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CONTENTS

Africa is often referred to as the forgotten continent. It only catches the headlines when revolutions, massacres or massive electoral fraud take place. Africa is not a poor continent however. There is both hydrocarbon and mineral wealth. Oil and gas resources are valuable assets for the countries that possess them, and globally for an energy hungry world. In this issue of *Forum* five authors assess successes achieved and problems faced by some African countries in the hydrocarbon and electricity fields.

Jean-Pierre Favennec sets the scene describing first the main features of the energy sector in the continent, most remarkably the very low level of primary commercial energy consumption particularly in sub-Saharan countries (other than South Africa). This reflects the state of under-development of the region and in turn may well be a contributing cause. Yet oil reserves in Nigeria, Angola and Libya are substantial, as are gas reserves in Algeria, Nigeria and Libya. Recent discoveries in the Gulf of Guinea, Mauritania, Chad and Sudan have widened the set of countries with hydrocarbon potential. Disappointingly, oil revenues have been misused almost everywhere. Some governments facing rebellions, civil wars or unrest purchased weapons. Others were unable to prevent the diversion of funds into private purses.

In North Africa, Algeria and Libya, albeit in different contexts, governments have invited foreign investors to participate in the development of oil and gas upstream. Bassam Fattouh shows how Libya managed to attract a very large number of foreign oil companies from the super majors to newcomers from the East after the lifting of sanctions in 2004. This was not done by offering cheap and easy terms in production sharing agreements. On the contrary, Libya imposed tough fiscal agreements taking advantage of a strong bargaining position.

Algeria began a long process of opening-up in 1990 having suffered economically from the lean years of the 1980s. The final stage was the adoption of the 2005 Hydrocarbon Law which took four years of political debates involving the parliament, trade unions, political parties and various interests in the civil society. It succeeded in attracting foreign investors both in gas and oil despite an insurgency which caused security concerns. Walid Khadduri mentions in addition some of the

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problems encountered by Algeria in realising its ambitions of becoming a player in the Spanish domestic gas market.

On certain criteria, Nigeria is the most important oil country in Africa. Philippe Copinschi notes the dynamism of investments by oil companies since 1998, the year when the military dictatorship ended, and the results in offshore discoveries. Production capacity will increase as these new reserves are developed, but whether production will grow as a result is a different question. True, the insurgents are less able to disrupt offshore activities, but complacency on the security issue is not warranted. The obstacles to progress in the development of the Nigerian hydrocarbon sector and indeed the whole economy are well known but deserve to be repeated and repeated.

Electricity is in many respects a superior form of energy. It reaches the point of application at the end of a wire; no messing about with pipes carrying a toxic fuel, dirty coal to be shovelled under a boiler, or oil products either viscous or vaporous, unsuitable for lighting and awkward in domestic uses. Gerald Doucet and Latsoucabé Fall rightly stress the important role that electricity can play in deprived Africa: 'it is a cornerstone for economic progress.' Their contribution is about the Inga projects that aim at realising some of the huge hydropower potential of Africa, a 'potential of which only 7 percent is presently exploited'.

This issue includes two other articles. Michael Lynch addresses the topical question of changes in the US energy policy that may result from the Presidential election. What would Clinton, or McCain or Obama do in this complex area if elected? The current administration was expected to adopt pro US oil industry and pro Arab domestic and foreign policies. What actually happened was different. There were few benefits to the oil industry and President Bush turned out to be more sympathetic to Israel than to Arab positions.

The three presidential hopefuls have similar intentions as regards curbing greenhouse gas emissions. They are all in favour of renewable energy which needs subsidies. They rightly believe that this is good for the environment and less convincingly that it is also good for energy security. They are in favour of biofuels, but will they change their minds when the unintended consequences of this preference become clear? The Democrats will want to reduce tax breaks on the industry but McCain has not expressed views on this issue. Clinton and Obama may try to increase excise taxes on petrol despite past failures of such attempts; McCain will not. And there are other differences which Lynch defines carefully.

Forum is a debating journal. We welcome letters and longer comments. James Jensen is contributing very significant comments to the articles published in the last issue of *Forum* (No. 72). His comments are on the crucial topics of gas demand growth, contracts and prices. Two of his main messages are: first, although 'international gas markets are more flexible than they used to be…the long-term contract is far from dead'; and secondly that nobody seems to have an answer to the crucial question of how to place a value on long-term gas supply. Without such an answer investment decisions on major gas projects become very difficult.

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Energy in Africa

Jean-Pierre Favennec on the importance of oil in Africa

Africa is unique because it has a very low primary energy consumption, of the order of 0.4 tonnes of oil equivalent (toe) per inhabitant, compared with 1.7 worldwide and no less than 8 in the United States. South Africa alone consumes 40 percent of the energy used in Africa, and North Africa, mainly Algeria and Egypt, 25 percent. By contrast, sub-Saharan countries (West Africa, Central Africa and East Africa), from Mauritania to Namibia and Sudan to Mozambique, use very low quantities of commercial energy. This low energy consumption is both the cause and the effect of the low level of development in the region.

Biomass (wood, plant residue, and so on) represents two-thirds of total household energy consumption. South Africa uses very large quantities of coal, and North Africa uses substantial quantities of natural gas, but oil is widely used everywhere, particularly in sub-Saharan countries.

Recent Discoveries and Considerable Reserves

In many regions of the world, oil production began in the nineteenth century (the United States, Russia and Indonesia) or at the beginning of the twentieth century (the Middle East and South America), but the discovery of hydrocarbon deposits came much later in Africa where production only started in the 1950s. It is concentrated in a few countries in two areas: first, the coastal area around the Gulf of Guinea, with two major producers, Nigeria and Angola, and several significant producing countries, in particular the Congo, Gabon and Equatorial Guinea (a recent newcomer but expanding fast), and secondly North Africa, with Algeria, Libya, Egypt and to a lesser extent Tunisia. Sudan and Chad have recently joined this group of significant producers, and other West African countries already produce oil (Ivory Coast, Mauritania) or will do so soon (Ghana and possibly Niger or Mali). Uganda is also a future producer.

Africa's proven oil reserves amount to 15 billion tonnes (Gt), i.e. approximately 10 percent of the world's total reserves, and are fairly evenly distributed between North Africa and West Africa. In 2006, African production reached 10 million barrels per day (Mb/d) – equivalent to 475 million tonnes – i.e. over 10 percent of the world's total production. Given its reserves and production, Africa is therefore no 'new Middle East', but its role as a supplier to the United States and Europe makes it a key player and the setting of a battle for influence between the main consumer zones. Indeed Africa uses only 30 percent of the oil it produces, leaving considerable quantities free for export and making the continent the third largest oil-exporting zone, just behind the CIS but far behind the Middle East.

Oil in North Africa

Algeria and Libya are substantial suppliers of oil to Europe, unlike Egypt which consumes most of its production and where production has been falling slightly for the past ten years. The oil simply has to cross the Mediterranean to reach France, Italy, Spain, Greece and Turkey, so over two-thirds of North Africa's oil exports are destined for Europe. However, the share of the United States is growing.

North African producing countries are more closely related to Middle Eastern producing countries than those of West Africa: Algeria and Libya are OPEC members, their oil industries were nationalised in the 1970s, their national companies (Sonatrach and NOC Libya respectively) still play a very important role, and there is greater sensitivity to political tensions in the Arab Muslim world.

Libya produced almost 3.5 million b/d in the early 1970s. But its production then dropped sharply with the decline of investments as a result of the restrictive terms imposed by Colonel Qaddafi's government on oil companies present in the country, and the government's wish to reduce production. Having fallen to a little over 1 million b/d during the 1980s, production rose again to 1.8 million b/d in 2006. Algerian production, on the other hand, has increased progressively and is now 2 million b/d.

In Algeria and Libya production prospects are good. In Algeria the liberalisation of the hydrocarbons sector that took place around 1990 allowed foreign companies, in association with Sonatrach, to seek and exploit hydrocarbons, and this has considerably increased both reserves and production. But the total liberalisation of the sector, which would have enabled foreign companies to operate independently, was rejected by the National Assembly. In a context of very high prices and abundant revenue, it did not appear advisable – apparently – to allow a substantial share of hydrocarbon revenue to go to foreign companies.

Table 1: Oil in the Economy of the main North African Producers

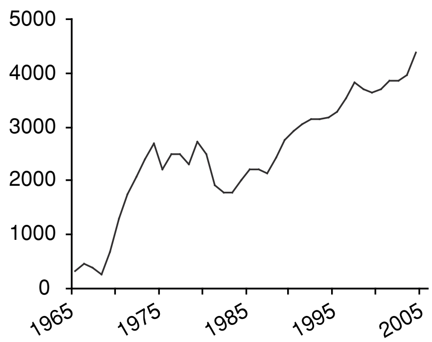
	Proven reserves (GTonnes)	*Production (Mb/d)*	*Consumption (Mb/d)*	*Exports (Mb/d)*	*% Share of oil in exports*	*GDP*	*State resources*
Libya	5.4	1.8	0.3	1.5	95	50	60
Algeria	1.5	2.0	0.3	1.7	>95	30	60
Egypt	0.5	0.7	0.6	0.1	40	4	10

Source: *BP Statistical Review of World Energy*, June 2007 & www.doe.eia.gov

In Libya the sector opened up after the United States lifted its sanctions, leading to the return of the American companies that had contributed to the discovery and exploitation of oil in the country. This return is a logical move.

Oil in West Africa

Trends in Oil Production in West Africa, thousand barrels per day



Source: *BP Statistical Review of World Energy,* 2005

More recently, in the 1960s and 1970s, the Gulf of Guinea area joined the world oil scene. Its reserves are certainly limited in global terms with only 4 percent of reserves and 6 percent of production. Nevertheless, since the end of the 1980s, the Gulf of Guinea has become a favourite destination for international oil investors and production here has almost doubled in fifteen years. The oil – although offshore – is relatively easy to produce and is of high quality. This region has also been the location of some of the biggest recent discoveries. Finally, the region is well situated in relation to consumer markets in Europe and the United States. Exports from the area are therefore quite well balanced between the main centres of consumption: 45 percent to the United States, 40 percent to Asia and 15 percent to Europe. However, there are powerful rivalries between consumers, as we shall see.

The biggest oil-producing country in the region is **Nigeria**, which has substantial reserves in the area around the mouth of the Niger. The basin of sediments created by the Niger alluvium also contains deposits belonging to Cameroon, Equatorial Guinea and Sao Tomé. However, tensions between the local population, the oil company and the government have a great impact on production. Installations and personnel are the object of frequent attacks, forcing the operators to interrupt production for varying periods of time.

