Kurdistan unhappy as Baghdad opens upstream

By Derek Brower

The IRAQI oil ministry opened six oilfields to foreign companies yesterday in an attempt to boost production to 4.5m b/d by 2013. The announcement will trigger a rush of bidding by companies eager to tap the world’s third-largest oil reserves. The ministry also hopes to sign short-term agreements with a handful of majors in the interim in an effort quickly to increase production by 0.5 m b/d.

Before the ministry’s announcement yesterday, Shell boss Jeroen van der Veer said he hoped contracts with the Iraqi government could be signed “within weeks rather than months”.

But oil minister Hussein al-Shahristani named another 35 companies that will also be allowed to bid for longer service contracts on the Kirkuk, Remila, Zubair and Qa’na West fields. Al-Shahristani described the fields as “the backbone of Iraq’s oil production”. Output is presently about 2.5 m b/d.

Bids must be submitted by end-March, with awards to be made next June. A 25% stake in each contract must be held by an Iraqi company, said the ministry.

However, yesterday in Madrid the minister of natural resources for the Kurdish autonomous region of Iraq, claimed the fields in Baghdad would cost the country “trillions of dollars” in lost revenue, result in slow development of its oil production and contravene the constitution.

In an interview with WPC News, Ashti Hawrami said the technical-service agreements (TSAs) on offer are “likely to fail. We don’t encourage these contracts. It is not in the interests of Iraq or the interests of the companies.”

The KRG yesterday published the results of a study it commissioned to compare the production-sharing contracts it has offered to companies operating in Kurdistan with the Iraqi oil ministry’s proposed risk-service contracts (RSCs).

The report, by consultant Pedro van Meurs and law firm Clifford Chance, concludes that there is “no doubt” the RSC model “would be a real tragedy” for Iraq, and “completely misaligns the interests of the investor and the host government in terms of cost efficiency”.

The report also faults the oil ministry’s TSAs, an interim model that would invite companies to help boost output from producing fields. “International oil companies do not really have an incentive to give good advice. They receive the same consulting fees regardless of the results of the field production.”

Hawrami predicted the contracts would not encourage the majors to invest adequate resources on given oilfields, and asked: “Since when did the majors become consultants?” He also criticised a lack of transparency in negotiations with the majors, who were granted exclusive access to data relating to the fields they hope to develop on short-term contracts.

And Hawrami warned potential bidders companies that they could be blamed when the TSAs fail to deliver the kind of growth in production Iraqis expect. “It is a trap,” he said, adding: “You’ve been waiting five years, wait another five.”

Output of “7m, 8m or 9m barrels a day” would not be achieved by offering companies “loose contracts” that don’t encourage them to develop all of Iraq’s oil.

And Hawrami said any new contracts signed are unlikely to be approved by parliament or the government, given that they will not maximise revenue from Iraq’s resources, as demanded by the country’s constitution. “Anyone sensible will not sign [an agreement],” he added.

“If you don’t have a legal framework it will end in tears.”

Iraq’s cabinet agreed a proposed oil law in 2009, but opposition to the KRG and others has so far prevented it from passing into law.

By Tom Nicholls

PETROBRAS won’t seek privileged access to unlicensed parts of Brazil’s pre-salt province, José Sergio Gabrielli, the firm’s chief executive, said yesterday.

“We are not looking for kind of privilege,” Gabrielli told WPC News. He added that unitisation agreements with neighbouring acreage holders would be necessary if reservoirs identified by Petrobras continue into other blocks.

However, he would not comment on a proposal by Brazilian energy minister Edison Lobao last week to set up a new national oil company to oversee development promising sub-salt layer acreage that has not yet been licensed to exploration firms. “The decision to do a 100% state-owned company is a government decision. Petrobras has nothing to say on that.”

Petrobras has made a string of large discoveries in the Santos basin’s pre-salt frontier, in deep water offshore Rio de Janeiro. Its Tupi field alone could hold up to 8bn barrels. Petrobras plans to commence an extended well test in the first quarter of 2009, producing 20,000-30,000 barrels a day (b/d). Flows will rise to 100,000 b/d in 2010, when a pilot project comes on stream and the ramp-up to full output – 1m b/d has been discussed – will probably not occur until after 2014.

Other nearby discoveries hold even greater promise. In April, Haroldo Lima, head of Brazil’s upstream regulator, blurted out that the reserves in Petrobras’ Carioca field might amount to as much as 33bn barrels of oil equivalent (boe).

Petrobras quickly distanced itself from those remarks, saying it had drilled only one well in the area and could not produce a reliable reserves figure. It is likely to be several months until the company is able to start work on a second well at the field, because its rigs are all in use elsewhere, said Gabrielli.

Petrobras is producing about 1.9m b/d in Brazil and 2.3m boe/d worldwide. Not including production from pre-salt discoveries, it aims to lift that to 3.1m boe/d by 2012 and to 4.1m boe/d by 2015.
BP calls for new model for IOC-NOC relations

By Derek Brower

INTERNATIONAL oil companies (IOCs) must move beyond the “historical model that requires ownership of reserves and production” as the sector adapts to an era of rapidly rising demand and high energy prices, Tony Hayward, chief executive officer (CEO) of BP, said yesterday.

Speaking to delegates at the WPC in Madrid, the BP boss said national oil companies (NOCs) and IOCs must co-operate better if the industry is to satisfy rapidly rising demand.

Hayward echoed comments by Total chairman Thierry Desmarest, who said earlier this month that his company’s agreement with Gazprom to develop the huge Shтокman gasfield, in the Barents Sea, could be a new model for relations between IOCs and NOCs.

And yesterday Shell’s CEO, Jeroen van der Veer, said joint ventures between Gazprom and foreign partners are likely to follow the Shтокman model (see right).

The Shтокman agreement, which also includes Norway’s StatOilHydro, gives the foreign partners a minority stake in the company developing the field. But Gazprom says it will own all of the reserves at Shтокman. Analysts have described the deal as a “glorified service contract”.

BP’s Russian joint venture TNK-BP was last year forced to sell its stake in the large Kovykta gasfield, in Russia, to Kremlin-controlled Gazprom. The UK major has since sought to tie up a strategic agreement with its Russian gas partner.

Hayward’s words yesterday were a concession to the shift in power of recent years from the majors to resource-rich NOCs. Iraq also indicated yesterday that it would seek to hire a host of IOCs as service providers for upstream developments. BP is likely to be among the bidding companies.

NOCs hold 80% of global reserves, noted Hayward, but IOCs still hold technological skills, know-how and operating experience. “We need more partnerships, more joint ventures, and more alliances,” he said. “In my opinion, the time has come to develop new forms of contractual relationships that move beyond the historical model that requires ownership of reserves and production.”

