, better margins from gas than crude oil refining.
- GTL produces cleaner products, a plus for company profile in public perception and environmental responsibility.
- Diversification
- Overall improvement in companies' refinery pool – Cetane and Sulphur

Qatar needs to monetise its large gas reserves for its future economic stability. To date the primary route for this monetisation has been via LNG. GTL presents an alternative and is a close competitor to LNG.

In addition to the monetisation of large fields, GTL also has a role in the monetisation of associated gas where flaring is recognised both as a waste of resource and as a source of emission of greenhouse gases. Nigeria is one location, for instance, where efforts to curtail flaring by implementing GTL facilities are being aggressively pursued.

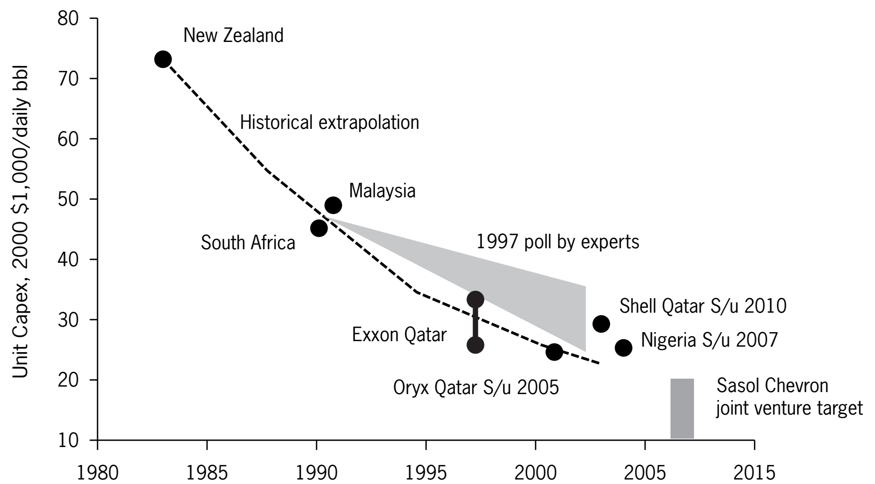
The following is an economic assessment of LNG vs. GTL for resource monetisation, and a comparison between crude oil refined products and GTL products.

Plant Overall Economics

The economic viability of a GTL plant is affected primarily by three main variables, the crude oil price, the capital cost and the operating costs including the cost of gas feed. This is different to the economics of LNG, which are related not to the crude oil price, but to the gas market dynamics. The operating costs of an LNG plant are also much lower as the process does not involve expensive catalysts; furthermore, the number of processing units in a LNG facility are fewer than those required for a GTL facility.

In terms of capital investment, both GTL and LNG involve high upfront investment costs. Although the LNG facility is less capital intensive than GTL (about 50 per cent of a GTL facility) the overall costs, taking into

Figure 1: GTL Capital Costs – Trend



consideration full value chain (costs of LNG ships and re-gasification facilities) are essentially similar.

Another important factor is the product yield or carbon efficiency. The LNG plant being a physical change process exhibits high carbon efficiencies in excess of 92 per cent, whereas the GTL chemical change process results in lower product yields reflected in carbon efficiencies of around 77 per cent range. A higher efficiency means lower feed costs.

Products from crude oil refining dominate the GTL products market. However, a key economic distinguishing characteristic of the two processes is that, unlike refinery ventures where the feedstock (crude) accounts for majority of the cash outflow, the capital cost repayment for a GTL venture represents the majority of the cash outflow. Consequently, the capital costs of a GTL facility play the most important role in the plant economics, and this high capital cost has been one of the criteria that have until now prevented GTL technology from reaching commercialisation.

Capital Costs

The capital cost of an integrated GTL facility (including the upstream gas plant) ranges from $25,000–35,000 per daily barrel of liquid capacity. This wide range in capital cost illustrates the effect on cost of a number of project specific factors. These include:

- Technology utilisation
- Location and site specific conditions
- The degree and scope of product upgrade facilities
- Availability of shared infrastructure
- Size of the plant

The capital cost trend of some of the projects over the past twenty years is illustrated in Figure 1. (Standalone basis)

The economies of scale have a profound impact on the capital cost of a GTL plant. This is illustrated in Figure 2.

All GTL complexes essentially consist of similar units with only minor variations specific to the technology selected.

Operating Cost

The most effective method of reporting operating costs for a GTL facility is to link it to the end product rather than to use a gas feed basis. This provides a more accurate assessment based on the unit cost of production and the unit of product sales.

The operating cost for a GTL plant excluding the cost of feedstock ranges from US$4.00–5.50/barrel of liquid product. The major part of this cost is associated with the cost of the FT catalysts.

The cost of the natural gas feedstock to the facility also represents a significant share and may be as much as $10/barrel based on a cost of approximately $1.0 per million Btu of gas.

Capital cost repayment is by far the largest portion of the overall GTL production cost.

A typical production cost comparison based on a barrel of GTL product, crude oil refined product and for a MBtu of LNG is shown in Table 1.

Profitability

Although Capex is a significant factor in determining the viability of the GTL venture, the swing in netback value is much more pronounced and influenced by the crude oil price. Consequently the decision to invest in GTL is largely dependent on the perception of future oil prices. A low crude oil price of $14–16 would place

Figure 2: Economies of Scale

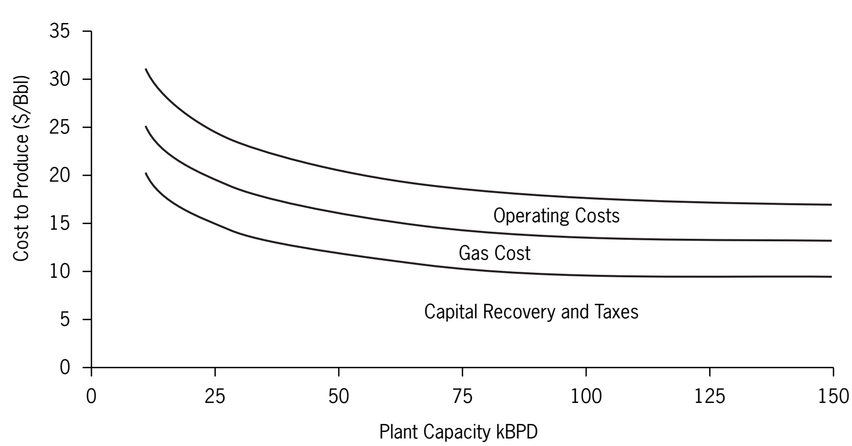


Table 1: GTL – Product Valuation (Typical Cost of Production)

	Cost per barrel		Cost per MBtu
	GTL	Refinery	LNG
Natural Gas	\$6–10		\$0.6–1.0
Crude Oil		\$18–25	
Operating costs	\$3-4	\$2–3	\$0.2–0.3
Cash costs	\$9–14	\$20–28	\$0.8–1.3
Capital costs	\$9–14	\$4–7	\$1.8–2.0
Cost of Product	\$18–28	\$24–35	\$2.6–3.3
	Integrated GTL 100 Kb/d	Standalone Refinery 100 Kb/d	Full chain LNG 7.3MMtpa

GTL ventures in an area of economic uncertainty. The overall profitability of a GTL plant can, therefore, be benchmarked against crude oil prices.

