EUROGULF:

An EU-GCC Dialogue for Energy Stability and Sustainability

"The Oil Supply and Demand Context for Security of Oil Supply to the EU from the GCC Countries"

Report by Dr Robert Skinner and Dr Robert Arnott,
Oxford Institute for Energy Studies
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Background

The following report was prepared as part of the EUROGULF project carried out under the European Commission's Synergy Program by a consortium under the coordination of the Robert Schuman Centre for Advanced Studies, European University Institute, Florence. A slide presentation on the report given at the final conference in Kuwait, April 2, 2005 is available at http://www.oxfordenergy.org/presentations/Eurogulf%20Conference.pdf .

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Index

List of Figures

1. Background and Introduction

Task 1 of the EUROGULF Project addresses the "Economic and Political Conditions for Energy Security". This is a very broad subject whose analysis would encompass virtually every area of economic and political endeavour in the Gulf and in Europe. This would be beyond the intended scope of this study. The more relevant questions within this framework are: what is the scope for continued supply of oil and gas from the Gulf countries such that European countries could believe that the conditions for their energy security, however defined, would be satisfied? This paper looks mostly at oil supply. Other papers address issues of economic diversification against the background of oil and gas development.

1.1 Introduction

Most world energy outlooks project a growing share of oil and gas supply from the Middle East region. The IEA (WEO 2004) most recently projects OPEC's market share to rise from 37 per cent in 2002 to 53 per cent in 2030, slightly above its historical peak in 1973, while acknowledging that sustained higher prices would lower this share through the combined affects of stimulating non-OPEC production and unconventional liquids. Between 2002 and 2010 non-OPEC oil is expected to meet most of the growth in demand. At any rate, the IEA's reference case holds that of the 31 million b/d rise in world oil demand between 2010 and 2030, 29 million b/d would come from OPEC Middle East (IEA, World Energy Outlook, 2004; MEES 47, November 2004). Recent projections by the United States Energy Information Administration and the International Energy Agency indicate the world's call on oil from the Middle East will rise from less than one third in 2003 to nearly a half by 2030. This reflects the continuing depletion of reserves elsewhere in the world in comparison to the dominance of oil reserves in the Middle East at a time when the global economy continues to expand, in particular in the highly populated countries of China and India. With more than two thirds of the world's oil reserves, it is just a matter of time before the Middle East region supplies a dominant share of the incremental barrel of demand, rather than at present a share of growth more or less equal to its market share.

The growing dependence on this region for what are considered strategic commodities constitutes the essential context for this study. In simple terms, the European Commission's Directorate General of Transport and Energy poses the question, 'does this dependence constitute a concern in terms of security of energy supply to Europe and what forms of partnerships (the "Economic and Political Conditions" in the overall heading for this part of the study) can bolster security of supply?' This report examines the first part of this question, the prospects for and implications of the growing contribution of oil and natural gas from the GCC countries.

The approach taken in this study is to assume that production from GCC countries (along with other OPEC members) will continue to be the marginal supply; in other words, once oil supply from other sources has been absorbed, the call on GCC countries will increase. Therefore, in order to understand the prospects for production expansion in the GCC countries, we must first understand the production outlook outside the GCC (and OPEC). It goes without saying that assumptions about global oil demand are of critical primary importance.

This analysis does not rely on a model. The approach is to start within the empirical data that forms the starting point for others' projections, and then examine the prospects for demand and to a much greater extent, different supply scenarios. Thus, while readers of the literature on energy projections have a tendency to look at the 'Right Hand Side' of projection charts, the approach here is to focus on the Left Hand Side', or the starting point. By thus grounding the analysis in the empirical data, we work out into the future to the extent the data and our analyses of them permit.

Using a simple assumption of annual average growth in oil demand, together with estimated rates of depletion of several categories of existing supply, we examine the principal sources of Non-OPEC/GCC supply, and assess their potential to meet—or not meet—growing world demand. This then is a subjective analysis based on our understanding of the supply industry and the drivers that influence it. We discuss the key factors that could reduce or accelerate supply from Non-OPEC sources then examine OPEC's potential supply and in particular that from GCC countries. Against this background, the more hypothetical or theoretical questions of optimal pricing and production strategies are examined.

By way of further introduction to our projections, some additional comments are warranted regarding the 'sport' of energy supply and demand projections. There is a rich literature on the subject of oil and gas demand and supply projections. For a recent review of this sport the reader is referred to Lynch (Journal of Energy Literature, Volume X, pp 33, 2004). All energy projections depend on assumptions of population growth, GDP, policy and the rate of deployment of new technologies. The price of oil is usually exogenously imposed and in turn influences the prices of other fuels. No serious and well-informed projection sees world energy demand declining in the absence of major policy changes. All see fossil fuels continuing to dominate future energy supply, and meeting more than 85 per cent of the growth in primary energy.

Oil's dominance in the energy sector with the largest share of primary energy at least out to 2025 is almost universally acknowledged. While there is general acceptance that the geologic petroleum resource is sufficient to meet even the most bullish projections of demand for at least the next 40 years, there is a growing coterie of proponents of the notion that world oil production is about to peak. This assumption of sufficient resources, however, can lead to presumptions about production strategies on the part of certain key countries that in turn beg many questions. For example, while it is recognized that Saudi Arabia could achieve 20 million b/d, the question remains, 'Why would it want to do so?' This politico/economic question is perhaps more relevant than whether it would have the *capital* to do so, a question which preoccupies the IEA and the US DOE (IEA World Energy Investment Outlook, 2003; Caruso, Oxford Energy Forum, 2001, May).

Projections by major energy institutions generally tend to reflect the pressures from their 'owners' or constituencies to take into account if not reflect certain politically desirable outcomes embraced by their constituencies. Of greatest interest to institutions making projections recently is the issue of Climate Change and specifically to gauge the energy sector's contribution of greenhouse gas emissions, and to test assumptions in models that can influence outcomes measured in terms of greenhouse gas emissions reductions. Most such projections of significantly less emissions of greenhouse gases and other pollutants rely on faster than historical rates of uptake of more efficient energy end use technologies and the accelerated penetration of currently non-commercial energy production technologies that rely on renewable fuels.

Projections that aim for a significantly different future than that of 'business as usual' are better referred to as 'scenarios'. They tend to reflect a greater or lesser degree of wishful thinking, which is imposed on models by tweaking assumptions about technological change and policy. Their utility is that they can serve as a point of departure for discussions about policies and their potential to influence desirable outcomes. For example, some scenarios[1] are based on assumptions of rates of energy efficiency improvement greater than historical experience. Authors of such scenarios also tend to wish outcomes that override the friction from countervailing policies. An example is market reform in the power sector, which has tended to limit the choice of fuels and generation technologies.

Finally most projections that present 'scenarios' representing outcomes different from 'business as usual' where assumptions of a different world are exogenously imposed on the model in use, will invariably generate widely varying calls on OPEC and Middle East oil. This is because most authors assume that this region will continue to play the role of 'swing producer' of oil. Therefore output from the region is like the end of a whip in the logic of assumptions in models; it is very sensitive to the level of world demand and that depends on the assumptions made regarding population, price, GDP, policy and technological change. Not surprising, and this can not be emphasized enough, demand is far more uncertain than is supply. This is not only clear in the theoretical outcomes of models with minor differences in assumptions, but also in the empirical evidence of IEA Oil Market Reports since July, 2002 in which global oil demand was underestimated by two or three times the amount non-OPEC supply was over-estimated. Of the key variables, changes in GDP account for most of the variance in outcome from that projected[2]; changes in policy have been of secondary importance. Even with similar assumptions in population and other variables, different practitioners of energy projections tend to develop widely varying estimates of the 'call on Middle East oil'. With this experience in mind, while this study does not rely on modelling, it does adhere to the assumption that OPEC will continue as the swing producer, but an increasingly important swing producer.

In examining the prospects for oil and gas supply from the GCC countries, we draw on the evidence that the supply of oil and gas from the region has been relatively reliable, notwithstanding the region's perceived political instability. The approach taken here starts from this empirical observation; namely, that supply from the region will be available when called upon, as it has in the past. Oil and gas are of central importance to the economies of most GCC countries. Hydrocarbons provide the basis on which to gradually diversify GCC economies. Continued hydrocarbon-based economic growth provides the platform for economic diversification

[1] 'Save Scenario' in World Energy Outlook, International Energy Agency, 1995; EU-GRN Scenario in European Commission, 1996, "European Energy to 2020: A Scenario Approach", in Energy in Europe, Special Issue, Spring 1996

[2] A good example can be seen between the projections for China in the IEA's WEO of 2002 and 2004; China's energy demand for 2010 is now projected to be 25 per cent greater than it was projected in 2002 owing essentially to different GDP growth rates assumed. China has been growing at almost twice the rate assumed.

which can in turn underpin internal social and political cohesion and stability of these countries. Broadly speaking, Russia and the rest of the FSU will increasingly dominate the world's oil supply outside OPEC and the Middle East, while China, India and North America will continue to determine oil demand. The political evolution of the FSU and the economic evolution, and macroeconomic policy making in particular, of the big Asian countries and the United States will be the determinants of the prospects for the call of GCC oil. Two scenarios of oil supply and demand; namely, Russia's oil supply falters while China's demand soars, versus Russia's oil supply soars while China's demand collapses, present two totally different outcomes for the economies of the GCC, and specifically affecting their ability to invest in their comparative advantages and diversify their economies. Paradoxically then, the internal prospects of the Middle East depend on external developments. Thus, this analysis looks *outside* for a basis to develop propositions for the *inside* with respect to, for example, 'How much of the global oil and gas markets can GCC countries count on supplying?' This constitutes the essential framework for the analysis that follows.

This report is divided into three main parts. The first section (Subtask 1.1) of the report surveys the oil and gas endowment of the GCC countries, development history and prospects and sets out the major differences between countries. The diversity among GCC members in their oil and gas endowment, dependence and other social and economic factors limits the extent to which one can draw conclusions for the group as a whole in terms of strategies for the development and export of oil and gas.

The second section (Subtask 1.2) of the report addresses the subject of oil price developments and the supply response. It begins with a discussion of oil supply security to put into context the underlying basis for this study. It addresses the chronic dilemma imposed by prices if either too high or too low in terms of investment strategies. This section examines in greater detail the implications of being a swing supplier and having to second-guess the developments of other producers both within and outside the region, and within the context of other national economic objectives.

The third section (Subtask 1.3) examines the call on GCC members' oil production under a set of qualitative assumptions of future oil supply and demand.

2. Prospects for Oil and Gas Exports from the GCC member countries

2.1 Introduction

Against a background of assumed continued robust increases in demand for oil discussed above, this section examines the outlook for increases in production capacity of the GCC countries, up until 2020. It should be noted that the maximum productive capacity is unlikely to be achieved because of a number of factors (e.g. technical, economic and political). With particular regards to the GCC countries of Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates, the key issue is how quickly new, spare productive capacity can and will be brought on stream. With the exception of Oman and Bahrain, all members of the GCC are members of OPEC and in the absence of some policy change by OPEC and by its individual members, there is little incentive to invest in new capacity when existing capacity is not being fully utilised, or when the group's spare capacity is adequate to meet OPEC's requirements to respond to fluctuations in the market. In the case of Oman, whilst existing capacity is being fully utilised, cooperation with OPEC may mean there are times when the country has spare capacity. For the OPEC members of the GCC, spare capacity remains important in order to exert, through the volumetric lever, some influence over the oil price if only in direction, as opposed to any precise level. For example, Saudi Arabia is re-building its spare capacity to approximately 2 mmb/d. In addition, the UAE could increase production by 200,000 b/d and Kuwait could deliver an additional 160,000 b/d.

Within the GCC itself it is also important to compare the resources of each member in order to highlight the difficulty that the GCC faces as a whole in implementing a uniform oil policy. With specific reference to production capacity, Saudi Arabia has recently made statements to the effect that it has the capability to raise capacity in a reasonably short time to around 15 million b/d, from its 2002 production level of 9 million b/d. The Government of Kuwait has revealed plans to increase capacity from 2.4 million b/d to 4.0 million b/d by 2020. The UAE has announced plans to increase its capacity to around 4.6 million b/d by 2020. Finally, Qatar's oil capacity could increase slightly. In contrast, Oman has reserves of 17 billion barrels and is struggling to even sustain production and Bahrain is actually importing oil from Saudi Arabia.

Figure 1: Contrasting Reported Oil Reserves of GCC members

Country	2003A (‘000 b/d)	2020E (‘000b/d)	Reserves (billion bbl)	R/P Ratio	Spare capacity (‘000b/d)
Bahrain	49	49	0.1	7.8	0
Kuwait	2238	4000	96.5	n/m	0
Oman	823	450	5.7	18.58	0
Qatar	917	900	15.2	45.5	160
Saudi A	9817	15000	262.8	73.3	800
UAE	2520	4500	97.8	n/m	200
Total	16364	24899	478.1	80.1	1160

Source: OIES estimates, BP Statistical Review of World Energy 2003

The resources and current gas production of the GCC members are shown in Figure 2 below. The table highlights the implicit contrast in policies of the various GCC members. For example, whilst Saudi Arabia, Qatar and the UAE have significant gas reserves, only Qatar and the UAE are monetising gas in the international LNG business. Saudi Arabia does not have any plans in the near term to develop any of its vast gas reserves for export, despite recent initiatives to attract private oil companies to assist in developing gas for electricity and water production. It is also interesting to note that the relatively resource poor Oman exports over 50 per cent of its gas through its new and growing LNG business. In addition, there are significant plans by Qatar to further monetise its gas reserves with investments in major gas to liquids (GTL) plants. Further work is required to review the comparative economics of natural gas between producers in the region, and the prospects for intra-regional gas grids (started with the Dolphin Project) in order to develop sensible estimates with regards to growth in export capacity. However, it is clear from Figure 2 below that there is no uniform GCC policy on gas and this on its own means that trade with the region must take into account the individual needs of each country.

Figure 2: Contrasting Reported Gas Reserves of GCC members

Country	2003A (bcm)	2003A Exports (bcm)	Exports (%)	Reserves (tcm)	R/P Ratio
Bahrain	9.6	0.0	0.0	0.09	8.80
Kuwait	8.3	0.0	0.0	1.56	n/m
Oman	16.5	9.4	56.9	0.95	57.3
Qatar	30.8	19.2	62.3	25.77	n/m
Saudi A	61.0	0.0	0.0	6.68	n/m
UAE	44.4	7.1	16.0	6.06	n/m
Total	170.6	35.7	20.9	41.11	n/m

Source: BP Statistical Review of World Energy 2003

2.2 Bahrain

Bahrain is the least endowed nation of the GCC nations in terms of oil and gas resources and is likely to become a net importer of natural gas due to the country's growing power generation demand. Bahrain had intended to purchase 5-10 bcm of Qatar's North field project, but plans have been delayed to 2006.

With respect to oil production, Bahrain receives its production from the Bahrain oil field (the oldest in the region) but mainly from the Saudi Aramco operated Abu-Safah field which produced around 146,000 b/d in 2003[3]. Bahrain shares production from the field with Saudi Arabia but receives its full income. There are plans to increase capacity to 300,000 over the next three years. Beyond this there are limited plans to try and increase production through the drilling of 17 oil wells and 8 gas wells to be completed by 2007.

2.3 Kuwait

If the share of oil output from the Neutral Zone is shared equally with Saudi Arabia, Kuwait was the sixth largest oil producer within OPEC in 2003 as well as the ninth largest exporter of crude oil in the world. Crude oil production averaged 2.2 million b/d but according to Nader Sultan, (then) Deputy Chairman and CEO of KPC, Kuwait planned to increase capacity to 3 million b/d by 2005 and to 3.5 million b/d by 2010. These targets were widely viewed as being too ambitious, especially as the Burgan field, which generates over 80 per cent of the country's oil, is now suffering from a deep water cut problem. As a result of these concerns the country has recently revised its expansion target with the focus now being on reaching 4 million b/d by 2020 (PIW March 29, 2004, p.8).

Most of Kuwait's current production is generated by its southern fields while its northern fields produce some 400,000 b/d. It is in the north that most of the expansion plans are aimed. It is anticipated that much of the expansion will take place under the so-called Project Kuwait which aims to bring in foreign partners in order to raise production capacity of those fields near the border with Iraq to 900,000 b/d within five years from the start of operations. Project Kuwait includes the Raudhatain, Ratqa, Adbali and Bahra fields and is expected to cost some $7 billion.

Protracted discussions with the authorities have delayed Project Kuwait. Although significant progress has been made, the main obstacle seems to have been the Kuwaiti parliament which has so far been reluctant to approve partnerships with foreign oil companies in the development of strategic oil reserves. Not only is foreign ownership of oil reserves strictly prohibited by the

[3] Saudi Arabia recently stopped the supply of 50,000 b/d of Arab Light to Bahrain as part of an arrangement related to shared offtake from the Abu-Safah, Arab Medium field. The field was recently expanded in production capacity to 300,000 b/d to be shared 50:50. Bahrain imports about 210,000 b/d and exports over 250,000 b/d of products, consuming about 15,000 b/d (MEES 47:44, Nov 2004)

country's constitution but there is a view in the Parliament that even operating service agreements may be unlawful.

Despite these protestations, KPC has continued to negotiate with potential partners and some progress is being made. By the end of October 2003, Kuwait had received a final batch of comments and proposals from three short-listed consortia. One consortium is led by ChevronTexaco (50 per cent) with Total (20 per cent) as well as Sibneft, Sinopec and Petro-Canada. The second consortium comprises BP (65 per cent) as well as Occidental (24 per cent) and the Indian Oil Company (10 per cent). The third consortium comprises ExxonMobil (37.5 per cent) with Royal Dutch/Shell (32.5 per cent) with Conoco-Phillips (20 per cent) and Maersk (10 per cent).

Along with the major plans to expand production capacity the country also has a plan to expand its oil export facilities, boost domestic and refining capacity and import natural gas from its neighbours. The upstream capacity expansion program involves the construction of several new oil gathering centres. Prior to the Iraqi invasion in 1991, Kuwait had 26 gathering stations, with a total capacity of 4 million b/d. All of these gathering stations were destroyed during the war and although operations have been restored in many of them, a lot more investment is required in order to restore full capacity.

Kuwait is also planning a $900 million expansion at the port of Mina al-Ahmadi, the country's main export port for crude oil which was nearly completely destroyed during the Gulf War. The intention is to build up storage capacity in conjunction with increased oil production in future years. Current plans envisage 19 new storage tanks with a total capacity of 11.4 million barrels by 2005.

With respect to upstream gas, although Kuwait has very substantive gas resources, with estimated proved reserves of 1.56 tcm, most of these reserves are associated with oil, and current production is not sufficient to meet growing domestic needs, mainly related to power production, while gas is re-injected into producing reservoirs in order to maintain reservoir pressures.

Kuwait has tentatively agreed to import Qatari gas produced as part of Exxon-Mobil's Enhanced Gas Utilisation Project. If this deal becomes a reality then it would make Kuwait an important link in the regional Middle East gas pipeline grid that Qatar and others are hoping to develop.

2.4 Sultanate of Oman

Oman has been one of the great success stories of oil production over the past 20 years. However, about 50 per cent of oil reserves have now been produced and output has dropped steadily since 2000. The decline in production has been attributed to the maturity of the main fields as well as technical difficulties. By Middle East standards, Oman's oil reserves are modest and at the end of 2003 stood at 5.7 billion barrels. Oil production fell to 823,000 b/d in 2003 from 902,000 b/d in 2002 and from a peak of 961,000 b/d in 2001.

Just less than 95 per cent of Oman's production is controlled by state Petroleum Development Oman (PDO), which also holds 90 per cent of the proved reserves base. PDO is a consortium in which the government holds a 60 per cent share. The other partners are Royal Dutch/Shell (34 per cent), Total (4 per cent) and Bangladesh's Partex (2 per cent). One of PDO's key objectives is to maintain production at 800,000 b/d and in order to meet this target it plans to spend around $1 billion to $1.5 billion annually through to 2007 with the aim of increasing production to 900,000 b/d by that time. In order to encourage more foreign participation in the country, PDO signed a number of new production sharing agreements with foreign companies, including Talisman Energy, Total and Amerada Hess. On the basis that the ventures are successful, the Omani oil minister has forecast that PDO will increase capacity by 50,000 b/d from 2005.

The unexpectedly sharp decline in Oman's oil production has continued despite the ambitious plans and at this point in time the prospects for near term production growth remain uncertain. PDO is continuing to struggle with a very heavy water-cut which amounts to some 4 million b/d. The whole thrust of the annual $1.5 billion capital budget is to increase recovery factors to 50 per cent. Particular projects include the construction of miscible gas injection facilities across seven fields in the Harweel cluster in the south of the country. In addition, PDO is also going ahead with the construction of steam injection facilities at Mukhaiznah and Qarn Alam in order to increase output as a part of the enhanced oil recovery program.

Facing a decline in its oil reserves and production, natural gas has become the main focus of Oman's diversification strategy. At the end of 2003 these reserves stood at 0.95 tcm. This represents a 72 per cent increase in reserves over the past 10 years. These gas reserves have helped Oman to diversify its dependence on crude oil by producing LNG for export and use in domestic industry. LNG exports began at the start of 2000 with most exports sold under term contracts to Asian countries.

Most of Oman's gas reserves are located within the PDO concession and are usually associated with or lie in the vicinity of existing oil fields. PDO is currently in the middle of a $2 billion investment program that aims to expand gas production over the next two year. The gas plant at Sur is to be expanded with a third processing facility and the gas pipeline to the facility is to be expanded. In addition the government has invited a number of companies into the country to try and accelerate gas development. BP, together with Fortum has announced the development of a jointly owned company in order to explore and produce gas in Northern Oman. Anadarko have been awarded an offshore block and plan to invest $60 million over the next eight years to develop three gas fields. Elsewhere, Novus Petroleum is already producing gas in the Straits of Hormuz and has signed an agreement with Iran for the development of the Hengam/Nukha offshore field that straddles the line between the two countries' territorial waters.

By far the most important part of Oman's natural gas strategy has been the development of its LNG business. By late 2006, capacity should reach more than 10 million tons/yr. The third LNG train is already under construction and is scheduled for completion at the end of 2005. Oman LNG supply is largely sold out until 2005.

2.5 Qatar

Qatar has proved to be one of the most active members of the GCC in encouraging foreign investment in order to increase oil and gas production capacity. Qatar has relatively modest oil reserves, which at the end of 2003 stood at 15.2 billion barrels, but it has a very large natural gas resource, which at the end of 2003 stood at 27.8 tcm. This makes Qatar the holder of the third largest gas resource base in the world after Russia and Iran. In 2003, Qatar produced 917,000 b/d of crude oil and 30.8 bcm of natural gas, making it OPEC's smallest producer.

Most of Qatar's natural gas is located in the North Field, which is the world's largest known non-associated natural gas field and which extends into Iran where it is known as the South Pars Field. In addition, the onshore Dukhan field contains an estimated 142 bcm of associated and 14.2 bcm of non-associated gas. Smaller associated gas reserves are located in the Id al-Sharqi, Maydan Mahzam, Bul Hanine, and al-Raydan offshore oil fields. Currently, Qatar has two LNG exporter facilities, the Qatar LNG Company (Qatargas) and Ras Laffan LNG Company (Rasgas). Qatar Petroleum owns 70 per cent of Qatargas II with 30 per cent held by Exxon Mobil. ConocoPhillips signed an agreement in 2003 to develop a $5 billion LNG project with Qatar Petroleum to supply gas to the US. Production is forecast to ramp up to 45 million tons/yr by 2010 and 60 million tons/yr by 2015, up from 14.6 million tons/yr in 2003.

Qatar also is diversifying into Gas to Liquids (GTL) in a bid to become the world centre for GTL technology. In 2003, Qatar Petroleum and Royal Dutch/Shell signed an agreement under which Shell will invest $5 billion to develop upstream gas and liquids facilities and an onshore GTL plant that will produce 140,000 b/d of GTL products. The project will be developed in two phases with the first phase operational between 2008 and 2009, producing around 70,000 b/d of GTL products.

With respect to oil production, Qatar is targeting an expansion to one million b/d by 2006[4]. Occidental is developing a major project in the Idd al-Shaqi North Dome (ISND) and it also has rights in the South Dome (ISSD). Under two agreements, Occidental is investing some $780 million over the next three years aimed at boosting ISND production to 127,000 b/d, whilst at the same time bringing on ISSD production at 17,000 b/d.

[4] The North Field gas also has condensate liquids which are produced at the rate of 40,000 b/d for every 1 bcf/d of gas produced. At least 400,000 b/d of liquids and NGLs are expected from the LNG expansion.

In 2002, Total won approval for a $150 million plan to expand the offshore al-Khaleej field. Expansion of production from this field is expected to raise production to 80,000 b/d from 60,000 b/d. Maersk Oil is also undertaking $11.2 billion expansion program at its offshore Al-Shaheen field where it hopes to boost production to 200,000 b/d by the end of 2004.

Figure 3: Qatar's Future LNG Projects and Investments

Type	Name	Location	Cost ($m)	Parties	Details
LNG	Qatargas 3	The North Field	5,000	QP, ExxonMobil	Development of an LNG project to supply gas to the US. Aims to supply 7.5 million tons/yr by 2007
LNG	Qatargas II LNG Expansion Project	Ras Laffan	Unknown	QP, ExxonMobil	Massive new onshore facilities and receiving terminal for the Qatargas II venture
LNG	RasGas LNG Export plant	The North Field	12,000	QP, ExxonMobil	Construction of the world's largest LNG facility at 15.5 million tonnes, consisting of two trains that will each manufacture slightly more than 1Bcf/d

Source: Energy Intelligence 2004

2.6 Saudi Arabia

Of all of the GCC nations, Saudi Arabia is the only one with an ability to balance oil markets because of its willingness to invest in and maintain spare capacity. At the time of writing, Saudi Arabia is the only one of the GCC nations with any significant spare capacity and during 2004 was under great pressure from the international community to increase production to alleviate upward pressure on the oil price. H.E. Ali Naimi, the Saudi Oil Minister has stated clearly (MEES, February 14, 2005) that Saudi Arabia plans to increase its capacity to 12.5 mmb/d within the next four years, adding that production would be maintained at 9 mmb/d for the time being. To be clear however, they are not doing this because of international pressure, but rather to retain the capability to influence the market through the volume lever with a view to achieving stable prices. It has been argued by many private oil companies that Saudi Arabia needs to offer them access to its reserves base in order to help the Kingdom finance future increases in production capacity. However, the oil sector is unlikely to require foreign investment as the cash flow generated by

Saudi Aramco has historically been sufficient to maintain existing production as well as provide sufficient capital for additional capacity. The issue is more to do with how the country should manage an increase in capacity without signalling to the oil markets that a supply glut will depress prices. This central dilemma is addressed in Section 4 below.

Saudi Arabia's continued support of relatively high oil prices does seem to be a policy change compared to the 1970s and 1980s when Saudi authorities appeared to be concerned about too high oil prices endangering their longer-term oil market. The large budget deficits of the 1980s and 1990s, the rapidly growing population and the heightened socio-political pressures after September 11 all appear to have shifted the emphasis towards maintaining relatively high prices in order to maximise near term oil revenues. However, it must be said that 'relatively high prices' is a loaded phrase and needs some qualification. While OPEC's target price has evolved through time and in the nineties became a price band, the value of the US dollar has deteriorated relative to, say the Euro, so what was 'high' just a few years ago may be 'low' today. Recently, most analysts tend to converge on the view that the price band should be shifted up and in the absence of OPEC itself concurring on what it should be, an average target price of $35 would seem feasible without doing injury to the espoused policy of balancing consumer and producer interests. This is further discussed in Part 4.

At the end of 2003, Saudi Arabia's proved reserves of oil stood at 263 billion barrels. This represents over 20 per cent of the worlds total reserve base. Estimates by independent consultants suggest that the total resource base could ultimately reach some 1 trillion barrels. For the past 20 years, Saudi Arabia has maintained the world's largest sustainable production capacity at over 10 million b/d and it remains the world's largest producer and exporter of crude oil. Of political importance is the fact that for many years Saudi Arabia has been one of the main suppliers of crude oil to the United States, although more recently Venezuela, Canada and Mexico have challenged it position. Asia now receives over 40 per cent of Saudi Arabia's crude oil exports.

With the global oil markets becoming increasingly reliant upon Saudi Arabia to be the volume regulator or 'central bank', especially now to meet robust demand, questions are now being asked as to both the sustainability of Saudi Arabian oil production and its ability to invest in new capacity. The Oil and Gas Journal 2004 Year Book alludes to this by stating that 'Saudi Arabia relies heavily on its Ghawar field, whose sustainability is uncertain' (p.137). Furthermore, many commentators have downgraded their expectation of Saudi oil capacity originally believed to be between 10.5 and 12.5 million b/d, down to 9.5 million b/d. It has been speculated that high rates of decline in existing fields require Saudi Aramco to add a minimum of 600,000 b/d of new capacity simply to maintain current production.

Recently the Saudi Arabian Government has tried to quash fears over its ability to sustain and grow production. In a recent (February 2004) well-publicised debate Matt Simmons argued that there was a ‘total lack of reliable OPEC data’ on reserves and field production. Furthermore, he argues that the Ghawar field could be on the verge of a major decline in production which is unlikely to be offset by new fields. This view is based on the fact that the field has been producing for over 40 years, that the water-cut had been increasing and that like many other major oil and gas fields once production had gone into decline there was very little that could be done to reverse it. In a very forthright rebuttal the representatives from Saudi Aramco for the first time presented some very detailed descriptions of the major oil and gas fields, and showed that most of Matt Simmons’s arguments with respect to the Ghawar field were in fact flawed. In particular it was demonstrated that water-cuts in the field had actually declined over the past 5 years, not increased.

Of particular interest during the debate were the strategic statements with respect to oil policy. In particular it was made clear that it was Saudi Aramco’s intention to replace annual production with new reserves. With respect to long term production objectives, Saudi Aramco (Al-Husseini, Oil and Money Conference, Nov 2004) has tested various scenarios to see how long various levels of production can be sustained. It was shown that the current company plan to sustain production at 10 million b/d could be maintained for a minimum of 50 years based on its existing reserves base (roughly equivalent to 15 per cent of probable and possible reserves already discovered). It was also stated that if production of 12 million b/d were required then this could be sustained for over 50 years so long as an additional 70 billion barrels could be brought into the proven category from the probable reserves already discovered. Saudi Aramco is very confident of its ability to maintain and control production. It is difficult in the absence of any detailed information to speculate on which position might ultimately prove to be correct. However, for the moment the benefit of the doubt should be given to Saudi Aramco which has proved to be very technically adept.