The region's second largest producer is **Angola**. Production there started in the enclave of Cabinda during the Portuguese colonisation, and is now expanding fast, thanks in particular to the discoveries made off the enclave (60 percent of the oil produced in Angola comes from this area). Significant production has also been developed in the deep offshore further south, off the coast of Luanda.

In neighbouring **Congo Brazzaville** production is much more modest, but has also increased consistently since the 1970s, and recent deep offshore discoveries should make it possible to maintain production at a high level in the coming years. In both these countries, practically all production is offshore, which explains in part why it has never been interrupted for any length of time, despite the conflicts in the area.

Production in **Equatorial Guinea** started off very modestly in 1992 and only became significant in 1997. It is growing fast, and the recent discoveries make the country one of the major players in the region. By contrast, production in **Gabon**, which had doubled at the end of the 1980s, is in decline and unlike its oil-producing neighbours, few offshore discoveries have been made there recently. **Sao Tomé and Principe** could soon become an oil producer, since its territorial waters probably hold significant quantities of oil.

Central and East Africa

Oil production in **Sudan** began in 1995. The production deposits are located in the centre of the country and are exported via a pipeline over 1500 kilometres long, opened in 1999, which takes the oil to Port Sudan on the Red Sea. The deposits are mainly exploited by the Chinese company CNPC. Western companies involved in production in Sudan withdrew following pressure from non-governmental organisations (NGOs). It is very likely that there are other substantial deposits, but they are located in the zones of combat between the Khartoum government forces and the armed opposition movements.

Chad is a recent arrival on the oil production scene. Its first barrels arrived on the world market in 2003, after the opening of the Chad–Cameroon pipeline. Oil reserves were identified around Lake Chad in the north of the country in the mid-1970s, but they were too limited to justify the construction of a pipeline to the Cameroon coast (over 2000 km away) to export the crude oil. In addition, the civil war meant that the Chadian dream of becoming an oil producer was delayed on several occasions. Continuing in the South the exploration operations that had been conducted in the North, the American oil companies Conoco, then Exxon, revealed the presence of considerable

Table 2: Oil in the Economy of the main West African Producers

	Proven reserves (GTonnes)	*Production (Mb/d)*	*Consumption (Mb/d)*	*Exports (Mb/d)*	*% Share of oil in exports*	*GDP*	*State resources*
Nigeria	4.9	2.5	0.3	2.2	95	20	80
Angola	1.2	1.4	0.1	1.3	90	85	-
Congo	0.3	0.3	0.01	0.2	90	65	70
Gabon	0.3	0.2	/	0.2	80	51	63
Equ. Guinea	0.2	0.4	/	0.4	90	72	-
Chad	0.1	0.2	/	0.2			
Sudan	0.9	0.4	0.1	0.3	70		

Source: *BP Statistical Review of World Energy*, June 2007 & www.doe.eia.gov reserves in the Doba region. A pipeline 1300 kilometres long had to be constructed across Cameroon to exploit them. This project was delayed for a long time, in particular by the intervention of NGOs who highlighted the environmental risks of the project: the pipeline crossed fragile areas, and there were risks for local populations, particularly for the pygmy community. The project, with a total cost of almost $4 billion (production installations and pipeline) eventually went ahead thanks to the intervention of the World Bank which, after extensive studies, finally gave the go-ahead and financed part of the investment.

"Dependence on oil revenues is not unique to the large producers of West Africa"

The reserves in Chad and Sudan, which are of prime importance for the economic development of these countries, are marginal in global terms. However for the past several years they have been the subject of intense international controversy, due to the nature of the political regimes in power in Khartoum and N'Djamena, and the political and economic situation in the two countries.

Oil Rent and Development

The use of oil revenues remains confusing. The economic situation, indeed the political one as well, of the large African producers is not good. **Nigeria**, for example, is placed at 183 out of 201 in the categorisation of countries by Gross National Product. Exports of oil and gas represent almost the entire exports of the country, but contribute nothing to its development. The share of food in total imports has doubled between 1974 and 2001. Dutch disease has prevailed in Nigeria as in many countries.

In **Angola** the money from oil has been used by the MPLA government to purchase arms for the longstanding conflict against Joseph Savimbi's UNITA (UNITA uses the profits from the sale of diamonds in the zones that it controls to supply itself with military equipment).

In **Congo Brazzaville** the situation is similar; a long civil war has destroyed part of the country's infrastructure. A few years ago the Congolese bishops proposed a break in oil production and a national conference to consider the best way of utilising the oil revenues.

Dependence on oil revenues is not unique to the large producers of West Africa. Many OPEC countries show the same characteristics and diversifying their economies appears to be difficult. Nearly 100 years after its first oil exports, Venezuela remains largely dependent on hydrocarbon exports. Takings from the sale of oil and gas play a prominent role in the Russian economy. But the weakness of African administrative structures has aggravated certain tendencies towards the wasteful use of oil revenues.

Conclusion: different uses of oil

While the respective shares of the different energy sources in the energy mix of the entire continent are close to the global average, these statistics hide important differences in the way oil is used – and the high consumption of coal in South Africa masks the fact that in the rest of Africa oil represents almost 60 percent of the energy consumption (excluding firewood). Although oil products are increasingly used worldwide exclusively in captive sectors (basically transport), in Africa they are still used mainly for the generation of electricity. The continent's transport infrastructures are relatively underdeveloped so there is a lesser need for automobile fuel. The small size of the markets (due to low income), and the fact that consumers are widely dispersed, means it is practically impossible, and not profitable, to develop a natural gas distribution network, except in the Ivory Coast and Nigeria, where a critical size can be achieved. The use of coal, which is almost non-existent in the region outside South Africa, would lead to the same economic difficulties.

The low density of energy consumption makes oil particularly attractive because of its liquid state: it is easy both to transport and to store. Despite all the potential advantages of photovoltaics (environmental factors, independence), small oil-fired power plants remain an economic source of electricity, often very competitive in remote areas that are difficult to access for electrification. Oil, in the form of fuel for vehicles or power plants, is therefore the main source of energy, apart from traditional sources such as wood, charcoal, plant and animal residue.

Bassam Fattouh considers the history of foreign oil companies in Libya

The first Petroleum Law enacted in 1955 in Libya was innovative in many aspects compared to the concessionary systems adopted in most of the Middle East Gulf. Rather than granting concessions over large areas, it limited the size of single concessions to 75,000 sq. km which ensured that the oil sector is not dominated by a few big oil companies. The law also set a relinquishment requirement so firms that lease blocks and do not engage in exploration and development activity could lose their concession to other competitors willing to develop the block. The 1955 Petroleum Law fostered competition and succeeded in attracting the reluctant majors and a wide range of other companies which had few available upstream opportunities outside the country. This gave the Libyan government a powerful bargaining position.

The tight oil market conditions of the 1970s strengthened further the bargaining position of the Libyan government vis-à-vis the concessionaires. In September 1970, the government reached an agreement with Occidental wherein this independent company agreed to pay income taxes on the basis of increased posted rather than realised prices, and to make retroactive payment to compensate for the lost revenue since 1965. Soon after, all other companies operating in Libya submitted to the new terms. As a result of this agreement, other oil-producing countries invoked the most favoured nation clause and made it clear that they would not accept anything less than the terms granted to Libya. Negotiations conducted in Tehran led to a collective decision to raise the posted price and increase the tax rate. However, the Tehran agreement resulted in better fiscal terms than those negotiated in Libya and thus the Libyan government reopened negotiations with foreign oil companies to bring the terms in line with the Tehran agreement.

During the period 1971–73, the Libyan government began to revise existing concessions in favour of 51 percent participation agreements with the state oil company, the Libyan National Oil Corporation (NOC) created in 1970. After months of negotiations, many oil companies accepted the new participation agreement including BP, Agip, Occidental, Marathon, Amerada Hess and Conoco. For those oil companies that rejected the new participation deal such as Exxon, Mobil, Texaco and Chevron, the government issued a decree on 1 September 1973 nationalising 51 percent of their concessions. This has been the most radical decision that the Libyan government has ever taken against foreign oil companies. In the same year, Libya announced that any future involvement of foreign oil companies would be based on exploration and production sharing agreements.

During the period 1973–78, the government signed exploration and production sharing agreements (known as EPSA I) with foreign players. In an effort to intensify exploration activity, the government forced existing companies to relinquish some of their blocks. These blocks were then offered to foreign companies under a second generation of exploration and sharing agreements (EPSA II) whose terms were even less attractive than EPSA I.

In the 1980s, Libya was hit by a series of US sanctions which resulted in the departure of several US companies. Exxon and Mobil (now ExxonMobil) exited in 1982. Amerada Hess, Conoco, Grace Petroleum, Marathon, and Occidental, continued their activities until 1986, when President Reagan ordered their withdrawal from the Libyan oil sector. The departure of US companies allowed a range of non-US oil companies such as Italy's Eni, Spain's Repsol YPF and Petro-Canada to fill the void.

Faced with a decline in oil revenues in the mid 1980s, the Libyan authorities felt the need to increase exploration activity. In 1988, it introduced a third generation of exploration and production sharing agreements (EPSA III) which is more attractive than the previous ones. For the first time, Libya agreed to provide foreign firms with a percentage of oil production to compensate companies for exploration and development costs they had incurred. EPSA III was relatively successful and allowed the entry of new players into Libya.

The Lifting of Sanctions

In 2004, the USA lifted its sanctions imposed on Libya which allowed for the resumption of most commercial activities on the part of US companies including investments in the oil sector. US oil companies have thus been making their way back into Libya through participating in the exploration rounds and/or renegotiating the resumption of operations they left behind. In 2005, Occidental returned to Zueitina Oil Company (ZOC) as a minority partner to the NOC. ZOC was established to take over Occidental assets when this company exited in 1986. Output suffered heavily as the result of Occidental's departure and US sanctions; ZOC's output declined from 140,000 b/d in 1986 to 60,000 b/d in 2006. The year 2005 also saw the return of Conoco, Marathon, and Amerada Hess to the Waha Oil Company (WOC) where the joint venture partners signed a deal with the Libyan government to return to fields they abandoned in 1986 and extended their licences to 2034.