The GTL-FT should not, however, be viewed as a standalone business based on purchased gas conversion to high-value liquid product. It should, rather, be viewed as a gas-monetisation option, and the economics of the upstream facilities need to be accounted for in the overall assessment.

The Internal Rate of Return (IRR) for a typical project based on an integrated facility is much higher than one based on standalone facilities. This is primarily due to the additional products, such as condensate and NGL liquids, produced from the reservoir while processing only the lean gas in the GTL facility.

An illustrative IRR profile at various crude oil prices is shown in Figure 3.

The cost of the GTL facility will be largely determined by its location and be specific to particular site conditions and the availability of appropriate infrastructure. Qatar currently provides some of the most attractive frameworks for implementation of GTL projects, with its opportunities for further integration with other facilities and infrastructure within an industrial set-up.

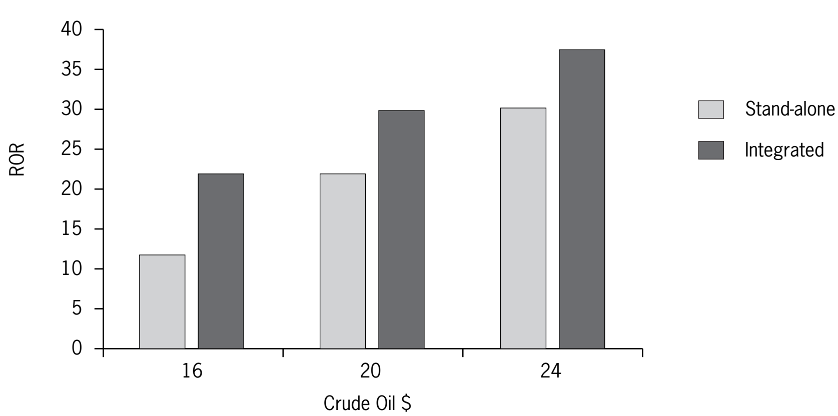
Conclusions

The main reasons for GTL to be the 'flavour of the year' can be summarised as follows:

- Diversification of resource monetisation
- Substantial technology and capital cost improvement potential
- Profitable and comparable economics to LNG alternative
- Large market for the products

Qatar exhibits characteristics which are conducive to GTL venture developments and can rightfully claim to be the capital of the GTL world.

Figure 3: Economics of GTL



Why Oil Prices Have Moved Higher

Paul Horsnell

The central point to be made about the move up in oil prices is that it reflects structural rather than cyclical issues. That is to say that higher prices are not the result of a random coincidence of short-term factors that could easily go away again. Instead, the move represents a significant structural shift upwards from the circumstances of the 1990s. Over the past two years, that shift has become reflected in longer-term market values, as is seen in the time curve for West Texas Intermediate (WTI) crude oil prices (Figure 1).

The back end of the oil price curve stayed between \$18 and \$21 for almost the entire period from 1986 to 2002. Whether prompt prices were at \$40 or \$10, longer-term prices rarely strayed from the narrow \$18 to \$21 band. A powerful consensus formed around the view that oil prices could not be sustained at levels above that band, and indeed that the longer-term trend had to be downwards. Over the past two years that consensus has been shattered by the sharp move up along the entire price curve. Over the course of 2004, crude oil for December 2010 delivery has not traded below \$27, and it has at points traded above \$30. Even during periods of weaker prompt prices, the middle and back of the curve have remained robust, with any moves down creating a burst of consumer hedging that has supported prices.

We see the move up in prices as being a drama in two acts. The first act was the period in which the market realised that the \$18 to \$21 consensus was too low for longer-term equilibrium. The second act has been a period in which further upwards pressure has arisen, primarily because of the consequences of keeping prices too low in the 1990s and creating absolutely the wrong set of market signals. In other terms, in the first act the market signalled that prices had to be higher to avoid a longer-term capacity crunch, and in the second act it signalled that just maybe things had been left a bit too late.

Figure 1: Time Curve of WTI Prices ($/b)

Source: *Barclays Capital*

The main component in the first stage of the move up in prices has been the increase of at least $10 in longer-term prices. There are several strands behind the justification of this rise, but three key elements can be isolated. First, and most important, several key producers face economic challenges due to high birth rates and the consequent implications for social expenditure and labour markets. Low oil prices did not give those producers an adequate ability to deal with those challenges, and therefore low prices proved to be both unsustainable and undesirable. Secondly, changes had been taking place in global oil demand, which was becoming less sensitive to prices and more closely linked to longer-term structural changes in emerging economies. Finally, non-OPEC supply was beginning to struggle in mature areas. Outside the Former Soviet Union, non-OPEC supply growth has been stagnating, providing a further support for higher prices.

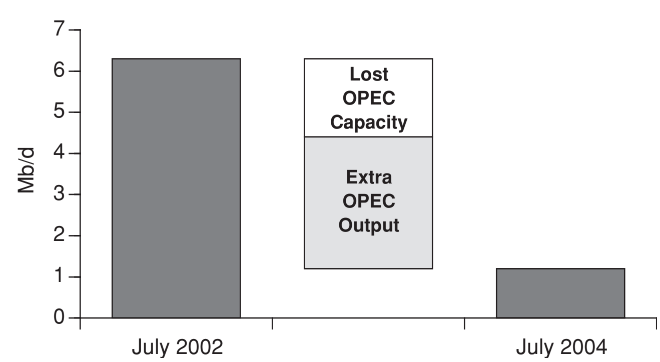
Price rises this year have been part of another phase, which has added further upwards pressure particularly at the front end of the price curve. The fundamental influences that helped producers to achieve more acceptable prices in the first phase, have continued with increased vigour and have started to get a little out of hand. The main dynamic has been a rapid increase in demand combined with a moribund supply side. This combination has reduced the amount of slack available at several points along the supply chain. This lack of flexibility, particularly in the downstream, is to the greatest extent the legacy of a lost decade.