With respect to specific project details, there seems to be a real drive towards increasing light oil production in the Eastern Province as well as to the south of Riyadh. Two projects already underway are the 500,000 b/d of Arab Light crude from Qatif, and an increase of 150,000 b/d of Arab Medium from the offshore Abu Safah field. The $1.2 billion Qatif project will process crude oil from fields in the area and will involve construction of two gas oil separation plants as well as gas treatment and oil stabilisation facilities. Work on both of these fields is expected to be completed by the end of 2004. Saudi Arabia is also looking at Abu Hadriya and Khursaniyah in the Eastern Province and Nuayyim in the centre which together could have a production potential of around 500,000 b/d by 2007. It should be emphasised that these are not new projects; rather they are projects that were mothballed or postponed when the oil price collapsed at the end of the 1990s. A potential $3 billion project at the Khurais field west of the giant Ghawar field could potentially increase Saudi production by a further 800,000 b/d by the end of 2005

In addition to its vast oil reserves, Saudi Arabia also has significant gas reserves which at the end of 2004 stood at 6.7 tcm, ranking it fourth in the world after Russia, Iran and Qatar. Most of Saudi Arabia's gas consists of associated gas from the Ghawar field and the offshore Sabaniya and Zuluf fields. Saudi Arabia aims to triple natural gas output to 15 bcf/d by 2009. Unlike its neighbour Qatar, Saudi Arabia does not plan to develop LNG facilities. The Government has tried to attract foreign investment in the gas sector but it initially had difficulty finalising contracts. The most notable example being the collapse of the Exxon Mobil-led consortium in the Core Venture 1. These failed plans have been revived in more scaled down projects including the $2 billion gas exploration and development contract between Royal Dutch Shell, Total and Saudi Aramco followed by a call for bids, which resulted in three other consortia and companies being assigned gas exploration projects. One of the key issues why foreign participation has proved difficult has been a lack of agreement over the rates of return on projects on offer.

In addition to the Gas Initiative involving foreign firms, in September 2003 Saudi Aramco awarded a major contract for the construction of an NGL recovery plant in the Hawiyah processing and the Juaymah fractionation plants. This plant will be the first facility to process non-associated gas. The development of the gas industry is part of an overall strategy to expand the petro-chemical industry using natural gas as the main feedstock.

2.7 United Arab Emirates

The United Arab Emirates is a loose confederation of seven emirates dominated by Abu Dhabi and Dubai. Dubai is the UAE's financial and commercial centre and over the past twenty years has had great success in economic diversification thereby reducing its dependence on it declining oil and gas reserves. Ironically that decline has of course jeopardized its role in providing the main marker crude for the Asian market. Oil production in Sharjah, the third largest emirate, is negligible. In total the UAE is the fifth largest oil exporter amongst all OPEC countries and is the world's sixth largest exporter of crude oil. Dubai has never considered itself to be a member of OPEC and has rarely complied with OPEC quotas even before its reserves base began to go into decline.

At the end of 2003, the UAE's proved reserves stood at 97.8 billion barrels, down from 98.1 billion barrels a decade earlier. However, with production averaging 2.5 million b/d the reserves life is still in excess of 100 years. The UAE also has 6 tcm of gas reserves, which accounts for just over 3.5 per cent of the world's total gas reserves base. Abu Dhabi accounts for 94 per cent of the crude oil production and the federation's output average about 2.2 million b/d throughout most of 2003. In total the UAE's production capacity was estimated to be around 2.6 million b/d at the end of 2003. The various authorities are targeting an increase to 3.2 million b/d by the end of 2006, with the entire increase accounted for by Abu Dhabi's National Oil Company (ADNOC), in joint ventures with foreign oil companies.

ADNOC accounts for over 50 per cent of the Emirates' total production capacity. It is planning limited additional opening of upstream oil production to foreign firms. Elsewhere, Zadco, a 520,000 b/d producer that runs the Upper Zakkum field is majority owned by ADNOC, but operated by Japan's JODCO with a 12 per cent stake. Recently ADNOC has put up its stake in the company for sale and has received bids from BP, Shell, Total, Exxon and Chevron-Texaco.

There are many infrastructure projects that require upgrading to accommodate the increase in production capacity. In particular, a $320 million contract to increase the capacity of the onshore Hasa field was awarded to Snam in September 2003. This project aims to increase production from around 100,000 b/d to 480,000 b/d. Expansion is also planned for the onshore Asab field aimed at increasing capacity to 310,000 b/d by 2006. Adco is also proceeding with the development of the Al-Dabbiya and Rumaitha fields that have estimated recoverable reserves in excess of 8 billion barrels.

With respect to the development of gas reserves, the UAE was the first country in the Gulf to develop LNG (based on associated gas) and recently has already embarked upon a multi-billion dollar program of investment in its natural gas sector including a major shift towards gas-fired power generation. An ambitious $3.5 billion plan, the Dolphin Project, to interconnect the natural gas grids of Qatar, the UAE and Oman, is currently under way with plans to bring 2 billion cubic feet per day of gas from Qatar's North Field to Abu Dhabi. It is projected that most of the UAE's natural gas needs over the next decade will come from Qatar.

2.8 GCC Reserves and Production Conclusions

The diversity among GCC members in their oil and gas endowment, dependence and other social and economic factors limits the extent to which one can draw conclusions for the group as a whole in terms of strategies for the development and export of oil and gas. Moreover, to the extent there are 'group strategies' pertaining to oil production, these are worked out for some GCC countries within the context of their membership in OPEC.

In the discussion of each country above, it is clear from a resource point of view Saudi Arabia remains the most important and in the context of this study, Saudi Arabian oil policy will remain the key in the context of security of supply. It is true that Kuwait and the UAE do have substantial remaining reserves but the potential for significant near term increases in production capacity do appear to be limited, as is the potential for the discovery of further significant reserves. In the case of Qatar, Oman and Bahrain the prospect for significant increases in oil production is very limited. Therefore in the context of this study the emphasis firmly lies in the ability of Saudi Arabia to sustain existing production and invest in new capacity to help meet increasing crude oil demand. From a purely technical point of view this does appear to be possible, but much will depend on the political will as discussed above and a calculus that must take into account a complex array of external parameters, including the development prospects, strategies and policies of other, principally Non-OPEC, producers (who in turn are trying to second guess GCC producers) and how these strategies might vary under different price scenarios, and the outlook for demand growth in consuming countries such as China with its opaque statistics, and the United States, with its troubling economic imbalances. This dilemma, and how the GCC countries, especially Saudi Arabia, manage the volume lever to achieve some optimal price is addressed next.

2.9 Non-GCC OPEC Member Supply

A short section is included here to cover those countries that produce oil under the OPEC umbrella but who are not members of the GCC. The incorporation of the supply potential from these countries is important as it completes the overall supply picture that is presented later in this report. However, so long as these countries remain members of OPEC then it must always be recognised that estimates of production will be totally reliant upon future OPEC production policies. For the purposes of this study we have relied heavily on estimates from the US DOE, MEES and Energy Intelligence[5]

2.9.1 Algeria

Algeria has benefited from significant foreign investment in the oil industry but at the same time this has caused internal conflict between the needs of the foreign producer and OPEC market management. The country has officially petitioned OPEC to raise its share of the OPEC ceiling to more than two times the current cap of 750,000 bbl/d. Foreign companies assume that any cutbacks in oil output should be taken out of Sonotrach's position, leaving the joint ventures free to produce at capacity.

Within OPEC, Algeria is the ninth largest producer of oil. Its proved reserves at the end of 2003 were 11.3 billion barrels, up more than 2 billion bbls from a decade earlier. Production has been rising steadily since 1996 and in 2003, production averaged 1.1 million barrels per day. Algeria's crude oil capacity currently stands at 1.2 million b/d. Along with Nigeria, the Algerian oil minister has expressed his country's intention to lobby for a larger quota to reflect the recent expansion in production capacity. Furthermore the country is targeting expansion of oil capacity to 1.5 million bbl/d as early as 2005.

Sonatrach produces more than half of Algeria's oil output, primarily from Hassi Messaoud and Rhourde El Baguel, over 300,000 bbl/d each. Projected declines in these fields are likely to be more than compensated for by new field development in the Berkine and Ourhoud areas and enhanced oil recovery projects at the 6.4 billion bbl Hassi Messaoud field where only 20 per cent

[5] The Oil supply Dilemma: The Financial Positions and Investment Needs of Major Oil Exporters, Energy Intelligence Research Special Report, 160pp, 2004.

of the hydrocarbons have been recovered. It is hoped that by using EOR techniques production will double by the end of the decade.

2.9.2 Indonesia

Since its recent peak production level of 1.45 million barrel per day in 1991, Indonesia's production has been on a steady decline. By the end of 2003, production had fallen below 1 million barrels per day and the reserves base of 4.7 billion barrels had fallen by 29 per cent from the peak in 1991. The country recognises that major steps will be required in order to reverse the decline in production. In fact the situation is now so critical that not only is Indonesia unable to meet its production quota but that the country is now close to the time when it will be importing more oil than it is exporting, and its qualification to continue as an OPEC member is put in question.

In the past year, Indonesia has put up 11 areas for tender for oil and gas exploration and the government also awarded 15 contracts offering higher production shares to investors in an effort to boost investment in the sector. The government hoped that this will encourage firms producing from existing fields to increase recovery rates in order to prolong the life of the fields. For instance, Caltex, a part of Chevrons Texaco, has the largest operation in the country and is undertaking a major expansion of its steam injection project at the Duri Duri field on Sumatra

2.9.3 Iraq

The future development of Iraq's oil and gas industry is clearly linked to the development of a stable post-Saddam political structure. At the end of 2003 reserves were estimated at 112 billion barrels and gas reserves were nearly 3,100 bcm. Due to decades of war and sanctions the amount of exploration activity has been severely limited and it is estimated that just 10 per cent of the total surface area has been fully evaluated. The USGS has estimated that an additional 45 billion barrels could be present.

In terms of crude oil production, the US-led Coalition reconstituted the Ministry of Oil and the State Oil Marketing Company (Somo) and other institutional components of the oil industry after the military action and by the end of 2003 production had risen to about 2 million bbl/day of which oil exports were estimated to be around 1.7 million bbl/day. The Ministry of Oil is currently targeting crude oil production of about 2.5 million b/d. This expansion will require ongoing repair and rehabilitation work.

The further expansion of Iraq's crude production is planned in two further stages. The Ministry of Oil hopes to restore Iraq's pre-August 1990 production capacity of 3.5 million b/d by the middle of this year, although this looks quite an ambitious target. It then hopes to add a further 0.5 million bbl/d by early 2006. Beyond that time, it is hoped that the development of new fields to the south, north and east of Baghdad, with the involvement of foreign partners will push crude oil production to 5.5 million bbl/day by around 2010. The total cost of this expansion in capacity is roughly estimated at around $5 to 6 billion for production to reach 3.5 million bbl/d and a further $30 to $40 billion to reach 5.5 million bbl/d. Of course, these ambitious targets will rely on a stable political framework to create the conditions for investment. In the absence of these conditions it is likely that production capacity targets will slip. Furthermore, since Iraq remains a member of OPEC, Iraq may be additionally constrained by production policies in place at the time.

2.9.4 Iran

The development of Iran's oil and gas reserves has been constrained by political considerations and this is set to continue for the foreseeable future. The country has been forced to take a unique approach to upstream investments by sanctions imposed from the outside and internal restrictions by the Islamic regime.

The Iranian constitution prohibits foreign ownership of hydrocarbon resources by foreign companies. However, foreign participation has been allowed through 'buy-back' contracts which are usually short-term (7 years) arrangements. Unfortunately these buy-back contracts have been largely unsuccessful and NIOC is trying to structure new contracts in order to attract new foreign investment.

At the end of 2003 proved oil reserves were 125.8 billion barrels. Oil production averaged 3.9 million bbl/d, giving the country a reserves life of 92 years. The country's gas reserves are even larger and are likely to be much more significant for the country in the longer term. At the end of 2003 the gas reserves amounted to 812 tcf and were the second largest in the world after Russia.

Iran's current crude oil production is unofficially capped at 4 million bbl/d, excluding NGLs and some condensates. The oil ministry has claimed that the production capacity is 4.3 million bbl/d but the decline rate in mature fields is likely to have reduced that figure. In November 2003, a senior advisor to the Ministry of Petroleum announced plans to nearly double Iran's crude oil production from the current official estimate of 4.2 million bbl/d in two stages: a targeted 5 million bbl/d by 2010, rising to 8 million bbl/d by 2020. The increase in production is expected to come not only from the upgrading of mature fields, primarily using gas injection, but also from the development of new onshore prospects near the Iraqi border.
Put in perspective this target is not overly ambitious given that the country produced 6 million bbl/d in 1974 before the serious political disturbances which ultimately led to the fall of the Shah.

Although these expansion plans look ambitious it should be noted that Iran does have a number of large undeveloped fields that, since 1995, have been gradually opened to international oil companies under buy-back and service-type agreements. Total, which signed the first development agreement in 1996, is the dominant IOC although others, including Shell and ENI, are also active in Iran.

Progress in reaching additional buy-back contracts has been slowed not only by technical considerations but also by political pressure from the United States not to invest until Iran's intentions on the development of nuclear power are clarified and the government gives assurances that nuclear weapons development is not an objective. The Iran Libya Sanction Act 1996, ILSA, was extended for a further 5 years in July 2001, providing penalties against non-US companies investing more than $20 million per annum in Iran's petroleum sector. ILSA has not been enforced effectively and has had only a limited impact. However, restrictions on American companies, imposed in 1995, have kept them out of Iran, with the exception of Haliburton, recently involved in a service contract for a project in Iran. More recently the chief executive of BP stated that it was unlikely to try and access Iran as it would not want to offend the United States where a significant proportion of is operations are located.

2.9.5 Libya

Libya has the potential to make major capacity additions as it re-emerges into the global economy following years of isolation by international and US sanctions. The country is Africa's largest oil reserves holder with 36 billion bbl and it has 12 fields with more than 1 billion barrels each. With the formal suspension of United Nations sanctions in August 2003 the international oil companies have recently returned to the country after a recent licensing round.

In 2003, Libya was the eighth largest producer of crude oil among OPEC's eleven members and also the eleventh largest exporter of crude oil in the world. At the end of 2003 its proved oil reserves stood at 29.5 billion barrels. Total liquids production has fluctuated in a range between 1.35 mmb/d and 1.50 million bbl/d over the past 10 years. In 2003, production averaged 1.44 mmb/d, giving the country a total reserves life of 59 years.

With the opening up of the oil sector, Libya hopes to attract some $30 billion of foreign upstream investment in an effort to increase production from the present total of 1.6 mmb/d to 3.0 million bbl/d by 2010. In order to achieve this goal the Libyan National Oil Company has said that this will require 70 per cent of its territory to be opened up to foreign exploration from the current 25 per cent.

2.9.6 Nigeria

At the end of 2003, Nigeria's proved oil reserves were 25 billion barrels and the country was the fifth largest producer in OPEC and the seventh largest exporter of oil in the world. Oil production has held steady at between 1.9 and 2.3 million barrels per day over the past decade and the reserves to production ratio is currently 32 years.

Nigeria has the capacity to significantly increase its productive capacity over the next year from 2.5 million bbl/d to around 3.0 million bbl/d when recent discoveries come on stream. As always in

Nigeria, political turmoil and a tradition of corruption are a major disincentive for investment decisions, as are tight budgets set for the domestic industry and occasional bouts of adherence to OPEC commitments. The political factors have kept production some 500,000 bbl/d below stated capacity for the past two years and continue to cast a shadow over the country's longer term plans to increase production capacity to 4 million bbl/d by the end of 2006.

Whilst the impact of these concerns on investment plans is difficult to measure, since cuts tend to be focused more on exploration than development, there is no doubt that some of the major projects have been affected. For example Royal Dutch/Shell's Bonga field is advancing much more slowly than originally planned. NNPC's cash shortages also take on increasing significance as joint venture companies shift to costlier integrated onshore oil and gas schemes in order to comply with a 2008 deadline to phase out the flaring of associated gas.

2.9.7 Venezuela

Venezuela has 77.8 billion barrels of proven conventional oil and 148 Tcf of natural gas. The oil reserves are the largest outside of the Middle East and the government continues to seek foreign investment. However, investors have reacted to the political turmoil seen in 2002 and 2003 depending on the size of their commitment and the fit of projects in their portfolio. More recently a new hydrocarbon law was decreed in which royalty rates on oil production were increased from 16 per cent to 31 per cent.

With respect to the resource base, Venezuela is the third largest producer of oil within OPEC and the fifth largest exporter of crude oil in the world. Crude oil production peaked at 3.5 million bbl/d in 1998 but since that time has declined steadily to 3 million bbl/d in 2001 to 2.3 million bbl/d by the end of 2003. To some extent the decline in conventional crude oil output has been partially offset by the rising output of synthetic crude oil produced in cooperation with foreign joint venture partners. In 2003, synthetic crude output averaged 475,000 bbl/d accounting for more than 18 per cent of all liquids produced (see Unconventional Oil).

PDV had ambitious plans to raise the national oil production capacity to 5 million bbl/d by 2009. It plans to shoulder most of the investment itself and in this respect has allocated $35.4 billion in capital spending up until 2009 to achieve its goal. There is however little in the way of detail as to which projects will be developed or their timing. Investment plans became even less clear when the national oil company undertook a corporate re-organisation in January 2004.

3. Energy Security, Non-OPEC Supply Responses to Price Changes—Past and Future

3.1 Introduction

This section (Subtask 1.2) of the report addresses the subject of oil price developments and the chronic dilemma imposed by prices if either too high or too low in terms of investment strategies. This represents the core of this study: namely, what is oil supply security, and what are the prospects for non-OPEC supply to meet demand growth, and under what price range assumptions can we expect continued supply from Non-OPEC regions? By implication, the results of this analysis pose the dilemma for GCC producers as swing suppliers and having to second-guess the developments of other producers both within and outside the region, and within the context of other national economic objectives. The objective is to describe the potential for supply from other sources and the range of factors affecting its uncertainty rather than attempt to develop some balanced model of future demand and supply.

Because the EUROGULF project responds to the Commission's concerns regarding energy security, this section commences with a discussion of the subject. In this context the specific issue of security of oil supply from Middle East countries is discussed. The relationship between the European region and the Arab energy producers is not a new issue—it was the subject, for example, of an OAPEC/EC seminar in Morocco in 1990—in fact, dialogue on this essential element of Arab-Euro relationship began with the creation of OAPEC (see A. A. al-Turki, in The Integration of Energy Markets: Prospects for Euro-Arab Cooperation, OAPEC publication, 1992).

As background to understanding the potential for new supply from Non-OPEC regions, a review is provided of the key sources of new supply in response to price changes after 1973. The section then looks forward to the medium term by analysing the supply potential of countries outside the GCC, and in the non-OPEC world in general. But rather than taking a strictly country-by-country approach, Non-OPEC supply potential is addressed in terms of key or major 'plays' and regions. This is followed by an analysis of the cost of production to establish at what price levels Non-OPEC production is economic and, by inference, whether new developments might be accelerated or deferred.

3.2 Security of Energy Supply: What is it?

The drive to secure supply of the essentials to survival is manifestly the essence of evolution; through eons of geologic time organisms have devised strategies to assure acquisition of food (energy) and other necessities for survival in the face of recurring bouts of volatility of the cost of doing so driven by the vagaries of climate and earth processes. Institutions and organizations, concerned with their survival, not surprisingly harbour the same preoccupations as organisms. Over the last several centuries as trade between nations increased, the political preoccupation by states with the security of supply of what they needed to import at the time, is a thread through history that has and will continue to define geopolitics—if geopolitics can be defined at all.

Concerns about the security of energy supply did not start with the European Coal and Steel Community in the early fifties, which led to European unity as we know it today, nor with the International Energy Agency (IEA) within the OECD in response to the 1973/4 oil price shock. Nonetheless, the pursuit of energy security has been central to the purpose of the IEA since its beginning, and most of what the European Commission does in the area of energy is designed to bolster the community's security of energy supply. For the last fifteen years, the often conflicting policy objectives of market reform and liberalization and reducing energy-related greenhouse gas emissions in the face of concern about climate change have compounded the complexity of policies aimed at achieving energy security and have presented more than a few contradictions and dilemmas for policy makers.

Numerous international bodies and academics have attempted to define 'energy security' or 'security of supply'. Some examples follow:

- "an adequate supply of energy at reasonable cost" (IEA, *Energy Technology Policy*, 1985);
- "security of supply means the ability to ensure that future essential energy needs can be met, both by means of adequate domestic resources worked under economically acceptable conditions or maintained as strategic reserves, and by calling upon accessible and stable external sources supplemented where appropriate, by strategic stocks", European Commission, 1990, (*Security of Supply, Energy in Europe* No. 16); the Commission more recently defined energy security as, "…the availability of energy at all times in various forms, in sufficient quantities, and at reasonable and/or affordable prices" and in their study, focus on "the availability of oil and gas in sufficient quantities, and in particular on the risk of oil and gas supply disruptions." (EC, *Study on Energy Supply Security and Geopolitics*, 2004.)
- "If security of supply is the assurance of the physical availability of oil during a supply disruption, then a country can be said to have achieved this goal if it is always able to guarantee that a given quantity of oil is available with certainty to its domestic market, independently of possible market disturbances" (Lacasse, C. and A. Plourde, 1995, *On the renewal of concern for the security of supply.*, The Energy Journal, 16(2): 13, 1-23.)
- "a condition in which a nation and all, or most, of its citizens and businesses have access to sufficient energy resources at reasonable prices for the foreseeable

future free from serious risk of major disruption of service." (Barton, B., C. Redgewell, A. Ronnel, and D.N. Zillman (2004), *Energy Security: Managing Risk in a Dynamic Legal and Regulatory Environment.* Oxford University Press: 5, 3-13.

- "Energy security has three faces. The first involves limiting vulnerability to disruption given rising dependence on imported oil from an unstable Middle East. The second, broader face is, over time, the provision of adequate supply for rising demand at reasonable prices—in effect, the reasonably smooth functioning over time of the international energy system. The third face of energy security is the energy-related environmental challenge (to operate within the constraints of 'sustainable development')" (*Maintaining Energy Security in a Global Context*; # 48, A report to the Trilateral Commission by William Martin, Ryukichi Imai and Helga Steeg, 1996, p. 4)
- In June of 1993 IEA Ministers agreed to Shared Goals for energy policies, of which energy security was central, although not dominant—the establishment of free and open market was seen as the fundamental point of departure; the encouragement of dialogue within a global context was seen as essential. The elements of energy security were set out in the Goals as follows: "Diversity, efficiency and flexibility within the energy sector are basic conditions for longer-term energy security; the fuels used within and across sectors and the sources of those fuels should be as diverse as practicable…Energy systems should have the ability to respond promptly and flexibly to energy emergencies. In some cases this requires collective mechanisms and action…Improved energy efficiency can promote both environmental protection and energy security…Continued research, development and market deployment of new and improved energy technologies (contribute to the objectives)…Undistorted energy prices enable markets to work efficiently…Free and open trade and a secure framework for investment contribute to efficient energy markets and energy security…Cooperation among all energy market participants helps to improve information and understanding…(and) to help promote the investment, trade and confidence necessary to achieve global energy security and environmental objectives." (International Energy Agency, Statement of Ministers, June 1993, IEA/OECD Paris.)

What comes through in all of these attempts to define the concept is the use of relative or qualitative terms such as 'adequate', 'reasonable', 'essential', 'appropriate', 'sufficient', 'foreseeable' and 'major'. While these words might puzzle some as to just precisely what their authors meant in using them, anyone experienced in international attempts to codify desirable economic policies or outcomes of international cooperation will recognize in their imprecision an enormous amount of diplomatic and drafting effort to achieve consensual comfort with their meaning. Everyone can come away from such definitions reasonably assured that they offer comfort. And that might just be the point—comfort. The IEA's Shared Goals are perhaps the best example of an attempt to be all things to all parties yet still codify the essential practical elements of how to ensure that energy policies based on these goals would incidentally strengthen energy security but at the end of the day assist countries in creating “the conditions in which the energy sectors of their economies can make the fullest possible contribution to sustainable economic development and the well-being of their people and of the environment.” Thus energy is seen properly as an economic input and the security of its supply is just part of a larger set of economic objectives and not an end in itself.

But, the idea of energy security should be decomposed further to get at the essential motivators to make it such a preoccupation for politicians. To economists, ‘supply’ is the schedule of quantities of a good or input that will be available at different prices; the less there is available, the higher will be the price. The ‘security’ of supply of a good, service or input may not have meaning in economic theory, since markets clear and the scarcity of a good will be reflected in its price, and supply will be rationed accordingly. Therefore, the definition of ‘security’ embodies the element of ‘price’ or at least achieving a state where the risk of rising prices is reduced or eliminated. And, therefore, the concern comes back to the political economy and energy’s essential role in it. Consumers do not want to pay ‘too much’ and politicians do not like the effect on economies when input costs suddenly rise.

At the end of the day, ‘security’ is a feeling—consumers either feel secure (comfortable) about the supply of something, or they don’t. Articles in the media and statements by politicians can contribute to the public’s feeling of insecurity. Politicians can enact policies and programmes and make statements to reassure consumers. Yet, consumers large and small will read or misread signals from the media, the market and from politicians and agents perceived to have some influence over markets. An example from the late seventies is relevant: long queues at petrol stations in California developed when consumers believed, prompted by TV newscasts, that there was a shortage of petrol and all rushed at once to fill up their vehicle tanks, thereby causing a shortage, which compounded the fear of shortage, which became self-fulfilling. The lesson should not be lost on policy makers.

3.2.1 Energy Security: The Importance of Context

The example from the late seventies raises another essential qualifier of what influences perceptions of energy security, and that is ‘context’. Context has temporal and spatial elements; for example, the particular state of global markets at the time, the state of regional political stability, and above all the nature of the relationship at any particular time between buyer and seller of an energy commodity. It also depends on the commodity—grid-based energy, gas and electricity, have elements of co-dependence between producer and consumer that is not as evident with crude oil. At the macro level, the importance of context and ‘the times’ is revealed by the IEA’s 1993 Shared Goals compared with the Agency’s earlier Policy Principles confirmed by its Ministers in 1979. The earlier policy principles were at a time of rapidly rising oil prices, acute global macroeconomic dislocation and a palpable tension between consuming countries and producing countries. Thus, whereas the 1993 policy goals were issued in an environment of relatively low prices and therefore comfortably couched in a framework of market forces, the 1979 principles were clear about picking winners (coal and nuclear), reserving gas for special uses (certainly *not* for electricity generation) and calling for explicit reductions in oil demand. This latter policy principle played a significant role in setting the tone of the subsequent consumer/producer dialogue and debate in which producers are seeking demand security (i.e., consuming countries not 'outlawing' oil). Finally, the starkest expression of the changed context pertains to the use of gas in power generation: OECD countries that prohibited the practise in the eighties have since, by the absence of policies, essentially found themselves relying on nothing but natural gas to fuel new power capacity. The US and the UK, having dashed for gas (while ostensibly for environmental reasons, the reality was no other fuel was permitted by their publics), now find themselves grappling again with the 'ghosts' of energy security centred on natural gas supply.

The IEA's concerns were again affected by a change in context presented by the end of the millennium (Y2K) and the apprehensions that energy delivery systems might break down owing to glitches in computer software. Meanwhile the political context between OPEC and the IEA had been softening and cooperation regarding Y2K brought their staff together, also to discuss the importance of coherent oil market data with the formalization of the Producer Consumer Dialogue in the International Energy Forum. Not surprising then, by May of 2001, IEA Ministers were emphasizing improved transparency in world energy markets "especially the oil market;" maintaining the existing energy dialogue with non-member countries; as well as the old energy security chestnuts of building stocks, continuing diversification; working to improve energy efficiency; and politically correct if often problematic and contradictory developing and using "the most effective possible means to achieve sustainable development" (International Energy Agency, Energy Policies of IEA Countries. 2002 Review).

The international context for the short term security concern of Y2K was dramatically redefined further with the terrorist attacks in New York and Washington on September 11, 2001. Thus, the IEA Ministers added references to protection of vulnerable infrastructure to sabotage and terrorist attack, and this concern was reiterated in the Agency's 2004 World Energy Outlook in references to the major choke points in seaborne international oil and gas movements. IEA Ministers never announce what is no longer of concern to them: they merely add new themes and for the 'losers', like the practice in China with respect to leaders no longer in favour, simply no longer mention them. They use the annual World Energy Outlook as a vehicle to flag and examine security concerns. Recent examples include the preoccupation with "adequate investment in supply" and "adequate oil reserves"

On a more micro level, context plays an important role and it can change with time. A case in point is the EU's perception of security of gas supply from the Former Soviet Union in general and from Russia in particular. At one time, while the United States urged Europe to avoid relying on gas from Russia, Brussels considered FSU/EU gas trade as 'relationship-building'. Today it is questionable whether the EC would feel the same. Thus the degree of insecurity depends on the bilateral political relationship and the magnitude and nature of the trade. To use an example offered by John Mitchell (at PASS Conference on Security and Energy, Prague, Oct. 20, 2004), the security of supply of LNG from Trinidad to Europe is different from that of LNG from other sources, or of pipeline gas from Russia—because the bilateral contexts differ. A stark example of the importance of the bilateral relationship is offered by the bullying tactics of Turkmenistan at the end of 2004 in renegotiating its gas supply contract with the Ukraine, at a time when the latter's political echelon was changing, fragile and very uncertain. Clearly, Turkmenistan felt in a position of power—allegedly emboldened by Russia—and applied tactics (cutting off gas) that it is difficult to imagine it might use with, say Germany. Thus, context matters and EU policy makers need to pay attention to other issues in the political relationship with the GCC and its members (migration, trade, Palestine, Kyoto) rather than focus on just one element of the relationship, energy trade. Moreover, it must never be forgotten that political context has two sides, in this case, not just Europe's energy security.

Price is also important, although it is often downplayed as a factor determining, for example, the deployment of stocks. Policy makers nonetheless seek policies that will conduce to 'price stability' for a good or commodity. Security of supply is perceived to be at risk when the volatility of the price of a good increases. That price volatility is the 'canary in the cage', an important signal to consumers to reduce demand and to investors to increase supply, seems lost on many policy makers who mistrust or have little faith that functioning markets will, with time, calm volatility. To be fair to them, on the other hand, it must be acknowledged that when there is a price shock, for whatever reason, the consuming public invariably turn to politicians rather than to industry for answers. So, it is natural that political institutions will seek policies that obviate the risk of price shocks—specifically, sudden, significant and lasting price rises.

Freedom from significant price rises, however, does not adequately define security of supply. Otherwise, IEA governments essentially led by the United States government would have agreed to release Strategic Stocks of oil in 2004 with the doubling in oil prices. Instead, the IEA apparently tried to influence prices by reminding readers of its monthly oil market report (IEA OMR, August 11th, 2004) that this 'weapon' was in its arsenal. This price rise was evidently not considered to be *significant*. U.S. Vice President Cheney subsequently stated, and the White House confirmed that 'insecurity' of supply was not evident: *that* would require the loss of 5 or 6 million barrels per day of U.S. supply (Reuters, August 26, 2004). Therefore, security of supply for some refers to the freedom of *physical* interdiction of production or distribution due to political intervention, war, accident or simply mechanical breakdown. This stance appears to contrast with that of the European Commission, given its draft Directive in September 2002 on Oil and Gas Emergency Measures in which the Commission proposed that it retain the authority to release member states' strategic oil stocks to counter sharp price increases. The European Parliament subsequently rejected the proposal and the EU Commissioner for Transport and Energy, Loyola de Palacio subsequently abandoned the idea. Nonetheless, price is not irrelevant. It is the price effects on the economy that ultimately concern policy makers, even though for years, statements from the International Energy Agency suggested that strategic oil stocks would be released only to meet physical shortages and not to influence prices (Commentary by R. Skinner, OIES Website, 'Exuberant Irrationality', August, 2004).

