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The story of plenty is yet to be realised

Exciting frontiers: workers on a drilling rig in the Eagle Ford Shale near Encinal, Webb County, Texas Bloomberg

An increase in opportunities has galvanised the energy world, writes *Guy Chazan*

In 2008, with crude soaring towards $150 a barrel, the world was full with talk of peak oil and dire predictions of energy scarcity. Four years later, the rhetoric has changed. Now it is less of scarcity than abundance.

The main driver has been North America's shale gas revolution, where techniques such as hydraulic fracturing have unlocked vast resources. The shale boom has created a "world of infinite gas", says Tony Hayward, head of oil explorer Genel Energy and former chief executive of BP.

Now those techniques are working the same magic on America's "tight" oil reserves, creating an oil surge in places such as North Dakota's Bakken Shale. According to BP, thanks to its increasing output of biofuels, shale gas and unconventional oil, North America will become almost totally self-sufficient in energy by 2030.

Moreover, shale's proponents are convinced the revolution will soon spread round the world, as "fracking" opens up the shales of South Africa, China and Argentina.

But shale is only part of the story – one element of a long-term shift towards unconventional resources. The oil industry's centre of gravity is gradually moving away from "easy oil" in places such as the Middle East, towards new developments of extraordinary complexity that will require hundreds of billions of dollars of investment but hold vast potential for an energy-hungry world – for example, the tar sands of Canada, heavy oil in Venezuela, and Brazil's ultra-deepwater "pre-salt" fields.

The emergence of this spectrum of opportunities – ones that previous generations of petroleum geologists and geophysicists could only dream of – has galvanised the energy world.

"I haven't seen Calgary, Houston and Aberdeen more revved up in my 30-odd years in the industry," says Tony Fountain, head of refining at Indian oil group Reliance.

Yet there is one troubling wrinkle in this narrative of abundance: the price of oil. The shale boom might have driven US natural gas prices down to 10-year lows, but despite the rise in North American oil production, prices remain high. It is no wonder, considering the bulk of the world's crude continues to come from the volatile Middle East.

"The industry seems to continue to find oil, but higher costs, the pace at which producing fields deplete, plus potential geopolitical shocks and Opec, are keeping the oil price above $100," says Philip Wolfe, head of energy at UBS Investment Bank.

Despite that, the exciting frontiers that have opened up in the past decade have provoked breathless reappraisals of the world's oil and gas potential, fuelling this rhetoric of abundance.

One example of this revisionism is a recent study by Leonardo Maugeri, the former head of strategy at Italian major Eni, which sought to assess

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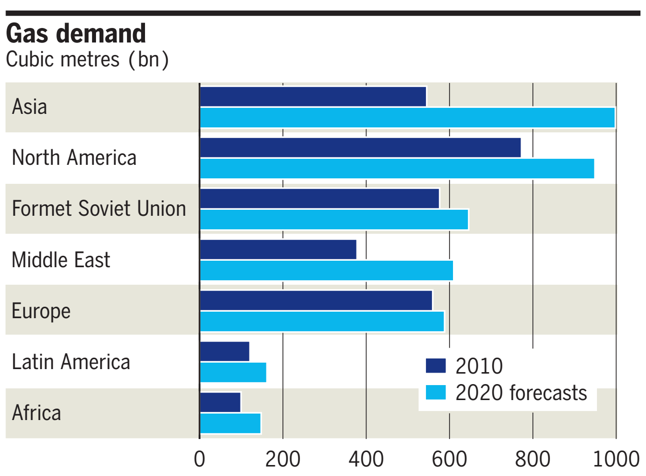
Gas replaces coal as the favoured fuel

US example

Sylvia Pfeifer finds that North America's success is down to a unique set of circumstances



Source: Wood Mackenzie

For more than a century, the coal plants of America's Southern Company have been generating electricity for towns and businesses throughout the country's south-east.

Coal, as in other regions, has dominated the energy landscape. Until today. Over the past few years coal's share of Southern's electricity mix has dropped sharply. Four years ago, it produced 70 per cent of its energy from coal. Last year, this had dropped to about 40 per cent, and this year, it is expected to fall to 35 per cent.

The newcomer providing competition is natural gas. Five years ago gas accounted for between 10-12 per cent of Southern's energy. The company expects this to grow to 47 per cent in the future.

The reason for the switch its simple: US natural gas prices have touched 10-year lows. The discovery of shale gas – trapped in rocks thousands of feet under the ground – coupled with new extraction techniques have transformed the country's gas production.

Ten years ago, America was preparing to import gas. Now, some estimate the new reserves will last 100 years.

Low natural gas prices have prompted many utilities to shift large parts of their generation from coal to gas. North America's energy transformation has been watched by the rest of the world. After assessing the potential in 32 countries, the US's Energy Information Administration has estimated shale could increase the world's technically recoverable gas resources by more than 40 per cent.

The International Energy Agency has heralded "a golden age of gas", predicting it will account for more than a quarter of global energy demand in 2035, overtaking coal as the second largest primary energy source after oil.

Royal Dutch Shell is also bullish. By 2030, it predicts global gas demand will be 4.8 trillion cubic metres a year – up 50 per cent on the 2010 level.

"This increase in gas demand equates to five times today's global liquefied natural gas [LNG] industry," says De la Rey Venter, head of LNG at Royal Dutch Shell.

It is achievable, he says, citing significant production expected from North and South America, Australia, China and South Africa. Countries such as Mozambique and regions such as the eastern Mediterranean are also coming into play as producers.

Not everyone is convinced. For one thing, North America's shale gas success has its roots in a unique combination of circumstances, including a well-developed, low-cost service industry and accommodating regulation.

