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One way bets always fail

Swiss bank UBS launched its Oilfield Strategy Index on 19 June. The bank says it is the equivalent of owning "the financial performance of an oil field producing WTI crude." What is new is that the index invests in futures over five years, rather than in the front month.

The reason for this innovation is that traditional commodity indices that have facilitated the avalanche of investment in commodities are no longer performing so well. If an index is based on the front-month of a futures curve, the position has to be rolled forward as each contract approaches expiry. If the new month costs more than the old, the investor loses money.

In tight markets, the outright price of oil rises and the structure of the forward curve usually provides a return as contracts are rolled forward. In today's market, characterised by short-term physical oversupply but large future risk, rolling positions on the front month makes losses. UBS is trying to move out of the front part of the forward curve to stem these losses. Other banks are looking at different ways of achieving the same goal.

Unfortunately, all these indices are flawed. Firstly because they are 'long only' – ultimately an unchanging bet on rising prices – and, secondly, because commodities do not provide a natural yield. When prices plateau and rolling positions forward makes negative returns, these indices must struggle. And, of course, the investor's virtual WTI oil field does not pump real oil.

Extending the position over five years may ease the pain, but market structure will eventually follow the money. The real question is what happens when the investment funds that have flooded into the oil markets over the last three years decide that up is not the only possible market direction? At today's elevated prices, there is much greater potential for volatility than in the past, but it cuts both ways, up and down.

Ross McCracken

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Georgia sees role as East-West energy corridor

Georgia's potential as an East-West energy corridor means interest in its strategic location and domestic energy security has never been higher. Talking to Energy Minister Nika Gilauri in Tbilisi, **John Roberts** found that while old habits persist, there have also been profound changes in both the manner and means of Georgian energy policy.

For the last 15 years or so, the task of Georgia's energy ministers has been pretty grim – first coping with civil war, then patching up decaying Soviet-era infrastructure and coping with countless interruptions to gas and power supplies. And there is still much to be done. Cutoffs persist, accusations of Russian malevolence abound, and major energy deals still involve surprisingly untraceable companies.

But there are changes. There's more money in government coffers, there's a fresh supply of gas via the brand new pipeline from Azerbaijan. And there's a lot more outside interest in the country's energy future than for many a year. All this means that Nika Gilauri, who currently holds the energy portfolio, is able both to maneuver and to speak with a little more freedom than his predecessors.

To begin with, Georgia has dropped plans to sell off its last major state-owned energy transportation asset, the vital north-south Caucasus gas pipeline that brings Russian gas to both Georgia and Armenia. More specifically, there is no longer any question of selling the line to Russia's Gazprom. Secondly, with US help, Georgia is about to embark on a two-year programme to rehabilitate the Caucasus line. Thirdly, Georgia is now looking to purchase increased supplies of non-Russian gas – an inconceivable thought only a year or two ago when finances were so strained that even essential maintenance works were being put on hold.

And yet a sense of confrontation and obfuscation hangs in the air. Georgian President Mikhail Saakhashvili asserts that in the last two-and-a half years, his government has turned Georgia into one of the least corrupt countries in Europe – a claim he made recently at a conference in Tbilisi co-organized by his office and the International Energy Agency. However, this does not necessarily imply transparency in those with whom Georgia does deals.

Gilauri currently has on his plate three major issues of interest not only to Georgia itself, but to its neighbors and to the international energy industry in general. These are the future of Georgia's own gas supplies, the question of how Georgia handles its own energy investments and Georgia's role at the heart of the newly emerging East-West Energy Corridor.

Georgia's own gas supplies

Gas remains the main concern. "One hundred per cent of our gas is from Russia," Gilauri says. He pauses, then adds: "Make that 99.9%". Georgia does produce a little gas, but its reliance on Russia to date has been total. Whenever there have been interruptions to Russian supply, usually in winter, freezing Georgians in the mountain capital of Tbilisi have been just as likely to lay the blame on Russian politicians as on infrastructure weaknesses in either Georgia or Russia. And there is still no generally accepted explanation for the event that epitomizes the issue of reliance on Russia for most Georgians, the simultaneous severing of both Russia's main gas and electricity delivery systems to Georgia in late January, an act of terrorism for which no one has yet been charged.

In March, Gilauri carefully declined to rule out a possible sale of the Caucasus line to Gazprom, but current government policy is that it should remain in state hands. But one thing has not changed: the line desperately needs repair. "There are a lot of problems right now. We have had some accidents in the pipeline," Gilauri says. "It's in a bad state." But things are looking up. Gilauri says a $45 million rehabilitation program, with financing from the US government's Millennium Challenge account, is starting now. A feasibility study has been completed and actual repair works, expected to take 18-24 months, are due to start later this year, according to Gilauri.

The work, whilst long overdue, constitutes only the tip of the iceberg in terms of restoring a line which today carries only around 3 Bcm/yr – divided pretty equally between Georgia and Armenia – to anything like its nominal 24 Bcm/yr capacity. Last year, the Georgian International Gas Company told Platts that whilst initial works were costed at around $40 million, long-term rehabilitation of the line would cost $190 million. And Georgia, even with gas coming from Azerbaijan, anticipates a rapid increase in domestic gas consumption. In Soviet days Georgia used to consume around 6 Bcm/yr.

Whilst Gilauri was talking to Platts, experts from his ministry were engaged in discussions with their counterparts from Azerbaijan and Turkey on a major increase in Azerbaijani gas supplies to Georgia. The talks are taking place just as Azerbaijan's Shah Deniz gas field is on the verge of regular production. Most of its output is to be exported to Turkey via Georgia through the newly-constructed South Caucasus Pipeline, otherwise known as the Baku-Tbilisi-Erzerum gas line.

Georgia, which is currently due to receive around 250 million cubic meters of gas from Azerbaijan next year, is asking for this to be increased to 1.5 Bcm. Turkey is involved in the talks because it is the prime recipient of initial Shah Deniz gas and any increase in Georgian deliveries would almost certainly have to come from agreed Azerbaijani sales to Turkey.

The new South Caucasus Gas Pipeline, designed to carry Shah Deniz gas to Georgia and Turkey, is due to enter service on September 30. Trial gas shipments have already reached Georgia and the line's commissioning now awaits completion of a connecting Turkish pipeline, which will carry the gas from the Georgian-Turkish border to Erzerum on Turkey's main east-west gas trunk line.

Under current arrangements, Georgia is entitled to take 5% of the gas delivered through the pipeline as a transit fee and can also take some additional volumes at a fixed price of $55/1,000 cu m. By 2011, Georgia would be receiving some 825 million cu m under this arrangement. Gilauri says he envisages paying "not more than $110" for any increased gas purchases. Azerbaijan is currently paying Russia $110/1,000 cu m for delivery of up to 4.5 Bcm a year. Even with Shah Deniz coming on stream, it will still be a couple of years before Azerbaijan becomes a net gas exporter.

Gilauri ties the projected increase in Georgian purchases to ending Russia's monopoly of Georgian gas supplies and thus strengthening both Georgian and regional energy security. "This will make Georgia strong, because we will not be dependent on Russian gas," he says. "1.5 Bcm is not very big, certainly in terms of keeping Georgia strong for the Euro-transit of gas."

According to Gilauri, Georgia last year consumed some 1.3-1.4 Bcm of gas, but with a rapidly growing economy and current hydropower shortages, demand is expected to soar this year to around 2 Bcm. And while Georgia still wants to receive gas from Russia, says Gilauri, it fears a repetition of past winter cutoffs by Russian gas suppliers. This means it will want to receive 1.5 Bcm a year from Azerbaijan for several years to come, he adds.

Power and the energy investment issue

On the electricity side, things are looking much brighter than even a year ago. Indeed the amount of neon lighting Tbilisi's streets at night seems to have quadrupled. The main reason for increased gas consumption this year has been the four-month outage of the giant 1500 MW Enguri hydro plant. For once, the outage was actually good news, as the plant, delicately situated on the edge of Georgian state control, was being rehabilitated under a $70 million program jointly funded by the EBRD, the European Union and the Georgian government. The power station is due to reopen on July 15. The project is delicate because whilst Georgian security forces are in control of the dam itself, the power station lies in territory controlled by Russian-backed Abkhaz secessionists.

Georgia is also putting together a $1 billion program to bolster its own hydropower and to generate electricity for export abroad. The World Bank, Gilauri says, is financing a feasibility study for a new 700 MW power plant – expected to cost around $500 million – at Khudoni, above Enguri, and a cascade of smaller plants at Namakhvani, which would have a combined 450 MW capacity and cost around $400 million. At Paravani, in southern Georgia, near the Turkish border, there are plans for a $100 million hydroplant.

The goal, says Gilauri, is to increase both Georgia's own energy security, by making its power generation 100% reliant on indigenous hydropower, and also its capacity to export electricity. Georgia, he says, is currently only utilizing 12% of its hydro potential. He adds: "We are ready to make it available to any large company. We have some sites, we have design works, and we are starting negotiations with some private companies from China, Europe and Turkey." He did not specify the companies.

But there are still question marks surrounding one of Georgia's biggest privatization projects. Gilauri spoke proudly of the current privatization of six hydropower plants – ranging in size from 150 MW to small scale 16-18 MW plants. In addition three distribution companies, serving Ajaria, Kakheti and central Georgia, were also included in the initial auction. "The winner came back with a bid for all of the power stations and companies up for auction" all, that is, he adds, except for a small distribution company which serves the Kakheti wine growing district.

It was because this auction was conducted openly, with the winner bidding $320 million – or $317 million according to some officials – that prompted so many Georgian officials to claim it as a great triumph for the country's privatization program. A few years ago, Gilauri notes, the government was so despairingly doubtful that it would ever be able to get on top of the power shortages that the power plants were put up for sale for one single Georgian Lari – in other words, for just a nickel and a dime.

Addressing the IEA conference on 20 June, President Saakhashvili hailed the sale as a triumph, saying the winner had first sought to circumvent the auction bidding by offering $50 million and promising unspecified further investments. But, the President subsequently told Platts, he had then said "You are not going to restrict us to $50 million… and then they came back with $320 million."

But who is the 'they' to whom the President referred? The answer, at least in part, is a Czech- registered company called EnergoPro. But Gilauri says he does not know who constitute the principal shareholders in EnergoPro, which thus joins a select list of companies – including Itera, TransEuralGas and RosUkrEnergo – which have poured billions of dollars into energy projects in the former Soviet Union and Eastern Europe without clarification of their ultimate ownership. All Gilauri says on the matter, in specific response to questions as to whether EnergoPro might involve Russian interests, is: "I hear rumors that RAO is behind it, but RAO doesn't hand out that much cash."

It's a strange comment: RAO constitutes the Russian initials signifying a limited company, but in Georgia they are generally followed by one name in particular – Gazprom. Gilauri does not elaborate. He just adds: "We have a certificate from the Czech Export Fund that they are the clients" and that EnergoPro has investments in Bulgaria, Turkey and Moldova. Ukrainian sources told Platts the company had also recently bought a power plant in the Crimean city of Feodosia.

East-West Energy Corridor

There's still the bigger picture. Georgia believes its energy security lies not only in achieving its own energy independence from Russia, but in providing a corridor for new export pipelines between the producers in the Caspian and current or prospective markets in Europe.

To a large extent, it achieved this goal when former Georgian president Eduard Shevardnadze concluded a series of agreements between 1995 and 2000 with Azerbaijan's President Geidar Aliev, Turkish President Suleiman Demirel, and the host of oil companies involved, that Azerbaijan's main oil export pipeline would transit Georgia. These agreements led to the construction of the newly opened 1 million b/d, 1,768 kilometer Baku-Tbilisi-Ceyhan oil pipeline and its twin, the 20 Bcm/yr capacity Baku-Tbilisi-Erzurum gas line.

But Georgia considers there is still so much more to be done by way of transit. It wants to see oil from Kazakhstan, and both Kazakh and Turkmen gas, brought into BTC and BTE. There is a need, says Gilauri, both to enhance Georgian energy security and to boost the security of the energy corridor being created to carry Caspian oil and gas to European markets.

The main Georgian government exponent of the Energy Corridor is Foreign Minister Nicolas Natbiladze, who set out his government's thoughts on the issue in a paper delivered to a UK conference in March. "One of the drivers behind the development of the South Caucasus Energy Corridor has been the inflexibility of the Russian state pipeline monopolies," Natbiladze said. "In order to reduce dependence on a monopolistic supplier and create stable and lasting alternatives, put an end to monopoly on Central Asian and Caspian energy carriers and politically-motivated manipulations, it is necessary to elaborate a common approach and a common strategy in the entire Euro-Atlantic Area," he added.

To Natbiladze, the need to break Russia's monopoly control was shown by the two crises in January: the dispute between Russia and Ukraine which led to a brief but alarming disruption in Russian gas supplies to the EU, and the still unexplained simultaneous explosions in southern Russia which briefly halted deliveries of both Russian gas and electricity to Georgia.

"These crises illustrate that we can no longer rely on one source for our energy needs and that we have to find alternatives to build a safe future," Natbiladze said.

Natbiladze further appeared to endorse one specific project proposed by the Georgian private sector, a 650-km, 24-inch diameter gas pipeline under the Black Sea from Georgia to Ukraine's Crimean peninsula. "We have to formulate a new Euro-Atlantic Energy Security strategy, which will identify alternative ways of transporting energy resources from the Caspian Sea via the Black Sea region to the European states," he said. "Pre-feasibility studies are underway and are expected to be completed by the end of the year," one of the promoters of the line, Georgi Vashakmadze, told Platts.

However, although President Saakhashvili used the IEA/Georgian conference to state that "I'd like to add my support for those who favor a new TransCaspian Pipeline," so far there has been no indication as to who might agree to provide gas for such a pipeline.

Valekh Aleskherov, the wily veteran head of Azerbaijan's state oil company, Socar, told Platts in Tbilisi that while there was a lot of talk about pipelines that seek to unlock Central Asian gas and bring it to Europe, "what's needed is a purchase-and sale contract." In particular, he added, referring to Ukrainian President Viktor Yushchenko, "what's needed is for Yushchenko to sign a purchase-and-sale agreement."

In principle, Aleskherov is right; in practice, however, it is likely to be a few years before Yushchenko's cash-constrained Ukraine, currently borrowing heavily to fund its complex purchase of Russian and Turkmen gas, can afford to sign an alternative agreement for gas purchases at anything close to world prices.

Not that this has stopped senior US officials from making the strategic case that a subsea gasline from Georgia to Ukraine would improve European energy security. And the US is backing up its words with at least a little bit of cash – as is the EU.

In a carefully choreographed series of moves, the US Trade Development Administration will furnish $1.5 million to fund a preliminary study into a direct subsea gas pipeline under the Caspian to link Kazakhstan with Azerbaijan, while EU officials told Platts they will furnish €1.7 million ($2.13 million) for a study on developing an energy corridor between the Caucasus and Europe. In other words, the US will pay to assess the Caspian section of the corridor, while the EU will pay for the Black Sea section of the study.

These are not big sums, but they are indicative of the current strategic thinking in both Brussels and Washington. And with the European Commission voicing ever stronger support for the proposed Nabucco pipeline, which would link the Turkish gas network with Central Europe and enable a host of suppliers to access EU markets – including Caspian suppliers reaching Turkey via the SCP and BTE pipelines – European and US interest in Georgia's strategic location, and thus in Georgian energy security, has never been higher.

Nuclear growth faces supply-side constraints

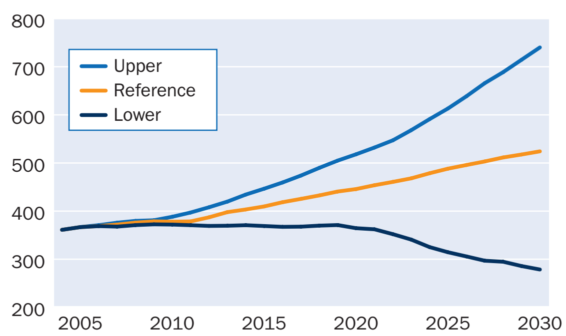
Security of supply and climate change considerations have created a turning point in the fortunes of the nuclear industry. However, its expansion faces substantial constraints, most notably limited construction capacity. All the major cost components of newbuild are rising: fuel costs, raw materials, EPC contracts and interest rates. And behind all this is the question of the uranium resource. **Ross McCracken** reports.

Growth in energy demand and the perceived need to reduce carbon dioxide and other greenhouse gas emissions have together given a new lease of life to the nuclear industry. Russia, China and India have all announced large-scale programs for nuclear newbuild, driven by the desire to improve or maintain diversity, security of energy supply and, in China and India's case in particular, to help meet the massive growth in energy demand their dynamic economies are experiencing.

Nuclear stalwarts Japan and South Korea retain targets of producing 40% of their electricity from nuclear, while there are also strong signals that in some other OECD countries, where no nuclear plant has been built for decades, governments are willing to support a new generation of plant. Some countries are even considering nuclear for the first time. Only a few have taken the opposite route; Belgium, Sweden and Germany, for the moment at least, have rejected the possibility of newbuild, favoring instead the total phase out of nuclear generation.

There is little doubt that a turning point has been made in the fortunes of the nuclear industry, even though the protracted problem of waste management persists with no better solution than to stick it in the ground. However, the industry's expansion faces constraints, the most serious of which is its limited newbuild capacity. The engineering, procurement and construction industry is overheating and vendors will all seek greater profit margins from other sectors, which will rebound on nuclear costs. There is also a lack of experienced staff, particularly in countries where no new plant has been built recently. The demographic gap in nuclear engineers will be hard to overcome in countries that have seen training and academic programs atrophy.

World Nuclear Capacity Forecast (GWe)



Source: World Nuclear Association

The challenge faced by the supply side is enlarged by the issue of decommissioning. According to Hadi Hallouche from Shell, in a paper delivered to the IAEE International Conference in Potsdam, Germany, in June, the combined call on the industry for decommissioning, plant replacement and newbuild suggests that capacity restraints will limit the expansion of the nuclear industry to a peak in 2030. Hallouche points out that there will be a huge difference in the investment cost and construction capacity required for nuclear to maintain its absolute level of power generation capacity, as oppose to retaining its percentage share of world generation capacity, which is currently around 16%. The 2030 peak is based on an average plant life of 65 years. If average plant life is reduced to 55 years, then the peak moves commensurately backwards to 2020, according to Hallouche.

As a result, the expansion of the nuclear industry depends critically on the ability to grow its construction capacity. This is likely to depend on the level of technology transfer to expand vendor capacity in countries like China and India, which now have the capacity to build their own reactors and may develop designs for export. South Korea is thought to be in the process of developing an export capacity for nuclear newbuild. However, the supply side constraints are severe. For example, there are only two companies, one in Japan and one in France, that currently can produce forged reactor vessels.

Nevertheless, companies with the capacity to export are recognizing the potential profitability implied by the supply chain bottleneck. Japan's Mitsubishi Heavy Industries said in June that it was keen to enter the US market and is preparing to introduce a larger version of its Advanced Pressurized Water Reactor. The first APWRs are in the licensing stage in Japan. Kiyoshi Yamauchi, general manager of MHI's Nuclear Energy Systems Engineering Center, said the US APWR concept is for a 1,700 MW reactor. The company has already completed major testing, including those for reactor flow, the separator, reactor coolant pump, and low-pressure turbine.

Meanwhile, the cost of raw materials has also risen significantly, particularly for materials like copper and steel and this is having a big impact on the cost of newbuilds.

According to Areva's Didier Beutier, EDF has had to revise upwards its estimate for the new reactor at Flamanville in France by 10% from the original estimate made three years ago, as a result of rising raw materials costs.

A recent study by IBM Business Consulting Services noted that the global supply chain for nuclear newbuild was likely to be constrained by "the capacity of design owners to support multiple concurrent build programs." The report says that over the last decade an average of five new reactors were commissioned annually worldwide. Based on IAEA forecasts of demand growth, the supply chain will have to expand to cope with more than 50 new power stations under construction simultaneously, more than doubling current capacity.

Ignoring competition from other sectors for general EPC services, the report identified two key supply-chain constraints specific to the nuclear industry:

- The limited number of design owners offering modern reactor designs and the potential that demand will outstrip the capacity of design owners to meet it.

- The capacity for large low-alloy ring forgings required to support fabrication of the reactor pressure vessel, and to a lesser extent the primary circuit pressure vessels, are in global short supply.

Uranium security

While the main economic constraint on nuclear newbuild is the cost of capital, the price of fuel has also been rising. The price of uranium ore averaged just over $10/lb between 1993 and 2003, but has since risen fourfold to around $40/lb. Some forecasts suggest that the price will continue to rise to over $50/lb in 2007, with significant upside potential. This price applies to unprocessed uranium and is only a fraction of the cost in producing uranium dioxide reactor fuel. Conversion, enrichment and fuel fabrication add another $700/lb, according to the World Nuclear Association. A 1,000 MWe nuclear plant uses about 59,400 lbs of reactor fuel in a year. The cost of producing reactor fuel has also risen because the cost of the electricity used in the process has gone up.

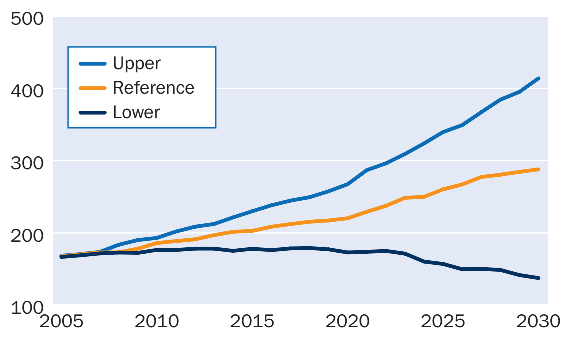
However, a key question regarding uranium comes from a security of supply perspective and is whether there is sufficient supply to support an aggressive expansion of nuclear capacity. The uranium mining industry has received a large upturn in interest with the rise in uranium ore prices and is in bullish mood. Part of that mood stems from the fact that the industry is recovering from an extended period in the wilderness.

Because of military applications, the market for uranium has always been heavily distorted. Before 1970, the US government was the only purchaser and there was no commercial market for the element. The US enrichment contracting policy drove prices to a peak in the late 1970s and production expanded, remaining above annual reactor requirements until 1985. However, the curtailment of nuclear newbuild meant that utilities were left with large inventories. In addition, material started, in the early 1990s, to arrive from the then Soviet Union and the 'Megatons-to-Megawatts' program between Russia and the US has provided a steady supply of heavily enriched uranium from the Russian nuclear weapon stockpile. The current HEU program runs to 2013.

Secondary sources of uranium supply and lack of industry growth combined to depress the uranium market from the early 1980s to 2000. It reduced the number of surviving uranium mining companies to a handful and exploration expenditure plummeted. There was a major outflow of experienced people and little new training. A major current constraint on the 'in situ leach' method of uranium ore mining is the lack of people who know how to do it.

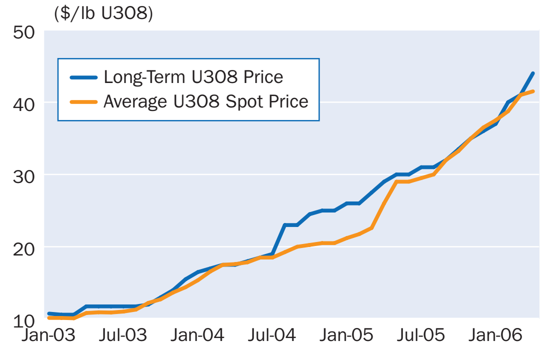
By 2000, according to specialist stockbrokers Hargreave Hale, primary uranium production accounted for only 50% of total demand. That situation has changed and there is now a potential supply deficit in the short term. Total world reactor requirements in 2004 were 172 Mlbs, compared to primary supply of 104 Mlbs. Demand is rising while sources of secondary uranium supply are falling.

World Uranium Requirements (Million lbs U3O8)



Source: World Nuclear Association

Uranium Price Trend, 2003 – Present



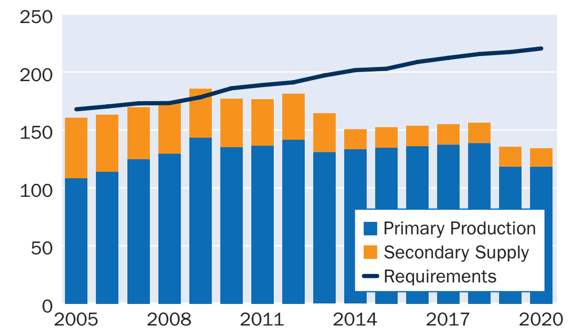
Source: Hargeave Hale

Friendly producers

The supply of uranium ore is much more concentrated than that for oil and gas. Its strategic advantage is that plants do not need much to build a stockpile and its energy density means a large stockpile can be easily stored. According to 2004 data from the World Nuclear Association, 77% of primary uranium ore production came from just five countries – Canada, Australia, Kazakhstan, Niger and Russia – and 95% from just ten, the additional five being Namibia, Uzbekistan, the USA, Ukraine and South Africa.