Meanwhile, Hayward also called for governments to lower taxes on oil firms in order to boost sluggish production growth around the world, which he said failed to respond to rapidly rising demand.

Taxation has become “dangerously high” for oil companies, he said. “Any future for humankind is going to depend, for a long time to come, on fossil fuels and coal is the fastest growing fuel type.”

And while demand from developing countries continues to drive demand, Hayward said oil companies must retool and refire to keep up. “We need to get people and resources in the right place. We don’t have enough experienced scientists and engineers. We have too few university graduates with the right qualifications and training, and not enough are joining our industry. To compound the problem, many of the most well-qualified people in the industry are close to retirement.”

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Amendments to Social Responsibility

Global Village programme

(Stand 7460, Pavilion 7)

Tuesday, 1200-1230 CDA: Corporate Engagement Project (CEP)

Wednesday, 1030-1100: Spanish Guitar/ Guia-Shell: Program of socio-environmental capacity building and mobilisation

1430-1500 Engineers Against Poverty: Engineer Against Poverty and Amenc

Awards results

Youth award

Best young author:

Jaime Turazzi Naveiro, Petrobras

For large companies:

Sarkhoon Gas Treating Plant’s Oily

For small to medium-sized companies:

Responsibility of Overgas

Responsibility of Overgas

Social Responsibility category:

Gas Development and Utilization

Jifeng Liang, China Offshore Oil and

Title of paper: Putting talent at the heart

Laura Watt, Accenture, UK

Aquino, Pedro Leonardo Neves

Co-authors: Fernando Mauricio de

Jaime Turazzi Naveiro, Petrobras

Best young author:

Youth award

Engineer Against Poverty and Amec

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mental capacity building and mobilisation

Gaia-Shell: Program of socio-environmental capacity building and mobilisation

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So you’ll have an idea how deep we go in the pursuit of energy.

Cap, trade, capture and store carbon, please – but no EU subsidies

By NJ Watson

A COMBINATION of systems to cap and trade emissions, and to capture and store carbon, is the only sustainable way to meet the world’s demand for energy over the next 50 years, but don’t expect the European Commission to subsidise this, delegates were told yesterday.

“From the EU side, the most we can do is to provide the legal framework and also to support research and development activities, but you can clearly read my lips: there is never an intention to have subsidies for carbon capture and storage (CCS),” Andris Piebalgs, the energy commissioner for the European Commission, said.

The EU, which now believes CCS technology can reduce CO2 emissions on a “massive scale”, is planning to build 10-12 industrial-scale demonstration projects, costing some €1bn each.

“The only subsidies for CCS we are seeking are as demonstration projects, produced on how to support all CCS in a safe and transparent way,” says Piebalgs.

Jeroen van der Veer, Shell’s chief executive, said CCS – together with cap-and-trade systems like the EU’s Emissions Trading Scheme (ETS) – form a two-pillar approach that Shell sees as the only realistic way to reduce emissions while continuing to deliver the energy that the world needs to prosper.

“We need to deliver all the energy we can from many different sources. We need to grow the renewable business and continue to develop the fossil fuel business,” said van der Veer.

However, one pillar can’t survive without the other – something that politicians in many parts of Europe seem unable to understand, he added. He said many believe the only purpose of capping and trading carbon emissions is to penalise the use of fossil fuels, which in turn would stimulate the development and use of alternative energy sources, particularly wind and solar. “I think those people are wrong,” he said. “We need both CCS and ETS, and we need both at the same time, one can’t be successful without the other.”

The EU’s ETS, despite its flaws, is generally regarded as having done a fairly successful job of driving down emissions. “It remains far from certain whether a global agreement could ever be achieved,” But BP’s chief executive, Tony Hayward, is optimistic that progress will be made.

Carbon trading is starting to have a global market structure, with regional blocks in the US, Europe and Asia, and with regional markets such as California already talking about joining up with the EU’s ETS system, the market appears to be doing its work and “a global price for carbon will soon emerge.”

RasGas LNG mega-trains on track for 2009 start-up, despite Gulf challenges

By Alex Forbes

QATARI LNG producer RasGas is confident of bringing both its new LNG mega-trains on stream during 2009, despite Gulf shortages of materials, said Al-Muhannadi, “and the equipment vendors are also experiencing some delays. The industry as a whole has experienced a crunch – so we have been affected by what is going on around us.”

Another challenge for RasGas will be the new technology being used for what will be the world’s largest gas liquefaction trains. “We did experience some problems with Train 3, but we had fewer problems with Train 4, and with Train 5 things were pretty smooth,” said Al-Muhannadi. “With Trains 6 and 7 – because we have built this experience – we have teams that have been dedicated to really understanding the new technologies that are coming.”

But Van der Veer said any cap-and-trade system must eventually include all the OECD countries, plus Brazil, Russia, India and China; and greenhouse-gas emissions certificates should be fully convertible across those markets.

Given the difficulties that the EU’s 27 governments have had in agreeing on the structure of the ETS, it remains far from certain whether a global agreement could ever be achieved.

A more interesting question, said Gautier – who had been speaking at a Congress session entitled Chasing the third trillion – would provide precise guidance on the United States.

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USGS looks towards fourth trillion

By Tom Nicholls

THERE are around 0.5 trillion barrels of conventionally recoverable oil yet to be found in undiscovered fields and “probably” over 100bn barrels in the Arctic. Donald Gautier, a geologist at the US Geological Survey (USGS), told delegates yesterday.

The USGS, a government-funded research organisation, is due to publish an assessment of the Arctic’s hydrocarbons potential in the next few weeks. That study, said Gautier – who had been speaking at a Congress session entitled Chasing the third trillion – would provide precise guidance on the United States.

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“We need to deliver all the energy we can from many different sources. We need to grow the renewable business and continue to develop the fossil fuel business,” said van der Veer.

However, one pillar can’t survive without the other – something that politicians in many parts of Europe seem unable to understand, he added. He said many believe the only purpose of capping and trading carbon emissions is to penalise the use of fossil fuels, which in turn would stimulate the development and use of alternative energy sources, particularly wind and solar. “I think those people are wrong,” he said. “We need both CCS and ETS, and we need both at the same time, one can’t be successful without the other.”

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Sanctions, underinvestment, internal squabbling, rising costs, schedule delays: take your pick of the problems that face Iran’s ambitions to become an exporter of liquefied natural gas (LNG). The country has them all, and not even the world’s second-largest reserves of natural gas is enough, it seems, to counter them.