Exploration Rounds

In 2004, substantial new acreage was offered under the terms of EPSA IV. In the first round of bids, NOC received 104 offers from 56 companies. Competition was intense as reflected in the large number of bids for some of the blocks (fifteen bids were made for the offshore area 54 and area 106

Table 1: Awards of the First Licensing Round

Basin	*Contract Area*	*Blocks*	*Company*	*Available Open Acreage*	*No of Bids*	*Contractor Share of Gross Output (%)*	*Bonus ($ million)*
Sirte	106	4	Oxy Liwa	6520	15	12.4	25.6
Murzuq	131	4	Oxy, Liwa	10381	10	13.3	25.6
Sirte	124	3	Oxy, Liwa	6113	4	10.8	15.3
Murzuq	163	4	Oxy, Liwa	11236	9	15.9	15.3
Cyrenaica	59	2	Oxy, Liwa	5298	1	38.9	1.1
Offshore	36	4	Woodside , Oxy, Liwa	10414	7	17.4	16
Offshore	52	4	Woodside, Oxy, Liwa	6182	6	17.9	10.05
Offshore	53	4	Woodside, Oxy, Liwa	8047	8	19.8	8.12
Offshore	35	4	Woodside, Oxy, Liwa	9070	3	10.4	5.21
Offshore	54	4	Amerada Hess	9769	15	12.4	6.18
Murzuq	177	4	Chevron Texaco	11317	6	12.8	0.6
Sirte	86	4	Oil India, Indian Oil	7078	5	18.4	0
Offshore	18	4	Petrobras, Oil Search	10307	2	31.8	1
Ghadames	65	2	Sonatrach	4374	4	25.0	2
Ghadames	47	4	Verenex , MEDCO	10531	9	13.7	0.25

Source: MEES; Daniel Johnston, 'Impressive Libya Licensing Round Contained Tough Terms, No Surprises', *Oil&Gas Journal* 18 April 2005

Table 2: Awards of the Second Licensing Round

Basin	*Contract Area*	*Block No*	*Company*	*Available Open Acreage*	*Contractor Share of Gross Output (%)*	*Bonus ($ million)*
Sirte	102	4	Oil India/Indian Oil	2,750	10.5	3
Sirte	123	1,2	BG	(2750, 2000)	10.9	7.5, 7.5
Sirte	123	3	Pertamina	2,030	8.8	7
Ghadames	81	1	ONGC Videsh	1,900	11.8	6
Ghadames	81	2	Teikoku/Mitsubishi	2,650	7.5	6
Ghadames	82	3	Teikoku/Mitsubishi	2,500	7.5	6
Murzuq	146	1	Norsk Hydro	2,444	7	7
Murzuq	147	3,4	Turkish petroleum	2,270	9.7	7.262
Murzuq	161	1	Eni	2,750	8.5	3.1
Murzuq	161	2,4	Eni	3,900	7.9	4
Murzuq	176	3	Eni	2,750	9.8	3.3
Murzuq	176	4	Japex	2,750	6.8	3
Cyrenaica	42	1,4	Total/Inpex	3,352	27.8	1.8
Cyrenaica	94	1,2,3,4	Statoil	10,000	24.9	2.95
Cyrenaica	40	3,4	Japex, Nippon, Mitsubishi	4,540	8	1.7
Cyrenaica	44	1,2,3,4	ExxonMobil	10,290	28.5	1.5
Kufra	171	1,2,3,4	Statoil/BG	11,000	19.8	1
Kufra	186	1,2,3,4	Eni	8,400	15.4	1.1
Offshore	2	1,2	Nippon,Mitsubishi	4,650	8	2.5
Offshore	17	3	Pertamina	2,010	11.7	8
Offshore	17	4	CNPC	2,535	28.5	6

Source: MEES

in the Sirte basin). The first round of licensing was concluded in 2005 and resulted in the award of 15 areas covering 126,639 km^2. The oil companies agreed to a total work programme of US$299 million which include drilling 24 exploratory wells and 2D and 3D seismic survey. The upstream licensing round was dominated by Occidental Petroleum and Australia's Woodside Petroleum. Occidental (in partnership with UAE based Liwa) were awarded five blocks. The consortium led by Woodside Petroleum which also includes Occidental (35 percent) and Liwa (10 percent) won an addition of four areas. Amerada Hess won the much contested licence for offshore 54. The first licensing round also saw the return of Chevron/Texaco which relinquished all holdings in the country in 1977. Interestingly, no European company was able to secure a licence. Some observers claim that granting the bulk of licences to American firms was politically motivated as Libya tried to foster its relations with the US government. However, this is unlikely given the nature of the competitive bids. The absence of European firms is better explained by the fact that they have been outbid by their competitors. In any case, Libya was comfortable with such a result as it rebalanced the mix of companies which was heavily dominated by European oil companies.

Encouraged by the success of the first round, the NOC announced a second bidding round in May 2005 offering 44 blocks and 51 companies participated. In the first quarter of 2006, the Libyan government awarded 40 of the 44 blocks covering an area of 94,080 square km. The oil companies agreed to a total work programme of US$482 million which include drilling 36 exploratory wells and 2D and 3D seismic survey. The second licensing round was dominated by European and Asian companies with a strong entry for Japanese oil companies.

In August 2006, the Libyan authorities embarked on a third international bidding round for 14 areas (41 blocks). Seven licences were first awarded on 20 December 2006 followed by three additional awards for areas that only received single bids. The oil companies agreed to a total work programme of $951 million. The third round saw the entry of the Russian firms Gazprom and Tafneft.

Bilateral Negotiations

Libya also awarded some contracts (mainly gas) to foreign companies without going through competitive bid rounds. One such agreement was concluded with Shell in 2005 which involved commitments to spend between $105 million and $405 million to upgrade an LNG facility, and to invest $187 million in exploration of five blocks in the Sirte Basin. Another agreement was reached with BP in 2007 awarding it three offshore and four onshore blocks in the Ghadames basin. These agreements secured the return of Shell and BP into Libya after their departure in 1974. A similar agreement was concluded with ExxonMobil in 2007 over four blocks in contract area 21. ExxonMobil committed a five-year work programme consisting of at least 4000 km of 2-D seismic and 2000 square km of 3D seismic, drilling one deepwater exploration well at cost of $97 million, and payment of a signature bonus of $72 million. Although the awards granted

Table 3: Awards of the Third Licensing Round

Basin	*Contract Area*	*Blocks*	*Company*	*Contractor Share of Gross Output (%)*	*Bonus ($ million)*
Offshore	20	4	Exxon Mobil	22.30	10
Offshore	43	4	ONGC	28	10
Murzuq	113	2	Inpex	12.9	10
Offshore	19	4	Gazprom	10	10.1
Ghadames	82	1	Tafneft	10.4	10
Ghadames	98	2	Tafneft	10.4	10
Sirte	69	4	Tafneft	12	10
Sirte	137	2	PetroCanada	18	10
Murzuq	162	2	CPC	7.8	5
Kufra	201	4	Wintershall	13.5	3

Source: MEES

were not the result of a bid round, it is unlikely that these super majors managed to secure more favourable terms than obtained under a bid, given that Libya applied EPSA IV terms and judging from the extra commitments that these companies made. For instance, the commitment made by BP for exploration was described by Tony Hayward as 'the single biggest exploration commitment' with an initial budget of $900 million.

Renegotiations with Existing Companies

NOC has also been busy renegotiating the outdated contracts with foreign oil companies already operating in Libya. ENI was the first company to renegotiate, followed by Occidental, OMV and PetroCanada. The renegotiations resulted in the extension of these firms' contracts by 25 to 30 years. But this came at a high cost for oil companies as the new contracts involved heavy investment commitments aimed at increasing the recovery rates of existing fields, new fiscal terms in line with EPSA IV harsh terms and hefty signature bonuses. The new terms meant that oil companies' share of post-tax gross production fell dramatically. But oil companies seem to have little choice. As OMV spokesman Thomas Huemer puts it: 'the oil price is much higher than before and therefore NOC wants to adjust its contracts. It is a fact of life that we have to live with.'

Harsh Fiscal Terms

The high interest shown by foreign oil companies during these three licensing rounds may suggest that Libya has been offering attractive fiscal terms. But on the contrary, the Libyan terms have been described as the toughest so far. Take for instance the EPSA signed between the Libyan NOC and Verenex Energy and its partner MEDCO for area 47 granted under the first licensing round. In appearance, the EPSA follows the conventional production sharing contract but there are some major differences. Under EPSA IV, the government followed new procedures with sealed-bid rounds, non-negotiable conditions, selection criteria (based on contractor share, exploration commitments, bonuses, parallel investment and local content), pre-qualification procedures and minimum expenditure commitment. Unlike EPSA III, awards were granted for companies that made the highest bid on the share of gross production going to NOC. This bidding parameter is usually referred to as the production factor while the remaining share going to the contractor is referred to as 'cost recovery'. This can be considered a novelty as the share going to the national oil company is generally pre-determined in the model contract or subject to negotiation. It is unusual for the production factor to be subject to a bidding process. In effect, this production factor acts like a royalty since it is taken from gross revenues and is not accessible to the foreign investor. In our example, the bid yielded a production factor of 86.3 percent or a cost recovery bid of 13.7 percent .This means that the company has to recover its exploration, development and operational costs from its 13.7 percent share of production.

In case of a tie on the production factor, the company offering the highest bonus would receive the licence. Thus, the companies had to compete on bonus payments. As can be seen from Tables 1–3, the bonuses were quite high in some cases especially in the first round of bidding. That being said there is a large divergence in the amount of bonuses paid, varying from zero to $25.6 million. Bonuses are most burdensome to the contractor as they are paid regardless of whether a discovery is made. Furthermore, the contractor is not allowed to recover bonus payments as cost oil.

The new agreements also give the option for NOC to participate in the venture if a commercial discovery is made. In this case, NOC is said to be carried through the exploration phase. In other words, it has the option to take a working interest in the venture without reimbursing the exploration costs incurred by the contractor but it would pay its share of development costs. In the example of Verenex, the NOC has the option to be carried through exploration and obtain a 50 percent working interest of the venture. In return, NOC agrees to pay 50 percent of capital expenditure. The NOC is also carried further through the development phase where it would pay 86.3 percent of the venture's operating expenditures. The NOC pays 100 percent of all royalties and Libyan taxes incurred on each discovery, including the contractor group share.

Until the contractor recovers his costs, the entire 13.7 percent share of production goes to the contractor. Once the contractor recovers his costs, the difference (i.e. profit oil) is shared between the contractor and NOC based on two sliding scales: R factor calculated as the ratio of accumulated receipts by the contractor to the accumulated capital expenditure and the current year total project production rate (P factor). The share of profit oil accruing to the contractor in each quarter is equal to: $R \times P \times$Profit Oil.