> 'This increase in demand equates to five times today's global LNG industry'

"You have to ask, 'a golden age' for whom," says Noel Tomnay, head of gas at Wood Mackenzie, the consultancy. "Globally, we have more supply options – shale in North America, LNG from Qatar and soon to come from Australia. But it is still expensive. If you want cheap gas, you need it to be on your doorstep."

Europe, he says, is not well placed to benefit similarly. Compared with other regions, a lack of relatively low-cost, local gas and an absence of government policy to promote its benefits relative to other energy options are discouraging demand growth.

Not only are policy signals missing on the demand side, there is constraint on the supply side. Some European countries, such as France, have imposed moratoriums, given widespread environmental concerns about hydraulic fracturing, or fracking, the technique used to extract the gas from the rock.

Fracking involves pumping sand, chemicals and water at high pressure deep into the rock. Much of the opposition to it has focused on fears of water contamination.

The energy industry insists its practice is safe, while acknowledging more needs to be done to convince policy makers and the public.

One of the benefits of burning more gas, says the industry, is its lower emissions profile compared with coal. Executives point to the US, noting that since many utilities switched to burning more gas than coal the country's carbon dioxide emissions have dropped. Figures from the IEA in May showed that CO_2 emissions in the US in 2011 fell 1.7 per cent.

Others caution that over the longer-term, investing in gas-fired power plants could take away funding for renewables. Ben Caldecott, head of policy at Climate Change Capital, a think-tank, says: "In developed economies such as Europe, and Japan, more gas-fired generation is a real issue. It could crowd out renewables, making it harder to meet carbon reduction targets."

The deployment of renewables at scale is vital, he argues, as only that will drive down costs.

Given the long-term nature of the energy business, governments are in the tricky position of having to take decisions that will determine investment decisions for decades against the backdrop of today's economic downturn.

Mr Tomnay says: "If you are looking for a global gas revolution, the question you should ask is: 'Where is the next cheap gas going to happen?' My bet is China or Latin America. But it's not happening quickly."

Supply chain and price pressures haunt majors

Exploration costs Big western companies are squeezed on all sides, says *Guy Chazan*

Tightening up: the costs of developing projects are rising

The bogeyman of rapidly rising industry costs has returned to haunt the western oil majors. Cost inflation was a big issue for oil companies four years ago, when the price of crude rose to an all-time high of $147 a barrel and the cost of goods and services in the resources industry increased in lockstep.

The majors responded with aggressive cost-cutting campaigns, and seemed to have slain the demon. But now it is back. Labour shortages, the rising cost of inputs and sky-high leasing rates for deepwater rigs are all conspiring to increase cost pressures in an overheated market.

Even a low level of inflation can have a huge impact on an industry that is spending more than ever before to find and produce oil. IHS, the data provider, says capital expenditure for exploration and production in 2012 was $641bn, up from $586bn in 2011. That is more than the gross domestic product of Saudi Arabia.

A key reason is that high oil prices are spurring companies to embark on more costly and ambitious projects.

"There was a lot of spare capacity available post-Lehman Brothers, as projects were deferred," says Stuart Joyner, an oil analyst at Investec. "But that's gone now."

The increase in activity puts pressure on supply chains that are already tight, especially for the kind of highly specialised services and equipment the modern oil industry needs. Squeezed vendors and subcontractors inevitably respond by raising prices. The majors are being squeezed on the demand side, too, with many receiving less for the oil and natural gas they sell in the US.

Peter Voser, chief executive officer of Royal Dutch Shell, acknowledged the issue in a July earnings call, saying costs were going up because Shell's production was rising. He also linked the increase to a wave of projects Shell is working on, each of which needs expensive preparations. These, he said, were "value-generating costs" because they would ensure new medium-to-longer term growth.

One of the worst-affected places is Australia. Earlier this year, BG Group, the UK-listed oil and gas company, increased its cost estimates for its Queensland Curtis liquefied natural gas project by 36 per cent, from $15bn to $20.4bn.

"Australia is becoming a more difficult place to operate in," says Martin Houston, BG's chief operating officer, pointing to the tight labour market and increased costs of compliance with toughening regulation. Environmental approvals, he says, are a "moving target".

Simon Henry, Shell's chief financial officer, says Australia is a cost "hotspot", and that the US Gulf Coast, where activity has risen since the Obama administration lifted a drilling moratorium imposed after the 2010 Deepwater Horizon disaster, could also have an "inflationary bubble".

Data confirm the cost inflation trend. IHS says its upstream capital cost index rose 2.3 per cent over the six-month period ending March 31 this year, to a new high index score of 227. That means that capital costs of $1bn in 2000 would now be $2.27bn.

Operating costs were up 2.1 per cent to an index score of 189 over the same period – meaning that if the annual cost of operating an oilfield was $100m in 2000, it would be $189m now.

The group attributed the rise to the much higher day rates for deepwater rigs, which are increasingly in demand as oil companies venture further offshore and into ever deeper waters to explore for and extract oil. Rising fuel and labour costs mean rigs demand premium rates.

Michel Hourcard, head of developments at Total, the French major, told investors last month that he got several calls a day from competitors asking: "'Have you got a rig? A subsea platform? A crane?' "Everything is short," he said. "The market is extremely tense." He added that there are cases of contractors trying to take advantage: some cost increases were "absolutely not justified", he said. IHS added that skilled labour for construction, drilling teams and operations continues to be in short supply, with employers struggling to retain crews. It says labour is the top concern for oil operators: they can always ask vendors to build them an extra piece of equipment, but training competent workers takes months or years.