In the 1990s, capital and commodity markets treated energy as if it was a declining industry with a permanent and irremediable overhang of excess capacity. It was seen as needing little new investment, and hence the returns to capital were derisory. The markets were wrong, or at least went far too far. Further, much of the ethos under which some OECD governments looked at energy was shown to be dogmatic and incorrect. In reality energy is an expanding industry with large and increasingly urgent capital requirements. By getting that wrong for a whole decade, conditions were created for the current decade to be one in which the main theme throughout the energy industries has been dislocations and the erosion of spare capacity down to suboptimal levels.

In the case of the upstream oil industry, spare capacity has shrunk dramatically over the past two years in the face of rampant demand growth, as is shown in Figure 2. Sustainable capacity is an often elusive concept and difficult to pin down precisely. However, on Barclays Capital estimates, global spare sustainable oil production has shrunk from about 6.3 mb/d in July 2002 to 1.3 mb/d in July 2004. This erosion of 5 mb/d over so short a period is perhaps the best illustration of quite how strong demand dynamics have been in relation to supply dynamics.

The 5 mb/d reduction in spare capacity can be split into two elements. First, there has been a reduction in sustainable capacity within OPEC, and most especially in three member states. In Venezuela, the oil workers' strike led to a significant loss of capacity. In Iraq, the legacy of a decade of under-investment under sanctions appears to have been exacerbated by the post-war policies of the coalition, and sustainable capacity has been reduced. In Indonesia, an increase in decline rates and a shortage of new projects has led to a consistent fall in capacity. While capacity has increased elsewhere in OPEC, the net change over the past years has been a reduction in sustainable capacity of more than 1.5 mb/d. The other, and more important, element in the reduction in slack is the extent to which OPEC has had to increase output to attempt to keep the market balanced. The need for this has in turn been created by the extent to which global demand has outpaced non-OPEC supply.

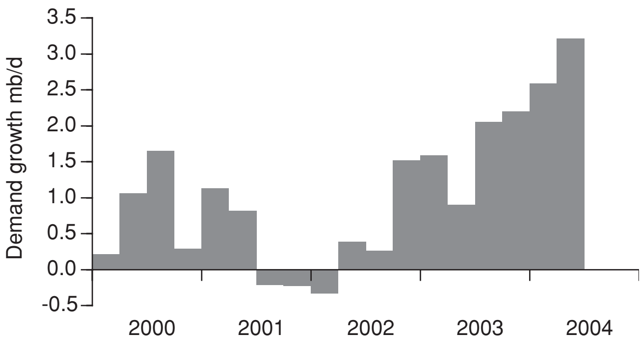
Figure 2: Spare Upstream Production Capacity (mb/d)



Source: *Barclays Capital*

The year-on-year changes in global demand are shown on a quarterly basis in Figure 3. Apart from the temporary reduction in growth caused by SARS in Q2 of 2003, there has been a clear acceleration in demand growth over the past two years. The previous conventional wisdom that prices above $20 would cause demand growth to cease has turned out to be very wrong. The highest prices for 20 years have been accompanied by the fastest demand growth for 25 years, because income effects have dominated price effects. Price elasticities appear to be much lower than was expected, and GDP sensitivities appear to be much larger. The surge in growth has happened on a global basis, although it has been led most strongly by the USA, China, India and Latin America.

Figure 3: Growth in Global Oil Demand (mb/d)



Source: *Barclays Capital*

In the face of so strong a demand surge, the supply side has been caught rather flat footed. Outside of the Former Soviet Union, non-OPEC supply fell between July 2002 and July 2004. All non-OPEC growth has come from the Former Soviet Union, and most particularly Russia. Output from the Former Soviet Union has increased by some 2 mb/d over the past two years, well short of demand growth, but enough to have stopped the world completely running out of spare capacity. This has left OPEC to take up the slack. OPEC has found that by the current quarter the call on its crude oil has exceeded even very recent expectations by up to 4 mb/d. Given the lags involved in bringing new capacity on stream, it is hardly surprising that this great a shock should have compressed spare capacity so significantly. That compression has also been reflected in the downstream. For several years the lack of flexibility in US refining has been having a major impact on prices and causing frequent product price spikes. This year, the demand shock has meant that the tightness in oil refining has become a global phenomenon.

The scale of demand growth, and the associated reduction in spare capacity, has been so great as to render as unnecessary any other explanations for the additional push up in prices this year. However, there are two other explanations which have gained wide coverage and acceptance. We believe that both are incorrect and unhelpful.

The first of the alternative explanations is that higher prices are due to the actions of speculators. To be specific, it is alleged that there has been a rush by hedge funds and commodity trading advisors to buy oil. The suggestion that normally goes with this theory is that higher prices are not justified, because hedge fund buying must necessarily involve a decoupling from fundamentals. There are two problems with this theory. First, hedge fund buying is not necessarily unrelated to views of the fundamentals. Earlier this year, some analysts said that the funds were artificially inflating prices, because the fundamentals implied lower prices due to an impending huge surplus of oil in Q2. The reality proved to be quite the reverse, but nobody has said that in retrospect maybe the hedge funds were buying on the basis of what proved to be the correct view of the fundamentals.

The other problem with the speculative driven market theory is, however, far more serious. The reality is that speculators have in fact been net *sellers* of oil in 2004. In the first week of 2004, net speculative (i.e. non-commercial) long positions across all US oil futures contracts amounted to 115.5 million barrels (mb). By the last week of June, those positions had shrunk to just 32.5 mb. In other words, a period of rising prices has been accompanied by net selling by speculators of 83 mb. Far from creating any unsustainable bubble, speculators have on balance had a depressive impact on oil prices in 2004.

The second alternative view is the 'fear' or 'risk' premium theory. This is ingenious and runs as follows. An analyst will take a view as to what the fundamentally justified level of oil prices is, sometimes by reference in isolation to the level of US crude oil inventories, sometimes just by the contention that their own price forecast must be the correct fundamental price. The gap between the actual price and this 'fundamental' price must then be due to something which is 'non-fundamental'. If you then say that this something else must be fear of supply outages from terrorism or other shocks, you must have a 'fear premium'. By this method you also have an exact measure of that premium. Then analysis becomes very easy, because every daily change is explainable. Prices fall, so clearly the fear premium must have contracted, prices rise so clearly there must be a larger fear premium. The problem of course is that the result is used as an assumption. It is assumed that the model used to derive the fundamental price is correct and that there has been no structural shift upwards in prices. This process then generates the result that there has been no structural shift upwards in prices because all the increase is fear or risk. In other words, the fear premium theory is the intellectual equivalent of the three card trick.