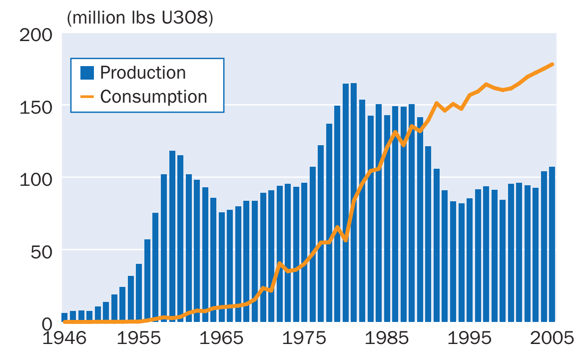
This is a very different grouping from OPEC, but in a tight supply situation, marginal production will still be dependent on countries in Central Asia and Africa, areas with significant country risk profiles. In addition, just ten mines contribute 68.8% of world supply. In 2003, a fire at the Olympic Dam mine in Australia, the world's third largest uranium producer, and flooding at the McArthur River Mine in Canada, the world's number one, led to a doubling of the uranium ore price. Uranium supply is both geographically concentrated and installation concentrated, both of which suggest that political or natural supply disruptions might be relatively rare, but their impact will be large when they do occur.

World Uranium Market Balance



Source: Hargeave Hale

World Uranium Production and Consumption, 1946-2005



Source: World Nuclear Association

Of planned new production by far the largest project is Cigar lake in Canada, which will eventually add some 6,900 tons per annum. The next three largest projects are all in Kazakhstan and have a combined capacity of 3,500 tons. The next seven largest planned projects have an average size of just 390 tons per annum.

Secondary sources come from HEU, inventory drawdown, mix oxide fuel, reprocessed uranium and the re-enrichment of depleted uranium tails. According to an International Atomic Energy Agency paper published in September 2005, secondary supply will cover only 15% of demand by 2020, which implies an 80% increase in primary uranium production from the 2004 level. This assumes the HEU agreement with Russia is not extended. If it is extended, secondary supply will account for 22% of total demand. Uncertainty over the level of secondary supplies – most inventory levels are not reported – also has an impact on mining companies' ability to raise finance.

Without the addition of new mining capacity, the IAEA report suggests there would be a shortfall in primary capacity of 1,140 tons of uranium in 2007, rising to 7,130 tons in 2010 and nearly 34,000 tons in 2020. If all planned projects come on-stream at the earliest date technically feasible, the deficit would be eradicated until 2012, when new capacity would again be required, owing to the depletion of the Ranger resources in Australia.

Given this outlook, the level of political and technological risk that projects do not come on stream at their earliest date, or in some cases, at all, is relatively high. Regulation and popular opposition is a key barrier to the development of new uranium mines and a major contributor to the long lead times necessary to get projects to the production phase.

There is a strong case to suggest that the price of uranium ore is likely to rise over the medium term and to have a higher degree of volatility than in the past. The rising share of primary production in meeting demand means output will be more vulnerable to mining disasters. In addition, the speed with which primary production needs to expand to meet the decline in secondary sources is large and vulnerable to delays as a result of popular and environmental objections to the development of new mines. This suggests a positive outlook for those mining companies with projects close to production, as Hargreave Hale suggest, but a less positive one for uranium consumers.

It also means that while still small in comparison with the capital cost, the fuel cost of nuclear plants will rise. In January, the World Nuclear Association estimated that getting one kilogram of uranium as UO2 reactor fuel would cost about $1,633. This would yield 3,400 GJ thermal energy, which gives 315,000 kWh, equating to a fuel cost of just 0.48 cts/kWh. The Association argues that even with the higher cost of uranium included "the total fuel costs of a nuclear power plant in the OECD are about a third of those for a coal-fired plant and between a quarter and a fifth of those for a gas combined-cycle plant."

In addition, the WNA argues that fuel use is an area of steadily increasing efficiency and cost reduction, quoting the example of Spain, where the electricity cost from nuclear was reduced by 29% between 1995-2001 as a result of boosting enrichment levels and burn-up to achieve a 40% fuel cost reduction.

Long-term resource?

On 1 June, the Nuclear Energy Authority presented the new version of the Red Book, formally know as Uranium 2005 – Resources, Production and Demand. The findings show a rise in exploration expenditure both around known resources and in greenfield sites, prompted by the rise in uranium prices. The Red Book identifies resources by the estimated cost of their recovery. Total Identified Resources in the less than \$80/kgU category were 3,804,000 tons and 4,743,000 tons in the less than \$130/kgU category, both up on the 2003 data. Identified resources in the less than \$40/kgU category increased 13% from 2003. The bulk of increases were due not to new discoveries but to re-evaluations of previously identified resources "in light of the effects of higher uranium prices on cut-off grades." Undiscovered resources (prognosticated and speculative) were about 10,000,000 tons of uranium, up 25,000 tU from those reported in 2003.

According to the Red Book, uranium production in 2004 totaled 40,263 tU, up from 35,492 tU in 2003 and 36,050 tU in 2002. Output in 2005 is expected to reach 41,250 tU, with the largest increases coming in Kazakhstan and Uzbekistan. In terms of demand, end-2004 saw a total of 440 commercial reactors in operation, with a net generating capacity of 369 GWe, requiring about 67,320 tU. By 2025, nuclear capacity is forecast to grow to between 449 GWe in the low demand case and to 533 GWe in the high demand case. This would require between 82,275 tU and 100,760 tU per annum by 2025.

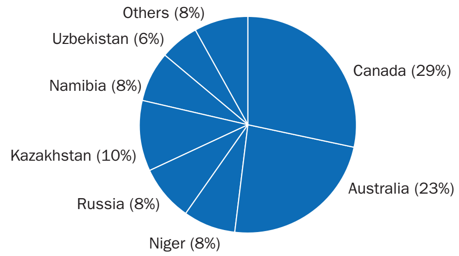
Based on the low demand scenario, this suggests uranium resources below \$130/kgU will last just under 50 years from 2025. The high growth scenario suggests resources will be exhausted 35 years from 2025 in 2060, falling short of the expected 55-60 year life of reactors commissioned in the 2015-2025 period. Much longer usage is envisaged by the exploitation of prognosticated and speculative resources, but these remain as labeled. In addition, the fast breeder option is not yet commercial and the forecast expansion of nuclear capacity will be built without it. Moreover, some analysts criticize the methodology of categorizing resources by the cost of recovery rather than the net energy value of the resource once the costs of extraction have been taken into account. The latter analysis, they argue, would leave unconventional resources uneconomic to exploit, as well as many conventional resources where the concentration of uranium is very low.

The longevity of the uranium resource is uncertain, particularly in a high demand scenario, but interest in exploration has only just been rejuvenated after a long period of stagnation. It will be telling to see if the new interest significantly expands the known resource base over the next few years. Experience with other minerals suggests that this will indeed be the case. The risks to uranium supply are in fact more in the short term. There is a serious risk of supply crises as secondary sources of uranium are depleted. The situation is so tight that it would only take the failure or delay of one large near-term project to create a supply shortfall.

As the Red Book notes "a sustained near-term strong demand for uranium will be needed to stimulate the timely development of needed Identified Resources. Because of the long lead-times required to identify new resources and to bring them into production (typically of the order to 10 years or more), there exists the potential for the development of uranium supply shortfalls and continued upward pressure on uranium prices as secondary sources are exhausted."

Uranium Production – 2005

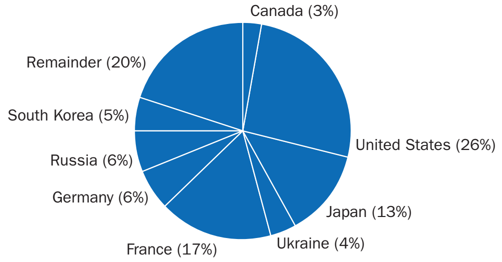
Total – 109.1 million lbs U_3O_8



Source: World Nuclear Association

Nuclear Generating Capacity

Total – 368,496 MWe



Source: World Nuclear Association

Risks rise for declining African oil producers

Mitigating factors have spared Cameroon, Gabon and Congo-Brazzaville the full consequences of their declining oil output, but all three remain vulnerable to a drop in crude prices. As the countries' governments compete to attract investment, **Neil Ford** looks at the risks and opportunities presented by the three old-time African producers.

International interest in the Gulf of Guinea is generally focused on the big two oil producers, Nigeria and Angola, plus rapidly growing oil powers, such as Equatorial Guinea. Relatively little attention is paid to the region's established, but declining oil producers, yet Gabon, Congo-Brazzaville and Cameroon are faced with a very specific set of problems as they struggle to cope with falling output. Particularly given the stubbornly high oil price, the three could provide opportunities for smaller independents to make the most of marginal or previously abandoned fields.

The relationship between political and economic security on the one hand and the oil industry on the other is a central theme of the situation in the Gulf of Guinea. Oil companies can be deterred by uncertain sovereignty and unstable governments, but it takes a great deal of civil unrest to persuade them not to invest in an oil rich area. As the current instability in the Niger Delta has demonstrated, the operations of insurgents can be put down as an unwelcome although accepted risk when large reserves are on offer. Moreover, oil sector operations continued almost unhindered during Congo-Brazzaville's various civil wars over the past decade.

Yet declining oil production can also have a huge impact on the security of a country. Most of Africa's net oil exporters are heavily dependent on hydrocarbon revenues to generate export revenues and fund most government expenditure, so a collapse in the oil price or in production can have a devastating effect. The resulting recession, rising unemployment, growing national debt and lower spending on infrastructure and social spending can prompt social unrest and possibly the overthrow of a government.

This in turn can result in lower oil industry investment. Taking a risk in an unstable country with plentiful oil reserves and growing oil production can be seen as an acceptable bet, particularly where the oil company in question is already operating in that country. Yet investment is far less likely in a declining oil producer where new discoveries have dried up and there is little new acreage on offer. Governments can make the terms of investment more attractive, but this can result in reduced income at a time when production is already falling.

To a greater or lesser extent, Congo-Brazzaville, Cameroon and Gabon are all caught up in this predicament. During the 1980s, Congo-Brazzaville and Gabon vied for the position as the third biggest oil producer in Sub-Saharan Africa, behind Nigeria and Angola, and were considered of great strategic importance. Cameroon did not hold the same importance in the oil sector, but it made a valuable contribution to the region's overall significance. However, production in all three has fallen gradually but relentlessly over the past few years and today they have already been overtaken by Equatorial Guinea and Sudan in terms of output, while new or potential oil producers, such as Chad and Sao Tome and Principe, are emerging in the region.

Falling output

Oil production in Gabon peaked in 1997 at 371,000 barrels a day and has fallen over the past decade to average 233,000 b/d in 2005. Production on the country's main fields, the Shell-operated Gamba and Rabi-Kounga structures, has fallen as they have matured. Output on Rabi-Kounga dropped from 217,000 b/d in 1997 to just 55,000 b/d in 2003. The government's official estimate of the remaining proven reserves is 2.5 billion barrels, but this figure has not changed for many years. Some industry sources believe the real figure could be much lower, perhaps as low as 700 million recoverable barrels.

The decline in oil production in Congo-Brazzaville has followed a similar path. Output peaked at 280,000 b/d in 2000 and has since fallen to 227,000 b/d, as the country's mature onshore fields have been exhausted. Average well productivity stands at just 680 b/d and the geology of the country is rather different to much of the rest of the region, where a smaller number of wells yield more oil. Elf Congo is the biggest producer with average output of 91,000 b/d in 2005 and its Nkossa field is the most important development, yielding around 70,000 b/d from reserves of 500 million barrels.

More oil is produced on Nkossa than on all of Cameroon's fields combined. Total output in Cameroon reached 185,000 b/d in 1985, but has now fallen below 60,000 b/d, again because the country's mature fields have been exhausted. Most existing production comes from the Rio del Rey Basin, where Total's Kole Marin structure is the most significant field. It is predicted that Cameroon will become a net oil importer at some stage over the next decade unless significant new discoveries are made.

Oil price windfall

The fall in oil output could have been sufficient to provoke political and economic dislocation in the region but for three mitigating factors. First, Cameroon's lower oil production meant that it never relied on oil revenues to the same extent as the other two countries. With a far more diverse economy, it possessed a small manufacturing and industrial sector that was significant in comparison with most other African states, and so growth elsewhere was able to cushion the blow. In addition, the Chad-Cameroon oil pipeline came on stream in 2003, so Cameroon has retained a significant position in the oil industry by replacing oil production with oil transit fees.

Second, the people of Congo-Brazzaville have suffered relatively little from falling production, partly because the decline has been less pronounced than in the other two countries, but also because they never benefited a great deal in the first place. Congo-Brazzaville suffered from civil wars in 1993, 1997-99 and 2002-03 and armed rebel groups are still active in several areas, particularly the Pool region. Social and infrastructural spending has been limited over the past decade, as successive governments have concentrated on winning the various wars. The current government of Denis Sassou-Nguesso is still trying to get the country back on its feet after the prolonged fighting. Amid all the upheaval, the fall in production could have an impact on government finances, but is of little relevance to the lives of most people and so has not affected the country's stability.

Third, and perhaps most importantly, steadily rising oil prices over the past three years have helped all three countries, but particularly Gabon. The rising cost of a barrel of oil has compensated for falling production, so Gabon has been able to record modest economic growth of 2-3% a year over this period. Gabon enjoys a reputation as the most stable country in the region and President Omar Bongo, who has ruled since 1967, has founded his longevity and his support on the large educated, urban middle class in the capital Libreville. Most are employed in the large civil service, which is funded by oil revenues and which is widely regarded as overstaffed.

People from other countries in the region, including Nigeria and Congo-Brazzaville, have moved to Libreville over the past 30 years to take up jobs as servants and other low paid positions in order to benefit from the trickle down of oil money. Any large reduction in oil revenue would result in the government losing support among the urban elite and could result in increasing discontent among the large communities of poor urban Gabonese and foreigners. With GDP per head of $4,000-$5,000, Gabon is one of the most prosperous countries in Africa and the boom in oil prices has come at a fortuitous time. However, there is no sign of the fall in production coming to an end, so oil prices will have to continue climbing if the Gabonese economy is to avoid an almighty crash. A fall in the international oil price could cause an economic collapse. Little progress has been made on economic diversification during the boom years and oil income still accounts for about 60% of government revenues.

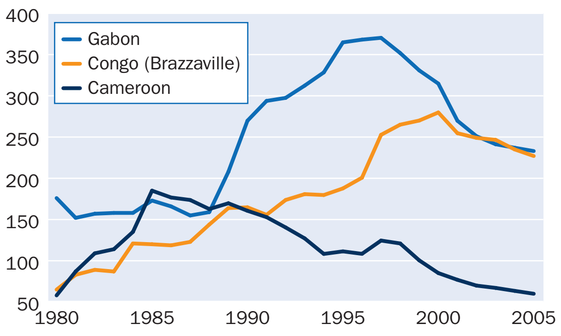
Government action

As a result of the mitigating factors, the level of stability in the three countries has not declined in line with oil production and so oil investors may not be deterred from a security point of view. At the same time, the high oil price makes hydrocarbons that were previously regarded as of marginal interest or uneconomic a great deal more attractive. A large proportion of the exploration work that has been carried out in the region took place during the 1980s at a time when crude prices ranged from $10-$20/barrel. A number of finds were not developed because of their small size or higher production costs. There is likely to be far more interest in developing such discoveries in the current era of the $70 barrel, so while there is little that governments can do to increase their oil reserves if the geology is lacking, they can at least offer incentives to make the most of what they have got to manage their declining production.

The Gabonese government has introduced a range of tax incentives over the past five years, but they have not had a noticeable impact on the uptake of acreage. A comprehensive new oil bill is being prepared for passage into law later this year but the government has not revealed the details of the proposed legislation. An online oil sector information service has also been developed to collate all the exploration results to date. Production could be buoyed by new investment by Shell in the Rabi-Kounga field. The company has signed a ten-year extension to its production sharing agreement for the field, which will now stretch until 2017. Shell expects that gas reinjection and other enhanced production techniques will enable it to extend the field's life.

The government can influence upstream exploration efforts to an extent through its 25% stake in Total Gabon, but there have been few significant discoveries in recent years. Perhaps the biggest is the Etame field, which now produces 25,000 b/d thanks to investment by PanOcean, Sasol and Vaalco. In addition, FirstAfrica Oil, a subsidiary of Energem Resources, announced in December 2005 that it plans to develop the offshore East Orovinyare field and hopes to attract support for its $68 million investment.

Production of crude oil (thousands b/d)



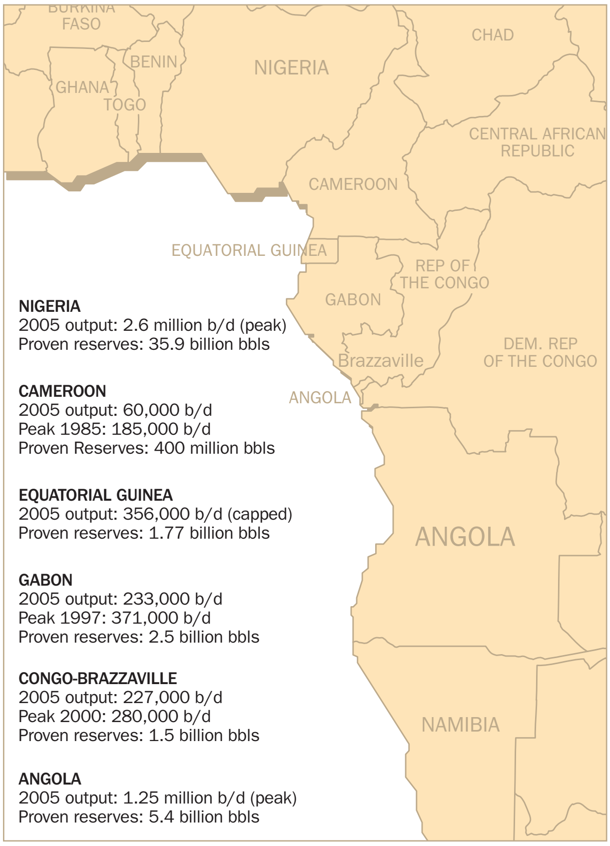
Source: EIA

However, licensing rounds in 1998 and 2000-01 failed to attract much interest and Libreville has now decided to offer an open door policy to oil companies interested in any available acreage. Perhaps surprisingly, despite the fact that commercial oil production has taken place for 50 years in Gabon, around 60% of all acreage has not yet been licensed and ministers confidently talk of further discoveries once licensing does take place. However, it seems likely that many of the blocks involved may not have been explored because of their poor potential.

The settlement of a territorial dispute with Equatorial Guinea could open up new acreage for exploration. The two countries have long disputed the sovereignty of maritime territory around the uninhabited islands of Cocotiers, Congas and Mbagne in Corisco Bay off the coast of Gabon. There have been several incidents of clashes between naval and fishing vessels over the past decade and the dispute seemed a possible cause of war as the two sides mobilized their armed forces. Oil companies have been understandably reluctant to take on acreage in the area because of the dispute.

However, relations have thawed over the past two years. Talks took place between Equatorial Guinea's President Teodoro Obiang and Gabon's President Omar Bongo under the aegis of the United Nations and the Gulf of Guinea Commission in 2004 and the two governments agreed in February 2006 to reach a long-term settlement. Given their popularity elsewhere in Africa, a joint development zone could be one option, but whatever solution is finally adopted it could give Gabon the opportunity to bring more oil production on stream over the longer term.

West African oil producers



Source: EIA

A JDZ has already been set up in the common maritime borderlands of Angola and Congo-Brazzaville. Known in French as a Zone d'Interet Commun (ZIC), the JDZ was set up in 2001 and covers part of Total Congo's Haute Mer block in Congo-Brazzaville and Chevron's highly productive Block 14 in Angola. All production and revenues from the JDZ are to be shared equally between the two countries. Chevron made a major discovery on its Lianzi 1 exploration well at the end of 2004 and exploration work is continuing.

Congo-Brazzaville perhaps offers more opportunities for new discoveries than the other two countries. Interest in the county's acreage has picked up as the security situation has improved and offshore discoveries in other countries, such as Equatorial Guinea, have made the adjacent Congolese acreage more attractive. The government finally gave Total Congo the go ahead to start developing the Bilondo and Moho fields on the Haute Mer block last year and they are expected to come on stream by end-2008 with joint production of 90,000 b/d. Total holds a 53.5% stake in the concession, with partners Chevron (31.5%) and the state owned Congolese oil firm Société Nationale des Pétroles du Congo (SNPC) (15%). Total Congo also plans to develop satellite fields to Nkossa, including Nkossa Sud.

Despite the recent focus on offshore acreage, the largest new field could be onshore. French firm Maurel and Prom estimates reserves on the Mboundi field at 1.3 billion barrels, although not all of this could be recoverable. The final test wells during 2005 yielded promising results and the French company is now drawing up field development plans. It has a stake of 57% on the concession, with the remaining equity held by Burren Energy of the UK and SNPC. Several other discoveries have been made over the past two years, but it is not yet known whether they will prove to be commercially viable.

The main improvement in Congo-Brazzaville's investment terms has been the replacement of joint ventures with production sharing agreements, which the government hopes will help to reduce the wild swings in oil revenues and prove more attractive to investors. All upstream development financing is now provided by foreign firms, which recoup their investment and profit once production comes on stream. The government's allocation is sold on the international markets by SNPC.

Cameroon has also improved its investment terms in order to attract more exploration interest. In the past, foreign oil companies were required to sell part of their output within the country, but they can now take all production and all profits out of Cameroon. A more favorable tax structure has been introduced and the division of profit oil between oil companies and the government is now open to negotiation, so that particularly attractive terms can be offered on marginal fields. As in Gabon, formal licensing rounds have been abandoned.

Despite the apparent lack of potential in existing areas of production, two frontier regions may offer far more hope of a reversal of the country's oil fortunes. The Logone Birni fields in the north of the country have not been developed to date because of the cost of transporting the oil to the coast for export. However, the new Chad-Cameroon pipeline passes relatively close to the area and the government of Cameroon insisted that the pipeline treaty include an option for the construction of a spur pipeline to the Logone Birni Basin.

The other attraction is the Bakassi Peninsula, where a sovereignty dispute between Nigeria and Cameroon has deterred exploration work. The maritime territory off the Peninsula is highly prospective and the possibility of large oil discoveries made both sides dig in their heels. However, the International Court of Justice awarded the area to Cameroon in 2002 and although the withdrawal of Nigerian forces has not yet been completed, there seems every prospect of several blocks being licensed in the area in the medium term.

Deepwater future

The biggest area of new oil production in the Gulf of Guinea as a whole over the next ten years is likely to be the deepwater arena. A string of major deepwater fields are being developed in Nigeria and Angola that should push production capacity in Sub-Saharan Africa's biggest producers to 4 million b/d and 2 million b/d respectively well before the end of the decade. As a result of the political and physical geography of the Gulf of Guinea, however, the three declining producers have very limited deepwater acreage.

Congo-Brazzaville has just 18,647 square kilometers of maritime territory, including both shallow and deepwater areas, while Cameroon's location in the 'armpit' of Africa gives it just 4,500 square kilometers. By contrast, Sao Tome and Principe's location in the heart of the Gulf of Guinea enables it to claim jurisdiction over a far bigger area, up to 180,000 square kilometers, although its maritime boundaries have not yet been determined and its land area covers just 1,000 square kilometers.

Although there is obviously no precise correlation between the size of a country's maritime territory and the number of oil finds, more territory obviously provides more opportunities. Moreover, the lion's share of the maritime territory of Gabon, Cameroon and Congo-Brazzaville lies close to the coastline and comprises relatively shallow water, whereas the other Gulf of Guinea oil producers all possess plenty of the deepwater acreage that has proved so fruitful for oil exploration in recent years. Without a great deal of deepwater territory, oil companies in the three countries under discussion have had to largely focus on established areas of production.

Main sub-Sarahan crude oil producers (thousand b/d)

		2005	Trend
1	Nigeria	2,600	Rising
2	Angola	1,250	Rising
3	Sudan	363	Rising
4	Equatorial Guinea	356	Capped
5	Chad	249	Rising
6	Gabon	233	Falling
7	Congo-Brazzaville	227	Falling
8	Cameroon	60	Falling
9	Cote d'Ivore	56	Rising

Source: EIA

Some discoveries have, however, been made in what little deepwater acreage Congo-Brazzaville possesses. Murphy Oil of the United States had mixed results from its test wells on the deepwater Mer Tres Profonde Sud block in 2005 and plans to explore the concession more fully this year and next before deciding whether any finds are commercial. It operates MTPS with an 85% stake alongside SNCP (15%). Total's Pointe Noire Grande Fonds has produced commercial discoveries in the form of the Libondo, Litanzi, Tchibouela and Yanga Sud, although it is still too soon to predict likely output. Advances in production technology on ultra deepwater fields could also open up more acreage on the edges of Congo-Brazzaville's maritime territory.