Companies such as Shell say they are trying to address the cost issue. Shell talks of its "strategic enterprise framework agreements" with long-term suppliers, which it claims reduce prices by between 10 and 25 per cent against market benchmarks in important categories of spending such as pipes and valves.

Mr Henry says Shell's 24 upstream developments had already locked in costs ahead of the latest bout of inflation, but "we are being very careful about the next wave of investment projects". The company was, he said, developing suppliers in China, Turkey and Mexico to ensure "sufficient competition" to keep costs down.

Closer working helps to plug the skills gap

Oil services companies *Michael Kavanagh* finds a sector of the industry is booming

As oil and gas gets more difficult and expensive to produce, there are almost imperceptible movements in the relationships between the owners of oil and gas assets and the services companies.

These shifts, as subtle as the movements of the tectonic plates that play a key role in the production of these natural resources, are changing the way hydrocarbons come to market. As the Deepwater Horizon disaster in the Gulf of Mexico illustrated, beyond the lead operator – in that case BP – of wells and platforms lies a supply chain of service companies, including the likes of Halliburton and Transocean and their subcontractors.

But while Deepwater has led to disputes between BP, Halliburton and Transocean as to where fault for the disaster lay, traditional oil majors and national oil companies are increasingly letting services companies play a bigger role in deals that let both sides profit.

In this arena oil services companies co-operate as much as they compete to win the favours of large oil companies.

Schlumberger, the world's leading oilfield services company, came together with Petrofac, the largest London-listed oil services supplier by market capitalisation, at the start of the year to offer a "one-stop shop for clients in emerging field development". Both say the alliance is a way of pitching to "major resource holders" keen to further exploit reserves "against an industry environment characterised by a shortage of capability and capacity".

As Tim Weller, Petrofac's chief financial officer, says: "Things are getting deeper, wetter, and colder." This requires more contractor expertise. And while western oil majors are increasingly keen to sell on maturing fields to smaller independents, nationally owned companies are also keener than ever to compete globally to own and operate oil and gas assets.

The result, says Mr Weller, is that an increasing number of oil and gas projects are being left in the hands of owners without the in-house experience to exploit them to the limit.

An example of Petrofac and Schlumberger plugging a skills gap is a deal struck with Pemex, Mexico's state oil monopoly, in June. They are being paid on a commission basis for production improvements in fields previously operated solely by their client.

That deal followed Petrofac's success in winning two of the first three private oil production contracts granted in more than 50 years by Pemex in August last year. The growing role played by oil service companies has helped to establish them as a growing constituency in the energy sector where their market capitalisations can often exceed those of their clients.

Schlumberger, for example, enjoys a market capitalisation just less than BP's, in excess of ConocoPhillips and well in excess of the next tier of US-listed oil producers such as Apache, Anadarko and Marathon. Companies in this tier compare in value with the likes of leading US oil services companies Baker Hughes and Halliburton.

In the UK, too, Petrofac, Amec and John Wood Group, alongside oilfield pump supplier Weir Group, have emerged as FTSE 100 constituents whose value often exceeds those of mid-tier London-listed oil explorers and producers.

And, while spluttering demand for fracking equipment in North America has damped a previously hot segment for some services companies, many have continued to outperform leading stock market indices handsomely in spite of some concern over softening oil prices.

Mr Weller argues a shift in control over oil and gas assets away from so-called IOCs (western-owned independent oil companies) to NOCs (national oil companies) has left oil services companies well positioned to fill the skills gap created by sovereign states wishing to maintain formal control over their assets rather than simply hand them over to western oil majors.

"In the past the NOCs had only one direction to go – the IOCs," says Mr Weller. "The IOCs have to be able to take ownership of oil and gas reserves, but that is difficult and anathema to many countries as ceding ownership of reserves is not a popular thing."

> 'Things are getting deeper, wetter, and colder'
> **Tim Weller Petrofac**

At Amec, John Pearson, managing director of natural resources for Europe and west Africa, agrees this picture of countries keeping control of assets should benefit the sector. Meanwhile, a shift away from majors seeking to control all or most elements on projects, as well as selling maturing fields, should also strengthen the place of operators in the oil services marketplace.

"Assets are being transferred to people with less record of running assets – whether NOCs or smaller independents – who may have less competency," says Mr Pearson.

Majors that used to dominate research and development and have large numbers of project management staff are now more willing to run "skinny teams" that bring the best suppliers together, he argues.

Claudi Santiago, managing director and chief operating officer of First Reserve Corp, a private equity firm that invests in energy, agrees the sector's tectonic plates continue to shift, but he says that their final destination is still unknown. "There's been a huge transfer of expertise from IOCs to NOCs, and the oilfield service companies have played a key role in that. Over the next few years, we're going to witness an interesting phenomenon. Will service companies help NOCs become totally independent? We will see."

Clouds fog hopes of global export boost

Natural gas Some market watchers are dismissive of estimates of a supply surge, says *Guy Chazan*

Japan's decision last month to phase out nuclear power will boost its renewables industry, but in the short term the main beneficiary will be natural gas.

Japan's imports of liquefied natural gas (LNG) are already at elevated levels. The country's appetite for LNG increased sharply in the aftermath of the 2011 Fukushima disaster. But the Japanese move comes at a time when demand for LNG – gas cooled in massive fridge-like plants to -162C and exported in tankers – is rising globally.

BG Group, the UK-listed oil and gas company, says the share of LNG in global gas consumption will rise from about 9 per cent in 2010 to nearly 14 per cent by 2025. A lot of that growth will come from Australia. Companies such as Chevron, Royal Dutch Shell and Woodside Petroleum have invested $180bn in ventures that have put Australia on track to overtake Qatar as the largest LNG exporter by the end of the decade.

