Conclusions

In summary, the dash for gas faces several major hurdles including high prices leading to demand destruction and regulatory uncertainty. Gas prices over $4.75/MMBTU will make gas-fired power generation difficult in most scenarios, thus both pipeline gas and LNG suppliers will have to be wary of price elasticity in the Indian power market. Innovative contractual arrangements in which power plant owners bear less of the price risk are needed for the dash to continue. The first adopters are likely to be large-scale CCGTs and industrial plants needing process heat or firms looking to escape high power tariffs from the state electricity boards. Looking beyond gas prices, it is likely to be regulatory and taxation decisions that will have the greatest impact on gas demand, and policy makers will have to be wary not to hobble investment and risk losing a gas-fuelled elixir for economic growth in India.

Oil Production Expectations outside the Middle East

Andrew Hayman considers West African production growth from 2005 to 2010

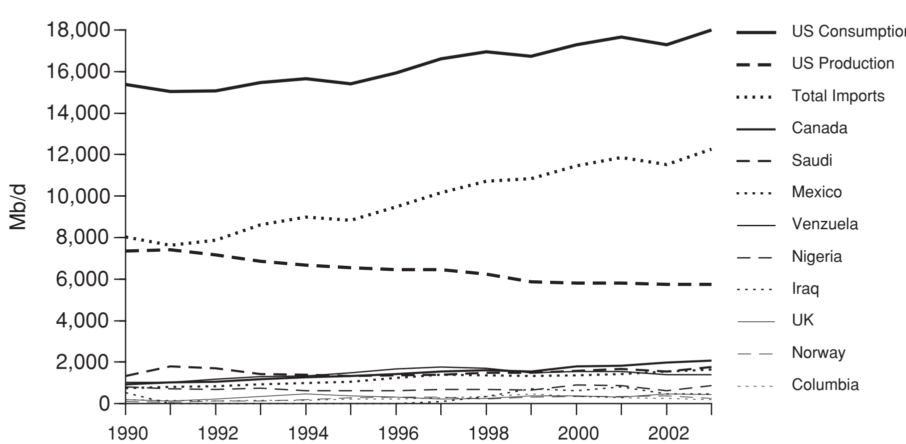
The West African margin continues to attract significant attention from the oil-consuming nations, most notably the United States. In a time of increasing uncertainty of oil supply, particularly from traditional OPEC partners in the Middle East, the USA is looking to supply its ever-hungry economy from partners in West Africa – notably, but not exclusively, Angola and Nigeria. It is no coincidence that President Obasanjo of Nigeria was the first African leader to be received in Washington, in December 2004, after President Bush's re-election to a second term. During his visit, at a forum held by the influential Leon Sullivan Foundation (whose President is ex-US Ambassador to the United Nations, Andrew Young), President Obasanjo said that Nigerian imports would rise from 7 to 15 per cent of US demand. Likewise, President dos Santos of Angola was received in Washington in May 2004.

The US domestic consumption is projected at 20.9 million barrels of oil per day (Mb/d) in 2005, with a 2 per cent per annum growth thereafter. Imports consisted of 12 Mb/d in 2003, or 60 per cent of demand. It is this latter figure, showing the growing dependency of the USA, which is driving oil politics (Figure 1).

The traditional top producers are shown in Figure 1. But with obvious long-term problems in Iraq, tensions with President Chavez of Venezuela, and ongoing ideological differences with Mexico, the USA is looking to secure long-term ties with the African producers. Both Nigeria (currently no. 5) and Angola (no. 7) will move up in the scale of suppliers to the United States.

Major US companies such as ExxonMobil and ChevronTexaco seem to be comfortable working in Angola; industrial projects get done in acceptable time-frames and according to plan. The country is now producing over 1.1 Mb/d (November 2004), and in the last year has successfully put on stream the Exxon-Mobil operated deepwater field Kizomba A (to reach 250,000 b/d in Q1 2005). Girassol-Jasmim, operated by Total, now contributes

Figure 1: US Oil Production, Consumption and Imports



over 240,000 b/d; Xikomba A was put on stream by ExxonMobil in November 2003. Deepwater development operations ongoing at the moment include Kizomba B, BP's Greater Plutonio complex in Block 18, and ChevronTexaco's Belize-Benguela-Lobito-Tomboco compliant tower plan (Block 14). The latter block has been extremely prolific for ChevronTexaco, and significant exploration upside remains.