As can be seen from this example, the contractor's take is low. Furthermore, there are also limits on how much the oil company can benefit from the upside potential of its investment. In fact, the overall government take for EPSA IV blocks averaged around 88 percent which is considered as one of the highest in the world.

Evaluation

Oil companies' willingness to accept such tough terms indicates how much the oil scene has changed in the last few years. Specifically, these hardened terms can be explained by:

- Libya's attractive geological characteristics where it is considered as a high quality oil province with low cost of production and relatively under-explored in part due to sanctions imposed since the early 1980s
- The limited opportunities available for foreign oil companies to access high quality reserves elsewhere
- Libya's geographic location at the doorstep of Europe
- The competitive nature of the bidding process that NOC adopted

- The current environment of high oil prices; and
- Oil companies' expectations that oil prices will not return to1990s levels.

Although the government feels confident that it will meet its target of capacity expansion from the current level of around 1.7–1.8 mb/d to 3 mb/d by 2010–2013, some risks remain. First, the strict fiscal terms mean that making some of the projects profitable is very challenging. Lower oil prices, unexpected escalation of costs, and/or failing to make big discoveries may render many of the projects unattractive for the contractor. In such cases, the oil company would want to renegotiate existing contracts. These renegotiations can prove costly and may cause serious delays in implementing some of the marginal projects.

Second, there is always the risk that harsh terms may dissuade firms from participating in future rounds. In the latest gas bid round last year, 35 companies were pre-selected to bid for 12 exploration areas (41 blocks) of prospective gas areas which cover more than 700,000 km². This round attracted big players such as Shell, Gazprom, and Sonatrach but the turnout was rather low. Only 13 companies put in bids and so far NOC has only awarded five of the 12 exploration rounds. This lack of interest may be due to lack of the gas potential of the blocks on offer, but also may be related to the unattractive fiscal terms on offer. Unattractive fiscal terms may also dissuade firms from participating in a proposed new licensing round aimed at attracting investment in enhanced oil recovery and improved reservoir management to offset the decline in production from mature fields.

Finally, there is the issue of institutional capacity. NOC has been doing too many things simultaneously: running bids, awarding exploration licences, negotiating with returning US companies, renegotiating with existing operators, conducting bilateral negotiations with some super majors, and trying to develop its gas potential. These activities are taking place against a background of a weak institutional environment, inefficient bureaucratic system, stifling customs procedures, and shortage of qualified employees. Low institutional capacity can delay the conclusion of agreements and the implementation of projects.

Conclusion

Despite its reliance on foreign oil companies, Libya has proved over and over again its ability to impose tough fiscal terms by timing its renegotiations with favourable changes in oil market conditions, introducing innovative bidding procedures, attracting different types of oil companies, and using negotiation tactics that aim at obtaining maximum concessions from one of its partners and then applying the new terms to the other oil companies. The pressures from long sanctions and the desire to re-establish political and economic links with the West do not seem to have changed Libya's approach towards dealing with foreign oil companies. To many observers, this came as a surprise. For Libya, it is business as usual.

Walid Khadduri looks at Algerian petroleum development and its imperfections

Algeria has been able to increase its crude oil production from around 750,000 b/d in 1975 to approximately 1.4 mb/d in 2007. The country also produced in 2007 around 330,000 b/d of liquids (condensates and NGLs), and 168 mboe/d of natural gas. Furthermore, Algeria's national oil company Sonatrach has signed an increasing number of joint venture contracts with IOCs, for projects both inside and outside the country, all along the value chain from the upstream to the downstream. Algeria was able to increase its hydrocarbon production with the assistance of IOCs in the 1990s and beyond at a time when it was adopting a controversial Hydrocarbon Law, and suppressing an Islamic militant insurgency.

The adoption of the 2005 Hydrocarbon Law involved a lengthy period (four years, from 2001 to 2005) and a transparent process (public debates about the draft with civil society, trade unions, political parties, and in parliament). Initially, the draft met strong resistance as there were fears that it would weaken Sonatrach and ultimately lead to its privatisation. Later on, the Law received wider support when the draft was revised to address these and other concerns and to define more clearly the respective roles of Sonatrach and the IOCs in the oil and gas sectors.

The Hydrocarbon Law covered more than issues relating to public/private sector involvement in the oil and gas upstream sector. One of its main characteristics was to distinguish the roles and functions of the State, public sector corporations and private companies in gas transmission and distribution, and in other parts of the hydrocarbon sector. It established a model for the creation of independent institutions which will perform supervisory and regulatory functions in sectors that hitherto had been covered solely by state agencies. The Law provides for the creation of two new agencies, Alnaft, which is responsible for organising licensing rounds and the award of new hydrocarbon exploration licences, and the Hydrocarbon Regulatory Authority which oversees technical regulations, tariffs and open access arrangements for pipeline and storage facilities, health and safety regulations, studies of transportation capacity, and, requests for transportation concessions.

Sonatrach has also opened the door for IOCs to own equity in oil and gas projects in Algeria itself. The In Salah Gas consortium, comprised of Statoil, BP, and Sonatrach established in 2004 (before the adoption of the Hydrocarbon Law), was the first major gas partnership between Sonatrach and foreign operators. The consortium has development rights for seven of the twelve existing fields in the In Salah area which is located south of the country's main gas hub Hassi R'Mel. The In Salah region is crucial to Algeria's plan for increasing its natural gas production. The fields controlled by the consortium contain proven reserves of around 6 tcf, and a potential of 10 tcf in total recoverable gas. Production began in July 2004 from an initial capacity of 880 mcf/d.

Additional gas projects with foreign equity include agreements for three blocks – Ohanet, In Ammenas, and Gassi Touil – in the Illizi province of southeast Algeria. Ohanet, led by a consortium of BHP-Billiton and Sonatrach, is on the northern edge of the Sahara. Production of natural gas, NGL, and LPG in this block began in October 2003. The Ohanet project includes a natural gas processing plant with a capacity for 30,000 b/d of condensate, and 26,000 b/d of LPG.

In November 2004, Algeria awarded to Repsol-YPF and Gas Natural a project at Gassi Touil, a block with around 9 tcf of proven reserves of natural gas. The $2bn integrated project consists of 52 development wells, a 780 mcf/d natural gas processing facility, a 630 mcf/d natural gas pipeline, and a 500 mcf/d natural gas liquefaction terminal at Arzew. Unfortunately, because of long implementation delays and huge cost over-run, the relationship between Repsol and Sonatrach ended up in tears. The contract with Repsol was cancelled and Sonatrach took over implementation of the project.

In July 2001, a consortium led by Spain's Cepsa (20 percent) and Sonatrach (20 percent) agreed to build a gas pipeline linking Algeria and Europe: Medgaz. The $1.2bn 120 mile Medgaz will link Beni Saf, Algeria to Almeria, Spain, with an eventual extension to France. Initial capacity of the line is 390 mcf/d, increasing to a maximum of 1.55 bcf/d. Algeria already has two gas pipelines across the Mediterranean, the 670 mile Transmed, extending from Hassi R'Mel via Tunisia to Sicily and mainland Italy. This line was completed in 1983 and its capacity doubled in 1994. And in 1996, a consortium consisting of Sonatrach, Spain's Enagas and Morocco's SNPP completed construction of the 1000 mile 820 mcf/d Maghreb–Europe Gas pipeline (MEG). The line connects Hassi R'Mel with Cordoba, Spain, via Morocco.

In the downstream, Sonatrach has started construction of a $3bn 300,000 b/d refinery with an IOC partner at Tiaret, located 200 km from Arzew. The project is part of a plan to double the country's refining capacity to around 1 mb/d by 2010, and to upgrade the existing refineries at Algiers, Skikda, and Arzew. Sonatrach also plans to award $7bn worth of petrochemical projects with IOCs during the second half of 2008 to increase production capacity from 360,000 t/y to around 6 mt/y during the early 2010s. Plans also include a Gas-to-Liquids project.

> "because of long implementation delays and huge cost over-run, the relationship between Repsol and Sonatrach ended up in tears"

Algeria undertook these major hydrocarbon projects, among many others, at a time when the country was affected by a struggle between the army and Islamic militants. At first the struggle was with the home-grown Islamic Salvation Front (FIS) following the refusal of the army to recognise the results of the 1991 legislative elections and the subsequent annulment of these elections. Violent clashes continue but now involve the al-Qaeda Organization in the Islamic Maghreb. The intensity of the fighting has lessened and is now at a much lower level than it was in the early 1990s. While FIS did not target oil and gas personnel, al-Qaeda on the contrary put this group at the top of its list of targets. Nevertheless, in both cases the army maintained strong vigilance and provided security for installations and personnel, declaring the oil and gas zones as security areas; and at one point civilians were not allowed to enter these zones without a permit from the Ministry of Defence.

Sonatrach's expanding oil and gas sales to Europe eventually gave rise to differences with the European Union. The EU has been seeking to eliminate the 'destination clauses' (whose aim was to prevent gas from being sold to third parties by specifying the end user of the contracted sale) from contracts with its member countries. This encouraged Sonatrach to consider other markets for its gas.

A second difference has been the result of an understanding between Russia and Algeria to strengthen bilateral relations following the visit of Russian President Vladimir Putin in 2006 and his talks with Algerian President Abdelaziz Boutaflika. The main public result of that visit was Moscow's express readiness to write off Algerian debt in exchange for the purchase of Russian arms. It also transpired later that the talks had expressed a desire for 'successful' gas negotiations between Gazprom and Sonatrach toward a joint development of gas resources in North Africa. The EU is worried about an increased dependence on gas imports from Russia which would increase if Gazprom and Sonatrach were to jointly supply gas to Europe. The leadership provided by Algeria and Russia in the attempts to establish an 'OPEC Gas' organisation is another cause of concern. Will this lead to the emergence of a cartel able in the future to exercise some monopoly power in a European market increasingly dependent on gas for its future energy needs? The moot question is whether these worries are fully justified.

A dispute erupted between Algeria and Spain over how much gas Sonatrach would be allowed to market in Spain. This was partly resolved in July 2007 when the Spanish Ministry of Industry, Tourism and Commerce overturned the Energy Commission (CNE) decision to limit Algeria's freedom to operate in the country. Accordingly, construction of the 210 km

8 bcm/year Medgaz subsea pipeline began in early March 2008. However, the issue was not totally resolved as Sonatrach called for legal mediation of the Repsol operated integrated Gas Touil project.