Meanwhile, in North America, technologies such as hydraulic fracturing and horizontal drilling have opened up vast resources of shale gas previously considered too difficult or uneconomic to develop. The resulting production rise has forced gas prices to 10-year lows. Terminals built to import LNG are being altered to export instead. Canada, too, is progressing plans to export gas.

Meanwhile, the world has suddenly seen the emergence of two hydrocarbon frontiers – the eastern Mediterranean and offshore east Africa – that boast large quantities of gas. Both Israel's Leviathan field and the 100tn cubic feet of gas discovered off the coast of Mozambique in recent months could sustain LNG plants that will vastly increase global capacity.

That could have far-reaching implications for the LNG trade, and particularly for pricing. North America's LNG exports will probably be indexed to US Henry Hub prices, in contrast to most other long-term LNG contracts, which are linked to oil prices.

Eurasia Group, a consultancy, says the abundance of supply could accelerate the move from oil-linked pricing, leading to a convergence of worldwide prices, and opening the prospect of global trade in a commodity that has, until now, been split into regional markets.

But some dismiss the predictions of a supply surge so large it could disrupt the traditional LNG trade.

"On the supply side, LNG projects are getting more difficult, taking longer and costing more," says Martin Houston, BG Group's chief operating officer. He cites statistics that show a 17 per cent drop in supply prospects between 2007 and 2011 as projects in places such as Venezuela, Iran and Russia were cancelled or deferred.

The latest example came in August when Gazprom, the Russian gas exporter, shelved plans to develop the Shtokman gas field in the Arctic Barents Sea, because of cost pressures.

Even in places likely to develop a thriving LNG industry in the next decade, there are big uncertainties. The gas finds offshore of Mozambique and Tanzania have been staggering: but these countries are poor, and lack the laws, regulatory framework and infra-

Inbound: an LNG tanker brings its product to Japan Bloomberg

structure needed to create a big domestic energy industry. It is even doubtful oil companies now active off east Africa could reach agreement on how to develop this gas resource.

Doubts are also emerging about the prospects for large-scale US LNG exports. So far, only one project – Cheniere Energy Partners' Sabine Pass facility in Louisiana – has won all the necessary export permits.

Others have tried: applications filed with the Department of Energy could put the US on course to export 150m tonnes of LNG per annum, nearly twice Qatar's output. However, BG thinks only 45 mtpa of exports will be approved.

US officials have said no decisions will be made on the other projects until they have seen the results of a study commissioned by the Department of Energy on how allowing companies to sell natural gas overseas will affect consumer prices.

Gas demand has already grown sharply in the US as the supply glut encourages a switch from coal to gas in power generation and from oil to gas in transport. Growing consumption will leave less for export.

Political opposition to more exports is also growing. Some fear exporting LNG could push up US gas prices, sending electricity bills higher and jeopardising the renaissance in domestic manufacturing.

In the near term, the expansion of LNG capacity in the US "will be constrained by practical planning considerations and funding limitations", says Tim Day, a managing director at First Reserve Corp, the energy-focused private equity firm. The US, he says, "will remain a high-cost producer of LNG for the foreseeable future".

Prospects for LNG exports from Canada, and even for established producers such as Australia, are also clouding over.

"In the end, the LNG export market is not expected to experience the boom some predict," says Mr Day.

The popular story of abundant energy supplies has yet to be realised

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recent increases in global oil production capacity. His conclusion: "Contrary to what most people believe, oil supply capacity is growing worldwide at such an unprecedented level it might outpace consumption."

Mr Maugeri, a senior fellow at the Geopolitics of Energy Project at Harvard's Kennedy School, carried out an analysis of the world's big oil projects and found that additional production of about 49m barrels a day (b/d) of oil were being targeted for 2020, more than half the world's current production capacity of 93m b/d.

Risk factors and depletion rates at existing fields bring that figure down to 17.6m b/d. But that would still, he says, "represent the most significant increase [in global oil production capacity] in any decade since the 1980s". It was the result, he says, of an "unparalleled investment cycle that started in 2003 and has reached its climax from 2010 on".

But it is a controversial view. Writing in Petroleum Intelligence Weekly, where Mr Maugeri's essay originally appeared, Sadad al-Husseini, a former head of exploration at Saudi Aramco, the state oil company, begged to differ. He faulted the Italian's study for setting aside technical realities such as the difference between non-gas liquids and conventional oil. He said Mr Maugeri underestimated the rate of global oil capacity decline, citing International Energy Agency data showing decline rates of 6.7 per cent per year for oil fields that had passed their production peak – a rate it predicted would rise to 8.6 per cent by 2030.

Others agree that the issue of accelerating depletion rates is critical.

"Existing reservoirs are depleting three times faster than 20 years ago," says Claudi Santiago, chief operating officer of First Reserve Corp, the energy-focused private equity group. "The world is squeezing these reserves at a faster rate."

Taking the IEA's 6.7 per cent decline level, Mr Husseini wrote, the world would need 5m b/d of additional capacity annually just to maintain a flat level of supply, so even the new additions identified by Mr Maugeri "would only extend current liquids production on a flat trajectory to 2021".

"It isn't an oil glut by 2020 that is keeping oil prices as high as they are," he wrote. "It is the reality that the oil sector has been pushed to the limit of its capabilities and that this difficult challenge will dominate energy markets for the rest of the decade."

Mr Santiago is also sceptical about the talk of abundance, predicting that supply will barely be able to keep up with rising demand, particularly from fast-growing Asian economies. "If you assume 1 per cent GDP growth per year, then by 2020 the world will need to find about 40m barrels a day of oil," he says. "So in less than 10 years we need to bring on four times what Saudi Arabia produces today."