A Gabonese deepwater field has also been brought into production. The Etame field is believed to contain around 60 million barrels and 15,000 b/d is produced via a floating production storage and offloading vessel, which will also be employed on the second phase of development on the field. Production from other smaller fields in the area, such as North and South Tchibala, will be tied back into the FPSO. The development is operated by PanOcean with a 31.35% stake, alongside partners Vaalco Energy (28.07%), Sasol (27.75%) and Energy Africa (7.5%).

Looking ahead, it seems that the success of Gabon, Congo-Brazzaville and Cameroon as oil producers will depend on deepwater discoveries being made. As the smallest producer, Cameroon is at most risk of becoming a net importer, but it also has perhaps the most attractive unexplored acreage, in the form of the territory offshore the Bakassi Peninsula, which borders on both Nigerian discoveries and Equatorial Guinea's deepwater fields. It seems likely that at least one of the three will have to face a collapse in oil revenues at some stage, as oil prices are unlikely to compensate for falling output in the long run, but a buoyant oil price could yet throw up some surprises as competition for Gulf of Guinea acreage becomes increasingly fierce.

Global Gas: the IEA on world gas markets

The Paris-based International Energy Agency sees a gradual breakdown in the regional nature of gas markets and the growing transmission of pricing signals internationally. Further dynamic growth in natural gas demand has created a serious risk of under investment in the period to 2010, while the OECD's growing dependence on non-OECD gas is increasing the level of political risk.

In its Natural Gas Market Review 2006, released in June, the Paris-Based International Energy Agency said that the world's proven gas reserves of 180 Tcm represent 64 years worth of production at current levels of consumption, but that gas reserves have grown 15% since 2000. However, OECD countries' reserves are equal to only 14 times annual production and declines in output in some countries are offsetting gains in others, leading to an increased reliance on non-OECD gas.

"In practical terms, this means that total OECD countries' gas production cannot be sustained at current levels for much longer and, in some countries, has already peaked." The agency argues that the flurry of exploration activity, driven by high prices, in the US and Canada has not been matched by a commensurate rise in production. With declining UK output offsetting growth in Norway, Europe's gas production is expected to fall back to the 2000 level by 2010.

On the demand side, the IEA forecasts that global gas demand will grow from 2.8 Tcm in 2005 to 3.2 Tcm by 2010, driven predominantly by power generation in the OECD, and by power and other sectors in the Middle East, China and India. This represents a slower pace of growth than in the first half of the decade, but is still substantial. The current high level of gas prices, if it persists, will see investment in power generation level off only after 2010, according to the IEA.

The message for OECD countries is clear. As a whole, they face growing import dependence and increased exposure to an international rather than regionally-based market. As with oil, there is a distinct imbalance between consumers and holders of major gas reserves. The Middle East holds 41% of global gas reserves and the former Soviet states 32%. The OECD has just 9%. By 2010, the IEA predicts that dependence on non-OECD gas imports will range from below 10% in North America, to 48% in Europe and 63% in Asia-Pacific.

These imports will be delivered increasingly as LNG, where the main risk is not reserve size but political. With the exceptions of Australia and Norway, most new LNG projects are being developed outside of the OECD. As the OECD becomes more reliant on LNG, its exposure to the political risks associated with the producing countries also grows. New developments in the Middle East, particularly in Qatar, mean there will be a concentration of LNG tankers transiting the strategic bottlenecks of the Strait of Hormuz, the Suez canal and the Straits of Malacca.

Power sector

The power sector is expected to account for 55% of demand growth for gas to 2010. Despite high prices, 78% of new power generation capacity built between 2000 and 2010 will be gas-fired: regionally, the figure is 93% for OECD North America, 70% for OECD Europe and 26% for OECD Asia, according to the IEA. Even so, the growth in gas demand by the power sector in the OECD has slowed in the last five years.

About one-third of installed gas-fired generating capacity in the OECD can switch fuel. The IEA says that as electricity demand is volatile, gas demand will also become more volatile as gas-fired generating capacity expands. However, the agency notes that with gas prices at the levels of early 2006, CCGTs are often the "marginal technology" and this implies that the presence of large shares of CCGTs "is not a guarantee of corresponding shares of gas demand."

Investment risk

The agency predicts that $520 billion in investment will be needed to support the growth of gas markets over the next five years and with only $210 billion committed, there is a risk that under-investment may retard growth. A further $300 billion investment is planned, but for the moment remains uncertain. The agency says investment commitments in pipelines, particularly in non-OECD areas, look weak in comparison with that in the LNG market. The report says, "although several significant pipeline projects are coming to fruition, risks for pipeline investments crossing multiple frontiers are perceived to be growing." Gas projects are also seeing shortages in skilled personnel and rising raw material costs.

The IEA says, "there is a serious risk of under-investment in the sector unless all projects currently planned are also delivered by 2010, which is unlikely." Commenting specifically on Russia, which holds the world's largest gas reserves, the IEA writes "there is serious concern that the upstream and midstream investment necessary to meet existing export commitments is not being committed." The solutions the IEA proposes for Russia are greater third-party access to pipelines, bringing domestic prices more in line with international ones, increased pipeline maintenance, more efficient domestic use of gas and a reduction in the amount of flared gas.

LNG's share of planned investment is very large compared with its share of the overall market. Relatively, there are only much smaller amounts targeted at transmission and storage. One of the reasons behind this is the attractiveness of LNG projects to international oil companies, which find the time to market for LNG quick in comparison with large pipeline projects. The IEA sees IOCs as retaining a competitive edge in the sector, owing to their familiarity with the technology, ability to manage projects, global market expertise and reliability as both buyers and partners for banks.

Global LNG growth

LNG is expected to make up almost 20% of OECD countries' gas supply by end-2010. "LNG will become an essential supply source at the margin" for North America and Europe, argues the IEA. Growth in the LNG market has been explosive. The agency notes that in the last five years, trade flows have increased by 29%, liquefaction capacity by 48 Bcm a year and the LNG fleet by 75%. Current investment plans suggest existing capacity will double again by 2010 and the IEA makes what it calls a "conservative" forecast for LNG production at 350 Bcm by 2010.

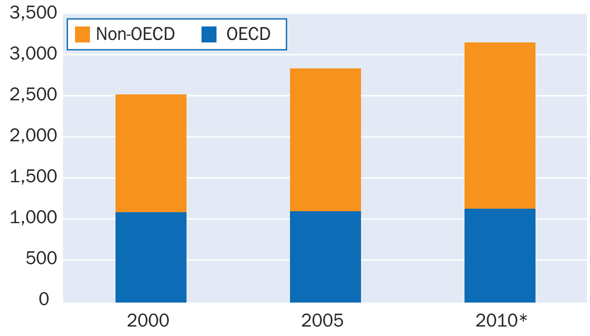
The amount of LNG capacity being built without long-term contracts reflects confidence in the market and also heralds the future expansion of spot markets and sellers' intention to supply to the highest bidder. The agency predicts that the Atlantic market will grow to at least equal the Pacific market by end-2010 and the pivotal role of Middle Eastern LNG suppliers will increasingly transmit price signals between the Asia-Pacific and Atlantic basin markets. While the industry will remain dominated by long-term contracts, the spot market for LNG had grown to 11.1% of international LNG trade in 2004 and this share is expected to rise to 20% by 2010. The agency also sees the incidence of shorter-term contracts as supporting further gas-to-gas and inter-fuel competition.

As a result of its high level of investment and reserves, Qatar will supply between 25-30% of the LNG market by 2010, serving both the Atlantic and Pacific basin markets. While Indonesia's relative position is expected to decline, Algerian gas exports are expected to rise from 64 Bcm in 2003 to 76 Bcm by 2010. Australia is also seen as emerging amongst the "top rank" of LNG exporters within the next five years. While the LNG market continues to grow in South Korea and Japan, neither India nor China contracted substantial new volumes when prices were high in 2005 and 2006. The IEA says the expected shift in market share from Asia-Pacific to the Atlantic basin could have important implications for the former's price setting power.

The IEA highlights the growing transmission of pricing signals between markets, noting that deliveries to the Isle of Grain in the UK have followed the logic of the arbitrage between the UK National Balancing Point and prices at Henry Hub in the US. However, it also notes that Spain managed to attract cargoes away from the US, even when gas prices in Spain, which are regulated, were lower than in the US. The reason was that Spanish buyers were taking LNG on contracts linked to Spanish power indices. LNG's infiltration of national markets is also shown in the incidence of LNG for pipeline gas trades. The IEA writes, "the gas market is not yet global, but policy makers and other stakeholders can no longer ignore what is happening in the other regional markets."

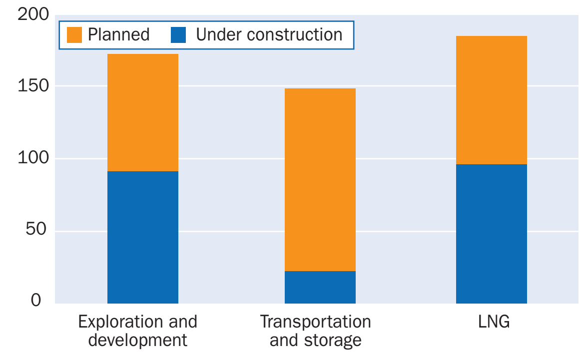
Natural Gas Market Review 2006: Towards a global gas market, International Energy Agency. pp. 136 (612006211P1) ISBN 92-64-10984-6 Price: €80.

Global gas production (Bcm)



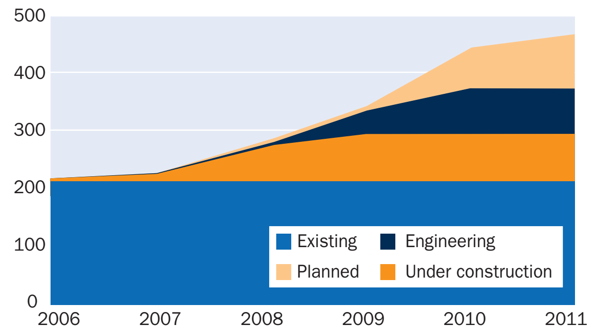
Source: IEA data

Gas market investment ($ billion)



Source: IEA data

Global liquefaction capacity at 90% load factor (Bcm)



Source: IEA data

Mongolia – the last coal frontier

Junior miners from Canada and China are taking bold steps to explore and develop coal deposits that could turn Mongolia into a major exporter. Meanwhile, the world's mining giants are giving the country a close but cautious look. **Cecilia Quiambao**.

Following the trail pioneered by Canadian junior miners, Chinese and local firms in the exploration and development of Mongolia's coal reserves, global mining majors are beginning to take an interest in the resources of this landlocked central Asian country. With a population of just 2.5 million, Mongolia's coal is destined for export, the most obvious market being China's burgeoning power, steel and cement industries. However, developers in the region are also looking further afield, hoping to construct export infrastructure that will take Mongolian coal to China's international coal loading ports of Qinhuangdao and Tianjin.

Mongolia has the potential to be a major world exporter of coal. The Ministry of Infrastructure and Development commissioned a US mining and geological consulting firm Norwest to conduct an assessment of the Tavan Tolgoi coal deposits in the Gobi desert. According to industry sources, the aim was to provide a prospectus for foreign companies. Using old Soviet Union drilling data and other available information, Norwest estimated that Tavan Tolgoi, a small part of the Gobi desert, holds about five to six billion mt of coal. Reserves of such magnitude would mean a mine life of 50 years, producing annually at least 100 million mt, one mining engineer explained. In comparison, Australia exported about 235 million mt of thermal and metallurgical coal in 2005, while Indonesia exported more than 100 million mt of mostly thermal coal.

The coal basins identified in the southern Gobi desert are of Permian-age, according to Paul Zweng, chief operating officer of Canada-listed miner QGX, a company active in Mongolia. Geologists describe Permian-age coal as the type which all miners dream of producing in their concessions – the Rolls Royce of coal-bearing formations. Zweng says there are at least four Tavan Tolgoi-like deposits in the southern part of Mongolia's Gobi desert, bordering China's northern provinces and the Chinese autonomous region of Inner Mongolia, as well as Cretaceous and Jurassic age formations.

Existing production

Mongolia currently produces metallurgical and thermal coal from three large mines in the southern Gobi desert, mostly for export and mainly for the Chinese market, according to Ts. Enkhbold, in charge of project development for QGX. There are also 40 small-scale mines, each producing from 50,000 mt to 4 million mt. These mines have total annual output of about 7 million mt of mostly lignite coal, which is used for domestic consumption.

The biggest producer is the Nariin Sukhait mine, in the southern Gobi desert, an equal joint venture between MAK, a private Mongolian firm, and Chinese company Qing Hua. The mine produced about 2 million mt of thermal coal with a calorific value of about 6,000 kcal/kg and semi-soft coal last year. The output was railed to a steel plant in Inner Mongolia. Nariin Sukhait is reported to hold 134 million mt of reserves.

The region's second large export-orientated mine, Eldev, is fully owned by MAK. It started exporting to China last year and is estimated to contain reserves of 50 million mt. The Mongolian government has 100% equity in a third mine at Tavan Tolgoi, which is producing coking coal from two open pits. In 2005, this mine produced about 1 million mt of coking coal, which was carried over land to a steel plant in China. The small thermal coal output was sold to a local power plant.

Baruun Naran coal project

Source: QGX

Major interest

Large mining groups are beginning to take more of an interest in Mongolia and the government wants to attract more foreign investors. Xstrata has acquired an equity interest of 9.8% and has a representative on the board of junior Canadian coal miner Erdene Gold, which is exploring coal and base metal projects in northeast Mongolia. There have also been unconfirmed reports that BHP Billiton has a joint venture to explore for coal and other minerals using geophysical surveys on the mining concessions held by Canadian miner Ivanhoe. Meanwhile, QGX is believed to have signed agreements with three large companies related to the exploration and/or development of its Baruun Naran coal deposits. Major Chinese steelmaker Capital Steel is also said to have a coal project in Mongolia.

In addition, the Mongolian government is thought to be close to launching an international tender allowing private companies to acquire substantial equity at the government-controlled Tavan Tolgoi coal deposit. Companies which previously expressed interest in acquiring equity at Tavan Tolgoi include an alliance between BHP Billiton and Mitsubishi, Japan's Mitsui, China's Shenhua, Brazil's CVRD, and Ivanhoe. The tentative plan is thought to be for the Mongolian government to allow foreigners to acquire a 40% equity interest in its Tavan Tolgoi coal property.

Export routes

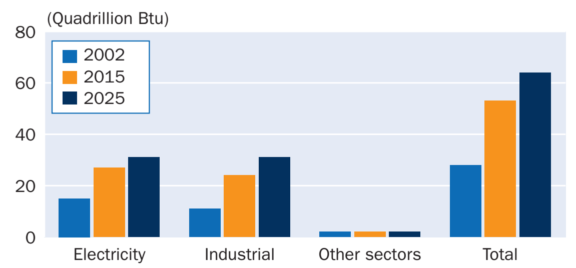
The main hurdle in the development of Mongolia's coal deposits is its inadequate infrastructure for transporting coal to China and from there by sea to markets further a field. The cost of developing this infrastructure is huge and the Mongolian government would need foreign capital for a project of this magnitude. It would also need Chinese participation and cooperation.

The coal areas currently in production and/or being explored in Mongolia are about 1,200 kilometers or so away from Beijing, which lies close to the coal ports of Qinhuangdao and Tianjin. The majority of China's seaborne thermal and metallurgical coal exports goes through these two ports.

QGX and Ivanhoe are planning to start production soon at their coal mining concessions. QGX is planning production at its Baruun Naran concession, which borders the government's Tavan Tolgoi deposit, by the second half of 2007, expecting to produce mostly coking coal for export to northern China. The initial plan is to produce 500,000 mt to 1 million mt in 2007.

A more ambitious plan to produce 5-10 million mt of mostly coking coal for export to China hinges on the construction of a 200 kilometer railway from Baruun Naran/Tavan Tolgoi in the Gobi desert to Inner Mongolia, where metallurgical coal can be railed to steel mills in northern China. However, industry sources say the agreement between Mongolia and China to develop the railway has yet to be signed. Existing railways should enable Mongolia's producers to sell some coal to steel makers situated north, west and south of Beijing.

Coal consumtion in China by sector



Source: EIA

QGX also has plans to sell metallurgical coal to Japan, South Korea and Taiwan by railing its coal output through the existing Chinese railway system onwards to Qinhuangdao or Tianjin and then finally by panamax or capesize vessels to steelmakers in north Asia. In addition, the company has plans to convert some of its future Mongolian bituminous coal production into synthetic fuels, including methanol and dymethyl ether.

Meanwhile, Ivanhoe expects to start open pit production at its coal concession at Nariin Sukhait late this year, according to Gene Wusaty, president of Ivanhoe's Mongolian coal division. Ivanhoe's Nariin Sukhait concession should produce 1 million mt in the first year of operation, rising to 4 million mt by the eighth year, according to papers presented by Ivanhoe in a Coaltrans China conference held in Shanghai in April. Ivanhoe has the potential to produce more, Wusaty said.

In addition, Ivanhoe hopes to develop a smaller coal mine at Tsagaan Tolgoi in the Gobi desert, mainly to provide feedstock to a planned 250-300 MW power plant that would be used at its Oyu Tolgoi copper and gold deposit, which has yet to be developed. Ivanhoe Chairman Robert Friedland points out that Mongolia's coal does not have to be physically exported to China, but could be exported as electricity produced by Mongolian coal-fired power plants.

Investment climate

The investment climate in Mongolia is thought to be positive towards foreign companies with the government keen to encourage inward investment in the minerals sector. However, there have been some statements made by ministers concerning government interests in mines that have caused concern and which sparked a running battle between miners Invanhoe and Canadian newspaper the Toronto Globe and Mail. Ivanhoe presents material on its website that it says shows that the newspaper failed to report fairly and accurately on the Mongolian government's position on foreign ventures.

Nevertheless, in May, the government introduced a new tax measure that applies a windfall tax on copper and gold, when the prices of the two commodities reach a certain threshold. Ivanhoe said that the measure was introduced "with little advance notice, and debated and approved in inexplicable haste." The fact and nature of the measure's introduction highlights at least the potential for a volatile regulatory environment.

Israel assesses new oil shale technology

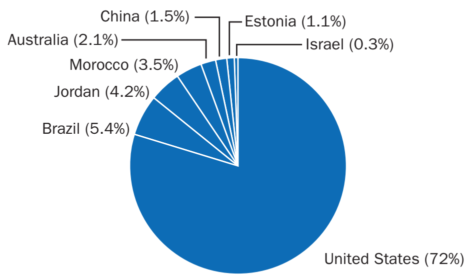
High oil prices have once again turned attention to oil shale, despite the costs of its extraction and treatment. Israel is assessing a new process, which it believes can return a healthy profit based on a long-term average price for conventional oil of $45-$50/barrel. It would also represent an important indigenous energy source for a country that lacks significant natural resources, writes **Neal Sandler** in Jerusalem.

With oil prices around $70/barrel, and given the country's near total dependence on imported oil, gas and coal, Israel is taking another look at the 12 billion tons of oil shale located in the southern Negev and in parts of central Israel. In the 1980s, an attempt to produce oil directly from shale was found to be economically unfeasible. The government then focused on producing electricity. PAMA (a Hebrew acronym for Alternative Fuel Production) was established by three state-owned companies in the energy and chemical fields and, in 1988, began operating a 15 MW power plant at Mishor Rotem. The plant is still operating, using technology based solely on shale rock as a power plant feedstock.

This time around, however, the government is revisiting shale's potential for oil, but using a unique technology developed in the early 1990s by a Russian-born immigrant. Unlike existing technologies, the new process produces oil from a mixture of oil refinery residue, in the form of bitumen, and oil shale.

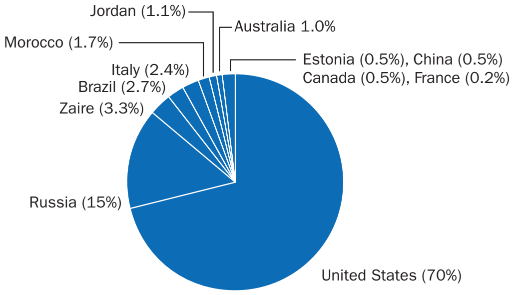
The company that owns the technology, Haifa-based AFSK Hom Tov (Hebrew for 'good heat') resumed its efforts last fall to market the process. Its proposal calls for the construction of a plant at Mishor Rotem, south of Beer Sheba, where the oil shale resource is estimated at 1.25 billion tons. The plant would use 6 million tons of shale a year and 2 million tons of bitumen to produce 3 million tons of oil, roughly equivalent to a refinery with capacity of 60,000 b/d. The percentage of shale to bitumen is determined by the caloric value of the shale.

World share of oil shale resources



Source: US Department of Energy 2005

World share of oil shale resources



Source: US Geological Survey 2003

Economic viability

An initial technological and economic study of the process was conducted more than ten years ago. It found that using an oil price of $18/barrel a plant producing 3 million tons per annum of oil from the mixture would turn a profit of $20 million to $59 million annually. The report issued by a panel of experts strongly backed the process and recommended that the Israeli government finance a pilot plant.

"Falling energy prices and Israel's decision to switch to natural gas led the government to put the home grown technology on the back burner," says Moshe Shahal, a former Israeli energy minister and now a lawyer representing AFSK Hom Tov. But this has all changed with the spike in oil prices. To stimulate interest in the new technology Shahal proposed that the 1995 study was reviewed and updated.

Eco-Energy, an energy analysis firm, based its new study on US Department of Energy price projections. The assumption is that in the long term the price of refined products will be derived from a $45-$50/barrel average price for crude over the coming 25 years. On this basis, Eco-Energy found that a plant using the AFSK Hom Tov process would produce a profit of $159 to $250 million annually.

The study estimated the cost of producing a barrel of oil from the process at $16-$17. Eco-Energy noted that if November 2005 oil prices were used as a basis for cost calculation instead of the US Department of Energy average price of $45 to $50/barrel, the annual profit of the plant would range from $188 to $317 million. The cost of a production plant, including infrastructure, is estimated at $700-$800 million.

The AFSK Hom Tov plant incorporates in one installation a system of facilities that perform combined catalytic thermal cracking of oil refinery residue and oil shale. The process required to supply all the production services itself includes preparing the feed, catalytic cracking and thermal extraction, treating distillates and other services such as cleaning emission gases, treating by-products and auxiliary facilities and production services.

Strategic resource

"We see tremendous economic and strategic benefits for going ahead with the process," says Amit Mor, managing director of Eco-Energy. First and foremost, the updated study stressed a reduction in dependence on imported oil, coal and natural gas. Israel currently imports over 10 million tons of crude and over 12 million tons of coal annually. In addition, the country is switching to natural gas. At present, the gas comes from a field off Israel's southern Mediterranean coast. But in years to come most of the gas will be imported. Mor added that a 3 million ton per annum plant would also produce thousands of jobs in Israel's Negev region.

Israel's National Infrastructure and the Industry, Trade and Labor ministries are currently studying the patented process, but are expected to give the green light for an industrial scale pilot plant to test the technology. The process itself has only been tested at laboratory scale so far. A formal request has been submitted to the National Infrastructure Ministry for mining rights at Mishor Rotem, and to the Industry, Trade and Labor Ministry to obtain government grants for the project. The company hopes to have the necessary licenses and support in hand by early 2007 at the latest.

"Our plan is to build a small reactor in Haifa to handle 1 to 2 tons an hour and later expand it," says Israel Feldman, co-founder and managing director of AFSK Hom Tov. A plant of this scale would cost several million dollars. Once the technology is tested, plans call for a full scale plant to be built at Mishor Rotem. "Full scale production is likely to begin in 2010 or 2011," predicts Feldman. The plan envisages construction of a pipeline from the Ashdod refinery located 80 kilometers to the north that would be used for transferring the necessary asphalt needed in the production process. A parallel pipeline would ship the synthetic oil produced at Mishor Rotem back to Ashdod where it would be refined.

The use of the bitumen would also solve the problem of an expected excess refining capacity at Ashdod in the coming years, owing to Israel's switch from fuel oil to natural gas for power generation. Israel's two oil refineries at Ashdod and Haifa do not have a solution for the surplus capacity. The situation is becoming more difficult as time goes on, owing to the increasing restrictions in most western countries against the use of heavy oil and refinery residue.

In addition, Feldman is proposing the use of the shale left over from the production of the synthetic oil to run a power plant at the site. Initial indications are that a 1,000 MW plant could be set up. A further potentially profitable sideline might also be the use of the shale dust from the proposed power plant in the production of cement.