It is best to avoid attributing the sustained strength of prices to speculators or artificial notions such as the fear premium. In so doing, one runs the risk of missing the true reasons. Oil prices have moved higher due to structural factors and not temporary or artificial distortions. Indeed, from the point of view of securing longer-term supplies and market balance, any significant move lower in the short to medium terms would hold some dangers.

The Value of Oil and Gas Reserves

SEC Definitions of Proved Oil and Gas Reserves (Regulation S-X, Article 4)

So much has recently been heard of these SEC definitions that we felt it would be useful to record precisely what they are. We realise that some readers of Forum will be able to quote them, probably in their sleep, line by line, but there may be others who will be surprised to find how uncomplicated they seem to be, at least until the experts set about complicating them. At any rate, here they are: subsections (2), (3) and (4) of the Definitions under Reg. 210.4-10 which 'prescribes financial accounting and reporting standards ….pursuant to Section 503 of the Energy Policy and Conservation Act of 1975 (EPCA) …. And section 11,c of the Energy Supply and Environmental Coordination Act of 1974 as amended by section 505 of EPCA.'

(2) *Proved oil and gas reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the 'proved' classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(a) oil that may become available from known reservoirs but is classified separately as 'indicated additional reserves';
(b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors;
(c) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and
(d) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

(3) *Proved developed oil and gas reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as 'proved developed reserves' only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(4) *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates, for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Peter Nicol considers the accounting of reserves

Reserves accounting has hit the headlines in recent months following Royal Dutch/Shell's announcement regarding its 'proved reserve recategorisation'. A number of other companies have also announced significant changes in their published reserves including El Paso, Nexen and Forest Oil. In addition there has been the widely publicised debate around the reserves booking for the Ormen Lange gas development in Norway and whether Norsk Hydro and BP will be able to reflect the same reserve numbers in their annual US financial filing (20F) as in their Annual Reports.

There are a number of debates. The adequacy of company reserve disclosure, the definition of the reserves which are disclosed, the interpretation of the existing US Securities and Exchange Commission (SEC) rules and consequently whether this is an industry generic issue or limited to certain specific companies or both. In this discussion we will look at the issues from the standpoint of an investor in the companies.

There are two investor standpoints in financing companies – the viewpoint of a lender and the viewpoint of an equity investor in the corporation. The discussion will concentrate on the viewpoint of an equity investor, but it is worth highlighting that equity investors and debt investors may have very different preferences in terms of reserves. Even assuming that both sets of investors are considering the same P50 (proven and probable) reserve estimate their preferences in terms of the distribution and probability of reserve estimates could well be different. The debt investor would be more concerned to ensure that the P90 (proven) level gave comfort for the repayment of principle and interest, whereas an equity investor may be prepared to take more risk here if there were greater potential upside from the P50 to the P10 level (proven probable and possible). So even when there is agreement on the most likely reserve estimate, there will be different priorities and preferences from different user groups. The remainder of this discussion will be taken from the viewpoint of an equity investor or shareholder, the ultimate owners of the company and, in turn, the underlying reserves.

The Adequacy of Company Reserve Disclosure

Analysts and investors looking at the international oil companies tend to spend a disproportionate amount of time on the upstream compared to gas and power, refining and marketing and chemicals. There are two reasons for this: financial disclosure is greater for the upstream and secondly the upstream in recent years has accounted for the majority of the assets and the highest (book) returns within the industry. In simple terms, investors buy oil companies for their oil.

One difficulty in analysing an oil company balance sheet is that it does not reflect value. The balance sheet records the historic costs associated with drilling for, development of, or acquisition of oil and not the value of the oil and gas interests. The reserve disclosure while not perfect helps investors to fill this information gap.

Different Reserve Disclosures

The Penwell International Petroleum Encyclopedia gives a description of reserve definitions on its web site *http://orc.pennnet.com*. The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) published updated reserve definitions in 1997 to include the use of probabilistic evaluations. The SEC definitions tend to be based (albeit not exclusively) on deterministic methods. Deterministic methods provide a single best estimate of reserves based on geological, engineering and economic data. Probabilistic methods generate with similar data a range of estimates and their associated probabilities – proven (P90), proven & probable (P50), proven probable and possible (P10).

There are a number of reserves disclosures and standards around the world with P50 reserves disclosure allowed in the UK, Norway, Canada and Australia amongst others. However, the most widely used disclosure is that required by the US SEC due to the importance of US capital markets and the fact that most major private oil companies have a US listing. Under the US disclosure companies are required to report their ‘proved’ reserves similar to, but not equivalent to, proven or P90 reserves. While the SEC will accept probabilistic reserve estimates if professionally prepared, the difficulties arise under the SEC definition of what constitutes ‘reasonable certainty’. In the USA deterministic reserves remain the most common method as it satisfies the SEC proved reserve definitions in establishing ‘reasonable certainty’ where e.g. there is no known hydrocarbon-water contact or there are untested fault blocks that may be dry when drilled.

European and Australian based companies will adopt IFRS (International Financial Reporting Standards) from January 2005, but at present there is no IFRS that specifically addresses the accounting for the exploration and evaluation of mineral resources. In addition, mineral rights and mineral resources including oil and natural gas are excluded from the scope of IAS 16 (Property Plant and Equipment).

A move to International Accounting Standards will provide an opportunity to harmonise, re-evaluate the data presented and, in the view of some, update the information relative to that currently presented under US GAAP (Generally Accepted Accounting Principles). However, the fact remains that the market will remain dependent on the requirements under US disclosure and the work of the SEC. It is debatable whether a number of non-US companies would be as forthcoming with information if it were not for the requirements of their US listing, so even if there are limitations with the data presented, it provides a useful source of information for the market place.

As mentioned above, US disclosure requires proved reserves, which for simplicity we will take as equivalent to the P90 reserves. The complaint is that this does not reflect economic reality or the reserves that the company is using when formulating its internal plans and projects. This requires the company to maintain two reserve data bases (the real reserves and those being allowed for financial reporting) and paints a conservative view of the company’s position. Investors are interested in the real economic data and, as shareholders, have no wish to see companies spend money unnecessarily and would broadly concur with these complaints.