"the USA is looking to supply its ever-hungry economy from partners in West Africa"

In the pipeline – approved but not started – are Total's Dalia field (240,000 b/d plateau), and tie-back of satellite discoveries in the same area of Block 17 in a follow-up phase of development.

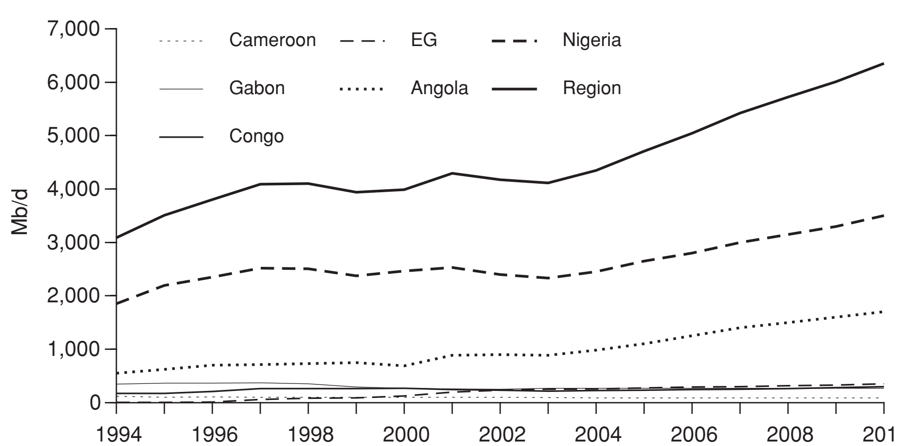
In the ultra-deepwater (Blocks 31, 32, 33), after a difficult start, the operators have successfully cracked sub-salt seismic imaging by using long receiver arrays, and advanced processing techniques including identification of DHIs (direct hydrocarbon indicators), and PSDM (pre-stack depth migration) of copious volumes of 3D seismic data. To date, it seems as though the recoverable oil volumes per discovery are in the range of 100 to 200 million barrels of oil, and clusters will have to be developed together to make commercial viability (? 500 Mb). In 2004, discoveries Gindungo 1 (Block 32), Saturno 1 (Block 31), Plutão 1 (Block 31), Marte 1 (Block 31), Negage 1 (Block 14), Clochas 1 (Block 15), Kakocha 1 (Block 15), Bavuca 1 (Block 15), Tchihumba 1 (Block 15) appear to be exploitable, although none is a giant. Most are Miocene-Pliocene turbidite plays. Sub-sea tie back to planned floating production storage and offtake (FPSO) facilities in shallower-water blocks 15 (Exxon-Mobil), 17 (Total) and 18 (BP) is also a plausible route to exploitation.

An interesting new find by operator ChevronTexaco is the KX-2 (Lianzi) field which is situated in the joint development zone between Angola and Congo. It appears to be commercial. Relations between Brazzaville and Luanda are cordial, and development should not be impeded. In the longer term, the Congo Canyon area is regarded as prospective, though operations will be difficult with the seabed topography.

Nigeria is the other pillar of West African production. Currently national production is around 2.5 Mb/d, of which Shell is the prime producer at over 1.0 million barrels per day. Although traditionally production has been onshore in the swampy Niger Delta, the logistical dangers of working onshore, plus the evident deepwater prospectivity, have motivated the operators to focus more and more offshore – first on the shelf, then into the deep- and ultra-deep waters. But due to internal government bureaucracy, politicking, and complications over gas utilisation, development times to first oil have been, and remain, unacceptably long. Field economics are also seriously degraded by such delays. The Bonga oil field was discovered in 1996 but will not be on stream before late 2005. Plateau production will be 200,000 b/d. The situation at Agbami is similar; a giant field discovered by Texaco in 1998, but which will not be on stream before Q4 2007. It will eventually add 250,000 b/d to Nigerian production. The ubiquitous prospectivity of the deep waters has led to other giant discoveries (Erha, Bosi, Usan-Ukot, Bolia-Chota, Akpo), all of which will be exploited. The key question is – how long will it take to obtain the necessary approvals and finance to move each of these projects forward? The government has often touted its desire to reach the 'Vision 2010' figures of 40 billion barrels of oil recoverable reserves and 4 Mb/d production capacity (from the end 2004 totals of 35.5 Bb and 2.5 Mb/d). Despite the theoretical possibility (given the size of the discoveries), these now seem to us to be unattainable. Perennial problems of adequately funding the government's share of exploration (the so-called cash call) in the traditional onshore and shallow-water permits is also restricting various phases of E and P. In addition, OPEC membership has restricted Nigerian output. We see that 3.5 Mb/d is more plausible by 2010.