Conclusion

Algeria is an example of a country which could still go ahead and develop its hydrocarbon industry despite serious domestic challenges. That the armed forces have remained united in the struggle against the militants has certainly helped. The fact that the opposition remained local and did not involve mujahideen from abroad was also a favourable circumstance. The determination of ministers and senior Sonatrach officials to expand production capacity and to undertake the more difficult task of promoting a wide debate about the Hydrocarbon Laws bore fruit. By making necessary compromises along the way they minimised opposition to the Law in the country after its adoption by Parliament. We have seen, however, that in some instances the relationships with foreign companies and with gas-importing countries in Europe were not without difficulties leading to legal processes of conciliation or arbitration.

Philippe Copinschi assesses frustrated contested oil ambitions in Nigeria

A Country in the Middle of an Oil Boom

In 1956 oil was discovered in commercial quantities for the first time in Nigeria, 100 km from Port Harcourt in the Niger Delta. The real take-off of production dates from 1970 at the end of the Biafran war which had pitched the central government against the secessionist forces of the oil region of the Delta. From half a million barrels per day (mb/d) in 1969, production rose to 1 mb/d in 1970, 1.5 mb/d in 1971 and 2 mb/d in 1973. Today Nigeria produces about 2.5 mb/d and its reserves stand at more than 35 billion barrels, which is about 70 percent of the reserves of sub-Saharan Africa and about 30 percent of total African reserves. Thus, Nigeria is the largest producer of sub-Saharan Africa and represents almost half the production of the region. It is the sixth largest producer in OPEC, after Saudi Arabia, Iran, Venezuela, the UAE and Kuwait.

> “unlike many OPEC members Nigeria has never completely nationalised the operations of the companies”

That production and reserves are continuously increasing is due to the dynamism of the investments by the oil companies since the end of the military dictatorship in 1998 and to the numerous discoveries in the last few years in the deep offshore (Bonga, Agbami, EA, Yoho, Erha and so on). The share of the offshore (about 50 percent) is relatively small by comparison with neighbouring countries but growing fast. During the last ten years significant deposits have been discovered in the deep and very deep offshore and are progressively coming into production. Production capacity in Nigeria will therefore increase as fast as the development of recent discoveries, even if the actual production remains theoretically limited by the OPEC imposed quotas.

With the exception of BP, all the majors are involved in at least one project, either as operator or partner. For although Nigeria has been an OPEC member since 1971 and, following its recommendations, has put in place a policy of nationalising the oil industry, progressively making the national oil company (Nigerian National Petroleum Corporation, NNPC) a partner of the foreign companies, unlike many OPEC members Nigeria has never completely nationalised the operations of the companies. Of course the NNPC has gradually become the majority partner in all joint ventures, but the foreign companies remain the operators (the main joint ventures are operated by Shell, Chevron, Mobil, Agip and Total). The NNPC receives by right about 55 percent of output, but 98 percent is produced by the companies.

In addition, Nigeria possesses significant reserves of natural gas (5.2 trillion cubic metres at end 2006, or a third of the reserves in Africa). This places Nigeria sixth in the world after Russia, Iran, Qatar, Saudi Arabia and the United States. Its gas production is increasing fast (more than 28 billion cubic metres (bcm) in 2006 against 6 bcm in 1999). This huge growth can be explained by the fact that gas, in particular associated gas, was neglected for a long time by the oil companies who until the 1990s flared it off since they were unable either to use it in the local market or to export it.

In the framework of a strategy aiming to eliminate flaring completely by 2010, a large gas liquefaction plant was inaugurated in 1999 on Bonny Island, operated by Shell as part of a joint venture bringing together the Nigerian gas company (NLNG), Total and Agip. The site, large enough for six liquefaction trains (about 20 bcm per year), exports its production to the USA and Europe. Other gas projects are being developed, for example the construction of liquefaction plants and a regional gas pipeline (the West African Gas Pipeline, 900 km in length). This is supported by the World Bank and intended to supply Benin, Togo, Ghana and the Ivory Coast with Nigerian natural gas. Finally, a gas pipeline project to cross the Sahara is frequently mentioned; this would enable natural gas to be exported from Nigeria to Algeria and then – by connecting to the network of Algerian gas pipelines – to Europe. However, it is not clear whether there is an industrial interest in this project.

Perspectives and Problems

The management of the NNPC aims to reach 40 billion barrels of oil reserves and 4 mb/d of oil production by 2010. This ambitious objective is based on the fact that all the majors, American and other, have large projects in the course of development in Nigeria and these should come into production in the near future. Nevertheless, several major problems are restraining the growth of production in the country.

First, political and ethnic tensions make it very dangerous for the oil companies to operate – particularly in the onshore areas. The taking of oil company employees as hostages, acts of sabotage against installations and intimidation have become frequent in the Niger Delta. Several times over the last few years the main foreign oil companies have had to suspend part of their operations for reasons of security. Indeed, attacks on Shell pipelines recently led to a drop in production of about 169,000 b/d for shipments in April and May. As a result the company announced it would be unable to honour its contractual obligations at the Bonny Terminal for those two months.

Although Nigeria is not officially at war, in the Delta where the oil is extracted there is a high level of criminal violence and rebellion is endemic within political activism and economic banditry. The people of the Delta know that the oil generates enormous wealth from which they do not benefit. This situation creates resentment, not only against the enterprises that produce this wealth but equally against the heads of the community who are accused of colluding with the companies. The cultural region of the Ijaw is today among the most affected by agitation against the oil companies. Confrontations between militias regularly result in deaths. Groups like the Niger Delta People's Volunteer Force (NPDVF) increase their attacks against companies such as Shell, Chevron, Agip, Total and so on. This movement is emblematic of the rootlessness of Ijaw youth of low social status who are unemployed and who are watching the benefits of the oil economy pass them by. They preach violent action and proclaim secessionist views, while trafficking in oil. Shell produces 40 percent of Nigerian crude but each day it loses 10 percent of its production through sabotage. Hostage taking is also increasing, for example in 2006 the Movement for the Emancipation of the Niger Delta (MEND) abducted nine expatriate workers from a company sub-contracted by Shell.

By virtue of its seniority and pre-eminence in Nigeria, Shell is often the primary target in a conflict. Relative to Shell, other companies have been saved from attacks by the population for the simple reason that the main part of their production – the whole in the case of Mobil, two-thirds in the case of Total – comes from reserves far from the coast whereas Shell's activities are all onshore.

> "widespread corruption is another indicator of the dysfunctioning of the political, economic and social institutions of the country"

In addition to attacks, kidnapping and ransom demands, there is also theft of equipment and piracy from pipelines. This technique known as bunkering consists of siphoning off oil in order to resell it as contraband and affects between 5 and 10 percent of Nigerian production. It is this aspect, which is proof of another type of criminality, that will be the most difficult to combat, for it reveals undeniable complicity between company employees and the mafias who resell the oil on the black market. Oil engineers secretly help the pirates by informing them of the whereabouts of the key points and precise layout of the pipelines, both underground and subsea. Within the context of an economy based on rent and extraction, not to mention looting, the oil boom of the 1970s destroyed the structure of Nigerian society, inflamed armed banditry, hastened the flight of capital and distorted a productive economy which, at independence, was largely based on agriculture.

Secondly, the widespread corruption is another indicator of the dysfunctioning of the political, economic and social institutions of the country and is a further obstacle to the development of economic activity in general and oil in particular. Nearly fifty years after independence Nigeria has still failed to find a model of economic development which would allow it to valorise its oil wealth. Oil represents 95 percent of its export receipts, 80 percent of budget receipts and 40 percent of gross domestic product. This places Nigeria among the top six oil-exporting countries, with revenues of more than 34 billion euros in 2006. However, in the last United Nations Development Report Nigeria was placed at 159 out of 177 in terms of human development, a drop of nine places since 2000 – despite an increase in production and in the price of oil on the world market. This low level of development is explained above all by the fact that with a population of 130 million (the most populous country in Africa), the redistribution of the oil rent takes place in a context of widespread corruption and clientelism, and a large part of the political elite have no consideration for the general interest and the public good.

Thirdly, the Nigerian state's huge economic and financial difficulties mean that it is regularly unable to cope with its obligations vis-à-vis the foreign companies associated with the NNPC. In a joint venture each partner (NNPC and foreign company) contributes to the financing of operations in proportion to its participation. The overdue payments of the national company amount to hundreds of millions of dollars. These recurring problems with delayed payment of the quota of the NNPC push the companies to demand a reduction of the NNPC share in the joint ventures, or even to replace them by production-sharing contracts. In these contracts the entire exploration and development costs are initially borne by the foreign company which is later compensated by a share of the production. For several years the government has offered production-sharing contracts for new projects in the Nigerian oil upstream, particularly those concerning offshore production.

Finally, Nigeria is a member of OPEC and as such it is subject to production quotas. Thus its oil production cannot increase to any great extent in the near future unless it succeeds in renegotiating its quota. It is not clear that this would be possible. In practice, a country like Nigeria has only a marginal effect on the protection of prices. Its quota is more formal than real and Nigeria respects it largely because it corresponds more or less to its production capacity. Before the deep offshore 'boom' there were no prospects of a significant growth of capacity in the country. Today it seems unlikely that Nigeria will curb the development of the many and prolific recent discoveries for having failed to obtain a reevaluation of its quota.

Gerald Doucet and Latsoucabé Fall stress the importance of the Inga hydropower projects for Africa

Introduction

Access to electricity is very poor in Sub-Saharan Africa and this has contributed to the continued poverty and underdevelopment that ravages the continent. Electricity is a bridge to provide sustainable access to modern energy and contribute to sustainable development. It is a cornerstone for economic progress, social development and environmental sustainability, and is imperative for harnessing technological development.

Development of the huge African hydropower potential, of which only 7 percent is presently exploited, will bring adequate electricity supply to Africa, and thus contribute substantially to the achievement of the three WEC Millennium Energy Goals of accessibility, availability, and acceptability, which are the fundamental pillars for achieving the sustainable supply and use of energy.

In that perspective, the Inga projects offer a unique opportunity to provide affordable and clean electricity to more than 500 million Africans who do not have it today, and to promote economic interdependence and peace and prosperity.

In particular, the development of Inga 3 and Grand Inga, as African integrator projects, will offer a great opportunity for supplying the majority of the African energy market, including the South African Power Pool (SAPP) countries in Southern Africa, and also other African countries in the West and North and East regions, via the other African Power Pools, namely the WAPP, PEAC, EAPP and COMELEC.