Going global

The Israeli process has led to substantial interest abroad. Some twenty five countries have large shale reserves, the largest being in the US. Israeli energy industry sources involved in the project say that energy giant Shell, which is active in oil shale in Colorado, has expressed interest in the project.

There have also been enquiries from neighboring Jordan and Morocco for building shale power plants. Shahal confirmed that he has held extensive talks with Jordan's Energy Minister Azmi Khreisat on building a plant in Jordan. Jordan has even larger and higher quality reserves than Israel, which would make the production of oil using the technology more profitable. Morocco also has large shale reserves.

Oil shale: a huge but low energy resource

According to the World Energy Council, using standard processing techniques, oil shale is competitive with conventional crude oil when the latter is above $40/barrel. However, in 2005, Shell said that its in-situ extraction technology deployed in Colorado in the US could be competitive at prices over $30/barrel. The AFSK Hom Tov process claims profitability at $16-$17/barrel. The Shell method has produced oil in commercial quantities, AFSK Hom Tov is at the laboratory scale.

Oil shale's ratio of energy used to produce oil compared to the energy returned is low. Shell reported a figure of 3:1, which compares poorly with conventional oil extraction which varies from 20:1 to 100:1. Oil shale does not in fact contain oil and is more like coal or peat. It consists of hard rock called marl that contains mainly kerogen, an organic material, which needs to be treated at a high temperature to be converted into synthetic oil or gas.

A report published in April for the US Congress estimated that the oil shale resources of Colorado, Wyoming and Utah contained the equivalent of 1.8 trillion barrels of oil in place, compared with Saudi Arabian conventional reserves of about 267 billion barrels of oil, so the resource is potentially huge. According to various estimates, it is not entirely clear which countries have what share of the oil shale resource. However, the US is always credited with the largest deposits, with a share of between 61-72% of the world's resources.

Data on the size of oil shale reserves is equally sketchy and incomplete. The World Economic Council, using data reported by members in 2000/2001, put proved recoverable reserves for the US at 60-80 billion tons of oil, Jordon 4 billion tons, Australia 1.725 billion tons, Thailand 0.8 billion tons, Israel 0.6 billion tons, Morocco 0.5 billion tons, Ukraine 300 million and Turkey 269 million tons. However, large deposits are also known to exist in many other countries, such as Brazil, South Africa, Zaire, Estonia and China.

The demand side is our starting point...

Ross McCracken summarizes the keynote speeches of the June IAEE conference and puts questions to a panel comprising **Olivier Appert**, President of the Institut Français du Pétrole, **Jean-Philippe Cueille**, President of the IAEE, **Georg Erdmann**, IAEE conference chairman and former UK energy minister **Lord Howell of Guilford**.

The central importance of demand management, the need for diversity and the alignment of market signals with policy goals were the key messages of the 29th conference of the International Association for Energy Economics, held June 7-10, in Potsdam, Germany. There was no promotion of 'silver bullet' technologies, rather recognition that a diverse range of energy sources is needed to meet the challenges presented by climate change, security of supply concerns and energy poverty.

However, some contradictions were evident between the role of policy and markets, with empirical evidence that market signals and outcomes were not synchronized with changing policy goals. While free market philosophy retains its primacy through belief in the efficiency of markets, questions remained over how markets can internalize the costs of climate change and the role policy should play in this process.

Lord Howell of Guilford: The most important need is for diversity and flexibility in our energy supplies. Within the EU there are three serious dependencies, the EU's reliance on piped Russian gas, France's dependence on nuclear, and the world dependency on oil. These have brought less energy security not more. We should look to Japan as an example, a country with precious few natural resources, but one that has persisted with energy efficiency since the 1970s and '80s oil shocks.

Europe's dependence on piped Russian gas was foreseen, but many felt that the supplier would need the customer just as much as the customer needs the supplier. However, even if we forget the unsettled political scene in Moscow, Gazprom will inevitably behave as monopolies do and find the best customer, which might prove to be Asia rather than Europe.

The Russia-Ukraine gas crisis at the beginning of the year unnerved the EU, but the European Commission's response has been to meet a monopoly with a monopsony – a single buyer. This will not work in practice as EU member states treat gas supply on a national basis and Russia has other buyers.

I put forward two propositions: first, there is no such thing as full energy security, because no such pattern can ever last. It will always be disrupted by events. Second, the best security is achieved through diversity and the ability to switch between sources of primary and secondary energy. This applies at all levels of the economy. Japan again provides a good example in its development of LNG and its moves towards spot market purchasing rather than long-term contracts.

China's strategy of establishing wider contacts abroad and securing foreign assets is not a guarantee of security of supply. It works in a buyers market, but when there is a shortage of oil they are as vulnerable as everyone else and diversity again comes to the fore. We all have to face reality in that security lies in diversity, market driven efficiency and the development of domestic resources.

The cost ruler must be applied to nuclear power and the question asked, is it worth it, given the risks and the level of investment required? Energy efficiency, driven by economics, offers much more hope. Coal can be gasified and liquefied for a carbon-free burn. Plant derived hydrocarbons can be developed with experience, although we must avoid the risk of a new subsidy regime.

Former executive director UNEP, Klaus Toepfer: Oil reserves depend on price, technology and demand. If we can achieve carbon storage and sequestration, then this will allow further increases in hydrocarbon production. But what is the overall economic and social end of the decisions that we take? How do we bring energy security of supply and ending poverty together? We need reliable and economically affordable energy sources, alongside policies that are socially responsible and environmentally sound. Energy is fundamental to achieving other goals of reducing poverty and promoting development.

The demand side should be the starting point. In the short-term most energy costs are fixed. Only over the longer term does the demand side demonstrate a more flexible response. Consumers react to price, but need signals.

Settlement structures reflect the relative price of gasoline. The global average for car ownership is 120 private cars per 1,000 people. In the US, the figure is 850, in the EU 750 and in China less than 50. There is the prospect of adding 13 million more cars, owing to increases in income and people's need for mobility. As a result, there is an urgent need to change the demand side. This is also true for buildings, where there is now the possibility of building zero emission houses. These technologies become more competitive as energy prices rise.

We need to cancel all subsides for all forms of energy supply. If subsidies persist, then there are no clear economic answers and no clear economic signals. Currently all forms of energy are subsidized. Fossil fuels are subsidized because the costs of climate change are not included. We have incomplete knowledge about carbon dioxide, but all decisions are taken with incomplete knowledge and the case looks persuasive. If the costs of climate change can be integrated into the production of fossil fuels, then we would have no need to subsidize other forms of energy supply. We would have the same structure of subsidy for all sources of power.

Energy Economist: Saudi OPEC governor Majid Al-Moneef expressed concerns about over investment. Do you see tensions between producer countries and the climate change agenda?

Olivier Appert: Producing countries were deeply hurt by the drop in demand after the first and second oil shocks and again in 1999. They are again under pressure to increase production, but do not want to invest for nothing. US President George Bush's recent statement on reducing US dependence on Middle East oil was naturally a cause for concern.

Now, however, oil is more related to the transport sector. If there is a global crisis, economic growth could slow and with it the demand for oil, but with no crisis, there is every expectation that the transport sector will continue to grow and so will demand for oil. As a result, producers perhaps overestimate their concerns. The real problem with a potential lack of investment is not in the next couple of years, but in the next ten to twelve. Producers were opposed to climate change mitigation, but now they see the level of prices and realize that these measures have had no impact on price.

Jean-Philippe Cueille: Oil producers also see carbon storage and sequestration as a technology that allows a greater future for oil, even if it is hard to apply to the transport sector, it represents a future for burning hydrocarbons. There are even some far off ideas of CCS in cars. But you can see the importance of the oil price to producers. Oil exporters' budgets are often highly dependent on the oil price and enormous economic and political pain can result from a sharp fall in prices.

Lord Howell: There is so much anxiety about oil supply and the situation in Iraq, but it is important to realize how much oil has been kept back from the market by supply disruptions. The London-based Center for Global Energy Studies, in which I have an interest, has estimated that some 2.2-8.8 million b/d has been missing from the market as a result of various disruptions, mainly in Venezuela, Nigeria and Iraq. This has reduced spare capacity to below 2 million b/d, but it also indicates that there is much more potential spare capacity than people realize.

EE: There are many signs that the physical market is over-supplied with oil. Are futures setting the price?

Olivier Appert: Looking at the market today, there is no question that the current price is not related to the fundamentals of supply and demand.

Lord Howell: As a general measure, I see $20/barrel of the price of oil as speculative, $10/ barrel of which relates to pure trading activities and another $10/barrel to more widespread concerns with the market situation. All it takes are some positive noises from Iran about talks over their nuclear program and the price of oil drops by $4/barrel.

Georg Erdmann: You have to get current price in perspective. It was only a few years ago that OPEC had a price band of $22-$28/barrel and even that sparked debate over whether the ceiling was too high. We are now at $60-$70/barrel.

EE: Despite predictions, why has the oil price rise had so little impact on inflation?

Olivier Appert: Non-OECD demand has not been so badly affected, but the burden has become heavier because of subsidy systems. These have protected consumers, but in many cases have taken up a significant share of state budgets. As a result there has been a delayed effect on demand, but it is happening.

Lord Howell: This time around, there are a lot of new factors. For example, deliberate oil reduction policies operating over the medium term, resulting in real demand destruction. This time, there would not be a corresponding impact on demand if oil prices fell.

Olivier Appert: There has been a small short-term demand effect, just like during the 1990 Gulf War. In the US, there was then a significant drop in demand. Three months after the price spike, demand fell by 1 million b/d. That is not the case today. There has been less impact on inflation in part because there are more tools to cope with inflation. Demand has been less affected because of the tax cushion – taxes in many countries make up 75% of the price consumers pay, so the actual rise in product prices is much smaller. In the non-OECD, there are three types of country, those like China and India, where their cost advantage is so large they have been able to cope with the rise in prices. Oil producers, which have accounted for a large share in oil demand growth. Some, like Venezuela and Iran, have large subsidies which for political reasons are impossible to get rid of, so there has again been little impact on demand. In other non-OECD countries, the rise in costs has been absorbed by governments concerned about the political costs of passing on the whole rise in prices.

Georg Erdmann: There are also other effects such as where demand falls on the marginal driver. With little elasticity of demand in the US, because of their social dependence on car transport, there is no marginal driver. In China, where demand for transport is growing rapidly, again there is no marginal driver effect because the Chinese government has been subsidizing the price of refined products. Europe has become the only area where there is a significant marginal driver effect.

Olivier Appert: More broadly, the world economy is in much better shape now than is was during the other oil shocks.

EE: Should the price of gas be de-linked from oil and are we seeing greater possibilities for substituting other commodities for oil?

Jean-Philippe Cueille: The US has had open gas markets, without this link to oil, for sometime, but even then there is a strong correlation because of the ability to substitute between oil and gas. It has been estimated that the capacity to switch is as much as one million barrels of oil equivalent a day.

Lord Howell: Over the last 30 years there has been a huge switch in the UK from oil to gas and there is likely to be more flexibility as spot market supplies of LNG increase. But the contractual link represents a form of insurance for both sides.

Olivier Appert: Oil is used 98% for transport and there are increasing levels of car ownership. It will take a long time and we are starting from nothing. Even if biofuels took 5% of the market by 2010, when the increase in car ownership is taken into consideration, there will also still have been an increase in demand for oil. So there will be little impact on oil over the short term. The first priority must be energy efficiency encouraged through policy. The average weight of cars is actually increasing by about 25 kilograms a year.

Jean-Philippe Cueille: Cost is everything. Ethanol in Europe is competitive with oil only when oil reaches a price of between $90-$150/barrel. The technological development of cars offers a way through, but so far we cannot say at what price the different technologies will meet.

EE: There seems to be some tension between policy and markets. Do markets always give good signals?

Jean-Philippe Cueille: It is necessary to have a clear regulatory framework and policy context, but it is wrong to rush into subsidies, which can stifle innovation. We have to ask what is the true cost of a barrel of oil, including the cost of carbon dioxide emissions, plus other hidden subsidies. The policy environment must reflect the true costs, which means that prices must become more transparent.

Olivier Appert: The experience of the UK gas market is interesting. The market appears to have been blind to two facts. The drop in North Sea production was not hard to predict. The second was seasonality, taking into account production on the UK continental shelf, there was no signal to invest in storage. Why didn't the market see these facts?

Lord Howell: The market is not always able to give good signals. It is unreal to think that markets offer all the solution, but in order to avoid a boom-and-bust cycle markets need long-term players for crucial investment. Therefore government must be more involved.

Georg Erdmann: Governments have a role. No market in the world is totally competitive. Power plants' marginal costs are very steep and this makes market entry very difficult. They operate in markets that have natural oligopolistic tendencies. These markets do not necessarily attract rational investors because oligopolies want to keep capacity as low as possible. Governments should facilitate open market entry and create incentives.

Lord Howell: There is also an important question, which is whether government is equipped to make these decisions. But if capital markets will not invest and investors themselves refuse to step up, then how do we get long-term investment?

Olivier Appert: Energy by its nature is a long-term sector. A power plant's life is somewhere between 40-50 years. Governments have short-term horizons as they are driven by elections and the market is also short term. How can these actors take long-term decisions?

EE: Combined heat and power generation technologies offer much higher efficiencies. Should they be an integral part of energy policy? What other developments do you see as important?

Jean-Philippe Cueille: CHP is a good solution where there is a large heat sink. It is a good solution in the case of the Nordic countries, but is not so good in southern Italy for example, where there is less demand for heat. It represents one part of the solution. It works best in places where district heating is already installed. It is very expensive and sometimes simply not practical to install in lots of different private houses, which already have different heating systems. In addition, it takes a lot of time and money to build from scratch.

Georg Erdmann: Finding a large heat sink is problematic, one that is big and requires heat for long hours. CHP can be applied mainly in buildings, but the requirement in industry is small. As it is hard to get people to change, small-scale CHP provides more of a solution. However, this requires the production of small motors and there are no economies of scale in downsizing motors, in fact there are diseconomies of scale. Fuel cells possibly offer an alternative route as these can be downscaled and the cost reduced per unit.

Olivier Appert: If there could be one breakthrough, I would hope that it would be in batteries. If we could store electricity efficiently it would solve so many problems. But batteries have been around for so long and there has been no breakthrough.

Lord Howell: Not using energy is our biggest resource. Energy efficiency, not just politically guided, but as a question of changing public attitude is of central importance. If that happens, we could reduce the need for energy substantially.

Jean-Philippe Cueille: I agree, education is of fundamental importance and it is key to achieving energy efficiency, both for access to energy and for energy conservation.

Home energy propositions remain marginal

Rising utility bills are heightening consumers' awareness of the potential of energy saving devices. While loft and cavity wall insulation remain top of the list, manufacturers are offering new alternatives for producing electricity in the home. While improving, however, most remain marginal consumer propositions.

High domestic electricity and gas bills are hitting consumers where it hurts – in their wallets. Disposable income is being squeezed as wage inflation lags the real rise in the cost of living. However, higher prices also make domestic energy saving devices more cost effective. Top of the list are loft and cavity wall insulation. They are easy to do, involve a relatively small capital outlay and the payback time is short.

Wind, solar and micro-CHP offer new alternatives for domestic consumers and as Toyota have found with the electric hybrid Corolla, there are buyers willing and able to pay a premium for environmentally sensitive technologies. However, to become more widely accepted, home-based energy producing devices need to become less economically marginal propositions.

A number of products are coming to market that offer homeowners a chance to cut their domestic energy bills, provided they are prepared to pay capital up front to make back savings over a number of years. As sellers of solar panels have found, this is not always an easy sell. Consumers are reluctant to spend large lump sums in the short-term for a long-term payback, even if the economics appear to work on paper.

This is particularly true for non essential items. It is easier to 'up sell' a boiler purchase on the basis that a costlier unit will save more over time because the consumer must have a boiler of one sort or another. Not so with solar panels, where the savings are small over time, and often too small to warrant borrowing. Unless environmentally driven, consumers will all too often have many other demands being made upon their ready cash.

Solar option

Solar water heating devices are listed by the UK Energy Savings Trust as the most cost-effective, affordable renewable technology for housing, providing up to 50% of hot water needs over a year and replacing about 400 kilograms of carbon dioxide emissions, depending on the fuel replaced. There are two main systems, a flat plate collector system at between £2,000-£3,000 ($3,686-$5,530), while evacuated tube systems cost between £3,500-£4,500. In the UK, grants of up to £400 are available through the Low Carbon Buildings program. Nevertheless, the up front capital cost is large compared with the period of time it takes to recoup the savings.

Solar photovoltaics go one step further and directly produce electricity, offering the possibility of selling power back to the grid in the summer, offsetting higher winter bills. Size reduces the installed cost, but most houses do not have sufficient usable roof space to power the whole house. Installers estimate the average UK house uses 3.5-4.0 kW peak – somewhat above the Energy Savings Trust figure of 1.5-2.0 kWp.

How much space is required to generate 1 kWp depends on the efficiency of the system. Firms suggest as little as 7.5 square meters in ideal circumstances, although others suggest that in the UK, as a rule of thumb, 25 square meters of PV panels are needed to produce 1 kWp. Estimates of the installed cost of a 1 kWp system range from £4,000 to £7,000, suggesting that a 3 kWp house system would cost anywhere between £12,000-£21,000, a big capital outlay that would take ten to twenty years to regain in savings, ignoring the opportunity cost of the capital employed.

In addition, the investment assumes the homeowner stays in the house over the investment period as there is no certainty that the energy saving cost will be factored into the property price, while the aesthetics might also impact on a house's attractiveness to buyers.

Government grants make the schemes much more affordable. Under the UK's Low Carbon Buildings Programme, the government will fund up to 50% of the installed cost of the PV panels, subject to a maximum £3,000 per kWp installed and a total maximum of £15,000, provided also that certain other energy efficiency criteria are met regarding insulation and low energy light bulb usage. If the maximum grant were achieved, this would cut both the capital outlay and pay back time in half, even if it makes the buying process more cumbersome.

Wind alternative

Windsave, a Glasgow-based company, is to produce a domestic wind turbine which can be fitted to most houses to generate electricity for direct consumption. The company's Plug'n'Save microwind system won 'Best New Product' at the European Business Awards for the Environment in June.

The system includes a three-bladed fan that is 1.75 meters in diameter and is mounted to domestic properties of 10-20 meters height. The system's electronic conditioning system is plugged into the building's standard ring mains supply for 230 Volt AC, 50 Hertz applications. The units operate in wind speeds from 3-4 m/s up to 15 m/s and are rated for 1kW at wind speeds of 12 m/s. Windsave estimates that when it is working, the net effect is a saving of up to 30% against an average UK domestic electricity bill.

WindSave expects the unit to give "in excess of 0.5 MWh over one year more or less anywhere" in the UK, with very good wind resources achieving up to 1.5-2.0 MWh. The turbine only provides savings when the unit is generating and when the consumer is using electricity. There is no storage capacity and any excess spills over into the district grid system.

A potential problem will be noise. WindSave estimates that at 5 meters behind the blades in winds gusting up to 7 m/s, the unit would give off LAeq 52 decibels, which is equivalent to a quiet washing machine or noise levels associated with a large office, but situated externally. The company website does not provide a noise level for the top wind speeds, 15 m/s, at which the turbine is able to operate.

Grant funding in the UK is available for domestic wind turbines up to £1,000 per kWh installed, up to a maximum of 30% of the total cost, implying that the WindSave product could attract a subsidy of just under £500. Windsave was approved as an accredited supplier by the Energy Saving Trust in November last year. Windsave also says that the system will on average produce enough energy to qualify for one Renewable Obligation Certificate, worth about £60.

The payback period depends heavily on the wind conditions at any one location, while the lack of storage or apparent 'earnings' from spillage into the grid suggest that the offset – which occurs only when the unit is generating and when the consumer is using sufficient electricity – might prove to be a lot lower than 30%. At 30% the payback period would be under five years, but if the savings are just 15% then the payback period extends to the expected life of the turbine. The reward would be counted in emissions rather than cash.

In addition, in the UK, any change to housing that extends above the roof line requires planning permission, which is an additional cost and means that any application would have to go through the usual public consultation procedure. Buyers' risk the application being turned down, although planning procedures are described as "encouraging" towards applications with environmental benefits. While WindSave have a product that in terms of price is in line with what the average consumer might wish to commit to an environmental technology, havng to get planning consent will prove a disincentive to marginal buyers.

Furthermore, the shafts of wind turbines experience significant strains and stresses. Although wind turbines have already been scaled down successfully for application on yachts, for example, how damage to a building as a result of their use might apply in terms of buildings insurance may also cause problems.

Micro CHP

Micro CHP has gained credence in energy circles, but appears to have attracted little customer awareness as buyers continue to see heating and electricity as separate issues. Most importantly, however, commercial micro CHP models that work for single homes have yet to hit the market. As a result, the investment cost for buyers is unknown.

In addition, the performance of micro CHP, as with other micro power producing technologies, will depend on the pattern of demand for both heat and electricity and how much reward is received for electricity 'exports'. As a recent paper by the Sussex Energy Group SPRU noted "if rewards for electricity exports are low, as they are in the UK, micro-generation will be more attractive to consumers with high demand. In addition, micro-CHP requires a minimum thermal demand to guarantee enough electricity output to pay back the additional up front costs."

Microgen, a subsidiary of gas company BG Group, is developing a new CHP energy system for homes and small business premises. The unit will be the same size as a conventional boiler and produce heat, hot water and electricity from the same energy input, allowing householders to save money and reduce greenhouse gas emissions at the same time. In addition, Siemens Building Technologies and Microgen are working to develop an advanced set of integrated controls for the system's to maximize energy efficiency.

The appliance incorporates the latest condensing boiler technology alongside a Free-Piston Stirling generator, which uses natural gas. The appliance also houses a second heat exchanger and burner, similar in design to traditional condensing boilers, to provide more heat for the home during high demand periods. Additional user controls will be developed, providing information on the performance of the appliance, indicating when and how much power is being generated, so that the household can take full advantage of the system. Microgen plans prototype field trials this year in the UK and Holland.

Consumer proposition

Ultimately, micro CHP boilers will have to be priced at an acceptable trade off between the up front cost and both the financial and environmental savings to be made. It should be noted that there is also a trade off with some technologies between the environmental gain and the electrical and total efficiency of the unit.

Boilers are essential to houses and the alternatives to CHP already represent a significant capital outlay to homeowners. A good analogy might be that between petrol and diesel cars. Diesel engines made significant in-roads into the market when they were priced a few thousand pounds above petrol engines, but also offered longer engine life, higher mileage and ran on what was then cheaper fuel. A large upfront cost to the consumer is probably the greatest barrier to a sale and the closer the cost of micro-CHP boilers can get to the next best alternative, the easier it will be to convince consumers of the benefits of the low running costs.

Forthcoming conferences

Baden-Baden Energiegespräche
July 6-8
Baden-Baden, Germany
www.rochusfisches.de

Fuel Price Risk Management
July 11-12
Singapore
www.iqpc.com.sg

International Solar Cookers Conference
July 12-16
Granada, Spain
www.solarconference.net

Gas Utility Forum
July 13-14
Boston, USA
www.platts.com

Atlantic Oil and Gas Symposium
July 18-19
Halifax, Canada
www.canadianinstitute.com

Managing Cost of Energy
July 19
New Delhi, India
www.indiainfrastructure.com

Utility Cost Recovery Forum
July 19-20
Baltimore, USA
www.platts.com

Feedstock and Product Pricing
July 24
Kuala Lumpur, Malaysia
www.ibc-asia.com

Excellence in Upstream Energy 2006
July 31-August 1
Sydney, Australia
www.resourcefulevents.com

Georgia BioEnergy Conference 2006
August 1-3
Tifton, USA
www.gabioenergy.org

World Renewable Energy Conference
August 19-25
Firenze, Italy
www.wrec2006.com

Offshore Gas Production Technologies
August 24
Singapore, Singapore
www.ibc-asia.com

ICEE2006 Energy and Environment
August 28
Kuala Lumpur, Malaysia
www.medept.com

Renewable Resources & Biorefineries Conference
September 6-8
York, UK
www.rrbconference.net

New Renewable Energy Sources
September 6-8
Bucharest, Romania
tripsa@asticontrol.ro

Third OPEC International Seminar
September 12-13
Vienna, Austria
www.thecwcgroup.com

29th Annual Coal Marketing Days
September 14-15
Pittsburgh, USA
www.platts.com

Alaska Oil and Gas Symposium
September 18
Anchorage, Alaska
www.americanconference.com

Fundamentals of Coalbed Methane & Shale Gas
September 18
Calgary, Canada
www.canadaininstitute.com

North African Oil and Gas Summit
September 19-20
Madrid, Spain
www.wraconferences.com

Green Energy 2006
September 20
Halifax, Canada
www.energyconsultant.ca

BIEE Energy Policies in a Global Context
September 20-21
Oxford, UK
www.biee.org

LETTER FROM BAGHDAD: JUNE 2006

Makoo nafut fi balad alnafut – No oil in the country of oil

“Makoo nafut fi balad alnafut” is a phrase widely used in Iraq whenever there is a fuel shortage in the local market. Literally translated, it means “there is no oil in the country of oil.” While billions of barrels of crude lie underground, ordinary Iraqis sit in their cars in the scorching sun as temperatures hit 50 degrees Celsius, waiting for hours to put gasoline in their cabs, for some the principle source of their livelihoods.