Despite stunning successes in the period 2000 to 2003, the first tranche of well results in deep- to ultra-deep waters (in the toe-thrust belt) – ChevronTexaco, Iroko 1; Petrobras, Erinmi 1; Agip, Dou1) – have been disappointing and have put a brake on the rush to ever-deeper waters. Nevertheless, a major programme of exploratory drilling is already firm for 2005. A drillship, the Transocean 'Deepwater Pathfinder', is to drill no

Figure 2: West African Oil Production



less than eleven wells in Nigeria in a rig-sharing contract, over the next fourteen months. Several are Royal Dutch/Shell. Although it is absent from Angola, Shell has many eggs in this Nigerian basket, and OPL 245 and OPL 322 are key to its long-term exploration strategy.

Turning to other countries, Equatorial Guinea is steadily moving up the league table of producers. Zafiro produces 280,000 b/d and is one of ExxonMobil's key West African assets. The Ceiba field – which was put into production in just fourteen months after discovery – will be joined by the Okoume complex (also operated by Amerada Hess) which will contribute 50,000 barrels per day. Hess is investing almost $1 billion. The government oil company GEPetrol has predicted that, unconstrained by OPEC quotas, national production will increase to 350,000 b/d, when it will be capped. On the exploratory side, there have been few heavyweight discoveries outside the Northern Block G area in 2004. However, Marathon has added over 160 million barrels of oil equivalent to its reserves (gas + condensate) in the Alba area through appraisal drilling.

> "In the ultra-deepwater … the operators have successfully cracked sub-salt seismic imaging"

Other countries in West Africa which may contribute to regional oil production by 2010 are Côte d'Ivoire and Ghana. Côte d'Ivoire has one deepwater field (Baobab) currently under development by Canadian independent CNR International (200 million barrels of oil recoverable; 70,000 b/d plateau production). A further Albian fault-block prospect, drilled in January 2005 as Zaizou 1, was unsuccessful. In the west of the Ivorian offshore, Houston-based US independent Vanco Energy has recently assembled a group of Chinese and Indian companies (in expansionary mood overall in Africa) as co-venturers to drill the San Pedro prospect in March this year. If the well is successful, we would expect a rapid development using an early-production leased FPSO. So far, the civil disturbances in Côte d'Ivoire have not affected the offshore operations, and in any case, contingency plans are in place to operate offshore assets from neighbouring Ghana.

Further east on the transverse margin, through Ghana-Benin-Togo, exploratory drilling has not been markedly successful through 2003 and 2004. Expensive deepwater wells have been drilled by Kerr McGee (2 in Benin, both with minor oil), Devon (Ghana) and most recently Hunt Oil (2 in Togo). But the perception will rapidly change with a good success in the vicinity – for example by Vanco. Other acreage – in the Cape Three Points area of Ghana – is in the initial stages of exploration by Vanco Energy, and newcomer Kosmos Energy, which has committed to undertake 3D seismic in Q1 of this year.

Other sub-Saharan African countries striving for deep-water oil discoveries in 2005 include South Africa, where in the Orange Basin, BHP-Billiton and Forest Oil/PetroSA should drill this year. The first well for the Nigeria-São Tome Joint Development Zone Block 1 may be drilled at the end of this year by ChevronTexaco. Prospect sizes are likely to be upwards of 250 Mb, to judge by the nearby Akpo success. But the proof of the pudding will be in the drillbit.

As Figure 2 shows, we see the West African region contributing up to 6.4 Mb/d to world production by 2010 – with the lion's share at 1.7 Mb/d and 3.5 Mb/d to Angola and Nigeria respectively. However, post-2010, there will still be a lot of fuel left in the tank.