In May, Shell and Repsol YPF withdrew from their role in Persian LNG, one of several proposed LNG plants in Iran. After negotiations with state-owned National Iranian Oil Company (NIOC), the two Western firms agreed a complicated deal: instead of developing phase 13 (including phase 14, which was rolled into the project) of the South Pars gasfield, which would have supplied the LNG plant, they will develop an as-yet undeclared future phase. Rumours say it could be phase 20 or 21, or both.

The world’s largest gasfield is divided between Qatar and Iran. And the contrast between Qatar’s development of its North field and Iran’s progress on its side of the border at South Pars is stark. In Qatar, the North field already supplies gas for five LNG plants, giving total exports of 30.2m tonnes a year (t/y). Another five are under construction and will add 46.8m t/y to capacity. The pace of development has been so fast that Doha has imposed a moratorium on new projects.

Analysts joke that in the time it takes Iran to decide to build an LNG project, Qatar brings one on stream.

Meanwhile, cost inflation has also afflicted Iran’s LNG programme. The investment needed on Persian LNG had risen from $2.25bn to $10.0bn – and may have gone beyond that, says Samuel Ciszuk, an analyst at Global Insight, a consultancy. The cost of Pars LNG, a smaller proposed plant in which Malaysia’s Petronas and France’s Total are partners, is likely to exceed $11bn.

Amid the uncertainty, Iran’s ultimatum to the Western investors to commit to their projects by June may also have forced the Persian LNG partners’ hand. The government’s urgency could be related to its claim that Qatar’s development will see gas migrate from Iran to the North Field side of the reservoir. But even if that is true – and there is no evidence it is – the tactic may have backfired.

Total says it remains committed to its project, which includes development of phases 11 and 12 of South Pars, with the latter to supply the LNG plant. But analysts are less sure. Chief executive Christophe de Margerie has been careful to say Total is in Iran “for the long term”, suggesting another postponement is on the cards.

And following Shell’s and Repsol YPF’s decision, the government has reshuffled its programme for South Pars, with domestic gas needs the priority and LNG now on the back burner, says Ciszuk. Indeed, if Shell and Repsol YPF take on phases 20 and 21, that will have other implications, given that those phases were to have supplied the Iran-Pakistan-India pipeline.

The upshot is that LNG exports appear as far away as ever, with Iran happy to develop its gas for domestic needs now and leave the exports for later. It leaves the majors holding on, waiting for the winds to shift.

Uncertainty surrounds Iran’s LNG ambitions

By Derek Brower

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“Iran is always a possibility, but something needs to change,” says Frank Harris, an LNG analyst at Wood Mackenzie, of the country’s export plans. Between sanctions, rising domestic gas needs and internal opposition to exports, the size of the resource is the only aspect of Iran’s LNG programme not in doubt. But Harris remains doubtful that any project will come on stream soon. “If you put out statements that you’re going to buy LNG from Iran, that shows that you’re not serious.”
THE MESSY, costly business of extracting oil from tar bitumen of Canada’s oil sands is roundly condemned by environmentalists and Canadian governments, led by California, draft legislation to ban the use of gasoline derived from sources that produce more GHGs per a unit of energy.

All that coincided in May with TV footage showing 500 dead ducks in a toxic-waste pond at Syncrude Canada, the world’s largest oil-sands producer. They were trapped when noise-making cannons used to drive off waterfowl could not be activated during a spring snow storm.

The oil sands have drawn negative attention when dealing with multi-billion-dollar cost overruns, fires and explosions at plants, and evidence that the industry is the most concentrated source of GHG emissions in Canada. But nothing has garnered adverse publicity on the scale of the waterfowl incident. Prime minister Stephen Harper, a vigorous advocate of the oil sands, described the duck deaths as a “terrible event” that would harm Canada’s reputation internationally. Bruce March, chief executive of Imperial Oil, a partner in Syncrude, said he was “deeply upset”. But he insisted that, with 13% of the world’s known oil reserves in Alberta, the only answer is to take up the environmental challenge.

The pace of development in Canada’s oil sands has accelerated in recent years. Projects valued at C$121bn ($12bn) are in various stages of development and output is forecast to grow from 1.4m b/d to 3.5m b/d by 2015, with two-thirds destined for US markets.

One of the most telling developments in 2007 involved joint ventures and partnerships to share production and US refinery capacity, with ConocoPhillips forming a partnership with EnCana, BP joining forces with Husky, and Marathon taking a 20% stake in Shell Canada’s Athabasca project. All three plan to invest about $15bn by 2015 in refining and their US refineries to process greater volumes of Canadian heavy blends.

To ease a transportation crunch, the National Energy Board handled applications in 2007 for 0.885m b/d of new pipelines and has more than 2m b/d more on the horizon if Enbridge, TransCanada, Kinder Morgan and Algonet Energy secure shipping commitments to establish a final link from the oil sands to US Gulf Coast refineries, which face falling deliveries from Mexico and Venezuela.

Wood Mackenzie, a consultancy, predicts pipeline firms and US refiners could spend $31.5bn in the US over the next eight years to handle oil-sands output. But the developments are on a collision course with environmental issues. Two rulings in May by the Federal Court of Canada threaten to delay by over a year Imperial’s plan for its C$8bn Kearl oil-sands project, which was due on stream at 100,000 b/d in 2011, growing to 300,000 b/d in 2018.

Challenged by environmental groups, the court ordered an environmental assessment panel to explain how it had decided GHGs from Kearl would not be significant. A second court hearing revoked a federal water permit allowing Imperial to divert two streams while building its Kearl site.

Shawn Denstedt, a lawyer representing Imperial, said the company has so far invested C$228m in Kearl, including C$52m to obtain the water permit. “It did nothing wrong,” he said. “The consequences are disproportionately dire in the face of a minor error” by the environmental panel. The government must now decide whether to issue the water permit, running the risk of a more protracted court action, or rewrite the rules.

Meanwhile, the Canadian government is drafting regulations to cut GHGs by 20% below 2006 levels by 2020 and by 60% by 2050, a prospect that investment firm Raymond James says that if GHG taxes amount to $15/ton, companies might “cite producers to shift exploration and development to other jurisdictions where GHG limits are less stringent or non-existent”.

Noting that oil prices of $70/b are needed for oil-sands projects to generate a return on investment of 8.5%, Justin Bouchard, a Raymond James analyst, says that if GHG taxes amount to $15/ton, companies might turn their attention to US shale-oil prospects. On top of labour costs and waste disposal, a federal climate change plan could impose “draconian” costs on the sector, he said. Gary Taylor, with the law firm Bennett Jones, doubts the industry is prepared for the upcoming climate-change legislation that could cost oil and gas companies at least C$8bn a year. Those gathering storm clouds are a threat to Harper’s dream of making Canada a “global energy superpower”, underpinned by the oil sands.
The Spanish Organizing Committee would like to extend a “Thank you” to the Sponsors of the 19th World Petroleum Congress for their support and commitment to this prestigious event.
High hopes for new deal in Nigeria

By Martin Quinlan

President Umaru Yar’Adua is nothing if not a reformer. In office alone, he has set out to break up the state’s Nigerian National Petroleum Corporation (NNPC) and to reform arrangements governing onshore and offshore oil operations in order to raise production. In mid-June, Yar’Adua set an ambitious output target of 4m b/d to be reached by 2010, double today’s level.