However the surprise from an investor standpoint is the extent and magnitude of the downward revisions to these 'conservative' reserves. Press reports suggest that the recent SEC enquiries were sparked off in light of companies booking reserves, but then failing to increase production, meet production targets or carry out further work on the announced 'discoveries'. Presentations by petroleum engineering consultants Ryder Scott appear to support this contention.

The conundrum from the investors' standpoint is whether the discrepancy between the reserves and the production represents timing differences (the lag between booking and production coming on-stream), over-optimism on the reserve estimates, or a problem with the existing reserves with higher decline rates or lower recovery factors than previously realised.

There is also the surprise that assuming that the proved reserves have been added conservatively (without probabilistic or portfolio assumptions) then the likelihood that the total reserve base should have had to be revised down at all should have been very low. This undermines the original claims of conservatism. If this problem were just affecting small companies with one or two assets then it would be more easily understood, but the fact that larger and more diversified portfolios have also been impacted with significant (which the SEC is believed to define as greater than 10 per cent) changes is very surprising. The conclusion must be that there are certain issues related to specific companies.

SEC Rules Interpretation

The SEC has also come under fire from a number of interested parties for its decision to tighten its interpretation of the rules and to disallow some common industry techniques in reservoir evaluation. 'Lowest known hydrocarbons' and the use of 3D seismic are the most obvious examples. This does appear to be an area in which the SEC is being unduly conservative or where its rules (dating back to 1978) need to be updated.

The different levels of reserve booking for the Ormen Lange gas field development in Norway have received considerable press, industry and investor interest. In terms of economic reality, it is not a case of some companies being more conservative than others by 'booking' lower reserve numbers for the financial accounts. The five partners (Statoil, Norsk Hydro, BP, Royal Dutch/Shell and ExxonMobil) have all agreed to a development plan and to finance their respective shares based on a common view of the P50 reserves and associated development costs. If the lower 'conservative' reserve bookings turned out to be correct, the economic disaster would afflict all, namely that all five partners had invested $12bn in an uneconomic project.

> "A simple adjustment to the existing SEC disclosure would eliminate much of the debate"

However this issue has highlighted another industry practice of when and how companies book reserves. The practice of 'smoothing' reserve bookings in order to show steady reserve growth can be just as misleading to investors as over-booking. While companies may state that the P50 reserve estimate is the most likely, the industry does not appear to book 100 per cent of the P90 reserve level once a field is recognised, preferring instead to recognise different and usually increasing volumes over time. 'Smoothing' effectively understates the reserve volumes compounding the problems of a reserve definition that the industry is complaining is too conservative in the first instance.

An Industry or a Company Problem

It would appear that there are industry generic issues – the definition of reserves to be disclosed, the definition and interpretation of reserve bookings and the timing of reserve booking – all come to mind. However as pointed out above, the magnitude of certain reserve restatements suggests that there are also a more limited number of company specific issues, which need to be addressed by the companies concerned. The question is 'what should companies have to disclose?'

What Should Companies Disclose?

A simple adjustment to the existing SEC disclosure would eliminate much of the debate on which company is conservative or aggressive in its reserve booking. Norsk Hydro and Pemex both detail the complete list of fields and the reserve quantities associated with their overall reserve booking. Companies will comment that this reserve information is confidential or cannot be disclosed under the terms of licence/operating or partner agreements. However this is debatable when the information being disclosed is not the 'real' P50 reserve estimates (it's the 'proved' or P90 reserve estimate) and the financial or fiscal terms are not being disclosed. In addition, given that many Western governments and NGOs are pressing for greater disclosure by the industry of its financial and tax payments to developing countries, this may prove to be a useful adjunct helping the companies in their argument for greater disclosure.

Amongst the many issues that the International Financial Reporting Standards will have to address are whether the disclosure of reserves should be supplemented with greater financial and value disclosure as reserves have very different values depending on their location, maturity and the fiscal regime. In terms of the volumetric disclosure, the reconciliation of annual reserve movements already presented under US disclosure would form a strong framework from which to start. However the disclosure could either be augmented to disclose movements in P10 and P50 reserve estimates as well as movements in proved (or P90) reserves.

Some may make the case that the P50 are the best estimates of reserves and hence are the 'real' reserves and that only this should be disclosed. However from an investors' standpoint there is an important overlay to the P50 levels which it would be helpful to disclose – namely the commerciality or likelihood of commerciality of these P50 reserve estimates. While P50 reserves may be produced many years into the future, there is a difference in the perception of value in many investors' minds between those P50 reserves associated with a development which is already underway or producing and a development which still may be many years from commerciality and final investment decision. It would be useful to put some economic criteria around the definition of P50 reserves rather than just that they exist volumetrically.

The SPE/WPC or the proposed UN framework for reserve definitions may be the means of determining the appropriate level of disclosure in terms of the number of definitions disclosed and the appropriate criteria behind those reserve disclosures. A balance will need to be struck between simplicity, the extent of the reporting burden to be placed on companies and the usefulness of the information.

Finally, while many may think that a move to P50 will solve many of the current problems by moving to a more realistic level of reserves, any change will necessitate a different mind set from both investors and the reporting companies. Larger companies have used the inherent conservatism of P90/proved reserves to demonstrate steady growth in the reserve base over the longer term. While this may understate the 'true' picture or value of these companies in any one snapshot, it does lead to the impression that large resource companies are sustainable and provide steady long-term growth. The challenge in moving to a P50 reserve disclosure is that reserve movements should be equally likely to increase or decrease. Investors will have to become used to greater volatility of reserves while companies will need to prove that they can indeed grow over the longer term.

Brian Rhodes and Andy Crouch define the valuation of reserves

The announcement by a number of high profile companies this year that they were revising the proved reserves being reported to the US Securities Exchange Commission (SEC) caused shock waves to pass through the industry. Other companies then looked hard at their own numbers and in some instances also amended their proved reserve statements. The impact has wider ramifications than for the individual companies. The stockbrokers, their analysts and institutional fund managers, let alone the shareholders themselves, do not know what to make of it all, or who has correctly stated their proved reserves, if indeed it is possible really to be correct.

Arguably one of the main results from these downgrades has been the acknowledgement that the basis for reserves numbers and even the terminology is not uniformly understood. At the outset then it is worth first reminding ourselves what the term 'reserves' means. By definition reserves are:

i) Discovered
ii) Recoverable
iii) Commercial
iv) Remaining

All four factors must exist. Reserves are also only ever 'estimated', never 'determined' due to the uncertainty that comes with the territory of working with nature and physical parameters you cannot see.