If security of supply is defined in terms of immunity from interdiction of physical supply, then it can be analyzed in terms of the probability of the causes; namely, political intervention, war, accident or mechanical breakdown. The greater the probability of any cause, the weaker will be the security of supply. But this still does not take into account slower forces affecting long term security, such as depletion of a resource or the lack of investment because investors misread the signals, or policies prevent investors' access to energy resources on terms that offer returns that can compete with other uses of capital. This latter situation is particularly germane to natural gas in North America and arguably at an international level for oil, as the large international oil companies seek access to oil and gas resources under terms that their shareholders find attractive, while some national oil companies are left insufficient capital by their owners to develop additional supply.

Any definition of security of supply that is sufficiently robust to use as a starting point for discussing policies for its achievement must embrace or acknowledge the following elements:

- The context of the trade relationship at the time;
- The potential for and degree of physical disruption of supply;
- The magnitude and duration of price change and its potential to cause macroeconomic dislocation;
- Whether sectors of the economy that depend uniquely on hydrocarbons, especially in the case of oil, can physically function in situations of disruption;
- How to assure over the longer term continuing investment in the energy supply chain, including in infrastructure and in the availability of a supply margin whether as capacity margin or strategic stocks.

No matter how these essential elements of security of supply are strung together in some definition, they provide a backdrop for discussing the prospects for hydrocarbon exports from the GCC member countries and to analyse these prospects within the context of the European Commission's perennial concern about 'security of oil and gas supply'.

3.3 The Middle East and Security of Oil Supply

A major share of the world's oil comes from the Middle East. The region possesses over two thirds of the world's oil reserves. It is perceived as a politically unstable region—indeed, the report on Energy Security for the Trilateral Commission (op cit) saw the Middle East as central to the issue of energy security, and somewhat perversely saw at the time (1995/96) that energy security might appear to have been "successfully regained…(and that) The threat of disruption to energy supplies (is) of little immediate concern. OPEC is currently weak." (op cit, p.1). Setting aside for a moment the proposition that a 'weak OPEC' is synonymous with energy security (a more convincing case can be made to the contrary), the linking of OPEC, the Middle East and insecure oil supply permeates the literature on the subject. As noted above, the EC needs to examine its relationship with the Middle East in broader terms in order to begin to understand what if anything can be done to bolster security of supply from this region.

Yet, if one considers the long standing tensions, wars and other events that have upset oil markets over the last 30 years, this perception would seem to be supported. However, when held up to the test of 'physical disruption of supply', the apparent political insecurity is not matched by interdictions of oil supply. Thus, in such an inquiry, one inevitably returns to other elements of the definition of security of supply and specifically those dealing with 'feelings' and sentiments; the physical historical record seems secondary[6].

Statements by OECD politicians, the media and the like invariably make reference to the 'growing dependence on oil from the Middle East'. The IEA in its semi-annual World Energy Outlook, repeatedly implies that oil from the Middle East is insecure and that growing dependence on the region for oil is a bad thing. In the first page of its most recent WEO, the IEA states that "A central message of the *Outlook* is that short-term risks to energy supply will grow... Rising oil demand will have to be met by a small group of countries with large enough reserves, primarily Middle East members of OPEC and Russia". In an alternative scenario, where environmental and energy scarcity policies are deployed "dependence on imported energy in major consuming countries and the world's reliance on Middle East oil and gas are …lower". Thus the IEA sees a virtue in a set of policies that conflate to less trade with this region. This seems at odds with the aim to integrate its economies and consolidate and enhance friendly relations, trade and economic ties. Indeed, US foreign policy is dedicated to expanding supply from other sources, notably the Caucuses regions and from Russia, and both candidates in the 2004 US Presidential election campaign made frequent statements about their energy policies in which they aspire to reduce or eliminate dependence on oil from the Middle East. Observers of the recent US election campaign will

[6] For a discussion of the lack of a necessary link between oil price increases and recessions, and price changes and Middle East political events and war, see, "Oil and the Macroeconomy Since the 1970s", Robert Borsky and Lutz Kilian, 2004, Working Papers 10855, National Bureau of Economic Research

understand that much rhetoric is designed to empathise with the received view of the electorate rather than attempt to dispel it.

Much of the phraseology that links Middle East with insecure oil derives from experience in the early seventies and references to the 'oil weapon'. The following are just a few examples of energy supply disruptions over the past three decades:

- The 'Oil Weapon'. Used once by producers against the United States and the Netherlands after the Yom Kippur War. Having used it once, producers seemed to have learned a lesson. Meanwhile it was used by consumer countries against consumers (South Africa); by consumers against producers (Iran Libya Sanctions Act; Iraq boycott, currently contemplated against Sudan); by producers against producers (against Russia in the late eighties; to counter and discipline Venezuela in its pursuit of market share in the late nineties);
- Internal Energy disputes and supply interruptions: UK coal miners' strike; 1981, Alberta cut off oil to eastern Canadian consuming region during federal-provincial price and energy dispute; tanker-drivers' fuel blockade in UK over fuel price increases in 2000; numerous strikes in France in the late nineties, especially 1995, when fuel supplies were at risk and in 2004 when the Labour Unions of a power utility cut off electric power to political leaders' residences;
- Internal political disputes; Venezuela, Nigeria (2002/2003-continuing), however the market was supplied by other OPEC members, principally those from the Gulf, who had extra production capacity;
- Intra-regional disputes: Ukraine and Belarus interrupt gas supply to Europe from Russia (1990s and 2003/04) although the market was served by back-up measures; Turkey delaying the exit of tankers from the Black Sea (2003/04); invasion of Kuwait by Iraq (1990); refusal of Bolivia to export gas to Chile (2004).
- Technical Disruptions due to technical and operator failure: Australian natural gas plant failure in 1998, Victoria State, which underscored the need for greater training and safety measures by operators, but also the importance of interconnection between regional gas markets within Australia; Electricity black-outs in eastern North America and Europe in 2003 due to combination of failures—to monitor, to maintain facilities and transmission ROWs, to ensure adequate training for operators, response failure to interpret and respond to routine technical upsets; nuclear reactor problems in Japan (the nuclear programme having been a conscious policy decision to reduce dependence on oil, Japan had to increase oil imports in 2003 to fill the gap left by the shut-sown reactors); California Crisis of 2000 due to combination of regulatory and policy failure and 'gaming' by traders.

Oil supply from the Gulf and in particular from the most significant supplier, Saudi Arabia and others with spare capacity, has met the market's requirements for the past 30 years. This was evidenced in the first Gulf War against Iraq and in the spring of 2003 during the second attack on Iraq, when supply disruptions occurred in Nigeria and Venezuela. Notwithstanding this record of physical supply availability, there remain concerns about security of supply. This came to the fore in 2004 with the erosion of OPEC spare production capacity and the market's perception of this narrow margin, which in turn contributed to the increase in oil prices. That Saudi Arabia in particular has added new capacity and repeatedly assured the market of its intentions to maintain a 1.0 to 1.5 mb/d capacity margin, may have assured some countries.

Price matters and there has been much discussion whether higher prices will lead to a drop in demand as higher energy costs work their way through the economy. If the price of oil concerns economic policy makers and if perceptions of Middle East geopolitics continue to add a premium on prices, then whether justified or not, the fact of perception rather than the reality of performance will continue to confound markets and influence prices, and therefore policies. In the final analysis, it would be unreasonable to expect that policy makers in any consuming nation would be permitted to take a position of indifference or passivity regarding growing dependence on any region or country for any commodity, particularly where the political and democratic institutions are not well developed and themselves assured of survival. But the degree of insecurity they might feel with respect to any supplying country or region should be in direct proportion to the general political relationship with the country or region. In this sense, energy security can only be addressed within the larger political context and it is submitted that the political relationship is not bolstered by repeated statements by political leaders of consuming countries that the Middle East is an insecure source of oil. The present study is confounded by this reality of the perennial and often misconstrued debate about energy security.

3.4 Historical Analysis of Non-OPEC Supply (1973-2003) - Is past necessarily prologue?

This section addresses a key component of the study; namely, what are the prospects for GCC supply after Non-OPEC supply is absorbed? To answer this question, it is helpful to review which sources of supply squeezed out OPEC/GCC market share in the past, and then pose the question, 'Is this repeatable?' If so, which sources have the potential to do so? Some commentators believe that the 2003/04 increase in oil prices is merely prelude to a repeat of the past and that we can count on a non-OPEC supply response surge similar to that experienced in the late seventies and early eighties. A critical examination of this proposition is essential in order to develop some measure of the space within which GCC countries have to manoeuvre in their production expansion strategies.

In 1973 world oil production was 58.5 Mmb/d. OPEC supplied 53% of world supply, it's maximum share ever, and the Middle East contributed 21.2 mmb/d; ten years later after a nearly four times doubling in prices, the world consumed 2 million b/d less, and OPEC's production had been cut to 16.7 Mmb/d and with it, the Middle East's production had dropped to 11.8 Mmb/d and was still falling. As Saudi Arabia went on to play the swing producer role, reaching an average of 3.6 Mmb/d in 1985 before calling it 'quits', Middle East production bottomed out at 10.6 Mmb/d in 1986—half of its 1973 output level.

The history of world oil supply since the collapse in prices in 1986 has been well chronicled: OPEC's enormous shut-in or surplus capacity which stood at slightly above 11 million b/d in 1985, and declined to about 3 million b/d in 1989. Then with the loss of Kuwait's production in the 1990/91 Gulf War, it dropped to 0.5 million b/d. Through the nineties it averaged about 2.7 million b/d until 1999/2000 when recovery in the FSU saw additions of annual oil supply increments that backed in OPEC supply, again increasing its spare capacity. Since 2002, spare capacity has been whittled away to meet the resurgence of oil demand primarily in the US, China and the rest of Asia. Through the nineties, to create value for shareholders, the international oil companies focussed on operational cost-cutting, mergers and acquisitions and took advantage of new technologies to reduce exploration costs and to extend their exploration reach into new resources such as the ultra deep water basins and unconventional hydrocarbons. Bullish oil supply outlooks, such as those of the US DOE/EIA's and IEA's in 2004, rely on assumptions of new exploration and recovery technologies, continued cost reductions and the opening of access to new areas by producing countries. These propositions can be questioned.

First of all, the major technological breakthroughs during the eighties and nineties included horizontal and long reach drilling, three and four dimensional seismic imaging, continuous coiled tubing drilling, and the development of drilling and production systems for ultra-deep water and the ultra-heavy and unconventional oil. While there are numerous technologies under development that will enhance the ability of industry to manage and apply information and control systems to improve, for example, reservoir depletion, there does not appear to be on the immediate horizon technologies with the potential to provide the step-jump or material impact in accessing or producing oil that the above technologies allowed. Water depths greater than those currently accessed generally do not have high potential sedimentary basins beneath them. Cost reductions are a salient of the industry and always will be, but the currently higher oil and gas prices tend to result in higher costs, given the high amount of energy embedded in the equipment utilized to explore for and develop oil. Finally, most of the world's sedimentary basins are open to the international oil and gas industry for exploration.

The only two major countries that do not allow foreign company E&P access are Saudi Arabia (for oil) and Mexico (for hydrocarbons in general). Other countries are accessible and with the exception of Iraq (for security/safety reasons), the terms are evidently not attractive to the shareholders of the private international firms. Therefore, the assumption of increased access implies that the terms of access will be softened, even where prices are higher than they were when these regions were first opened. That foreign state-owned oil companies are and will continue to access these resources raises other questions including whether they will be able to rapidly convert this access into significant production. This question is beyond the scope of this report. The point here is that the assumptions of a repeat of high-impact new E&P technologies, major cost reductions and dramatic changes in accessibility to resources are difficult to support unequivocally.

If we assume that there are sufficient, highly prospective and potentially prolific basins accessible to the IOCs on terms their shareholders find attractive, would they propagate another wave of rising Non-OPEC supply to shut in OPEC capacity beyond the 2.5 to 3.0 million b/d optimal level? If so this compounds the dilemma for OPEC members as to whether and to what extent they should invest to develop new capacity. OPEC may well ask itself whether there is a case to be made for letting higher prices 'smoke out' this Non-OPEC prospectivity, wherever it is, rather than risk repeating the 'accident' of 1986. To answer this question one needs to disaggregate the past pattern of supply responses and then assess where the potential for duplication might exist in the current circumstances of available or accessible sedimentary basins and technologies.

In 1973, the average decline rate of producing fields, even if it was as high as today's (say 5%, but today's average decline rate is believed by some to be closer to 7%[7]) would have required less than 3 mmb/d/year of production to be replaced annually. In the early seventies the world had just begun testing new exploration concepts within the recently confirmed, new geological conceptual framework of plate tectonics. This concept was to the earth sciences what the discovery in 1953 of how DNA transferred genetic information was to the life sciences. Such a unifying concept with comparable impact on exploration can not be expected to be repeated today. On a finer scale, as noted above, major enabling technologies for exploring offshore had just been developed in the seventies. The combination of an earth model plus new and more sophisticated geophysical technology for 'seeing' into the earth generated an explosion of exploration concepts and plays. Several high-impact producing areas were just beginning to be explored in the early seventies when the 1973 price crisis occurred. Some of these new areas and their increases in production from 1973 to 1985 included:

- Alaska: eventually reached 2 Mmb/d, temporarily delaying the decline in US production, which had started in 1970.
- Mexico: 0.5 Mmb/d to nearly 3 Mmb/d by 1985.
- North Sea: 0.04 Mmb/d to 3.5 Mmb/d in 1985 and went on to peak at more than 6 mmb/d in 2000.

[7] In the IEA's World Energy Investment Outlook, IEA, 2003, the Agency assumed that decline rates vary geographically and with time. Rates assumed were 4% to 6% for the Middle East, North America onshore, 9%, Europe, 11%, Asia, 6% to 9%, Latin America , 5% (Venezuela) to 9% in Argentina, North Africa, 6% and West Africa, 8%. These are rates of decline that would occur if no investment were made to improve production; thus, they are 'natural' rates of decline.

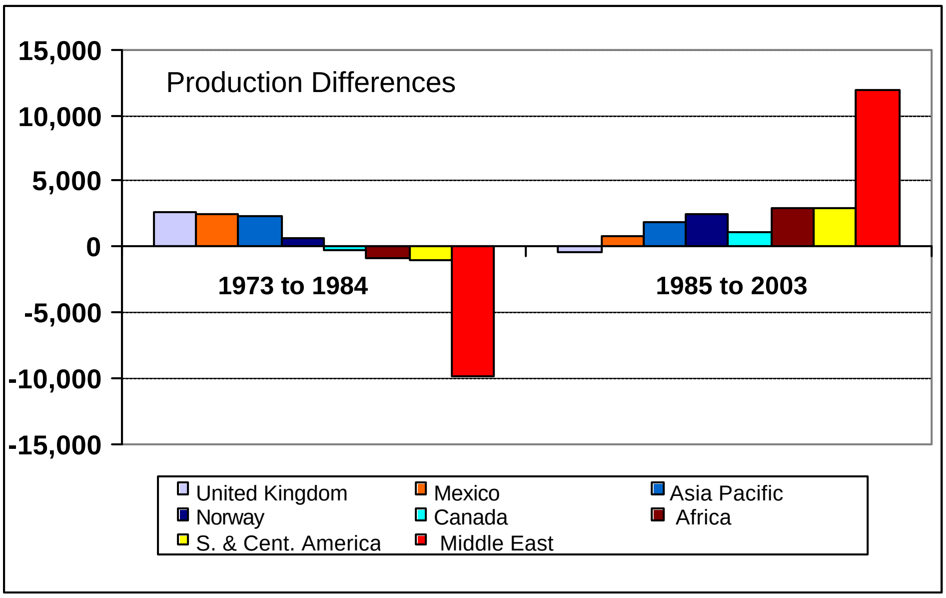
- Egypt: 0.16 mmb/d to 0.8 Mmb/d, and has more or less sustained this level since.
- China: 1.0 to 2.5 Mmb/d.
- India: 0.15 to 0.63 Mmb/d.
- Malaysia: 0.09 to 0.45 Mmb/d
- Indonesia: 0.9 to 1.34 Mmb/d

These 'new sourc es' contributed over 11 Mmb/d of incremental supply over a decade, and in the process forced an equivalent shut-in of Middle East capacity over this time. This supply does not include the output from the then Soviet Union, whose production increased by nearly 4 Mmb/d over the period.

Comparing the two periods, 1973 to 1984 and 1985 to 2003, it is important to note that different countries and regions played different roles. In the early period, OPEC countries shouldered the cut in production. Since 1985, they have become major contributors to incremental supply. This change is illustrated in Figure 4. The world cannot necessarily count on the same countries outside OPEC to again cause the shut-in of OPEC production and re-build a large surplus in production capacity.

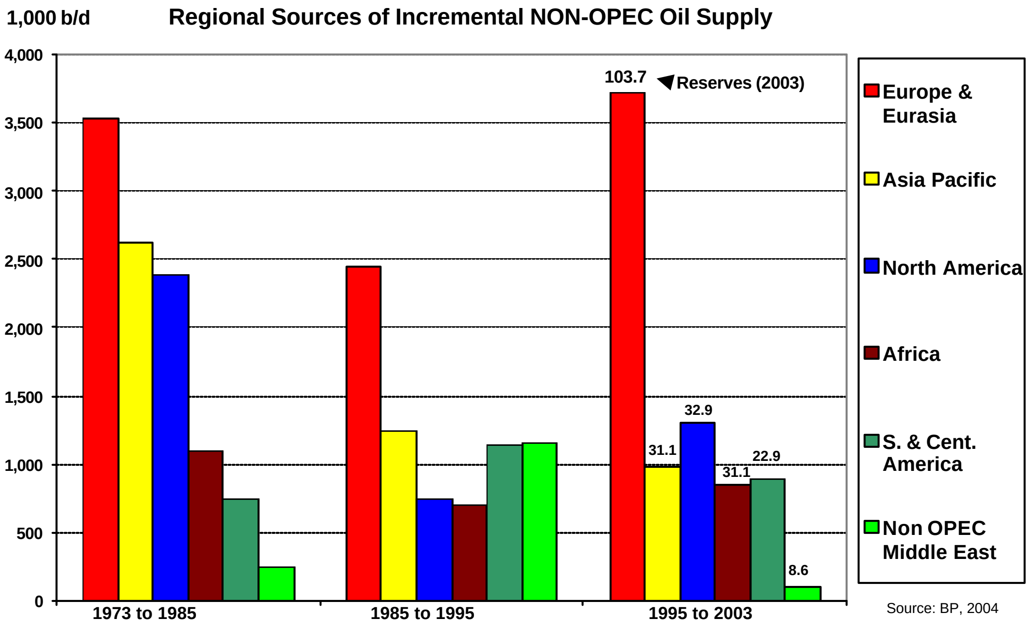
The section above looked at the performance of selected countries and regions, including OPEC countries, before and after the key year, 1985. To isolate OPEC and the Middle East and begin to understand the future scope for GCC countries, it is necessary to take a detailed look at Non-OPEC performance and potential, and examine recent performance and trends. Figure 5 focuses just on NON-OPEC countries on a regional basis and the contributions, or lack of, that they made over three 'periods' of oil supply history since 1973, which we might label, *OPEC Displacement* (1973-1985), *OPEC Surplus* (1985-1995) and *OPEC Re-emergence* (1995-2003).

Figure 4: Production differences of key suppliers over the pre- and post-1985 periods. Source of data: BP Statistical Review, 2004



It is reasonable to select periods of these lengths to assess the change in countries' contributions because it takes at least a decade to explore for and begin development and production of a new basin or area. Also, the year 1985 was a pivotal year in the history of world oil prices[8]. While prices were softening throughout the latter half of the year, it was on December 10th of 1985, when the oil price began its dramatic descent to less than $11 the following July. Thus, what happened to production in Non-OPEC countries after a decade under this post-1985, lower price regime is indicative of policy changes at the time and implicitly the attractiveness of exploration and development in these countries. The third period, *OPEC Re-emergence*, is underway. When it started is highly debateable. Perhaps 1998/99 after the 'Asian Crisis' might be a better choice—if only because OPEC discipline had been re-established after the debacle of its counter-cyclical increase in quotas at the beginning of the crisis, which led to a dramatic collapse in oil prices. Choosing 1995 is perhaps arbitrary, however oil prices began to turn up in that year and it is a decade after 1985, by when many high-cost, small impact producers should have run their course and begun to have been shaken out of the producer pack. Overall, as shown in the graph, supply increments from Non-OPEC producers (except Russia) were generally less through this period (and increasingly absorbed within their growing economies) except for, notably, Norway and the Non-OPEC Middle East producers (low cost, outside the strictures of OPEC and with no choice but to produce).

Figure 5: Regional Sources of Incremental Non-OPEC Supply



[8] 1985/86 represents a 'demarcation year' between two different eras in terms of prices, price setting, production shares, costs and market mechanisms. The year marks the beginning of a much-discussed factor in oil markets—so-called OPEC 'spare capacity'. This shut-in capacity was not the result of a conscious and magnanimous policy of over-investment on the part of OPEC countries. It was an 'accident' of the preceding years of rising prices and the supply response in non-OPEC countries. It has been much discussed in the past.

Several observations can be made from this breakdown of production increments over these different periods of the price and supply history.

- Although masked in the regionalized histograms in Figure 5, while more than two dozen countries managed to increase supply over each period (not the same countries for each period), the major contributions came from very few countries. During *OPEC Displacement*, Mexico, UK and China accounted for 60% of the increase (3 of 28 countries); during *OPEC Surplus*, 6 countries—Norway, Canada, China, Syria, Colombia and Oman—accounted for 60%; during *OPEC Re-emergence*, among 24 countries, 5—Russia, Brazil, Mexico, Norway and Canada—accounted for 60% of the increase.
- Countries that were important in the first period were less important or disappeared entirely as a net contributor by the third period. The UK is a notable example—its share of Europe and Eurasia during *OPEC surplus* was supplanted by Russia during *OPEC Re-Emergence*. China's increment of 1,430 mb/d in the first period declined to 407 mb/d in the third. Of the 40 Non-OPEC countries in this database, China has the highest reserves after Russia, yet its incremental production is declining.
- Fewer Non-OPEC countries contribute smaller amounts to an overall smaller increment in supply. The total increments for each of the three periods were 10,620, 7,430 and 7,870 mb/d (rounded to nearest 20); if Russia (+2,255 mb/d) is excluded from the last period, the largest incremental supplier was Brazil (834 mb/d), followed by Mexico (724 mb/d), Norway (672 mb/d) and Canada (584 mb/d).
- The proven reserves of the 40 recorded Non-OPEC producers are 230 Billion barrels, which is less than a third of the reserves of the Middle East. The only countries with a substantial reserves base and therefore the realistic potential to be producing significant quantities (>1,000 mb/d) more in 2013 than they were producing in 2003 are Russia, Canada and Mexico and possibly Angola and Kazakhstan. These are discussed in greater detail below, and as will be noted, these countries present a totally different matrix of factors important to production potential, in terms of political stability, technical difficulty and access to markets, than was the case for the 'new adders' in the early seventies.

Ascertaining the trend of Non-OPEC Supply requires disaggregating production of over 40 countries. To understand which countries have the potential to make a material contribution to future world oil supply, it is helpful to narrow the focus somewhat from the above analysis, and examine individual performances since 1998/99 after the major sag in oil prices in the wake of the Asian crisis and Venezuela's (more precisely, the executives' of its national oil company, PDVSA) failed dash for market share. Over this five-year period 25 Non-OPEC countries (Figure 6) managed to increase their output. The total increment was 5.86 Mmb/d. Of the 25 (24 plus

Russia), only 12 increased production by more than 100,000 b/d. Four countries accounted for 60% of this increase; Russia accounted for over 40%.

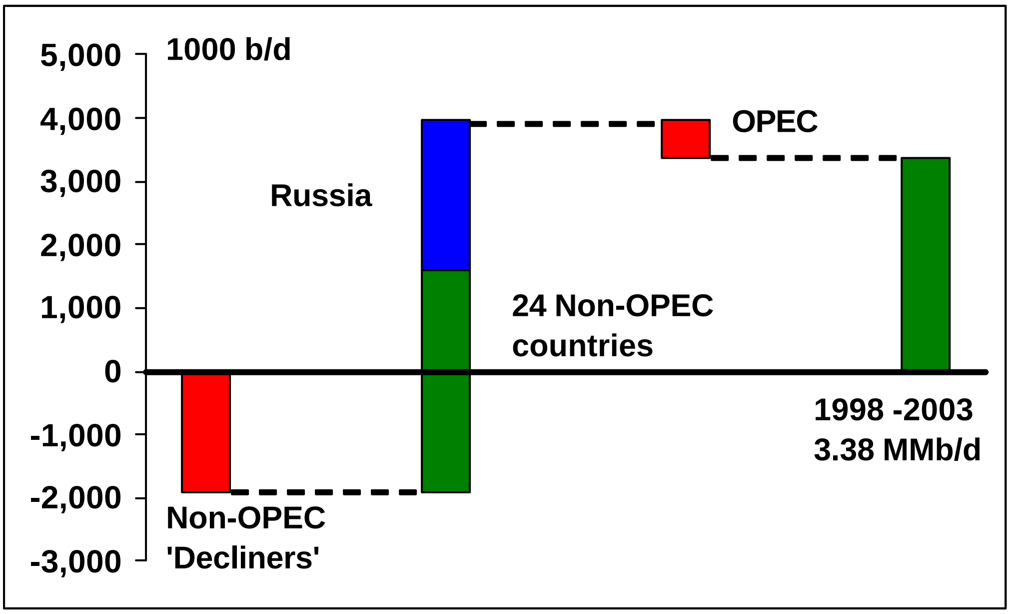
Between 1998 and 2003, world supply increased from 73.4 Mmb/d to 76.8 Mmb/d, or 3.38 Mmb/d, which, as shown in Figure 7, was the net of the increase by the 'Group of 25', less 1.9 Mmb/d of declines from other Non-OPEC countries ('Decliners') and an offsetting production cut-back by OPEC of 0.58 Mmb/d. Most of the countries that managed to increase their production over the period did so from a very small reserves base. Sixteen of the 25 had proven reserves of 5 billion barrels or less. Excluding those of Russia, the group's total proven reserves declined by nearly 5 billion barrels (3.4%). This picture suggests that there are relatively few potential high impact producers among a group with weakening overall scope to, on its own, meet growing world oil demand.

Figure 6: Changes in Production and Reserves from 1998 to 2003

		Production		**Reserves**	
Country	**Change**	**1998**		**1998**	**2003**
Russia	2,374	6,169	8,543	56.0	69.1
Kazakhstan	569	537	1,106	8.0	9.0
Brazil	549	1,003	1,552	7.4	10.6
Canada	314	2,672	2,986	15.1	16.9
Mexico	290	3,499	3,789	28.4	16.0
Sudan	243	12	255	0.3	0.7
China	184	3,212	3,396	33.5	23.7
Eq Guinea	166	83	249	0.5	1.1
Angola	154	731	885	4.0	8.9
Denmark	133	235	368	0.9	1.3
Vietnam	127	245	372	1.9	2.5
Norway	121	3,139	3,260	11.6	10.1
Thailand	96	121	217	0.4	0.7
Azerbaijan	83	230	313	7.0	7.0
Turkmenistan	81	129	210	0.5	0.5
Yemen	74	380	454	0.2	0.7
Malaysia	60	815	875	4.7	4.0
Brunei	57	157	214	1.0	1.1
Ecuador	43	384	427	2.6	4.6
Chad	40	0	40	0.9	0.9
Other LA	38	125	163	1.1	1.5
T&T	29	134	163	0.6	1.9
Syria	18	576	594	2.3	2.3
Other Africa	11	63	74	0.3	2.3
India	2	791	793	5.4	5.6
	5,856	**25,442**	**31,298**	**194.6**	**203.0**

Source: BP 2004 Statistical Review

Figure 7: Major contributors to Non-OPEC supply increases 1998-2003



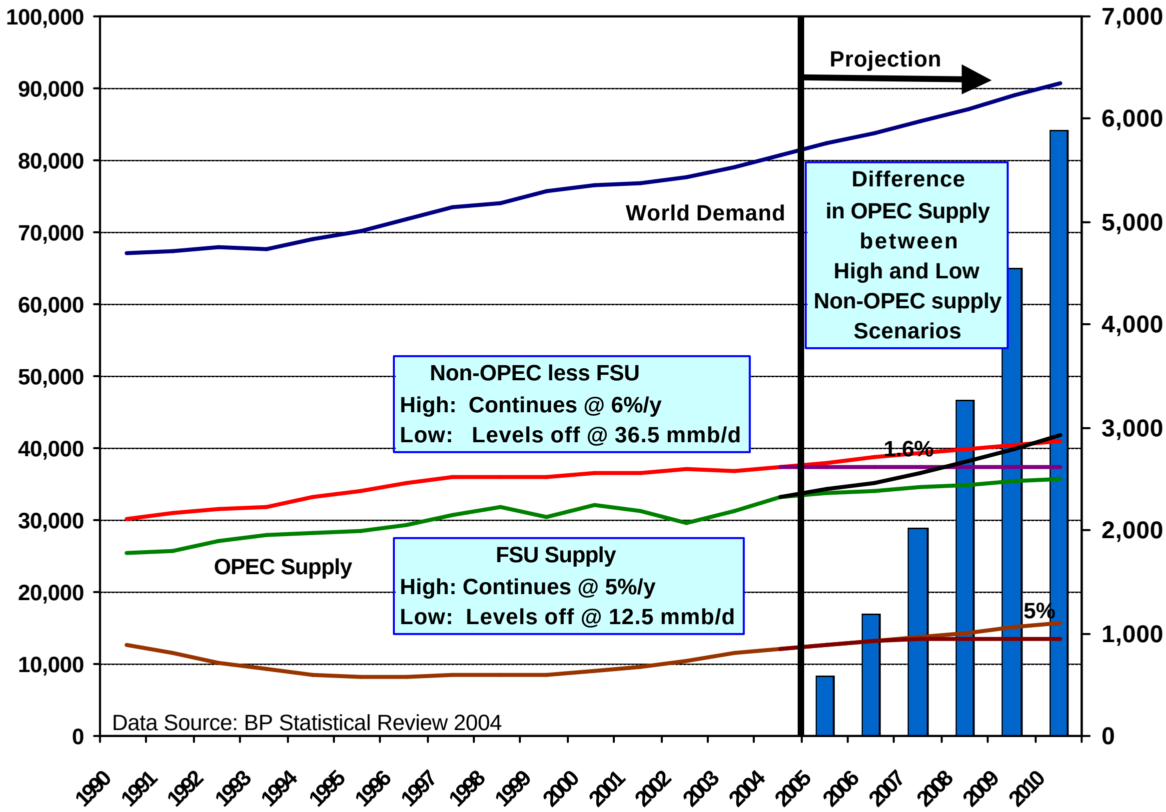
Source of data: BP Statistical Review, 2004

The 'high impact' contributors to the 1998 to 2003 increase in Non-OPEC production were Russia, Kazakhstan, Brazil, Canada, Mexico and Sudan. Of these six countries, only Russia, Canada, Mexico and Brazil have sufficient proven reserves to underpin a continued increase in output, and only Russia—at least on the physical evidence of its reserves base—might be expected to increase output by an amount similar to their increase since 1998. But, as discussed below, much depends on the political evolution within Russia and how it in turn will influence the exports of oil and gas. Of the other high reserves countries in the 'Group of 25', reserves in China, Mexico and Norway have declined, China's significantly so. Mexico's write-down of reserves was a function of having to adopt SEC Reserves definitions. Angola's doubling of reserves is noteworthy, but on the scale of world demand, its reserves are relatively small. Combined with the other West African producing countries, this region is expected to contribute important incremental volumes of Non-OPEC production over the next few years, but the longer term is uncertain.