The plan calls for the country’s joint-venture (JV) agreements – the older agreements, covering most of the onshore and shallow-water fields, which account for over 80% of production – to be replaced by “incorporated joint ventures” (IJVs). These will be single corporate entities in which companies and NNPC hold interests, operating with their own boards of directors and – crucially – with the ability to raise capital and borrow commercially.

To tackle the immediate financing crisis, Shell, ExxonMobil and Total have agreed to lend NNPC a combined total of $6.1bn this year

Under the country’s present JVs – derived from the participation agreements resulting from the nationalisation moves of the 1970s – capital and operating expenditures are financed by monthly cash-calls, which the parties are obliged to pay. The problem is that NNPC is often short of cash and cannot pay – the company’s revenues from its shares of production go to the government, leaving it lobbying for funding in competition with the numerous other state-owned entities.

The amount of funding available to NNPC sets a ceiling on the volume of work that can be carried out. But if the JVs became IJVs, the new entities could raise funding by borrowing internationally against their own assets and cash-flow, with repayments made from production income. The volume of work could then rise to the levels the IJVs consider appropriate.

To tackle the immediate financing crisis, Shell, ExxonMobil and Total have agreed to lend NNPC a combined total of $6.1bn this year to cover arrears and kick-start projects. In May, Total said it would loan $1bn to NNPC to fund its portion of its upstream JV operations. NNPC will pay Total back in cash, not with crude as was the case in the past. Later that month, Yar’Adua set an ambitious output target of 4m b/d to be reached by 2010, double today’s level.

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Licensing confusion threatens India's image

By Ian Lewis

A WRANGLE over tax concessions is stalling efforts to carry through India’s latest round of exploration licensing. The seventh round of the New Exploration Licensing Policy (Nelp 7) was launched in December, with 57 blocks up for grabs, of which 19 are in deep water, nine shallow-water and 29 are onshore.

The bid deadline was set originally for 11 April, but that target has been extended three times, with the latest one being 30 June. The government says demand for licences has been high and that the delays have given “prospective bidders more time to prepare their bidding strategy”.

But industry sources say a stumbling block has been confusion among potential bidders over changes to tax incentives offered under the Nelp framework. Under Nelp 7 legislation, “mineral oil” activities are eligible for tax holidays, but a dispute has flared up between the finance ministry and the oil ministry over whether gas, as well as oil, is covered by the term.

The oil ministry says historically gas has been covered by the term “mineral oil” and should continue to be so, but the finance ministry says gas should be excluded and not benefit from the same incentives. As companies often do not know whether they will discover oil or gas, differing incentives make a big difference to whether they will discover oil or gas, differing incentives has been high and that the delays have given “prospective bidders more time to prepare their bidding strategy”.

It’s also worth noting that the government hopes to attract around $3.5bn of investment through Nelp 7, given the $2bn forthcoming from the six previous Nelp rounds since 1999. These have resulted in around 50 discoveries, adding around 4.5bn barrels of oil equivalent (boe) reserves.

The licensing delays come at an inopportune moment for the government, which is desperate for investment in the sector to add to reserves and boost production to reduce its oil-import bill. Domestic oil reserves at the end of financial year 2006-07 were a little over 5.5bn barrels, with gas reserves of around 1.1 trillion cubic metres, according to the oil ministry. Domestic oil output in 2006-07 stood at 0.65m b/d, falling short of refinery runs of 1.1m b/d.

The failure to boost domestic production significantly over the previous five years – it was 0.65m b/d in 2000-01 – indicates how badly the country needs to reinvigorate its exploration programme. But the Nelp years have been marked by some success. Reliance’s large deep-water gas discovery in the Krishna-Godavari basin in 2002 is scheduled to start production this year. With anticipated reserves of around 200bn cm, initial production of 40bn cm/d will rise to 80bn cm/d within a month, the company says.

Some market observers speculate that the imminent start-up of this new supply will force the finance ministry’s efforts to reduce tax breaks for the gas sector may not be unconnected.

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Spain’s double-digit gas growth set to continue

By Alex Forbes

SPAIN’S use of gas is likely to be in double-digits again this year, following the commissioning of numerous gas-fired combined-cycle gas turbine (CCGT) power stations over the course of 2007. Since 2002 the number of CCGTs has soared, with 14 400 megawatt groups commissioned in 2007 – taking total installed CCGT capacity to 21 gigawatts (GW). Gas had become the main source of energy for electricity production in Spain.

This wave of CCGT investment mirrors the UK’s dash for gas in the 1990s and has occurred for similar reasons: liberalisation of the gas and power sectors during the 1990s; low energy prices when the trend began; relatively low cost of CCGTs; and the environmental advantages of gas over coal and oil.

CCGTs also keep the Spanish electricity system balanced. By end-2006, Spain had 11 GW of installed wind capacity – but with that capacity dependent on wind conditions, other types of generation, mainly CCGTs, are needed to back it up. In 2006, wind power accounted for 23 terawatt hours (TWh) of generation, around 2,000 full-load equivalent hours of production, a load factor of under a quarter.

Industry accounts for most of Spain’s gas sales, but the power sector is catching up. In 2000, sales to the sector were under 1bn cm; by 2007 they had risen to 12.2bn cm. In January 2008, says Eragás, demand for gas for electricity generation was up by 31% on January 2007’s figure.

Imports account for 99.8% of supplies. Algeria is the largest supplier, exporting through the Pedro Duran Farel pipeline and as LNG. But its role is falling: to ensure a diversity of suppliers, Spain has set a maximum market share for any one country of 60% – almost exactly the share of supply that Algeria held in 2000.

Iberdrola, Endesa and Unión Fenosa have entered the gas market to compete with incumbent Gas Natural, securing gas for power plants through LNG, which now accounts for more than two-thirds of supply. According to estimates, this has required capital expenditure in gas infrastructure of €9.34bn between 1998 and 2007. And the government is devising policies to stimulate more investment.

Along with the UK, Spain leads the EU in the ease and regularity with which customers can switch supplier.