Prior to the invasion of Iraq, the country’s refineries produced sufficient quantities of gasoline to meet local demand and an excess of middle distillates and LPG. The excess was used for strategic stocks and for export to neighboring countries. Despite high rates of production, intermittent shortages occurred during the coldest winter months, particularly with kerosene and LPG. The cause was attributed to limited storage facilities and inefficiencies in the distribution system. However, private smuggling to neighboring countries and to Kurdish-led areas outside the jurisdiction of the central government was also a serious problem. Big differences in domestic and external prices meant that even the harsh measures taken by the Saddam regime failed to stop the trade.

The situation changed dramatically after the invasion. On the supply side, refineries operated at just 40%-60% of pre-war levels. The drastic fall in production surprised US commanders, who repeatedly stressed their policy of not targeting crude oil production and transportation facilities, refineries, gas processing plants, electric power generating stations and the electrical distribution network. However, they had not catered for the widespread looting, vandalism and pillage prompted by the fall of the old regime, owing to the breakdown of general order and the absence of the old security and protection apparatus. The looting was particularly severe around the vital southern gas processing plant, which supplies half the country’s needs, and around the power stations and electrical grid which supplies the oil installations with power.

Added to this was the start of the insurgency, which quickly saw the strategic importance of pipelines. A prime target were those linking the northern oil fields with the refining centre in Baiji, which produces half the country’s products, and the product pipelines that link these centers to Baghdad, the main center of consumption with around six million inhabitants. These attacks were successful for some periods in cutting off all supply to the refineries and for serious delays in distributing products to consumers.

Simultaneously, demand for oil products increased. The rate of gasoline consumption in 2005 was 43% higher than in 2002, kerosene demand was up 20%, gasoil 12% and only for LPG did demand fall, by about 5%. The rise was attributed to the import of tens of thousands of used cars after the invasion, as well as the huge rise in the use of industrial and domestic electrical generators to compensate for repeated long cuts in national power supply. In addition, product smuggling continued, mainly through the Shat Al-Arab. Ex-oil minister Dr Bahr Al-Uloom estimated that some 2.0 million l/d of gasoline was leaving the country by this route alone.

The shortfall between production and demand resulted in very long queues at gas stations and very high black market prices. To salvage the situation, huge quantities of products were imported from neighboring countries, principally Turkey, Kuwait and other Gulf states. In 2005, imports reached unprecedented levels and cost the national treasury more than $3 billion dollars. The net outflow is around $1 billion when the value of the unrefined exported crude is deducted. Domestic product prices were increased in mid-December, immediately after the last elections, and again in June, to bring prices closer to external ones to curb smuggling and reduce government subsidies as part of debt relief plans agreed with international financing bodies. The price of a liter of regular gasoline is now 150 Iraqi dinar ($0.10) and for improved gasoline 250 dinar.

The price increases and the other measures taken by the government to curb demand, such as rationing, driving on alternate days and coupons for LPG and kerosene purchases, were successful in stabilizing consumption in the first six months of 2006 at about 20% below 2005 levels. However, the queues at gas stations have been getting longer and longer, and the prices on the black market – usually the pavement adjacent to the stations – are between four to ten times the official price, depending on the product.

The causes of this persistent crisis have been compounded in 2006 by the reduction of imports, mainly from Turkey, which stopped exports at the end of January because of a dispute over methods of payment and accumulated debts. Imports were resumed at a reduced rate in May. However, the queues are unlikely to shorten while long electrical power cuts force petrol stations to rely on their local and unreliable generators and service hours are reduced to comply with curfews, usually from early evening to dawn.

Senior officials of the Iraqi oil ministry acknowledge that the solution is to repair and upgrade the country’s existing refineries, which suffered from a lack of investment over the last two decades. There are plans for new refineries – a 70,000 b/d plant in Kurdistan and a 140,000 b/d central refinery in Kerbala – but to date none of these contracts have been awarded apart from the 70,000 b/d distillation unit to be installed in the Dora refinery in Baghdad, which has been given to a Czech firm for completion in 18 months time.

Hence the prospects for a speedy improvement in the local fuel supply situation are bleak. Iraqi drivers will have to endure long queues or pay high prices for their fuel for some time to come, irrespective of how much oil Iraq has buried underground.

Faleh Al-Khayat

LETTER FROM WASHINGTON: JUNE 2006

Businessman Bodman to pick winners and reconstruct Iraq

Although he left the corporate world six years ago to join the Bush administration, Energy Secretary Samuel Bodman still appears as much a businessman as a policymaker when he talks about options for securing the United States' energy future. The former chairman and CEO of Cabot Corporation and president and chief operating officer of Fidelity Investments often sounds as though he's imparting advice on a potential acquisition or sound investment when he refers to advances in energy technology that he thinks could reduce US reliance on imported oil and provide less polluting energy.

That tact was evident recently when he addressed the Harvard Business School Global Leadership Forum in Washington, an invitation he joked was a surprise for him in light of the doctor of science degree he holds from the rival Massachusetts Institute of Technology and the six years he served at MIT as an associate professor of chemical engineering in the 1960s.

As he does at public events, Bodman hailed President George Bush's call earlier this year for the United States to reduce its oil imports, singling out several initiatives the administration has launched to meet that goal, including the Advanced Energy Initiative. That program aims to increase government funding for "clean" energy technologies, such as advanced nuclear reactors, emission-free coal power plants and various forms of renewable energy. It also aims to support research that changes the way Americans power their cars, putting money into better batteries for hydrid and electric autos and pollution-free cars that run on hydrogen.

"This initiative essentially proposes to pick some winners," he told the audience. "That may not be the usual role for government, but we must do it if we are to meet the demands of the future."

Solar, clean coal and cellulosic ethanol win out, but not hydrogen

Bodman went on to say the administration would "go after those technologies with the greatest potential to impact the market in the next few decades," then signaled where he, with his years of business and investment experience, sees the most promise. "In my view, the three technologies at the top of the list are: commercially competitive cellulosic ethanol; solar energy, including an acceleration of the development of solar photovoltaics; and new technologies to burn coal with near-zero emissions."

What about hydrogen, which Bush wants established as a commercial option by 2020 or so, one member of the audience asked him later. "I think that's a little longer term than the others," Bodman responded. "I suppose my not mentioning it betrays my own prejudice on the subject," he added.

Government expects private sector support

In pursuing those goals, the administration expects collaboration with the private sector, academia and other governments, Bodman said. He noted as a "prime example" of such cooperation an announcement days earlier by DuPont and BP that they would work together to develop and produce biobutanol. The companies said they intend to bring the biofuel to the market in the United Kingdom next year as component of gasoline.

The secretary is keen to recognize the increasing level of investment in energy technologies by the venture capital community. "There's a lot going on there, and frankly, I take greater heart from that than from the work we do in the government."

Bodman also takes personally his role as chief government advocate for transformational energy technologies, noting his age – 67 – and telling his staff he wants breakthroughs in his lifetime. "You can check the actuarial tables and figure out how long that might be," he said.

Bodman given Iraq advisory role

US domestic goals aside, Bodman faces a far more daunting task advising the new government in Iraq on the reconstruction of their oil and electricity industries. Bush this month told the energy secretary to start working with his counterparts in Baghdad on steps the Iraqi government can take to bring more oil to market and electricity to homes and businesses. Bodman told reporters he plans to visit Iraq soon.

In a telephone conversation Bodman, Iraqi Oil Minister Hussain al-Shahristani and Electricity Minister Karim Wahid al-Hasan said they expressed interest in developing a law that would "tell the private sector exactly how the Iraqis will permit development of their resources and provide rules of the road," the secretary recalled to reporters.

In a meeting with Energy Department personnel, Bodman said establishing such a law would be a first step toward attracting US investment in Iraq's energy sector. "My guess is that those companies are going to want to see that they have a better security situation than they now have, so I know [Iraq's officials] will be working on that," he said. "We will be working with them when we get there to try to understand that and understand what the possibilities are."

Bill Loveless

LETTER FROM MOSCOW: JUNE 2006

Russia closes ranks: gas export monopoly approved, field limits tightened

Russia's desire to protect its energy resources is well-documented, but June saw it go to extraordinary lengths to prevent foreigners from playing any substantial role in the country's energy sector development.

The Duma, the lower chamber of the country's parliament, approved in a first reading June 16 a draft law granting the state-owned gas monopoly Gazprom the exclusive right to export Russian gas. The proposed law would give Gazprom a monopoly in exporting both LNG and pipeline gas, but would exempt existing production-sharing agreements, including the Shell-led Sakhalin 2 liquefaction projects in far eastern Russia.

The bill was approved on the first reading by 386 deputies of the 450-seat parliament. Six lawmakers voted against the proposal and eight abstained. The proposed law would give "a company that owns Russia's united gas supply network or its 100% subsidiary the exclusive rights to export natural gas," a resource described in the draft as "a strategic raw material."

Lawmakers from the pro-Kremlin United Russia party, who proposed the law, want the text approved ahead of the July G8 Summit in St Petersburg to bolster Russia's position in talks expected to focus on energy security. "It's clear there is growing pressure on Russia from Western countries that want access to our resources and gas pipelines in order to force down world market prices for gas," said Valery Yazev from United Russia, one of the authors of the law. The text said the bill would help "defend the Russian Federation's economic interests, fulfill international obligations on gas exports, guarantee federal budget intakes and support the Russian Federation's energy balance."

Valery Nesterov, an oil and gas analyst at the Troika Dialog investment house in Moscow, said the bill showed the influence of Gazprom over the Russian parliament. By approving the law ahead of the G8 summit, Russian lawmakers wanted to show that "Russia is a global energy player that controls energy flows, a country where the government can control exports," Nesterov said.

The bill needs to pass a third and final reading in the Duma, followed by approval in the upper house, the Federation Council, before being signed into law by President Vladimir Putin. The Duma is scheduled to vote on the second and third readings on June 28, according to the energy committee.

EU requests for third-party access rebuffed

The EU has urged Russia to reduce Gazprom's monopoly over exports by giving non-state players a role and to allow greater access to Russia's gas market for European energy companies. The draft law is a direct rebuff to the EU's requests. "From Russia's point of view, the bill enhances the reliability of Russian gas supplies," even though it cuts out competition for gas exports," Nesterov said.

Russian oil giants, such as Lukoil and Rosneft, are also increasingly producing gas. Under the new law they will be compelled to sell their gas to Gazprom in order to export. Putin has described the energy sector as the "holy of holies" of the Russian economy and said Russia should receive compensation of equal value in exchange for freer access to its energy resources.

Europe depends on Gazprom for a quarter of its gas imports. That dependence has raised hackles, particularly after Gazprom briefly cut off supplies to Ukraine in January in a bitter price dispute that also affected deliveries to western Europe. The supply reductions increased calls in several European countries to diversify gas supplies, including speeding up proposed LNG import projects.

Gazprom Deputy CEO Alexander Medvedev earlier gave his backing to the legislation, saying, "We support the draft law since it confirms the real state of things in the gas sector and the existing rules of the game."

Strategic oil fields reduced to 70 million mt

Fears that foreign investors would be further limited from taking licenses to develop oil and gas fields in Russia deemed "strategic" were compounded June 13 as natural resources minister Yuri Trutnev told the St Petersburg International Economic Forum that the limits for defining such fields would be set at "not less" than 70 million mt of oil reserves and 50 Bcm for gas.

Trutnev denied that the stricter limits – originally it had been suggested in a draft subsoil law that fields would be off limits to foreigners if reserves amounted to 150 million mt and 1 Tcm – represented a case of "energy egoism." "We want foreigners to work with us," he said. The draft is now to be submitted to the Russian parliament with the 70 million mt and 50 Bcm figures.

Companies with foreign ownership of more than 49.5% will be barred from bidding for "strategic" fields and will be able to take part in the development of such fields only as minority partners. The draft also suggests that if a foreign company discovers a strategic field it should sell at least a 50% interest in the project to a Russian entity in order to receive rights to develop that field. The law is expected to be passed before the end of this year. Consideration of the subsoil draft law has been repeatedly postponed since October 2005, after the natural resources ministry sought more time to decide the criteria for defining strategic fields.

Stuart Elliott

LETTER FROM BRUSSELS: JUNE 2006

More talk, less risk, says European Union

Working world energy markets and more talk between energy producers and consumers are the key ways to reduce the EU's external energy risk, the European Commission and the EU's de facto foreign ministry said in a joint paper endorsed by EU heads of state in June. "We need to convince non-EU consumer countries that world energy markets can work for them," said the paper. "If they were to conclude that the only route to security lay in bilateral deals, the risk of disruption of the energy system would grow."

EU heads of state had asked for the paper at the March European Council, as part of a wider agreement for the Commission to prepare the EU's first strategic energy policy review by end-2006. This review is to include EC papers on renewables, the role of clean coal and nuclear power, a priority interconnection action plan, an energy efficiency action plan and a progress report on the internal EU gas and power market. EU leaders are to discuss the review at the March 2007 European Council.

"There is a continuing need for the EU to respond to the worldwide competition for access to increasingly scarce sources of energy," said EU leaders after discussing the paper at the European Council mid-June. And this response should include developing "strategic partnerships with the main producer, transit and consumer countries," they said.

EU sees need to extend market rules internationally

The paper noted that: "some major producers and consumers have been using energy as a political lever" and that a more focused and coherent external EU energy policy "would also help the EU face more effectively possible strategies by major external energy suppliers to adversely influence market fundamentals." Increasing dependence on imports from unstable regions and suppliers "presents a serious risk," said the paper, as did "the effects on the EU internal energy market of external actors not playing by the same market rules nor being subject to the same competitive pressures domestically."

With this in mind, EU leaders stressed again the pressing need to conclude the Energy Charter Transit protocol negotiations and for all Energy Charter Treaty signatories to ratify it. The key focus here is on Russia, which signed the ECT, but is proving reluctant to ratify it, partly as it would mean giving its Central Asian neighbors access to its pipelines to export their gas to western Europe.

The ECT aims to bring common market rules to international energy transport. EU leaders asked the Commission to start work on a specific agreement on energy with Russia, in preparation for renewing the present partnership and cooperation agreement. The post-PCA negotiations could start late 2007, said the EC.

The EU is also keen to extend the principles of its internal energy market to its immediate neighbors. The energy community treaty agreed by the EU and nine south-east European countries and territories comes into force on July 1, and potential new members include Norway, Moldova and Ukraine. In addition, the EC's European neighborhood policy could be used more to further the EU's energy policy objectives, said the leaders, particularly on improving talks with Algeria, a major gas producer.

New strategic energy cooperation with consuming nations

On relations with consumer countries, the paper noted that "a more political dialogue on energy is needed" with the US in particular, as well as China, India and Japan. The aim would be to improve world energy markets' transparency and operation, and to develop sustainable energy resources and energy efficiency.

The EU appeared to make progress with this approach at the EU-US summit on June 21 in Vienna, where both sides agreed to cooperate more on energy security and climate change issues. Both sides want to "promote market-based energy security policies that ensure competition, transparency, respect for contracts, and non-discriminatory trade, transit, and access," they said in a joint statement.

And they agreed that Russia was a mutual concern. "We are concerned about some recent developments in Russia and the region and will work with Russia to promote energy security," said the statement. They also agreed on the need for improved talks with the major producer, transit and consumer countries and for diversifying energy sources and supply routes, particularly in the Caspian sea region, Middle East, continental Africa and Latin America. The two sides plan to monitor their energy cooperation through an annual strategic review.

Perhaps more significant was the agreement on climate change, where the EU and US have previously been at odds. The two sides have agreed to set up an EU-US high level dialogue on climate change, clean energy and sustainable development. The topics to be discussed include experience with different market-based mechanisms to promote cost-effective reductions in greenhouse gas emissions (for example the EU's emissions trading scheme), developing and using cleaner, more efficient, low emission energy technologies, energy efficiency and savings, renewables and energy production and distribution systems. The first meeting is planned for autumn 2006 in Helsinki.

Siobhan Hall

Market News

Demand and supply growth both on a downward trend

In its June oil report OPEC said that purely fundamental considerations should have led to a cut in quotas at its June 1 meeting in Caracas. However, the organization kept output unchanged at 28 million b/d to keep an "extra supply buffer" in place to counteract high prices and volatility. Data for May showed that the OPEC-10 produced 27.79 million b/d, with Iraq contributing a further 1.96 million b/d. This represents a total rise in output of 120,000 b/d in May from a revised April figure of 29.63 million b/d.

While the immediate supply position is good and stocks are building, the level of spare world capacity is not expanding at a rate that provides a sufficient cushion against potential supply disruptions, especially considering the miss-match between the quality of crude supplied at the margin versus the quality demanded. The International Energy Agency in its monthly oil report estimates that notional spare capacity rose above 3.0 million b/d in April and May, but that effective physical spare capacity, excluding Indonesia, Iraq, Nigeria and Venezuela, was around 1.9 million b/d.

Nevertheless, US commercial oil stocks climbed substantially in May owing to a large build in gasoline inventories. Stocks across the US, EU-16 and Japan all remain well above both year ago levels and their respective five-year averages. According to the IEA, OECD industry crude stocks have risen by 13 million barrels to 1,005 million barrels, their highest level in 20 years.

OPEC, the IEA and the US Energy Information Administration, while varying in their specific estimates, are all recording downward trends in their predictions for world demand growth, but even larger downward revisions to growth in non-OPEC supply. In addition, the majority of growth on both the supply and demand side for 2006 is projected to occur in the second half of the year, suggesting room for further surprises.

Meanwhile, the world economy looks healthy, and GDP growth estimates have been rising, but OPEC in June injected an element of caution to their analysis, citing tougher monetary conditions ahead. The cartel kept its 2006 forecast for world GDP growth unchanged at 4.7%, but the impact on demand of both higher prices and interest rates remains a major uncertainty.

The IEA notes that non-OECD demand growth comprises close to 85% of world growth, despite the non-OECD area accounting for just 41% of the market. By contrast, OECD oil demand is expected to have contracted by 50,000 b/d year-on-year in the second quarter, the third consecutive quarterly decline in OECD demand versus previous year's levels. The highest rates of demand growth are in China, the Middle East, Africa and Latin America. US oil demand growth is thought to have rebounded in May, but over 2006 is likely to remain well below what typically might be expected given economic growth of 3.5-4.0%, said the IEA.

OPEC expects world oil demand to grow by 1.36 million b/d in 2006, marginally down from the 1.38 million b/d estimated in May. The estimate for growth in non-OPEC supply, which it expects to average 51.4 million b/d, was revised down by 84,000 b/d to 1.2 million b/d above 2005 levels. OPEC raised the expected call on its oil by 100,000 b/d to average 28.73 million b/d in 2006, versus output of 29.68 million b/d on average through first-quarter 2006.

The EIA also acknowledges that world demand growth has slowed as a result of higher prices, but continues to see significantly more growth than OPEC. The EIA predicts world demand growth of 1.7 million b/d in 2006 and then 1.9 million b/d in 2007. On the supply side, the EIA's estimate for non-OPEC supply is lower than OPEC's at 0.8 million b/d in 2006.

Meanwhile, the IEA in its June report put global oil product demand growth in 2006 at 1.24 million b/d, down from 1.25 million b/d in May. Non-OPEC supply in 2006 is estimated at 51.2 million b/d, a downward adjustment of 55,000 b/d from last month's estimate. This puts 2006 supply growth at 1.1 million b/d plus 265,000 b/d of OPEC NGLs and unconventional supply.

Country-by-country breakdown of OPEC production with figures (million b/d)

Country	**May**	**Apr**	**Mar**	**Feb**	**Jan**	**Quota**
Algeria	1.370	1.370	1.370	1.370	1.370	0.894
Indonesia	0.930	0.930	0.920	0.920	0.920	1.451
Iran	3.850	3.880	3.860	3.860	3.900	4.110
Iraq	1.960	2.010	1.820	1.790	1.530	N/A
Kuwait	2.540	2.540	2.540	2.540	2.540	2.247
Libya	1.670	1.670	1.670	1.670	1.660	1.500
Nigeria	2.300	2.200	2.150	2.370	2.400	2.306
Qatar	0.810	0.810	0.810	0.800	0.800	0.726
Saudi Arabia	9.200	9.100*	9.500	9.500	9.480	9.099
UAE	2.540	2.530	2.500	2.480	2.540	2.444
Venezuela	2.580	2.590	2.600	2.600	2.580	3.223
Total	**29.750**	**29.630***	**29.760**	**29.920**	**29.680**	**28.000**

* Revised.
For more information on OPEC, see "Platts Guide to OPEC" at www.platts.com/OPEC/index.shtml <http://www.platts.com/OPEC/index.shtml>
Source: Platts

China's resource politics wins friends in Africa

Chinese Premier Wen Jiabao in June made a landmark visit to Angola, which in February replaced Saudi Arabia as China's largest source of crude. Wen signed a raft of agreements to help rebuild the war-shattered southern African nation and went on to South Africa, where he was expected to sign a nuclear cooperation pact. He visits seven African countries in total on his tour, Egypt, Ghana, the Republic of Congo, Angola, South Africa, Tanzania and Uganda.

Wen's visit to Luanda was marked by a strong endorsement from Angolan President Jose Eduardo dos Santos for Beijing's economic policy in Africa. "The two sides have signed cooperation agreements, especially in the fields of health, technical assistance and reconstruction," a joint communiqué said. "The pacts are aimed at reinforcing bilateral cooperation," it said. Across Angola, Chinese workers are busy rebuilding roads, railways and technical institutes.

The work is financed by a $2 billion oil-backed loan from China's Eximbank that is to run until 2016. One of the key Chinese-funded projects is the reconstruction of the 1,300-kilometre (800-mile) railway from the west coast city of Benguela to the mineral-rich area on Angola's eastern border with the Democratic Republic of Congo. Angolan Transport Minister Andre Prandao said that the line would be operational by next year.

China and India have been busy offering record quantities of new loans to some of the world's poorest nations just as major western players have agreed debt relief and forgiveness programs to counter the problem of indebtedness. Western lenders have warned that a new cycle of developing nation debt could result.

However, Beijing and New Delhi are using the loans to increase their diplomatic influence and gain greater access to raw materials. The pattern of loans and visits by Chinese officials reflects a concentration on resource rich-nations in Latin America, Africa and the Middle East.

The strategy is meeting with some success as evidenced by dos Santos's tribute. Just as western countries wish to reduce their dependence on oil and gas, so producer nations wish to reduce their 'demand dependence' on western consumers. They can do this, and at the same time strengthen their ability to negotiate with international oil companies, by diversifying their customer base in Asia and striking resource development deals with national oil companies.

China, India and the NOCs are increasing their share of global reserves and production at the expense of the international majors. They are also changing the direction of the flow of raw materials and establishing rival financial and diplomatic relationships geared around the new Asian manufacturing centers.

Sinopec gains entry to Russian upstream

Anglo-Russian TNK-BP has agreed a deal with China's Sinopec for the sale of its Udmurtneft upstream unit in Russia's Urals region. "The parties have exchanged written confirmation of commercial terms," TNK-BP said in a statement, providing no details. TNK-BP expects the deal will be finalized in the near future, "following final agreement and signature of a fully termed sale and purchase agreement." A company representative declined to comment whether or not the price of the deal exceeded the $3 billion TNK-BP earlier indicated it wanted to receive for the 120,000 b/d upstream unit.

The main fields of Udmurtneft, which began production in 1969, are in the late development stage. The company's reserves are estimated at 922 billion barrels, with proven reserves of 551 million barrels as of end-2005, according to an evaluation conducted by independent auditors DeGolyer & MacNaughton. A total of 10 companies submitted indicative bids for Udmurtneft, among them Russia's Gazprom through its oil unit Gazprom Neft, and Hungary's MOL.

Russian anti-monopoly approval has already been obtained for the transaction. The deal "brings another major international investor working with strong Russian alliances into the country's oil and gas sector," TNK-BP president and CEO Robert Dudley said. Just how strong those alliances are was quickly revealed when Rosneft announced the same day that it plans to buy 51% of Udmurtneft from Sinopec. Having earlier denied rumors that it had teamed up with the Chinese company, Rosneft said it would exercise an option agreement reached with Sinopec in May once Sinopec and TNK-BP have completed their agreement.