Africa's energy needs are immense and continue to increase substantially, due to growing population, improvement of living standards and economic development. However the energy infrastructure is weak and the quality of energy services is poor. Electricity demand, estimated at 84 GW (515 TWh) in 2005, is expected at least to triple by 2030 (reaching 260 GW (1590 TWh) to 310 GW (1900 TWh)); of this demand, 87.4 percent is concentrated in Southern and North Africa (53.2 percent and 34.2 percent, respectively) and 8.1 percent in West Africa. A large increase in the electricity supply will be necessary to meet this demand.

Therefore, the World Energy Council (WEC) intends to support the Inga projects and to bring the relevant organisations and actors to carry out the renovation of existing installations (Inga 1 & 2), and the development of the Inga 3 and Grand Inga hydropower projects.

Background to the Inga Projects and current Issues

The Inga hydropower Projects are located on the low course of the Congo River, in the so-called Inga Hinterland area, about 250 km south west of Kinshasa (Democratic Republic of Congo, DRC) and 150 km from the West Atlantic Ocean. They would offer large energy potential and great benefits for the DRC and other African countries, if realised in a cost effective and timely way.

> "Electricity is a bridge to provide sustainable access to modern energy and contribute to sustainable development"

A hydropower potential of more than 44,000 MW is concentrated in the site, with potential annual energy production estimated at more than 320 TWh. But barely 4 percent of that potential is currently developed at Inga 1 and 2 power stations. These two power stations contained 73 percent of the total installed capacity of the country and produced two-thirds of the electricity generated in the country in 2005.

At present, two hydropower projects are being considered for future development in the Inga site, namely Inga 3 with a generating capacity of 4320 MW and Grand Inga with a hydropower potential estimated at 40,000 MW. Once the Grand Inga project comes into operation it would be the world's largest hydropower scheme, with about twice the generating capacity of the Three Gorges in China (22,400 MW) and three times that of Itaïpu Binacional Project between Brazil and Paraguay (14,000 MW).

Inga 1 & 2

The two existing power stations located in the Nkokolo valley, namely Inga 1 & 2, totalled an installed capacity of 1775 MW: 351 MW for Inga 1, commissioned in 1972; and 1424 MW for Inga 2, commissioned in 1982. SNEL (Société Nationale d'Electricité), the State owned National Electricity Utility, owns and operates these installations. However, at the moment, they are both functioning well below their nominal generating capacity (respectively 52 and 34 percent).

Renovation works are currently being undertaken on a few plants (plant number 2 of Inga 1, funded by the World Bank; and plant number 3 of Inga 2, funded by a public/private partnership with Mag-Energy). However, these works are insufficient and need to be reinforced by a complete and in-depth renovation programme, which would probably last between four and five years. It is also worth mentioning that the work currently being undertaken at the Inga 1 and 2 plants is experiencing a delay of at least fifteen months.

Inga 3

The pre-feasibility study of the Inga 3 project is now completed and was presented to the stakeholders in Kinshasa in February 2008. The technical, environmental and financial aspects of the project have all been examined in the SNC-LAVALIN study. The planned installed capacity of the power station is 4320 MW (sixteen plants of 270 MW power capacity each, equipped with Francis turbine with vertical axis).

The power station will be constructed in two phases: phase 1, 2009–2018 for an investment cost of US$1974 million, and phase 2, 2014–2021 for an investment cost of US$1569 million. (Thus the total construction cost is estimated at US$3.5 billion).

In order to move from the pre-feasibility study into a feasibility study, geological and hydraulic studies (mathematical model to simulate water behaviour) will need to be undertaken. The cost of these studies is estimated at US$5–6 million and could be funded by BHP Billiton or the European Investment Bank. The predicted timeline for their completion is estimated at one year from now, and this will allow the construction phase to start in 2009; meanwhile the feasibility study of the transmission system will be financed (likely by EIB) and carried out by an international consultant.

Preliminary investigations identified two main transmission routes from Inga 3 – one to Westcor countries (DRC, Angola, Namibia and South Africa) and a second to Moanda (150 km) to supply BHP Billiton aluminium smelter.

According to the DRC Government, the Inga 3 Project could be envisioned as a public–private partnership for the development, construction, operation and management of the facilities (power station and transmission system). The Government would hold a minimum share, allowing private shareholders to be involved and to play an important role.

Grand Inga

Grand Inga will be located in a natural valley of the Inga River with a reservoir naturally laid as a big basin with its own side and front walls. The area is quasi empty in terms of habitats and no one resides in the valley.

Key technical characteristics of the electricity facilities are:

- Potential capacity will be 40 GW (pre-feasibility study done by EDF & Lahmeyer International in 1997);
- Investment cost of the hydro plants is estimated at over US$40 billion;
- Investment cost of the transmission system is estimated at over US$40 billion;
- Selected interconnection transmission system (HVDC) would include:
  – Northern Highway (Inga–Sudan–Chad–Egypt, 5300 km),
  – Southern Highway (Inga–Angola–Namibia–Botswana–South Africa, 2734 km), and
  – Western Highway (Inga–Congo–Gabon–Cameroon–Nigeria (Calabar), 1400 km).

The overall project will be capital intensive, requiring huge investments (probably exceeding US$80billion) as well as technical and managerial skills and expertise to operate and maintain the facilities. Grand Inga would be the most powerful hydropower scheme in the world, with a very low production cost estimated at around US cents 1.1 to 1.4/kWh (compared to an average cost of US cents 4/kWh for coal, and even more for other energy sources such as fuel, gas, wind, solar and nuclear).

> "Once the Grand Inga project comes into operation it would be the world's largest hydropower scheme"

It has been estimated that when it is commissioned in around 2025, the Grand Inga contribution to African electricity demand would be between 26 and 30 percent. Consequently, most of the African energy demand would be met through the five African power pools, and the project would improve the lives of over 500 million Africans who are without access to electricity.

In order to allow the construction phase to start as soon as possible, and in line with the need to meet the growing and urgent energy needs of South Africa (Eskom) and other African countries, the feasibility study of Grand Inga should be funded and performed as soon as possible. Consequently, the search for finance is urgent and crucial; the total financing required is estimated at between US$15–20 million.

Social & Environmental Issues

The social and environmental aspects of the Inga site, emphasised by the official representatives of the Inga Hinterland are related to the legacy of the existing dams and electricity facilities. A detailed study on the environmental and social impact has been carried out by SNC-LAVALIN in the context of the pre-feasibility study of Inga 3. For that purpose, 365 people were surveyed (including 21 public hearings and interviews with 32 opinion leaders) and a site survey was conducted as well, to evaluate the impact on several factors, including quality of life, quality of the water, electricity access, supply of drinking water, livelihoods, ecosystem, compensation, displacement, fight against diseases, and so on. In order to overcome the possible related problems and to minimise the impacts, the study recommended creating an *Environment and Social Management Plan*, which will be implemented, managed and monitored by an *Environmental and Social Unit* to be set up by the DRC authorities.

As for the Grand Inga which is more complex with the creation of a reservoir, the design needs to be carefully considered so as to achieve zero or minimal environmental impact. Nevertheless, there are positive aspects with regard to the site of Grand Inga, because there are no humans or animals, fauna or flora that would need to be relocated for the introduction of the infrastructure. The site is naturally laid as a big basin with its own side and front walls and the machines could be installed into the natural walls.

In a nutshell, the *Environmental and Social Management Plan* should make certain that the benefits of the Inga projects are maximised and that negative social and environmental impacts are avoided, mitigated or compensated for. This will ensure that the Inga projects meet the 'Sustainability Standards'.

Further cooperation should also be established with local and regional activist groups, environmental defence and civil rights organisations, to work together to take into account the social interests and needs of the local population and affected communities, as well as to preserve the environment.

Principles

In order to improve the chances of success, the World Energy Council identify the following principles to move forward:

- Scaling up energy access through the development of the Inga projects, to overcome poverty in Africa, as well as to promote economic interdependence and peace and prosperity ;
- Promoting cooperation with African stakeholders and international supporters;
- Involving the potential stakeholders in direct relation with the project, namely countries crossed by the transmission lines, customers, energy companies, civil society, local communities, and so on;
- Developing a commercial project under favourable conditions, for instance by government guarantees to underwrite the risks;
- Creating a promotion company and a holding company;
- Creating an Inga Zone, a sort of hub for manufacturing and engineering support, in order to develop local manufacturing and to facilitate job creation for African workers; this hub should be implemented before the beginning of the construction phase of Inga 3.

Moreover, changing market conditions in the electricity sector (liberalisation/privatisation), as well as demands from the financial sector which is eager for high and short-term returns on investments, means that these projects must have strong political support from the DRC Government, the African Union, African Development Banks and Regional Economic Communities, as well as international Institutions.

WEC Actions and Prospects to move ahead on the Projects

From 16–17 March 2007, the WEC held an International Forum in Gaborone, Botswana on 'How to make the Grand Inga hydropower project happen for Africa'. The forum brought together high-level representatives from governments, top-level executives from major energy companies and related businesses, leading financial institutions and the WEC Member Committees. An Action Plan was established, and three Phases to move ahead were identified:

Phase 1: Ensuring support by a broad range of stakeholders, including G8 and establishing a Promotion Company (PROCOM).

Phase 2: Setting up a project framework and establishing a Holding Company (HOLCOM).

Phase 3: Developing the project, raising finance and preparing for construction.

A 'Team Inga' open to external companies/institutions was established at the Forum to achieve Phase1 of the WEC Inga Action Plan, under the leadership of WEC.

The WEC is also planning to organise a high level workshop on the financing of the Inga projects, in London from 21–22 April 2008. The main objective will be to identify the key financial requirements and partners for an accelerated and sustainable development of the projects. The workshop will also be the opportunity to launch the creation and financing of the Promotion Company and to define the bases of the Inga Infrastructure and Services Integrated Zone.

The creation of PROCOM should facilitate and accelerate the start-up of the Inga 3 and Grand Inga projects as well as the refurbishment and renovation of the existing facilities (Inga 1 & 2 power stations, HV transmission system and MV and LV distribution network).

The Inga Infrastructure and Services Integrated Zone would be a hub to support engineering, equipment maintenance and other services and manufacturing, in order to develop technology transfer and local capacities and to facilitate job creation. Its establishment would be facilitated and supported by a consortium of suppliers (equipment and material producers and other contractors), PROCOM, DRC and other governments – the World Energy Council and Team Inga will help in establishing this Zone.

US Presidential Candidates and Energy

Michael Lynch

With one of the most contested presidential elections under way in the United States in decades, the impact on the energy industry is a particularly relevant issue. On the one hand, all three remaining contenders are likely to be much less favourably inclined to the energy industry than the current Administration; on the other hand, there are serious nuances between them.