The preponderance of LNG has helped make Spain the most liberalised market in continental Europe. At the start of 2008, the regulated market disappeared completely. Along with the UK, Spain leads the EU in the ease and regularity with which customers can switch supplier.

The trade association Sedigas says that in 2007, the liberalised market accounted for 42% of gas sales to the residential and commercial market, and 89.8% of sales to industrial consumers.

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Companies with no moral basis do not deserve to survive and probably won’t

By Geoffrey Chandler

T HE END of the Cold War, and the decrediting of Communism and of state control of national economies offered vast opportunities to the oil industry. The countries of the former Soviet Union and established oil producers in the developing world opened up to Western companies, providing access to previously inaccessible reserves.

They also brought social and environmental challenges, problems of insecurity and human-rights violations, for which companies were unprepared. Without appropriate policies, companies made worse, rather than improving, the situations they confronted. The benefits they brought to the world were too often accompanied by collateral damage – with the 1989 Exxon Valdez oil spill and the 1984 Bhopal gas tragedy, in which some 3,800 people died, enduring reminders.

By the turn of the century, about 70% of oil and gas reserves lay in countries with poor human-rights records. Oil companies reckoned this was none of their business. The human-rights movement was also slow to recognise the significance of potential corporate influence on human rights for good or ill. Companies and non-governmental organisations (NGOs) regarded each other with a mutual ignorance, suspicion and dislike. No-one was prepared to cross this no-man’s land, although it should have been clear to both – as it became later – that each was dependent on the other if it was to attain its objectives.

In 1991, a group of Amnesty International UK members set up a business group and asked me to chair it. As I spoke, as it were, both languages (industry and NGO) having been a director of Shell International and having spent six years as chair of the National Council for Voluntary Organisations; I agreed. Its objectives were to make companies aware of the human-rights context in which they operated and encourage them to use their influence to support these rights.

I went to Shell, BP and the other major UK-based transnational companies suggesting that the protection of human rights should be written into their business principles. The response was negative. Shell said this was the domain of governments, not business; Robert Horton, chairman of BP, said I was ‘asking him to stand at the top of a very slippery slope’. Within four years, both companies, suffering unprecedented reputation disaster over human-rights issues – Shell in Nigeria and BP in Colombia – were asking Amnestee’s help to develop human-rights policies relevant to their business responsibilities.

This was the watershed. Two of the world’s largest companies acknowledged the relevance of the UN Universal Declaration of Human Rights (UDHR), of which they had been previously unaware, making it a basis for business policy and setting an example others were to follow. In less than 10 years, there has been a sea change. Today, nearly 100 transnational firms acknowledge the UDHR as a basis for their business principles.

There is, however, a growing underestimation of the significance of potential corporate influence on human rights for good or ill. Companies and NGOs are not always conscious of or interested in human rights issues – Shell in Nigeria and BP in Colombia – were asking Amnestee’s help to develop human-rights policies relevant to their business responsibilities.

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The shift in the country’s fortunes began in June 2007, when US firm Kosmos Energy announced its Mahogany-1 discovery in the West Cape Three Points block. The now-called Jubilee field is the “largest discovery made in deep-water west Africa since 2005”, Kosmos, claims. Follow-up wells, the third and fourth, drilled west of the field, drilled in May, chief executive James Musselman said this was the domain of governments,

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‘Immense benefits’ of a culturally and gender-diverse workforce

By Tom Nicholls

INTERVIEW with Jim Andrews, head of diversity at Schlumberger.

Q Why have women historically made up such a small percentage of the oil and gas industry’s workforce?

A I think there are two principal reasons. First, engineering as a profession has always attracted fewer women than men. Sadly, this continues to be the case, although it is pleasing to see a shift in this trend in universities in China and India, for example. Second, the oil and gas industry has always had a very macho label associated with it. This inevitably acts as a barrier and makes it a less attractive career choice for many women. As an industry, I think we have only woken up to benefits of having a gender-diverse workforce over the last few years.

Q What can and is being done about this situation?

A I think a lot is already being done and in many, many parts of the world, women are commonplace in the industry. However, there remains a compelling need for the industry to market itself better into academia, particularly into the school systems around the world. We all know that this is an incredible industry, but we need to sow this seed into the minds of 13-16 year olds to ensure the brightest join us in the future.

Q In what ways does having a more balanced workforce (between women and men) make that workforce more efficient?

A I also believe that the workplace becomes more natural and more appealing to today’s graduating population when there is a balanced workforce. No where is this more apparent than when I visit one of our training centres and see 400-plus new trainees living and working together. I am not sure we could attract the number and quality of people our industry needs for the future if we expected them to work and live in an all-male environment.

Q What is Schlumberger’s strategy for boosting the recruitment of women?

A Schlumberger has always recruited graduates in large numbers and we maintain very close links with academia in all the countries in which we work. The recruitment of women is really no different to that of men, although we do have scholarship programmes in some universities that specifically target women.

The internet provides today’s graduates with access to an unprecedented amount of information. They appear less impressed by glossy promotion and marketing material and instead use the web and social-networking sites to find out what our companies are really like to work for. We are very focused on ensuring that Schlumberger offers an equally attractive career to both men and women and this seems to be working with our reputation on campus.

Q Over the last few years, have you seen a change in the numbers of women coming into the business or an improvement in the numbers of applications? If so, why?

A Without a doubt there has been a change in the number of women entering the industry. In Schlumberger, over the last decade we have nearly doubled the percentage of female graduates we recruit and in 2008 over 30% of our new engineers will be women.

But perhaps what is even more exciting is that we increasingly see our women wanting to stay in the industry. In the early 1990s, we started recruiting women in greater numbers, but because we were still welcoming them into a very male-dominated environment, unfortunately many did not stay. Having worked hard to make sure we are an attractive employer to genders, it is pleasing to now see the same low attrition numbers from both our men and our women.

Q How does the picture look in engineering and also in management?

A To achieve real diversity within an organisation where advancement is truly based on merit takes time. The diversity of nationalities that Schlumberger enjoys today owes its success in no small way to some far-sighted decisions made by the management team 50 years ago.

Since 2000, we have doubled the number of professional women in Schlumberger and doubled the number of women in management at all levels, from first-time managers to the executive team. This is real progress, but we still have a long way to go. Women now make up over 16% of our management team and we expect the gender diversity of our professional workforce to continue to improve. Ultimately, we will have achieved the same success with gender as we have nationality diversity when the management of the company reflects the same percentage of women as our recruitment targets.

Q What are the challenges in improving diversity in this area for the oil and gas industry in general?

A The industry has made huge strides forward over the last 10-15 years on nationality diversity. Nationalisation of the workforce is now the norm in most countries where we work and this increasingly translates into much greater diversity of nationalities in management teams.