And the new reserves that need to be mobilised are far more expensive to develop than what came before. "The resource is abundant, but the low-cost resources have been running down," says Chris Skrebowski, founding director of Peak Oil Consulting. "So the challenge is how we cope with high-cost energy." Dealing with that, he says, will entail having to "reorganise our economies".

The new riches are not only expensive – they are potentially more polluting. Environmentalists oppose oil sands because they are energy-intensive and dirty; deepwater drilling because of the risk of spills such as the 2010 Gulf of Mexico disaster; and shale-gas extraction because of fears that fracking may contaminate water supplies.

Such opposition is expected to grow, translating into increasing regulatory problems for companies. Patrick Daniel, chief executive of Canadian pipeline company Enbridge, says the biggest challenge facing the industry is the difficulty of winning public acceptance of oil and gas projects – what he describes as the "social licence".

The obstacles are epitomised by Royal Dutch Shell's travails in Alaska. The Anglo-Dutch major has spent $4.5bn and seven years preparing for an ambitious programme to explore in the Arctic Chukchi and Beaufort Seas, but has yet to complete a single well. Hurdles have ranged from encroaching sea ice to a flurry of legal challenges by green groups and indigenous peoples.

Shell's troubles show that it is far too early to declare victory in the campaign for energy security. "A lot . . . needs to happen over the next 10 years to bring on the resources the world needs," says Mr Santiago. "If we don't hurry up, we're going to run out of time."

No smoke without fire: an Anadarko vessel hunts for gas off the Mozambique coast. Estimates are that there could be as much as 80tn cubic feet to be found in Mozambique and 15tn cubic feet in Tanzania Anadarko

'Embarrassment of riches' hard to exploit

East Africa Finds off Mozambique and Tanzania have caused excitement, but the remote region presents big challenges, says *Guy Chazan*

A few years ago, any mention of the Rovuma Basin would have been met with a blank stare. Not any more. In the boardrooms of oil companies in Houston, London and Tokyo, the words elicit a level of excitement rare in the tightly buttoned world of petroleum geology.

The reason is the extraordinary spate of gas discoveries made in the area in the past few years. So far, some 100tn cubic feet (tcf) of gas deposits have been found in the waters off Mozambique and Tanzania, equivalent to nearly all of Iraq's gas reserves, with the bulk of that in the Rovuma Basin.

It is now considered to be one of the most prolific conventional gas plays in the world, with enough to support huge liquefied natural gas (LNG) plants aimed at energy-hungry Asia.

The frenzy was underscored this year by the bidding war for Cove Energy, a small London-listed oil explorer with an 8.5 per cent stake in the Rovuma Area 1, site of one of the biggest finds. Thailand's PTT Exploration and Production eventually won it with an offer valuing Cove at £1.22bn.

Some 25 companies were in Cove's data room, taking a close look at its assets, ranging from western majors to state-owned Asian energy groups.

"It was highly sought after and very competitive," says Philip Wolfe of UBS, who advised PTTEP on its bid.

That is not surprising, considering the huge international interest. "You almost have an embarrassment of riches in Mozambique and Tanzania, in terms of the volumes of gas being discovered," he says. "In Mozambique, they've only scratched the surface and have already found so much gas."

Indeed, Wood Mackenzie, the consultancy, estimates there could be as much as 80 tcf to be found in Mozambique and 15 tcf in Tanzania. It says there is enough gas to support up to 16 LNG trains, as liquefaction facilities are known.

Yet huge obstacles will have to be overcome before such developments can go ahead. The region is remote, notes Giles Farrer, senior LNG research analyst at Wood Mackenzie, it has no skilled workforce and will have to build deepwater ports capable of servicing big tankers.

Then, Mr Farrer says, there is the question of government capacity, "whether there is sufficient impetus and capability within the governments and national oil companies to advance the huge legislative, bureaucratic, customs and financial challenges that such a development would bring".

Despite the obstacles, foreign interest remains intense, and the coming months could see much more activity in mergers and acquisitions.

A lot of attention is focused on what Anadarko and ENI, two of the biggest companies in Mozambique, will do with the big finds they have made in adjacent blocks in Rovuma – Areas 1 and 4. The two are talking of pooling their assets into one big project – so-called unitisation – and will probably join forces on a single big LNG plant.

Analysts say that, once unitisation is complete, they will both reduce their stakes, so providing opportunities for others seeking exposure to Mozambican gas. Such "farming down" will allow them to share the capital burden, mitigate the risk of the project and improve credit ratings, making financing easier, says Simon Ashby-Rudd, global head of oil and gas at Standard Bank.

> 'The first movers want to offload because the cost of getting gas out of the ground will be so high'

"The equity structure of these projects now looks set to change," Mr Ashby says. "Some of the existing partners will sell down and others will exit entirely."

Those considered likely to sell out completely are the small companies such as Videocon Industries, controlled by the Indian mobile-phone billionaire Venugopal Dhoot, which has a 10 per cent stake in Rovuma Area 1. Such small outfits do not have the appetite for the multibillion-dollar LNG plants needed to process Mozambique's gas for Asian markets.

Matt Ash, energy lawyer with Norton Rose in South Africa, says: "The first movers want to offload because the cost of getting the gas out of the ground will be so high."

Wood Mackenzie estimates a two-train, greenfield LNG development in the region will cost at least $25bn.

Possible acquirers of parts of ENI and Anadarko's stakes include big oil majors with experience of building LNG plants such as Shell, which lost out to PTTEP in the Cove bid, BP and Total. Other interested parties include Japanese "off-takers" or buyers of LNG, which have started investing directly in upstream energy assets. Sumitomo Corp, Marubeni and Mitsubishi have all been buying into shale plays in the US and Canada.