3.5 Non-OPEC Supply and Trends

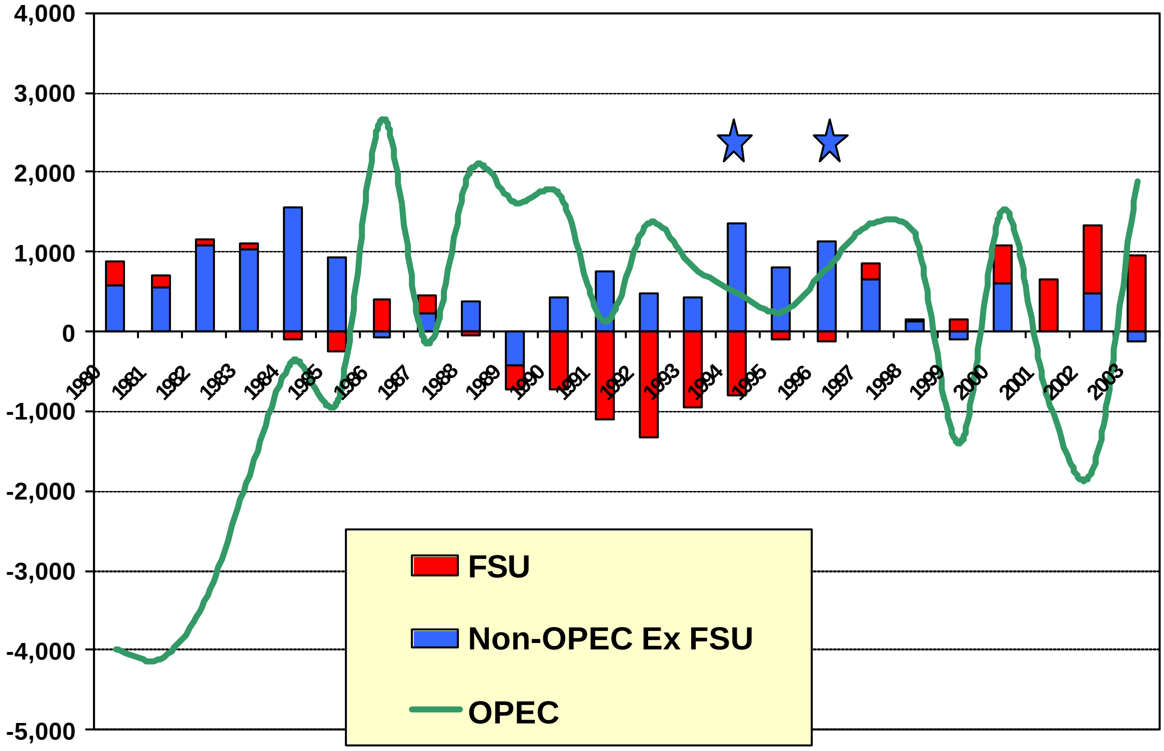
To set out a framework for discussion of the potential call on GCC countries, Figure 8 presents a simple picture of past and projected world oil demand and supply by major category: Non-OPEC (less FSU), FSU and OPEC. The following simple cases are shown: World oil demand is assumed to increase on average 2% per year for both cases. This compares with the IEA's assumption of 2.1% in its 2004 World Energy Outlook. For supply from FSU and the rest of Non-OPEC, high and low cases are shown as follows: FSU supply continues to grow at 5% (High), its rate of growth since 1997 (when it came out of the doldrums), or it rises to 12.5 mmb/d then levels off. For the Rest of Non-OPEC, it continues to grow at 1.6% (High), which was its rate of growth from 1990 to 2003, or it rises to 36.5 mmb/d and levels off. The call on OPEC then is what is required to meet demand and the range of differences between the scenarios is shown in bars to the right hand scale on the graph. This range—nearly 6 mmb/d in 2010—underscores the difficulty for OPEC countries in judging the degree of investment required given just the uncertainty of these two groups of Non-OPEC suppliers. The role of the GCC countries can be discussed within this context.

Figure 8: World Supply and Demand 1990 to 2010 (Scenarios; 1,000 b/d)



The case for fairly weak growth of Non-OPEC, Non-FSU supply is informed by two empirical observations of production history—long term and short term. Figure 9 illustrates the increments of Non-OPEC/Non-FSU countries since 1979/80. Since 1985 together they managed to add an annual increment of production greater than 1 mmb/d in only two years (1994 and 1996, marked with stars). Since 1999, even with higher prices and greater investment, their record so far has not been impressive. Between 2000 and 2004, total Non-OPEC production increased by a little over 4 mmb/d (OPEC MOMR, Dec 04), about 1.35 mmb/d/year, and is expected to increase by less (1.22 mmb/d/year) in 2005 (supply additions are discussed in greater detail in the next section). Finally, as reflected in expectations by the IEA in its monthly Oil Market Reports over the past two years, Non-OPEC supply has continued to disappoint—6 months ahead, the IEA over-estimated Non-OPEC/Non-FSU output by nearly a million barrels per day. Recent retrenchment of resource nationalism in Russia and difficulties in receiving final approvals in Kazakhstan also suggest a slowing down in output growth. This region, in our judgement, is more likely to under-perform than over-perform, thus we tend to support the low case in Figure 8.

Figure 9: Annual increments of supply from FSU, OPEC and Non-OPEC/Non-FSU since 1979/80



Source of data: BP Statistical Review, 2004

We have approached the analysis of non-OPEC supply by breaking it down into regions or play types of five different categories. The advantage of this approach is that it allows the reader to readily visualise the most important aspects of non-OPEC supply that might be lost in a 'bottom-up' country by country approach. The five categories are as follows:

- ***Mature***: such as the North Sea, the US onshore, Alaska and Canada conventional oil where there is little scope for major increases in supply and where the effects of depletion are having a major impact upon cost structures.
- ***Russia***: is included as a separate region given its importance in contributing to incremental non-OPEC supply over the past five years and the important contribution it is likely to make over the next decade.
- ***Deepwater***: which includes the provinces of West Africa, the Gulf of Mexico and offshore Brazil where there is much industry activity and where there is still significant exploration upside
- ***Frontier***: includes regions such as the Caspian which is currently under active exploration and where new developments have yet to come on stream.

- ***Unconventional***: includes an assessment of the tar sands of Western Canada, the Orinoco heavy oil in Venezuela with a very brief reference to oil shales and coal. Unconventional also includes GTLs given the significant amount of investment that is being put into the new technology and the potential impact they might have on supply if all of the planned projects are brought on stream. Biofuels are also gaining importance, especially in the US, where they are already partially displacing conventional fuel sources.

The breakdown of non-OPEC supply in this manner is obviously subjective and some countries might actually fall into two categories. For example the onshore US clearly falls into the 'mature' category, however the deep, offshore Gulf of Mexico sub-basin is generally viewed as in the new 'deepwater' play category.

Outline descriptions of the more important countries within each category are included in Section 3.5 below. We have deliberately described the more important future suppliers of non-OPEC for this report. We recognise that there may be a number of countries where production is forecast to rise over the next 20 years. The contribution from these countries is included in the overall forecasts presented in later sections 3.6. and 3.7.

Section 3.6 includes a forecast of non-OPEC supply from 2004 to 2009 based on actual projects that are currently being undertaken. It also reviews the outlook for non-OPEC supply from 2010 to 2020. This forecast takes into account the detailed descriptions of country and company policies highlighted in this section as well as an analysis and discussion of the sensitivity of this forecast to various factors such as economic, political, technical and institutional issues.

3.5.1 Mature

The most important mature provinces of the world include the UK and Norwegian sectors of the North Sea, Canada conventional oil, Mexico, onshore US and Alaska. In all of these regions the benefits of new technology have helped to lower costs and accelerate production. However, the mature provinces are now all suffering from higher than forecast rates of depletion. As a result the rapid exploration and development of new reserves is unable to keep up with the effects of depletion and this has a knock-on and adverse effect on costs.

3.5.1.1 North Sea

The UK and Norwegian sectors of the North Sea are recognised as being mature provinces. Production costs are now in excess of $5 per barrel and finding and development costs exceed $8 per barrel. The increasing effect of depletion is likely to continue to drive up costs even further.

In 1999, the UK was the world's tenth largest exporter with net oil exports of nearly 1.1 mb/d. However since that time oil production has begun to decline and in 2003 oil production fell to around 2.2 million b/d. By September of 2004, with several major platforms closed for refurbishment the UK became a net importer of crude oil for a few weeks. With a reserves base of 4.5 billion barrels at the end of 2003 the reserves life was a mere 5.4 years. Despite record high oil prices exploration activity is now at an all time low with the average new discovery averaging just 10 million barrels. Of course there have been one or two spectacular discoveries over the past two or three years, most notably the Buzzard field, which could contain up to 1 billion barrels. However, for the most part it is generally recognised that such exploration successes are likely to be few and far between. The prospect of the recognition of a major new geological concept with the potential to yield a new series of major discoveries is remote.

The UK sector of the North Seas is therefore recognised as a mature province and one where there is more an issue of 'managing and prolonging the decline' rather than investing for future growth. In particular, the rate of production decline will clearly depend on fiscal stability and policy changes and the rate at which private oil companies are prepared to invest in ever decreasing field sizes. Most of the large private oil and gas companies are exiting the UK sector. For example BP has sold many of its major producing fields, which are now very much in decline (e.g. Forties) but it has retained control over much of the pipeline infrastructure which generates significant tariff income, and it has recently announced its intention to invest more than $7 billion over the next four years in the North Sea, mostly on current fields and infrastructure and on a new gas field. While the majors might be rationalizing their assets in, or exiting, the North Sea activity is still relatively high as new independent oil companies believe their lower overheads and operating costs can continue to generate profits from their assets. These investments, while prolonging the life of facilities, are unlikely to lead to any near term increase in production since the size of new discoveries is unlikely to offset the impact of production declines in the major oil fields.

Of particular concern at this point in time is the issue of access to infrastructure, stability of the tax regime and an asset market that has stalled as a result of the high oil price. With respect to the issue of access to infrastructure, the independent companies have long complained (unofficially) that the major companies exert monopoly powers over pipelines, which in effect drives down the economics of new developments. Whilst there has been legislation in place to allow parties to complain with respect to the level of tariffs charged, companies have been reluctant to use it for fear of greater Government interference in future developments. A new code of practise has just been introduced and it is hoped that this might lead to a number of smaller undeveloped fields brought on stream. With respect to fiscal stability, the supplementary tax introduced in the budget in 2003 is recognised to have had a negative impact on investment in the UK North Sea. The tax was introduced by the UK Treasury apparently without much internal discussion regarding the impact on E and P activity. This has created uncertainty in industry with the obvious results. The UK North Sea has always had an active asset market, which has had a positive affect on regional investment. However at currently high oil prices, companies will tend to hold on to and squeeze old assets to reap their cash flow. Meanwhile, potential buyers of assets are reluctant to pay 'high' prices and sellers are reluctant to release their cash cows. The consequence is that the asset market has in effect dried up and the knock on effect is that levels of new investment continue to fall not withstanding, in late October 2004, when a large Canadian mid-cap company, NEXEN, purchased the majority share of the new Buzzard field from EnCana, another large Canadian independent for $12.80/bbl.

3.5.1.2 Norway

Norway differs from other oil producers in a number of ways. As a member of the OECD and the IEA[9], and as an affiliate of the EU, it clearly has one foot in the camp of the consumer. However, it has also historically co-operated with OPEC, which has caused friction with the IEA.

The Norwegian sector of the North Sea is also recognised as being mature, even though the potential volume of undiscovered reserves is estimated to be much higher than in the UK sector. In 2003, Norway's net oil exports were 3.1 million b/d making it the world's third largest oil exporter. Oil production totalled 3.3 mb/d (estimate includes condensates and natural gas plant liquids), which was down slightly from its historical peak of 3.4 million b/d in 2001. At the end of 2003, its proven reserves base was 10.1 billion barrels giving it a reserves life of around 8.5 years. Natural depletion in the medium term, rather than political, economic or institutional risk, will be the main problem affecting Norwegian supplies.

As one of the most thoroughly and systematically explored regions in the world the Norwegian Continental Shelf (NCS) is already showing strong signs of maturity. There is little scope for major new discoveries in the NCS although some smaller discoveries could be developed as satellite fields. The future really lies in the relatively unexplored areas such as offshore central Norway and the Barents Sea, where the focus has been on finding and developing natural gas. The transition into maturity is also apparent in new investment which has been waning since 2001. Since the start-up of production in the 1970s, investment has increased annually until 2002 when the total investment of $7.4 billion was some $420 million lower than the previous year. This downward trend in investment is likely to continue unless new acreage is opened. At the moment the most significant project underway is the $6.3 billion investment in the Snohvit LNG project.

In the past the oil industry has had a good track record of not only maintaining production but also expanding it. In the decade to 2002, oil production increased from 2.2 million b/d to over 3.4 million b/d. However, looking forward, production is likely to level off this year and then begin to decline over the coming decade as a lack of new discoveries, apart from very small satellites, fails to offset the decline in the mature fields as well as middle-age fields. Exploration levels fell to record lows in 2003 and in order to encourage increased activity, operators in the sector have

[9] It has an opt out condition in its IEA membership regarding oil-sharing in times of 'shortage', an arcane detail that says less about the largely obsolete mechanisms of the Agency's earlier oil-response mechanism than it does about where Norway's true instincts lie.

been pushing for a change in taxation. In particular, operators have been pressing Government to accelerate the tax relief on exploration activities.

3.5.1.3 Canada

In 2003, Canada was the ninth largest crude oil producer in the world, the eight largest producer of crude oil and Natural Gas Liquids (US DOE/EIA) and the fourth largest Non-OPEC net exporter of crude oil and petroleum products. Output in 2003 increased nearly 6% over 2002 production, reaching a level (2,986 Mb/d) not seen since the mid-seventies. As of late 2004 Canada's production of crude oil, NGLs, bitumen blends and synthetic crude and blends exceeded 3 Mmb/d. Total conventional crude, synthetic oil and NGLs production averaged 3.1 mmb/d in 2004. Canada exports about 1.5 Mmb/d of crude to the US, but its net exports of crude and product are slightly less than 1 million b/d. According to the US DOE/EIA, in 2003 Canada was the third largest supplier of crude oil but the largest supplier of crude oil plus petroleum products to the United States, followed by Saudi Arabia. Canada is the only OECD country whose exports of hydrocarbons are expected to grow significantly.

The outlook for conventional oil supply in Canada is modest yet despite this increase the Western Canada Sedimentary Basin is considered to be mature. The decline of production is irreversible. Minor amounts of oil will continue to be drawn from stripper wells in Central Canada in northern parts of the Michigan and Williston Basins. The east coast offshore has seen a great deal of exploration since the sixties and, apart from a few discoveries off Newfoundland and off Sable Island (produced and abandoned), results have been disappointing. Most discoveries have been modest in size and not considered commercial at prices below $20/bbl, given the very harsh conditions (sea state, ice pack pressures and the risks of iceberg bottom scour and collision). Three offshore fields are producing or under development off Newfoundland; 2004 production is expected to be 330 mb/d, peaking at 345 mb/d in 2006 and, as small satellite fields are brought on, production is expected to range between 260 to 315 mb/d out to 2015. Drawing on experience in exploration on the continental slope, exploration is moving further into deeper water. Drilling on the slope off Nova Scotia over the past four years has failed to yield significant discoveries.

The nature of Canada's oil production is changing. Production of conventional light and heavy grades of crude is expected by industry to continue to decline at about 5 to 6%/year. This decline will be more than offset by increases in production from the unconventional oil sands and from projects on the continental shelf off the east coast of Canada. The Canadian Association of Petroleum Producers (CAPP) projects that total Canadian production in 2015 will reach 3.6 mmb/d, comprised of 0.28 mmb/d from the east coast offshore; 0.6 mmb/d conventional light and heavy crude; 0.15 mmb/d of pentanes-plus and condensate, and 2.6 mmb/d of liquids from the oil sands, in the form of light sweet synthetic crude or bitumen blended either with crude condensate or synthetic crude. In other words, over 70% of Canadian oil supply by 2015 is expected to come from the oil sands, or so-called unconventional, which is discussed in greater detail under the heading, 'Unconventional'.

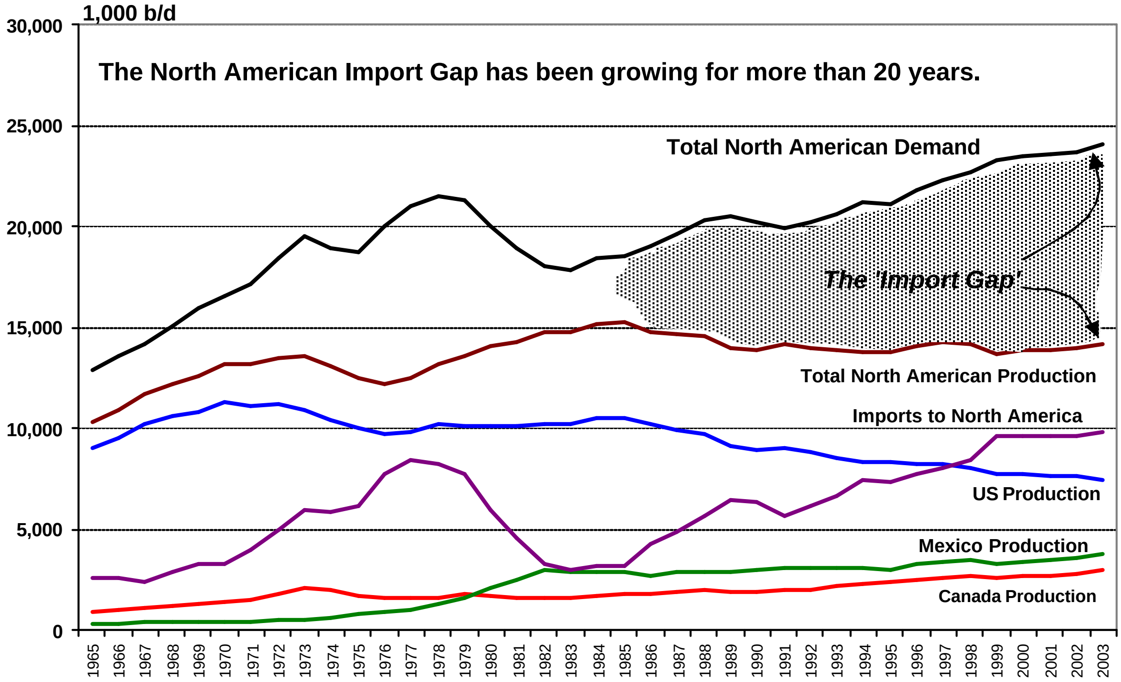
Any examination of Canada in terms of how its supply competes with supply from the GCC countries must consider the disposition of Canadian crude oil and products to the US market. Canadian crude oil production has traditionally been 'land-locked' and has little option but to go to the closest market, namely the US, thus discussions of North American oil supply tend to assume Canadian oil is part of the United States' supply. At the moment, very little crude is exported from the continent. Occasionally some very heavy grades have been shipped to China and Korea. Because Canadian producers do not sell through a single seller, they compete with each other and therefore, at times, tend to reduce the value to Canada of the overall supply. This happens when light/heavy crude price differentials in the U.S. market widen and there is no easy way to remove heavy crude from this market and move some of it at discount over the mountains to gain a better price for most of the crude. A perennial preoccupation of the Canadian oil industry has been the search for export options besides the northern tier states of the US. Therefore the importance of recent proposals to expand or build new oil pipelines aimed at moving output from the oil sands to the west coast. Recent announcements of Chinese interest in accessing this product hold the potential of future changes in the western hemisphere heavy oil markets. For purposes of this analysis, it is reasonable to conclude that the combination of production decline in the US plus the failure of Mexico to significantly increase production, together with the slow, costly and small increments in supply from Canada, a steady growth in det for imports from elsewhere in the world to fill the gap will be assured (See Figure 10).

Since the late sixties, North America has required on average an annual increase of 200,000 b/d of extra-continental crude supply to match continental crude oil demand. The import requirement is projected by the IEA to increase by 500,000 b/d for each of 2004/03 and 2005/04, indicating just how important changes in North American GDP are to its oil demand and therefore to the world oil markets.

Accepting that there will continue to be contractions in this 'import gap' through time, for reasons discussed below under Mexico and Unconventional supply, it would be very surprising if supply from these North American neighbours of the United States could ever exceed on an annual basis the sum of the growth in continental demand and the decline in US production. The growth in this sum – the import gap in Figure 10 - has averaged nearly 380 million b/d per year since 1990.

What share of these imports will derive from GCC countries depends on many variables including, but not limited to, the trend in US product demand, refining capacity and type and quality of other crude in the Atlantic Basin, and the export strategies of Venezuela, Brazil, Nigeria and West Africa. Volumetrically, however, North America will create space in the world demand picture into which GCC countries can increasingly export crude and product.

Figure 10: The North American Import Gap



Source of data: BP Statistical Review, 2004

3.5.1.4 Mexico

Mexico has been included in the mature provinces of the world since the depletion of its reserves base is now beginning to outpace its discoveries of new hydrocarbons. In terms of oil reserves, the country has the fourth largest oil reserves in the Western Hemisphere after Canada, Venezuela, and the United States. At the end of 2003 proven reserves stood at 16.0 billion barrels and all of this is controlled by Petroleos Mexicano (Pemex), the state oil company, which is also the world's seventh largest oil company. The country had to write down reserves in 2003 because it had to follow the very conservative strictures of the SEC as a consequence of raising capital in US financial markets.

Pemex retains the exclusive rights to oil exploration and production in Mexico, a right enshrined in the country's constitution. Pemex provides the government with over 40 per cent of its total fiscal revenues. Over 60 per cent of the company's revenues are turned over to the federal authorities and as a result the company is left with little or no funds to invest in exploration and development. This has naturally impaired PEMEX in replacing crude oil reserves. It has now been recognised by the Government that investment must increase if production is to be sustained. As a result the investment budget in 2003 exceeded $10 billion for the first time and this is set to rise to over $12 billion in 2004, with over 75 per cent of the budget going towards sustaining production.

With more money invested in exploration activities there has been intense speculation as to the volume of reserves discovered. For example, Pemex, recently stated it had yet to discover new deep-sea crude reserves in the Gulf of Mexico, but added that it recognized the potential in those waters. The statement was in response to local press reports, which cited Luis Ramirez Corzo, head of Pemex Exploration and Production, as saying potential deep-sea crude oil reserves in the Gulf of Mexico could total some 54 bn barrels. If such quantities were discovered, Mexico could increase its current production from nearly 4 mm bpd to an average 7 mm bpd, placing the country "on the level of great (oil) powers, like Iraq (112.5 bn barrels of proven reserves), the United Arab Emirates (97.8 bn) and Kuwait (94 bn)," said Ramirez Corzo

Although Pemex might like to speculate on the exploration upside, the real challenge for the Mexican government is actually ensuring that production will expand quickly enough in order to meet rising domestic demand. Mexico also wants to maintain and if possible expand exports of crude oil to the United States market. According to the EIA, these amounted to 1.6 million b/d of crude and 500,000 b/d of product in 2003. Quite how this can be achieved without significant new investment is difficult to understand. For example, existing Mexican demand for oil products was 2.1 million b/d in 2003 and yet Mexico has just 1.5 million b/d of refining capacity.

Estimates of the total amount of investment required for the Mexican government to meet its strategic objectives vary tremendously. On his appointment in September 2003, Mexico's new energy minister claimed that the country needed more than $150 billion to stem the rising tide of crude oil and product imports. Investment on this scale would appear to be unlikely. Despite this, the Mexican Government appears determined to raise crude oil output capacity. The head of Pemex has recently stated that it aims to increase production from 3.8 million b/d in 2003 to 4.0 million b/d by the end of 2006. Quite how this will actually be achieved remains to be seen. What is clear though is that for the next few years at least Mexico will continue to struggle to achieve its production goals so long as there is continued pressure on Pemex to deliver fiscal revenues at the expense of new investment.

3.5.1.5 Onshore United States and Alaska

Although United State production as a whole is forecast to rise over the next decade much of this is expected to come from US deepwater Gulf of Mexico fields. Increasingly this new production will be unable to offset the increasing declines in Alaska and the lower 48 states. The potential for softening the decline in production in the lower 48 states is recognised as being very limited. The decline is following the path predicted by Hubbert in the fifties and despite high oil prices the volumes of new oil brought on stream are insufficient to break the trend.

In Alaska the potential for offsetting the decline rate will depend on the development of reserves in the Naval Petroleum Reserves west of Prudhoe Bay and the subsequent opening of the Arctic National Wildlife Refuge (ANWR) to the east. The 1.5 million-acre coastal plain of the 19 million-acre Arctic National Wildlife Refuge is the largest unexplored, potentially productive geologic onshore basin in the United States. The primary area of the coastal plain is the 1002 Area of ANWR established when ANWR was created. A decision on permitting the exploration and development of the 1002 Area is up to Congress and has not been approved to date. Also included in the Coastal Plain are State lands to the 3-mile offshore limit and Native Inupiat land near the village of Kaktovik.

The USGS estimated:

- a 95 percent probability that at least 5.7 billion barrels of technically recoverable undiscovered oil are in the ANWR coastal plain,
- a 5 percent probability that at least 16 billion barrels of technically recoverable undiscovered oil are in the ANWR coastal plain, and
- a mean or expected value of 10.3 billion barrels of technically recoverable undiscovered oil in the ANWR coastal plain.

The EIA postulates two development rates for each of the three USPS probability estimates without specifying the effect of various levels of oil prices and technology advancements, ranging from 250 to 800 million barrels developed per year. EIA projects peak production rates from 600,000 to 1.9 million barrels per day over the six cases, with peak production estimated to occur 20 - 30 years after the onset of production.

Seven to 12 years are estimated to be required fom an approval to explore and develop to first production from the ANWR Area. The EIA bases its forecasts first production in 2010. The time to first production could vary significantly based on time required for leasing after approval to develop is given. Environmental considerations and the possibility of drilling restrictions would directly impact the time interval to reach first production. This of course remains the subject of enormous political controversy and the new plurality of the Republicans in the House of Representatives and the Senate do not necessarily assure an easy ride for any new legislative initiative to open up ANWR. In the meantime much will depend on the level of activity in the existing Alaskan fields. If this is not sustained then production could decline quite sharply. This was illustrated during the last fall in the oil price when capex programmes were cut back leading to a 150,000 b/d fall in production.

3.5.2 Russia

Although many of Russia's sedimentary basins have been explored for decades, some for more than a century, we have included Russia as a separate section because of the important contribution it has made to non-OPEC supply over the past three years and its singular potential and expectation to increase in importance going forward.

Russia's oil production rose from less than 6 million b/d between 1995 and 1999 to estimated 9.2 million b/d in 2004, an increase of over 40 per cent since 2000. More important though from the point of view of non-OPEC supply is the level of Russian exports, which have risen from 3.6 million b/d in 1999 to 6.1 million b/d in 2003, a 67 per cent increase. The actual potential for Russian production is very difficult to predict because of a multitude of factors not least political. Estimates vary from between 10 million b/d to 12 million b/d in 2010 depending upon infrastructure constraints or political constraints on investment. Historically, projections of Russian oil production by both official and private analysts have tended to be overly conservative. For example, in 2002 the then chairman of Yukos stated that he expected Russian oil output to be boosted to 9 million b/d by 2005, a target that had already been met in early 2004. While projections continue to vary widely regarding the future oil production capacity there is little doubt that the potential for further output and exports is great. Sceptics would however point out that much of the recent increase in production has been from simple procedures in existing fields and that the real challenge will come when this 'easy' oil has been produced and when significant new investment will be required to develop green-field sites.

The resource base does not seem to pose a problem. Russia's proved oil reserves were estimated to be 69 billion bbl at the end of 2003. However, this estimate by BP is considered by many to be very conservative with other commentators suggesting that the true figure could be much closer to 100 billion barrels. The Russian ministry of Natural Resources also estimates that the country has in addition around 180 billion barrels of oil and 100 Bcm of gas on its offshore shelf. However, to date, only a small portion of this potential has been proved up offshore Sakhalin Island.

The development of much of these reserves will ultimately depend on how quickly export capacity can be constructed. In this respect improvements to facilities are underway at the Black Sea ports of Novorossiysk, Odessa and Butinge. Rosneft has also received permission to use land in the port of Primorsk on the Baltic Sea to construct an additional export terminal capable of exporting 600,000 b/d. BP-TNK is also considering constructing a terminal near Primorsk capable of handling 200,000 to 300,000 b/d. With respect to pipelines, the government is currently considering constructing a 3,900 km pipeline from Angarsk in Western Siberia to its Pacific port of Nakhodka to access Pacific markets. This project would cost in excess of $9 billion and is preferred to a shorter line to the declining Daquing field in eastern China. As a result of the constraints to the export system, many Russian oil companies have turned to the railway network to increase exports. For example the national fleet of rail tank cars has risen sharply from 180,000 to over 200,000 in 2003. It has been estimated that rail exports of oil and oil products accounted for in excess of 4 million b/d in 2003. Quite whether this trend will increase is in doubt. Lukoil recently reported that it has not ordered any more rail tank cars in 2004.

The petroleum sector now accounts for much of the country's economic activity, government budget receipts and merchandise export revenues. For example it has been estimated that in 2002 oil and gas generated as much as 30 per cent of GDP. All of this has been helped by a combination of surging export volumes and higher crude oil and gas prices. Although Russia's energy companies remain largely in private hands increasing control is being exerted on them by the current Putin administration. This is done directly by the imposition of higher tax rates and export duties and also by way of Transneft, its oil export monopoly which remains under state control. The arrest and incarceration of Mikhail Khordokovsky, the head of Yukos, in October 2003 was also seen by many as increasing control by the state on the industry and one consequence of this has been to scare-off foreign investment. The Russian government would argue that the recent and successful sales of a 7.6 per cent stake in Lukoil to Conoco-Philips and proposed sale of Novatek to TOTAL are evidence that foreign investors are still willing to invest in the Russian oil and gas sector and also that the Russian government is happy for foreign companies to invest. Although foreign investors are also likely to be offered a major stake in Sibneft in the next two years, the curious manner in which the core asset of Yukos, Yukanskeneftegaz, was auctioned for back taxes and ended up with the state company, Rosneft, with rumours that the combined asset might end up with Gazprom to constitute a major, world scale Russian oil and gas company, has been the source of much speculation, only exceeded by the increased uncertainty about Russia as a prospective theatre for investment by foreign oil and gas companies. Only time will tell, although the announcement February 10th, 2005 by the Russian Ministry of Natural Resources that companies bidding on Russian hydrocarbon and mineral resources would have to be majority-Russian owned, signalling a definite chill. With higher prices and the expectations of greater rents, resource a resurgence in resource nationalism is not at all surprising.