However, we should not kid ourselves that everything is going in the right direction. We still have some way to go in successfully marketing our industry as attractive to graduates of both genders, but in particular women. Although we often have to work in harsh environments, it is important that we continue to improve those field locations where basic facilities and accommodations for men are sub-standard and for women non-existent.

The immense benefits of having both a culturally and gender diverse workforce clearly outweigh the relatively low cost of improvement and making the workplace and our industry attractive to all.
Egypt opts for pragmatism

**By Derek Brower**

**Egypt says it will pay more for deep-water gas. Will that trigger a new era of offshore development?**

With a population of over 80m and an economy growing at almost 7% a year, rising demand for gas – now at about 1.56trillion cubic feet a year (cf/y) – alone ought to provide the incentive for Egypt’s deep-water developers. Yet the successes of a few years ago, when the UK’s BG alone successfully drilled 19 exploration wells in the West Delta Deep Marine (WDDM) concession and Egypt brought two LNG plants on stream by 2005, have scarcely been repeated.

For operators with an eye on the export market, the problem has been the country’s energy policy. Energy minister Sameh Fahmy famously said Egypt’s gas must be divided three ways: for domestic use, “for our children” and for export. Yet subsidies for domestic gas use continue to stimulate the demand.

Combined with cost inflation, the low price the government offers for gas from east/lower offshore regions has often made projects unattractive. BG, it is understood, would like to invest up to $1bn upgrading its 0.8bn cm/d Rosetta development. But the price offer – around $2.65/m Btu – makes it unattractive to sell.

But change is afoot. Lobbying by IOCs yielded one success last summer, when the government agreed to increase the price state-owned Egyptian General Petroleum Corporation pays BP and its partner RWE Dea for gas produced from two licences in the Nile Delta: West Mediterranean Deep Water and North Alexandria. For gas produced in the shallow waters to 2009, the companies will continue to receive $2.65/m Btu. But that will increase in stages to up to $4.70/m Btu for gas from deeper waters.

Earlier this year, the government extended this to other producers, offering a maximum price of $3.95/m Btu for gas from five other concessions, including RWE’s North Idku, Eni’s and Hess’ North Bardawil and West Mediterranean Block 1 and BG’s Rosetta and WDDM projects.

The new approach reflects the government’s pragmatic approach, says Craig McMahon, an analyst at Wood Mackenzie, even if it probably won’t help Egypt meet its target of 120 trillion cf in reserves by 2010. Look around the world at the actions of other governments in the energy sector, says McMahon, and Cairo’s willingness to listen to the IOCs is encouraging.

There wasn’t much else the government could do, says Bill Farren-Price, an analyst at Medley Global Advisors. “The sector had been grinding to a halt.” In deed, natural gas in Egypt is becoming something of a premium. Plans to export through an extension of the Arab gas pipeline – which supplies 39bn cm/y to Jordan – are on the back burner. OMV’s ambition to import Egyptian gas through a pipeline to central Europe is out of the question.

Beyond Egypt’s own market, the biggest hope of operators is to find sufficient gas to support another LNG train. Of the two existing plants, at Idku (ELNG) and Damietta (ELNG), the second is attracting most attention. That reflects the diverging upstream fortunes of the two companies that are racing to find enough gas to support a new train. BG has long hoped to develop a third train at ELNG. But since finding enough gas to support the first two trains, its upstream record has been modest. Its decision to pull out of Israel could free up to 1 trillion cf for sale from a field offshore Gaza, but that would account for only a third of the gas needed to support a new train.

**Significant discovery**

BG, meanwhile, hopes recent finds will support a second train at Segas. In January, the company announced Satis, a “significant” gas discovery in the North El Burg concession it shares with Eni, in the Nile Delta: its second large discovery in the Nile Delta in a year. The Giza North-I well in Taurus, announced in 2007, and Raven, found in 2003, are both within the nearby North Alexandria A concession the companies share with RWE Dea.

Giza-1 could hold 1 trillion cf. But BP has not said yet what volume of gas it has found in the other two fields. Local reports put Satis at 1.3 trillion cf. Raven, according to rumours, could hold as much as 5 trillion cf. With an estimated 3 trillion cf needed to support a second train at Segas, the recent discoveries could put up to 7.3 trillion cf at the company’s disposal. But subtract two-thirds for Egypt’s domestic use and that still leaves BP short of the necessary volumes to support a new facility in Damietta.

**Kremlin freshens up its energy strategy**

**By Derek Brower**

Where Dmitry Medvedev, Russia’s new president, redrafted the presidential administration in May, the stock exchange soared. But domestic gas-price increases and a reduction in taxes on oil companies could prove an even bigger boon to the country’s energy industry.

Europeans – who import over 150m cubic metres a year (cm/y) of Russian gas – have long called on the Kremlin to bring prices for domestic supply into line with prices paid in the European Union (EU). Gazprom, which needs money to invest in the country’s upstream, would like the same. The company it lost R38bn ($380m) in 2006 and R11bn in 2007 by selling gas to domestic users at controlled low prices. Consumers in Russia pay $50-75/cf, compared with prices of $2.65/m Btu in the US.

Within a week of Medvedev becoming president, the Kremlin approved a plan to approve a second policy to increase prices to households by 25% next year, by 30% in 2010 and by 40% in 2011. Lifting domestic price controls would help Gazprom raise money to pay for new exploration in the Arctic and other frontier regions. The company has set up plans to spend almost R1 trillion over a decade, 25% in 2010, compared with an outlay of R330bn last year.

Domestic price rises will face opposition. Inflation in Russia was around 12% in 2007, and in a country accustomed to energy conservation, paying more for gas will come as a shock. “Household prices will still be lower than industrial prices in 2011,” says Jonathan Stern, a Russian energy analyst at the Oxford Institute for Energy Studies, “but they will rise faster than expected.” That does not necessarily mean the gap with European prices will close by 2011, however. Stern says that when the government pledged parity last year it had not expected European prices to accelerate so quickly. And reaching European levels now does not cover further expected price rises in Europe by 2011.

But if the Kremlin holds firm, it should trigger other improvements in the Russian economy by pushing industry to replace inefficient capital stock, much of which has not been updated since the Soviet period and remains grossly inefficient. Stern says evidence from Ukraine, where Gazprom has raised prices since 2006, shows that once the level hits $100-700/kwh, firms begin to replace wasteful machinery.

Meanwhile, oil taxes look likely to fall in 2010 due to a new greenfield tax for firms working in Timan-Pechora and the Yamal Peninsula. He added that output should rise by 1.3m b/d by 2015 and hinted at another cut in taxes, by raising the exemption threshold from $9 a barrel to $15/b.