The Asian appetite for east African gas is understandable. "It's very important for Asian customers to secure gas free of the Strait of Hormuz risk," says Pascal Menges, energy fund manager at Lombard Odier, an investment firm.

That risk has grown as fears rise of a potential Israeli military strike against Iran, which could paralyse the flow of oil and gas from the Gulf.

Need for energy is driving force behind global thirst for assets

NOCs

National players have shaken off their dull image to go on an acquisition spree, writes *Sylvia Pfeifer*

For decades criticised as overstaffed, uncompetitive and politically driven, national oil companies have long been recognised as important but dull players in the energy industry.

For many, America's ExxonMobil and Europe's Royal Dutch Shell still count as "Big Oil" compared with the smaller independents but the term largely ignores their equally big, if not sometimes bigger, national oil company (NOC) peers.

All that is changing. Over the past two decades many NOCs have engineered a remarkable transformation, thanks in part to an aggressive acquisition spree around the world.

This year, for the first time, NOCs are on track to spend more on buying international oil and gas production and exploration assets than their private sector rivals, according to Wood Mackenzie, the consultancy.

The estimate – 55 per cent of the total value of M&A production and exploration deals – is up to September this year and includes the recent high-profile $15bn bid by China's Cnooc to take over Canada's Nexen.

The dominant position is even more striking when compared with NOCs' share of 19 per cent in 2010. In 2005, it was just 4 per cent.

What has driven this thirst for assets is countries' need for energy, notably in Asia.

"Most of the Asian countries have a supply deficit," says Simon Flowers, head of corporate research at Wood Mackenzie. "The primary driver is capturing security of supply against a rising import bill."

The International Energy Agency, the western nations' oil watchdog, predicts that over the next 25 years some 90 per cent of the projected growth in global energy demand will come from non-OECD countries. China alone will account for more than 30 per cent, consolidating its position as the world's largest energy consumer.

Chinese NOCs, such as Cnooc, Sinopec and Sinochem, have been involved in some of the most high-profile acquisitions since 2009.

But the deal that has made the rest of the industry sit up and take note is the bid for Nexen. Seven years ago Cnooc made headlines for all the wrong reasons, launching a hostile bid for US oil group Unocal. Political opposition in Washington eventually forced it to drop the bid.

Cnooc's offices in Shanghai

By contrast, the Chinese group's approach to buying Nexen is "a sea change" away from the last time, says one London-based energy banker.

"The two are almost worlds apart in terms of sophistication," he says, noting that this time round Cnooc has ticked all the right boxes. Under the proposed takeover Cnooc will list the shares in Toronto and make Calgary its North American hub.

If the deal structures have changed, so have the targets. Where mature producing assets were once on the shopping list, over the past five years many NOCs have adopted a different tactic, buying up long-life assets such as shale gas in North America or deep-water fields in Brazil.

Many of the NOCs have "become more nimble in the last decade", agrees Amy Myers Jaffe, executive director for energy and sustainability at UC Davis Graduate School of Management. She says that "investor scrutiny" faced by government-led companies raising funds from international financial markets has "corporatised" them.

Many NOCs took advantage of the weak dollar in 2005-06 to pick up international assets. That trend accelerated after the financial crisis in 2008-09 when companies began to "chase value as investors as opposed to for political reasons", she adds.

Yet progress has not been smooth in every case. An NOC is often the largest commercial institution in a country so, when the government needs funds, a company's plans can often be derailed by the state.

Robin West, chairman of PFC Energy, cautions against generalising.

Ecopetrol of Colombia, for example, has managed to restructure its contracts and encourage the private sector to invest. The company's share price soared as a result. And Saudi Aramco is "a serious, well-managed company". But he adds: "There are some success stories but many still suffer from state interference."

NOCs are making lots of acquisitions but the deals have so far "not really changed the balance in international competition with the dominant IOCs".

Mr West says that, while NOCs still have a huge home advantage in access to domestic resources and markets, the international majors have the ability to develop large capital-intensive, long-life engineering projects that require skill and cash to get completed on time and on budget.

And despite the recent flurry of M&A in exploration, in the international arena the NOCs are still small. Of the 35 Asian companies that Wood Mackenzie tracks, their combined exposure to global exploration hotspots such as Angola or Brazil is the same as that of a small international major. "They are tiny on an individual scale," Mr Flowers says.

This could change over the coming decade as NOCs move deeper into capturing exploration assets as well as more technically challenging resources.

If there is one thing the recent deal flurry has underlined it is that NOCs may be big beasts but they are certainly not dull.

Contributors »

Guy Chazan
Energy Editor

Sylvia Pfeifer
Special Correspondent

Michael Kavanagh
Companies Reporter

Adam Jezard
Commissioning Editor

Chris Tosic
Steven Bird
Design

Andy Mears
Picture Editor

Elizabeth Durno
Sub-editor

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Baghdad eases Kurdistan grip

Iraq The federal government's relations with the region are easing, says *Michael Kavanagh*

Opening the pipeline: an employee at the Tawke oilfield in Dohuk province, in the autonomous region of Kurdistan Getty

The quicksands of Iraq's federal constitution are a quagmire for companies seeking to do business there – particularly in the autonomous region of Kurdistan.

Protracted disputes between the Kurdistan Regional Government (KRG) and federal authorities in Baghdad over who holds sway over oil and gas in the north of the country, close to energy-hungry Turkey, continues to constrain attempts to improve Iraq's exporting potential.

But, after years of legal dispute and months of an embargo over exports from Kurdistan that have left reserves in the region largely excluded from international markets, there are signs of change in Baghdad.