And it must be admitted that the current Administration has not been successful in delivering the kinds of benefits to the oil and energy industries that many had expected when it was elected, partly due to conflicts with the Democrats in Congress. (The initial energy policy proposal quickly became mired in legal difficulties over who had advised the Vice President in its construction.) But also legal challenges have restricted some of its preferred policies, especially where environmental regulations have been involved.

George W. Bush and Richard Cheney had rather brief careers in the petroleum industry, but were assumed likely to adopt strongly pro-industry – and pro-Arab –industrial and foreign policies. Instead, Bush immediately embraced Israel's Ariel Sharon as a 'man of peace' and failed to deliver any significant benefits to the petroleum industry, which had hoped for better access to prospective drilling areas in Alaska, the Rockies and the Gulf of Mexico. Only modest benefits have accrued to the energy industries, as nearly all of the Administration's energy policy proposals have been blocked by the opposition in Congress. (Then, too, the war on terror and the war in Iraq have diverted most of the Administration's attention from other policies.)

The industry did benefit from the Administration's environmental policies, which attempted to roll back the Clinton Administration's late-hour shift in the approach to New Source Review. That move had tightened regulations on existing energy facilities (especially utilities) that maintained or modernised their plants. They also fought attempts to have carbon dioxide declared a pollutant subject to federal regulation, thus slowing environmentalists' legal efforts to fight global warming. And they were resistant to proposals to increase regulated automobile efficiency standards, which were, nonetheless, passed into law last year.

However, it appears as if the next Congress will be somewhat more liberal and Democratic, making it easier for some policy changes to be enacted, depending on the identity of the President. Most notably, all three candidates can be expected to take a stronger stance on curbing greenhouse gas emissions, and to do it fairly quickly. Much of this will take the form of subsidies, as all three embrace the notion that renewable energy is good for both the environment and the supposed improvement in energy security. Given the recent move to regulate higher automobile efficiency, new steps in that direction should not be expected, at least initially, but Clinton has suggested raising fleet efficiency standards to 55 miles per gallon by 2050, and Obama proposes doubling efficiency by 2025.

The fight for US energy independence, which was lost decades ago, remains on the minds of all three, who argue for a combination of increased biofuel usage and Clinton and McCain highlight the potential of plug-in hybrid vehicles. None, admittedly, is very open about the difficulty (or impossibility) of eliminating US oil imports, or the irrelevance of reducing oil imports from the Middle East.

On the other hand, taxes could be a major battle, particularly if imposing some form of carbon or energy tax is attempted again. The last time this was tried, in the first Clinton Administration, a huge political and lobbying battle ended the effort very decisively. But the changed political atmosphere, and the greater concern about global warming, might encourage the Democratic candidates to try again; John McCain is almost certain to resist any such effort.

Still, the three candidates remaining are actually strongly similar in their views on energy and the environment, at least compared to the current Administration. Both Clinton and Obama have released detailed policy statements, while McCain has made remarks indicating his general preferences, but these conform to what is understood about their inclinations.

Global warming is the most important issue for at least the Democrats, but all three candidates support cap-and-trade systems to reduce long-term greenhouse gas emissions (Clinton and Obama 80 percent by 2050, McCain 65 percent), and all are technological optimists, pointing to other challenges met and overcome (most of them not very relevant, such as McCain's noting the massive improvements in cell phone technology).

Still the fiscal situation for the oil industry is likely to worsen, as all three candidates view it unfavourably. Both Democrats have made clear that they will reduce so-called tax breaks on the industry and redirect the funds towards (primarily) renewable energy, and while John McCain has not taken as strong a stance on taxing the industry, he has not been regarded as friendly to it.

On the other hand, McCain's focus on national security and the war on terror could see him pushing some aggressive attempts to reduce American dependence on imported oil, especially from the Middle East. This could include a new push to open up more US territory for drilling, including ANWR in Alaska, but might also devolve into efforts to 'acquire' access to non-Middle Eastern sources. Past such efforts have been relatively marginal and low-cost, with limited success, but diplomatic pressure on oil producers (Russia, perhaps?) to allow easier access for exploration are likely to ensue.

The two Democrats can be expected to favour a demand-side approach, pushing for appliance and building efficiency standards, for example, and possibly taxing large vehicles, while subsidising efficient ones. Funding for mass transit and railroads will increase, but probably not enough to make a significant difference in the short or medium-term. Clinton has proposed a $50 billion Strategic Energy Fund with financial assistance to low-income home owners and automakers alike, while Obama supports a ten-year $150 billion Clean Energy Fund, with emphasis on both R&D and working retraining. (McCain emphasises tax breaks for R&D rather than government spending.)

The fuel of choice for power generation is going to be a major source of conflict, whoever the next president is. Coal has many environmental problems, but much political support in both parties; even green Democrats listen to coal miners' unions. As a result, policies to reign in emissions from coal combustion are heavily focused on new technologies, including those that allow economical carbon sequestration. Only Obama seems ready to ban construction of 'traditional coal facilities'.

Nuclear power's public perception remains schizophrenic, with many environmentalists still opposed to it, but growing support among the general public. A McCain administration is likely to encourage new power plant construction, and while neither Democrat will evince the same level of support, either one might come to accept it. Given Barack Obama's more populist credentials, he is the most likely to push for wind and solar over nuclear, while the more pragmatic Clinton has noted the benefits of 'emission-free' nuclear power.

And while the traditional liberal view of microeconomic regulation, such as requiring specific technologies for emission control, appears to have become discredited, nonetheless, the two Democrats are much quicker to emphasise government spending programs in support of new energy technologies, particularly renewables, especially where they appear to provide for the creation of new jobs. McCain, on the other hand, emphasises R&D and deregulation as means to improve overall efficiency of energy programs.

Also, both Democrats can be expected to adopt much stronger etatist attitudes, attempting to 'correct' market imperfections, something the current oil price has highlighted. While it is possible that they will attempt to reign in 'speculation' such as investment in the commodity index funds, the complexity of the task should defeat them. More likely, an SPR drawdown such as occurred in 1996 to dampen then-exorbitant crude prices, would be used to deflate the current oil price bubble.

In the past, energy-policy making (and policy analysis) has suffered from a boom and bust cycle largely correlating with energy prices – and public attention. However, this seems somewhat less likely this time, as worries about global warming, energy security, and high energy prices are much less likely to fade as quickly as similar problems in the past. Thus, not only will energy policy-making for the new administration be a high priority, but unlike previous administrations, early efforts seem less likely to be abandoned when they meet resistance.

Of course, given past policy failures, often caused by overreaction to transient problems, this can hardly be considered a good sign.

Comments on Gas Demand, Contracts and Prices

James T. Jensen

The February issue of the *Oxford Energy Forum* contained five excellent articles on the future role of natural gas. There appear to be two recurring themes – strong growth in gas demand and issues of contracting and pricing.

Gas Demand Growth

Superficially, there appears to be a conflict between Michael Stoppard's optimistic description of the very large increase in LNG capacity between now and the year 2010 and Jonathan Stern's more subdued recounting of the forces that are likely to constrain future gas supply. In fact, the two positions are not inconsistent since they focus on two different time periods. With a four- to five-year lead time between the initiation of a new LNG (or pipeline) project and its completion, Stoppard is effectively describing capital expenditure decisions that were set in motion between 2003 and 2006. Stern is asking whether the present growth in gas supply is likely to continue once the existing wave of new capacity is finally completed.

Much has changed in world energy markets since the early part of this decade. In 2000 North America experienced its gas price shock, and revived its long-dormant interest in LNG. Spain was in the midst of a surge in demand for LNG that would make it the Atlantic Basin's largest LNG importer by 2002. And by 2004 the UK had changed from a net exporter of North Sea gas to a net gas importer.

But perhaps the biggest change has been in energy price levels. In 2003, Brent crude averaged less than $29 per barrel. Last year it averaged more than $75 – up 160 percent over 2003. Gas prices have also risen, but their increase has been far more modest, substantially altering the earlier relationship between gas and oil prices.

Obviously, there has been a rather dramatic change, not only in absolute energy price levels, but in the relative prices of fuels that compete with one another in the marketplace. And it raises two interesting questions: What effect will the uneven energy price increases have on interregional gas trade? and What determines the price of long- term gas supply? When coupled with the fact that construction costs of both pipelines and LNG facilities have risen substantially in the last several years, it should not be surprising that there is a lot of soul-searching going on over capital investment decisions for new gas projects.

Both the IEA and the EIA, in their periodic forecasts, have weighed in on the first question. Both agencies have been progressively reducing their projected estimates of gas demand and increasing their estimates of gas production. The net effect of these two price responses has been to squeeze the expected level of interregional gas trade required to balance supply and demand.

Last year, Jensen Associates undertook a study for the California Energy Commission projecting world LNG trade out to the year 2020. Our estimates came in well below most other public projections. They were based on two assumptions: 1) they accepted the view of the IEA and EIA that high prices have depressed the long-term outlook for interregional gas trade, and 2) they concluded that there are increasing constraints on the potential for new supply projects. These include both those geopolitical constraints that Stern has outlined in his OEF piece, but also concerns about costs and the technological and economic challenges inherent in increasing reliance on Arctic gas supplies for new projects.

While the forecast for the California Energy Commission focused on LNG, it necessarily had to make assumptions about the balance between LNG and pipeline trade. In this context, it is worth noting that both North America and Northeast Asia will be dependent on LNG for their interregional imports, while Europe, China and India have both supply options. On the supply side, the two largest long-term future potential suppliers are the Middle East and the FSU (Russia plus the Central Asian Republics). The Middle East supplies are likely to be predominantly in the form of LNG while the FSU's will be largely by pipeline.

It is apparent that our low forecast rests on conservative assumptions, both of the future demand for gas, and of the willingness of suppliers to provide it. What can go wrong with these assumptions?

On the supply side, there are obviously great uncertainties. Relying for future supply on countries that have not previously been LNG exporters (or even gas exporters) and have not shown much enthusiasm for LNG is problematic at best. The supply estimates could be higher or lower and the results will have a significant effect on future supply/demand balances and on prices.

On the demand side, the 800 pound gorilla in the room is carbon regulation, which has the potential to shift much of the stationary energy demand to gas. If the optimistic gas demand forecast materialises in the face of supply constraints, it would obviously threaten substantial price increases.

Contracts and Pricing

A common assumption during the early days of gas market liberalisation was that gas would become just another internationally traded commodity. Long-term contracts would become obsolete and an LNG-based international pricing system would develop. To date, gas has failed to follow that script. While international gas markets are more flexible than they used to be, and LNG provides a degree of interregional price arbitrage, the long-term contract is far from dead. And there is no consistent international approach to gas pricing.