Ivan Sandrea analyses South American (Non OPEC) medium-term production outlook

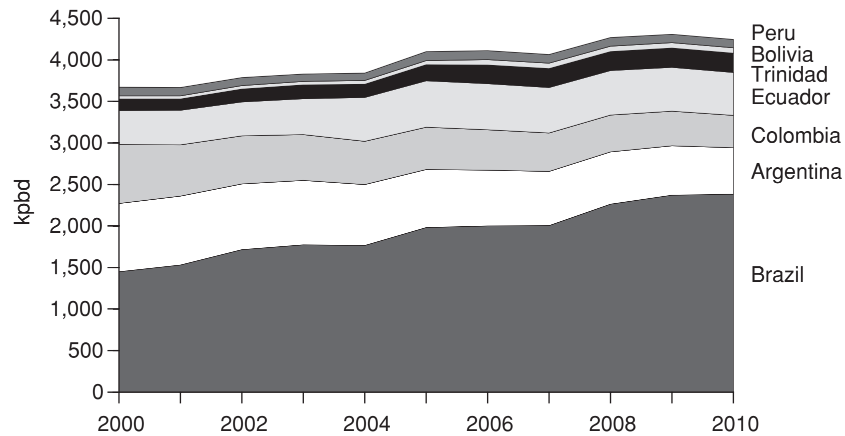
During the1960s, oil production in South America (i.e. Argentina, Bolivia, Brazil, Colombia, Ecuador, Peru, and Trinidad) rose gradually to average 2 per cent of World oil supply or 1 million barrels per day (Mb/d). Oil production then continued to rise slowly due to limited access to prospective areas and technological constraints, except in 1973 when production increased sharply to 1.25 Mb/d (Ecuador began pumping from the Shushufindi field). In 1979, oil production reached 1.4 Mb/d and the largest producers were Argentina, Ecuador, Peru, and Trinidad (i.e. 80 per cent of total production from South America ex Venezuela). Oil production in Brazil remained flat through the 1970s, and in Colombia it declined by half.

However, the next twenty years from 1980 to 2000 saw profound changes in technology, and in the fiscal and industry structure in most South American countries, particularly in the 1990s. This led to increased exploration, the discovery of several giant fields and the start-up of new projects from the Andean foothills to Brazil deepwater. Oil production increased to 3.4 Mb/d in 2000 from 1.4 Mb/d in 1980 and South America's share of World oil production doubled to 4.6 per cent from 2.3 per cent. Proven reserves also increased to 18 billion from 7 bn barrels. By 2000 virtually all South American countries allowed foreign participation in E&P except Brazil, where the oil industry remained nationalised until 1997. Despite the fact that Brazil was the last to open its industry, the discovery of the Campos basin, combined with the successful development of cost effective technologies by Petrobras, made Brazil the engine, but not the only country, driving production growth in the region. Of the 2 Mb/d net volume growth between 1980 and 2000, Brazil accounted for 1.2 Mb/d, Colombia 580 thousand barrels per day (kb/d), Argentina 313 kb/d, and Ecuador 203 kb/d. On the other hand, production declined in Peru which saw its peak production in 1983, as did Trinidad in 1978.

In terms of exports, all countries except Bolivia, Brazil, and Peru were net exporters by 2000. The relatively superior quality of South American crude and its proximity to the US market made the region an important supplier to the United States – in 2000 South America (ex Venezuela) accounted for 6 per cent of US imports or 500 kb/d. Outside of the USA, oil exports remained limited to other countries in the region as well as Central America and the Caribbean due to low spare export capacity and lack of suitable markets beyond.

From 2000 to 2004, oil production in South America rose further to 3.87 Mb/d (4.7 per cent of World oil supply), due to contributions from deepwater projects in Brazil, together with expansions in Ecuador and Trinidad (Table 1). However, larger than expected field declines in Colombia and Argentina, and the accident in Brazil (P36), slowed the growth trend of the region. Total proven reserves also increased in all countries, except in Colombia, to reach 21 bn barrels in 2004. In terms of exports, Ecuador increased its supplies to the USA to 228 kb/d in 2004 from 128 kb/d in 2000 after the OCP pipeline began operating. But exports from Argentina and Colombia to the USA declined by 200 thousand barrels per day.