Of as much interest, however, is the reshuffling of seats in Russia’s energy sector. Recent announcements suggest that while Gazprom’s future will remain the domain of the Kremlin, oil policy will be within the realm of the prime minister’s office. The replacement of Viktor Khristenko with Sergei Shmatko as energy minister implies that the ministry’s emphasis will also change. Shmatko was formerly head of AtomStroExport, a state-owned nuclear-technology export firm.

The role of Igor Sechin, who headed the oil faction in the Putin Kremlin, is unclear. Medvedev has appointed him as a deputy prime minister and the new director of energy policy. One of the so-called siloviki (hawks) of the previous administration, Sechin was widely assumed to come from the oil faction in the Putin Kremlin, is uncertain. Medvedev’s pragmatic approach, says Craig Brown, is that the oil faction continues to represent the interests of Gazprom. It was the success of that lobbying on behalf of Rosneft that won the tax concessions for the oil sector last month, runs that theory.
Opec and the dollar

If Opec pulled the plug on the dollar, the financial turbulence of the last year could be eclipsed by even greater problems. But the cartel will not take the step

By Derek Brower

You OWN the world’s most valuable commodity. And when you sell it, the buyer gives you a piece of paper whose value has plummeted for months. In these terms, it is not hard to see why Opec members wince when they talk about the persistent weakening of the dollar. They sell oil, they receive dollars in exchange and when they come to use them – to buy food, luxury goods, weapons and whatever else they need to import – they find that the currency is now worth a little less than it was when they sold the oil.

The erosion of the oil producers’ purchasing power is part of a cycle that is, to a large extent, out of their hands. As the US economy has spluttered, the Federal Reserve has cut interest rates in an effort to rescue it from full-blown recession. As lower interest rates make the dollar less attractive compared with other currencies, such as the euro, in countries where interest rates are higher, the dollar-denominated price of oil rises to compensate. And, as oil prices rise, the threat of recession in the world’s biggest consumer countries – and especially the US – becomes greater again.

Dollar under threat

It is not quite that simple: there are other reasons for the oil-price rise, not least the apparently unquenchable appetite for crude in the booming economies of Asia – inflated in many countries by generous state subsidies on refined products – and the industry’s failure to keep supply growing as quickly as demand. But the dollar is, nonetheless, under threat.

The issue came to a head at an Opec meeting in Riyadh in November, when Venezuela and Iran both called for the group to abandon the dollar – “a worthless piece of paper” – and price its oil either in euros, against which the dollar’s fall has been stark, or a basket of currencies. In February, Iran’s long-awaited oil bourse opened on Kish Island, trading oil and products in euros and Iranian rials.

The opening of the bourse passed largely unnoticed – and failed to trigger the collapse in the dollar predicted by some analysts. But elsewhere among the Opec nations, the momentum for a wider switch away from the dollar has grown. “Maybe we can price the oil in the euro,” Abdulla El-Badri, the group’s secretary-general, said in February. “It can be done, but it will take time.”

As a symbol of US power in the world, the pre-eminence of the dollar takes some beating. That is why its recent decline has also been heralded by some, gleefully, as a signal of the “empire’s” decline. “With the fall of the dollar, the deviant US imperialism will fall as soon as possible too,” Venezuela’s President Hugo Chávez said last year.

But dropping the dollar would have wider repercussions. China’s foreign-currency reserves stand at almost $1.5 trillion, according to the CIA; Japan’s at almost $0.9 trillion; and Russia’s at almost $0.5 trillion. Over 60% of global reserves are in dollars. If Opec suddenly demanded euros instead of dollars for its oil, the plunge in the currency’s value would hardly be welcomed in the capitals where the reserves are concentrated. If China sold its dollars, the currency would collapse – but so would China’s ability to export goods to the US.

Nor would such a move be welcome in the euro-zone, where pricier euros would hit exports and wipe out any benefit the zone accrues by buying energy in dollars.

But perhaps most significant are the $4 trillion of dollar reserves held by the Middle East states themselves, suggests Stephen Schork, editor of the Schork Report, a newsletter about oil prices. The Gulf’s Opec members would be unlikely to devalue their currency reserves overnight. Saudi Arabia, for one, quickly dismissed the currency shift idea in November. Other producers around the world would also take a hit from such a switch, given that consumers are transferring some $1.8 trillion a year to oil exporters, according to to investment bank Goldman Sachs.

And there are other fundamental reasons why such a switch would not work. Despite the Iranian bourse and the efforts of Dubai to become a regional trading hub for commodities, Opec has no real ability to set the price, says Manouchehr Takin, an analyst at the Centre for Global Energy Studies. “They follow what happens in New York and London.” It may be in the interests of Opec’s Gulf states to develop a benchmark to rival Brent or WTI, but the varying qualities of the crude sold from the region would make that difficult, he says.

Economics tells us that it does not matter whether I buy something by paying Australian dollars for it, or euros or euros; the market will adjust to whichever piece of paper became its reserve currency.

And it would be just as hard to unravel an entire trading complex that is based on dollars. Until that happens, prices for the world’s oil markets will be decided by traders in the US and UK. Schork agrees, pointing out that the volume of screen trading in futures on ICE and Nymex – all in dollars – is at least as big as the trading in physical oil elsewhere.

Other solutions exist. The dollar pegs in the Gulf could be adjusted to increase the value of local currencies – and their purchasing power. Kuwait dropped its dollar peg for the dinar last year and the currency remains the highest valued in the world, but one dinar buys almost four dollars.

For some economists, the debate is irrelevant anyway. “Ultimately economics tells us that it does not matter whether I buy something by paying Australian dollars for it, or yen, or euros,” says Andrew Oswald, professor of economics at the University of Warwick. “These differences eventually come out in the wash.”

In other words, the market would adjust to whatever piece of paper became its reserve currency.

A TAX change agreed by the UK government should give a lift to new developments at the country’s older oil and gas fields. The authorities are to allow new fields to be designated within the areas of the existing fields still paying Petroleum Revenue Tax (PRT).

Because PRT was abolished for fields given development consent after 16 March 1993, the newly designated field will be exempt from the tax while the older field surrounding it continues to pay the tax. The Department for Business, Enterprise and Regulatory Reform (DBERR) says the change will affect about 30 PRT-paying fields and could lead to new developments that together could flow a peak of 20,000 barrels a day. It is understood that about 120 fields are potentially still liable to PRT, so producers have to make payments because the tax reliefs available exceed the income.

The change – announced by prime minister, Gordon Brown, and the finance minister, Alistair Darling, at a meeting with the industry association, Oil & Gas UK – apparently took companies by surprise. The association said the change “will provide further stimulation for future investment”.