We must then consider the various frameworks for reserves estimating. Reporting reserves to the SEC is currently the biggest area of debate, due to the impact that it has on the financial world. The SEC has its own set of definitions which have remained unchanged since first written in 1978, but these deal only with Proved Reserves as they should be calculated under those definitions, which state:

> Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Whether they are right or wrong, or as is widely suggested whether they need to be updated due to technological advances or other reasons is not debated here. It is a simple fact that companies can and still do report according to those definitions. Perhaps the problem is that the SEC limits the amount of information that the companies can release, and that the information that can be released is too restrictive to demonstrate adequately their business. The result may be that companies end up testing the limits of the definitions.

> "it would appear that there is a wide range of uncertainty, which looks like anything other than 'Reasonable Certainty'"

The more-widely used industry definition is the Resource Classification System generated jointly by the Society of Petroleum Engineers (SPE), World Petroleum Congress (WPC) and the American Association of Petroleum Geologists (AAPG). It deals with all assets from undrilled prospects to Proved Reserves and its use as the industry base would allow companies the opportunity to demonstrate adequately the extent of their assets.

One problem we currently face is that reserves reported under the SPE/WPC/AAPG Proved Reserves definition can be different to those under the SEC's. While the SPE Reserve definitions wording for Proved

Reserves is essentially the same as that of the SEC it differs in its use of 'current economic conditions', which allows for averaging of historic prices and costs that are 'consistent with the purpose of the reserve estimate'. The SEC requires prices to be used at the date of the reserves estimation, so even when we see the term Proved Reserves quoted, we are not necessarily looking at the same thing and, of course, Proved Reserves stated during a high oil or gas price may be much less when estimated under a lower price.

The fundamental requirement of both the SEC and SPE/WPC definitions is that for Proved Reserves there must be 'reasonable certainty' that the volumes will be recovered. Although the recent high profile revisions made by one of the companies affected a number of its assets, focusing on just one of those assets can show large differences of opinion. In this specific instance some of the joint venture partners have also made their own public statements to defend their positions; one stated '... [the company] has not made any changes to the ... reserves it has placed with the SEC…'; and another advised 'We are completely confident of the reserves we have booked'. Yet when each of these individual companies' net Proved Reserves is grossed up to a full field basis the result is a fourfold variation. All of these are supposedly estimated using the SEC's Proved Reserves definitions which are worked under the banner of 'Reasonable Certainty'. However, it would appear that there is a wide range of uncertainty, which looks like anything other than 'Reasonable Certainty'. This is just one field, so how are readers of this information going to make judgements on investment in all of the assets of these companies involving vast sums of money with such a diversity of numbers? Remember that it has been the SEC's goal to provide investors with the ability to compare companies on a like-for-like basis.

From the companies' perspectives, the decision to invest in the development of any field would not be made on the sole basis of the Proved Reserves disclosed under SEC definitions, nor would a government necessarily approve the development on this basis alone. The companies would have made that decision on the basis of their 'best estimate', or however they refer to the outcome that they expect to be the more likely than not. These 'best estimates' will have been tested for robustness with a series of sensitivity tests looking at all of the fundamentals of ultimate recovery, depletion scheduling, capital costs, operating costs, sales prices, inflation and exchange rates, before the company and then the collective joint venture decides to make the investment. In the case of the specific field alluded to above, this is close to a US$10 billion investment decision. It is unlikely then to be a decision taken lightly or in the face of the implied diverse Proved Reserves element.

"Current trends show that the F&D costs across the industry are increasing"

Perhaps there is reason to suggest that the better reporting criteria are those that reflect the level at which the investment decisions are made, since that is the level at which shareholder funds are invested. The case presented by the above field's fourfold variation in Proved Reserve volumes, would suggest that there is perhaps more certainty among the owners around the 'best estimate' reserves level upon which the joint venture has made its investment decision.

However, with all of this in mind, how does the financial world look at the companies and what metrics do they use to measure and compare? Analysis of financial data is of course historic in nature and the analysts use other measures such as Reserves Replacement Ratios (RRR), allocation of Proved Reserves between Proved Developed (PDP) and Proved Undeveloped (PUD), Reserve life, and Finding and Development costs (F&D cost) to look at companies. These can reveal important trends when presented year-on-year and offer insights into the future potential of the companies. But at the same time these numbers are related only to the Proved volumes and thus in themselves can lack information which displays the real future of the companies from the overall resource base.

What do these metrics show us about the companies? The analysts tend to want to break them down into their peer groups (e.g. Five Sisters, Large E&P, US Integrateds, and so on) for comparison purposes and certainly this helps to see how the groups are performing relative to one another and how the companies within each group compare with their peers. However, for US reporting companies this analysis is based solely on Proved Reserves. A company could have a dynamic year with the drill bit but the volumes to be included in any company analysis may only be considered once they are booked as Proved Reserves, which could take several years. The phasing of Proved Reserve recognition and related capital costs could therefore distort a company's F&D costs. It may also be inconsistent with other reported actions. As noted in the example above, a fourfold variation in the Proved Reserves for a US$10 billion development would create incompatible comparative F&D analyses for the same field.

Current trends show that the F&D costs across the industry are increasing, albeit some of this may be as a result of declining volumes of lower classified resources/reserves which can be elevated to the Proved category. While it is agreed that it is important to know the capital outlay for the future since this can point to higher capital employed which can mean lower returns, this in itself is linked to oil price. The period from 1990 to 1999 showed an average Brent price of around $19.70/barrel, but this has increased since then with the period 2000 to May 2004 averaging over $27.3/b with 2004 itself over $33/b, and record prices at the beginning of June. Thus, while the recent trend for increasing F&D appears to be a negative factor, the oil price has worked in the opposite direction with many companies reporting record-breaking profits.

Similar variations in RRR and reserve life would also occur as these are also determined from only the Proved Reserves. However, the one metric where more can be learned is from the ratio of PDPs to PUDs since this is simply the split of the Proved Reserves. Movement year-on-year in this regard, especially in an increasing upward trend of PUDs, could be a clear adverse indicator for a company since capital is required to develop these assets and therefore re-categorise them as PDPs. Also it should always be the intent of the company, at least in terms of oil reserves (gas reserves may be developed in line with long-term sales contracts) that once reserves have been classified as PUDs they should be elevated to PDP status in a reasonable time frame. Proved oil Reserves remaining as PUDs for a significant period of time are (and should be) at risk of downward revision, subject of course to allowance for other factors such as OPEC constraints and limited pipeline capacities.