Figure 1: South American Production Outlook



Outlook for the Region

Looking ahead, in the period between 2005 and 2010 oil production in South America (excluding Venezuela) is forecast to expand to 4.3 Mb/d by 2010. Brazil, however, is expected to be the only source of growth where it is anticipated that oil production will reach 2.3 Mb/d in 2009/2010. At least twelve deepwater projects are scheduled to start bringing 1.3 Mb/d of new volume excluding field declines. Production is forecast to remain broadly flat in Trinidad, Ecuador, Bolivia, and Peru as field declines are expected to be offset by new projects (most of which are small) and expansions in gas fields that contain liquids (i.e. Camisea field in Peru, Margarita field in Bolivia). In Argentina and Colombia, production is forecast to continue to decline at around 4 per cent p.a. accelerating to >6 per cent p.a. towards the end of the decade. Some positive surprises from Trinidad and Ecuador should not be ruled out, although, in terms of volume, any positive surprises are unlikely to represent more than a maximum of 2 per cent of South American oil production in any given year.

In terms of exports, future trends do not look much different from those in the 2000–2004 period although Ecuador's export growth is likely to be limited. In Brazil, domestic demand growth is forecast to broadly match domestic supply plus net trade growth until 2007/08. Post 2008, Brazil is expected to become a net crude exporter but the volume is unlikely to be material, unless domestic market demand growth is less than predicted.

Uncertainties

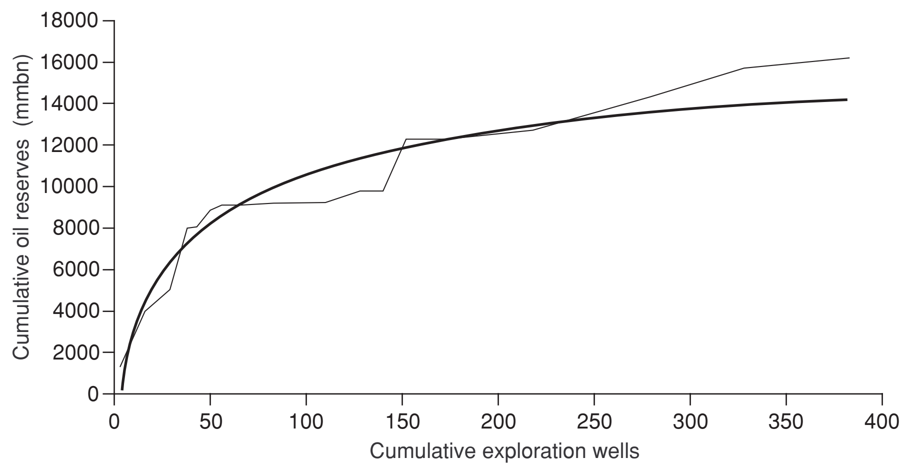
The ability of the industry in South America, except in Brazil, to maintain oil production and deliver growth can be described, compared to other regions of the world, as highly uncertain and technically challenging. This assessment is supported by increasing decline rates in key fields – in some of which the causes remain unexplained – the small size and low number of new projects, the low average size of recent discoveries, and the relatively more attractive opportunities outside the region from a technical and political point of view. The last point is particularly important given that strategic and financial commitments

Table 1: South American Oil Production by Country (kb/d)

	1980	*1990*	*2000*	*2004*	*% of production available for exports (2004)*	*Peak Year*	*2003 Reserves (bn bo)*
Brazil	188	650	1,451	1,770	0 per cent	not yet	10.6
Argentina	506	517	819	730	51 per cent	1998	3.2
Colombia	131	446	711	522	33 per cent	1999	1.5
Ecuador	206	292	409	530	40 per cent	2005	4.6
Trinidad	212	150	138	157	30 per cent	1978	1.9
Bolivia	33	34	38	46	0 per cent	not yet	0.2
Peru	196	130	104	89	0 per cent	1983	1.0
Sum	1,472	2,219	3,670	3,844			23.0
Per cent World	2.3	3.4	4.9	4.7			