The North Sea Tartan oil platform

A DBERR official said: “It will be up to licensees to make a case for a change of field determination on economic grounds”. Applications will be scrutinised by officials and the tax minister in order to assess whether the change “satisfied economic, geological and wider fiscal requirements”. Because of the declining number of fields paying PRT, abolition of the tax has been discussed at government-industry meetings for some years. Companies with interests in the old, formerly-large producers say additional investments can be come unattractive when the field-lifetime allowance against PRT has been used up. But there are differing positions. Companies with fields coming up for decommissioning want PRT to be retained, or other arrangements made, because PRT allows decommissioning costs to be offset against past profits. There is also concern that, if PRT is abolished, the government will raise another tax to compensate – probably the 20% Supplementary Charge, an increase which will affect all producers.

PRT, set at 50% after reliefs, yielded £0.61bn ($3.22bn) in the 2007-08 tax year, down from a peak of £1.77bn in 1984-85. The UK’s main petroleum tax is of course PRT, which yielded £3.61bn in 2007-08, while the Supplementary Charge yielded £2.500bn. Including licence fees, oil and gas production gives the government a total of £7.92bn last year.
Upstream investment should set a new record this year, helping Colombia build towards 1m b/d of production by 2020

By Tom Nicholls

COLOMBIAN oil production could reach 1.5m b/d by 2020, according to Agencia Nacional de Hidrocarburos (ANH), the country’s upstream regulator. Proved reserves could increase by 4bn barrels by 2020, from 1.35bn barrels, it claims – with half of the additions coming from established fields and half from newly discovered acreage.

Intensifying licensing activity and rising upstream investment are behind the optimism: last year 54 exploration licences – comfortably above its annual target of 30. This year, says ANH’s director general, Armando Zamora, the total will exceed 50 and could reach 100 in parallel with its open-door licensing policy. ANH is offering 43 blocks in a large licence round and 100 smaller blocks in a so-called mini-licensing round.

Foreign direct investment (FDI) in the oil and gas sector continues to set new records and drilling activity has increased to unprecedented levels. In 2007, FDI reached $3.4bn and 70 wildcat wells were drilled. But neither record is likely to stand. ANH says FDI will amount to $4bn-5bn this year and the agency is expecting 90-120 new wells by the end of 2009.

Anecdotal evidence suggests that the regulator’s bullish view of investment: in March, Spain’s Cepsa – of which France’s Total owns almost 50% – bought the 20,000 b/d Caracara block, in the southern Llanos basin, in the centre of the country, from Texas-based Hupercor for $0.92bn. Given that the area contains estimated proved-plus-probable reserves of 40bn barrels, the price paid suggests a particularly high valuation for undeveloped reserves, says Zamora – in the region of $20 a barrel.

“That deal demonstrates the level of confidence in the country,” he says. “It has sent out a very important signal.”

The rise in upstream investment is already filtering through into encouraging upstream statistics. Oil output in January averaged 0.557m b/d, continuing the modest growth that started three years ago. Gas production also continues its steady rise, reaching 0.733bn cubic feet a day (cf/d) in January.

A few years ago, the situation looked very different: in 2000, when ANH was created, then energy minister, Luis Ernesto Mejía Castro, told Petroleum Economist the country risked being bypassed by upstream activity.

The idea of bypassing Singapore – a staunch US ally – would appeal to Iran, which is worried the imposition of sanctions against it might result in Singapore refusing its vessels access to the Straits. A corridor through Malaysia would offer a safety valve for Iranian exports, says John Balch, an Asia expert at IHS Energy. The project could cut shipping times by using compressed natural gas technology and ease congestion in the busy Straits, which is worried the imposition of sanctions against it might result in Singapore refusing its vessels access to the Straits. A corridor through Malaysia would offer a safety valve for Iranian exports, says John Balch, an Asia expert at IHS Energy.

Recent discoveries provide further encouragement. Canada-listed Pacific Rubiales Energy’s La Creciente gas find in the Ciéncias de Oro reservoir, in the north of the country, may contain as much as 3 trillion cf of gas, says ANH. The company has preliminary plans to export gas from the field to Central America and the Caribbean, but will need to demonstrate to the government that the local market’s needs – at present 0.7bn cf/d, but growing rapidly – will be met first before being granted an export licence.

Gas exporters in general face the constraint of a lack of export infrastructure. Pacific Rubiales hopes to get round that by using compressed natural gas technology. In addition, ANH is hopeful that the pipeline through which Colombia supplies 150m cf/d to Venezuela will be extended in the other direction to Central America, enabling exports to that region when the flow of the pipeline is reversed in five years’ time.

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Indeed, the project has also received cautious interest, but so far nothing has materialized. In mid-2007, prime minister Abdullah Ahmad Badawi said the government would support the project. But it is yet to provide funding and the opposition leader says the project lacks transparency and has urged the government to freeze the development.

Another disadvantage is the absence of Petrobas from the development. Transpen claims to be in talks with various potential investors – including Middle East oil companies, Indonesian refiners and large Asian consumer companies. It is also considering tapping debt markets or a stock-market listing. The outlook for the project could be significantly enhanced by a big-name backer, such as Petronas.

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Colombia’s 1m b/d goal

The Malacca alternative

A PIPELINE across Malaysia that would provide oil shippers with an alternative to sailing through the Malacca Straits could be on stream as early as 2011, claims its developer. Trans-Peninsula Petroleum (Transpen) says the Trans Malaysian Pipeline (TMP) will save time and money, and ease congestion in the busy Straits, which ship carrying more than 10bn barrels of oil pass each day.

The project could cut shipping times from Saudi Arabia to China by three days, says Transpen, which holds an exclusive contract for the pipeline’s construction. It could also mitigate the threat of piracy.

TMP would stretch 200 miles from one side of the Malay Peninsula to the other. Tankers would offload at Yan, on the west coast; the oil would move through a series of pipelines, running through an inland basin, to a tanker on the eastern coast, near Bachok.

Linked to the pipeline plan are proposals to build refineries in Kedah, on the northwestern coast, and in Kelantan, on the northeastern coast. In a first phase, costing an estimated $2bn, the pipeline would have a capacity of 2m barrels a day. This could rise to as much as 6m b/d in a second phase, which, including the refineries, could cost $4-6bn. Assuming work begins this year, start-up is scheduled for 2011; with the second phase on stream in 2014.

The TMP link would stretch 200 miles from one side of the Malay Peninsula to the other.

Transpen continues to make progress; it has contracted local group Ranhill Engineers & Constructors and an Indonesian consultancy, Tripatha, to work on the project; the pipework would be supplied by Indonesia’s Batik & Brothers.

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…I can build one this big

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