"Sinopec will be responsible for financing the acquisition, and funds will be repaid based on the asset's cash flows, without recourse to Rosneft assets," Rosneft said, adding "the deal is a significant step toward closer collaboration between the two companies and toward the development of strategic relations with China's leading industrial corporations. This will enable Sinopec to implement its strategy of entering international markets, including oil and gas in Russia."

The decision to surrender a 51% stake in Udmurtneft is likely to reflect the draft subsoil law currently making its way through Russia's Duma. The law originally defined all oil fields above 150 million mt (1.1 billion barrels) in size and all gas fields above 1 Tcm as strategic. Strategic fields can only be developed by companies that are more than 49.5% Russian owned. Moreover, Russia's natural resources ministry has proposed that the size of oil and gas fields considered strategic should be radically reduced to 50 Bcm for gas and for oil should take into account recoverable reserves, which might reduce field size to 70 million mt.

The law is expected to be passed before the end of this year. The Duma has postponed the subsoil draft law on a number of occasions since October 2005, after the natural resources ministry asked for more time to finalize criteria for defining strategic fields.

Russia's oil output will see decline in two to four years

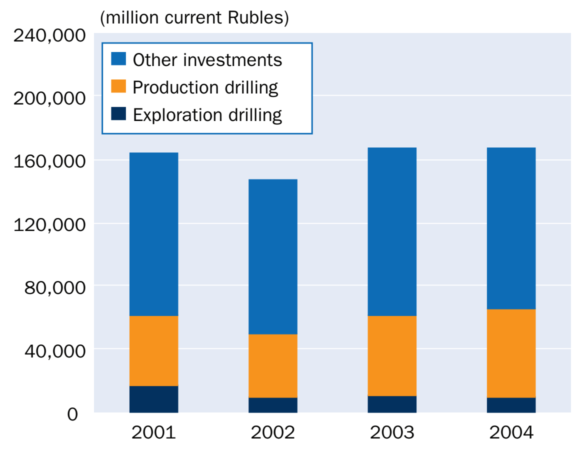
The rise in Russian oil production since 1998 has been instrumental in meeting world demand growth. In the period in which OPEC's excess capacity has dropped to less than two million b/d, Russian production has risen steadily from just below 6 million b/d at end-1998 to 9.5 million b/d in 2005. Domestic consumption has yet to recover above 3 million b/d, allowing the increase in output to be directed towards export markets either as crude, or increasingly as refined products. Russia now vies with Saudi Arabia as the world's largest oil producer.

However, while Saudi Arabia expects to add a further 1.5 million b/d capacity to its system over the next five to six years, some analysts are predicting that Russian output will not just level off, but start to fall. In addition, they see little prospect that the state or the major Russian oil companies are prepared to adopt policies that might reverse this trajectory. Growth in Russian oil production has already flattened out to some extent. It increased by an estimated 2.0-2.5% in 2005, after growing annually by 10% in both 2003 and 2004.

Since 1998, there has been a rapid expansion of reserves by Russian oil companies, giving them flattering reserves to production ratios, which are substantially better than their western competitors. However, according to research by Valery Kryukov of the Russian Academy of Sciences in Novosibirsk and Arild Moe of the Fridtjof Nansen Institute in Norway, presented at the International Association of Energy Economics conference in Potsdam, Germany, on June 9, closer scrutiny of Russian companies' R/P ratios reveals a more worrying picture.

The authors argue that additions to reserves have fallen below production since 2003. Russian companies have been able to expand production by exploiting nearby and easily accessible reserves. They have not spent money on exploration or on firming up the potential of more speculative reserves. The result is that 'easy' reserves have been exhausted. The time needed to bring the next tier of the existing reserve base into production will be much longer than before.

Investment by Russian oil companies



Source: Fridtjof Nansen Institute

Russian reserves are classified as A, B and C1, which are explored reserves and as C2, C3, D1 and D2, which are unproven reserves. Russian companies have concentrated on moving reserves from C2 to C1, but the C2 potential is coming to an end. Bringing resources from D2 to C1 can take between 15-20 years. Moe argues that a balanced resource management policy moves resources from the uncertain categories into the more certain ones.

Furthermore, recent additions are almost entirely made up of acquisitions. New appraisals and discoveries make up a only fraction of the additions and these are often relatively easy extensions of existing fields.

Moreover, as in maturing basins, the trend in new discoveries in Russia is to find smaller fields and fields in increasingly remote areas. As a result, the cost of bringing discoveries to market is rising. Yet despite these trends, Moe notes that exploration expenditure is not increasing. He argues that there is a discrepancy between the behavior of the companies and their need to replace production. Funding is not the issue; Russian oil companies have money, but are not prepared to direct them at exploration, Moe argues.

There are a number of reasons for this lack of enthusiasm for exploration. Foremost is that property rights in Russia are uncertain and there is no guarantee that a company making a discovery will ultimately be the one that retains the development license – a situation that applies to state-owned companies as well as private ones. This acts as a strong disincentive for exploration.

The weak property rights of companies are in the government's interest, at least in the short term, because they are a means by which the state can force companies to share the rents from oil acreage. While long-term investment requires strong property rights, they would weaken the government's control over the oil sector. Rather than extend independent companies' rights, Moscow has been taking the industry back within the state, as evidenced by its break-up of Yukos, the key assets of which have ended up with state-owned companies Rosneft and Gazprom.

In addition, Russian oil companies are often owned by their management or the management have very close relations with the owners. This, Moe argues, creates a preference for short-term dividends rather than supporting a long-term outlook.

The result is that Russian output has been built up on an unsustainable basis. It will need large investments to put it back on a sustainable growth track, but the disincentives to doing so remain in place and company behavior continues in the opposite direction. This, concludes Moe, means that within the next two to four years, Russian production will start to decline. Eventually this will result in a struggle between the state and companies as to who pays for new exploration. Ultimately, Moe argues, it is in the interests of both industry and the state that the sector is dynamic and growing, but it may take a substantial decline in output before solutions to the problem are ironed out.

BP says world oil reserves rose 0.6% in 2005, 40.6 years use

The world's remaining oil reserves rose by just 0.6% to 1.209 trillion barrels at end-2005, outpaced by oil demand growth of 1.3% in the same period, BP said in its latest statistical review of world energy released in June. Global oil consumption last year averaged 82.5 million b/d, up 1.3% from a year earlier, BP said, although demand growth fell by 1.8 million b/d to 1 million b/d due mainly owing to slowdowns in the US and China and weakness in developing Asia Pacific.

Despite the rate of demand growth cooling last year, the world's proven oil reserves are enough to last 40.6 years at current levels of consumption, down from 40.7 years at end-2004, BP said. "Capacity in most segments of the energy industry remains constrained and perceptions of geopolitical risk have increased," BP's CEO John Browne said in his introduction to the review, adding that, despite recent record oil prices, "there has been no physical shortage of either oil or gas."

Saudi Arabia remains the world's largest producer and holder of oil reserves, accounting for 22% of the world's total reserves last year. The country's proved reserves at end-2005 were little changed from a year earlier at 262.2 billion barrels, while it produced an average of 11.04 million b/d of crude and NGLs, BP said. The biggest increase in proved reserves came from Iran and Russia, which saw a jump from 132.7 billion barrels to 137.5 billion barrels and 72.4 billion barrels to 74.4 billion barrels respectively.

On supply, BP said global oil output climbed a lower-than-expected 889,000 b/d, or 1%, to reach 81.1 million b/d last year. "This was lower than expected for a number of reasons; many OPEC producers had reached or were close to full capacity, security problems in Iraq, hurricanes in the US, declines in both the UK and Norwegian North Sea, a slowdown in Russian output, a number of accidents and disruptions to production and rising cost inflation which reflected constraints in the contracting and engineering sectors, leading to delays."

BP's chief economist Peter Davies said the apparent 1.4 million b/d overhang of oil demand compared with supply may be explained by the counting of ethanol and time lags in the data. "However this (demand) failed to remove excess supply, and inventories continued on an upward trend, firmly above historic average levels in aggregate," BP said.

Prices rose further with Brent crude averaging $54/barrel for 2005 as a whole – a development considered to be due less to 'fundamentals' than to the perception of risk, exacerbated by limited spare capacity. Commenting on oil prices, Browne said he believed they were being driven by anxiety about the reliability of supply, with oil now more expensive in real terms than at any point since 1983. He said BP saw oil prices of $40/barrel in the "medium term," adding: "It's not a forecast, it's the way we think." Despite geopolitical concerns affecting prices, supply is "enough" to meet demand, he said.

Presenting the review to press, Browne said global spare production capacity stands at around 1.8 million b/d, a level which should return to 3 million b/d by the end of the decade, Davies added. World refining capacity grew by 700,000 b/d in 2005, lagging the 1 million b/d growth in output, BP said.

In production, Russia was ranked second behind Saudi Arabia as it increased output by 2.7% to 9.55 million b/d. Other notable increases were seen from Angola (up 26% to 1.24 million b/d), Azerbaijan (up 43% to 452,000 b/d), Thailand (up 25.2% to 276,000 b/d). The largest declines in production came from the UK (down 11% to 1.8 million b/d) and Syria (down 11.4% to 469,000 b/d). US oil output fell 5.5% to 6.83 million b/d.

Strong demand growth was seen in Singapore, where consumption rose by 11% to average 826,000 b/d. Other sizeable rises in demand came in Kazakhstan (up 11.4% to 208,000 b/d), Azerbaijan (up 11.3% to 103,000 b/d) and Qatar (17.1% to 98,000 b/d).

Key oil demand statistics

Country	2004 demand (million b/d)	Change	Share of world total
US	20.655	-0.20%	24.60%
China	6.988	2.90%	8.50%
Japan	5.360	1.40%	6.40%
Russia	2.753	1.40%	3.40%
Germany	2.586	-1.70%	3.20%
India	2.485	-3.50%	3.00%
South Korea	2.308	0.80%	2.70%
Canada	2.241	-0.20%	2.60%
France	1.961	-0.70%	2.40%
Saudi Arabia	1.891	4.50%	2.30%
Brazil	1.819	2.40%	2.20%
Italy	1.809	-3.50%	2.20%
UK	1.790	1.70%	2.20%

Source: BP Statistical Review of World Energy 2005

Key oil supply and reserve statistics

Country	2004 output (million b/d)	Change	End-2004 reserves (billion barrels)
Saudi Arabia	11.035	4.30%	264.20
Russia	9.551	2.70%	74.40
US	6.830	-5.50%	29.30
Iran	4.049	-0.80%	137.50
Mexico	3.759	-1.60%	13.70
China	3.627	4.20%	16.00
Canada	3.047	-1.30%	16.50
Venezuela	3.007	1.10%	79.70
Norway	2.969	-7.50%	9.70
UAE	2.751	3.70%	97.80
Kuwait	2.643	6.50%	101.50
Nigeria	2.580	3.10%	35.90
Algeria	2.015	3.80%	12.20
Iraq	1.820	-9.50%	115.00
UK	-1.808	11.00%	4.00

Source: BP Statistical Review of World Energy 2005

NOAA sees above average Atlantic hurricane activity in 2006

The US hurricane season started June 1 and runs through until November 30. After last year's record activity and the devastation caused to energy infrastructure in the Gulf of Mexico still fresh in people's minds, this year's season will be closely watched. Physical crude markets have sufficient supply and US gas in storage has risen strongly in recent months, but there has been no rebuild in marginal spare crude capacity worldwide and oil demand is still expected to grow by over 1 million b/d in 2006, despite high prices. Hurricane activity has the potential to add to already high levels of volatility in world oil prices.

The US National Oceanic and Atmospheric Administration expects another very active season. NOAA is predicting 13 to 16 named storms, with eight to 10 becoming hurricanes, of which four to six could become 'major' hurricanes of Category 3 strength or higher. On average, the north Atlantic hurricane season produces 11 named storms, with six becoming hurricanes, including two major hurricanes. In 2005, the Atlantic hurricane season contained a record 28 storms, including 15 hurricanes. Seven of these hurricanes were considered "major," of which a record four hit the US. "Although NOAA is not forecasting a repeat of last year's season, the potential for hurricanes striking the US is high," said NOAA administrator Conrad Lautenbacher.

NOAA issues an updated hurricane outlook in August, when climatic conditions for the prediction of hurricanes have become much clearer. In 2005, NOAA's early forecast indicated activity below that currently predicted for 2006. It was revised upwards substantially in August before Hurricanes Katrina and Rita struck.

Warmer ocean water combined with lower wind shear, weaker easterly trade winds, and a more favorable wind pattern in the mid-levels of the atmosphere are the factors that collectively will favor the development of storms in greater numbers and to greater intensity. Warm water is the energy source for storms, while favorable wind patterns limit the wind shear that can tear apart a storm's building cloud structure, the administration said.

This confluence of conditions in the ocean and atmosphere is strongly related to a climate pattern known as the multi-decadal signal, which has been in place since 1995. Since then, nine of the last 11 hurricane seasons have been above normal, with only two below-normal seasons during the El Niño years of 1997 and 2002. With neutral El Niño/Southern Oscillation conditions expected across the equatorial Pacific during the next three to six months, NOAA scientists say that neither El Niño nor La Niña are likely to be factors in this year's hurricane season.

Pemex needs capital to exploit Coatzacoalcos Profundo

State-owned Mexican oil and gas company Pemex said in June that its Noxal-1 discovery in the southern Gulf of Mexico has flowed some 10 MMcfd of natural gas – its first major gas discovery in deep waters. Noxal 1, drilled in water depth of 935 meters, lies 102 kilometers northwest of the city of Coatzacoalcos, a major Pemex petrochemicals center. Carlos Morales, director general of upstream subsidiary, Pemex Exploracion y Producción, repeating earlier claims by President Vicente Fox, said that the well pointed to the likely existence of a new producing region, to be known as Coatzacoalcos Profundo (Deep-water Coatzacoalcos) that might hold as much as 10 billion barrels of oil and gas equivalent.

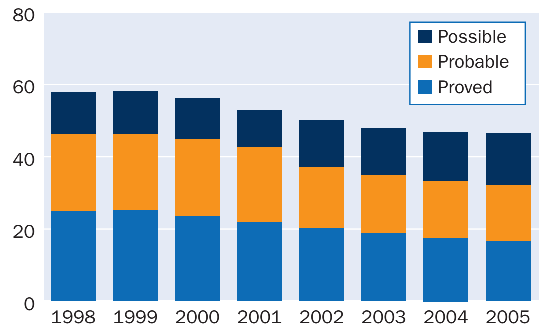
A discovery of such proportions would be a major boost to Pemex as it fights to replace production from the Cantarell super-field in the Sound of Campeche, where crude output has dropped in recent months to just over 1.8 million b/d from a peak of 2.2 million b/d. The company is also trying to reverse the steep decline in the country's reserves to production ratio, which fell from 20 years in 2002 to just ten in 2005.

However, Morales warned that much more drilling remained to be done in Coatzacoalcos Profundo, and at greater depths. He said bids would be invited in August for rigs to drill in deeper waters than Noxal 1, but said that a suitable deepwater rig was unlikely to be available until 2008 and would then be expensive.

To gauge the full potential of the new region, Pemex would have to spend about $13 billion a year, about $2 billion more than its current total upstream budget, Morales added. The Pemex budget, however, is set by Congress and, unless the new legislature voted in by the upcoming July 2 presidential election takes a radically different approach from its predecessors, spending on that level would appear to be out of the question amid public clamor for better public healthcare and education.

Felipe Calderon, presidential candidate of the ruling party, the PAN, favors the formation of risk-sharing alliances with private-sector companies as a way round the dilemma faced by Pemex. But though polls indicate that Calderon could win a tight race for the presidency, his party is sure to be a minority in Congress.

Mexican oil and gas reserves



Source: Pemex

First Chinese deepwater discovery could total 4-6 Tcf gas

Canada's Husky Energy has announced a "significant hydrocarbon discovery" in its South China Sea Block 29/36, the first deepwater find off the coast of China. The discovery at the Liwan 3-1-1 well could contain a potential recoverable resource of 4-6 Tcf of gas, based on the current interpretation of 2-D seismic and results at the well, said Husky.

The discovery was made in water depth of 1,500 meters in the Pearl River Mouth Basin. The 3,965 square kilometer block is 250 km south of Hong Kong and is one of Husky's three exploration blocks in the South China Sea. The Liwan 3-1-1 well was drilled on existing 2-D seismic data to a total depth of 3,843 meters on a large structure with 60 sq km of closure and encountered 56 meters of net gas pay on logs over two zones, Husky said. The well will be sidetracked for further evaluation and the company plans a 3-D seismic survey in the near future to assess several similar structures. Further drilling on the block is set to follow the evaluation of the 3-D data.

Husky has been exploring offshore China, in collaboration with the state-owned China National Offshore Oil Corp, since 2002. Husky signed the production-sharing agreement for Block 29/26 in August 2004, starting operations in October of that year. CNOOC holds the right to participate in the development of any discoveries, taking up to a 51% working interest. CNOOC also jointly owns two other deepwater blocks in the South China Sea with Kerr McGee and Devon Energy, but no exploration has yet taken place.

Meanwhile, CNOOC has also signed two production sharing contracts with BG Group for deepwater blocks 64/11 and 53/16 in the western South China Sea, as well as a Geophysical Survey Agreement for block 41/06 in the eastern South China Sea. Both of the PSC blocks are located in the Qiong Dong Nan basin, and block 41/06 is in the Pearl River Mouth Basin. All are from the list of 12 blocks CNOOC offered for cooperation in 2002, covering a total area of 25,800 sq km in water depth ranging form 180 to 2,100 meters.

Under the terms of the contracts, BG will conduct 2-D and 3-D seismic in Block 64/11 and 53/16, and drill one exploration well during the first phase of the exploration period on each block. BG will retain 100% interests during the exploration phase, while CNOOC can take up to a 51% working interest in any discoveries.

Qatar seeks to diversify buyers for expanded LNG output

Asian buyers could vie for a share of Qatari LNG output when it rises to 77 million mt/year in 2010, provided they meet some "commercial and technical conditions," according to Qatargas' chief executive Hamad Al-Baker. Qatargas, majority owned by state company Qatar Petroleum, currently operates 9.5 million mt/year of liquefaction capacity, and is on track to add another 31.2 million mt/year by the end of the decade, in various joint ventures with ExxonMobil, ConocoPhillips and Shell. RasGas, also led by QP, has existing LNG capacity of 16 million mt/year capacity and will add another 20.3 million mt/year by 2010.

Qatar has targetted the US and European markets with the majority of its 51.5 million mt/year of planned incremental LNG output, but some of this could be diverted to meet pressing needs in Asia, Al-Baker told the 11th Asian Oil and Gas Conference held in June in the Malaysian capital of Kuala Lumpur.

However, Al-Baker warned that Asian buyers would need to be able to accept "a wide range of LNG specifications." This refers mainly to the calorific value of gas. Asian LNG buyers prefer 'rich gas' or gas with higher calorific value, while their US and European counterparts take 'lean gas', which has a lower calorific value. Some 70% of total Qatari LNG output when the emirate completes its current slew of new liquefaction projects will be lean gas. Qatargas' first three trains, which are currently operational and serve mostly Japanese long-term customers produce rich gas. RasGas currently supplies rich gas to India's Petronet LNG.

In addition, Asian ports are currently unable to accept the size of ship that Qatar will use for transporting the new LNG output. The carriers being built will be bigger than any currently in operation. One class of vessels will be 210,000-217,000 cubic meters in size (Q-Flex) and the other 262,000-265,000 cu m (Q-Max). Qatargas and RasGas have together commissioned over 50 such newbuilds. The new ships are much larger than the 135,000 cu m vessels currently used to deliver Qatargas' LNG production to Japanese customers.

It was Qatar's distance from LNG markets in both Asia-Pacific and the Atlantic basin that challenged the country to reduce its production costs by simultaneously boosting the unit capacity of liquefaction trains and using larger vessels. At 7.8 million mt/year, Qatar's planned new trains are 65% bigger than the world's largest existing ones, also in the emirate.

Furthermore, some of the new offtake agreements are short and mid-term. The gradual emergence of a global spot market for LNG, helped by a shift from 25 and 30-year agreements to short and mid-term sales contracts and the removal of destination restrictions in the newer deals means surplus cargoes can be pulled into any country willing to pay the highest price.

Al-Baker's pitch to his Asian audience then, was not surprising, given that traditional and new Asian LNG importers like China and India could all be crowding the market for future supplies. Added to that are possible new contenders mulling LNG imports such as Singapore, Thailand, the Philippines and Pakistan.

Although the global industry is reeling under tight availability and spiralling costs of equipment and skilled manpower, the problems have not impacted Qatar's LNG plants or shipbuilding schedules, according to Al-Baker.

Indonesian LNG exports 15% below contract in 2007

Indonesia expects it will have to cut LNG exports to its long-term customers by up to 15% of contractual volumes next year, similar to the reduction this year, state-owned oil and gas firm Pertamina's president Ari Soemarno told Platts in June. "We are talking about (a reduction of) maybe 10%, even more, maybe 15% (of the total LNG supplies contracted for next year)," Soemarno said on the sidelines of the 11th Asia Oil and Gas Conference held in Kuala Lumpur.

Indonesia has already asked its customers to accept fewer deliveries than contracted due to faster-than-expected depletion of its gas reserves and the government's policy of prioritizing supply to domestic users. Indonesia has also resorted to buying spot LNG cargoes from other producers to meet its obligations, although lack of availability has made this hard. "We were able to find one, two or three cargoes, that's all. But the requirement is not for one or two. It is more like 60 to 70 cargoes," said Soemarno, referring to the shortfall Indonesia faces.

Pertamina, which has a controlling 55% stake in Indonesia's 22.25 million mt/year Bontang LNG facility in East Kalimantan, said in February this year that its term LNG customers had agreed to take just 328 cargoes this year, 46 less than the original contractual volume. It later tried to persuade buyers to reduce delivery by another 14 cargoes, but met with strong protest especially from Japanese buyers, who threatened to seek compensation if Pertamina did not meet its obligations. The Arun LNG plant in North Sumatra – also 55% owned by Pertamina – reduced its term supply to customers this year from 71 to 62 cargoes.

In response to a question on whether Pertamina was prepared to pay compensation, Soemarno said: "We are in the middle of negotiations with Japanese customers for dropping cargoes based on mutual agreements." The company was depending on reciprocal goodwill, he said, especially given that it had not exercised the take-or-pay clause in its term contract with buyers whenever they failed to lift the committed volumes.

Last year, Indonesia's customers agreed to take 51 fewer LNG cargoes than the contractual 455. Bontang supplied 334 instead of 376 cargoes, while Arun, currently operating at around 4 million mt/year, shipped 70 instead of 79 cargoes.

Contract renewal uncertain

Meanwhile, it remained unclear whether Indonesia would renew, even partially, long-term LNG contracts with Japan that will expire around 2010-2011. Pertamina has signalled that it is favorably disposed towards renewing the contracts, but would have to abide by state policy.

"We are willing to extend the LNG supply contracts with Japanese customers as we have been dealing with them for many years and we would like to retain their trust," Soemarno said. "However, our government may choose not to extend the contracts in order to meet domestic gas demand," he added.

The Indonesian government has repeatedly said that Jakarta will prioritize domestic use of the country's gas resources over exports, prompting expectations that Indonesia would not extend LNG export contracts after 2010. Pertamina tried to keep out of such "policy debates", and was only fulfilling the role of a seller in the LNG contracts, Soemarno said.

A group of Japanese buyers hold LNG contracts with the Bontang plant that are due to expire around 2010-2011 for a combined 12 million mt/year. Indonesian upstream regulator BPMigas said late last year it expected to sign a Heads of Agreement with Japanese companies at the end of November 2005 to renew 6 million mt/yr, half the existing contractual volume. But negotiations were subsequently halted and the agreement remains unsigned.

US FERC approves LNG projects with 8.2 Bcf/d capacity

The US Federal Energy Regulatory Commission in June approved the construction of five LNG projects. Three are regasification terminals and two are expansions of existing facilities. Together, the new projects will add 8.2 Bcf/d of regasification capacity, rising to 9.7 Bcf/d of capacity over time. They include 18 new storage tanks, 361 miles of takeaway pipeline and laterals and 23,000 horsepower of new compression.

The most contentious is an expansion of the Dominion terminal at Cove Point, Maryland. Dominion plans to expand the existing 1 Bcf/d facility to 1.8 Bcf/d. The proposal has been in the spotlight since Washington Gas Light said supply from the terminal was responsible for a rash of leaks in its distribution lines in Prince George's County, Maryland. Dominion has countered that poor maintenance of aging pipeline couplings on the utility's system is the real culprit. FERC has largely dismissed the notion that the regasified LNG had anything to do with the leaks. Cove Point currently receives about 90 ships each year, with a maximum accommodation of 120 ships. The expansion would raise the average number of LNG tankers to about 200.