towards the region, particularly in Argentina, Bolivia and Colombia, appear to be short-term rather than long-term, and at best, gas oriented. In addition, the absolute level of exploratory activity in the region (including Brazil) has declined in spite of $40 oil. For instance, although in Colombia fiscal changes have been introduced in order to attract investment in exploration, the industry has yet to respond. New areas offshore Colombia in the Pacific (deepwater) will also be offered soon, although these are unlikely to draw material interest given geological constraints. Argentina's economic challenges have created uncertainty in the entire energy sector and this has resulted in investment plans being delayed and changes in the strategy of some producers. In Trinidad and Bolivia, the successes of the last few years have resulted in greater policy and industry focus on gas projects. Last but not least, there seems to be some renewed interest in Ecuador and Peru, but activity remains limited due to complex geology and access.

Figure 2: Brazil Cumulative Exploration Wells vs Cumulative Reserves



Brazil: Challenges and Projects

In contrast to the rest of South America, Brazil has an extensive programme of projects, but expected production growth is subject to additional and particular challenges; on the one hand a tight delivery schedule for twelve complex deepwater projects and, on the other, accelerating decline rates in giant deepwater fields producing heavy crude, such as Marlim and Albacora. There is also a heavy ongoing investment requirement for these projects which could be subject to oil price volatility or domestic policies.

Recent experience shows that the average delay from the original start-up date to the completion date of major deepwater projects in Brazil has been around ten months. For instance, construction delays pushed back the start-up date of Barracuda and Caratinga by almost a year. Over the next four years, at least twelve green and brown field deepwater projects are expected to come on stream. Barracuda and Caratinga are already producing, with a combined output of 300 kb/d at peak (see Table 2). Two more projects are scheduled to start later in 2005, Jubarte Phase I and Albacora Leste, with a combined output of 240 kb/d at peak to be reached in 2006. No major green field projects are scheduled for 2006, but Albacora Leste could slip to late early 2006 due to bidding and construction delays. In the 2007 to 2008 period five more projects are scheduled to start, including the giant Roncador field. But, the programme for the Roncador field as well as the expansion of several new fields in the Campos basin is also dependent on the execution of the recently sanctioned PDET project, forecast to start commercial operations in December 2006. The PDET project will allow tankers to load oil from a group of platforms for transportation to coastal terminals or directly for export to other countries.

Table 2: Key Deepwater Projects in Brazil

Project	*Start Year*	*Period*	*Operator*	*Volume at peak*
Albacora Leste	2005	3Q	Petrobras	180
Barracuda	2005	1Q	Petrobras	150
Caratinga	2005	1Q	Petrobras	150
Jubarte Phase I	2005	2Q	Petrobras	60
PDET (facilities)	2006	4Q	Petrobras	
Marlim Leste	2007	2Q	Petrobras	140
Roncador P 52	2007	1Q	Petrobras	180
Roncador P 54	2007	4Q	Petrobras	180
Frade	2007		CHX	110
Marlim Sul P 51	2008	1H	Petrobras	180

Considering that the giant Marlim and Albacora fields (among others) which account for 30 per cent of Brazil's total output are already in decline, any material delays in the start-up of new projects, will impact Brazil's output growth rate and consequently the growth rate of the entire South American region. The decline rate of deepwater fields post peak tends to be higher than in offshore/onshore fields and Brazil's deepwater fields are no exception. In fact, the difficulties are greater in Brazil compared to other deepwater provinces given the water depths, reservoir depth and crude properties. There is no doubt that Petrobras has a fine technological track record, but the physics of deepwater fields once they begin to decline remains highly uncertain, as already seen in the Gulf of Mexico (i.e. Mensa, Brutus, and so on).

It is also necessary to point out that Brazil has been experiencing a lack of exploration success in searching for commercial oil deepwater (and onshore), and, if this trend continues, deepwater oil production growth could be constrained post 2010. International companies have been disappointed with exploration results across the country and this has led to an overall decrease in the level of exploratory activity despite the level of oil prices of the last five years. Recent discoveries have tended to be relatively small, low API, away from infrastructure (i.e. Espirito Santo basin) and not necessarily in shallow water. By the end of 2003, a total of 383 exploration wells had been drilled in deep water resulting in 34 discoveries (9 per cent success rate). However, discoveries peaked in 1987 and 82 per cent of the reserves discovered have been concentrated in the Campos basin. As a result, Brazil's deepwater creaming curve, which in theory shows the maturity of the region, already displays a profile comparable to that of a mature region such as the North Sea (Figure 2).