Last month Iraq's federal cabinet ratified an agreement to increase oil exports from the region and the release of payments due to companies operating in the area.

This followed the partial resumption in August of oil exports from Kurdistan through Iraq's federally controlled pipelines in a move by the Erbil-based KRG aimed at securing $1.5bn of payments it claimed was due from the federal oil ministry.

Ashti Hawrami, minister of natural resources for the Kurdistan Regional Government in Iraq, told the FT Global Energy Leaders conference in London last month that the deal could lead to oil exports through the federally controlled pipeline system reaching 200,000 barrels a day by the end of the year and 250,000 b/d in 2013.

Both sides have agreed on a high-level committee to sort out draft oil laws aimed at ending disputes over the legitimacy of licences and revenue-sharing agreements between Iraq's provinces.

The apparent thawing of relations between Erbil and Baghdad follows a decision by several major western oil companies to follow the lead taken last year by ExxonMobil to strike exploration and development deals with the KRG. This was in spite of threats from Baghdad to exclude them from working in the rest of Iraq, where most of the nation's hydrocarbons have been exploited.

Chevron of the US, Total of France and Gazprom of Russia this summer joined early stage investors in Kurdistan, including London-listed Genel Energy, led by former BP chief executive Tony Hayward.

The drift among oil companies in committing to production-sharing contracts with the KRG has echoes of an agreement between Erbil and Ankara to build a pipeline to the Turkish border capable of exporting 1m b/d, to be operational by 2014.

That would tackle the bottleneck over exports stranded in the region without recourse to Baghdad's federally controlled network.

But the legal disputes continue – in late July Iraq's oil ministry called on Chevron to cancel its "scandalous contract" with the KRG, calling it illegal, contradictory to Iraq's 2005 federal constitution, and unfairly skewed to give the company too high a share in oil revenues.

But Baghdad's seeming lack of success in preventing oil majors dealing with the KRG comes as its own approach to partnering foreign companies to extend and rehabilitate fields in the south and east of the country is coming into question. Royal Dutch Shell, BP, Eni and ExxonMobil were among the first oil companies that struck technical service contracts (TSCs) with Iraq's oil ministry.

But there was limited interest among western companies in the latest auction of TSCs this summer – contracts that might offer little more

> Iraq had overtaken Iran as second-largest Opec oil producer for the first time since the late 1980s

than $5 a barrel royalty and relatively limited incentives for boosting retrieval rates.

The willingness of Baghdad to soften its stance towards the KRG, and ease the relatively parsimonious terms of its TSCs to attract more western interest, remains hard to gauge. After all, in August the International Energy Agency confirmed Iraq had overtaken Iran as the second-largest Opec oil producer for the first time since the late 1980s.

Though this was partly based on sanctions depressing demand for Iranian oil, it also reflected a steady if slow improvement in Iraqi production since the disruptions caused by the US-led invasion 10 years ago.

According to Ben Holland, partner at law firm CMS Cameron McKenna, commercial terms on offer to the north are attractive in spite of political risk. " It's estimated that up to a quarter of the easy-to-reach oil in the world lies under the unexplored acres in Iraq," he says. "That's worth the risk of uncertainty about the legality of the oil concessions in Kurdistan."

But this slow increase in output is taking place against a story of growing social need, pressures on federal budgets, and halting progress on tackling bottlenecks in exports of production directly under its control. This could yet prompt more pragmatism along with hostile public rhetoric in its dealing with the KRG and western oil interests.

Industry battles to fulfil Arctic potential

Barents Sea

Despite some setbacks there is great optimism for the future, writes *Sylvia Pfeifer*

For centuries little has disturbed the tiny island of Melkøya, near Hammerfest, the world's northernmost town. Over the past five years, however, it has been transformed into a transport hub for gas, with huge tankers picking up cargos of liquefied natural gas (LNG) and taking them to Europe, Asia and South America.

The reason for this change lies offshore, 300m beneath the icy waters: Statoil's Snøhvit gasfield in the Barents Sea – the first Norwegian energy project in the Arctic. Since opening the LNG terminal on the island in 2007, Statoil has pointed to Snøhvit as proof of the exploration potential of the Norwegian continental shelf.

And Statoil insists it remains committed to oil and gas exploration in the Arctic, even though it decided earlier this month not to expand the capacity of the Snøhvit project after agreeing with its partners there was not enough gas to justify the move.

Exploration first began in the 1980s and Snøhvit took 20 years to develop and bring into production. At the time the company started it did not have the LNG technology to do it, says Tim Dodson, head of exploration at Statoil.

However, the company's perseverance has paid off. Recent significant discoveries in a newly explored area of the Barents Sea – the Havis oil prospect and another oil find at Skrugard, an adjacent but geologically separate prospect – have "truly opened up" the region, says Mr Dodson. Estimated recoverable reserves across the Skrugard and Havis structures are thought to be between 400m-600m barrels of oil equivalent.

The discoveries have helped vindicate more than 30 years of exploration in the Barents Sea, during which Statoil has been involved in all but five of 94 exploration wells drilled in the area.

According to the Norwegian Petroleum Directorate, up to 6bn barrels of oil equivalent could exist in Norway's portion of the Barents Sea. This does not include an area half the size of Germany, which is set to be opened to exploration after last year's resolution of a four-decade border dispute between Russia and Norway.

As the first large development on the Norwegian continental shelf without any installations on the surface – every day a mixture of natural gas liquids and condensate hydrocarbons is transported 143km through a seabed pipeline to the LNG plant – Snøhvit is also proof of the technical and logistical capabilities needed in the Arctic.