Looking forward, the most important problem facing Russian production and exports is the significant economic risk from a fragile economic performance and continuing strains from social needs. These pressures could cause political instability for some time in the future. While two significant investments by foreign IOCs have been lauded (TNK/BP and the Shell consortium in Sakhalin), it is not clear that the political or country risk factors have been sufficiently reduced to expect many other deals to be completed in the near term. For example, Exxon/Mobil continues to wait on greater fiscal and legal certainty before sanctioning its oil supply project in Sakhalin. The Oxford Institute for Energy Studies will be publishing a book in 2005 on Russian Oil; it chronicles the history of production in the various basins and points to many of the technical challenges confronting future production, especially from the core region of western Siberia.

3.5.3 Deepwater

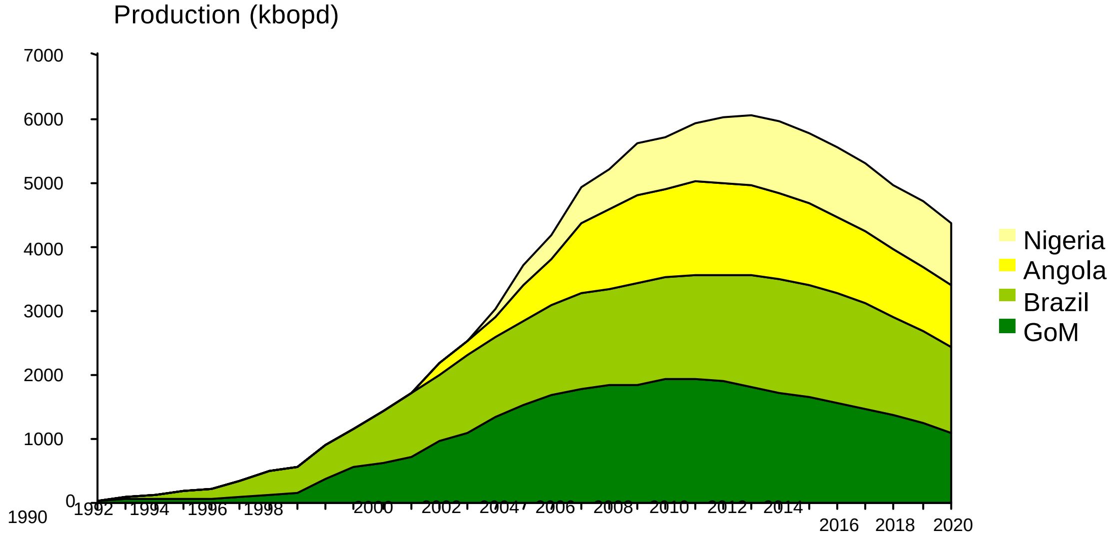
One of the most exciting new geological plays for oil exploration in the last few decades has been the very deep waters at the edges of continents. While exploration had to wait on the development of the technology to suspend a drill stem and hold a drilling ship several kilometres above a prospect, it was also not certain whether the sediments in which oil was suspected would easily and economically yield any oil if found. The model was proven and the play is being explored around the world. Over 50 billion barrels of oil reserves have already been discovered in the deepwater plays, principally in the GoM, Brazil, Nigeria, Angola and others. Of these, only 6 billion barrels have been produced to date. So far, the creaming curves (rate and size of discoveries) for all of these deep plays show no sign of maturing. Using these curves it is estimated that 114 Billion bbl of oil are yet to be found with a large share (around 30 per cent) of this believed to be located offshore Mexico. In fact, more than half of the undiscovered reserves are believed to be in Mexican and US Gulf of Mexico waters. The US Gulf of Mexico creaming curve, at 14 billion barrels, continues to climb as do the reserves in Brazil (20 billion barrels), Angola (11 billion barrels), and Nigeria (9 billion barrels).

As a province the deepwater accounts for 65 per cent of all oil and gas discovered from 2002 to 2003 and the success rate for deepwater wells is not yet in decline, remaining around 25 per cent, with about 40 discoveries per year. The average size of discovery, although down from 300 to 250 Mmboe in the 1996 to 1999 period (followed by the exceptional year of 2000—at 450 Mmboe), is considered to be more or less steady at 200 Mmboe. In addition, the volume of reserves discovered per discovery well in the deepwater averaged 50 Mmboe and dwarf the average of 15 Mmboe discovered in other provinces since 1996.

Since the late 1970s, four giant (> 2 billion boe) discoveries have been made in water depths down to 1100 metres or so. While significant discoveries have been made below that depth, no giants have been discovered at depths below 1500 meters. Given that only the largest prospects would be drilled first in such extreme conditions, this suggests that the future of the ultra-deep basins will be mid-sized discoveries, but still significant (>500 million barrels).

Since 1990, oil production from the deepwater has increased from 0 to over 3.5 million b/d, and is projected to increase to about 9 million b/d by 2010, with Brazil, US GoM and Angola and 'yet to find' contributing in equal measure around 1.7 million b/d. Nigeria and others are forecast to add about 0.5 Mmb/d by 2010. A study by Wood Mackenzie projects Brazil and the Gulf of Mexico to peak some time in the 2007 to 2009 period. Of the twenty or so companies active in this play, the major reserves holders expected to be producing the bulk of oil from these plays in 2010 are Petrobras, BP, Shell and Exxon/Mobil. Merrill Lynch recently undertook a detailed study of all deepwater projects and its projection of production from current and potential future discoveries is shown in Figure 11.

Figure 11: Projection of production from deepwater projects (1990-2020); Source Merril Lynch



3.5.3.1 Brazil

At the end of 2003, Brazil was the largest non-OPEC producer of deep offshore oil and had oil reserves of 10.6 billion barrels with plenty of scope for further discoveries. According to the USGS, the undiscovered resources amounted to around 55 billion barrels. Much of the oil discovered so far is heavy crude and in order to be commercial significant discoveries are required. It is not clear whether higher oil prices will attract more foreign explorers or whether it will prompt renewed resource nationalism and further entrenchment of the state company Petrobras as the main operator offshore Brazil. According to the IEA, which apparently agrees with the US DOE/EIA, the country will account for much of the increase in oil production in Latin America over the next 20 years. It estimates that production will rise from around 1.7 million b/d at the start of 2004 to over 4 million b/d in 2030. It is expected that Brazil will become a net exporter of crude oil in the foreseeable future. In total, Petrobras expects to invest around $34 billion in the period from 2003 to 2007, mainly in exploration.

3.5.3.2 Gulf of Mexico

The deepwater GOM has contributed major additions to the total reserves in the GOM. Additions from the shallow waters of the GOM declined in recent years but, beginning in 1975, the deepwater area started contributing significant new reserves. Between 1975 and 1983, the majority of these additions were from discoveries in slightly more than 1,000 ft of water. It was not until 1984 that major additions came from water depths greater than 1,500 ft.

During the last 10 years, the average shallow-water field added approximately 6 million boe of proved and unproved reserves. In contrast, the average deepwater field added over 64 million boe of proved and unproved reserves. In the most active deepwater exploration area, water depths between 1,500 and 7,499 ft, the average deepwater field contributed more than 73 million boe (12 times more than the average shallow-water field addition).

Projecting discovery rates is more difficult. The USGS has used creaming curves to assess the amount of hydrocarbons yet to be discovered in the GOM. The shallow-water GOM is characterized by a curve typical of a mature trend. The recent slope of the curve is very flat as smaller fields are being discovered. In contrast, the deepwater creaming curve contains fewer new field discoveries; however, these fields tend to be large, resulting in a curve with a steep slope. This slope indicates an area that is still in an immature exploration phase with many large fields awaiting discovery. The limited number of discoveries, steep slope of the curve, and large amount of hydrocarbon volumes already discovered support this prediction. On the basis of the deepwater creaming curves the reserves potential has been assessed approximately 71 billion barrels of oil equivalent (BOE), of which 56.4 billion BOE remains to be discovered. This compares with the shallow-water ultimate reserves of approximately 65 billion BOE, of which 15.2 billion BOE remain to be discovered.

The deepwater GOM oil production is in the midst of a dramatic increase similar to that seen in the shallow-water GOM during the 1960's. This production surge has not yet peaked. This strong increase in deepwater oil production more than offsets recent declines in shallow-water oil production. In 2003, deepwater oil production accounted for 65 percent of GOM oil production. These trends in oil and gas production indicate that the deepwater GOM is an expanding frontier with the potential to produce up to 2 million b/d by 2005 from around 1.4 million b/d in 2000. However, sharp decline rates in existing fields may mean that it will be difficult to sustain that level of production and recent estimates suggest that by 2010 deepwater production could fall back to around 1.8 million b/d.

High well production rates have been a driving force behind the success of deepwater operations. For example, a well within Shell's Bullwinkle field produced about 5,000b/d in 1992. In 1994, a well within Shell's Auger field set a record, producing about 10,000 b/d. From 1994 through mid-1999, maximum deepwater oil production rates continued to climb, especially in water depths between 1,500 and 4,999 ft. Since mid-1999, the maximum production rates have declined.

A significant portion of deepwater production comes from subsea completions. Very little deepwater oil production came from subsea completions until mid-1995, but by the fall of 1996 that production had risen to about 20 percent. Deepwater subsea oil production increased through 1999, representing almost 30 percent of all deepwater oil production in January 2000. Numerous subsea projects began production in 2003, and many more are expected in the next few years. Therefore, we do not anticipate a continued decline in oil and gas production coming from subsea completions, currently accounting for about 20 percent of deepwater oil production and about 25 percent of deepwater gas production.

Prior to 1998, deepwater oil and gas production was confined almost entirely to major oil and gas companies. Shell and BP have been the driving forces behind increasing deepwater production in the GOM, with Shell being the clear leader in both oil and gas production[10]. Shell's dominance in deepwater oil production began before 1992 and has continued. Shell also led in deepwater gas production, including a dramatic increase in 1997. Although BP's deepwater oil production started slightly behind Shell's, their oil production increases paralleled one another throughout the 1990's. Since the mid-1999, however, Shell's deepwater oil production increase has outpaced that of other major companies. ExxonMobil currently runs a distant third in terms of deepwater GOM oil production, but is slightly ahead of BP in deepwater GOM gas production.

3.5.3.3 Gulf of Guinea

For many of the countries that border the Gulf of Guinea in West Africa, the offshore deep waters hold great potential and crude oil remains the most significant part of West Africa's energy mix. Development in oil has grown steadily, since the 1950s when it was first discovered, produced and exported by Shell from Nigeria. In fact, Nigeria is the largest oil producer in the whole of Africa. From a modest volume of about 5,000 b/d back in the '50s, the current output is now 2.08 million b/d. Angola, with its giant finds in offshore deepwater, is sub-Saharan Africa's second biggest oil producer. Production in that country has increased from about 150,000 b/d in 1980 to an average 900,000 b/d last year. In addition, there are other promising oil producers, including Cameroon, Congo, Gabon and Cote d'Ivoire. In 1980, Gabon was producing about 175,000 b/d while Cameroon was pumping around 60,000 b/d. By 2003, Gabon and Cameroon were producing approximately 290,000 b/d and 110,000 b/d respectively.

Total average oil output in West Africa, went from 2.45 million b/d per day in 1980, to 3.5 million b/d in 2001. Thus production represented 4.5 per cent of the world's total output last year. Output is expected to increase as new deepwater projects pump up production.

Until about a decade ago, there was not much interest in searching for oil in the deep waters off the Gulf of Guinea. However, West Africa has become a classical example of the successful deployment of new technology to produce crude oil from deep water offshore. Technological advancement such as 3D seismic have led to a significant reduction in deep water prospecting costs, as well as an increase in success rate and the frequency of discoveries.

Over the last three years alone, the success rate in Angola has been stunning and more than a dozen fields totalling more than 500 million barrels have been made. In addition to boosting overall reserves, the development of these new discoveries will more than replenish the depleting

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[10] The reader is referred to a forthcoming book by Juan-Carlos Boué of the Oxford Institute for Energy Studies on the evolution of oil and gas development in the GOM and the influence of resource conservation regulations governing access and licensing of exploration and development.

onshore oil reserves. In fact, consensus projections show West African production rising to over 6 million b/d by 2020. Within Angola alone, current forecasts suggest production will rise to 2.1 million b/d by 2010 climbing to 3.3 million b/d by 2020—the US DOE projects Angola to reach 3.4 Mmb/d by 2025.

Aside from Angola and Nigeria, Cameroon, Chad, Congo, Gabon and the Ivory Coast are expected to reap the benefits of substantial exploration activity and with hundreds of thousands of square kilometres of largely under explored ultra-deep waters West Africa has become one of the most sought after new frontier regions in the offshore industry.

It is the materiality of the discoveries and the fact exploration is still in its infancy that continues to attract the major private oil and gas companies. In addition, with the exception of Nigeria, all of these countries will not be subject to the restrictions that OPEC might impose on production.

With respect to gas, the situation is understandably different from that of oil. In particular, there has not been a deliberate effort to prospect for gas even though it is perceived as more environmentally friendly and there is a demonstrated large potential demand for LNG. Marathon Oil, for example, is developing an integrated Methanol and LNG project in Equatorial Guinea from gas on the offshore Alba Block.

Virtually all of the gas discoveries in the sub-region have been associated with oil drilling activities. Although some arrangements have been put together to harness part of the gas, the commodity has been mostly flared. Only in some instances is gas re-injected to aid or boost oil recovery. However, gas is now enjoying steady and increased use, especially by electricity, and industrial firms.

Nigeria currently flares over 50 percent of the gas it produces, 33 percent is used commercially and 17 percent is re-injected to enhance oil recovery. Although high, this is significantly below the 98 per cent flared in 1971. The situation is similar in Angola, which, according to estimates, has 1.6 tcf of proven gas reserves. Presently, about 85 per cent of gas produced is flared, but some is re-injected to aid oil production. With a few exceptions, the situation is about the same for gas producers across the sub-region.

Consensus that most host countries could more profitably use gas than other hydrocarbons. Schemes have already been or are being put in place, to start utilizing more of the flared gas, either domestically or by neighbouring countries via gas pipelines. For instance, Shell in Nigeria is committed to a flare-down policy by 2008, which will eliminate the 1 bcf of gas it currently flares daily. While some electricity generation, iron smelting, cement and aluminium plants are already utilizing gas produced from various oil fields most of the flare gas is likely to go into the Nigeria LNG project.

Shell is currently investing $7.5 billion into the next phase of the NLNG development. This development exported its first cargo of LNG in early October 1999 and Nigeria joined the league of LNG exporting countries. Angola is also pursuing a number of domestic gas projects to drastically reduce, and eventually eliminate flaring. Angola's Sonangol and Chevron-Texaco entered into a deal for a US $1.7 billion plant that will collect and process natural gas from offshore blocks, mainly for export. Other producing countries in the sub-region have been making concerted efforts to end gas flaring. Both Gabon and Côte d'Ivoire have been using gas from their fields to generate electricity domestically.

Billions of dollars of private capital are required to the exploit new discoveries but the prize for the majors is volume growth. While the private oil companies were implementing cost-cutting schemes that affected their operations in many areas around the world, the West Africa sub-region was not affected.

In fact, in Angola the rate of investment has had to be tempered by the host government because of the shear number of development projects. Private oil companies who have tried to pressure the host government have found themselves at the back of the queue. In total more than US $17 billion in investments have been planned for the sub-region in the next three years. This is a substantial part of the oil majors’ E and P budgets.

On a cautionary note there remains considerable technical risk. Over the last few months there have been some major exploration disappointments in some of the deepwater blocks. In fact, it is sobering to note that the total amount of signature bonuses on the blocks where there has been recent failure, amounts to more than the entire market capitalisation of the UK independent sector. However, such concerns are always allayed when big discoveries are made.

Political risk remains a key issue in the region. Although political and economic problems are by no means peculiar to West Africa, the redoubling of concerted efforts towards solving these problems would help to enhance the sub-region's investment climate.

There have been some encouraging developments in the political sphere but risks remain. In Nigeria, there are continued doubts as to whether it will ever manage accountability, freedom of expression and human rights as well as open government. Since his election in May 1999, President Obasanjo has been faced with ongoing inter-ethnic tensions. In general, the security situation in Nigeria is poor, with high rates of violent crime, including kidnapping, ethnic and religious strife.

Nigeria also faces serious economic problems, including wide income disparities. There have been persistent attacks against foreign oil companies by youths protesting the environmental degradation of indigenous homelands and there are issues surrounding the allocation of the federal resource. The attacks have resulted in continued disruptions of oil production and exports, which are of course a worry to the majors. Illegal fuel siphoning as a result of a thriving black market for fuel products has increased the number of oil pipeline explosions in recent years. The most serious disaster was the October 1998 Jesse fire in which over 1,000 people died. Unfortunately such attacks seem only to highlight the role of the oil companies with local human rights issues. Last year, the Nigerian navy announced plans to clamp down on arson attacks on oil facilities. This followed the loss of about $4 billion in oil revenues last year due to vandalism. These issues have affected all of the majors involved in Nigeria and they must learn how to deal with these issues in the future, in particular the issue of human rights.

Angola has been in a state of nearly constant civil war since it achieved independence from Portugal in 1975. More than 500,000 people have been killed in the strife, Africa's longest running conflict in the post-colonial era. Angola's civil war has ravaged the non-mineral sectors of the country's economy, destroyed much of its infrastructure, and displaced an estimated 2.5 million people. Other developments, which must be sustained within the sub-region, are the cease-fire agreements in the Congo and the peace accord, which ended the highly destructive civil war in Sierra Leone.

To complement these efforts, West African countries must try to streamline their fiscal regimes and investment laws, which still remain cumbersome, rigid and inconsistent. It is no longer sufficient for the private oil companies to sit back and claim that oil will continue to flow despite local political difficulties. If they do not engage with the human rights activist or the environmentalists in the region then they will ultimately suffer disruption to operations. This might not necessarily occur in West Africa but in areas closer to home where increasingly unelected, unaccountable NGOs are exerting far greater influence on corporate behaviour than are accountable regulators appointed by elected governments. However, despite all of these risks, West Africa and in particular the deepwater province will continue to be an increasing source of non-OPEC supply. Of all the Non-OPEC regions excluding the FSU, West African countries have accounted for the greatest regional increment of supply since 2000—nearly 600 kb/d added as of 2004.

3.5.4 Frontier

The frontier regions of the world include all of those where significant investments are currently being made and those regions, which hold significant exploration potential and remain relatively unexplored. Such basins include the Caspian, as well as East Siberia.

3.5.4.1 Caspian Region

The Caspian region (here defined as the offshore and immediately proximal areas to the Caspian Sea area of Iran and Russia and the offshore and onshore areas of the riparian states, Azerbaijan, Kazakhstan, Turkmenistan and Uzbekistan) is expected to make an important contribution to world oil supply, increasing from around 1.7 mb/d in 2003 to anywhere between 2.4 and 5.9 by 2010 (See the US DOE/EIA Country Reports as of November and December, 2004, summarized for Caspian Sea Region in Figure 12 below). Going out further, this area is expected to produce 4 mb/d by 2015 according to the DOE/EIA 2004 outlook. Over half of this increase is expected to come from the North Caspian region, especially the giant Tengiz field in Kazakhstan (producing at 290,000 b/d in 2004, projected to 700,000 b/d by 2010), followed late in the period with the ramping up of production of the giant offshore Kashagan field. Meanwhile, Kazakh exports continue to rise and reached 915,000 b/d in 2003.

Figure 12: Proven Reserves in the Caspian Region

	Proven Reserves			**Total**	
Country	Low	High	Possible	Low	High
Azerbaijan	7	12.5	32	39	44.5
Iran	0.1			15.1	
Kazakhstan	9	17.6		41	49.6
Russia	0.3			7.3	
Turkmenistan	0.546	1.7		32.546	33.7
Uzbekistan	0.3	0.594		32.3	32.594
Total Region	**17.246**	**32.794**		**167.246**	**182.794**

Note: These reserves estimates derive from estimates by the Oil and Gas Journal. Estimates for Russian and Iran only refer to those in the Caspian Sea region.

The Caspian region is estimated to have between 17 and 33 billion barrels of 'proven oil reserves' (EIA, December 2004 Update for Caspian Sea Region). In other words, the whole region is comparable to Qatar on the low end and China on the high side, and its potential impact on future supply should be viewed within that bracket.

Azerbaijan's most significant oil prospect is the giant ACG structure operated by B.P., with reserves of 5.4 billion barrels, constituting a major share of the country's estimated proven reserves. Of all the Caspian countries, Kazakhstan is considered to have the greatest upside potential, both in terms of developing its current reserves and adding to its proven reserves base. Its proven reserves of 9.0 billion barrels (BP, 2004 estimates at 10.1 billion barrels) seem modest, but recent exploration activities suggest that these reserves estimates are very conservative. The offshore Caspian area around the Kashagan field, now due on stream later this decade, is complemented by some prospective onshore areas around Tengiz in the northwest and Kumkol in the centre of the country. The Karachaganak field near the Russian border is reported to have 2.4 billion barrels of reserves and is expected to increase its output from 210,000 b/d in 2004 to 240,000 by 2008.

Despite this upside potential, the local oil industry faces significant technical, economic and apparently political constraints in the short term. First of all, the Kashagan field development faces very challenging reservoir and oil quality issues, including high gas/oil ratios and high acid levels, as well as surface conditions of sea ice. Kazakhstan lacks the required infrastructure and pipelines to move the oil to tidewater markets. Also, recent projects have been delayed by the Kazakh government's refusal to sign off on certain approvals and its signalling changes in the fiscal regime.

In general, while the investment climate varies between the Caspian states, all of the CIS countries are still in very difficult transition. None has managed to improve the economic condition of its populations. The political situation in most countries, if anything, is deteriorating. At least in the cases of Kazakhstan and Turkmenistan, virtually all deals must be negotiated directly with the President. While the leaders may believe this is a strength, it really indicates they are negotiating from a position of weakness (there is no fallback in the negotiating process) and therefore investors can not be confident that any agreement reached will not be re-opened should market conditions improve, or the leadership in these countries even suspects conditions might have changed. This appears to be the motivation behind stalled approvals and threats of changes in the fiscal regime, for example, in Kazakhstan. Also, while the northern riparian states have agreed on their offshore boundaries, Iran and Turkmenistan remain outside. Finally, while in the early nineties the United States put great emphasis on developing this region's hydrocarbons and infrastructure for its evacuation to market, as a geopolitical counterweight to the Middle East, it now appears that Russia is in the ascendancy and has largely supplanted this U.S. influence. Thus, for example, Russia acquiesced to the recent brutish approach of Turkmenistan in the renegotiation of its gas export contract to Ukraine. Turkmen cut off the gas in the dead of winter during the electoral chaos of Ukraine to extract a higher price. Given this and other examples of atavistic behaviour by these regimes, the investment environment should be viewed as highly risky. Therefore our estimate of future oil output from this region is tempered, notwithstanding its significant potential.

3.5.4.2 Other Regions

Other frontier regions in the world could include East Siberia where the size and nature of the resource base is very unclear. At present it has been assumed by many that this is a gas province but this has yet to be confirmed. In any event it is unlikely that production from the region will become important before the end of the period discussed in this report.

Vietnam has been cited as a new frontier region. Its production reached 400,000 b/d in 2004 (OPEC MOMR, Dec 04). Its reserves are less than a billion barrels but this figure could rise with further exploration. However, in the context of the global non-OPEC the country remains rather unimportant. Other frontier regions that might become important could include the Arctic where the USGS suggests there is considerable potential. This area includes several basins offshore Russia, offshore east Greenland, thought to be an extension of the North Sea geology, offshore west Greenland and off Baffin Island, Canada, and in the Arctic Islands of Canada. Assuming that environmental clearances could be obtained (highly doubtful in some cases), even if there were to be further exploration success in these regions (oil was discovered in the Canadian Arctic Islands in the seventies), the lead-time to first production would likely fall beyond 2020.

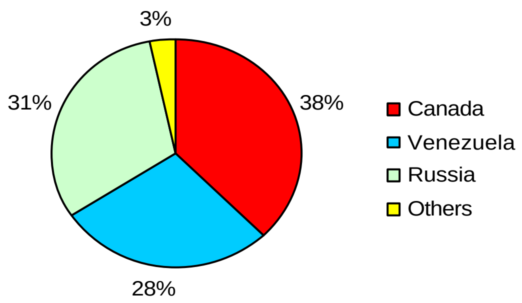
3.5.5 Unconventional Resources

In this section, the status of unconventional hydrocarbon liquids production and their costs are reviewed. There are long-standing and unresolved definitional problems as to what is included in the category, 'unconventional oil'. Some define it as oil that does not flow to the well bore on its own under normal reservoir conditions and therefore needs some form of artificial stimulation to be produced. But this can include light crude remaining in reservoirs after application of primary and secondary production techniques. Also, this definition would exclude the Extra Heavy Crude oil in the Orinoco of Venezuela, which is invariably *included* in most reports about unconventional oil. For purposes of this report, we employ the term, '*unconventional hydrocarbon liquids*' (UHLs) because these liquids substitute in the market place for the hydrocarbon products derived from crude oil. Only those UHLs that might reach at least 0.5 Mmb/d by 2020 are addressed in this overview. Oil Shale is discussed only to note its long reputed potential to contribute supply and to summarize the major challenges in its doing so. Similarly coal, currently the source of more than 150,000 b/d, and therefore demonstrably (South Africa and China) capable of being a very large source of UHLs, is only discussed briefly. The following unconventional hydrocarbon liquids are examined:

- Bitumen and Synthetic Crude Oil from Canadian Oil Sands
- Synthetic Crude Oil from Venezuelan Orinoco Extra Heavy Crude
- Liquids from Oil Shale and Coal
- Liquids from the 'Gas to Liquids' processes
- Liquids from agriculture crops or 'Biofuels'

The first four categories are derived from fossil, non-renewable, organic resources, the last category is renewable. Each constitutes an enormous resource. Figure 13 illustrates the geographic shares of unconventional oil resources, according to the IEA. The key resources are in Canada and Venezuela. Russia also has reserves but is focusing on its conventional oil at the moment. The questions are: how much of this resource can and potentially will be converted to marketable liquids over the next two decades; what are the incentives and barriers; and what are the costs of production?

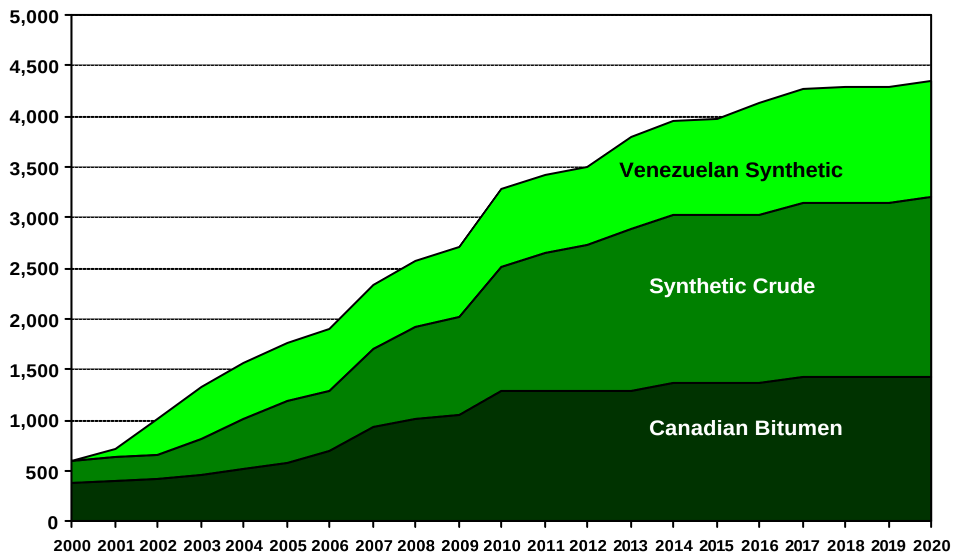
Figure 13: Distribution of unconventional oil reserves in 2002



Source: IEA

Our projection of production from the first two categories is shown below in Figure 14. The IEA assumed in its 2003 Investment outlook that *Non-Conventional* (sic) Oil production would reach 9.5 Mmb/d by 2030, of which most would come from Canada and Venezuela. Canada, according to the IEA, will produce 1.8 Mmb/d by 2010 and 5.1 Mmb/d by 2030. Venezuela, with lower costs but higher risks, is projected to produce 950,000 b/d by 2010 and 2.9 million b/d by 2030. Given that no new projects have been approved in Venezuela as of late 2004, it is highly doubtful, for the reasons cited above, that two or three new full scale grassroots projects could be launched in time to meet the IEA's projection of 0.95 million b/d for 2010. At most, one could expect to see an additional 200,000 b/d projects start-up before 2010 in the Orinoco.

Figure 14: Total potential unconventional crude production 2000-2020

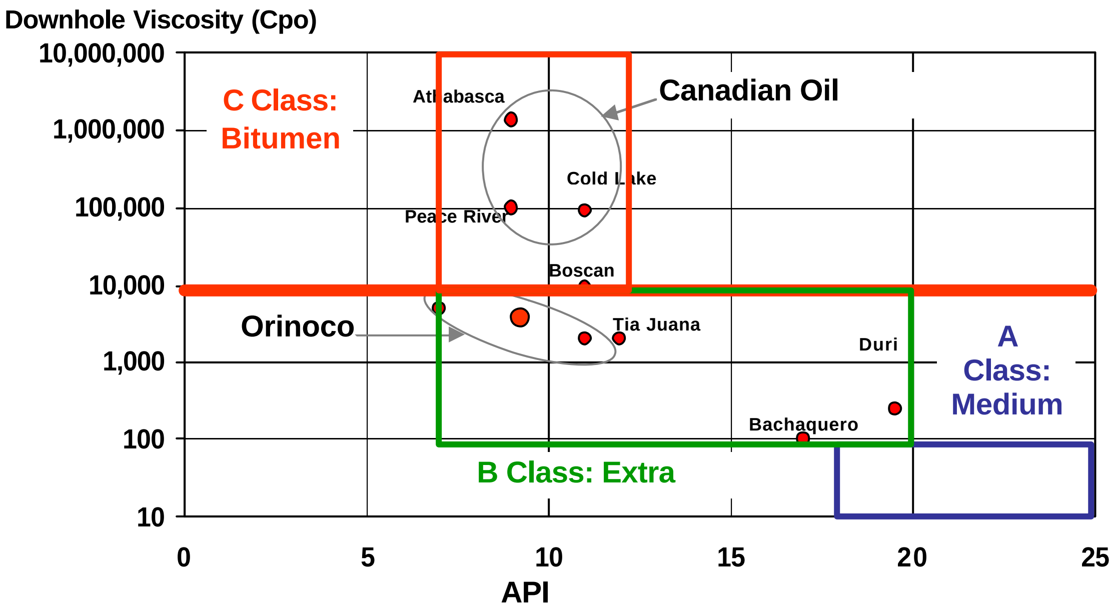


Source of data: Company data, OIES estimates.