The effect of changes in oil (or gas) prices on reserves bookings is also worthy of comment. Companies invariably have a mixture of petroleum legislations in which they have their operations, which will mix tax and royalty regimes with production sharing contracts. A changing oil price has opposite effects in these regimes – a higher oil price can mean higher proved reserves in a tax and royalty regime, whereas in a production sharing contract the higher price means lower entitlement volumes, which is the proper way to present such contracts. Thus a significant shift in oil price at any time during corporate reporting periods could make significant changes both up and down, depending on the legislation and direction of price, while in reality the gross volumes themselves may be no different.

Thus, in summary, we must ask ourselves whether the analysts have sufficient data to measure company performance properly. Certainly they are only looking at one specific element of the business (the Proved Reserves) albeit this is the area where, in many cases, most of the value can be attributed and thus a valuable metric in itself. However, several of the other metrics are inter-dependent and determined only from the Proved component of the total resource base and thus may not provide the full assessment of company performance. Can we be sure then that the results of their analysis can be taken as 'reasonable certainty'?

The SPE states 'Estimation of reserves is done under conditions of uncertainty'. In an ideal world the aims should be to do our best to if not reduce then certainly quantify that uncertainty. GCA has many years experience in estimating resources and reserves and classifying them according to both the SEC and the SPE/WPC/AAPG definitions. This includes not only the calculations themselves but also advising on internal company guidelines and on internal processes to ensure that companies understand and appropriately categorise their hydrocarbon assets.

Personal Commentary

Peter R. Odell

During the recent oil price 'crisis' it was ironic that the UK's Chancellor of the Exchequer, while castigating OPEC's members for failing to produce enough oil to bring prices down, ignored the UK's role since the early 1990s as one of the top-10 global oil producers. He also failed to admit that the now-declining UK oil output results from a less than pro-active government policy for the country's hydrocarbons industry.

Initially, this reflected the government's unwillingness to make economically worthwhile public investments in oil and gas to supplement the private sector's effort. More recently, however, it has also reflected the government's obsession with a perceived need to constrain carbon fuels' use and to stimulate 'green' energy production with generous subsidies.

Last year's Energy White Paper (reflecting the PIU's earlier Energy Report to the Prime Minister) epitomised the government's anti-oil and gas attitudes. There were, indeed, only 60 lines of text on the UK's world-scale upstream hydrocarbons industry in the White Paper – from a total of 5000 lines in the document!

Such perfunctory treatment of the country's massive hydrocarbons industry grossly understates the economic and political significance for the UK of this overwhelmingly dominant sector in the country's energy economy. Since 1974 some 4500 millions tons oil equivalent of oil and gas have been produced, equal to the equivalent of over 75 per cent of the UK's *total* energy use during this period. Over the five years to 2003 their share was 95 per cent.

The Importance of Hydrocarbons Production to the UK

Apart from the long-term security of energy supply which indigenous hydrocarbons production has given to the UK in a world of uncertainty over energy supplies, the favourable impacts of the oil and gas industry on the country's GDP, on direct and indirect employment and – most of all – on its balance of trade has been formidable. Indeed, net export earnings from indigenous oil and gas over the five years from 1998 have contributed almost £6000 million per year to the balance of trade, while the value of the energy import substitution effect has averaged £9000 million per year. This £15,000 million per year net external payments' contribution from indigenous hydrocarbons' production can be compared with the average annual balance of trade deficit over this period of £30,000 million per year. Without oil and gas this deficit would have been 50 per cent greater.

Given these political and economic advantages for the UK from its hydrocarbons industry, the absence of calculations in the Energy White Paper of the resource costs which will emerge for the country from the change from net energy exports of 28 million tons oil equivalent in 2003, to net imports of 190 million tons in 2020 (assuming energy use in that year of 250 million tons) is inexplicable. At current price levels, a swing from net exports to net imports will generate a major additional annual burden on the UK's balance of trade of some £25,000–28,000 million (depending on the shares of oil, coal and gas in the volumes of imported energy), adding 65 to 85 per cent to the already formidable deficit on trade. Moreover, the current near-100 per cent security of energy supply through the availability of indigenous production will be reduced by 75 per cent.

Necessity for an Inquiry into the UK's Oil and Gas Prospects

The Energy White Paper and the policies based on it neither address this prospective massive deterioration in the UK's balance of trade nor the loss of energy supply security arising from the forecast rapid decline in indigenous hydrocarbons production. Likewise, there is no consideration of the country's consequential GDP and employment losses; nor of the impact of reduced annual inward flows of foreign investment to the upstream hydrocarbon industry. There is thus a pressing need for a comprehensive inquiry into the validity of the assumptions that lie behind the government's acceptance of a rate of decline in oil and gas production, which is without precedent in the global history of the industry (except for declines arising from purely political circumstances).

Such an inquiry must include the following elements –

- *first*, an examination as to why the government views the UK's remaining resources of oil and gas so pessimistically that it forecasts a 35 per cent production decline by 2010 and one of 75 per cent by 2020; implying a cumulative output of only about 16 billion barrels of oil equivalent over the 18-year period 2003–2020. Yet even the relatively cautious estimates of the oil companies indicate that there are at least as many resources which remain to be exploited as have been produced to date, viz. some 33 billion barrels oil equivalent, while Dr. J. Munns, a Senior Geoscientist at the DTI, estimates that there could be up to 47 billion barrels oil equivalent of remaining recoverable oil and gas under the UK's continental shelf and slopes, most of which still remain geographically and/or geologically under-explored (see *Offshore*, 62(4): 48–50, April 2002, and 63(4): 38–40, April 2003).
- *second*, an evaluation of the failure of the present antiquated discretionary concession system and its associated tax regime to ensure a continuing process of exploration for, and exploitation of the UK's offshore hydrocarbons.
- *third*, consideration of an alternative manner of exploiting the country's remaining ultimate hydrocarbons resources through the introduction of tried and tested production-sharing agreements between a publicly-owned entity (say, a Strategic Oil and Gas Authority) representing national interests, and the exploring/producing companies. Under such arrangements, state investments, usually requiring a lower rate of return (compared with the much higher rates expected by the private sector), reduce the financial risks to the companies concerned, so enhancing oil and gas production.
- *fourth*, a comparison of the highly pro-active Norwegian state involvement (through Statoil ASA, the Norwegian Petroleum Directorate and Petoro AS) in the exploitation of that country's hydrocarbons wealth, with the UK government's essentially reactive approach to oil and gas development in which the effective decision-takers on the levels of exploration and exploitation activities are the concessionary companies. Such decisions necessarily take only the companies' interests into account, as demonstrated in the recent partial withdrawal of both BP and Shell from their commitments to the UK's upstream hydrocarbons exploitation in order to finance their operations elsewhere in the world.
- *fifth*, consideration of the need for an entity independent of the producers, for ensuring the timely development of optimal offshore pipeline networks to collect and deliver the oil and gas to markets – as in the case of the defined role of the recently-formed Norwegian company, Gassco AS, for this purpose.
- *sixth*, an analysis of the degree to which actions by OFGEM to enhance competition in gas and electricity markets have discouraged investments in the UK's upstream gas developments.