Two major differences between gas and oil are gas capital-intensive, front-end-loaded investment pattern and for pipelines, at least, geographic inflexibility. The first characteristic means that projects are usually debt-financed and someone has to assume the obligation to cover debt service. And the second characteristic exposes buyers to the risk that their suppliers will fail to deliver.

Burckhard Bergmann addresses the second issue in describing Germany's need to compete for future supply and to diversify its supply risks. He suggests that the future industry structure will include some mix of long-term contracts and spot market transactions.

He speaks from the perspective of the country that imports more Russian gas than any other except the Ukraine, and is thus in the centre of the controversy between Russia and the European Community over supply reliability. But Germany is not alone. The issue of third country transit rights has long plagued natural gas pipeline projects and has often fostered less economic LNG projects as a means of avoiding the geographic limitations of pipelines.

The contract issue is essentially about risk sharing for capital-intensive gas projects. While the North American gas markets have largely dispensed with long-term contracts, there is nothing inherently inconsistent between long-term contractual relationships and free markets. For capital-intensive projects, the contract provides assurance to the financing agency of debt service coverage by the parties to the agreement. It also provides a mechanism for risk-sharing between buyer and seller. (Not to mention rent sharing with host governments) The old adage, 'The buyer takes the volume risk and the seller takes the price risk' has led to take-or-pay clauses for the buyer and price escalation clauses for the seller in traditional contracts.

The concern for financial risk protection remains, even in fully-liberalised markets. For new pipeline investment in North America, for example, the sponsor holds an 'open season' for potential shippers to acquire capacity. If the project is viable, the shippers then assume a ship-or-pay financial obligation to the project sponsor. While not a long-term contract in the traditional sense, the resulting control of capacity may also inhibit more flexible commodity competition. .

In traditional contracts, the pricing clause was most commonly linked to oil prices – crude oil in Northeast Asia, oil products in Europe. But in the liberalised markets of North America and the UK, where gas-to-gas competition prevails, such clauses put the buyer in an impossible position when gas prices fall below oil levels. A resulting temptation to protect the buyer by linking pricing clauses to gas market indicators, such as Henry Hub or the NBP, effectively shifts much of the project risk to the seller, since the buyer can so easily cover his risk by trading in the liquid spot market. The response of the sellers is to integrate downstream through what might be described as self contracting. Increasingly, we are seeing project venture partners contracting with their own ventures to sell the gas downstream in North America or the UK. The contract commitment is still there, but it has moved upstream from the earlier buyer/seller interface.

Stoppard calls this group 'aggregators' and describes how they provide destination flexibility similar to that provided by the spot market. As he points out, they are most common in the Atlantic Basin, where North America/Europe arbitrage is active, and the Middle East, which can act as the arbitrage agent between the Atlantic and Pacific Basins.

However, the flexible Atlantic Basin contracting is largely focused on the liberalised markets in North America and the UK. Much of the Continent still retains traditional long-term contracts. The fault line between the two systems runs down the middle of the North Sea between the UK and the Low Countries and inward from the Continent's Atlantic LNG re-gasification terminals.

Many long-term contracts – both LNG and pipeline – are now in a state of flux. The price caps and S- curves in oil-linked contracts that were included to protect buyers from oil price shocks are now protecting buyers from what suppliers argue is a new permanent level of world energy prices. Japanese LNG prices averaged 101 percent of JCC (the Japanese crude price indicator) in 2002; but in 2006, they averaged only 64 percent. Vigorous efforts at contract renegotiation and a number of international contract arbitration disputes are underway in essence to resolve the question: What determines the price of long-term gas supply? This raises the issue of gas pricing, a recurrent theme in a number of the articles.

Theorists would argue that its value should be established by price competition in a free market. But a number of the articles point out that pricing systems differ in various parts of the world, and describe some of their departures from the ideal. Thierry Bros argues that the liberalised UK market may have worked well in surplus, but as the UK has become a net importer, it provides a highly volatile pricing system with little or no price guidance for making long-term investment decisions. In short, it does not provide the answer to the question: What is future gas worth? And financial derivatives have lost some of their lustre as a tool to provide long-term future price certainty following the Enron debacle.

Stern discusses the common underpricing of gas practised by gas-exporting countries and describes some of the market distortions that result, both in the Gulf and in Russia. Simon Pirani details Russian progress towards adopting European netback pricing as a means of correcting these distortions.

The Unanswered Question

During the 1970s and 1980s, when North America and the UK restructured their gas industries, the working assumption was that market competition would set gas prices and oil prices would be irrelevant. In such a formulation, the traditional long-term contract, with its linkage to oil prices, was viewed as a relic of an over regulated era.

The position of both those market structure options has changed significantly since that time. North America and the UK both liberalised when their domestic markets were in surplus and supplier competition cut prices below oil parity levels. Now the surpluses in both regions have disappeared and they – like the Continent and Northeast Asia – have become importers.

When the North American supply surplus disappeared in 2000, oil prices once again became important through inter-fuel competition in boiler applications. The UK had a short price run-up following its transition to net import status. But both regional markets are now in sufficient balance that they are in gas-to-gas competition – their prices remain well below oil parity levels.

There has also been a substantial change in the position of the oil-linked contractual markets on the Continent and in Asia. The use of oil-shock-limiting clauses in long-term contracts has effectively decoupled gas and oil prices in many of these markets. In 2007, the relationship between border prices and Brent for the six largest Continental markets ranged from 58 percent in Italy to 72 percent in Spain. In Japan it was 59 percent; in Korea 73 percent. But there is some evidence that the low relative prices in Northeast Asia have enabled some buyers to cross-subsidise spot LNG cargoes at prices well above oil parity.

The push by producers to restore the oil link, either by contract renegotiation or international arbitration, is strong. Few would argue that oil prices any longer have the competitive meaning that they once had, but it has been difficult to find a suitable substitute. But Tokyo Electric's efforts to replace its lost nuclear generation suggests that – were Japan markets fully liberalised – gas and oil prices might still be indirectly linked.

In Northeast Asia tight markets, suppliers' efforts may well meet with success. On the Continent, the competition from the gas-to-gas competitive supplies delivered via LNG or the pipeline links to the UK is beginning to penetrate some of the Continental markets. The current pressures are downward, not upward.

So the question remains: How do you place a value on long-term gas supply? It is a question that is important in making major gas project investment decisions, but I am not sure that anyone has an answer.

Asinus Muses

One hymn sheet?

When the whole world seems to be singing the same song (for example, the great ode to decarbonisation at the end of the Bali conference) big trouble cannot be far away. Momentarily it did seem as if the moribund Kyoto agreement might be replaced by something better. The all-seeing ones of the IPCC had produced a report Delphic enough to bring vague general agreement yet specific enough to provide some benchmark for policy making. They were interpreted as saying that the future might be tolerable if CO_2 concentration in the atmosphere was held below 450 ppm (it now being about nearly 390 and rising at about 2 per year), thus using its factoids to establish a goaloid.

Climate poker

The EU rapidly made this 450 ppm goaloid the basis of its global warming policy with '20-by-20' as a first step to this (carbon emissions reduced 20 percent by 2020). China and India said that it would be unjust for them to make reductions unless the USA did something radical (this was a 'zero-by-who-knows-when' to be followed by a 'who-knows-what-by-who-knows-when' policy). In the end even George W. joined the bidding, offering on behalf of the USA 'zero-by-25' followed by another 'who-knows-what-by-who-knows-when' stage, conditional on a prior offer by India and China of a 'much-by-soon' policy. Three months after Bali we are left with this insoluble set of simultaneous equations.

Biofools rush in…and out

Europe's first practical post-Bali initiative – mandating the use of biofuels – came a spectacular cropper. Only days after the new rule that motor fuel sold in the UK had to contain 2½ percent biofuel, the Government, responding to the general conclusion that biofuels were responsible for food price rises, announced a reconsideration (read abandonment) of the whole idea and the European Commission is heading in the same direction. Of course, all this was foreseen two years ago in this column; there are times when even Asinus just has to bray.

The moving target

The scientists as well as the politicians are also adding a few unscored cadenzas to the song of Bali and are finding major deficiencies in the IPCC report. Since Bali, they have made the following pronouncements:

a. the IPCC seriously overestimated the continuation of 'automatic' decarbonising technical progress, and so the world does not possess the technology to combat global warming. Conclusion: a massive technical progress programme will have to be financed;
b. some claim warming seems to have stopped since 1998 though others say that this is nonsense; cautious experts argue that you can 'cherry pick' any one of a number of plausible but contradictory accounts of recent temperature change;
c. Lord Stern has admitted that his review had severely underestimated the problem, because CO_2 is rising much faster than expected;
d. James Hansen of NASA, threw a bomb into the debate by saying that historically when the earth had a CO_2 concentration of 450 ppm (the post-Bali consensus goaloid), it was ice-free. So, if it remained at that level the sea level would rise by 75 metres (i.e. submerging Buckingham Palace and the New York Stock Exchange, not to mention a good part of Africa, Asia and America). So, actually achieving the world's new climate goaloid would amount to unimaginable catastrophe.

Fatigue

To give an Executive summary of the foregoing section – experts are saying that, compared with the IPCC's assessment, climate change avoidance will be a lot easier, a bit easier, more difficult, considerably more difficult or virtually impossible. This constant barrage of seemingly inconsistent scientific advice may well produce confusion in the fight against warming. Appropriately the Climate Change Summit, convened by *The Guardian* for May 2008 is entitled: 'Fighting climate change fatigue; keeping the individual engaged'. One imagines a melée of climate-change-cheerleaders, global-warming-syndrome-therapists, CO_2-attention-deficit-disorder-advisors, irritable-global-warming-syndrome-healers and personal-CO_2-trainers.

Strike for the planet

As I go to press, almost all the above is rendered irrelevant by an event of immense significance for energy and climate change. Workers at an oil refinery in Grangemouth have gone on strike in defence of their pension scheme (for younger readers I should explain that a strike, until recently believed to be extinct, is a protest in which employees refuse to work). The two day strike is expected to stop a significant fraction of the UK's production, import and use of oil and gas during a whole month. And that means lower CO_2 emissions. Isn't that the answer? Combat global warming through strikes. Carbon offset firms, instead of paying for the planting of trees should be financing strikes. After a long air trip, forget about changing the light bulbs, go on strike. This policy is backed by science: in recent decades there has been an almost exact (inverse) correlation between the average global temperature and the number of strikes.

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