3.5.5.1 Bitumen and synthetic crude oil from Canadian oil sands

The Oil Sands deposits in Alberta, Canada constitute a vast resource, estimated to exceed 2 trillion barrels of bitumen in place. Crude bitumen is generally defined as petroleum with a density greater than 960 kilograms per cubic metre. Much of the petroleum in Canada's oil sands has densities that exceed 1,000 kg/m^3, which means that it has an API Gravity of 10 or less. What really characterises the Canadian bitumen from the petroleum in the Orinoco belt of Venezuela is the viscosity of the former. This is illustrated in Figure15. There are other important differences that determine the greater difficulty in producing, transporting and marketing the bitumen of Canada versus the extra or ultra heavy crude oil of the Orinoco (See below).

Figure 15: Characteristics of Canadian and Venezuelan Bitumen and Heavy Oil



After Kupcic,

The resource occurs as a discontinuous arc of heavy oil and bitumen accumulations extending from south eastern Alberta, north to the Athabasca region where it occurs at the surface, then the bitumen bearing formations dip to the west to the Peace River area. Generally speaking, the more deeply buried the oil, the lighter is its gravity, and the thinner the oil-bearing zones. In the southeast around Lloydminster, Alberta, the crude is between 14 and 20°API. At Fort McMurray in the Athabasca part of the resource – by far the greatest share of Alberta bitumen – the poorest quality bitumen occurs: 7–9°API, 4–5% sulphur, with high nickel and vanadium content. Bitumen also occurs under the semi-unconsolidated sand reservoirs in Palaeozoic carbonate rocks (the 'carbonate triangle'), but is usually excluded from resource and reserve assessments because to date no process has been developed, even at laboratory scale, that can extract it.

Of the extra heavy oil and bitumen resource (excluding the carbonate triangle), the most recent official assessment by the Alberta Energy Utilities Board is shown in Figure 16.

Figure 16: Estimates of Canadian unconventional oil resources

	Billion Barrels
Resource in place:	1,631
Initial Established Reserves	178
Remaining Reserves	174
Mineable	33
In Situ techniques	141
Ultimate Potential	315

Source**:** Alberta Energy Utilities Board

There are basically two main methods used to extract the bitumen: mining or in situ (steam assisted) techniques. Mining is essentially limited to that part of the resource with less than 75 metres of overburden. Where the bitumen is more than 150–200 metres deep, in situ techniques are employed. Technologies are under development to extract the bitumen buried at shallower depths, yet too deep to mine.

The mining projects originally relied on bucket-wheels, draglines and conveyor belts, but these are being phased out in favour of ‘shovel and truck’ operations. By switching to shovel and truck mode, Suncor realised a 15% over-night reduction in costs. Today Canada’s oil sands mines employ the largest shovels and trucks in the world. One shovel can handle enough oil sand to yield, after upgrading, 50,000 b/d of Synthetic Crude Oil (SCO). Each truck if fully loaded contains the equivalent of nearly 200 bbls of SCO. Such figures reveal the essence of this business – logistics management and cost reduction. While costs continue to be reduced, there is unlikely to be a step-change such as that associated with the shift from bucket-wheels and conveyor belts to shovel and truck systems.

Production of raw bitumen from the Canadian oil sands in 2002 was about 830,000 b/d. In terms of extraction method, this was divided into 540,000 b/d from mining operations; about 200,000 b/d from enhanced or steam in situ projects, and the remainder as primary produced lighter grades of bitumen. The mined bitumen was converted into 435,000 b/d of light sweet synthetic crude oil (SCO). The nearly 20% difference between mined and synthetic product was converted into sulphur coke or burnt in processing and upgrading. The raw bitumen that is not upgraded at mines must be blended with a diluent to enable pipeline transport. Light condensate, refinery naphtha and synthetic crude is used as diluent. Currently the industry reports ‘bitumen’ production to be more than 500,000 b/d, which includes various grades of diluted bitumen, or as it is known in the oil trade, ‘Dilbit’ and ‘heavy sour crude’, a term along with ‘Synbit’ (a 50:50 blend of synthetic crude and bitumen) that will increasingly be seen in oil trade journals. Current grades of SCO are basically mixtures of naphtha and middle distillates, including a poor grade of diesel. SCO requires hydro-cracking in order to produce marketable products. Most refineries cannot take a full diet of SCO because they must dilute it with natural crudes in order to optimise use of their processing units.

Figure 16 illustrates the projected output of all projects that are proposed, for which applications have been submitted to the Alberta Energy Utilities Board or are announced as ready to or about to apply. There are other projects, some of which actually have a higher probability of being launched before 2015, that are not included in this figure. They would add an additional 860 kb/d by 2015. They are included in a projection as the solid black line on Figure 18. There is no other basis at present to assume ramp up from the 3900 kb/d from these projects, apart from creep and de-bottlenecking, so a stretch theoretical volume by 2020 would be 4,000 kb/d. However, it is much more likely that production will not exceed 2.3 million b/d by 2015, and 3.0 by 2020. The sources of data for these charts include company websites, CERI, AEUB, First Energy Capital, and estimates by the OIES

Although these figures appear to substantiate the growing importance of unconventional oil there is a real question as to whether all of the projects will actually go ahead. If they did then the IEA's projected level of output might be reached. But, all proposed projects will not go ahead. Considering just the projects that are under construction, it is more likely that production will be about 1.5 mmb/d by 2010, and given recent problems with water management, clean-up and recycling equipment, labour shortages and large unit deliveries, even 1.5 mmb/d could be a stretch.

In developing its outlook for UHLs, the IEA apparently accepted the 'official' reserves figures for both these unconventional hydrocarbon resources. This issue requires amplification because a 'resource-based' approach to postulating future supply is not necessarily a sound basis for confidence that supply will occur.

Figure 17: Recent projections of output from the Canadian Oil Sands (Synthetic crude oil and raw bitumen)

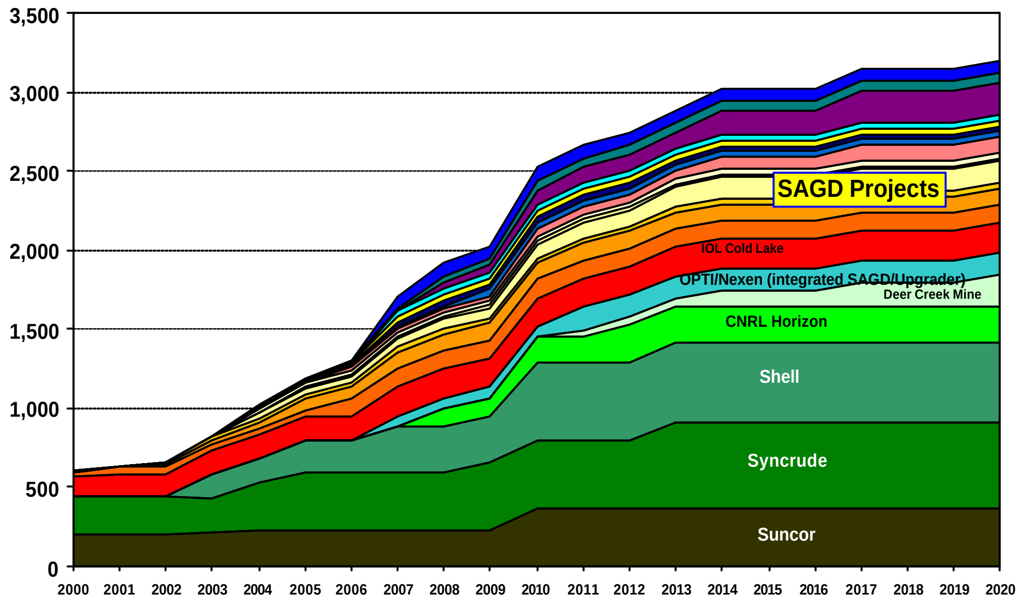
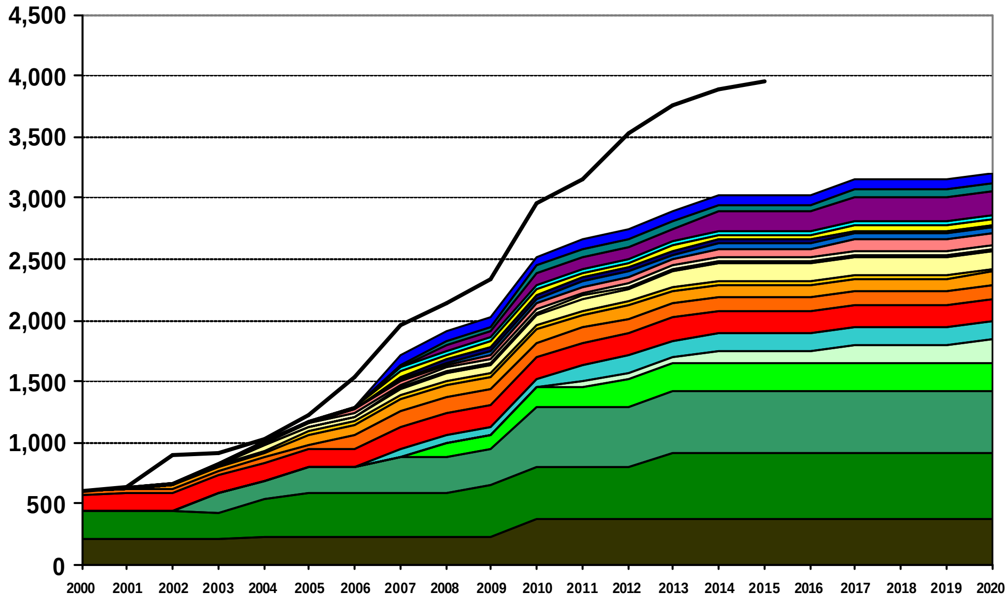


Figure 18: Projected Output from Canadian Oil Sands including upside (black line)



In the case of Canada, the reliance on natural gas for energy and hydrogen in oil sands development as noted earlier is a factor creating considerable uncertainty about future production. Applying the definition of proven reserves; i.e., the oil must be capable of production using today's technology/techniques at today's prices, then the technologies that rely on gas-fired steam boilers may not be appropriate to recover the 174 Billion barrels that the government of Alberta claims are yet to be recovered. The remaining proven reserves of natural gas would have to be entirely dedicated twice over to oil sands, which of course is a nonsense. An alternative higher cost technology employs gasification of the bitumen or its coke or heavy asphalt fraction. The off-gases provide fuel for steam injection and the very light upgraded product eliminates the need for diluent. One such project (OPTI/Nexen, Long Lake Project) is underway that involves primary de-asphalting of the bitumen then production of hydrogen and synthetic gas from the asphalt, followed by severe cracking and hydrogen addition. The industry and government authorities are watching this project very closely. Other technologies are being piloted that aim to reduce or eliminate the requirement for natural gas as a fuel for raising steam to inject underground to mobilize the bitumen.

Several agencies have assessed the supply costs for Canadian oil sands bitumen. The most recent study by CERI, cited above, is probably the most comprehensive and authoritative study. Supply costs in constant 2003 dollars are those needed to recover all capital costs, operating costs, royalties and taxes, and earn a specified return on the investment. The study used a 10% real discount rate (inflation at 2%). The analysis indicated that while supply costs at the plant gate ranged from C$14.51 to C$17.77 for raw bitumen, the industry would require WTI prices of about $25/barrel at Cushing, Oklahoma to cover all costs and earn an adequate return on investment. Upgrading the bitumen costs C$12.71; integrated mining/upgrading projects also require at least $25/bbl WTI. In general then, production of crude bitumen and other products from the oil sands can be expected at prices at the lower end of the former OPEC price band ($22-$28), but there would definitely be a cooling off in oil sands project announcements if the world price settled close to these levels. Also, with the recent decline in the US dollar and the price increase for most commodities, especially steel, the above costs are now expected to be on the low side.

While studies such as the above referenced study by CERI are helpful to understand the theoretical potential of oil sands, real market technical experience such as occurred in late 2004 and early 2005 provides a more realistic perspective. With the world over-supply of heavy and medium crude and the resulting extremely wide spread in price differentials, the price of raw bitumen at the plant gate of steam injection projects sunk to negative values in late November 2004. Furthermore, with the very wide light/heavy differentials and extremely low heavy oil prices at the end of the accounting year with respect to SEC filings, many producers in the oil sands had to take significant reserves write-downs. On another level, in late December, a fire in a fractionator at Suncor's upgrader, resulted in the loss of over 100,000 b/d of production, not expected to be returned to full output until 3Q05. These developments are sobering reminders that the oil sands business is not for the faint of heart.

Most estimates of the rate of increase in production from the Canadian oil sands are considered to be too optimistic owing to a number of factors that are leading to, or could lead to, project delays. These include:

- Recent projects have suffered from major cost overruns, which have damaged project economics.

- Uncertainty about the prices for future crude bitumen, synthetic crude oil and natural gas;
- Concerns about the price of natural gas and diluent, both increasingly in tight supply;
- Water management and re-cycling technologies and upsets resulting in missed production targets at all of the major SAGD projects;
- Infrastructure constraints—will there be sufficient take-away capacity in the pipeline systems, and will the electricity transmission grid be strengthened, and by whom in the competitive power market of Alberta, to support projects?
- Availability of skilled and unskilled labour: a new project proposes to fly in labour from the same labour pools that GCC countries draw on;
- Availability of capacity in the downstream markets to process diluted bitumen;
- Environmental constraints, not the least of which is the issue of greenhouse gas emissions.

A detailed analysis of each of these factors and constraints is beyond the scope of this report, apart from noting that probably the most troubling factor that could cool the output from the oil sands is the availability of natural gas. Significant volumes of natural gas are required to remove and process the heavy oil from the tar sands, which currently consumes around 1.5 bcf per day, a not insignificant volume. The high cost of North American gas has not only added to the cost base of projects, but in addition it has led to calls that such a highly-valued commodity as gas should not be used in such a fashion. While new technologies are under development that would eliminate or significantly reduce the use of natural gas, early signs are that some of these would pose other problems in terms of emissions or costs (for example, gasifying the vast quantity of petroleum coke produced by the cokers at the mines). Meanwhile, if oil prices remain in the $30+ range, and more importantly the continued increase in heavier grades of crude prompt investment in additional deep conversion capacity at refineries in the US such that the light/heavy crude price differential narrows, bitumen production will be increased despite high natural gas prices.

In summary, the Canadian oil sands will continue to expand their contribution to world oil supply. Canada will continue to be one of the main Non-OPEC countries able to add incremental supply, but as noted earlier it would take a major increase in the rate of investment and project development to come anywhere close to equalling the net of US production decline and North American demand increase. Therefore, while important, oil sands development will still leave room for imports from GCC countries.

3.5.5.2 Venezuelan Orinoco Heavy Oil and Bitumen

The other great 'oil sands' resource is the Orinoco Oil Belt in Venezuela. According to the state oil company, Petroleos de Venezuela SA, the belt contains more than 1,200 billion barrels of resource of which 270 billion barrels are proven and recoverable. For many years this resource remained unexploited, with only a few wells drilled into it. Unlike the bitumen from the oil sands in

Alberta, Canada, the ultra heavy oil from the Orinoco is not semi-solid under reservoir conditions—nor is it true bitumen, a distinction pivotal to understanding the economic/commercial debacle of Orimulsion™ (See Mommer, MEES, 15 March, 2004). The reservoir temperature in the Orinoco is around 55º C, as opposed to 7º to 8º C in the Athabasca region of Canada. Therefore, the viscosity is sufficiently low for Orinoco extra heavy oil to flow naturally from wells (assisted considerably by the dissolved gas coming out of solution as pressure is reduced). Once at the surface, if allowed to cool to room temperature, this ultra heavy oil (about 8º API) becomes very viscous.

After years of research under PdV's research branch, INTEVEP, the company launched a programme to start monetizing this resource. To overcome the viscosity problem at surface in order to ship it, PDV mixed the oil with water to form an emulsion, which is maintained with a surfactant. Since aqueous slurries of finely powdered coal can be burnt in power plants, it was not a great leap in technology to burning this emulsion in steam boilers for power generation. PDV launched an aggressive marketing program for the product, Orimulsion™ as a competitor with coal, thereby escaping OPEC's quota constraints. PDV also escaped the constraints of the norms of resource conservation and value maximization, and commercial accounting, as recently documented in detail by B. Mommer (above). Orimulsion™, a blend of 70% heavy oil and 30% water with a minor amount of surfactant, was (up to recently) priced to easily compete with coal in the power generation market. We have not heard the last of Orimulsion although we are unlikely to see its production expand: in effect, given its high metal and sulphur content, special metallurgy is required in boilers to burn it, adding to the costs. In effect the high capital costs for converting the heavy oil into useful petroleum products with added value, in the case of Orimulsion, were simply shifted to the buyer of the emulsion to build expensive kit to essentially destroy value of the heavy oil molecules. As detailed by Mommer, the net-back price of the heavy oil in the emulsion product is a fraction of its value as crude oil priced into an upgrader. In fact it is precisely the same oil that is being processed in the Cerro Negro (see below) integrated upgrader projects. Eventually, all extra heavy crude produced from the Orinoco belt will be devoted to producing petroleum products rather than devoted to the value subtraction scheme of Orimulsion™.

In the early nineties Venezuela invited international oil companies to propose projects to extract and upgrade the Orinoco crude in Venezuela. Attractive fiscal terms were attached to these projects, the most important of which was a 1% royalty on the value of the heavy crude feedstock for up to nine years. Not surprising, the offer was taken up and there are four projects currently producing upgraded or synthetic crude from this resource. The state company, PDV has an interest in all of the projects.

- The first to come on stream, the Petrozuata project, is a joint venture between Conoco/Phillips and PdVSA, reached its target of 120,000 b/d of 9º API oil by February 2001, which is upgraded to produce, after losses, about 105,000 b/d of partially upgraded synthetic crude of 16 to 20ºAPI, which is shipped to the US Gulf Coast for further refining.

- The Sincor project (a joint venture between TOTAL, Statoil and PdVSA) started heavy oil production in December 2000. Its upgrading plant came on stream in March 2002 and the project is expected to produce an average of 180,000 b/d of fully upgraded crude of 32^{o}API.
- The Hamaca or Ameriven project (a joint venture between Conoco/Phillips Petroleum, Chevron/Texaco and PdVSA) is due to reach full production at the end of 2004, when it will yield about 190,000 b/d of partially upgraded crude (25^{o}API) from about 210,000 b/d of Orinoco heavy feedstock.
- The Cerro Negro project is a joint venture project between ExxonMobil, Veba (BP) and PdVSA. Output rose from 60,000 b/d in 2000 to 120,000 b/d of heavy crude which is subjected to minimal upgrading to produce about 105,000 b/d of 17^{o}API before being exported to the Gulf Coast.

Figure 19: Extra-heavy oil projects - Orinoco Belt, Venezuela

Strategic Associations	Petrozuata	Cerro Nego	Sinco	Hamaca
Partners	PdVSA 49.9% ConocoPhillips 50.1%	PdVSA 41.67% Exxon Mobil 41.67% BP 16.66%	PdVSA 38% TOTAL 47% Statoil 15%	PdVSA 30% ConocoPhillips 40% ChevronTexaco 30%
Exrta-Heavy Oil Production Capacity	12,000 bbl/d 9.3° API	12,000 bbl/d 8.5° API	200,000 bbl/d 8-8.5° API	200,000 bbl/d 8.7° API
Synthetic Crude Production Capacity	104, 000 bbl/d 19-25° API	105, 000 bbl/d 16° API	180, 000 bbl/d 32° API	170, 000 bbl/d 26° API
Initial Production	October 1998	November 1999	December 2000	October 2001

Source: US DOE/EIA

These four projects, once all on line, will have involved an investment of about $12.8 billion and should produce about 545,000 b/d of synthetic crude from 610,000 b/d of extra heavy crude. These Venezuelan heavy oil projects were very attractive investments because, besides the 1 per cent gross royalty on the heavy feedstock (not the lighter upgraded crude), the income tax rate on heavy oil production is 34 per cent, rather than the normal rate of 62 per cent. More recently, President Chavez halted the 1 per cent royalty and required the projects to immediately increase to the 16.67 per cent royalty. No companies have complained too loudly with respect to this increase and they would probably we most wise not to. To be fair, when the investments were agreed to, the world oil price hovered around $16 per barrel. Also, there were relatively few wells in the deposit and its behaviour was not well known, so the project risk was considerable. Through major advances in horizontal drilling and 3-D seismic, the projects have performed much better than expected. With oil prices more than twice as high as the basis on which the economics were calculated, these projects will not be impaired by the decision to increase the royalty. Moreover, there is still great interest in new green-field sites.

Using data from the US DOE/EIA, company websites, and interpolating from the IEA WEO 2004, we have developed an outlook for output from Venezuela as follows. We assume that debottlenecking, improvements and creep from the existing four plants in the Orinoco will take production up to 760 kb/d by 2010. Thereafter we envisage 2 new grassroots projects of about 160 kb/d synthetic crude each, which with a reasonable expectation of improved output due to debottlenecking and creep, will see total Venezuelan synthetic output reach 1,160 kb/d by 2020. At least TOTAL and Chevron Texaco are definitely keen to build new plants.

In Venezuela, a little discussed issue is the very low recovery rates for the integrated projects in the Orinoco. At best the projects are recovering less than 10 per cent of the original oil in place. It is highly unlikely that the first entrants to this play are located in any part of the resource other than the 'sweet spots' or the richest, most prospective areas. Therefore current recovery factors should be among the best to be expected from this resource using existing technology. The official reserves for the Orinoco, 267 billion barrels recoverable from 1,200 billion barrel resource, implies a recovery factor of 22%, more than twice the actual performance. The Venezuelan authorities will likely (or at least should) make expansion or new green-field projects contingent on improving recovery factors, to be consistent with their proprietary and long term interests in resource conservation.

Technical costs for heavy oil from the Orinoco region are between $5.00 and $6.50/bbl, including extraction and the cost of upgrading it into lighter oil at a refinery. The cost of extracting the oil is now believed to be about $2/bbl. Figure20 shows illustrative net backs for both Athabasca and Orinoco synthetic crude based on a $21/bbl WTI.

Of the two regions, the political risk associated with the Orinoco projects is more than offset by its commercial attributes. The Athabasca bitumen production suffers from a location disadvantage (remote, extreme temperatures summer and winter, distant from market, and few marketing options) but the technical risk is considered to be low and the political risk minimal. With regard to the latter, there are recent indications that the Alberta government may be examining how to accelerate its access to a greater share of rent on these projects. None the less, continued expansion is expected.

Figure 20: Indicative Net-backs for Canadian and Venezuelan Unconventional Oil Projects

CANADA	**Syncrude**	**Suncor**	**AOSP (Shell Cda)**
	32 – 33 °API	**31 -35 °API**	**28 °API**
All-in Net-back	**$8.30**	**8.58**	**10.00**
Royalty -	(0.57)	(1.67)	(0.10)
Pre-Royalty Netback	(8.87)	(10.25)	(10.09)
Sustaining CAPEX	(1.52)	(1.00)	(0.84)
OPEX	(10.11)	(7.77)	(7.92)
Realized Upgrader Gate Price	$20.50	18.95	18.85
Quality & Transport Differential	(0.50)	(2.05)	(2.15)
WTI	**$21.00**	**$21.00**	**$21.00**
Transport	(0.90)	(0.90)	
Quality Differential	(2.90)	(0.50)	
"Technical Costs"	?< (5.00)	(6.50)	
Pre-Royalty netback	(12.20)	(13.10)	
Royalty on Raw Crude	(0.14)	(0.14)	
All-in Net-back	**$12.06**	**$12.96**	
	22 °API	**32 °API**	
VENEZUELA	**Petrozuata**	**Sincor**	

Source: OIES, Companies information, TD Securities; Chem Systems

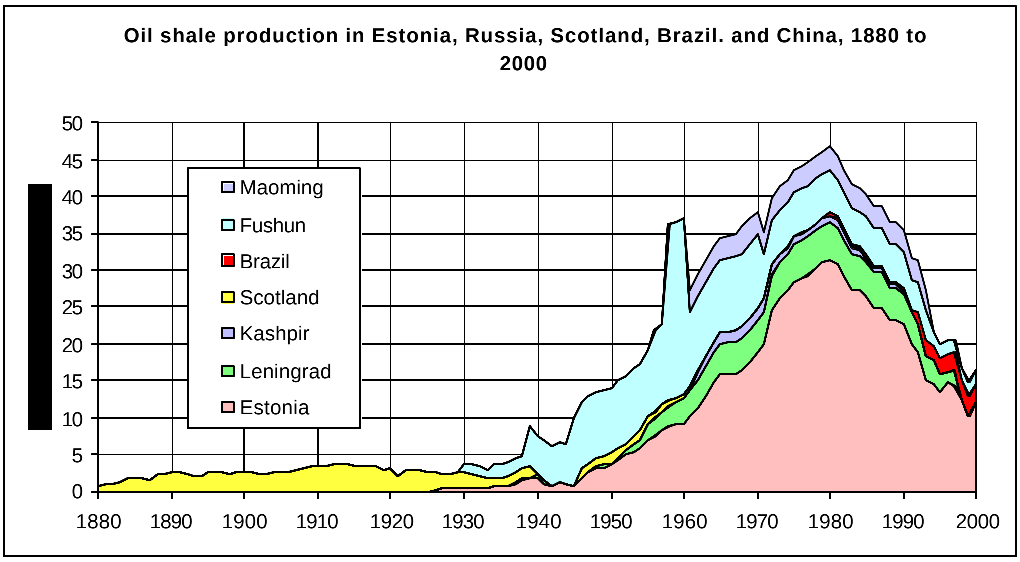
When discussing the unconventional oil, it might be stressed that care should be taken if attempting to extrapolate the volumes of Synthetic crude as some indication of volumes of light sweet crude equivalents. Some are, but not all. The Venezuelan synthetics, with the exception of Sincor, are only partially up-graded crudes—sufficient to qualify as having added value in Venezuela and to reduce the viscosity sufficiently to be transported without diluent to the US Gulf Coast for further conversion. The Canadian situation is different. The upgraders all produce a fully upgraded synthetic crude (32API to 42API projected for the Long Lake Project). Because the supply of natural gas-associated condensate is declining, and bitumen volumes are increasing, producers of raw bitumen in the oil sands region are buying synthetic crude to use as a diluent. Not only does this solve the diluent problem, it also creates a 'product' that is more attractive to refineries; in fact, its yield tends to resemble that of the Mars crude from the US Gulf. The blending of synthetic with bitumen is 50:50 to 40:60. Thus, while the overall volume of output from the oil sands will not change, the mix of light sweet synthetic and heavy to medium sour product will be other than as shown in these figures.

3.5.5.3 Oil shale and Coal

According to the World Energy Council, Global oil shale resources exceed 3.5 trillion barrels, but recoverable reserves are about 160 billion barrels. The largest accumulations are found in the Former Soviet Union (1400 billion barrels), the USA and Brazil (each 700 billion barrels), China (400 billion barrels), and Canada (300 billion barrels). While there are shale deposits with natural crude oil (the oil did not migrate from the shale), most of what is referred to as 'oil shale' are black shales with organic material mostly in the form of kerogen. In essence, they are merely organic deposits that have not been subjected to the temperatures and pressures that produced conventional oil. Benefaction of oil shale requires the duplication of this earth process to convert the kerogen into hydrocarbons—implicitly a high energy consuming process. There are two conventional approaches to processing oil shale. Both processes use considerable volumes of water. In addition, the total energy and water requirements together with the safe disposal of huge quantities of waste material have so far made production uneconomic. Australia has oil shales of which the Stuart Shales are particularly rich in kerogen, yielding a barrel of synthetic liquid per 1.3 tonnes of shale (this compares with one barrel of synthetic crude per two tonnes of Athabasca oil sands). A large pilot project (4,500 b/d) has been operating intermittently since the late nineties but has experienced operational problems and its emissions of noxious gases have raised the ire of local opponents and environmentalists. According to its proponents, the project has the potential to reach 85,000 b/d of very light product of very high quality naphtha and very low sulphur middle distillate.

Oil shales have been produced in the past, some of which are consumed directly as a substitute for coal, as is the case currently in Estonia. The Brazilian production is a hybrid pilot project that combines used tires and oil shale to produce a minor amount of liquid hydrocarbons.

Figure 21: Production of oil shale 1880-2000. After Dyni, USGS, 2000



Ultimately, oil shale might find a place in the world's hydrocarbon liquid fuel supply but with development costs believed to be well in excess of $25 per barrel, excluding any mitigation costs, it seems unlikely productive capacity can be expanded to the point where it could make a major contribution as part of the supply of UHLs.

Producing liquids from coal has been with us since the first coke ovens. The liquids were mostly a waste product, but some tars were converted into useful chemicals. Technology to convert coal gas into waxy hydrocarbon liquids was invented by German scientists in the twenties and fuelled the German army and Luftwaffe during WW II. This patented process, known as Fischer-Tropsch (FT) Process, converts synthetic gas produced in the anaerobic gasification of coal into liquids. It has since been adapted to convert natural methane in the presence of catalysts into petroleum liquid products including diesel and other middle distillates along with lubricants and petrochemicals. South Africa, in what amounts to one of the most dramatic pursuits of energy independence as the foundation for its security of energy supply, applied FT technology to produce over 100,000 b/d to sustain its apartheid regime through many years of economic sanctions by the international community. SASOL currently produces 160,000 b/d in Sasolburg. The principal point with respect to coal and UHLs is that it represents an immense ultimate resource. Given the continued research efforts dedicated to the clean use of coal, and given oil prices sustained above $25/bbl, one could imagine over the longer term greater volumes of UHLs derived from coal. A factor that should not be ignored with respect to gasification of coal and other fossil fuels, is that it provides the basis for hydrogen production accompanied by sequestration of carbon from the process. The nature of the gasification process produces a very pure stream of CO2. China is currently developing plans for coal to liquids projects.

3.5.5.4 Gas to Liquids

The conversion of natural gas into more complex hydrocarbon liquids (as opposed to compressing natural gas into a liquid state—LNG) relies on the Fischer –Tropsch Process (see 3.5.5.3 above). It is accomplished through three steps:

- Synthesising gas production. Hydrogen and carbon monoxide are produced by putting natural gas, oxygen, and steam through steam reforming, autothermal reforming, partial oxidation or a combination of these processes in the presence or absence of catalysts;
- Fischer-Tropsch synthesis, where the synthesised gas flows into a reactor containing a catalyst (cobalt, iron) that converts it into hydrocarbon liquids; and finally
- Upgrading of the product, normally a mixture of paraffinic distillates and waxes with some olefins and oxygenates. The light ends, LPGs and naphtha, make up to about 20% of yield and are used for petrochemical feedstock and ideal for steam cracking to olefins. Note that this is not a gasoline producing process.
- The resulting synthetic crude is further upgraded to finished product using conventional refinery technologies, usually mild hydrocracking and hydroisomerization.

One of the main driving forces to convert gas to liquids has been the discovery of large volumes of gas considered to be stranded; in other words, gas in remote areas of the world, with no economic transportation links to markets. Stranded gas reserves not only include remote reserves, but also small volumes of gas reserves and sometimes associated gas (e.g. Nigeria where it has historically been flared because of the lack of infrastructure), where little or no commercial value could be assigned, in fact if the gas has to be re-injected at cost, to pursue other options to use the gas would imply that it could have a negative opportunity value. In cases where gas is deemed to have a very low or zero price, converting it to liquids can be very commercial.