Cheniere Energy's Creole Trail and Sabine Pass LNG projects, both in Cameron Parish, Louisiana, were also cleared. The Creole Trail proposal includes an import terminal with sendout capacity of 3.3 Bcf/d. The Sabine Pass design will expand the existing project to add another 1.4 Bcf/d in regasification capacity to the 2.6 Bcf/d now under construction.

Also winning FERC approval was Sempra Energy's 1.5 Bcf/d Port Arthur terminal in Jefferson County, Texas. FERC has already approved Occidental Energy Ventures' 1 Bcf/d LNG import terminal and ExxonMobil's 1 Bcf/d Vista del Sol facility near Port Arthur. In addition, BP's Crown Landing LNG terminal in Logan Township, New Jersey, was approved.

Ukraine epicenter of new gas price crisis

Turkmenistan has proposed that Russia purchase its gas at $100/1,000 cubic meters, $35 more than the current price, and has threatened to cut off supplies if Russia fails to comply. Whatever the outcome, the move will have a devastating knock-on effect for Ukraine, which sources the majority of its gas from Turkmenistan via the Gazprom subsidiary RosUkrEnergo at an average price of $95/1,000 cu m. Ukraine is the main conduit of Russian and Central Asian gas to Europe, with about 120 Bcm transiting the country annually.

Turkmenistan's energy minister Gurbanmyrat Atayev said June 21 that "if no contract is concluded with Gazprom during the next six weeks for the supply of Turkmen natural gas, Turkmenistan will stop gas supplies." He added that Turkmenistan had categorically refuted Gazprom's proposal to maintain the current pricing level of $65/1,000 cu m.

Gazprom nonetheless said it expected Turkmenistan to meet its obligations under the contract for 2006, according to which the Central Asian country is to supply some 30 Bcm this year at $65/1,000 cu m. "We are sure that our contract will be fulfilled during 2006," a Gazprom representative said. Moreover, it is questionable whether Turkmenistan would carry out its threat to cut off supplies to Russia, its main customer and one of the country's largest revenue generators. It could theoretically divert supplies eastwards to China, but lacks the infrastructure to do this in large volumes.

Ukraine ill-prepared for price hike

Ukraine's gas monopoly Naftogaz Ukrayiny is already bracing itself for more financial hardship as Gazprom readies itself to raise prices for its gas exports to Ukraine on July 1. Gazprom's rhetoric in recent weeks has been telling, with officials saying they expected "difficult negotiations" with the Ukrainians over gas prices in the second half of 2006, not least because Naftogaz is currently without a chairman following the resignation of Oleksiy Ivchenko in May.

Gazprom has already said that it could increase the price Ukraine pays for its imported gas via Gazprom subsidiary RosUkrEnergo from the $95/1,000 cubic meters agreed in January to $130/1,000 cu m on July 1. This would damage Naftogaz, which is already struggling both to pay RosUkrEnergo for the gas received so far this year and to inject sufficient quantities into storage for the winter season.

Ukraine's Prime Minister Yuriy Yekhanurov in June admitted that the gas injection process was 2 Bcm behind schedule. Naftogaz usually has to buy and store about 18 Bcm by October 15. Industry sources suggest only 1.5 Bcm has been stored, 16% below requirements.

To counter the financial problems Naftogaz is facing, domestic gas prices are to be hiked for heat producing companies by 79%, for households by an average of 85% and for state bodies by 80%. Prices were previously increased 25% on May 1, the first change in seven years. Naftogaz also needs to cover it debts and has announced plans to borrow $300 million in the near future to pay bills to two traders that total $700 million for supplies provided earlier this year. The company borrowed $200 million from ABN Amro earlier in June. Naftogaz's financial position deteriorated last year, when the government banned exports of gas from Ukraine, which had been an important hard currency earner for the company. Naftogaz, which produces domestically about 20 Bcm of gas a year, is the country's biggest taxpayer and ships about 120 Bcm of Russian and Central Asian gas to Europe annually.

Ukraine-Russia relations worsen

A breakdown in relations between Russia and Ukraine is all the more likely now that Yulia Tymoshenko is set to be returned as Ukraine's prime minister, heading a newly formed coalition government. She said June 22 that the Russia-Ukraine gas accord from January 4 would "definitely have to be reviewed." Tymoshenko has been highly critical of the deal struck after Gazprom cut supplies to Ukraine causing a shortfall in levels transiting the country to western Europe

One solution is that Ukraine could try to start direct imports of gas from Turkmenistan in the second half of the year, something that the country's energy and fuel ministry hinted at in June. Turkmenistan suspended direct deliveries at the beginning of 2006 due to a dispute over debts for earlier gas supplies.

Ukraine wants to buy 10-12 Bcm of gas from Turkmenistan in the second half of the year. As of early June, Ukraine still owes Turkmenistan $64.2 million for gas supplied in 2003-2005. According to an agreement between the two countries, Ukraine should send $59.5 million worth of steel pipes by September 10 and $7.3 million worth of equipment by August 1 to clear the debt.

Belarus faces gas shock

Belarus also had a shock this month following remarks regarding 2007 gas export pricing by Gazprom deputy CEO Alexander Ryazanov, who said that Gazprom had forwarded a contract to Belarus containing a starting price for next year's gas of $200/1,000 cubic meters. This is more than four times higher than the price Belarus currently pays – the lowest in Europe at $46.68/1,000 cu m – and 25% more than the $150/1,000 cu m that Gazprom officials had already hinted at earlier this year.

Belarus concedes that the price it pays for Russian gas will increase in 2007, but it suggested an 11% increase next year and a 10-15% hike per year in the medium term. An 11% hike would increase the bill to just $51.81/1,000 cu m in 2007.

A quadrupling of the price would likely cripple much of Belarus' manufacturing industry, which is heavily dependent on gas. Households would also be hit. The President of Belarus, Alexander Lukashenko, said earlier this year that he did not believe Russia would follow through with its threat to triple gas prices. "I don't think the Russian leadership will take the step of a serious increase in gas prices," he said.

Italy prepares to head off winter gas shortage

Fearing a new gas emergency this winter, Italy has drawn up plans to stave off the sort of gas shortages that brought the country close to crisis earlier this year. The plans, prepared by the economic development ministry and introduced June 22, aim to boost gas storage levels, increase the volume of gas supplied into Italy's grid and improve the country's security of supply.

Earlier this year, Italy was forced to draw heavily from its strategic gas reserves when a bitter pricing dispute between Russia and Ukraine resulted in Russian gas supplies to Europe being briefly disrupted. The country also rushed through emergency measures to allow a switch of feed stocks for power stations to fuel oil from gas and suppressed power exports from gas-fired plants.

According to Italian agency AGI, the present stand-off between Russia and the Ukraine is already affecting the amount of gas coming into Italy. A figure of 10 million cubic meters per day since the start of June was quoted by the agency, but Snam Rete Gas, the country's network operator was unable to confirm the figure. Paolo Scaroni, the CEO of Italy's dominant gas operator Eni said that if Ukraine failed to fill its storage and Europe faced a cold winter similar to 2005 there could realistically be a shortage of gas in the country and a repeat of last year's "gas emergency."

Using estimates from power grid operator Terna, the ministry highlighted best-case, median and worst-case scenarios for next winter. In the best-case scenario, gas demand from the power generation sector would be 12.9 Bcm between November and March, compared with 15.9 Bcm in a median and 16.1 Bcm in a worst-case scenario. Under the median-case scenario, gas demand from new power stations is seen totaling 2.6 Bcm, with demand from newly-connected domestic users likely adding a further 300 million cu m, and increased industrial demand possibly adding a further 100 million cu m. When added to the total volume consumed last winter – 48.8 Bcm – the ministry forecasts likely demand of 51.8 Bcm for the five months.

The intention is to pass a directive before end-July forcing shippers to maximize their gas imports from November 13 to meet the 51.8 Bcm forecast. At the same time, national storage levels would be kept topped up at the maximum 8 Bcm. Last year, storage was only 93% full at the start of winter. Gas storage is currently 52% full, the ministry said. In extreme circumstances, market mechanisms might be used to reduce the use of gas for power generation. This could be done by charging more for the transport of gas for use in power plants, and could save a further 300 million cu m.

Another strategy would be through the use of interruptible contracts. These would be determined by gas grid operator Snam Rete Gas. Other measures would involve reducing domestic gas use and switching fuel sources to oil. All of these measures were forcibly enacted last winter, but the ministry wants to implement them with foresight rather than hindsight this winter.

The ministry also plans to publish a decree by September to allow companies building new storage facilities to be partially exempt from allowing third-party access to their capacity. Amongst other measures on the supply side, the ministry noted its decision to bring forward by six months the expansion of the Eni-controlled TAG pipeline, which moves Russian gas through Austria.

Romanian bid reflects Korea's global nuclear ambitions

Kvaerner IMGB, a Romanian power engineering firm set to be acquired by South Korea's Doosan Heavy Industries & Construction Co., is expected to serve as a base for Korean industry to enter the market for supplying nuclear equipment outside of South Korea and the Asia-Pacific region, sources at and close to the Korean company told Platts.

On June 16, Kvaerner IMGB, a heavy equipment maker headquartered in Bucharest, announced that TH Global plc, formerly Kvaerner plc, the owner of IMGB, had "identified Doosan Heavy Industries as a suitable owner for IMGB." On June 21, senior Doosan executives confirmed the statement and said that the sale would likely be completed in July.

Doosan sources described IMGB as primarily a vendor of hydroelectric power equipment, but said that Doosan expects IMGB to feature as a fabricator of nuclear components in projects for which Doosan and utility Korea Hydro & Nuclear Power Co., supported by the Korean government, will be bidding. "We definitely see IMGB as a fabricator of nuclear equipment for our future projects, especially outside of Asia," one senior executive involved in the Doosan-KHNP partnership said.

Doosan is South Korea's prime nuclear equipment vendor. Beginning in the mid-1990s, top management at the company, then called Hanjung, began making plans to expand nuclear component fabrication activities outside its shop at Changwon. The Korean firm first set its sights on possible takeover or joint venture candidates in China and Vietnam. The plans were considered in part out of anticipation that China, Vietnam, and Indonesia would all emerge as buyers of nuclear equipment beginning in the late 1990s.

Since then, however, Doosan has set its sights farther afield, prompted by continuing globalization of the nuclear equipment market and in particular by Toshiba's pending acquisition of Westinghouse. That deal, Korean executives said, has challenged Doosan's position as a favored NSSS subcontractor of the US PWR vendor as Westinghouse owns the licenses for the Combustion-Engineering design that forms the basis for Korea's standard nuclear plant. Doosan entered the fray to acquire Westinghouse from British Nuclear Fuels plc last year, but, Korean sources said, it couldn't find partners with deep enough pockets to stay in the competition after Mitsubishi and Toshiba raised the bidding stakes.

Iberdrola crashes market and calls the regulator's bluff

A Spanish government economic affairs commission is considering what action to take against Iberdrola after the utility threw the Spanish wholesale power pool into chaos by intentionally under-bidding. Generation pool prices crashed on June 8 and 9 after Iberdrola ordered its distribution business not to pay more than the artificially low price set by the government in its 'provisional' February decree. The company proved its point emphatically – there were no takers at the government price and the system operator had to step in at some cost to balance the grid and avoid blackouts.

Iberdrola told its distribution business not to pay more than a flat price of €33/MWh ($41.5/MWh), which in practice climbs to €42.35/MWh when other system costs are added. In pool trading outside of intra-group transactions, the market sets the price, which this year has routinely been around €70/MWh.

The commission is scheduled to study a complaint from the industry ministry that pool regulations had been broken, and another from the economy ministry calling for a disciplinary investigation. The CNE national energy commission is also to study the situation.

With Iberdrola effectively withdrawing from the market, grid company Red Electrica de Espana (REE) was forced to apply the so-called 'restriction mechanism,' calling on premium-priced backup plant to generate and so avoid blackouts. Utilities with the most standby capacity, such as Endesa, are reaping the benefits. Iberdrola's action is aimed at forcing the industry ministry to drop the temporary decree and enact a stable pricing mechanism by July that recognizes the true cost of generation. The "provisional" decree was rushed through three days after Germany's E.ON launched its counter-bid for Endesa, and was aimed at stemming a soaring 2005 tariff deficit of €3.8 billion.

The decree has hit utilities in the pocket. They say it reduced Q1 income by €442 million. Since March 3, vertically integrated companies have been prohibited from simultaneously taking up buying and selling positions in the same hourly delivery slot on the Spanish wholesale market. Whereas before the power bought and sold by the distributors and generators of one company was registered as a trade done on the wholesale power market, now those generators and distributors must trade electricity based on physical bilateral contracts, which are capped at €42.35/MWh for the rest of 2006.

The policy harms Iberdrola more than other utilities because it distributes more energy than it generates, so it has to buy in power from other generators. It justified its 'direct action' by saying it could not continue "selling at a loss." Endesa, Union Fenosa and Hidrocantabrico are more comfortable because their generation covers their distribution needs. Iberdrola's decision not to pay more than €42.35/MWh meant that nearly 40% of energy on offer went unsold, and prices slumped from €70/MWh to almost €30/MWh.

Financial analysts welcomed Iberdrola's move. Merryll Lynch said it "could be a catalyst towards an immediate resumption of negotiations with the regulator aimed at setting reasonable energy prices." However, some observers feared the government could instead take retaliatory measures against the utility.

Dutch utility merger talks

Dutch utility Nuon confirmed in mid-June that it is holding merger talks with a variety of possible partners, with Essent rumored to be in the box seat. The confirmation came a few days after reports that Germany's RWE was sizing up Nuon as a takeover target. The stories served to strengthen expectation of M&A activity in the Netherlands as a result of the government's policy to unbundle ownership of networks.

Essent and Nuon are the two remaining large independent generator-network utilities in the Dutch market, owned by various provinces and municipalities. Electrabel and E.ON have acquired the other two main generators, while Delta and Eneco are principally power/gas network companies. Essent, the country's largest utility, has around 5,000 MW of plant, while Nuon has 3,400 MW, and 459 MW of renewable generation capacity. Both have profitable niche positions in the German market, Essent through Deutsche Essent and its 51% holding in municipal utility SWB, and both have expanded into Belgium.

Bringing together the first and third generators in the Netherlands would have regulatory implications. Market seculation is that an Essent-Nuon merger might require VPP auctions of 2,500 MW.

UK sees third dash for gas

Centrica is to build an 885 MW CCGT in Devon, it said June 19 – the first central plant to get construction go-ahead in the UK for about five years. In all there are nine large gas-fired power station projects awaiting consent, equating to more than 7 GW of capacity. So despite warnings from National Grid and regulator Ofgem that next winter's gas market will be tight, utilities still back gas-for-power ahead of alternative technologies.

Gas is increasingly seen, however, as the quick fix for a looming capacity gap in 2008, with two new-build phases thereafter ushering in clean coal around 2010-12 before perhaps a second wave of nuclear build, to complete around 2015. Utility bosses speaking at a UBS conference June 22 said they needed certainty on the existence of a carbon mechanism well beyond 2012 before committing to this generation 'diversity' that the majority of sector participants in theory wants.

E.ON UK chief executive Paul Golby said, "Diversity is the key to security of supply. If all the coal and nuclear plant coming offline by 2015 is replaced by gas, 80% of our power will come from gas and CO_2 emissions will have gone up. So we need a clear signal that phase one and two of the EU's emissions trading scheme is a stepping stone to phase 3 and beyond."

SSE champions clean coal, but CCS costs look high

UK utility Scottish and Southern Energy has contracted Mitsui Babcock, Siemens and UK Coal to undertake the front-end engineering design of a carbon capture ready 500 MW cleaner coal plant at its Ferrybridge Power Station in West Yorkshire. The plan involves the retrofit of the UK's first 500 MW supercritical boiler and turbine, boosting thermal cycle efficiency to over 45% (compared with 36% for conventional coal plant). The unit would be made 'capture ready' for subsequent installation of post-combustion carbon dioxide capture equipment.

"On completion, the installation of the supercritical plant would save around 500,000 tonnes of carbon dioxide a year compared with a conventional plant, which is equivalent to developing 230 MW of wind farm capacity," SSE said. "The subsequent deployment of carbon capture equipment would save a further 1.7 million tonnes of carbon dioxide, equivalent to almost 800 MW of wind farm capacity."

A final investment decision will not be taken until 2007, subject to which the plant could be in commercial operation in 2011/12. Installation is estimated to require an investment by SSE of around £250 million ($457 million). The post-combustion carbon dioxide capture equipment is estimated to require a further investment of around £100 million.

However, SSE's £100 million investment figure is for on-site carbon capture equipment and does not include storage costs. The utility would not be drawn on what is to happen to the CO_2 once offsite, but Ferrybridge is ideally sited to take advantage of proximity to the North Sea's depleted oil fields.

According to offshore operator association UKOOA, current estimates for the cost of CO_2 capture, transport and storage range from €60-100 per metric ton ($75-126/mt) or higher. The UK Parliamentary Office of Science and Technology, meanwhile, estimates CCS would add anything between £10-30/MWh to the cost of electricity produced. Put simply, CCS needs subsidies.

Injecting CO_2 into oil fields for enhanced oil recovery improves the economics of CCS substantially, expecially where the development has been undertaken with the option in mind from the design phase. However, CCS with or without enhanced oil recovery has not been used in the North Sea, and UKOOA says it raises significant legal, technical, environmental and economic issues.

CO_2 is highly corrosive. Existing platforms and processing facilities, as well as offshore pipelines and infrastructure are not designed for the transport and storage of CO_2 in existing reservoirs. CCS will require very large investment in new infrastructure both onshore and offshore, including substantial retrofitting of ageing installations, where there are already severe weight and space limitations. Moreover, the benefits of CO_2 for EOR may not be as large as anticipated. CCS will at best provide additional tertiary oil recovery, as EOR techniques such as water or gas injection have already been employed on the majority of oil fields in the UKCS.

In addition, the legality of CCS offshore is unproven. CO_2 is officially designated a "waste" product, and reinjection offshore is not allowed, UKOOA says, under current international law (OSPAR and the London Convention). "Further research is required to address the costs, prevailing technologies for CO_2 capture, transport and storage and the implications of long-term geological storage," the association concludes. "CCS may yet have a role to play in the future development of the North Sea; but viable individual field applications have yet to be identified and it may require a concerted approach by all stakeholders around the North Sea to establish whether opportunities ultimately exist."

CCS costs vary hugely

The projected costs of CCS vary hugely. Mitsui Babcock's Dr Mike Farley told Platts that estimates for full CCS in the UK range between £30 per metric ton CO_2 (if the gas is stored underground, near to the site), up to £80/metric ton CO_2 (for offshore storage some way from the site, to include enhanced oil recovery potential). A 2004 International Energy Agency greenhouse gas study, meanwhile, makes an estimate for an on-site post-combustion carbon capture unit (not including storage) for a CCGT plant of £600/kW.

In Norway, based on leaks from a forthcoming report from Gassco, the state company responsible for the transport of natural gas from the Norwegian continental shelf, Oslo business daily *Dagens Næringsliv* predicts that the costs of CO_2 injection "into the Draugen field alone" looked like reaching nearly NKr15 billion ($2.37 billion) – an enormous figure compared to estimates for other CCS projects. This includes NKr5 billion for either upgrading the Draugen platform itself, or building an auxiliary platform to hold necessary extra equipment, plus NKr8.5 billion for the carbon capture plant and pipeline transport to the field. Asked to comment on these estimates, Shell spokesman Øistein Johannessen said: "These are Gassco's figures. We believe it is too early to publish this yet, when we are at such an early stage of planning."

On the income side of the ledger, the picture is just as complicated, Johannessen said. Pumping CO_2 into Draugen could increase oil recovery, because the gas would blend with the oil in the reservoir, reducing its viscosity. But the amount of the increase was uncertain. "It could be between zero and seven per cent of the original reserves in place," he said.

As well as Draugen, Gassco has estimated the cost of eight different value chains involving six different fields. The cost of adapting the platforms concerned ranges from NKr1.5 billion to over NKr5 billion, while the CO_2 capture and transport costs vary from NKr8.5 billion to NKr22 billion.

Shell and Statoil want the state to participate in joint funding for CCS projects – something the government promised in its election platform. On energy ministry advice, the government has substantially increased – from NKr20 million to NKr80 million – an allocation for financing studies of carbon capture technology at Naturkraft's 450 MW Kårstø CCGT plant.

Queensland approves $617.5m coal infrastructure deal

The northeastern Australian state of Queensland has announced an A$825 million ($617.5 million) infrastructure injection for the state's resources industry, as Queensland tries to capitalize on a forecasted boom in coal and other commodities.

Queensland premier Peter Beattie said his government has pledged funding from the fiscal 2007 state budget announced June 1 to expand and upgrade coal rail networks and ports for the central Queensland region. "The coal industry supports thousands of Queenslanders in communities across the region. It will generate more than A$15 billion this year in export revenue," Beattie added in a statement.

The state government, through rail operator QR and port authorities, has approved a number of already announced expansion plans, including A$360 million to continue to expand Gladstone's RG Tanna Coal Terminal, including a third ship-loader, extra stockpiles and a third rail balloon loop. The project will see the terminal reach its maximum capacity of 68 million mt/year.

The government has also allocated A$274 million for 35 new coal locomotives, 1,150 coal wagons and upgrading 84 coal locomotives, and A$57.6 million towards a A$83.4 million project to construct a third rail loop at the Dalrymple Bay Coal Terminal near Mackay.

The state government has also chipped in A$63 million to expand the Abbot Point Coal Terminal near Bowen to increase capacity to 21 million mt/year, plus almost A$7 million for the ongoing feasibility study and acquisition of the land for the new rail corridor for the 69-kilometer so-called "northern missing link" between the Goonyella rail network and the Newlands network linked to Abbot Point.

At the port of Hay Point, the Queensland government will provide A$32 million to complete a A$60 million project to deepen the departure channel from Hay Point, and A$2.8 million to continue the upgrading of the Goonyella rail network to match the expansion at Dalrymple Bay & Hay Point, including a new electrical feeder station to accommodate more trains.

The government will also contribute more than A$29 million to undertake various capacity expansion works on the Blackwater rail system, including the completion of the Kinrola Branch upgrade for the Xstrata-owned Rolleston project and the duplication of lines between Windah and Grantleigh.

Indian 'ultra mega projects' to see surge in coal demand

30-36 million mt of annual coal imports could be needed to meet demand generated by three 'ultra mega projects' of 4,000 MW size each to be developed in Indian coastal locations, according to senior officials at the Power Finance Corporation. The first of the 800 MW size generating sets are to be commissioned in 2011. "Each project could involve 10 to 12 million mt/year of imports and the mine pit head project will require about 20 million mt/year of coal", explained a senior PFC official, apparently referring to high ash domestic coal, which has a lower heat value than imported coal.

The PFC is a government-owned enterprise which has been tasked by the power ministry to find private investment for these large-scale projects. The concept behind the 'ultra mega projects' is that "economies of scale leading to cheaper power can be secured through development of large size power projects using latest super critical technologies", according to the PFC.

It has the responsibility for initial and detailed surveys, site selection, administrative clearances, as well as power sale arrangements with state-owned utilities through a shell company for each project which will be transferred to developers. The aim is to remove problems associated with this initial work that have in the past frustrated investors and delayed projects sometime for several years.

The lack of payment security from state power utilities, which hold a monopoly of power distribution operations for power sales, has been a major stumbling block in the past for private power projects. However, investors interested in the 'ultra mega projects' are being promised by the government that they will be able to sell electricity directly to bulk power consumers under an electricity law operating since June 2003.

This has reportedly increased interest in four such projects, including three coastal schemes at Mundra in Gujarat state, Girye in Maharashtra and Tadri in Karnataka. The fourth project at the mouth of a coal mine is to be located at Sasan in Madhya Pradesh. A fifth project proposed at Akaltara in Chhattisgarh, also a pit head scheme, is yet to be tendered.

Power authorities are now working on issuing investment calls for two more similar sized projects at Krishnapatinam in Andhra Pradesh and at an unidentified location in Orissa, with the former most likely to be based on imported coal.

Mundra and Sasan are likely to go ahead first. These projects have progressed to the Request for Qualification stage with 13 RFQ offers for Mundra and 15 RFQs for Sasan arriving by the June 1 deadline. Technical and price bid submissions are due by November 15, and the selection of developers will be done by December 31. Bidders also have a deadline of September 2010 to commence power generation.

Under the terms of the tender, companies submit tariff based bids, where developers agree with power utilities owned by different states to sell electricity at pre-determined tariffs. These are the first power projects in India to use tariff bidding, following the relaxation of rules by the government in January 2005. All power projects have previously followed two-part tariff formula comprising fixed costs and the variable cost of fuels. Pricing of coal will therefore be a crucial factor in the submission of tariff price bids by investors.