One of the reasons why the Barents Sea has seen more success than other areas in the region is because of the absence of ice. Long regarded as the last great frontier for the world's energy industry, the Arctic remains relatively unexplored and there are only a handful of producing areas.

The tough physical conditions and environmental concerns remain big challenges. In a recent note on the Arctic, analysts from Société Générale

> The area within the Arctic Circle may hold 1,669tn cubic feet of natural gas

cited cost control, ice and the need for infrastructure as key issues facing companies exploring in the region.

Royal Dutch Shell last month had to postpone until next year an attempt to drill into oil-bearing rock off the Alaskan coast after a vital piece of safety equipment was damaged in tests. The company has so far spent $4.5bn and seven years preparing to drill.

Yet the delay has not altered Shell's view of its Arctic programme. The potential prize is too great. According to a 2008 study by the US Geological Survey, the area within the Arctic Circle may hold 90bn barrels of oil and 1,669tn cubic feet of natural gas, respectively 13 per cent and 30 per cent of the world's estimated undiscovered reserves.

Cost remains a problem. In August, Gazprom halted its ambitious Shtokman natural gasfield in the Barents Sea. The group said the company and its partners – Statoil and France's Total – had decided the project development costs were too high. Gazprom insisted talks would continue with its partners about how to best progress.

Calls for lower rates of tax to aid productivity

North Sea

Michael Kavanagh finds some relief for infrastructure plans

Shutdown: the Elgin platform, right, before the blowout AFP

The economic and political repercussions of mechanical failures on offshore rigs and platforms were well illustrated by the blowout at the Elgin installation, operated by Total of France, in the North Sea in March.

In August, the UK's Office of Budgetary Responsibility blamed the Elgin shutdown in large part for an unexpectedly sharp decline in North Sea output that had depressed UK tax receipts in July.

No one was killed or injured in the emergency evacuation from the Elgin complex, 150 miles east of Aberdeen, which once accounted for nearly 10 per cent of UK gas output.

The evaporation of 3,000 tonnes of gas condensate, and the escape of 3,000 tonnes of gas in a well blowout that took weeks to bring under control, has been matched by the evaporation of funds from Treasury coffers. Six months on, production has yet to restart at one the UK's biggest gas producing platforms.

If one clear message has emerged from the Elgin incident, it is that although UK oil and gas output from the maturing North Sea basin is well past its peak, the fiscal health of one of the world's leading economies remains prone to the success or failure of its offshore industry.

Fortunately there are signs that, while the UK sector of the North Sea remains in genteel decline, there is life in the old dog yet.

Last month US group Apache Corporation began installation of a £400m extension of its Forties Alpha platform, aimed at extending the life of one of the UK's most prolific fields, first developed by BP. Meanwhile, at the end of July, Premier Oil confirmed two orders worth £140m for oil platform components destined to be used in production at the Solan field west of Shetland. Both developments typify a two-pronged approach to eking out the remainder of the UK's rapidly depleting oil and gas resources.

While Premier is attempting to bring to shore one of the UK's remaining unexploited resources in remote waters, much of Apache's focus is aimed at extending and improving recovery rates at fields many thought would be abandoned by now.

Apache's decision to extend its Forties Alpha platform, installed its 1975 and designed to last 25 years, will be the most visible of a wave of further exploration and well drilling undertaken as part of a $3.5bn investment programme in the field since its acquisition in 2003.

Apache aims to repeat this trick of sweating assets – developed by oil majors – at its Beryl field, which it bought through a $1.75bn purchase of oil and gas assets from ExxonMobil last September

Such large-scale investments in physical kit come despite warnings last year after a £2bn tax raid by the UK government on North Sea oil and gas operators – which raised marginal tax rates to between 62 and 81 per cent – created fiscal burden and uncertainty.

Industry leaders argued such a move would undermine the confidence of operators in investing to ensure the UK's remaining hydrocarbon resources were exploited to the maximum.

Since then the chancellor has responded to lobbying from oil operators with the introduction of a range of tax allowances. While not reversing the increased rates of tax charged for many operators, they are aimed at reducing the tax bill for those attempting to access more difficult, remote, or smaller pockets of hydrocarbons that might otherwise be left in the ground.

The latest move announced in September – to extend allowances to companies planning extensions to existing fields – signalled an "absolute determination to get more investment in the North Sea, a huge national asset", according to George Osborne, the chancellor.

Simon Lockett, chief exec-

> Large investments in physical kit come despite the chancellor's £2bn tax raid

utive of Premier Oil, says the North Sea remains an attractive arena to explore and develop projects, many of which can benefit from piggybacking on infrastructure developed decades ago. However, tax raids by the former Labour and current coalition governments have not been forgotten.

According to Mr Lockett: "It's possible to get more oil out of the North Sea that is taxed at a decent rate and create jobs for people so yards are getting work."

He adds: "What the government has done by putting in plans for certainty over abandonment liabilities, the introduction of small field allowances and brown field allowances, are a good package of incentives for the industry. But the problem is confidence – and people still remember when the government changed things negatively. People are looking for stable playing fields."

Graham Stewart, chief executive of Faroe Petroleum, which is drilling in both the Norwegian and UK sectors of the North Sea, agrees. He also argues the UK has still some way to go to creating the "feelgood factor" being enjoyed in Norway following several recent oil discoveries.

"The UK has drilled a lot more, so what's left in the UK is much more difficult [to reach]," he says. And attempts to repair the damage done to the sector's confidence "through a patchwork quilt of [tax] allowances" has not been entirely successful.

Nonetheless, the business confidence index from industry lobby Oil & Gas UK shows optimism at its highest since the survey began four years ago. The start of some large projects should see investment in the sector rise from £8.5bn in 2011 to £11.5bn this year.