Stranded gas is estimated to make up approximately two thirds of the 5,500 tcf of gas already discovered in the world. The concept of 'stranded gas' should probably be discarded because often the nature of 'stranded' is very much in the eye of the beholder, and if the gas is stranded, incapable of economic production, it is by definition not reserves. Qatar hardly sees its gas as 'stranded'. The original concept that this gas could be converted to hydrocarbon liquids has not found industry-wide acceptance. This is because the very large volumes of gas are also attracting the attention of countries and companies eager to develop liquefied natural gas (LNG) export facilities. Such projects are often more attractive economically than the GTL schemes which also require significant infrastructure to gather and process gas.

Despite this, at the right price in the end-use markets, GTL does have some advantages over LNG. Its products are much easier to transport and market as they can be handled as refined petroleum products utilizing existing transportation systems. In contrast, LNG has to be cooled by compression until it liquefies, transported in special, dedicated carriers, and then stored and/or re-gasified before being transported in pipelines to final users. However it is worth noting that LNG and GTL only compete for investment funds, they do not compete as fuels. Another driver for GTL is environmental (very clean diesel); also, the product can alleviate blending problems for heavy sour crudes although this seems a very costly way to produce feedstock for a refinery.

There are at least nine pilot or demonstration plants (U.S., South Africa, Italy, Japan) and currently two commercial GTL plants that use natural gas as feedstock. One is operated by Mossgas in South Africa and the other by Shell SMDS at Bintulu in Malaysia. However, many new projects are currently being planned (Figure 22).

Figure 22: Existing, planned and potential new GTL projects (b/d) (* = at least at Pre-FEED stage)

Project/Company/Country	Existing	Under construction	Announced or Under Study
Mossgas, SASOL, South Africa	23,000		
Bintulu, Shell, Malaysia	14,700		
Pilots (9)	2,360		
ORYX, Sasol/QP, Qatar		34,000	
Sasol/QP, Qatar			130,000
Sasol/QP, Qatar			100,000
Exxon Mobil/QP, Qatar			150,000 (2 X 75,000)
Conoco/Phillips/QP, Qatar			160,000* (2 X 80,000)
Marathon/QP, Qatar			100,000
Shell/QP, Qatar			140,000* (2 X 70,000)
Shell/NPC, Iran			75,000
Statoil/NPC, Iran			20,000*
Sasol/NIOC, Iran			140,000 (2 X 70,000)
Shell, Pertamina, Indonesia			75,000
Sasol/Chevron/NNPC, Nigeria			34,000*
Sasol/Chevron, Australia			34,000
EGPC/Shell, Egypt			75,000
Rentech, Bolivia			10,000*
Amazon, Syntroleum/Petrobras, Brazil			?
Reema Int/Syntroleum, Trinidad			10,000
PDVSA/Sasol			34,000
Sasol/PetroTrin, Trinidad			30,000
Gazprom/Yukos/Syntroleum			120,000 (12 X 10,000)

Source: Company data, OIES, Technip, 2005.

If all these projects were implemented the additional liquid supply would be of the order of 1.44 mmb/d. A recent review of projects at the 4th Annual World GTL Summit (p. A5 MEES 47:21 24 May, 2004) reviewed the potential projects for Qatar and Iran. Together, these two countries could be producing over 900,000 b/d of FT-based UHLs by 2015. Qatar could be producing 780,000 b/d by 2014 according to Technip. There is a very important factor that makes these two countries such high potential producers of GTL and LNG: the North Field/South Par gas accumulation, one of the largest in the world, has considerable associated liquids (NGLs and condensate). The ratio is about 40,000 b/d per 1 Bcf/d of gas production. Thus, using a factor of 10,000 cubic feet per barrel of FT liquid produced, 900,000 b/d equates to 9 Bcf/d or 360,000 b/d of associated liquids. Coupled with the liquids associated with the gas feeding the LNG production, Qatar and Iran would add at least another 400,000 b/d of condensate and NGLs. In sum, the combined liquids production from these two Gulf countries could amount to 1,860,000 b/d (1,100,000 b/d of FT liquids, 360,000 b/d of FT associated liquids and 400,000 b/d of LNG associated liquids).

It is obvious why NOCs may want to invest in GTLs. It allows them to monetize their resources of gas. In the case of Qatar there are industrial and other intellectual property benefits in pursuing this strategy taking advantage of their unique and rich gas endowment. There are perhaps at least three corporate strategies driving IOCs to make investments in GTL. 1) an upstream strategy aimed at booking the reserves of natural gas underpinning the projects once the project is sanctioned, and in the case of Qatar and Iran, the associated liquids (NOTE: the SEC will not allow booking of GTL liquids per se, but the hydrocarbon reserves supporting the project can be booked once the project is on stream); 2) a downstream strategy where refiners can use the extremely clean FT GTL products as a blend-stock to meet higher emission standards without the need for further upgrading of existing crude refinery equipment; and 3) an integrated strategy, whereby investments in the upstream to produce blending stock can add reserves as well as improve returns on capital on a corporate or integrated basis. Under some financing structures it might make more sense to invest in a GTL plant than in upgrading a refinery that is returning less than the company's WACC. This latter strategy would seem to apply more in theory than in practice since most corporations look at the upstream and the downstream as separate profit centres. The blending driver mainly applies in the USA and Europe, but other countries are beginning to follow the same path.

Although the diesel derived from FT GTL has several environmental advantages, we believe it unlikely that it will substitute for conventional diesel for the following reasons. Firstly, the main benefit of GTL diesel is it contains no sulphur; its octane level is comparable to those in Europe. This advantage might be limited because the volume of GTL diesel needed to satisfy the requirement would be excessive and would require significant investment. For example, to move from 300 ppm to 50 ppm by blending GTL diesel with conventional diesel, would require a 6:1 ratio of GTL diesel to conventional diesel. Secondly, regulations are changing so quickly and dramatically that refiners will not be able to depend on GTL blending to satisfy longer-term emission standards. For refiners it is probably more economic to upgrade existing refineries than to invest in more GTL capacity. Further upgrading of refineries is likely to reduce the use of GTL as a blend-stock. Thirdly, the cost of upgrading appears to be coming down. For a typical refinery, the cost of getting from 50 ppm to 10–15 ppm is only 50 to 75 cents per barrel, assuming there is an existing hydrotreater in place. In the longer term, legislative moves toward a zero sulphur specification may provide the best incentive for GTL diesel as such a process might prove prohibitively expensive for refiners.

In a recent issue of the Oxford Energy Forum, Bipin Patel discussed the economics of GTL projects. He showed that the overall economics of a GTL plant is affected by three main variables; the crude oil price, the capital cost and the operating costs including the cost of the gas feed. This is very different to the economics of LNG, which are related not to the crude oil but to gas market dynamics. In terms of capital costs, the cost of an integrated GTL facility (including the upstream gas plant) ranges from $25,000 to $35,000 per daily barrel of liquid capacity. This wide range illustrates the effect on cost of a number of project specific factors including technology utilisation, location, degree and scope of product upgrade facilities, availability of shared infrastructure and size of the plant. Over time the unit capital cost of producing a barrel of liquids has fallen from around $75,000 for one of the first plants in New Zealand in 1983 to around $25,000 for the Shell Qatar plant today. Sasol and Chevron are targeting future costs of under $20,000 for a 75,000 b/d plant.

With respect to operating costs, the most effective method of reporting operating costs for a GTL facility is to link it to the end product rather than to use a gas feed basis. This provides a more accurate assessment based on the unit cost of production and the init of product sales. The operating cost for a GTL plant excluding the cost of feedstock ranges from $4.00-5.50/bbl of liquid. The major part of this cost is associated with the cost of the FT filters. The cost of the natural gas feedstock is also important and may be as much as $10/bbl based on a cost of approximately $1.0 per million Btu of gas. In total for a plant with a capacity in excess of 50,000 bbl/d, the total cost to produce a barrel ranges from $18-22/bbl.

With respect to the numerous projects highlighted above in Figure22, the decision to invest is very much dependent on a perception of future oil and gas prices. Therefore a low oil price of below $20/bbl would put many projects on hold. However, a GTL business should not be considered as a standalone entity and should rather be viewed as a gas monetisation option and the economics of the upstream facilities must also be taken into account. The GTL industry faces challenges including:

- continued cost reduction and improving scale economies;
- demonstrating value of premium quality diesel in the market;
- develop new technologies, such as floating plants for offshore fields;
- energy intensity of plants and CO_2 emissions;

It seems to us that the real niche for GTL schemes lies in areas where gas reserves are insufficient to justify an LNG development, or where associated gas cannot be flared. It might also be justified where the cost of gas is sufficiently low to give a satisfactory rate of return on a new investment. However, in our view most of the prospective GTL plants are unlikely to be developed unless there is significant government backing (as is the case in Qatar), where there are attractive associated liquids, or unless groundbreaking new technology can reduce the sensitivity of the project to gas prices.

3.5.5.5 Biofuels

Biofuels comprise the range of fuels that are immediately derived from plant matter. The liquids can be produced from a number of feedstocks via a number of chemical processes. The fuel range includes bio-diesel, produced from vegetable oil, bio-ethanol, produced from plant sugars and bio-methanol, produced from lignocellulosic material. Biodiesel and bioethanol are the two most developed and accepted of the range, however most of these fuels are derived from agricultural products. Transforming food or animal fodder to fuel may not be sustainable in the long term or socially justifiable in the short term as it could increase food costs. Biofuels, however, as an alternative to fossil fuels exploit a number of advantages. In general, present engines do not have to be converted for their use. The tailpipe emissions of SOX and NOX are also lower than the equivalent petrol or diesel fuel although this becomes questionable in the case of CO_2 emissions taking into account inputs calculated on a full cycle, ‘well-to-wheels’, basis. Nonetheless, Biofuels programmes are very popular with many governments for a variety of reasons, not all to do with energy supply, and we can expect these to continue and to expand. Also, new technologies including genetic engineering, can be expected to be brought to bear on the challenges of for example increasing the rate of fermentation of cellulose waste, or the application of Fischer-Tropsch and other technologies to extract liquid fuels from biomass. Therefore, at the margin, Biofuels will replace products derived from crude oil. This section briefly reviews the industry, some of the issues and the future prospects of biofuels.

The chemical processes involved in biofuel production are well established. The feedstock can be varied to suit regional conditions for crops. North America and Brazil account for 23 of the nearly 29 billion litres of ethanol used for fuel; US production relies on maize; Brazil uses sugar cane. Biodiesels are typically derived from oilseed rape in northern Europe, whilst sunflower oil is used in the south. Bioethanol/ETBE is produced from sugar-beets and wheat in northern Europe and from sweet soygerm in the south. The use of alternative biomass for production continues to be researched. This is necessary as the main cost involved in biofuel production is the feedstock.

Governments cite several reasons for launching and subsidizing biofuel production. These include energy supply security, reduction of storage crops (as a consequence of over-production under subsidy programmes—making a virtue out of folly!), improved vehicle performance, enhanced or sustained rural economic development, and the most compelling argument, emissions reduction. If the externalities associated with the use of fossil fuels are taken into account then the relative cost of biofuels can become more attractive, but the overall benefits are very difficult to quantify.

Europe is currently the world’s leader for the production of biodiesel. It produces half a million tonnes annually, representing about 1 per cent of the European diesel market. The main producers are Italy and France, mainly due to the agricultural policies of these countries, with large areas of set-aside available for non-food crop production. Europe currently has the capacity to double its production of biodiesel. The lobby to produce biofuels in Europe is strong, mainly from the agricultural community, who yield significant political power in several EU countries. Tax incentives also exist in the EU for the production of biofuels, under the Scrivener Directive, which some EU states have adopted. Without this type of incentive it is unlikely that the fuel price could compete with fossil fuels.

According to a recent study by the IEA of biofuels (IEA, Biofuels for Transport, 2004), ethanol only accounts for 2% of transport fuel in the U.S. while in Brazil bioethanol accounts for 30% of its gasoline demand. The relatively low cost of production in Brazil is accounted for by the use of the crushed cane (bagasse) as a fuel in distillation. The future market share of biofuels will be influenced by a number of complex factors. The biofuel manufacturing plants in the EU are subject to a fiscal incentive as a result of the Scrivener Directive, which is the difference between them being commercial or not. Without this incentive the cost of fuel would be between two and three times more costly than conventional fuels.

The potential of biofuels in countries like India has been explored by the United States Agency for International Development. There, alongside the Ministry of Petroleum and Natural Gas, three pilot studies were initiated in 2000 to explore the potential of blending ethanol and petrol in sugar-producing states. These pilots were successful and led to numerous other projects and R&D studies in six further states. The preliminary result has been a government mandate to supply 5 per cent ethanol mix petrol in nine states and four union territories, amounting to between 320–350 million litres annually. This will then be extended to the whole country and eventually the mixture will be increased to 10 per cent ethanol. In our view, this role out programme looks to be rather ambitious.

Gasoline-based vehicles in India account for approximately 20 per cent of all transport and the annual crude requirement for transport is approximately 105 million tons. The Indian government is therefore hoping to displace approximately 1 million tons of oil through the introduction of 5 per cent ethanol in petrol alone. No timeframe has been specified for this to be achieved. The introduction of 10 per cent ethanol in petrol would therefore save 2 million tons of oil in 2001 to 2002 terms, of which 70 per cent was imported. The remaining 80 per cent of vehicular transport in India is diesel based. Vehicle manufacturers state that their vehicles are capable of using between 10 and 20 per cent of biodiesel mixture, which can be derived from large resources of non-edible and wild seeds.

India could have the potential to make significant savings of oil, if the targets outlined above were implemented successfully. The success would be partly based on the extensive agrarian society and therefore a ready market of vehicles capable of accepting the biofuels without any modification.

While governments currently promoting Biofuels point to their environmental benefits, some studies suggest a relatively small or in some cases negative gain in energy flows arising from biofuels. That is, it is estimated that after taking into account all the energy inputs for the agricultural equipment, their fuel use, fertilizers and the energy used to produce them, the inputs can exceed outputs by some 20 to 30 per cent (See for example D. Pimentel, 2001, "The Limits of Biomass Energy", Encyclopaedia of Physical Sciences and Technology). However, most studies of corn or maize and ethanol from wheat using currently commercial processes, yield a 20% to 40% reduction in well-to-wheels CO_2-equivalent greenhouse gas emissions.

Because biofuels are being promoted by governments, automobile manufacturers, looking to improve their emissions outputs in the medium term, apparently consider biofuels as offering a lower cost alternative to other lower emissions technologies. The fundamental barrier to entry remains the price of biofuels compared to conventional oil products. At up to three times the price before subsidy, the only way biofuels can compete is if externalities are counted as part of the cost of conventional oil. Without this the costs of subsidy at greater rates of production would probably be unsustainable if left to compete openly with oil.

The introduction of bioethanol fuels into transport consumption over the next few decades will be determined by three factors; rate of technological progress, national energy policy and the price of conventional oil. The US Department of Energy biomass ethanol programme suggests that no major infrastructure barriers exist, which would hinder development of biofuels. However, there would have to be considerable investment by terminal operators and retailers. The freight charges for the movement of ethanol would be greater than for gasoline. One reason for this is that ethanol could not economically be transported by pipeline. For pipeline to become viable in North America, ethanol would have to comprise up to 20 per cent of all products moved by pipeline, or 40 per cent of all gasoline shipments. Were ethanol transported in these volumes the incremental costs would be similar to those for other fuels. This theoretical potential is tempered somewhat by the practical effects of ethanol fuels and the 'balkanization' of regional gasoline markets in the United States, blamed in part for the run-up in the price of West Texas Intermediate (a gasoline crude)—and thus world crude oil prices—in the summer of 2004. Getting to a theoretical happy ending must confront some serious practical dislocations that theoreticians should consider in their cost/benefit calculations.

The outlook for the production of biofuels is complicated and confusing. The IEA recently projected the output of ethanol and biodiesel out to 2020 (Biofuels in Transport, ibid). However, the WEO 2004 also talks briefly about Biofuels (pp 240-242) but does not accord with the IEA's Biofuels book, even on the starting point (2002). According to the IEA's Biofuels study, the total production of biofuels is currently 29,000,000 cubic meters of ethanol and 1.8 million cubic meters of biodiesel (capacity) per year. This is almost twice as much as the 8 Mtoes reported by the WEO, page 241. The distinction is largely explained by the difference between capacity versus actual production. It is also critical to understand the net energy in biofuels versus gasoline, and how this calculation is made. A review of the literature suggests that one gasoline equivalent litre of ethanol displaces 0.85 to 0.88 litres of petroleum on a net energy basis.

Even the most passive observer of the subject of biofuels, can not help but notice that their volumes are always announced and measured in terms of "billions or millions of litres per year" rather than thousands of barrels per day, the normal measure of the products they replace. For example, estimated biofuels capacity in 2003, if fully utilized would yield about 30 billion litres per year, or about 500,000 b/d, which on a net basis would 'replace' about 425,000 b/d, although less by the time another 15 to 20% is deducted for the oil products that go into their production.

According to the IEA's 2004 WEO, biofuels are expected by 2030 to nearly quadruple from 8 Mtoe in 2002 to 36 Mtoe, or about 700,000 b/d. This contrasts with the very bullish outlook in the Agency's Biofuels for Transport study (p. 168) which postulated (for alcohol) a "…quadrupling of world production to over 120 billion litres by 2020…on a gasoline energy-equivalent basis, …about 80 billion litres…" (or, using this much more conservative equivalency, over 2 Mmb/d). For purposes of this study, we assume that biofuels will continue to grow at 5%/annum as opposed to the IEA's WEO of 5.5%/annum, although we start at a higher base than the WEO.

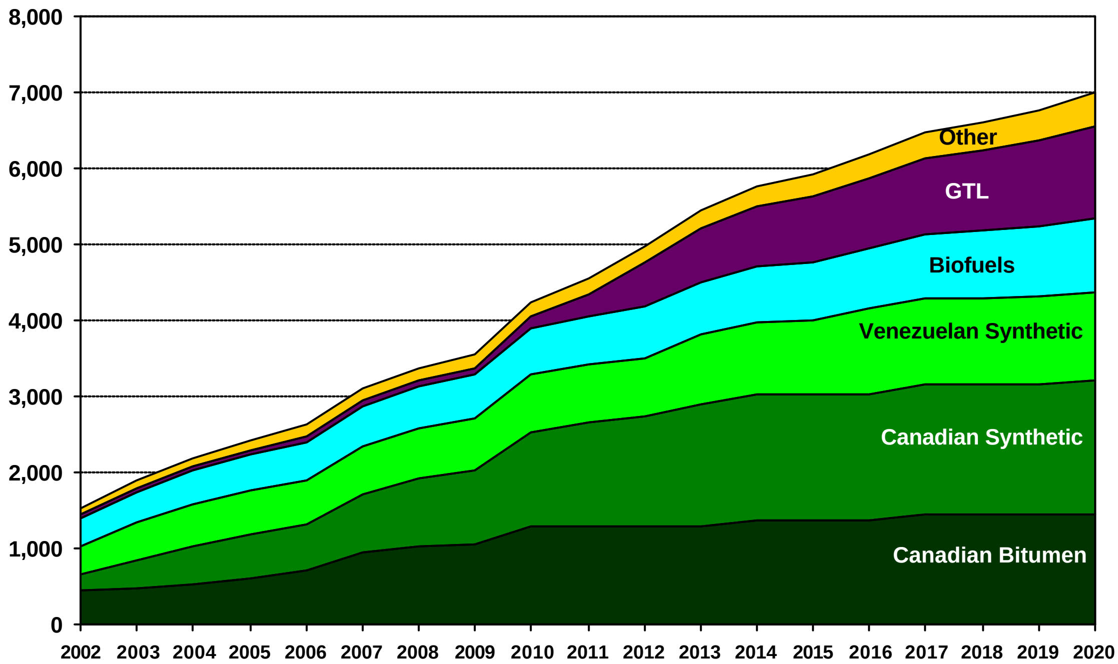
3.5.5.6 Outlook for Unconventional Hydrocarbons

Taking into account all of the various factors discussed above we have put together our forecast of unconventional oil supply up to the year 2020. These are summarized as follows:

- **Canadian Unconventional**: Based on actual projects and assessment of the operators, the stage of the approval process and location and nature of project (mining, in situ) each project is risked and scheduled accordingly. Projects are divided into raw bitumen (no upgrader) and synthetic (with an upgrader on site). 3,200 mb/d by 2020.
- **Venezuela Synthetic from Orinoco Heavy Crude**: Based on current project status and an assessment of pace of approvals, expressions of interest and current perception of political risk, a pace of development is deduced. 1,160 mb/d by 2020.
- **GTL**: Assessing the list of announced projects, versus those approved and financed and under construction. 1,200 mb/d by 2020.
- **Biofuels**: Assumed a growth rate of 5%/year. 980 mb/d by 2020.
- **Other** (from coal, shale, etc): Assumed a growth rate of 8%/year (admittedly bullish, but this arises from uncertainty of what China will do, but the assumption that if they do move ahead with coal liquefaction, they will do so aggressively. It includes SASOL in South Africa—already at 160,000 b/d, Stuart Shale in Australia, oil shale/used tires in Brazil as a starting point). 430 mb/d in 2020.

In total these could amount to a maximum of 7 million b/d by 2020 from just over 2 million b/d today (Figure 23). By 2020, it is estimated that the resources in Canada and Venezuela could contribute up to 60 per cent of total unconventional oil. However, the fastest growth rates in supply are expected to come from biofuels and GTL.

Figure 23: Total unconventional oil supply 2000-2020



Source: OIES estimates.

3.6 An Assessment of Non-OPEC Supply 2004-2020

Based on these projects and taking into account production of existing production in mature provinces we have shown below our best estimate of non-OPEC supply up until 2020. Clearly the forecast up until 2010 is going to be subject to less uncertainty than estimates beyond that time.

For simplicity we have illustrated non-OPEC supply separated into the five major play types as discussed above. The chart below highlights the impact of decline rates in mature provinces over the next 20 years. Historical data suggests that this decline is running at around 3-4 per cent per annum. The chart also highlights the growing importance of Russia to non-OPEC supply. It is interesting to note that the deepwater plays and frontier plays, whilst showing strong growth over the next few years, are still relatively insignificant compared to Russia. Unconventional oil, although currently not significant, is forecast to show the strongest growth rates over the next twenty years.

Figure 24: Forecast of Non-OPEC supply 2002-2020; Source: OIES estimates.

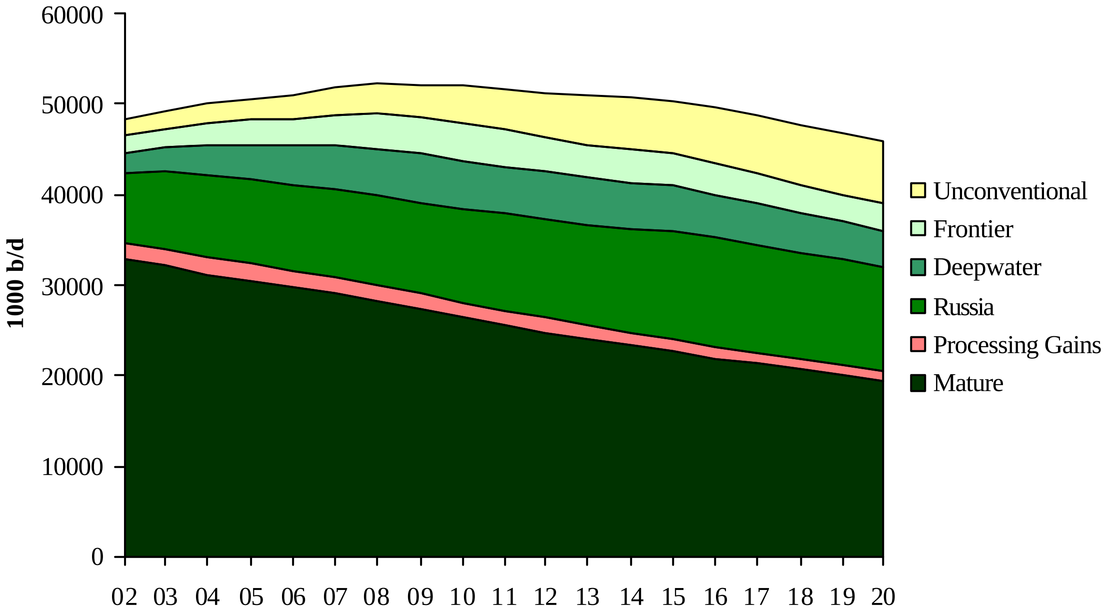


Figure 25: Major new Projects 2003-2012; Source: Petroleum Review, April 2005, OIES, and company reports.

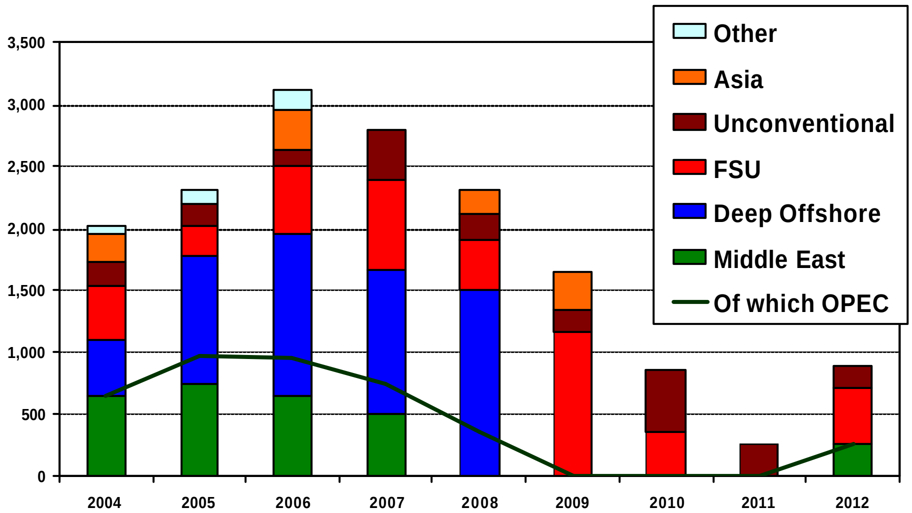


Figure 26: Forecast of Non-OPEC production 2002-2020

Oil: Production

Thousand barrels daily	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020
USA (Onshore/Alaska)	7081	6750	6345	6260	6030	5870	5790	5616	5448		
Mexico	3585	3789	3860	3850	3950	4010	4070	4070	4070		
China	3346	3396	3410	3280	3165	3054	2948	2844	2754		
Norway	3329	3260	3200	3060	2907	2762	2624	2492	2254		
Canada (Conventional)	1442	1455	1425	1352	1365	1284	1210	1134	1056		
United Kingdom	2463	2245	2100	1926	1820	1730	1620	1500	1372		
Malaysia	828	875	810	810	790	730	670	650	630		
Oman	900	823	760	740	740	740	720	706	691		
Argentina	808	793	740	777	760	760	730	700	677		
India	794	793	770	750	750	740	740	720	700		
Egypt	760	750	710	700	650	600	550	530	525		
Angola (Shallow)	690	660	663	636	611	587	563	541	519		
Australia	731	624	520	550	480	500	460	455	450		
Syria	572	594	500	560	560	560	560	550	550		
Colombia	601	564	520	450	430	410	390	350	320		
Other Europe & Eurasia	483	487	460	455	451	446	442	437	433		
Yemen	462	454	430	410	410	410	410	400	400		
Ecuador	410	427	530	590	610	590	550	545	540		
Denmark	372	368	390	367	360	340	330	300	260		
Brazil (Shallow)	750	570	540	527	513	501	488	476	464		
Rep. of Congo (Brazzaville)	259	243	230	220	217	215	210	200	195		
Gabon	295	240	240	225	200	195	195	195	195		
Thailand	191	217	190	176	172	169	166	162	159		
Brunei	210	214	210	185	185	185	185	185	185		
Other Asia Pacific	200	203	170	168	167	165	163	162	160		
Trinidad & Tobago	155	163	160	158	157	155	154	152	151		
Other S. & Cent. America	153	163	220	218	216	213	211	209	207		
Romania	127	123	122	121	119	118	117	116	115		
Italy	106	107	106	105	104	103	102	101	100		
Peru	98	92	91	90	89	88	87	87	86		
Other Africa	65	74	73	72	72	71	70	70	69		
Uzbekistan	171	166	160	150	140	130	120	110	100		
Cameroon	72	68	66	64	62	60	59	57	55		
Vietnam	354	372	400	400	380	370	360	355	350		
Tunisia	73	66	66	66	66	66	66	63	63		
Other Middle East	48	48	48	48	48	48	48	48	48		
Mature	32985	32236	31235	30517	29747	28976	28177	27288	26351	22628	19432
Growth/(Decline)	-2%	-2%	-3%	-2%	-3%	-3%	-3%	-3%	-3%	-3%	-3%
USA (Gulf of Mexico)	959	1100	1345	1540	1680	1790	1830	1867	1920	1634	1264
Angola	200	210	317	556	746	1111	1257	1380	1370	1289	946
Equatorial Guinea	237	249	310	375	380	385	390	395	400	370	330
Brazil	1020	1200	1230	1300	1390	1480	1510	1550	1600	1750	1445
Deepwater	2416	2759	3202	3771	4196	4766	4987	5192	5290	5043	3985
Growth/(Decline)	13%	14%	16%	18%	11%	14%	5%	4%	2%	-2%	-6%
Russian Federation	7620	8460	9200	9280	9600	9850	10100	10300	10538	12000	11500
Russia	7620	8460	9200	9280	9600	9850	10100	10300	10538	12000	11500
Growth/(Decline)	8%	11%	9%	1%	3%	3%	3%	2%	2%		
Azerbaijan	310	310	310	425	600	800	1000	1020	1000		
Kazakhstan	940	1030	1180	1300	1400	1450	1700	2000	1900		
FSU Others	450	470	470	470	470	470	470	470	470		
Chad	0	40	180	220	230	235	240	240	240		
Sudan	240	270	300	420	470	510	520	480	480		
Frontier	1940	2120	2440	2835	3170	3465	3930	4210	4090	3512	3016
Growth/(Decline)	29%	9%	15%	16%	12%	9%	13%	7%	-3%	-3%	
Canada (Synth + Bitumen)	741	862	1036	1182	1297	1707	1916	2021	2522	3023	3198
Venezuala (Heavy Oil)	350	500	550	580	600	630	660	690	760	960	1160
GTL	45	45	52	52	86	86	86	86	152	860	1207
Biofuel	375	400	451	473	497	522	548	575	604	771	983
Other	100	109	118	128	139	150	163	177	192	289	434
Unconventional	1611	1916	2207	2415	2618	3095	3373	3549	4230	5903	6982
Processing Gains	1730	1800	1830	1830	1782	1749	1704	1647	1594	1338	1078
TOTAL NON-OPEC	**48302**	**49290**	**50114**	**50648**	**51113**	**51901**	**52271**	**52186**	**52093**	**50425**	**45993**

** Source IEA, EIA, Deutche Bank, OIES

Figure 24 above is reasonably underpinned for the next few years since we have a good understanding of the major projects currently under development. Figure 25 is a compilation of oil production projects of a significant size (generally > 100,000 b/d), as updated and reported in Petroleum Review (April, 2005), together with a risked supply forecast from oil sands projects that include smaller projects. The category 'FSU' (Former Soviet Union) groups projects from Azerbaijan, Kazakhstan and Russia. It is important to note that the bars represent the year and the projected plateau volumes in that year for each project. These are gross volumes in the basins, thus do not reflect the decline in the underlying base production. On the other hand they do not include many small projects nor the likely response to recent higher prices. These projects will slip about—indeed, already some of the projects for 2004 are slipping into 2005 and so forth. Thus, for example, in 2006 we should not necessarily expect to see a 3 mb/d increment of supply from these projects, but we should expect to see a surge in non-OPEC supply before 2010. On the other hand, oil companies are increasingly cautious about statements of forward production, so this introduces a conservative element to these projections of plateau volumes. Finally, the tailing off of projects out beyond 2007 does not necessarily mean there will not be any. In fact there are potentially another 4 to 5 mb/d of potential projects that have not been sanctioned and announced by companies. It is too early to assess just what impact recently higher prices are having on short-term Non-OPEC deliverability from mature basins. Certainly spending has increased dramatically, and the fruits of this spending will be felt in terms of production over the next few years.