Brazil's renewables scheme faces construction shortfalls

The Brazilian government confronts serious challenges in fulfilling its ambitious promises for generating power from renewable energy, according to recent data on the country's alternative energy program, known as Proinfa.

The program's original target was to install about 3.3 GW of new renewables capacity in the form of 144 new plants, including 27 biomass schemes, 54 wind parks and 63 small hydropower plants, by 2008. But the latest snapshot of the program's development shows that only 916.6 MW of Proinfa capacity is under construction, Brazil's National Electricity Agency, known by the acronym ANEEL, acknowledged in its latest monitoring report. Only three projects are already operational: the 9 MW small HPP Carlos Gonzatto and the 16 MW Coruripe and 46.5 MW Goiasa biomass plants.

Even worse, four biomass plants have already had their Proinfa contracts revoked: 8 MW Brasilândia, 30 MW Energia Ambiental, 25 MW Sidrolândia and 25 MW Sonora. "This freed capacity will not be redistributed among other biomass developers, as prices are not sufficiently attractive," Onório Kitayama, advisor of the Sugarcane Agroindustry Union of São Paulo, said.

Brazil's Center of Reference for Small HPPs, known as CERPCH, followed up ANEEL's alarming report with a warning that a spate of small HPPs could be delayed because of financing problems. Proinfa has forged contracts with 63 small HPPs, but 15 small HPPs still have no guaranteed source of financing, CERPCH Business Director José Henrique Garbetta said.

"Financing agreements need to be secured as soon as possible for the plants to be able to launch in 2007," he warned. The small-hydropower segment accounts for 1,191.24 MW of Proinfa's 3,315.26 MW total contracted capacity. Brazil's National Economic and Social Development Bank, or BNDES, approved financing requests worth R$1.286 billion ($556 million) from 24 small HPPs, while considering applications from another 13. Of the 57 Proinfa projects that BNDES agreed in principle to finance, 37 schemes are small HPPs.

Time is running out. Following the expected opening of 10 other small HPPs between February and October 2007, 43 small HPPs totaling 834 MW of capacity are slated to come on line in December 2007. "Proinfa must allow the small HPPs a further three-month delay without any penalties, so the last plants could come on line in March 2008," said Augusto Machado, general coordinator of alternative energy sources at Brazil's Energy Ministry.

Renewable funds frozen

Following last January's election, Canada's Conservative government continues to evaluate its approach to renewable energy even as it enacts a freeze in new program funding. Emma Welford, spokeswoman for Energy Minister Gary Lunn, said, "do we have a supportive view to renewable energy? Absolutely. We do not want there to be any signal perceived by the industry that we do not support them and are not looking for the best way to support them."

But one renewables industry executive said the funding freeze is "akin to shutting down hospitals while debating the future of health care." Conserval Engineering's John Hollick, manufacturer of the SolarWall air heating system, said he is troubled by the government's move to suspend the Renewable Energy Deployment Initiative. Hollick charged the incentive program has become a disincentive to buy as customers wait to discover if they will receive a federal rebate. "My industry colleagues and I predict that until our government makes up its mind, the Canadian market for solar renewables will go into a tailspin," he said.

Industry executives expressed concern this spring about the government's budget, which they said ignored vital funding for renewable energy. The Renewable Power Production Incentive, a plan conceived last year to install 1,500 MW of small hydropower, biomass and landfill gas generation over 15 years, is also frozen, along with an expansion of the Wind Power Production Incentive, which provides tax breaks for wind energy. Last year, WPPI was quadrupled to 4,000 MW of installed capacity, also over 15 years, through a C1¢/kWh (0.89 US cents) incentive.

Bogota drafts new measures

The Ministry of Mines and Energy in Colombia is preparing a new range of incentives for alternative energy generation in the form of a draft law that will be submitted to the Colombian Congress for final approval.

The measures would exempt companies from income tax if they are involved in renewable energy production – wind, solar, geothermal, biomass energy and power from solid residues. Government benefits would be awarded to power generators or co-generators that obtain certificates of reduced greenhouse gas emissions, according to leading Bogota daily *La Republica*.

The plan comes five years after the Colombian Congress approved Law Nº697, which promotes the use of renewable energy in the country. Colombia's power generation expansion plan for 2005-2011 calls for the introduction of 820 MW of new capacity, including 82 MW of "alternative type cogeneration." As part of the proposal, investors would be required to channel at least 25% of the tax exemption into projects that will ensure social development in the municipalities affected by renewable schemes' construction and operation.

Companies already operating renewable energy projects would receive the tax exemption for 15 years, starting from the day the new law takes effect. For all renewable projects that come on line before December 31, 2010, the 15-year tax exemption would start from the day of their commercial launch. One of the country's leading alternative energy projects that could benefit from the proposal is the 19.5 MW Jepirachi wind farm. The project is expected to generate revenue of $3.2 million by selling carbon emission credits.

CO_2 Market

EUA trading masks focus on key issues

Trading activity in the European emissions Allowance market has slowed to a trickle relative to the bumper volumes seen in late April and early May, as traders narrow their focus to a few key issues. “It's all about Poland,” said one senior trader at a European bank. “Companies [there] want to sell their excess EUAs, but they can't since the national registry is not yet on line.”

Prices for Allowances for December 2006 delivery spent most of June either side of €15.00 ($18.8), with day-to-day price volatility rarely more than 30 euro cents. Most traders believe that once the Polish registry is operational there will be a rush to sell excess EUAs on the spot market, where payment and delivery are made within days. “When the Polish registry comes on line, there'll be some selling and the utilities can step in,” said another trader. “If you know a particular party is long, but cannot trade for technical reasons, the correct thing to do is wait for that party to be able to trade.”

A number of recent reports have estimated that Polish companies could have as much as 20 million surplus EUAs from 2005 to sell on the market. The spot market is the preferred outlet for industrial companies who seek to cash in on the value of excess allowances. Since compliance with the EU Emissions Trading Scheme is an annual cycle, the most popular trading contract is for delivery in December, but sellers are keen to bank the proceeds from their sale immediately, and this selling interest is what sustains the spot market.

Spot prices currently stand at a steady 30 euro cent discount to the benchmark December 2006 contract, reflecting the “cost of carry”, that is, the cost of money required to buy and hold EUAs until the next major delivery date. Yet not everyone believes that Polish companies will rush to sell all their excess EUAs. “This last winter was one of the coldest in recent years,” noted a source at a European trading house. “Power demand was strong, and generators may have emitted more CO_2 than forecast as a result. So they may not have as big a surplus in 2006.”

And this reluctance to sell would not be restricted to the Polish power sector, the source said, “Industrial companies in general are conservative by nature, and most don't have a lot of experience in trading. They may not want to sell any excess EUAs until they are absolutely certain they won't need them.” In this case, this means late 2007, when the first phase of the EU ETS draws to a close (Phase 1 EUAs must be used or sold before they lose their value at the compliance deadline in April 2008).

When and indeed if there is a rush to market to sell spot EUAs, buyers would likely come from among the ranks of European utilities and speculative traders, sources believe. “Utilities would always look for cheap sources of compliance,” said a continental trader. “If they believe those cheap EUAs will come in the spot market, they'll wait for that.”

The impact on spot prices, most sources agree, would be bearish, but there are those who see a wider impact. “Spot buyers would probably hedge these purchases by selling the December 2006 contract, which would bring that price down as well,” a London-based trader speculated.

“The December 2006 price in turn determines the December 2007 price through the cost of carry (currently around 60-65 euro cents),” the trader added. “And there would quite likely be some impact on the December 2008 price as well,” even though the December 2008 contract represents the first year of Phase 2 of the EU ETS and as such is subject to different regulations and caps on emissions across Europe.

The other main area of focus in the last month has been the December 2008 contract. Since European member states must assemble new National Allocation Plans for Phase 2 of the EU ETS (2008-2012) by the end of this month, the December 2008 contract is heavily influenced by as-yet incomplete regulatory processes.

Most traders agree, however, that Phase 2 limits on emissions will be tighter than in Phase 1, and that as a result EUA prices will be higher. December 2008 prices are currently assessed around €3.90 above December 2007 levels, a somewhat smaller premium than has been seen in recent weeks. Sources say this erosion in the premium is due to continued selling activity by traders looking to hedge their forward purchases of Certified Emissions Reductions from Clean Development Mechanism projects. Once a deal is signed for CERs, traders can sell EUAs for the same delivery period, locking in the price of, and the profit from, the CERs.

One trader noted that hedging activity has picked up since May 15, when EU states' verified emissions data for 2005 was published. The roughly 64 million mt surplus of EUAs in 2005 that the data revealed has led to fears that the EUA market may fall further.

Consequently, buyers of CERs are said to be selling 2008 EUAs more aggressively, and this is what traders believe is behind the shrinking premium for 2008 EUAs. But, one trader says, there is also a widespread belief that the European Commission will take a tough line with Phase 2 NAPs and force member states to trim their planned allocations for 2008-2012, which may be providing some price support for 2008 EUAs.

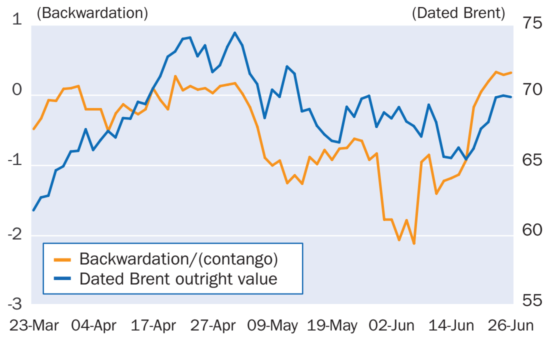
Platts CO_2 assessment monthly averages – 1-27, June 2006 (€/mt)

Delivery	High - Low	Midpoint
Dec-06	15.26 - 15.21	15.24
Dec-07	15.89 - 15.84	15.85
Dec-08	20.30 - 20.09	20.11

All prices are in euros per metric tonne of carbon dioxide equivalent as traded under the EU Emissions Trading Scheme.

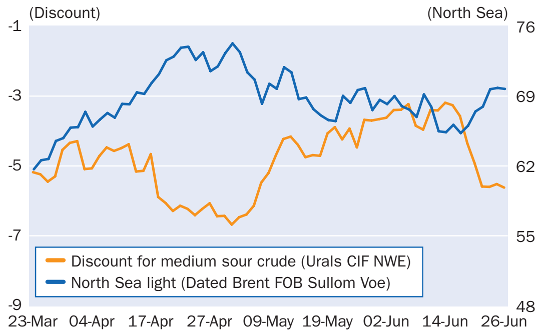
Source: Emissions Daily

Physical Brent and market structure ($)



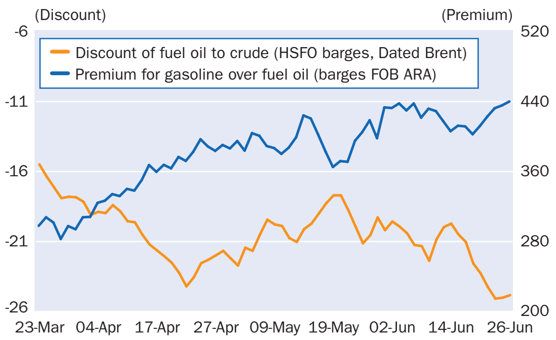
Source: Platts Global Alert

Brent crude and sulfur differential ($)



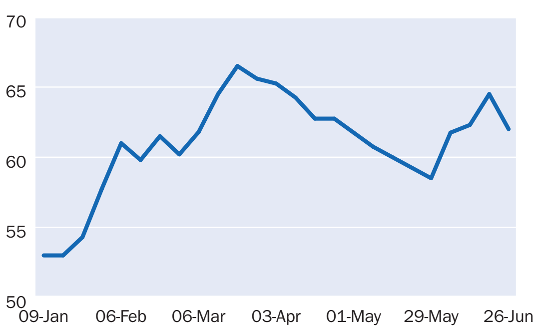
Source: Platts Global Alert

Light-heavy spread ($)



Source: Platts Global Alert

Coal ARA CIF 90-day ($/mt)



Source: Platts International Coal Report

Crude recovers lost ground

ICE/IPE crude oil futures looked likely to end June almost exactly where they started, settling June 26 at $70.73/barrel for the front month contract, having dipped during the month to close at $66.92/barrel on June 13. Commodity prices across the board were hit mid-month by a rally in the dollar, resulting from US inflation data that raised expectations of a further rise in interest rates by the US Federal Reserve.

In addition, statements by OPEC members suggested room for downward movement. Qatari oil minister Abdullah al-Attiyah said that while there was “no magic number” for oil prices at which OPEC would trim output, he believed the cartel would continue to pump all out as long as prices were higher than $50/barrel. The comments echoed others made by OPEC ministers at their June 1 meeting in Caracas that suggest $50/barrel represents a price floor in OPEC’s thinking.

Physical crude markets remained in contango throughout June, indicating an excess of oil for prompt delivery, even though the very front-end of the forward curve for Dated Brent moved into backwardation on June 21. The change in market structure is small and concentrated, reflecting a sudden rush of North Sea cargo trades that cleared much of the first half of the July loading programs. Robust refining margins currently favor low sulfur crude at a time when runs historically reach their peak globally, while the differential between low and high sulfur crudes has widened.

Crude prices recovered from their mid-month dip towards end-June, as the dollar started to weaken, despite the imminent US interest rate rise, and as a result of US refinery issues. In addition, crude found renewed support from ongoing international frustration over Iran’s apparent reluctance to respond to an international package aimed at defusing concerns over its nuclear program. On June 6, EU foreign policy chief Javier Solana presented Iran with an offer of multilateral talks and a variety of incentives. Iran appears to reject the key condition of suspending urnaium enrichment work. President Mahmoud Ahmadinejad has said a reply will be given in late August, whereas the major powers were calling for a reply before the end of June.

UK winter gas softens

Despite UK month-ahead prices jumping early June, bearish sentiment dominated the spot market as the UK-Belgium Interconnector went down for annual maintenance, preventing producers and shippers from selling UK gas on the continent. In addition, prices for winter 06 softened in the second half of June as Centrica Storage, the operator of the UK’s Rough gas storage facility, said June 26 that its train 1 compressor had been brought back on line ahead of schedule, allowing for a step-up in injections from 55% of normal injection rates to full capacity. The company said it still expects a return to withdrawal from October 1. The return of Rough, increased Interconnector capacity later in the year and expectations that the UK-Holland BBL interconnector will now come on-line as scheduled has taken pressure off the winter 06 contract.

Meanwhile, for nearby prices, mild weather has kept demand low, but a split in July emerged, owing to the start of the maintenance season, which will reduce supply, and the return of Rough, which will increase demand as injection rates are upped to full capacity. Traders said the combination could lead to volatility over the next month.

The premium between Zeebrugge and the UK remained relatively flat in June and was for the most part less than the cost of transport. Meanwhile, Dutch gas prices at the TTF settled lower across the board June 26, with bearish sentiment spilling over from neighboring markets, while sideways-moving gasoil futures at the ICE exchange failed to provide guidance. Dutch day-ahead prices showed a premium to its Belgian counterpart, and while this opened up arbitrage opportunities for those holding import capacity from Zeebrugge to the Netherlands, importers appeared to buy primarily for their own requirements, rather than to sell gas on at the TTF.

Weather keeps US gas price down

In the US, weather has been the main driver. Early in June, forecasts for a long spell of hot weather across much of the country meant expectations of buoyant demand from power generators eager to meet rising power consumption for air conditioning. After falling and then holding at around $6.20/MMBtu, the July NYMEX gas futures contract surged 7% on June 14, and then shot past $7/MMBtu on June 15 in reaction to a smaller-than expected storage injection.

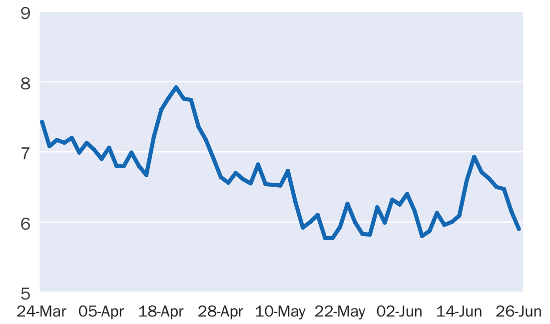
Nevertheless, the bullish sentiment proved short-lived: on June 26, the July NYMEX gas futures contract fell 25.7 cents from the previous settle to $5.969/MMBtu, ending at the lowest prompt-month settlement in a month as market players continued to look toward a shortfall of bullish fundamentals. Traders said weather forecasts now showed a lack of hot weather, while storage levels remain high.

European power: Spanish trauma

The Spanish power market has been left in a virtual coma since Iberdrola's decision to beat down the spot price on the Spanish wholesale market on June 8-9 in protest at changes made to the market by government in late February. The spot price dived June 8 after Iberdrola instructed its distribution arm not to pay more than €33/MWh for power on the pool. The subsequent slump in the day ahead pool price to €31.52/MWh saw curve prices plunge, although most trade was focused on the prompt as traders became wary further out along the curve. New market rules were expected by end-June.

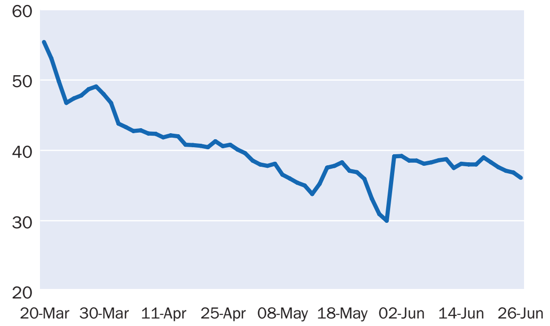
Meanwhile, French and German calendar power prices seemed to drift down on lack of news and a propensity among traders to pay less heed to the carbon market, opting to disengage power from more sedate EUA prices after the volatility seen in preceding weeks. Although outages were heard in Germany, warm yet not extreme temperatures held the demand and supply curves fairly balanced on the prompt. French nuclear plants were taken off line as the maintenance season

US Gas Henry Hub month-ahead ($/mmBtu)



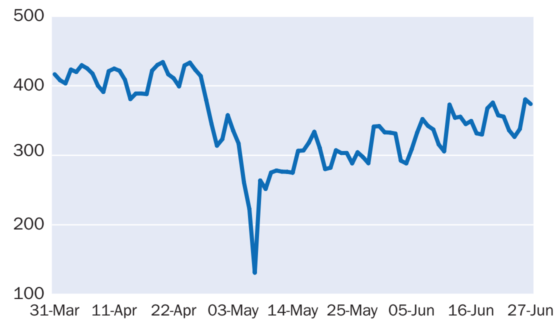
Source: Platts Natural Gas Alert

UK gas: NBP month-ahead (p/th)



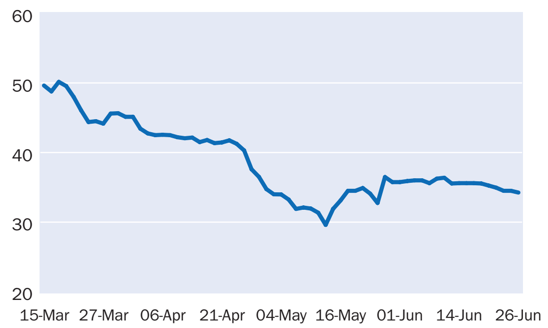
Source: Platts European Natural Gas Report

Nord Pool day-ahead close (NKr/MWh)



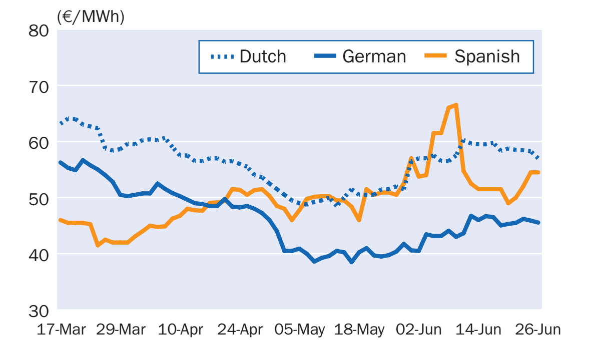
Source: Platts European Power Alert

UK baseload assessments month-ahead (£/MWh)



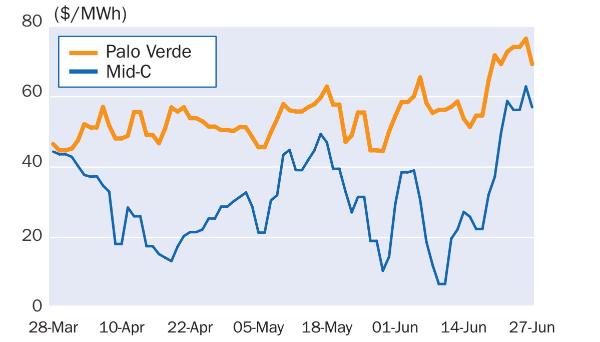
Source: Platts European Power Alert

European baseload assessments month-ahead



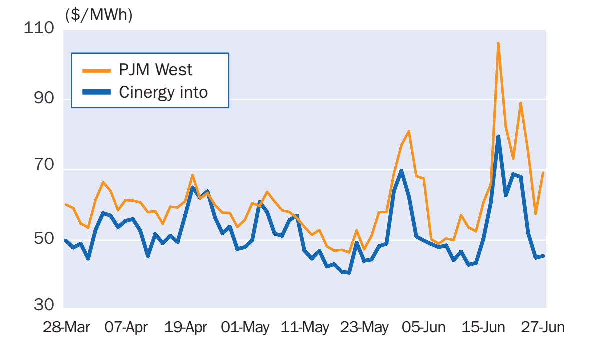
Source: Platts European Power Alert

Northwest/Southwest US power day-ahead



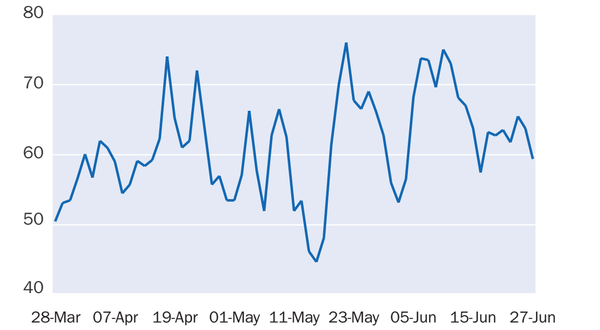
Source: Platts

Northeast/Midwest US power day-ahead



Source: Platts

ERCOT Texas peak day-ahead ($/MWh)



Source: Platts

got underway, but not enough capacity was off line to drive prices up. UK power saw a shift in the marginal fuel from gas to coal in first-half June, traders said, leaving power prices to find other drivers. The day-ahead baseload contract shrugged off low gas prices and found some room for strength, taking a lead from French and German power prices June 12 to trade as high as £40/MWh. The contract returned to its trend level for the month of around £28.50/MWh June 15.

US power: hot out west

In the US, weakening gas futures and the lack of any offsetting fundamentals took a large chunk out of forward power values towards end-June, with losses in the week ending June 23 reaching 20% in the front months in the heavily gas-dependent Entergy market and topping 10% in other Central markets. A similar picture emerged in eastern markets with forward prices for the rest of the summer falling sharply from New England to Into Southern. Daily and near-term markets were also bearish on cooler weather forecasts.

However, the picture was very different in western markets, where day-ahead power started summer with a bang mid-June, propelled by high temperatures blanketing California and the Southwest. The heat forced California's grid operator to call for maximum conservation and float the possibility of a "stage" emergency as peak loads consistently stayed above 40,000 MW. With the high temperatures expected to continue, market participants believe loads will remain strong and keep dailies propped up. Day-aheads leaped as the heat wave hit California. Southwest and Northwest markets were strengthened on power exports to the energy-thirsty state. The California Independent System Operator June 21 issued a call for increased conservation through June 25 on the expectation of hot weather pushing up demand. Pacific Gas and Electric also issued a request for conservation.

World coal

European steam coal prices rebounded in June as utilities sought replacement cargoes of mainly Russian coal following a five-week strike at Colombian coal producer Drummond that only came to an end June 22. The strike broke out over wages and social benefits on May 22 and resulted in the cancellation of scheduled cargoes to a number of European utilities. The labor dispute is thought to have cost Drummond 2.25 million mt in lost production. Spot delivered prices for northwest Europe reached an average of $62.64/mt CIF ARA in June compared with $60.05/mt in May.

FOB Richards Bay prices increased to $52.38/mt in June compared with their May average of $50.40/mt. Supplies of South African coals are only beginning to return to normal after a series of coal train derailments earlier this year, but still remain tight. Buyers have had to turn to Russian coal to cover short positions and prices rose to an average of $55.69/mt FOB Baltic ports in June compared with $51.55/mt in May. Prices are expected to soften over the summer months in Europe as demand wanes and supplies return to normal levels.