On present evidence, there is little doubt that the next leg of production growth in South America not only rests on one single Country and a single Company undertaking some of the most complex projects in the industry, but also rests on the ability of the industry to manage field declines effectively and discover new reserves in other South American countries in a highly challenging and uncertain environment. Beyond 2010, if the medium-term forecast turns out to be accurate, South America is likely to reach a plateau shortly after the end of this decade, accompanied by a peak in production in Brazil. Other areas of South America are unlikely to come to the rescue. Chile is a small oil producer (12 kb/d) and has no real prospects. And, although new frontier exploration activities are being undertaken offshore Guyana and Suriname, it will be some time before we learn about the commercial prospectivity, if any, of these two countries.

Russian Oil Supply: Performance and Prospects by John D. Grace

A New Book from Oxford Institute for Energy Studies, price £45

As the world confronts a new phase in the oil market with prices not experienced since the early eighties, we face an odd asymmetry. Demand growth is certain over the long term, but uncertain in the short term, especially given its preponderance in China. But the inverse is the case for supply: certain in the short term, less so for the long term. The most important non-OPEC exporter by far is Russia. Understanding Russia and its potential to help meet the growth in world oil demand is a key to postulating the future of the world oil market. In a new book soon to be published, Dr John Grace provides a timely and essential analysis for discussing the role Russian oil might play.

Russia's oil resources are not in question. Its conventional oil reserves are the largest of any non-OPEC country. Since the world oil industry began in the 1860s, Russia has produced more oil than any other country, after the USA. During the Soviet era its production rivalled those of the USA and Saudi Arabia. In 1987 Russia was the largest producer in the world. Nine years later in the chaotic wake of the Soviet collapse, production had sunk to nearly half. Since then Russia's production has steadily increased; by 2004 it again approximated Saudi Arabia's.

What is behind this recovery? Can Russia continue to expand and exceed its mid-eighties levels? And more important, will it and should it? This book provides the framework regarding Russia's oil endowment needed before one can consider answers to these and other questions. John Grace reminds us of how central oil has been to the modern economic history of Russia, beginning in Baku in the late nineteenth century. Oil has been the engine pulling the country's material production. But like any engine, its future performance depends on its past maintenance and in many ways oil reservoirs are no different. The author provides valuable insights into how geological caprice bestowed on Russia its hydrocarbon riches and how Russia exploited and abused that endowment.

The legacy of the Soviet era management and petroleum production practices is imprinted on today's Russian oil industry and in particular its structure. Understanding this aspect helps us comprehend the ranking and geographic focus of the Russian companies that are quickly becoming household names, which fields constitute their core assets, what their upside might be, and where they might sit as a potential target for renationalisation or merger. The concentration and size distribution of the companies is reflected in the size of the fields under production and development, mirroring to a certain extent a worrisome structural phenomenon among the international oil companies after their mergers and acquisitions during the nineties. Very large oil companies are not sustained by small oil fields. We also begin to understand why Yukos's return to state ownership might be about more than reprimanding its principal owner for interfering in politics.

Even a passing knowledge of post-Second World War Russian history shows how this background of the Russian oil industry, its endowment and management figured in the command economy. We also might appreciate why, during the Yeltsin interregnum, oil was the target of perhaps the most egregious appropriation of a nation's resources by private agents in history; and then understand the recent methodical and heavy-handed restoration of those resources to state ownership.

How the Russian leadership uses oil and gas to gain political legitimacy and leverage will be a force to understand and watch carefully. Just as Lenin saw electrification of Russia and Soviet control as defining communism, perhaps Putin sees oil and gas as defining post-communist Russia. Subsidised domestic energy prices and hydrocarbon exports underpin the current Russian economy. While this dependence alone might qualify Russia for membership in OPEC, more relevant is whether Russia and OPEC have competing or convergent interests in the oil market. This book provides the basis for beginning to understand what position Russia might take should oil prices ever decline to levels that begin to seriously erode Russia's revenues from oil.