It must be stressed that the projects in Figure 25, rather than being a consequence of recently higher prices, have their roots back in the nineties, a period of <u>low</u> prices. At the time, the IOCs were not prospect constrained—but they were financially constrained. Many countries (e.g., Venezuela, Canada, UK) changed their hydrocarbon fiscal regimes to attract the international oil industry; Russia and the Caspian region opened to the IOCs (in the case of the Caspian with considerable political 'air-cover' from the United States); and new geological concepts (e.g., continental margin turbidite sands play; sub-salt play in the GOM, oil sands geology) had been developed and enabling technologies (new seismic interpretation and data manipulation technologies, deep drilling, FPSOs, Steam Assisted Gravity Drainage, long-reach horizontal wells, LWD, etc) to pursue them were deployed.

Beyond 2010 certain major assumptions have been made. In particular it has been assumed that the mature provinces will continue to decline at between 3 and 4 per cent until 2020. With respect to the deepwater projects, there seems to be a real consensus that production will peak in these provinces around 2010 before going into a potentially sharper decline. With respect to frontier areas we have only included those areas where reserves are currently under development, there is therefore some potential for further growth in this category depending upon future exploration growth. The future development of unconventional oil depends on a whole host of factors discussed in the relevant section not least the potential impact of technological breakthroughs, economic and political factors.

Based on our estimates Non-OPEC supply is likely to platform within the next decade at around 53 million b/d. This clearly has major implications with respect to the role that OPEC will have to play going forward in meeting global demand. If our estimates are correct OPEC will have to increase production to at least 40 million b/d to meet global demand of around 90 million b/d and would have to meet any further increases in demand beyond that time. The implications of this are discussed in a later section which addresses the issue of optimal price bands.

If we include our analysis of non-GCC OPEC production we can see that the call on GCC members is expected to come under slight pressure up until 2010 after which time the GCC members will have to ramp up production significantly in order to meet consensus demand estimates (Figure 27). This figure represents the residual gap shown on Figure 28 where our estimate of total non-GCC production is plotted.

Figure 27: Call on GCC countries; Source: OIES estimates.

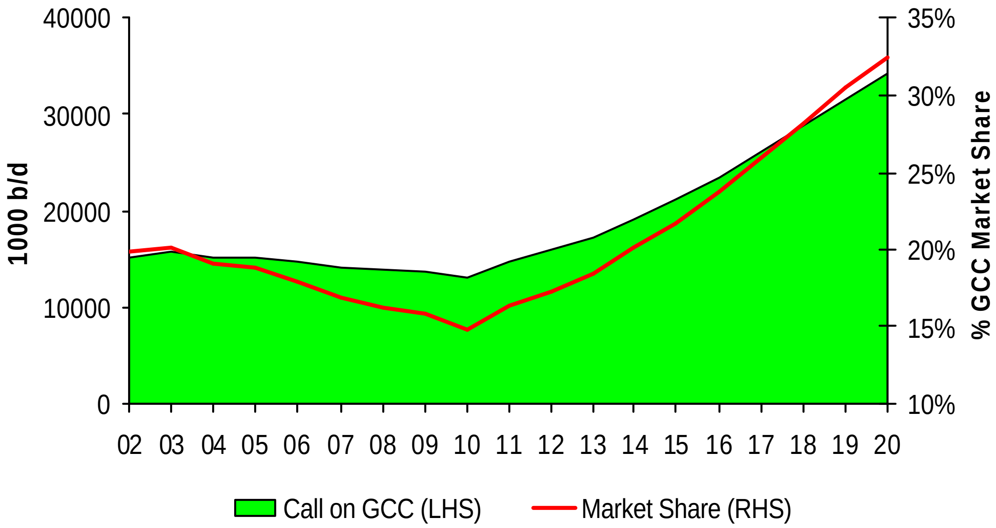
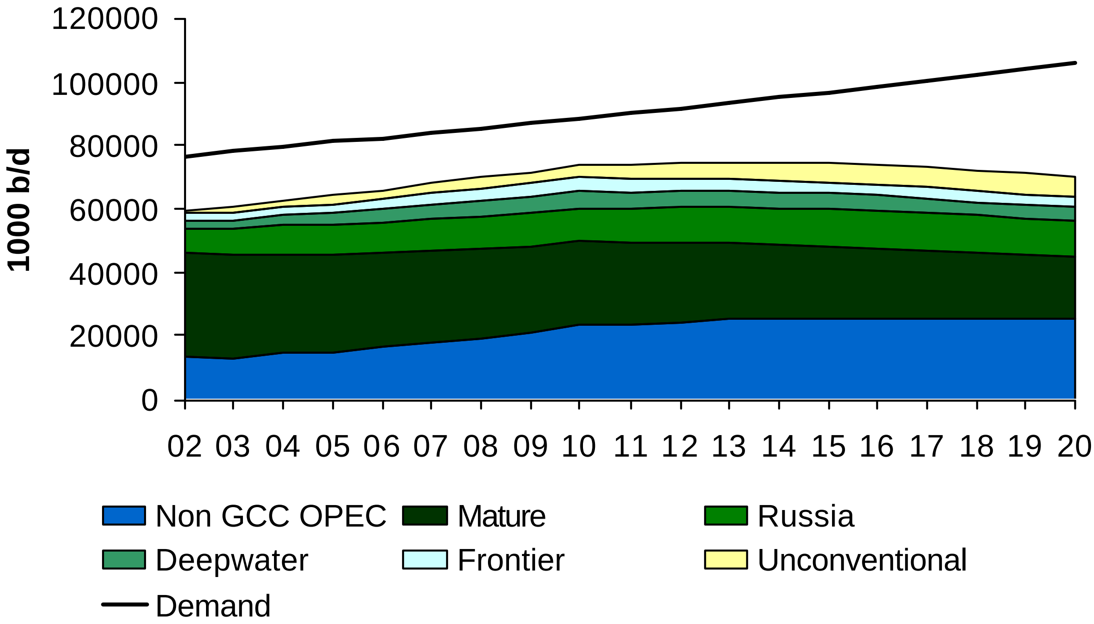


Figure 28: Total Non-GCC production and Global Oil Demand; Source: OIES estimates.



3.7 Non-OPEC Supply and Sensitivity to Price

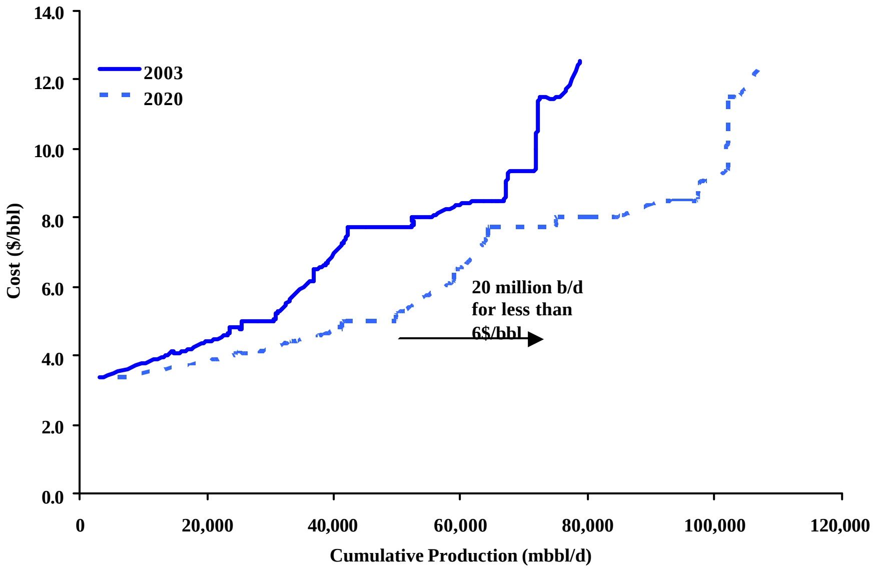
In this section we examine the cost structure of current conventional oil production on a country-by-country basis, and use knowledge from planned developments to make an assessment of the cost curve of the potential production capacity in 2020. We make a historical assessment of the evolution of the cost curve over the past ten years.

We have divided the costs into capital and operating expenses. For the purposes of this report we calculate capital costs by dividing the total investment cost (in dollars) by the total volume of barrels that are expected to be extracted from any particular field. We have ignored the exploration element of the capital costs. We have calculated the operating cost by dividing the annual running cost of extracting and processing oil production (exclusive of any taxes, royalties, or transportation) by the total number of barrels produced in any one year.

By dividing the costs into the two components it is possible to determine how low the oil price has to fall before currently producing fields become uneconomic; it is also possible to determine how the oil price might impact on new field development.

The cost curve of current and projected production capacity is shown in Figure 29. The chart plots the cumulative production by country in order of ascending costs (development and operating cost per barrel). For 2003, the curve stops just short of 80 million b/d, that being the estimate of productive capacity today. For 2020, the curve stops at 107 mb/d, that being our optimistic assessment of the potential productive capacity at that time.

Figure 29: Cost curve of production capacity in 2003 and 2020.



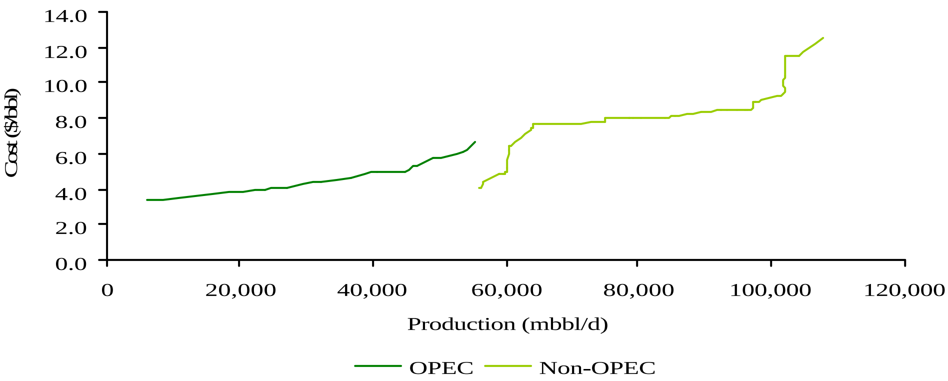
Source: OIES

The results of the analysis for 2003 show that nearly 80 per cent of conventional oil production has been developed and is operated at a cost of less than $10 per barrel. The cost of the remaining portion of production lies between $10 and $14 per barrel. What is important though is that most of this production is robust at oil prices down to $4 per barrel, that being the level at which operating costs exceed revenues. Therefore it would take very low oil prices to have any impact on current productive capacity.

Figure 30 highlights a well known and much debated oddity regarding the way the world goes about exploiting its oil resources endowment. Theory holds that the lowest cost part of the resource pyramid would be produced first. However, the supply curve for 2020 is lower than that for today, which graphically presents how theory has been turned on its head. Expansion of low cost OPEC productive capacity by 2020 extends the cumulative volume of low cost oil (sub $8 per barrel) from around 65 mb/d up to 90 mb/d.

It is interesting to note that in the United States the costs of operating and developing the deepwater offshore and some of the Lower 48 oilfields are very similar. However, although the deepwater is characterised by relatively high development costs, operating costs are forecast to be very low. This cost structure is expected in other regions of the world (such as Angola) where deepwater developments are expected to contribute to increases in productive capacity.

Figure 30: Cost structure for OPEC and Non-OPEC in 2020



Source: OIES (drawn from published material from a broad variety of sources).

In Figure 30 we show the cost structure chart for 2020, but have split the curve into OPEC and non-OPEC productive capacity. It can be seen that OPEC remains the low cost producer of conventional oil with less than 5 mb/d of lower cost capacity found in non-OPEC countries, which include Oman, Syria and Egypt. We also show the broad band of supply forecasts for conventional oil (discussed above). From Figure 29 one can see that if demand expectations were to reach 107 mb/d, then the marginal cost of production would reach around $12 per barrel. The figure also shows that if demand expectations reach the lower end of the reasonable range of forecasts, the marginal cost of new capacity could be as low as $8 per barrel. However, this all assumes that OPEC displaces non-OPEC capacity. Under a low demand scenario, which would ensue at higher oil prices, non-OPEC countries are unlikely to defer investments in infrastructure which are profitable at around $12 per barrel. As a result it is likely that increases in OPEC capacity will continue to be deferred.

Of course, all these cost curves are in essence static pictures which only incorporate current technological, political and economic circumstances. However, over the past ten years, a change in the mix of production combined with the benefits of new technology has led to a significant lowering of the cost curve in real terms. Whereas in 1991 over 50 per cent of global oil production cost in excess of $10 per barrel, today it is less than 30 per cent. In fact by 2003, over 40 per cent of global oil production was within $2 per barrel of average Middle East production costs. The perception therefore that Middle Eastern conventional oil is the cheapest might still be correct but the difference in cost with other countries in the world is narrowing.

Analysis of the historic cost curve also shows that the component parts change through time. In 1991, European countries were the highest cost producers. However, significant cost cutting efforts, particularly in the UK have moved the region down the curve. The increasing importance of West African production has meant that costs for African countries have fallen. An improvement in the efficiency of the Russian producers has lowered the average cost of production. In addition, there are whole numbers of projects due to come on stream over the next few years, particularly in the Caspian where initial cost estimates are likely to fall further.

Looking forward, the downward pressure on costs is beginning to be reversed. With increasing levels of capital expenditure as well as real pressure of companies and government to deliver growth inflationary pressures have crept back into the industry. For example finding and development costs for new discoveries have risen by over 30 per cent over the past three years alone. In addition, increasing decline rates in existing fields have driven unit operating costs higher. Add to this a general increase in commodity prices, not least steel, and the impact of new technologies is more than overcome.

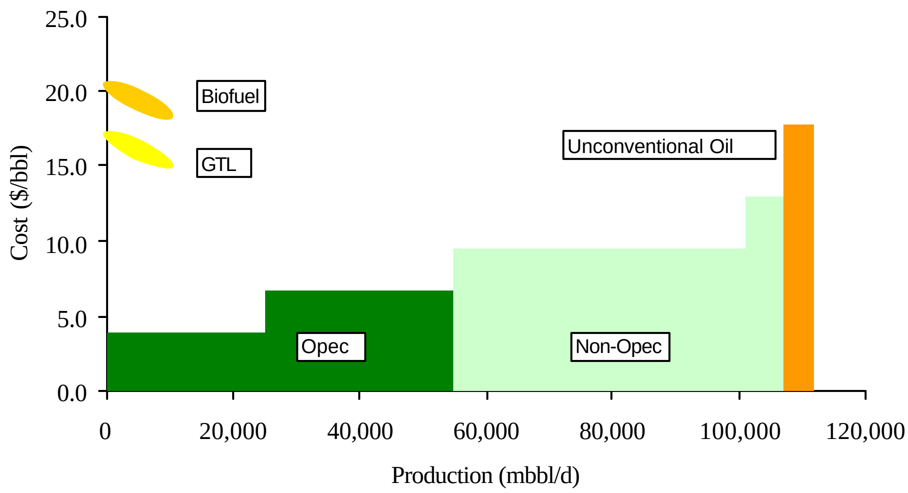
There is also a paradox between the prices required by the resource holding nations as compared to the prices required for private oil companies to meet the requirements of their shareholders. Private oil companies have historically published the minimum oil price that they would require to invest in new capacity, in order to achieve their targeted returns. For resource holding nations the oil price required is usually the price required to balance national budgets even though this may bear no relation to the targets set by individual national oil companies, both to sustain and increase capacity. Even though OPEC countries or national oil companies are the lowest cost producers, the oil price band required of these producers to meet State budgetary goals is higher than the prices required by private oil companies to invest in new capacity to meet shareholder expectations of return on capital. Therefore private oil companies that mainly operate in non-OPEC countries are more likely to invest in new capacity than OPEC countries themselves.

In summary, the oil market does not behave as a perfectly competitive market would; oil prices are much higher than the marginal cost of production. Cost structures vary substantially from the lows of the Arabian Gulf to the high cost new developments in the Caspian, and are even higher for unconventional oil sources such as tar sands or extra heavy crude oil. However, the fact that oil prices are much higher than the marginal cost of production means that investment in higher cost non-OPEC oil could continue to confound OPEC in its calculation of just how much investment they should/need to put into increasing capacity .

3.8 Overview of the Cost Structure of Non-OPEC Oil Supply

In this section we summarise the various price levels at which the different forms of energy discussed above are able to enter the market. The striking feature of the cost comparison in Figure 31 is the fact that nearly all sources of non-OPEC oil including unconventional oil, can be brought on stream at a cost of less than $25 per barrel. Therefore with the current oil price of around $50 per barrel, the forward curve to around 2020 of around $30 to $35 per barrel and with the targeted OPEC price band of between $22 and $28 per barrel, now looking increasingly likely to be shifted upwards, the outlook for supply based on cost alone is quite positive. The real issue though at this point in time is whether investment in the oil sector will be sufficient and timely enough should demand continue to be robust.

Figure 31: Cost comparison of global energy sources million tonnes oil equivalent



Source: OIES, based on numerous public sources.

4. Optimal Oil Price Bands

The results in the preceding sections of this report would seem to substantiate the commonly held view that oil production from the GCC is set to increase in importance over the next 20 years. However, the rate at which GCC production increases will be affected by increases (or declines) in non-Gulf and unconventional oil production, which in turn will be affected by a number of factors including and especially price.

This section addresses the question posed in Subtask 1.3, 'what is the optimal price band for crude oil prices?' The theoretical objective of optimality is almost impossible to achieve or even define in practice. Qualitatively, at least, it is that price at which economic growth continues while ensuring that investment in new oil production capacity takes place. The notion of 'optimality' implies a set of conditions where oil prices, their variability and direction would not impair economic development, and if 'optimality' is to reflect equity concerns, for *all* countries. This highly simplistic and hopeful characterization does not explicitly acknowledge the spatial and temporal nature of optimality—what might have been optimal in 1975 or 1995 for different consumers and different producers would not be optimal today. It ignores the different sensitivities of different economies to the price of oil as well as the current structure of the oil supply sector and its extremely broad range of costs of supplying oil. This subject could form the basis for a report on its own therefore this section only touches on some of the key questions, starting with the definition of the broadest price band, bound at its upper limit by a price level where incremental demand would surely and fairly quickly be negatively affected and a lower limit where supply would certainly be shut in.

The definition of the upper boundary can be estimated from studies of the price elasticity of demand for crude oil. There is an extensive literature on the subject of the impact of oil prices on economic growth. Increases in oil prices have been blamed for recessions, inflation, falls in productivity and lower economic growth. Some contrarians have postulated that, to a point, higher prices are good for overall economic growth. More serious theoretical analyses reveal a very complex and uncertain picture. Oil is less of a factor in the OECD economies than it was in 1973. More of it is in transport, where for reasons including taxation, hedonic values attached to personal mobility, and structural and other barriers to intermodal shifts in transportation, demand elasticity is lower. But the price of oil affects other commodity prices, not the least of which is natural gas. As gas continues to be the fuel of choice in power generation, and since electricity is essential to a modern economy, oil-linked gas prices will flow through to industry and other consumers. So, higher, sustained oil prices would eventually take their toll on economic growth. This is the conclusion of recent reports by intergovernmental agencies such as the IMF and the OECD/IEA (See Analysis of the Impact of High Oil Prices on the Global Economy, IEA, May, 2004; available on the IEA website). Their analyses in May, 2004, at the beginning of the current run-up in prices concluded the following:

- As in the past, the net effect on the global economy of higher prices would be negative. Producer gains would be more than offset by consumer losses.
- Depending on what producers do with the extra revenues (import goods and services or pay down debt and rebuild reserves), the effects would be less or more severe respectively.
- Impacts on trade deficits and budgets could put pressure on interest rates and therefore prompt tighter monetary policy responses.
- Exchange rates would be affected, leading to for example a rise in the US dollar, impairing certain developing countries' capacity to service dollar denominated debt and adding to current account imbalances, particularly in countries where prices of oil products do not reflect their costs.

In early 2005, the IMP 'fire-tested' its global economic outlook with $80 oil prices and concluded that even at this level the impact would not be disastrous. At the time of writing, some of these effects are beginning to appear. For example, the peak gasoline demand in the US during summer 2004 was less than the peaks of 2003 and 2002, suggesting a dampening effect of higher prices. This is confounded, however, by the fact that diesel demand, a better indicator of economic growth, has not been significantly less than a year ago, reflecting the continued movement of goods and merchandise to consumers. So, American consumption generally has not yet been seriously affected. The Federal Reserve Chairman, Alan Greenspan, acknowledges this lack of economic impact, although as usual with caution. What is confounding the whole analysis is the drop in the US dollar, reflecting fiscal imbalances in the United States, themselves a dark cloud on the global economic horizon. At what point oil price effects will start to take prominence over those imbalances in affecting the dollar remains an open question. Meanwhile, as for developing countries such as India and China, oil demand is continuing to expand albeit at a slower rate than last year. These and other developing countries are flowing through crude price increases to the final consumer.

Analyses of price effects on inflation and therefore policy responses and their knock-on macroeconomic effects confirm that this subject is a 'moving feast'. Oil does make up a smaller share of the consumer basket in OECD countries. Some research indicates that there was a shift in the impact around 1980; pre-1980 oil price increases fed directly through to the core CPI, whereas since then their direct impact has been negligible. This research conducted in 1999[11] looked at prices and inflation up to the current rise in prices and should therefore be re-examined. The literature on the effects of oil price shocks contains a diverse range of conclusions, all the

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[11] Mark A. Hooker, December 1999, "Are Oil Shocks Inflationary? Asymmetric and Nonlinear Specifications versus Changes in Regime." Federal Reserve Board paper.

way from (to paraphrase) ‘they have no significant macroeconomic effects’; ‘increases matter but decreases do not’; ‘price increases matter if they are large relative to what we have been used to’; and ‘increases matter depending on their magnitude within their current degree of variability’.[12] Some research suggests that the impact on the economy of price increases during the seventies were compounded by monetary policy responses, but this has been less the case since 1980. That prices have generally fallen between 1980 and 1999 invites a renewed analysis of this question as more data come available in the months ahead.

From today’s price level for oil of around $50 per barrel, it would seem that ‘extreme’ price levels—in other words, a true ‘price shock’—would be required before world economic growth would fall abruptly. Such extreme levels would seem to be above the current levels, but this tempting conclusion must be cautioned by the qualification that it is ‘too early to tell’. This caution is even more warranted, as indicated above, given the recent devaluation of the dollar.

The definition of the lower boundary can be estimated by looking at the operating cost of existing global production. Such analysis highlights the price level at which existing production would be shut-in as uneconomic. It is clear from such analysis that over 87 per cent of crude production today would still be economic at oil prices down to around $8 per barrel. In other words, it would take a complete collapse in oil prices to that level (and stay there for several months) before companies would start to close in production although they would certainly start to feel pain well before those basement levels were reached. Such a floor price is of course merely theoretical since no sooner would it be reached when reduced supply would be registered in firming prices, so it would be short-lived. More important is the price level at which new capacity will generate sufficient economic return to justify investment.

Initial results of the analysis for 2020, which we carried out at the beginning of this programme (late 2003), potential production capacity showed that nearly 80 per cent of conventional oil production, up to 104 million barrels per day, could be developed and operated at a cost of less than $8 per barrel, with OPEC remaining the lowest cost producer. More recent data suggests that, given the rise in steel prices and other inputs associated with the finding, development and production of oil, this marginal cost would have risen, perhaps to $12 - $14/bbl. Therefore the ‘price band’ has limits somewhere above $50/bbl and not much below $14/bbl and certainly not below $8/bbl.

In a free market, where there is no constraint on production capacity, it would be natural for prices to fall to the marginal cost of production, which in a low demand case would be around $8 per barrel. However, the fact that the actual oil price has traded within a band of $18 - $26 per barrel for over 80 per cent of the past decade demonstrates the market power of OPEC.

[12] See Hooker, ibid.

This has a number of important implications with respect to non-OPEC production. Under normal economic conditions one would expect the lowest cost production to be brought on stream first. However, it is clear that whilst oil prices remain well above the marginal cost of non-OPEC supply, then non-OPEC capacity will continue to displace OPEC capacity. This will continue to occur so long as OPEC maintains a tight control over supply and so long as adequate non-OPEC reserves are available to increase non-OPEC capacity, which has been the case for the past 30 years, but as suggested in previous chapters of this report, is becoming increasingly difficult to sustain.

In the light of these observations, is there an optimal price band which will guarantee energy security? Without returning to the quagmire of what is 'energy security', and debating whether 'guaranteed energy security' is an absurdity, from a simple top down point of view one could argue that the minimum price that will reasonably assure an economic supply of crude might be as low as $8 per barrel. However this does not take into account the requirements of shareholders of private oil companies or the requirement of the national governments of the resource owners. This is well illustrated in some initial work that we have carried out that examines the oil price required by private oil companies for projects to receive investment approval and the oil price required by national governments in order to receive the same revenue per capita in 2010 as they did in 2003. Our research suggests that the oil price required by the private oil companies and national governments is on average some $10 - $12 per barrel higher than actual development costs required for projects to break even. More interesting is the fact that the price required by private oil companies is lower than the price required by national governments even though they might be involved in more expensive and technically more difficult developments.

Although this work is only in its preliminary stage, it does point to the fact that there is no optimum price band and moreover certainly not one that will guarantee security of supply. To date our analysis and that of others underway (Mitchell and Marcel, Chatham House) suggests that a minimum oil price of $25 is sufficient to secure investment in new supplies, but even at this level pressure would likely be put on the budgets of some national governments. Moreover, as noted above, if steel and other commodity prices key to oil developments continue to rise, this price threshold will do likewise. In the final analysis, such a minimum price level is only sustainable so long as OPEC maintains internal cohesion and discipline to adjust its output to sustain price above this level, in full knowledge that there are sufficient non-OPEC conventional and unconventional oil reserves available in the near term to put downward pressure on prices.

An in depth analysis of patterns of investment in the oil industry to ascertain whether recent oil price strength has accelerated non-OPEC oil projects is beyond the scope of this report. In general, however, it might be said that some initial work suggests that the rate of IOC reserve additions and oil supply output has been less than the rate of growth of overall world demand. The statistics highlight the constrained world in which the private oil companies continue to operate. At the end of 1991, the oil and gas reserves of the top 20 private oil companies totalled 50 billion and 33 billion boe respectively. By the end of 2003, just 11 companies survived from mergers and acquisitions amongst the same group having oil and gas reserves totalling 57 and 40 billion boe respectively. In other words, throughout the whole of the 1990s reserves growth for oil was just 1.3 per cent per annum and 1.9 per cent for gas.

The story with respect to production growth is even less impressive. At the end of 1991, oil and gas production of the top 20 private oil companies totalled 11.8 and 6.2 million boe/d respectively. By the end of 2003, oil and gas production was 12.6 and 7.7 million boe/d respectively giving an annual growth rate for oil production of just 0.6 per cent and 2.0 per cent for gas production. Even with the cost-cutting measures the annual growth in net income has been just 1.9 per cent since 1991.

We also intend to examine OPEC, and in particular GCC, investment in the oil industry to examine whether it has been affected by oil price strength. This study would take into account regional economics and will also take into account the existing differences between Gulf countries with respect to openness to foreign direct investment and the participation of international oil companies in the upstream. On a more theoretical level, attempts have been made in the past to model the strategies of OPEC countries where models are informed by various assumptions that are proxies for behaviour and take into account the extremely varied nature of members in terms of reserves, production, dependence on oil exports, oil/gas ratios, costs, political structure and decision-making processes, status and structure of the industry and so forth. Such a modelling exercise is beyond the scope of this study. The reader is referred to, for example, recent work by Dermot Gately of the Economics Department of New York University, who has attempted to model 'behaviour' of different OPEC countries. (See for example, Gately, 2003; "OPEC's Incentives for Faster Growth", in Energy Journal). Such theoretical work often arrives at the conclusion, although generally stated more elegantly, that countries will tend to 'follow the money'.

In summary, given the challenges of formulating just what is meant by 'energy security' as discussed in this report, our conclusion is that there is no prescriptive or optimal oil price band that will guarantee long term security of supply of energy. We have identified that the broad range of prices where projects are economic but which do not adversely affect demand is between $8 and $50 per barrel. We have also shown that an oil price in excess of $20 per barrel is required for companies and governments to justify investments to shareholders and to balance budgets respectively. However, prices required by companies and governments are a moving target, compounded by shifts in the exchange rate of the U.S. dollar. In the case of private oil companies, cost-cutting and new technology could reduce the minimum prices required. In the case of governments, they would have to diversify their economies and critically examine their budgets. We do not subscribe to the view—if only because it escapes precision—that oil prices need to be sufficiently high and implicitly that some international mechanism should be contrived to ensure they are, for GCC members to 'bear the burden of the massive investment required to satisfy global demand'. It is clear that in the case of the GCC, an oil price of just $8 per barrel would be sufficient in theory to justify investment and raise finance, but for most countries it would fall well short in practice of meeting their budgetary requirements. Thus any discussion of the optimal price band must shift to an analysis of micro and macro-economic policies of the countries concerned, which is beyond the scope of this study. Instead, we have provided what we consider to be a reasonable international framework within which to discuss the prospects for oil developments in the GCC countries, for it is mostly on petroleum that they must build and eventually diversify their economies.

Finally it must be accepted that finding and defining a price band is not only elusive, it is inherently dynamic as reflected in the current (early 2005) debate regarding the need for OPEC to define a new price band, when they should do so, and what should be its boundaries. Even if and when they do, as soon as the oil price shows signs of resting at or around either the upper or lower zones of the new band, the dynamics of the market and its various agents would begin to put new pressures on the price, again begging the question of where to put the boundaries. This is the world of market uncertainty within which all players, both private and public, must make a set of calculations, judgements and decisions in allocating capital. This reality of uncertainty will always pertain, hopefully reduced with increased transparency on supply and demand data. An alternative world in which governments of all oil producing countries change their laws and effectively subordinate their sovereignty over resource development to some central, global oil supply 'utility' where investments in new supply are ranked according to a merit order and output is centrally managed and dispatched accordingly, remains a dream (or nightmare) world. This brings us to the conclusion that continued dialogue and mutual understanding of interests among producers and consumers, such as is offered by the IEF, is the only path forward to creating the political and economic conditions defining the bilateral context between the EU and the GCC, which in turn can bolster the feeling of supply security for the EU and provide the comfort of certainty of demand for the GCC.