A Re-vitalised UK Oil and Gas Industry is a Pre-requisite for the Shift to a Low Carbon Economy

These analyses will show the important modifications that can be made to the organisational, fiscal and technical systems of the UK's offshore hydrocarbons systems to ensure continuing expansion of exploration and exploitation. The present government assumption of an inevitable rapid decline in the UK's oil and gas production will certainly be undermined. Instead a more pro-active participation by the state to secure the national interest, through the development of the deeper and more complex geological opportunities on the UKCS, would ensure a continuing high level of indigenous oil and gas production until at least 2020. Thus, costly and less secure prospects of dependence on imports of oil and gas would be avoided.

A more intensive exploitation of the UK's remaining resources of oil and gas will, paradoxically, not even be at odds with the government's desire to move the country towards a 'low carbon economy'. The additional indigenous hydrocarbons production which can be achieved by 2020 (viz. at least 10 billion barrels oil equivalent above the White Paper's implied level of 16 billion), will replace the country's otherwise rapidly growing volumes of high-cost imports of oil, gas and coal. Over the period, that is, when there are only relatively limited possibilities of switching to the use of renewable energy. Thus, the creation of additional national income, in general, and of government revenues, in particular, through the full exploitation of the UKCS' hydrocarbons resources seems likely to be the only possible way whereby the state can sustain the necessary investments for the subsidies required by the private sector for the longer-term establishment of a low carbon economy.

Asinus Muses

Kyoto in Hollywood

Asinus reads that $125 million has been spent on the environmental disaster film, The Day after Tomorrow. It seems a pity that they didn't do a whole week for $1billion. By the end of the week the climate would surely have changed back again, creating, of course, another set of still greater disasters.

TIMED out

While thinking about oil exports from the Gulf, Asinus is wondering how to define the difference between Terrorists, Insurgents, Militants, Extremists and Dissidents.

Lost in Translation

There are, apparently, 85,000 pages of EU rules that must be translated into the language of each EU member before they become enforceable in national courts. So, if Latvia, for instance, doesn't like some clause or other in the EU Treaty, the apparent solution is to forget, or be unable, to translate it into Latvian. Could this, Asinus wonders, be applied in some way to the Constitution – or even to a referendum – for those in political trouble?

Alice in Kyoto

Asinus is fascinated to see whether negotiations for Kyoto 2 will begin before Kyoto 1 has come into force. It would seem logically perverse, but the climate does, after all, exist in a wonderland of its own.

Kicking against the Pricks

Asinus is reminded that about 1000 years ago King Canute called upon external forces to reduce the quota of tidal water lapping against the UK coastline – but he still got his feet wet. Now we have the Group of 8 finance ministers calling upon external forces to reduce the price of oil, in this instance by increasing the quota. They will probably get their fingers burned, except that these days retroactive reinterpretation of statements provides them with protective clothing.

Double Speak

On Nymex they say, 'Buy the rumour and sell the fact', so what do you expect the price to be when 124 million 'long' barrels are reported. Blame OPEC, of course.

Lunch Box

'EU finance ministers are now expected to discuss the oil price rise over lunch at a meeting next Wednesday…' Asinus imagines that the meal will have started with Caviar Iranien and ended with Bombe Americaine. Toasts will presumably have been drunk to OPEC and DG XVII.

On Bended Knees

Please, oh Opec, raise your quota
Thus declaring you denote a
Lower price. But whether this is low or high
Demand cannot exceed supply.

Wake up

It seems appropriate that a strike by Norwegian oilfield workers managed to put Snorr A and B platforms to sleep for a few days.

Bright Sparks

Asinus has heard a rumour that Shell Chemicals is engaged in research for an anti-depressant.

Pain and Grief

It must be a tough life for a trader faced one morning with the news from EIA that gasoline stocks have fallen by 700,000 barrels since last week and, simultaneously, from API that they have risen by 1.7million barrels. He could, of course, buy some soft dollar futures before they go out of fashion.

Cut-off

When some staff of EdF cut off the Prime Minister's electricity supply the other day they gave an example that surely many others will want to replicate in some form or another in their own countries. Meantime, Asinus has placed a guard on his carrot field.

Life of Cars

What we need is the statistic that tells us, not how many new cars have been sold in the last year (about 2.5 million in the UK alone, say the manufacturers triumphantly), but how many were actually destroyed at the end of their motoring life. We could then calculate how the gridlock factor increases, or just possibly decreases, each year.

Gale Warning

In its enthusiasm for encouraging the construction of off-shore windfarms the UK's DTI appears to have ignored the possibility – likelihood, many would say – that ships will collide with them and create far more environmental damage than can possibly be saved by the windfarms themselves.

Stay at Home

'We need to look at reducing the need to travel and switching to more sustainable modes like walking, cycling and public transport', says Transport 2000. This group has clearly taken to heart Robert Louis Stevenson's remark that 'to travel hopefully is a better thing than to arrive.'

Oxford Energy Forum. ISSN 0959-7727. Published by Oxford Institute for Energy Studies, 57 Woodstock Road, Oxford OX2 6FA, United Kingdom. Registered Charity 286084. Tel: (0)1865 311377. Fax: (0)1865 310527. E-Mail: forum@oxfordenergy.org EDITOR: Ian Skeet. Annual Subscription (four issues) £30/$50/€50.

Indexing/Abstracting: The Oxford Energy Forum is indexed and/or abstracted in PAIS International, ABI/INFORM, Fuel and Energy Abstracts, Environment Abstracts, ETDE and CSA Human Population and the Environment